PUGET SOUND ENERGY

2000-2001 Gas and Electric Least Cost Plan

December 1999

PREFACE

The purpose of this document is to satisfy state requirements regarding Least Cost Planning as described in WAC 480-100-251 and WAC 480-90-191. The Least Cost Plan was developed in consultation with Commission staff and with public input. This is Puget Sound Energy's first Least Cost Plan since the merger of Washington Natural Gas and Puget Power and Light.

Least cost planning is a never-ending process at PSE. Employees throughout the company continually examine and analyze, new procedures, approaches and technologies. This document is a snapshot of how the company plans in an ever-changing world. The plan is organized into nine chapters:

Chapter I - Introduction and Overview
This chapter describes PSE's approach to least cost planning (including guiding principles), provides an overview of recent industry developments affecting least cost planning and summarizes some of the conclusions reached by PSE through this planning process. The introduction concludes with a table that indexes specific WAC requirements to chapter locations where those topics are discussed.

Chapter II - Energy Demand Forecasting
This chapter covers demand forecasting, including discussion of modeling and assumptions. Chapter II also includes discussion of the demand scenarios that have been used in the integrated resource modeling.

Chapter III - Demand Side Management
This chapter discusses the company's approach to conservation and demand side management programs. New approaches are discussed and the company's current three year conservation program, approved by the Commission in March 1999, is presented.

Chapters IV - Energy Supply - Electric
This chapter reviews the company's electric supply portfolio and presents an assessment of electric energy supply issues and alternatives.

Chapters IV - Energy Supply - Natural Gas
This chapter reviews the company's gas supply portfolio and presents an assessment of gas energy supply issues and alternatives.

Chapter VI - Integrated Resource Modeling
This chapter provides an integrated analysis of energy demand and energy supply through use of the Aurora and Uplan-G models. Modeling results and conclusions are presented.

Chapter VII - Distribution System Facilities Planning
This chapter provides an overview of PSE's distribution planning process.

Chapter VIII - Public Involvement
This chapter summarizes PSE's public involvement efforts as part of the least cost planning process.

Chapter IX - Two Year Action Plan
This chapter presents a series actions company plans to take over the next two years as in implementing the least cost plan described in this document. Also included is a progress report on the action plans from the companies previous gas and electric least cost pans.

PUGET SOUND ENERGY SERVICE TERRITORY

(orange)	Combined electric and natural gas service
(yellow)	Electric service
(green)	Natural gas service

Puget Sound Energy is Washington state's largest energy utility, providing electric and natural gas service to more than 1.2 million customers, primarily in Washington state's Puget Sound region.

Puget Sound Energy's service territories:

Electric Service: Island, Jefferson, parts of King (not Seattle), Kitsap, Kittitas, Pierce (not Tacoma), Thurston, Skagit and Whatcom counties. (Public utility districts also serve parts of some counties.)

Natural Gas Service: King, Lewis, Pierce, Snohomish, Thurston and parts of Kittitas counties.

*limited areas of natural gas availability

PSE PUGET SOUND ENERGY

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I. INTRODUCTION & OVERVIEW

A. Introduction

This document is Puget Sound Energy's 2000-2001 gas and electric least-cost plan, prepared to comply with the requirements developed by the Washington Utilities and Transportation Commission under WAC 480-100-251 and WAC 480-90-191.

Puget Sound Energy (PSE) was formed in 1997 under the merger of the electric utility, Puget Sound Power and Light, with the gas utility, Washington Natural Gas. The company's combined utility service territory covers approximately 6,000 square miles. In this area, PSE serves over 900,000 electric customers and 560,000 gas customers, primarily in western Washington state. About 290,00 of these customers receive both electric and gas service from the company.

This is PSE's first combined gas and electric least-cost plan (LCP). This plan begins with an overview of the principles that guide PSE's least cost-planning process.

B. Overview of PSE's Least Cost Planning Principles

Purpose of This Document: PSE's LCP meets the requirements of WAC 480-90-191 and WAC 480-100-251.

The purpose of this gas and electric least cost plan is to fulfill the requirements of WAC 480-100-251 (the electric "least cost planning" rule) and WAC 480-90-191 (the gas "least cost planning" rule). PSE presents a plan that not only meets the technical requirements of these rules, but which is relevant in a changing industry. As such, this plan seeks to reflect the actual choices and alternatives facing the company in meeting its duties and obligations. PSE believes a least-cost plan developed in this context proves most useful to the WUTC, our customers, other interested parties and the company itself.

PSE's plan is a "snapshot" in time of its planning efforts.

The company's planning processes are ongoing, continual efforts. As new data, issues and opportunities arise, plans will often change in order to best meet the interests of the Company and its customers. All elements of the least-cost plan change over time; for example, every year PSE updates its demand forecast, and new supplies of energy are secured to replace expiring contracts, all within the context of an ever-changing wholesale marketplace. This plan represents the company's assessment of the future in 1999. Flexibility to adjust and adapt to changing circumstances, opportunities and challenges is essential.

PSE focuses on means to appropriately address uncertainty, rather than on prescriptive long-term planning.

Uncertainty and change have become pervasive in today's planning environment. It is better to find ways, on an ongoing, dynamic basis, to meet the challenges and opportunities that arise, than to remove important options through prescriptive efforts and an over-reliance on forecasts of uncertain variables. Investigating sets of optional courses of action can have great benefits to customers and the company alike.

A wide range of scenarios is considered. These scenarios are important in the development of planning options.

As contemplated by the least-cost planning rules, scenario analysis can be a useful tool for structured consideration of potential choices in an uncertain environment. As in prior least-cost plans, the company will continue to use this technique. The various scenarios illustrate the uncertainty that the company faces in the future, with an understanding that a scenario may actually occur that is not captured by the plan. Accordingly, given the current environment, the range of scenarios is quite wide, particularly as issues surrounding open access and retail choice have not been resolved in the State of Washington. Consideration of scenarios provides useful information for development of the company's planning options.

Focus on the value of flexibility so that beneficial opportunities can be captured, and risks can be appropriately addressed, at the time they appear.

Flexibility has great value in an uncertain and changing environment. While this value may not always be quantifiable, flexibility is an essential element of any least-cost plan developed in an uncertain industry environment. Conversely, removal of flexibility can create future risks for customers as long-term commitments can reduce the ability for customers to benefit from new opportunities and developing markets.

The company's plan focuses on taking advantage of the resource supply options provided by competitive wholesale energy markets.

Since the least-cost planning rules were originally established in the mid-1980's, many structural changes have been occurring in wholesale energy supply markets, particularly the opening of these markets to increased competition. Prior to these changes, various estimation procedures were often used to attempt to assess the range of potential costs of hypothetical resource alternatives. Now that wholesale markets have been opened to competition, the advantages of market-based resource options and alternatives over more traditional resource options should be recognized. It is very important to note, however, that any long-term projections of market prices are, by their nature, speculative, and should be considered in that light.

PSE's "public involvement strategy," as required by WAC 480-100-251 has been, and will continue to be, PSE's use of its Technical Advisory Group.

PSE's Technical Advisory Group has provided the company alternative perspectives and constructive input regarding its least-cost planning process. Since merger of Washington Natural Gas and Puget Sound Power and Light, fifteen TAG meetings have been held, covering a number of subjects including conservation planning, energy supply planning, distribution planning, economics and load forecasting, legislative issues and regulatory issues. PSE uses the Technical Advisory Group process as a key means to engage constructively in a "public involvement strategy" that informs customers, the public and interested parties about the company's planning processes. PSE will, of course, also consider information that becomes available from other sources regarding the interests of its customers and other stakeholders as part of its planning processes. While the public involvement process can provide constructive and useful input to the company, the company's plans represent the company's own assumptions, analysis and conclusions.

C. Overview of Changes in Energy Supply Markets

As stated in the principles above, PSE seeks to make this least cost plan relevant to current and currently projected future industry conditions. In doing so, it is important to recognize the developments that have taken place over the years since the least cost planning rules were developed and earlier plans were submitted. These industry conditions are discussed more fully in Chapters 4 and 5, electric and gas resource supply, respectively.

A utility's obligation to serve its customers has traditionally been the fundamental basis of electric and gas utility planning. This obligation requires utilities to make long-term investments in energy supply resources as well as in transmission capacity and distribution facilities with an understanding that all of the utilities' costs would be recovered over the lives of those assets and commitments. Under traditional cost of service regulation, utilities were willing to make long-term resource commitments as this regulatory scheme provided for necessary recovery of all those investments and expenditures.

The utility obligation to serve has also come to serve as a conduit to advance federal and state public policy objectives, such as energy conservation programs, services directed toward low-income customers, and mandated acquisition of Qualifying Facilities under the Public Utility Regulatory Policies Act (PURPA), among others. As elsewhere, the electric and gas least-cost planning rules were developed within this context in the State of Washington. Plans have been prepared and filed with the Commission by regulated utilities, including PSE, and these plans, in turn, have guided the associated resource acquisition decisions.

At the time the gas and electric least-cost planning processes were introduced in this state in 1987, today's competitive wholesale electricity markets did not exist and wholesale gas markets were just beginning to develop. Utility least-cost planning processes, conducted through "collaborative" efforts, served as the primary mechanism by which resource development decisions were considered and analyzed.

An important piece of this process was development of the electric utility's long term Avoided Cost in compliance with PURPA. The costs of various resource alternatives were based upon estimation procedures, subject to inaccuracies inherent in such a process. Avoided Costs were estimated through analytical processes that compared potential or hypothetical resource alternatives.

In the past two decades, the gas and electric utility industries have undergone fundamental changes nationwide. The transformation of the natural gas industry began first. Prior to 1978, the FERC regulated wholesale gas prices that producers charged to interstate pipeline companies, which then sold gas to local distribution companies ("LDCs") at FERC regulated rates. Phased-in deregulation of natural gas well-head prices began with passage of the Natural Gas Policy Act in 1978. In 1984, the FERC issued Order 436, which spawned the development of regional spot markets for natural gas. During this time, interstate pipelines still sold fully bundled gas service to LDCs at FERC regulated rates, but those services began competing with spot market sales where pipelines simply transported the gas supplies. Since implementation of measures required under FERC Order 636, issued in 1993, interstate pipelines only serve to transport gas owned by others. Today, LDCs acquire and manage their own portfolios of supply and delivery resources in order to provide reliable cost-efficient bundled service to their core (predominantly residential and commercial) customers. In many jurisdictions, large commercial and industrial customers are free to acquire their own resources and rely on the LDC only for local delivery service. Both LDCs and large industrial loads rely on mature, active, liquid and transparent wholesale energy and capacity markets.

The electric industry restructuring process started later and, like the gas industry, is still progressing. Through the 1992 Energy Policy Act and FERC Orders 888 and 889 of 1997, the federal government has restructured the framework within which the wholesale electric supply markets now operate. Paralleling natural gas transmission, electric transmission operators must now provide non-discriminatory access to transport the wholesale energy of others. As a result of state-by-state adoption of retail open access schemes, many vertically integrated electric companies have sold or spun-off their generating assets, creating a new breed of electric production companies, not unlike the gas producers and aggregators of today. This restructuring, in combination with advancements in generation technology and increasing use of natural gas as fuel for generation, have all contributed to the establishment of competitive wholesale electricity markets. It is expected that natural gas prices will have a increased impact on electric markets as convergence of these markets continues. These wholesale markets are expected to continue to grow, not only in number of transactions but in the depth of the resources they trade.

Electric utilities in many jurisdictions have been required by legislation or regulatory action to unbundle their supply and delivery functions and provide retail open access for many, if not all, customer classes. What is most unclear is to what level, if any, retail open access will occur in Washington State. Large industrial customers, who expect to be the primary beneficiaries, have typically been driving the push for open access at the local level. Many industry observers expect that, as in the gas industry, there may be little interest in open access among residential and commercial customers in the near term in Washington State. Additionally, some do not expect that these customers will benefit from open access due to a number of factors including: 1) certain projections (though speculative over the long term) showing electric wholesale prices rising over the long term due to rising gas prices; and, 2) a concern that the Northwest could lose some of the regional advantages it currently enjoys, including the benefits of low-cost hydropower, under certain open access scenarios. However, federal or state legislation may mandate unbundling down to the residential level. To date, policymakers in the State of Washington have not resolved this critical issue.

D. Range of Outlooks Considered in the Least Cost Plan

In consideration of these current industry conditions and the uncertainties facing PSE and its customers, this least-cost plan provides a structured means to address the range of uncertainty of potential futures the company might face given that many issues associated with the eventual state of the gas and electric industries in the State of Washington have not been resolved. For instance, movement toward open retail access is uncertain at this time, while, throughout the nation many states have dealt with this issue. Below follows a summary of the scenarios developed by the company to address major uncertainties through a structured approach.

Electric Scenarios

This Least Cost Plan includes a variety of planning scenarios to address uncertainty regarding the loads it will plan to serve in the future. These scenarios demonstrate the level of uncertainty the company faces and drive resource strategies discussed throughout the plan. The following briefly summarizes the nine scenarios examined in this Plan. These scenarios fall into three broad categories.

Fully bundled service scenarios:

Three scenarios assume PSE retains all its customers, continues to provide fully bundled electric service to all customers. That is, no open access occurs over the next 20 years in PSE's service territory. These scenarios are labeled "Low", "Medium" and "High" reflecting different levels of load growth due, primarily, to economic and demographic variability.

Open access scenarios:

Three scenarios assume that open access becomes available for various numbers of PSE's customers. These scenarios are labeled "Access A," "Access B" and "5% Attrition" and each make different assumptions regarding the progression of open access in PSE's service area.

Distributed generation scenarios:

Three scenarios assume various levels of installation of distributed generation in PSE's service area. These scenarios are labeled "D.G.," "D.G. 10%" and "D.G. High" reflecting different levels of adoption of distributed generation.

Gas price sensitivities:

The cost of gas is an important determinant for the electricity market, as the marginal electric unit is generated from a combined cycle gas turbine. Three different projections of gas prices are used to test sensitivity of incremental electric supply costs to gas prices.

Gas Scenarios

Fewer gas scenarios were considered than electric scenarios. As discussed above, natural gas is further along in terms of market restructuring than electricity. The nature of the uncertainty the company faces in its gas business is, at this time, different from that of the electric business. Additionally, PSE's natural gas portfolio has a significant level of flexibility, comprised as it is of numerous supply and capacity contracts with staggered renewal dates. The gas scenarios examined three economic and demographic sensitivities: high, medium, and low load growth.

E. Summary of Conclusions

The least cost plan considers the implications of these scenarios in development of a series of conclusions regarding the company's current gas and electric resource supply strategies. While current conditions are discussed in more detail in Chapters 4 and 5, and the results of modeling are discussed in Chapter 6, a number of key conclusions become clear through the planning process. As broad principle, PSE will structure its gas and electric supply portfolios so that they are consistent with the term, pricing, quality and other attributes of its supply commitments to customers.

Gas Supply Strategies

PSE will continue to utilize competitive market forces in the gas supply market to maximize benefits for our customers. PSE has developed, and will continue to develop, a portfolio of gas supply resources that are consistent with customer supply commitments and pricing provisions. PSE' gas portfolio contains a mixture of short-term and long-term contracts. Much of PSE's winter gas supplies are contracted on a seasonal basis. This provides year-to-year flexibility to optimize use of the most favorable supply basin. Contracting on a shorter-term basis can also allow an opportunity to incorporate new and innovative contracting terms as they develop in the market. PSE also utilizes some existing long term supply contracts, all of which expire by 2005. PSE's gas supply portfolio is well positioned for future demand uncertainty because contracts are priced at market and can be sold in the unlikely event that contracted supply exceeds demand. PSE's long-term contracts benefit in other ways from the competitive market. Beyond simple commodity market pricing provisions, PSE's long-term contracts contain annual re-negotiation provisions, which allow the Company to negotiate other aspects of the contract to reflect changes in the market. PSE will continue to utilize the dynamic, competitive forces in the Pacific Northwest gas supply market to benefit our customers.

Current projections suggest that additional capacity to deliver gas to PSE's distribution system will not be needed for at least 4 years, under the most liberal growth scenario. This is primarily due to additional, cost effective transportation capacity acquired in association with the recently completed expansion of the Jackson Prairie storage facility, near Chehalis, WA. To meet the needs of our firm customers on a longer term basis, PSE will continue to seek opportunities for strategic, cost effective supply and capacity resource options that match customer expected customers supply commitments.

Electric Supply Strategies

It is important to recognize how electric energy markets are evolving as compared, and contrasted, to natural gas markets. While there are commonalties in the opening of gas and electric wholesale markets to competition, the structures of two industries have different histories. In natural gas markets, LDCs in most jurisdictions have not owned and operated natural gas wells, which are the supply counterparts of electric generators in electric markets. Firms that specialize in natural gas production have developed to capture upstream economies of scale and scope. Gas production firms are large (usually multinational) and optimize operations across several related petroleum markets including oil and propane. LDCs like PSE are better positioned to specialize as buyers in the competitive market place, reaping benefits of competition among firms specializing in gas production. Considering that PSE presently purchases approximately 65% of the power in its electric supply portfolio and the industry conditions discussed in this plan, PSE believes it is best positioned to meet its customer's electrical energy needs by focusing on being an effective buyer as competitive electric markets continue to evolve, and by relying less on owning and operating new generation resources.

PSE will continue to seek to structure its gas and electric supply portfolios so that they are aligned consistently with the various attributes of its expected supply commitments to customers, including term, pricing, quality and other attributes. These customer supply commitments to customers, of course, evolve within the context of national, regional, and state energy policies. As described above, such policies in the gas and electric industries have different histories, and, while becoming similar in important ways, still are markedly dissimilar in the State of Washington at this time. Correspondingly, PSE's gas and electric resource portfolios have evolved differently. PSE's gas supply portfolio has been structured to be responsive to PSE's supply commitments to its gas customers within the context of the PGA and PGA incentive pricing structures and a gas industry structure set forth by federal and state policy. These issues of pricing structure and industry structure, while resolved for now for PSE's gas business, are enormously more uncertain for PSE's electric business. For instance, the scenarios in this plan demonstrate dramatically the degree of uncertainty faced regarding the term of customer supply commitments going forward due to the possibility of retail open access occurring at some time over the planning horizon. Further uncertainty is added to the planning process when addressing issues of electric supply pricing to customers.

In the absence of resolution of these issues, PSE must manage its electric supply portfolio to be responsive to its customer supply commitments as they are expected at the current time, recognizing fundamental uncertainties. This uncertainty drives a need for additional flexibility in PSE's electric supply portfolio. A noteworthy contrast between PSE's gas and electric supply portfolios is flexibility. The natural gas discussion above provides an overview of the flexibility inherent in PSE gas portfolio. This flexibility allows PSE to take advantage of rapidly evolving market opportunities, which carries over into long-term contracts. Shorter duration contracts also provide a hedge against uncertain future retail market structures, minimizing potentially uneconomic resource costs. A strategy to diversify its electric supply portfolio through adding market-responsive resources incrementally to the electric portfolio appears to provide a degree of the market and flexibility benefits similar to those of gas supply portfolio.

In the current environment where fundamental issues associated with retail access and other structural changes have not been resolved in this state, long-term resource planning over a 20-year time horizon is extremely difficult. Generally, it does not appear that making large new 20 to 30-year resource commitments today would prove to be beneficial to customers and the company under many of the scenarios identified in this plan. Consider, for instance, if PSE were to build and operate a large new central station generation resource to serve incrementally the expected loads of core customers over next 20 to 30 years. Should market prices not rise above the cost of this resource its cost may prove, in hindsight, to be uneconomic. The company and its customers would have been better off had this resource not been acquired in the first place - the company should have relied on market purchases. Further, should open access or other industry changes occur over the 20 year planning horizon, this resource may not be needed to serve core loads, and, beyond this, if market prices were to stay relatively low, the resource many become difficult to liquidate. This is an illustration of the difficulties in making large new long-term resource commitments in today's environment.

Following the path of building (or contracting for) new, inflexible long-term power supply generation facilities is risky for customers as such commitments could prove to be 1) uneconomic, due to changes in technologies or market costs, or, 2) unnecessary, due to movement of core customers to non-core status (see scenarios). In short, at this time, it is difficult to make long term capital or contractual commitments for resource acquisitions, after considering the many risks to customers such commitments present. Generally, such a new resource commitment appears inconsistent with overall expected customer supply commitments.

To PSE it appears reasonable to address such risks through pursuing a strategy of increased use of flexible, short and intermediate term market responsive supply to meet incremental needs through this transition period until the context of PSE's customer supply commitments are made more clear by policymakers. However, this is not to say that under all scenarios this incremental reliance on the market will always prove, in hindsight, to be the best path. Scenarios can be constructed where market prices rise so greatly that this strategy may appear, in hindsight, best under certain sets of long-term industry assumptions. Even so, at the current time, it appears clear that, on balance, this incremental use of market purchases minimizes the risks illustrated by the scenarios in this plan.

It is important to note that PSE's existing electric supply portfolio currently contains a significant amount of long-term, (relatively) fixed price supply resources. PSE will continue to pursue opportunities, as they arise, to mitigate and streamline certain high cost resources in the existing resource portfolio. Existing long-term resource commitments may be replaced by substitute long-term commitments if overall cost savings and other benefits can be achieved. At the same time, PSE is vigorously pursuing a fair allocation from BPA of the benefits of the federal hydropower system for our residential and small-farm customers and a continuation of the benefits of its very low cost Mid-Columbia power purchase ageeements. As the costs of the federal hydropower system are expected to be below market, fair access to this resource is critical for PSE's residential and small farm customers. This regional resource, in combination with PSE's Mid-Columbia contractual supplies, can form a large, stable, and very low cost resource base for PSE's customers. PSE's overall resource portfolio can then be further diversified by building in more flexible, short- and intermediate-term market-responsive power supplies, as opposed to inflexible, long-term commitments. This diversity provides protection for customers by mitigating the impact that electric market price changes would have on customers through the future.

Regulatory Issues

In order for PSE to be able to plan appropriately for meeting future customer supply commitments and to best take advantage of the benefits for its customers of moving incrementally toward market-responsive energy supply, a regulatory mechanism is needed that can allow PSE to match the qualities of its resource supply commitments to its customer supply commitments. Under the current regulatory structure for electric energy cost recovery provided in the Merger Rate Plan, PSE absorbs market price risks as customer rates do not change in accordance with market costs. Continuation of this, or any other structure where the utility is required to absorb market price risks increase long-run costs to customers by adversely affecting the utility's cost of capital and encouraging the utility to pursue costly efforts to attempt to insulate against this risk. Conversely, it appears that customers would benefit from a regulatory policy that better encourages innovation, shares the benefits of competitive wholesale markets, encourages conservation and effective load management, and does not adversely affect the company's ability to raise capital on reasonable terms. Therefore, PSE encourages the WUTC to adopt an electric energy cost adjustment clause and incentive mechanism, generally similar to its Purchased Gas Adjustment (PGA) and PGA Incentive Mechanism, for the post-Rate Plan period.

Under such a mechanism, a yearly adjustment for changes in market costs would be made. Beyond this, customers could choose to see daily, weekly or monthly changes in market prices, which would provide real market signals to those customers providing market-based incentives for active load management and conservation. Long-term volatility would be mitigated as PSE's electric resource portfolio is very diverse as it is expected to include a mixture of incremental market purchases, BPA power provided under the subscription process, PSE owned resources, and long-term contracts. Even so, it is important to note that if current projections that gas and electric wholesale prices will rise over the long-term turn out to be true, both the current PGA mechanism and a similar electric cost adjustment mechanism would pass through these rising costs over the long term.

As the Commission considers such a mechanism, PSE urges the WUTC to consider that, the fact that wholesale energy markets have changed dramatically while retail regulation has not raises a critical issue of regulatory policy. Under the current situation, PSE, as a regulated electric utility continues to operate under cost of service regulation and a duty to serve. In doing so under the current Rate Plan structure, PSE is now effectively serving as buffer between volatile market forces and customers. Serving as this buffer is costly now, and, over the long term even more costly, as the utility's cost of capital will rise to reflect this new risk should this situation continue over time. Eventually, customers will absorb those costs.

This situation is a sharp contrast to that of the past when utilities could make long-term resource commitments under a least-cost planning framework with the assurance that all those known investments and expenditures would be recovered under a well-understood cost of service regulatory framework. Energy supply commitments and customer commitments were much more clearly and easily matched. At this time though, incremental reliance on short- and intermediate-term market-based purchases for resource acquisitions appears to be best course during this uncertain period, as discussed above. However, should the company continue to absorb the variability in market costs, customers will ultimately face significantly higher costs due to an increased cost of capital, lack of opportunities for market-based load management, and possible missed market opportunities. In this state, as opposed to others, there has been change in regulation that sets forth future customer supply commitments that fully address the changing structure electric supply markets and associated resource alternatives. It is important to note that this risk of absorbing market price volatility was largely nonexistent for utilities in the past. Puget Sound Energy believes that an alternative structure after the end of the Merger Rate Plan period is critical and looks forward to the Commission's policy guidance on this important matter.

A second, related, set of regulatory changes PSE plans to pursue regard implementation of more time-sensitive pricing in utility services for those customers who desire such service. Passing wholesale price signals to retail customers is very important for aligning market information with customer choices. At this time, PSE electric customers (aside from Schedule 48 and special contracts) see no near-term market price signals whatsoever. Generally, a disconnection between wholesale and retail prices can create very distorting signals to the generation market, which will determine when additional generation is needed. This misalignment can lead to resource decisions being made in energy supply markets that do not have the benefit of customer interests and values. Conversely, customers may be able to benefit significantly from modifying use patterns and/or using energy efficiency measures in response to market information. The closer customers come to seeing real time prices from wholesale markets, the better able they are to make choices reflective of real energy supply market economics. Market-based conservation and load management actions taken by customers in response to this information may be tremendously valuable for customers, possibly enabling them to avoid market price spikes and other market costs. If broadly implemented, such load management could allow generation markets to avoid production increments when those increments are most costly, producing potential benefits to the entire system.

In the past, technological barriers have stood in the way of providing real price signals to customers with the precision necessary to enable efficient short-run customer decisions. The necessary metering and communication technology has not been available, but this is changing quickly. PSE will be completing implementation of its Automated Meter Reading (AMR) system within the next two years. PSE will be investigating how this and other enabling technologies can be used to pass through real market price signals to customers so that they can take action to manage their loads, ultimately effecting least-cost solutions. As innovative opportunities are created, PSE will work with the Commission, Staff, Public Counsel, and other interested parties to successfully implement new services based on more precise and market-reflective pricing.

PSE, for its part, is focused on flexibility in accessing competitive wholesale electricity markets as part of its efforts to positioning its resource portfolio to match the expected, though very uncertain, characteristics of its future customers' supply commitments. Generally, PSE expects to increase its use of incremental short- and medium-term market responsive alternatives presented in the competitive wholesale electricity markets, rather than on long-term commitments, for resource acquisition. This flexibility is especially important because a utility's obligation to serve may change dramatically as a natural result of industry evolution and policy developments. PSE acknowledges that its obligation to serve continues unchanged until the U.S. Congress or the Washington State Legislature indicate otherwise.

F. Conservation Programs

As discussed above, emerging market-based conservation and load-management approaches may hold much promise in enabling customers and the region to avoid production costs at the very time when they are most economically costly. The existence of recent high price spikes in energy supply markets nationwide is reflective of the societal cost of resource scarcity at critical time periods. A great social benefit could be achieved by encouraging customers to reduce use during such peak periods. PSE plans to investigate such approaches that use enabling technology to provide real market signals to customers and enable active conservation and load management.

Currently, PSE is implementing the three-year conservation plan approved by the WUTC in March 1999. Cost effectiveness remains PSE's fundamental principle guiding investments in conservation programs. Conservation programs cover all market segments: residential, commercial and industrial, with additional emphasis on low income customers. To provide the most cost effective implementation, programs are delivered through a mixture of approaches including grants, direct assistance, information, training, etc, and they rely on cooperation with trade allies, vendors, public agencies and other utilities. Achieved electrical energy savings are significant, representing about 9% of current energy sales. Since 1980, electricity conserved amounts to 1,859,140 MWh (cumulative, annual) which corresponds to 212 aMW in current load reduction. In natural gas conservation, approximately 1,060,000 Dth have been saved in the past two years. In addition to saving energy, PSE was the first electric utility in the nation to be granted the ability to refinance conservation investments utilizing conservation bonds. The first conservation bond transaction involved over $240 million, and it created in excess of $36 million in cost savings to customers associated with funding conservation.

On March 31, 1999, the WUTC approved PSE's three year conservation program filing. This filing was developed in consultation with the TAG process. PSE also utilized an external consultant to conduct a nationwide investigation of conservation program offerings by other utilities that continue to undertake significant conservation investments. The 1999-2002 programs reflect new offerings and measures, and further streamlining and integration of gas and electric energy conservation programs and materials. At the same time, PSE has continued support of regional market transformation programs by providing significant funding to Northwest Energy Efficiency Alliance (NEEA). In the future, PSE will continue implementing energy efficiency programs and services which enable and empower customers to select their cost-effective energy efficiency measures and practices.

G. Reference Table for Specific WAC Requirements

To assist the reader in review of this Least Cost Plan, the table below references each requirement of the WAC rules governing the Least Cost Plan to chapters within the document where discussion of the topic can be found.

WAC 480-100-251 Requirement (Electricity)	Chapter
A range of forecasts of future demand using methods that examine the impact of economic forces on the consumption of electricity and that address changes in the number, type, and efficiency of electrical end-uses	**II** Demand Forecasting
An assessment of technically feasible improvements in the efficient use of electricity, including load management, as well as currently employed and new policies and programs needed to obtain the efficiency improvements.	**III** Demand Side Management
An assessment of technically feasible generating technologies including renewable resources, cogeneration, power purchases from other utilities, and thermal resources	**IV** Energy Supply Electric
A comparative evaluation of generating resources and improvements in the efficient use of electricity based on a consistent method, developed in consultation with commission staff, for calculating cost-effectiveness.	**III** Demand Side Management
The integration of the demand forecasts and resource evaluations into a long-range (e.g., twenty-year) least cost plan describing the mix of resources that will meet current and future needs at the lowest cost to the utility and its rate payers.	**VI** Integrated Resource Modeling
Public involvement strategy.	**VIII** Public Involvement
A short-term (e.g., two-year) plan outlining the specific actions to be taken by the utility in implementing the long-range least cost plan	**IX** 2-Year Action Plan
A progress report that relates the new plan to the previously filed plan.	**IX** 2-Year Action Plan

WAC 480-90-191 Requirements (Natural Gas)	Chapter
A range of forecasts for firm and interruptible markets	**II** Demand Forecasts
An assessment of technically feasible improvements in the efficient use of gas, including load management	**III** Demand Side Management
A projection of spot market versus long-term purchases	**V** Energy Supply Gas
An evaluation of the opportunities for storage	**V** Energy Supply Gas
An evaluation of the opportunities for participation in a futures market	**V** Energy Supply Gas
An evaluation of opportunities for access to multiple pipeline suppliers or direct purchases from producers	**V** Energy Supply Gas
The integration of demand forecast with resource evaluations in twenty year projection describing the strategies designed to meet current and future needs	**VI** Integrated Resource Modeling
Public involvement strategy.	**VIII** Public Involvement
A progress report that relates the new plan to the previously filed plan.	**IX** 2-Year Action Plan

Demand Forecasting

II. ENERGY DEMAND FORECASTING

A. Introduction

Puget Sound Energy (PSE), on an annual basis, develops a 20-year forecast of customers, energy sales and peak demand for the electric and gas service territories. The forecast is used in short term planning activities such as the annual revenue forecast, marketing and operations plans, as well as for many long term planning activities such as the integrated resource plan and transmission and distribution planning activities. This chapter provides a description of the forecasting methodologies employed for both the electric and gas sales forecasts, the development and sources of consistent forecasting inputs and assumptions, and then finally, a review and summary of the base case results.

B. Forecast Methodologies

The forecasting process is designed to provide forecasts of customers and billed sales at the customer class level. These include five classes for electric (residential, commercial, industrial, street lights and resale) and eleven classes for gas (residential, commercial, industrial, commercial interruptible, commercial large volume, industrial interruptible, industrial large volume, commercial firm transportation, commercial interruptible transportation, industrial firm transportation, and industrial interruptible transportation). Although the electric and gas service territories do not completely overlap, a set of assumptions about the economic outlook, demographic trends and fuel prices underlies these forecasts that are both consistent and specific for each of the service territories.

Electric

The electric customer and sales forecasting model is a mixed end-use and econometric model in the sense that the residential and commercial billed sales forecasts are produced using end-use models while the forecasts of customers and billed sales for industrial, street light and resale are produced using econometric models. Because this model is an annual model, monthly forecasts are generated by computing monthly allocation factors for customers and sales based on an average of the last five years.

<u>Customer Forecast</u>

Customer additions forecasts are based upon forecast of population and employment at the service territory level. For the residential sector, customer additions are a function of county population, both current and lagged, as well as commercial employment after adjustments are made for PSE's share of population and employment. This forecast is then disaggregated into three building types: single family, multi-family and mobile homes. These forecasts are inputs into the residential end-use model. The forecast of customer additions for the non-residential sectors are generated using an econometric equation that is dependent upon employment and trend factors.

Billed Sales Forecasts

The residential billed sales forecasting model is an end-use model based on the Oak Ridge National Laboratory's RRHEDM or Residential Reference House Energy Demand Model obtained in 1986. This model provides detailed analysis of energy use for three different housing types and nine end-uses. These end-use types are: space heat, water heat, air conditioning, cooking, drying, refrigeration, freezing, lighting, and others. In addition to the forecast of customers by building type which is a determinant in the building stock model, the projection of fuel prices also determine the operational costs of equipment, hence, the choice of efficiency and fuel type for the equipment. These factors all interact to influence energy use.

The commercial billed sales forecasting model utilizes CEDMS, or the Commercial End-Use Demand Modeling System purchased from Jerry Jackson and Associates in 1996 to produce energy use for 13 building types and 8 end-uses. These end-uses include: space heating, water heating, ventilation, air conditioning, cooking, refrigeration, lighting and others. Building types included in the model are: large office, small office, restaurants, large retail, small retail, groceries, warehouses, schools, colleges, hospitals, nursing homes, hotels and miscellaneous building types. In this model, commercial employment drives commercial floor space, and fuel prices influence the efficiency, utilization and penetration of electrical equipment to produce electricity sales. The forecast from this model is adjusted upwards for non-building sales, e.g., sales to agriculture, construction and public utilities, to obtain the total forecast of commercial billed sales.

The industrial billed sales model is based on econometric equations for seven industrial sub-sectors: food manufacturing, lumber and wood products, paper and allied products, chemicals, petroleum refining, transportation equipment, and others. Except for transportation, the equations are based on a relationship between customer use and industrial production patterns and energy prices. The basic assumption is that electric consumption for industries in the service territory is affected more by demand for their products than weather variations. Because transportation usage is dominated by Boeing, the econometric equation for this sector is aerospace employment which is more readily available than production data. The forecasts of billed sales for street light and resale are based on a simple trend equation, but adjusted for large one time increases such as building expansions or runway additions for the airport in the case of resale.

Billed sales forecast is further adjusted by the company's forecast of new programmatic conservation savings for each customer class before being summed to obtain the system billed sales. Finally, total system loads are obtained after accounting for transmission and distribution losses.

<u>Peak Hour Forecast</u>

Normal and extreme peak load forecasts are obtained using an econometric equation relating observed hourly system peak loads in the month against weather sensitive sales from both residential and non-residential sectors, and deviation from normal peak temperature for the month. This allows for different effects of residential and non-residential loads on peak demand. The functional form of the equation and its estimated coefficients are displayed below:

Peak MW = 2.04*Resid aMW + 1.02*Non-Resid aMW
+ 0.025*(Deviation from Normal Peak Temp)*(Weather Sensitive aMW)

The equation is estimated using monthly data from 1985 to 1998 resulting in coefficients which are statistically significant from zero. The normal and extreme peak load forecast are obtained by using the appropriate design temperatures into the equation for either condition. For Puget Sound Energy, these design temperatures are 23 degrees for normal peak and 13 degrees for extreme peak both occurring in January.

Gas

The gas customer and sales forecasting model is also a mixed end-use and econometric model in the sense that the residential billed sales model is an end-use model while the rest of the sectors are projected using econometric equations. The model is a quarterly model, hence, allocation factors from quarters to months are developed using the last five years of data to generate monthly forecasts of customers and billed sales. Within the core sales customer classes (residential, commercial and industrial), several customer types are considered by the forecasting model. For the residential class, three types of customers are considered: existing, new construction and conversion customers. Within the commercial class, 10 types of customers are considered in the model: offices, educational services, eating and drinking places, other retail trade, medical services, other business services, warehouses and transportation-communication-utilities, apartment buildings, natural gas vehicles, and miscellaneous commercial customers. For the industrial class, seven industrial sub-sectors are considered: food products, wood and paper products, sand and gravel, metals, electrical and electronic equipment, transportation equipment and miscellaneous industrial customers.

Customer Forecast

Residential customer counts grow as a result of new construction, conversion and changes in the existing base. New construction customers are a function of single family permits issued and relative fuel prices. Conversions are a function of the existing housing stock that can be converted to natural gas, relative fuel prices, per capita income and the rate of change in population. The conversion market is projected using a logit curve to predict the market share captured. The logit equation constrains the prospective conversion market saturation by following an '$\int$' shape over the forecast horizon. The net conversion rate is based on the size of the available conversion market and slows down as the saturation rate rises over time. The number of existing customers is a function of the prior year's customers, allowing for demolitions and disconnects.

For commercial and industrial core sales customers, the customer forecast is generated using an econometric equation that is dependent upon employment for each of the respective sub-sectors within the class and relative fuel prices. The customer forecast for commercial and industrial interruptible sales classes is also based on an econometric relationship using lagged dependent variables structure. Finally, transportation customer forecasts are developed outside of the model in another department, and is incorporated into the model as a fixed amount.

Billed Sales Forecast

In the residential sector, gas consumption is theoretically a function of the structural characteristics of the household, the appliances used in the home, household economic and demographic characteristics, heating degree days and a time trend. When one of these factors changes, so will gas consumption. The mathematical expressions that explain per customer gas consumption take the form of a time series regression and end-use analyses. Customers and appliance choices are predicted econometrically. Residential gas demand is calculated from end-use simulation of six gas appliance categories: space and water heating, cooking, dryers, fireplaces and other uses like gas barbecues, hot tubs and pools. Each one of the residential sectors (new construction, conversion and existing customers) has its own customer and use-per-customer projection. The end-use model incorporates own-price elasticity, the level of market saturation, base year energy use and each gas appliance's efficiency characteristics. The saturation of a particular appliance is defined as the percentage of customers who have that appliance. Saturation is altered by the current market penetration rate, which is, in turn, a function of relative prices, population growth, time trends and energy policy influences. The model uses econometric techniques to predict the penetration rates. Hence, the observed level of gas consumption is a function of weather, expenditures and home equipment/appliance characteristics. The model multiplies consumption of an individual appliance type, such as cooking, by the market saturation level, the average efficiency of in-use appliances, and own-price elasticity. That product, unique to each type of customer, is then multiplied by the respective number of customers to determine consumption. The sum of the three residential sector forecasts results in the total residential consumption. This number is later explicitly reduced by the anticipated impact of demand-side programs (DSM).

For non-residential customers, except transportation classes, the use per customer equations depends on relative fuel prices, weather, and in some cases employment or lagged dependent variables. A separate use per customer equation is estimated for each of the sub-sectors within commercial and industrial core classes, and for each of the major interruptible sales customer classes. Given the forecast of customers, total sales for each of the nonresidential customer classes is obtained by summing the product of customer counts forecast and use per customer forecasts. Again, transportation sales is an ex post forecast added to the model later on. The forecast system incorporates three more *ex post* forecast adjustments. These relate to natural gas sales for non-company owned natural gas vehicles, sales to co-generators, and the estimated impacts from the company's DSM activities.

Peak Day Forecast

Peak day requirements are calculated for a particular customer class using the following equation:

Peak Requirements = (Number of Customers) x (Base Load per Customer + ((Heating Load per Customer per Degree Day) x (Design Day Heating Degree Days)))

Where the Base Load is defined in "Therms per Day" or "Therms per Month" per customer for daily and annual estimates. The Base Load may or may not be significantly temperature-sensitive depending on the sector, and is generally considered to be related to water heating, cooking or other gas appliances. The Heating Load is defined as "Therms per Customer per Heating Degree Day." This load is usually due to heating or other air conditioning of the ambient air temperature. Heating Degree Days (HDDs) are determined by deducting the daily average temperature from 65°F.

The design peak day requirements for this forecast are based on the company's historically coldest day as measured at SeaTac Airport, containing 55 degree days (10°F average temperature, 24 hour), experienced in January 1950. PSE recognizes the possibility that similar weather conditions may occur in the future and has planned to meet these customer requirements on a least cost basis. The company has most recently experienced an 11.9°F average temperature at SeaTac for the gas day on December 20, 1990.

The peak day requirements for the year were determined by applying the above equation to the design peak day degree days in January. The heating load per customer per degree day was derived from regression analysis of the actual usage by customer class for the five winter months (November—March) over the last five years versus the respective monthly heating degree days. This resulted in regression equation coefficients that describe the relationship of use to monthly heating degree days. Previous non-base load methodologies focused upon an a single HDD series. This would give an annual average temperature response, likely over estimating shoulder periods and underestimating peak periods. It is also inconsistent with declining annual per customer consumption. The newer approach focuses on isolating responses attributable to each month. Hence, 12 HDD series have been implemented, one for each month. In this approach, January is the month with the largest temperature coefficient. It has the greatest temperature sensitivity, and therefore more likely to experience the design day. This also allows us to evaluate if there appears to be any changing temperature sensitivity over time, observed in the peak month. There does appear to be a declining trend in heat sensitive loads for residential customers, but not other customer groups at this time.

Base loads have been estimated using econometric equations, rather than being estimated from a simple average of the last five Augusts. This allowed for the identification of slight temperature sensitivities in August. It also allowed estimation of trends for each of the three core classes. Base loads were estimated with zero HDD and then subtracted from all months. The remaining daily demands were then attributable to temperature. All three core sectors tend to have base loads with increasing trends.

Large volume customer daily contract demand was estimated from January, rather than August. This data tends to have a seasonal shape, with interruptible customers taking more in January. The per customer January 1998 value is simply held constant over the forecast horizon, and multiplied by customers to form large volume peak demand. These data are added with their respective category, either commercial core or industrial core.

C. Key Forecast Assumptions

The forecast of energy use is dependent on inputs to the model. Major inputs into the model are economic activity and fuel prices. Regional economic growth increases employment and the demand for energy. Economic growth also increases the number of customers by attracting more in-migration. Fuel prices affect the type of fuel used in appliances, their efficiency and utilization levels. This section will present the assumptions and forecast of economic and demographic variables and fuel prices used for this forecast.

Economic and Demographic Assumptions

The Puget Sound area is a major commercial and manufacturing center in the Pacific Northwest with strong links to the national and state economies. These links create jobs not only for directly affected industries but also indirectly for supporting industries through the multiplier effects. As a consequence, the service territory economy is affected by the performance of the national and regional economies.

National Economic Outlook

The long term economic outlook is drawn from the Winter 1998 projections from DRI (Trend Long Model). As the name suggests, the forecast exhibit only mild variations in growth over the next 20 years. The economy's underlying growth rate will be significantly slower than in the past. Annual real GDP growth will average about 1.9% per year compared to 2.8% between 1970 and 1996. The major factor contributing to this result is declining labor force participation, as the percent of population of working age declines.

Table II.1 National Economic Outlook

United States	1999	2000	2005	2010	2015	2018	aarg
GDP (Bils,92$)	7,512.4	7,709.9	8,702.2	9,674.7	10,497.4	10,945.9	1.9%
Employment (mils)	126.7	128.1	136.3	143.4	147.4	149.1	0.8%
Population (mils)	272.8	275.1	286.5	298.2	310.7	318.3	0.8%

Near term, the deceleration of the national economy looks certain assisted by the slowdown in the Asian economies and a Federal Reserve Board bent on preventing the acceleration of inflation. The economy has been growing about 3.3% per year over the last two years which is above its long run growth rate of 2.4% per year. The uncertainties in the near term consist of how fast the Asian market can recover, and the stock market bubble and its impact on spending and consumption.

Regional Economic Outlook

Puget Sound Energy has two market areas: the electric and natural gas service areas. Geographically, the two service areas overlap one another to a considerable degree. As a result, they share virtually the same economy and industrial structures. There are two notable differences between the two areas. First, the electric service area contains Kitsap county, home of the Puget Sound Naval Shipyard, but not Snohomish county, the site of the largest aircraft assembly plant. Thus the electric service area has substantially more government employees but considerably less aerospace employment than the natural gas service area. Second, the electric service area includes four rural counties (Skagit, Island, Kittitas and Jefferson). With the exception of Kittitas, these counties have been among the fastest growing areas in the state. However, with small populations, the four counties have only a small impact on the forecast for total service area.

Electric Service Area - During the next two decades, employment growth in the electric territory is expected to grow at a slower rate (1.4%) compared to its 30 year historical growth of 3.3% per year. But even at that rate, local employers are expected to create about 550,000 jobs between 1997 and 2018 or more than one third of the jobs we have today. During the same period, the area is expected to add about 946,000 residents raising the population to about 4.1 million. The moderating national economy, plus, the near term cutbacks in aerospace jobs are the main reasons for the slowing employment growth.

Table II.2

Electric Service Area	1999	2000	2005	2010	2015	2018	aarg
Population (thousands)	3238.5	3300.4	3488.8	3690.5	3911.0	4059.0	1.2%
Employment (thousands)	1678.1	1707.0	1819.2	1947.4	2060.3	2134.1	1.2%

Most of the growth in employment is expected to come from the service sectors including business services and computer industries. Not all counties will grow at the same pace. The smaller counties like Island and Jefferson will experience a higher growth rate compared to the growth in King county. However, the absolute amount of jobs created will still be higher in King county than the smaller counties.

Gas Service Area Economic Outlook - As in the electric service area, employment growth in the natural gas area will slow due to declining Boeing employment and a moderating national economy. The regional economy has posted one of the fastest employment growth rates nationally in the last two years. Despite this impressive growth rates, the forecast call for a slower growth rate because of the following factors: a national economy that is slowing down, the end of Boeing upturn, slowdown in Asian economy. There are also impending risks: an overvalued stock market and the effects of a negative decisions on the anti-trust suit against Microsoft. While the chances of a negative growth increase in the near term, the forecast of employment still calls for a slower growth.

Table II.3

Natural Gas Service Area	1999	2000	2005	2010	2015	2018	aarg
Employment (thousands)	1,681.1	1,713.1	1,835.9	1,976.0	2,090.0	2,182.9	1.3%
Population (thousands)	3,195.0	3,257.1	3,447.8	3,643.0	3,860.6	4,010.6	1.2%

In the long term, slower growth will occur unless the aerospace and the computer industries experiences a prolonged employment growth that Boeing had in the 1980s. Representing a continuation of the past trends, most new jobs will be found in the service producing sector of the economy. The three fastest growing industries will be eating and drinking places, producer services, and health services. Employment in these sectors reflect the increasing demand for services as a result of rising income and expanded business activity, an aging population, and lagging labor productivity in service sectors.

Slower employment growth will mean slower income and population growth. Population, which grew at an annual rate of 2.1% in the 1980s, will slip to 1.2% in the next two decades. Again, while population growths are modest, the gains in absolute terms will be substantial. The forecast call for about 932,000 new residents between 1997 and 2018.

Fuel Prices

PSE's energy demand models require predictions of various fuel prices. Fuel prices affect the choice of fuel for new appliances, the efficiency levels, and utilization rates of existing and new appliances. While different forecasts were produced for residential, commercial and industrial sectors, the following table for residential fuel prices illustrates the assumptions used to develop the fuel price forecasts.

Table II.4

Forecast of Retail Rates (nominal)	1999	2000	2005	2010	2015	2018	aarg
Residential							
Electric, cents/kWh	6.08	6.17	6.75	7.48	8.78	9.57	2.3%
Natural Gas, cents/therm	57.66	58.80	66.37	79.67	95.62	108.99	3.2%
Commercial							
Electric, cents/kWh	6.38	6.45	6.90	7.48	8.72	9.53	2.0%
Natural Gas, cents/therm	51.34	52.36	58.63	69.62	83.09	94.04	3.1%
Industrial							
Electric, cents/kWh	4.69	4.71	5.06	5.54	6.55	7.25	2.2%
Natural Gas, cents/therm	46.67	47.68	55.46	69.01	84.96	98.77	3.8%

In the short term, between 1998 and 2001, electric retail rates are expected to be consistent with merger stipulations with the WUTC. The long term growth rate is based on DRI's projected growth rate of retail electric prices for the Northwest. For retail gas price, the near term also reflects merger stipulations for gas margins. However, the wholesale cost of gas reflects a 4.3% growth per year consistent with the 1998 PGA filing. In the long run, the retail price of gas follows DRI's projected growth rate of retail gas prices for the Northwest. Given a long term inflation rate of 3%, the forecast of electric rates show a decline in real terms, while that for gas rates show a flat or no growth in real terms.

D. Energy Sales and Customer Forecasts

Electric Sales Forecasts

Puget Sound Energy's electric sales are expected to grow at an average annual rate of 1.7% per year in this forecast, from 20,902 GWHs to 20,079 GWHs in 2018. Sales are expected to grow at a slightly higher rate in the next five years and at a slightly lower rate in the following 15 years. Compared to the historical growth rate of 2.1% per year, the new forecast of sales growth is the result of slower growth in population and employment in the long term, more multifamily units additions and the effects of conservation efforts.

Table II.5

Billed Sales Forecasts (GWHs)	1999	2000	2005	2010	2015	2018	aarg
Residential	9,451	9,575	10,012	10,465	10,904	11,172	0.9%
Commercial	7,431	7,664	8,819	9,808	10,834	11,412	2.3%
Industrial	4,191	4,282	4,888	5,521	5,893	6,076	2.0%
Street Lights	74	75	80	86	92	95	1.2%
Resale	142	157	194	237	288	324	4.4%
Total	21,289	21,753	23,995	26,116	28,010	29,079	1.7%

Most of the growth in sales is expected to come from the non-residential sectors, reflecting the increase in commercial employment in the next twenty years. As a result, the fastest growing sub-sectors are expected to be office buildings and food and retail places, consistent with the projected increase in employment in business services as well as in eating and drinking places. The share of commercial sector in total sale is expected to increase from 35% in 1998 to about 40% in 2018. Residential billed sales are expected to grow moderately at 0.9% per year as a result of slower growth in single family housing units because of declining amount of available land to develop. Further, residential use per customer is expected to decline with more multifamily units being built and conservation codes. Consequently, the share of residential sector in total sales is expected to decline from about 44% in 1998 to 38% by 2018. This sales forecast also assumes that about 5 aMW of conservation savings are achieved each year through the company's DSM activities.

Electric Customer Forecasts

Electric customers are expected to grow at an average annual rate of 1.3% per year between 1998 and 2018, or from 890,770 in 1998 to 1,143,100 customers by 2018. Customer growth is slightly faster in the next five years compared to the following fifteen years, consistent with the pattern of growth in population and employment. The long term projected growth rate of 1.3% is lower compared to the historical growth rate of 2% per year reflecting the slowdown in population growth and decreasing amount of affordable land to develop.

Table II.6

Electric Customers	1999	2000	2005	2010	2015	2018	aarg
Residential	805,225	819,651	871,933	928,532	976,756	1,005,097	1.2%
Commercial	97,013	99,118	108,033	116,801	125,093	129,572	1.5%
Industrial	4,341	4,445	5,000	5,605	6,262	6,602	2.2%
Street Lights	1,438	1,458	1,559	1,660	1,761	1,819	1.1%
Resale	9	9	9	9	9	9	0.0%
Total	908,026	924,681	986,534	1,052,607	1,109,881	1,143,100	1.3%

Currently, the residential sector accounts for 88.7% of the total number of customers in the service area. Although growing at a slower rate than commercial and industrial sectors, the residential sector is still expected to account for most of the growth in the number of customers, in terms of absolute numbers, because it has the largest share in the total customer base. The residential growth also reflects a gradually increasing share of multifamily units in the next twenty years. While the residential share of load is declining, its decline in the next twenty years is very small (about 1%).

Electric Peak Hour Forecast (Normal and Extreme)

Peak load forecasts are also based on the weather sensitive portion of the system sales forecast. The annual normal peak load is assumed to occur at 23 degrees, while the extreme annual peak load is assumed to occur at 13 degrees, all occurring in January.

Table II.7

One Hour Peak Loads -MW	1999	2000	2005	2010	2015	2018	aarg
Normal	4,861	4,951	4,951	5,738	6,095	6,301	1.4%
Extreme	5,418	5,519	5,519	6,394	6,793	7,024	1.4%

Peak loads are expected to grow by 1.4% per year in the next twenty years. Peak loads grow slightly slower than energy loads. The peak forecasting model is based on an econometric equation that allows for a different effects of residential versus non-residential energy loads. Since residential energy loads is growing more slowly than the non-residential energy, and since residential energy has a larger contribution to peak than non-residential energy, the system peak load grows slightly more slowly than the system energy loads. Hence, the system load factor increases slightly over time.

Gas Billed Sales Forecasts

Natural gas billed sales for PSE is expected to grow at an average annual rate of growth of 1.8% per year in the next twenty years, growing from 1,047,972 thousand therms in 1998 to 1,502,602 thousand therms by 2018. Compared to the historical growth rate of about 2.9% per year, the slower growth rate in the future is the result of slower customer growth in residential as well as a slight decline in residential use per customer due to increasing multifamily and appliance efficiencies.

Table II.8

Billed Sales Forecast (Thousands of therms)	1999	2000	2005	2010	2015	2018	aarg
Residential	473,257	489,488	558,322	627,676	702,437	745,397	2.4%
Commercial	199,037	205,491	230,460	244,844	260,670	268,597	1.7%
Industrial	42,053	42,206	44,180	44,151	45,139	45,451	0.3%
Interruptibles	98,923	101,692	117,324	138,850	164,343	179,953	4.0%
Transportation	263,203	263,203	263,203	263,203	263,203	263,203	-0.1%
Total	1,076,473	1,102,081	1,213,489	1,318,724	1,435,792	1,502,602	1.8%

While not the fastest growing sector, most of the growth in therms is still expected to come from the residential sector because it has the largest share relative to total sales. The growth rate of interruptibles reflect increasing use per customer due to increasing penetration of gas in commercial and industrial applications or processes. As a result, the shares of residential and interruptibles are expected to increase from 44% and 8% in 1998 to 50% and 12% in 2018 for residential and interruptibles, respectively. Currently, billed sales to transportation is projected outside of the gas model and assumed fixed in the planning horizon. This forecast also assumes that about 1.3 million therms in conservation is achieved through DSM activities initially, and then declines about 10% each year for the next 20 years as programs are retired.

Gas Customer Forecasts

The projected growth rate of gas customers is 2.5% per year in the next twenty years. In comparison with the historical growth rate of about 4% per year, the new forecast reflects slower population growth, hence slower demand for housing, and a declining pool of potential conversion customers.

Table II.9

Customer Forecasts	1999	2000	2005	2010	2015	2018	aarg
Residential	518,317	538,245	622,594	706,074	787,047	833,751	2.6%
Commercial	44,547	45,721	50,648	54,677	58,676	60,756	1.8%
Industrial	2,874	2,881	2,920	2,977	3,035	3,073	0.4%
Interruptibles	799	790	769	757	746	746	-0.4%
Transportation	123	123	123	123	123	123	0.0%
Total	566,658	587,760	677,054	764,609	849,626	898,442	2.5%

Currently, the residential sector accounts for about 91% of total customer base. With a growth rate of 2.6% per year in the next twenty years, residential's share is expected to increase from 91% to 93% by 2018. While accounting for only about 8% of total customer base, commercial sector is also expected to grow slightly, about 1.8% per year, in the next twenty years consistent with expected increase in penetration of gas in new buildings. The gradual slowing of interruptible customer growth over the planning horizon is due to increasing restrictions on the use of alternative fuels (especially oil and its associated liabilities) which reduce the number of customers eligible for interruptible service. Many current interruptible customers, especially the smaller sized customers, will choose to "firm-up" their demand by seeking solutions ranging from becoming all firm to various combinations of firm, interruptible and transportation services.

Gas Peak Day Forecast

Gas peak day forecast shows peak firm gas requirements increasing from 7.4 million therms in 1998 to 11.8 million therms in 2018, or a growth rate of about 2.4% per year in the next twenty years. While total billed sales is expected to grow about 1.8% per year, daily peak requirements is expected to grow by 2.4% similar to the growth rate of sales in residential because residential is the most weather sensitive sector and is expected to contribute more than 70% to total peak day requirements. The peak forecasts include the contribution of large volume customers to peak requirements, and are included in either the commercial or industrial sectors. Losses are computed using 0.8% of the peak day requirements from the three sectors.

Table II.10

Peak Day Forecasts (Therms)	1999	2000	2005	2010	2015	2018	aarg
Residential	5,525,522	5,748,735	6,676,826	7,565,297	8,429,831	8,920,394	2.6%
Commercial	1,818,145	1,871,423	2,088,782	2,259,703	2,427,943	2,520,262	1.8%
Industrial	268,158	269,513	272,735	278,705	283,920	287,503	0.4%
Losses	60,895	63,117	72,307	80,830	89,134	93,825	2.4%
Total	7,672,719	7,952,788	9,110,649	10,184,534	11,230,828	11,821,984	2.4%

Growth in peak across all sectors is primarily driven by the expansion in customer base. However, rising base loads also contribute moderately due to increasing saturation of gas in other end uses. This is offset slightly also by increasing efficiencies in appliances and the increasing penetration of gas into multifamily sector which has a smaller use per customer.

E. Electric Load Forecast Scenarios

On figure II.1 the primary series of the forecast scenarios is labeled "Medium." This is the most recent forecast based on the most reasonable assumptions of economic and demographic changes. The load represents the load of residential, commercial and industrial customers, excluding the load which is on index pricing (i.e. special contracts and Schedule 48). The average growth rate for the base case is 1.67% per year and the growth rate falls over time from about 2% for the first five years to 1.3% for the last five years. The forecast is driven primarily by two variables: population and employment.

The next two series are labeled “High” and “Low” in the legend. These series are estimates based on different economic and demographic changes such that the average high growth rate is 2.05%, and average low growth rate is 1.34%. The differences were derived from an economic analysis performed by an independent consultant in 1997.

The series labeled “Total Load” represents the load including the load which is priced on index. The index load is about 20% greater than the medium load, or conversely, the index load represents about 17% of the total load. Currently, the company does not plan its resource acquisition with this part of the load, as the needs of those customers are fulfilled by going to market, and passing through the price. However, the company does secure the electricity to meet this load and it does use its T&D systems to move the load to its customers. The difference between the Total Load and Medium series is the load priced on index.

The line labeled "Access A" assumes that all of the high voltage customers, plus 90 percent of the primary voltage and large secondary voltage customers, go to some sort of energy market. This is about a 20% decrease from the medium load, and the core that remains grows at a rate consistent with the medium case. It is uncertain at this time when either the Washington State Legislature or Congress will authorize restructuring, what the terms would be, and how companies will react to it. This scenario shows restructuring starting in 2003 and that the transition to market occurs over four years. The magnitude of the load loss in Access A scenario is based on PSE's response to a data request for SB 6560 regarding the impact of possible restructuring scenarios.

The series labeled "Access B" adds in 10% of residential and small commercial customers to the Access A scenario. The 10% figure comes from research on other states which have implemented some form of restructuring and market access. Most states have shown that their residential and small commercial customers have little interest in changing electricity providers at this time. Pennsylvania boasts the greatest change with 8% of small customers switching providers at this time. (The terms and requirements in Washington's restructuring legislation will greatly determine how much residential load will be lost.) The four year decrease is about 26% of load and the core that remains grows at a rate consistent with the medium case.

The line labeled "5% Attrition" is based on the same initial assumptions as "Access B," but it then assumes that the remaining core load continues to lose 5% per year. As the chart clearly shows, this results in a large loss of load over a decade and this scenario sets the lower bounds for these load scenarios.

The series labeled "D.G." assumes that fuel cells become economically viable in 2009, and they are adopted over 10 years to capture the large customers who would go to market in the Access

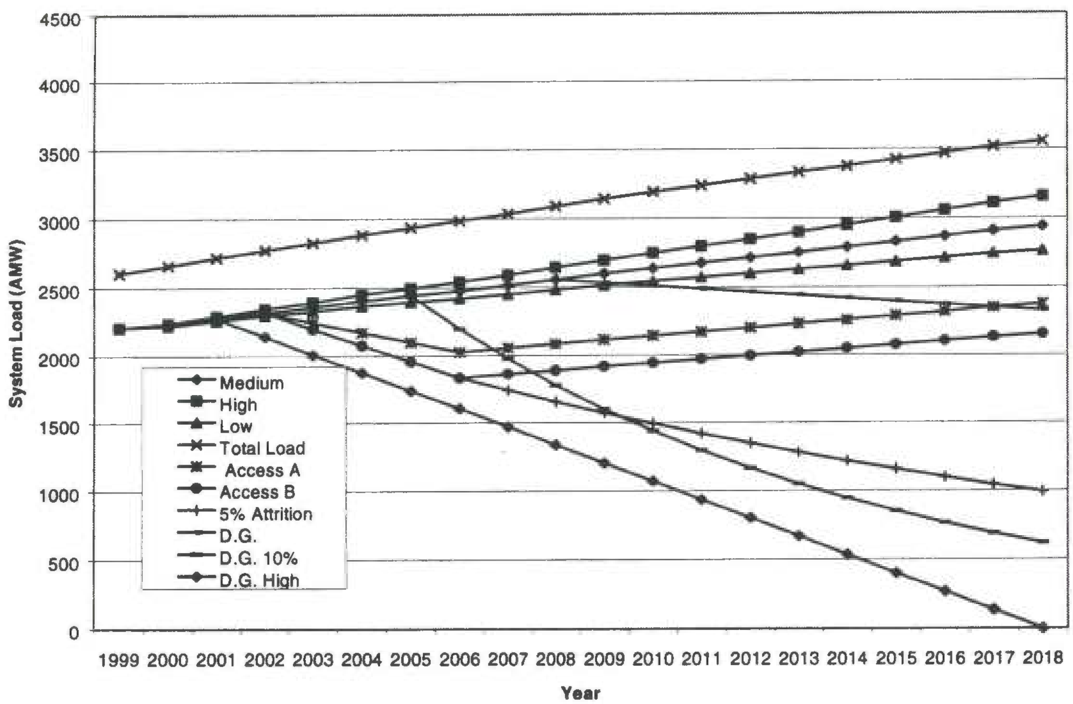
A scenario. Optimistic reports contend that the technology should be available commercially by 2005, for customers who face high cost electricity or have special reliability needs. Economic viability should occur later here because of the low avoided costs, and we may expect a slower adoption rate because the customer has greater engineering responsibility with D.G.

The series labeled "D.G. 10%" assumes a much more aggressive adoption of distributed generation. The initial year of viability is moved up three years to 2006, and the technology is assumed to reduce PSE's gas load by 10% per year for the forecast period.

The series labeled "D.G. High" assumes the extreme case that PSE's gas load is zero at the end of the forecast period. This scenario assumes significant technological breakthroughs and market transformation, as even the residential load is lost. The scenario does not presume the specific dates when massive shocks might occur; hence the straight-line constant reduction is used.

The above scenarios are based on the possibility of two significant changes to the industry: open market access, and the economic development of distributed generation. In both cases neither the date nor the magnitude of the change is known with certainty. Hence it is possible that a market change could look like a distributed generation scenario and vice versa. It is also not unreasonable to speculate that both impacts could occur simultaneously and one of the scenarios could represent that outcome.

1999 IRP Load Forecast Scenarios



Gas Prices

Three gas price scenarios were developed for sensitivity analysis. These forecasts all use the same year 2000 starting point but escalate at different rates over the time horizon of the analyses. PSE estimated the natural gas prices to average $2.27/mmbtu at Sumas for calendar year 2000 for purposes of estimating the Purchased Gas Adjustment (PGA) submitted to the WUTC on Sept. 30, 1999. This price and the WSCC data base information was used to establish the corresponding price at Henry Hub and at the Permian Basin. This price was escalated at annual average rates taken from previous Council analysis. These escalation rates are summarized in Table II.11 below.

Table II.11: Natural Gas Price Escalation Rates

High Gas Price Scenario	4.04%/year	(year 2000 to 2019)
Medium Gas Price Scenario	2.5%/year	(year 2000 to 2004)
	3.32%/year	(year 2005 to 2019)
Low Gas Price Scenario	2.5%/year	(year 2000 to 2019)

D. S. M.

III. DEMAND SIDE MANAGEMENT

A. Introduction and Overview

This chapter reviews PSE's conservation and demand side management programs. The chapter begins with an overview of promising new market-based approaches to load management. Then, the remainder of the chapter focuses on detailed discussion PSE's current conservation programs.

PSE has provided conservation services for its electricity customers since 1980, saving approximately 1,859,140 MWh (cumulative, annual) or 212 aMW (cumulative load reduction). These energy savings, approximately 9% of PSE's average annual electric loads, have been captured through energy efficiency programs designed to serve all customers, residential, low-income, commercial and industrial. Since 1993 natural gas conservation services have been provided, saving 10,581,000 therms (cumulative, annual). All savings have been cost-effective relative to the company's avoided cost in place at the time the measures were put in place. Annual energy savings are recurring for 10 to 20 years for most measures, while certain lighting and water heating measures may have shorter measure lives.

New Approaches to Conservation and Load Management

To date, the company's conservation programs have been developed within the context of a "traditional" energy pricing structure for customers. This structure does not allow for real time energy price signals to reach customers. Typically, "traditional" conservation or load management efforts have not been targeted at the impacts customer actions could have on energy supply costs at peak periods. Instead, customer bills could be reduced somewhat based upon reduced overall energy usage, but, because no clear real-time links existed between customers prices, customer use and supply market conditions, there has been little, if any, ability of traditional conservation programs to directly respond to supply market conditions.

By contrast, emerging market-based conservation and load-management approaches may hold much promise in enabling customers and the region to avoid production costs at the very time when they are most economically costly. The existence of recent high price spikes in energy supply markets nationwide is reflective of the societal cost of resource scarcity at critical time periods. A great social benefit could be achieved by encouraging customers to avoid use at such periods.

Accordingly, PSE plans to investigate approaches that use enabling technology to provide real market signals to customers and thereby enable active conservation and load management. Passing wholesale price signals to retail customers is very important for aligning market information with customer choices. At this time, PSE electric customers (aside from Schedule 48 and special contracts) see no near-term market price signals whatsoever. Generally, a disconnection between wholesale and retail prices can create very distorting signals to the generation market, which will determine when additional generation is needed. This misalignment can lead to resource decisions being made in energy supply markets that do not have the benefit of customer interests and values. Conversely, customers may be able to benefit significantly from modifying use patterns and/or using energy efficiency measures in response to market information. The closer customers come to seeing real time prices form wholesale markets, the better able they are to make choices reflective of real energy supply market economics. Market-based conservation and load management actions taken by customers in response to this information may be tremendously valuable for customers possibly enabling them to avoid market price spikes and other market costs. If broadly implemented, such load management could allow generation markets to avoid production increments when those increments are most costly, producing potential benefits to the entire system.

In the past, technological barriers have stood in the way of providing real price signals to customers with the precision necessary to enable efficient short-run customer decisions. The necessary metering and communication technology has not been available, but this is changing quickly. PSE will be completing implementation of its Automated Meter Reading (AMR) system within the next two years. PSE will be investigating how this and other enabling technologies can be used to pass through real market price signals to customers so that they can take action to manage their loads, ultimately effecting least-cost solutions. As innovative opportunities are created, PSE will work with the Commission, Staff, Public Counsel, and other interested parties to successfully implement new services based on more precise and market-reflective pricing.

Current Conservation Programs

The remainder of this chapter documents the current energy efficiency programs that comprise PSE's approved three year conservation plan. At the end of the three year period these programs will be reviewed based on the then current cost effectiveness standards, experience gained from operating the programs, and other factors that may influence future conservation investment.

PSE, with support and advice from the TAG process, developed its three-year conservation program, replacing the earlier "interim" effort in place since the merger. This filing, which includes conservation programs effective for three years, was approved by the WUTC on March 31, 1999. PSE is now implementing that three year plan. The plan targets 153 million kWh, or nearly 18 aMW and 2,111,100 therms cost-effective savings from all customer segments, at spending levels of approximately $25 Million over the three years. (not including amounts to secure energy savings from competitive bid demand-side performance contracts or to support low income programs beyond amounts recovered in tariff rider/tracker). The three-year period of stability is especially useful for undertakings involving trade allies, customers and other market transformation activities involving multi-year projects.

Customer expectations

Over the past 20 years or so, customers in PSE's service territory have come to expect the utility to provide good information on how to use energy efficiently. The PSE merger of former Puget Sound Power & Light and Washington Natural Gas provides fuel-neutral opportunities to address and support customer energy-efficiency needs regardless of fuel type. Customer demand for this service is in part met with PSE's Energy Efficiency Hotline which answers approximately 2,000 phone calls per month from residential customers interested in some aspect of energy efficiency. This energy efficiency service includes: over-the-phone review, trouble-shooting and recommendations for evaluating personal home energy use; cost-effective efficiency opportunities and options; appropriate follow–up literature (sent by mail); referrals to contractors; information on financing alternatives; and other technical assistance and contacts. In addition, many customers of PSE have directly benefited from financial incentives available over the past 15-20 years. PSE works together with its customers, with other Puget Sound area utilities, and with trade allies to continue to encourage cost-effective energy efficiency installations. Programs have evolved over time following the cost-effective thresholds based on the changing wholesale cost of energy.

During this same time, customer purchasing behavior has become more "energy-efficient", indicating that a certain amount of "market transformation" for some measures has taken place. This can in part be attributed to the successes of past utility incentive programs and energy code adoption. It is now commonplace to be able to purchase only efficient models of some items: for example, double-glazed windows, new energy-efficient mobile homes, and electronic ballasts for fluorescent lighting.

Cost Effectiveness

Cost-effectiveness remains PSE's fundamental guiding principle for investments in conservation programs. In accordance with the Commission requirements, the Company uses the Total Resource Cost test to assess program cost-effectiveness. In addition, PSE uses a Utility Cost test to define the upper limit of the utility's program funding (including both operations and any available customer incentives). The current programs were selected based upon expected cost-effectiveness and, as such, will provide direct benefits to PSE's customers. The DSM program includes a diverse set of offerings consistent with the diversity of PSE's customer base and in consideration of the cost-effective opportunities presented by that diversity. Programs cover all market sectors (e.g., residential, low income, commercial and industrial customers); and a wide variety of end-use applications (e.g., heating, lighting, motors and appliances, etc.). In order to provide for the most cost-effective implementation, programs are delivered through a mixture of approaches (e.g., grants, direct assistance, information, training, etc.). Some are delivered through company action, others through cooperative efforts with trade allies or other utilities or agencies, with special emphasis to support regional market transformation activities that PSE and the region funds through the Northwest Energy Efficiency Alliance (NEEA).

Financing PSE conservation programs

In 1997 the WUTC supported PSE's request for an accounting change for conservation expenditures. Current conservation program costs are expensed and recovered through an electric conservation tariff rider (Electric Schedule 120) on all retail electric sales and a gas conservation tariff tracker (Natural Gas Schedule 120) on all retail gas sales. The tariff rider and tracker provide for collection of a fee on the customer's use; the current rates are 0.039 cents per kWh and 0.117 cents per therm. On an annual basis, the rates are adjusted for over- or under-collection during the prior period.

The annual amount customers fund for conservation programs today through energy rates is close to the amount customers funded on an annual basis in the early 1990's. Today, however, programs are expensed and paid in the year incurred; whereas in the past annual conservation program spending was treated as capital in rates. This historical rate treatment each year created additional future rate funding requirements based on the cumulative unamortized balance.

As part of its overall strategy to address the challenges of a changing industry, PSE was the first electric utility in the country authorized to issue conservation bonds to secure prior conservation investments not yet recovered in rates. PSE issued conservation bonds totaling $240 million in 1995 and $36 million in 1997. The Company's success in issuing these conservation bonds to replace amounts formerly in rate base has reduced the overall cost of conservation programs to rate payers by over $36 million.

The Regional Review Process for the Electric Power Industry, recommended non-bypassable rate payer funding of public purpose activities. While various restructuring legislative proposals in Washington State have considered a statewide uniform "Energy Service Charge", none as yet has been adopted.

Energy Codes in Washington State

Part of the region-wide utility strategy in the past decade was to obtain energy efficiency less expensively in the long term through energy codes. Both residential and non-residential (commercial) building energy codes in the State of Washington, have been adopted in recent years (1991 and 1994, respectively) to achieve lower cost energy efficiency. PSE, other utilities, and other former energy efficiency programs are credited with providing support to enable the adoption of these codes. PSE alone contributed over $ 28 Million toward energy efficiency in residential new construction (between 1986 and 1994) and nearly $23.8 Million in commercial new construction programs (between 1989 and 1997). Together with funding from other utilities state-wide, these programs accelerated market demand for energy efficient products, the increased skills of designers, contractors and installers, and training of code officials. As a result, evaluation results have shown that much of the cost-effective energy savings potential for new buildings is now captured at the time of construction, rather than through utility retrofit programs.

Energy Services Companies (ESCOs)

During the time that PSE has offered conservation programs, a private sector industry commonly referred to as Energy Service Companies (ESCOs) has emerged and evolved in the marketplace. Many ESCOs formed in response to utility demand-side competitive bidding, and initially specialized in demand-side energy management. Successful firms are increasingly enhancing their services to take advantage of the rapid deployment of new technology to provide customers with better access to energy end-use information. Some are strategic ventures by utility subsidiaries to provide enhanced customer value in a competitive environment. Others are evolving from or in partnership with traditional energy-saving product manufacturers, installers, or maintenance contracting businesses. Some (mostly in the larger commercial and industrial facilities) use energy-savings/cost-savings, commonly known as "performance guarantees" as part of the financing service they provide. Experience has shown that these arrangements must be well understood by all parties when services are contracted for. Day-to-day operations and/or business changes beyond the control of one or the other party can greatly influence the customer's energy and cost-savings. PSE works with customers using ESCOs by providing energy-efficiency advice, energy-use information, and/or grant incentives to the end-use customer where applicable and where the activities fit with the parameters of PSE tariff programs.

PSE, at the request of the Commission, undertook two cycles of demand-side competitive bidding, issuing an RFP first in 1989 and the second in 1991. Six (6) contracts were negotiated and awarded to secure 8.5 aMW efficiency improvements at over 100 commercial customer sites. In each case, performance contracts were undertaken. Payment on each is a negotiated price per kWh, based on verified energy savings delivered. Currently, there are 5 remaining contracts with suppliers. Per regulatory agreements, payments for energy savings on these contracts are not included as part of the conservation rider.

B. Key DSM Accomplishments

Energy Savings

The PSE merger provided the opportunity to deliver both electric and gas "fuel-blind" conservation programs. In 1997 and 1998, the first two years of the merger, PSE produced 51336 MWh, or 5.9 aMW and 714,527 therms of cost-effective energy savings. These amounts bring the total energy savings from PSE conservation programs beginning 1979 through the end of 1998 to:
212 aMW (1,859,140MWh), equivalent to the annual electrical energy needed to serve 150,000 homes (roughly all the homes on the east side of King County). Gas savings for 1997 through the first half of 1999 is four million therms, or the annual natural gas requirements for about 4,000 homes.

Three Year Plan

PSE, with support and advice from the TAG process, developed the 1999 conservation program filing, effective April 1999 and continuing for three years. The plan targets 153 million kWh, or nearly 18 aMW and 2,111,100 therms cost-effective savings from all customer segments, at spending levels of approximately $25 Million over the three years (not including amounts to secure energy savings from competitive bid demand-side contracts or to support low income programs beyond amounts recovered in tariff rider/tracker). The three-year period of stability is especially useful for undertakings involving trade allies, customers and other market transformation activities involving multi-year projects.

The current set of programs represent an overhaul of the Company's efficiency efforts to take advantage of PSE's unique opportunities as a dual-fuel company, to accelerate implementation of programs that have been working well, and to emphasize a wide set of cost-effective opportunities. Existing programs were evaluated for cost-effectiveness and customer satisfaction, and have been enhanced as well. As part of its review of the conservation portfolio, the company hired a third-party consultant to conduct a nationwide investigation of program offerings by utilities that continue to invest significantly in conservation. The company integrated useful aspects of other programs from around the country with process modifications derived internally, to develop PSE's new and ongoing programs. The current set of program offerings reflects consideration of the numerous and thoughtful suggestions from TAG members as well as ongoing feedback from the Company's customers.

New Commercial/Industrial Programs

A number of new programs were developed. Two new commercial/industrial programs, Commercial New Construction and Building Commissioning, focus on designing and operating commercial buildings for energy efficiency. For existing buildings, the Commercial Retrofit program has expedited commonly applied measures with streamlined financing to now be able to reach larger numbers of customers. The Company seeks to broaden participation in the Resource Conservation Manager program, which is presently targeted at K-12 public school districts and cities. For the largest customers, an innovative new program developed jointly with eligible customers recognizes the on-site engineering and business expertise to develop cost-effective energy efficiency proposals, and as a result allows industries to apply nearly all of the amounts they contribute to the rider mechanism for cost-effective conservation investment at their own sites. Finally, a new program targets municipalities to accelerate the adoption of LED traffic signals, an, energy-efficient technology for which customer maintenance cost reductions provide significant benefits to allow this otherwise expensive measure to meet a Total Resource cost test.

Low Income Programs

A more comprehensive low income program is now offered which supports the installation of cost-effective measures in low income residences of all types: single family, multi-family, and manufactured or mobile homes. The program recognizes that economies can be attained when numerous energy efficiency measures are installed concurrently due to reduced overhead expenses. On a stand-alone basis, some of the particular measures may not be cost effective with today's lower avoided costs, but benefit from concurrent installation. There was mutual strong agreement among members of the advisory group that mobile homes represented a large component of low income housing stock that had not been significantly reached with weatherization improvements in the past.

The program recognizes the additional opportunity by leveraging available Federal and Washington State Matchmaker, and multifamily-property owner funds for low income weatherization related costs. (Public matching funds are used by low income agencies to augment measures receiving partial payment with tariff and non-rider funds and to pay for needed weatherization related repairs.) Additionally, with the Company's commitment in the merger agreement to spend $1 million per year, the Washington State Department of community, Trade and Economic Development (DCTED) and low-income agencies now may combine this funding with tariff funding to insure that they can cover the full measure cost. (Note: The funding provided as part of the merger agreement is not recovered in the tariff rider and is not subject to the cost effectiveness standards governing the tariffed low income program.)

Residential Programs

PSE has targeted a number of efforts for the residential sector that enhance past accomplishments, including saturation of weatherization and electric water heating measures in PSE's service area, as well as other factors such as Washington State Energy code improvements and decreases in conservation "avoided costs." Residential customers benefit from an expanded Information Hotline and PEP services. Both programs have been revised and expanded to insure that the constantly moving and growing residential population has ready access to information to use energy efficiently. The Duplex/Triplex Retrofit pilot initiated in late 1998 at the recommendation of TAG members will be continued should sufficient participation allow it to become cost-effective to administer.

School-age Education

In Concert with the Environment (ICE), the middle and high school energy conservation curriculum, continues to receive broad support. This program has many non-energy benefits (such as efficient use of other resources), as well as long-term benefits, even though quantification of specific near-term energy and non-energy benefits is problematic. Participating schools, other program company sponsors and TAG members familiar with ICE expressed support for continuation of this program given these issues. PSE continues this program and the Company continues to increase the number of sponsors for the program to lower PSE's cost, increase the penetration level, and appropriately allocate costs to other beneficiaries (which include water and solid waste utilities, as well as transportation and air quality authorities).

Regional Cooperation

The Regional Review Process for the Electric Power Industry recommended a continued role for local electric utility delivery of energy-efficiency services as well as a regional approach for broader "market transformation" activities. In 1997, the Northwest Energy Efficiency Alliance was formed to improve the efficiency of electricity use in the four state region. PSE provides a significant commitment and funding level to this non-profit group. NEEA's charter is to carry out "market transformation activities" that are potentially less costly to do at a larger scale than could be done by individual utilities. NEEA also became a venue for carrying forward many of the regionally applicable conservation activities that BPA had funded before it restructured it's financial commitment and conservation program funding available to public utilities throughout the region.

PSE continues active participation on the 20-member Board of Directors, together with representatives from each of the other investor-owned utilities in the Region, as well as BPA, public electric utilities, government, and public interest organizations with energy efficiency interests. Recently the Board of NEEA was expanded to include representation by industrial customers, and the funding arrangement of NEEA is anticipated to extend beyond the original three-year charter, for another three or more years. Where possible, PSE seeks to optimize joint implementation of NEEA and utility program activities on behalf of PSE customers and regional market transformation interests.

At the Puget Sound regional level, the Company is working with designers, builders, and other local utilities. PSE sponsors energy efficiency conferences for the dissemination of energy efficiency information and ideas. The company participates in building commissioning, and it promotes building operator training to ensure that buildings are built and run well. PSE has been involved in improving the state's energy codes and supports appropriate code enforcement. The Company has coordinated with federal DOE and EPA in efforts such as sustainable buildings and "Climate Wise" programs.

C. Conservation Cost Effectiveness Standard

Cost-effectiveness remains PSE's fundamental guiding principle for conservation resources. One of the elements required as part of the 1999 LCP is an updated set of market prices and cost effectiveness standards for both the electric and gas conservation programs. The methodologies are discussed below and the estimates for electric and gas programs are presented.

Electric Program Cost-Effectiveness Standards

As will be discussed further in Chapter VI, PSE's opportunitiy cost of electricity is equal to the price of electricity at the Mid-Columbia plus adjustments such as the transmission costs between the Mid-Columbia and PSE's system. Adjustments for transmission cost are based on the specific load shape of the conservation program. The electric price forecast used is the Mid-Columbia price for the medium gas price scenario presented in Chapter VI, Table VI.3. The numbers shown in Table VI.3 give the annual average prices while monthly averages from the same forecast are used in the calculation of the cost-effectiveness standard.

Under the Total Resource Cost Test and Utility Cost Test, conservation is compared as an alternative to generation resources. The cost effectiveness standard for conservation is derived from the price forecast following the steps outlined below:

1. The monthly prices are allocated to the heating/"winter" season (Oct. through Mar.) and the non-heating/"summer" season (Apr. through Sept.).

2. A seasonal index price is then calculated based on the seasonal distribution of loads for each of the program end use types. Three load shapes are applied in the residential

sector: space heat, water heat, lights and appliances. Two load shapes are applied to the commercial and industrial sectors: heating, ventilation The seasonal load distribution data is derived from ELCAP end use data and PSE historical load shape data.

3. The next step is to account for the regional conservation credit of 10% as specified in the Regional Act. The credit represents a non-quantifiable environmental externality cost.

4. Transmission and Distribution (T&D) line losses of 7.5% plus a cost of $5.00/kw-yr are included for all measures. These estimates are consistent with the NWPPC assumptions for conservation program evaluation.

5. The total cost is the sum of seasonal index price, the regional conservation credit, and the transmission and distribution losses and costs.

6. In turn, the levelized cost effectiveness standard is calculated for this total cost for measure lives of 1 through 30 years. .

The cost-effectiveness standard calculated for 5 program types are presented in Table III.1 below. The actual cost of a measure is compared to this cost effectiveness standard by the Energy Efficiency Services group for inclusion or exclusion of a measure.

Table III.1: Electric Conservation Program Cost Effectiveness Standards - ($/MWh)

Measure Life (years)	Residential Space Heat Measures	Residential Water Heat Measures	Residential Lights & App. Measures	Commercial & Industrial HVAC Measures	Commercial & Industrial Non HVAC Measures
1	32.79	29.82	29.69	31.63	29.59
2	32.98	30.36	30.20	32.16	30.15
3	33.46	31.03	30.86	32.83	30.84
4	33.77	31.53	31.33	33.32	31.35
5	33.93	31.81	31.61	33.62	31.65
6	34.02	32.00	31.78	33.81	31.83
7	34.31	32.43	32.20	34.24	32.28
8	34.59	32.80	32.56	34.62	32.65
9	34.76	33.03	32.79	34.86	32.89
10	35.06	33.43	33.17	35.26	33.29
11	35.38	33.84	33.57	35.68	33.71
12	35.72	34.24	33.97	36.10	34.12
13	36.07	34.65	34.37	36.52	34.53
14	36.39	35.01	34.72	36.89	34.89
15	36.68	35.34	35.04	37.23	35.22
16	36.98	35.66	35.36	37.56	35.55
17	37.28	35.98	35.68	37.89	35.87
18	37.58	36.31	36.00	38.23	36.19
19	37.89	36.64	36.32	38.57	36.52
20	38.20	36.96	36.65	38.91	36.85
21	38.50	37.28	36.96	39.24	37.17
22	38.79	37.59	37.26	39.56	37.48
23	39.08	37.89	37.56	39.88	37.78
24	39.36	38.18	37.85	40.18	38.07
25	39.64	38.47	38.13	40.48	38.36
26	39.90	38.75	38.40	40.77	38.64
27	40.17	39.01	38.67	41.05	38.91
28	40.42	39.28	38.93	41.32	39.17
29	40.67	39.53	39.18	41.59	39.43
30	40.91	39.78	39.43	41.85	39.67

Gas Program Cost-Effectiveness Standards

The methodology used to compute the gas program avoided costs and cost-effectiveness standards is slightly different than for electric programs. As discussed in Chapter VI, avoided costs for each program type are computed using specific program loads shapes using the Uplan-G model. This methodology gives the annual avoided costs for the three program load shapes delivered to the city-gate. These annual costs are used directly to compute the cost-effectiveness standard as described in Step 6 of the electric methodology shown above. The resulting cost-effectiveness standards for 3 program types are presented in Table III.2 below.

Table III.2 Gas Conservation Program Cost Effectiveness Standards - ($/Therm)

Measure Life (years)	Space Heat Measures	Water Heat Measures	Process Measures
1	0.188	0.189	0.193
2	0.176	0.176	0.178
3	0.179	0.178	0.182
4	0.184	0.176	0.184
5	0.198	0.189	0.193
6	0.218	0.205	0.203
7	0.232	0.214	0.210
8	0.243	0.223	0.217
9	0.252	0.231	0.223
10	0.264	0.241	0.230
11	0.275	0.249	0.237
12	0.283	0.257	0.242
13	0.290	0.262	0.246
14	0.297	0.268	0.251
15	0.302	0.273	0.256
16	0.310	0.279	0.260
17	0.315	0.283	0.264
18	0.320	0.288	0.268
19	0.324	0.292	0.272
20	0.328	0.295	0.275
21	0.332	0.298	0.278
22	0.336	0.300	0.281
23	0.339	0.303	0.283
24	0.343	0.305	0.286
25	0.346	0.307	0.289
26	0.349	0.310	0.291
27	0.352	0.312	0.293
28	0.355	0.314	0.296
29	0.358	0.316	0.298
30	0.361	0.318	0.300

D. Conservation Potential Estimates

Different electricity and natural gas models which estimate conservation supply potential have been used, refined, and developed in the recent past. The sets of customers for both fuels are not coincident; hence the pre-merger models are continued in use for this plan. The conservation potential for each fuel -- electricity and natural gas -- can be looked at with these independent models because common PSE sales forecast assumptions and parameters are used as inputs.

Conservation estimates are thereby tied to numbers of customers (for that fuel and end-use type), average use per customer, use by type and class, end-use loading, commercial building types, anticipated trends, etc. At the same time, in an iterative process, PSE's load forecast uses anticipated amounts of program conservation achieved, as well as economic parameters to yield "market-induced" conservation from changes in fuel prices and market or regulatory forces.

The development of PSE's conservation potential estimates requires large amounts of data regarding measure cost and unit energy savings, for a wide variety of customer types, building types, building and equipment vintage, and specific end-uses (heating, cooling, water heating, appliances, etc.). Much of this information has been developed and refined based on industry standards, ongoing evaluation and assessment by PSE, and by others in the region and elsewhere. For review purposes, the results are rolled into major customer sectors and end-use classifications.

Methodology

PSE has developed estimates of conservation potential, incorporating much of the methodology used by the Northwest Power Planning Council for the Northwest Conservation and Electric Power Plan, and using customer demographic and forecast data specific to PSE's service territory. In the first quarter of 1998, PSE's conservation supply curves were updated to reflect changes in the most recent NWPPC Plan (1996 Plan). All conservation measure data was updated to account for changes in codes/standards, new market information, utility evaluation findings, and further conservation program staff experience since the last LCP. All costs were updated to 1997 dollars using a forecast of the consumer price index. PSE has subsequently revised its projection for the 20-year forecast period of 1999 through 2019. The total amount is driven by both the conservation potential in the existing building stock, built and in operation as of 1999, and conservation to be derived from future forecasted new building construction, with energy savings benchmarked to kWh use projected using current energy codes.

Measures are looked at for each of thirteen groupings of customer segments and end-use, aligned with information collected in end-use surveys used in the forecast model, and used by the Regional Power Council model. Nine of these groups are identified in the residential sector, where utility end-use estimates are more homogeneous and more reliably extrapolated. Three categories are summarized in the commercial sector, although the measures analyzed are looked at separately for distinct business types. Industrial potential is summarized in one category, where again measures are evaluated for each of the major industrial SIC code categories in the service territory. As the diversity in building type and end-use type increases with each larger energy-user, the confidence in the estimates diminishes and is more sensitive to basic assumptions.

Each measure, for each customer segment, and for each end-use application within the segment, is run through a cost-effectiveness screen. The measure value, using the assigned measure life, is compared to the cost-effectiveness standard, which represents the value of the savings to the utility. If the measure is less than this value, it is included as part of the available conservation potential.

If the measure value, based on energy benefits alone, is greater than the utility cost-effectiveness standard, the measure is put through a second screen to determine if it satisfies the Total Resource Cost test. Each measure is evaluated to determine if the customer acquires additional non-energy savings benefits. If other, non-energy savings benefits can be quantified, they are added to the equation and the cost-effectiveness screen is re-run based on their dollar value. For some measures, non-energy savings benefits can be documented and are determined to be substantial, but can not be readily quantified. Only the customer (and not the utility) is able to determine the value of these additional benefits. In these cases, PSE reruns the cost-effectiveness screen by allowing these measures to be assigned up to 50% of the energy value as the non-energy benefits. If, within these parameters, the measure satisfies the Total Resource Cost Test, it is included in the conservation potential estimates. Measures not satisfying this second screening are considered more expensive that the Company's avoided cost.

Conservation energy savings are valued using the applicable end-use load shape, consistent with the five PSE load profiles uses in its conservation cost-effectiveness value tables: Residential Space Heat, Residential Water Heat, Residential Lighting and Appliances, Commercial/Industrial HVAC and Commercial/Industrial Other. Values are levelized using the weighted average cost of capital (WACC) of 7.88%.

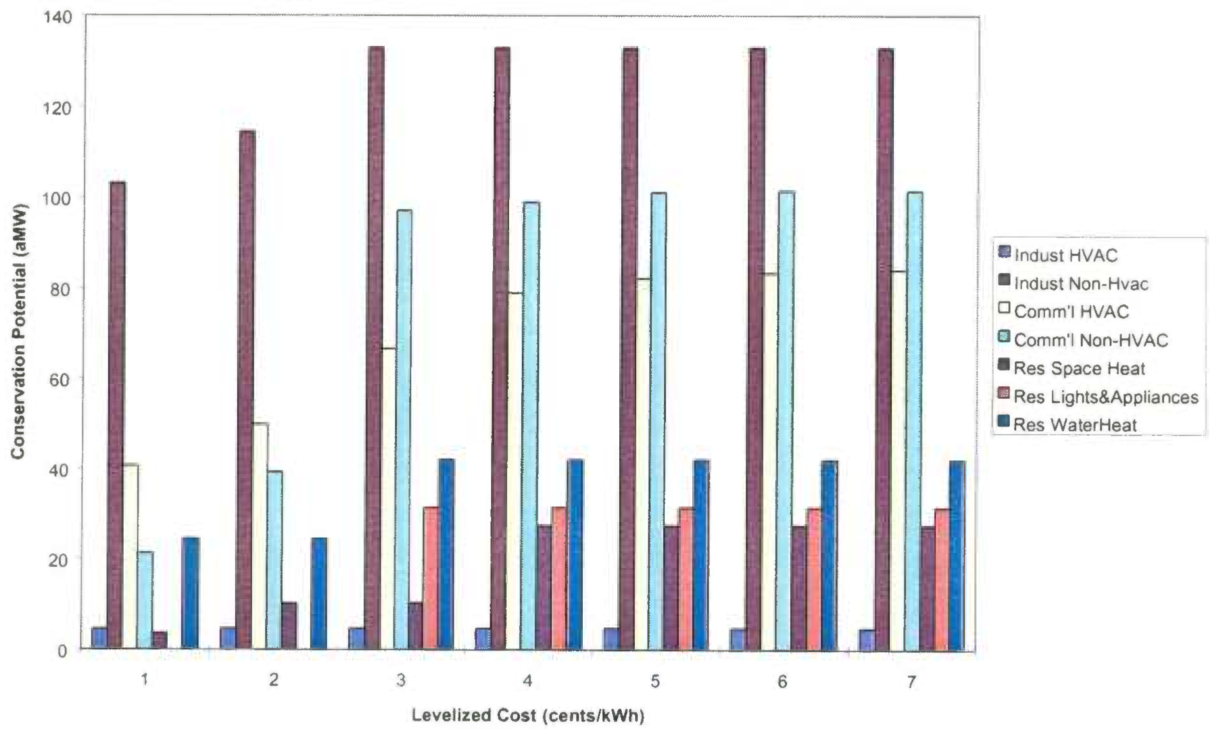
Using the estimates

Year-to-year program operation involves many practical influences not included in the total potential estimates. Determining program design and incentive level is done based on a review of the conservation potential estimates, however it should be noted that these are technical estimates, and are not able to predict customer preferences, market response to program incentives, etc.

In addition to broader market influences and utility business practices, the timing (or rate) at which the utility acquires conservation energy savings from existing (or "retrofit") energy users is a function of the design and scope of utility programs. Further, there are a variety of levels and ways to use incentives to encourage customers to adopt retrofit measures, to influence broader market response or to promote the introduction of newer, better and/or less costly options or technologies. Fuel conversion activities in the marketplace can similarly effect the outcome dramatically. For planning purposes, PSE requires some flexibility to "ramp up" or "ramp down" retrofit program opportunities based on the market environment, including customers needs, contractors' pricing for energy efficiency improvements, and the availability of new products. Timing with respect to conservation energy savings from new construction projects is more sensitive to the local economy and its' cycles. In this model, all available new construction conservation savings are tied to the company's forecast for new loads. Codes for both buildings and appliances are based on those in effect in 1997; no new (i.e. yet to be developed or adopted) codes are projected or anticipated in these estimates.

Finally, certain economic energy efficiency measures, including those precluded if they are not designed or installed at the time of new construction, are often best addressed with a goal of "market transformation". This generally refers to changing the longer-term selling and purchasing behavior for energy efficiency products and services. These efforts, which can include education of customers and training of trade allies, do not necessarily reap measurable short-term energy savings. PSE together with others in the NW Region have supported market transformation activities locally and at the regional level as another approach to acquiring some of the conservation potential identified in these estimates. Based on the activities of NEEA and other market influences, some of the identified conservation potential in PSE's service territory is expected to be realized through marketing and market behavior, broader regional and, in some cases, national efforts.

PSE Electricity Conservation Supply Curve by Sector and End Use



Summary findings

PSE has identified 291 aMW of potential electricity conservation savings for the next 20 years. Each of the three customer sector contribute to the total as follows: 72aMW residential, 108aMW commercial and 111aMW industrial sectors respectively. In Table III.3 below, these amounts are shown as a percent of the sector's forecast electrical average energy load in the year 2018. The cost-effective conservation savings potential for projected residential loads is 5.7% of forecast loads, for commercial 8.3%, and for industrial 16%. Overall conservation potential findings provide guidance for prioritizing customer segments and identifying cost-effective measures in program design and delivery.

Table III.3

Sector/End-Use	AMW	% of sector forecast sales (2018)
Residential, Existing, Single Family	0.00	0.0%
Residential, Existing, Multi- Family	0.00	0.0%
Residential, New Single Family	6.19	0.5%
Residential, New, Multi-Family	0.06	0.0%
Residential, New, Mobile Homes	0.00	0.0%
Residential Hot Water	40.05	3.1%
Residential Refrigerator/Freezer	18.53	1.5%
Residential Dryers	0.00	0.0%
Residential Lighting	10.55	0.8%
Total Residential	**72.4**	**5.7%**
Commercial Retrofit	15.8	1.2%
Commercial Remodel	18.3	1.4%
Commercial New	33.7	2.6%
Total Commercial	**107.7**	**8.3%**
Industrial	**111.1**	**16.0%**
Subtotal C & I	**218.8**	**11.0%**
TOTAL	**291.2**	**8.9%**

Nearly forty (40) aMW are estimated from new construction in commercial and residential sectors (33.7 and 6.2 respectively). Despite the current building boom, significantly less potential is identified since the last LCP based on the fact that Washington State's new energy codes for both residential and commercial buildings have been adopted and to a large degree are being enforced throughout the service territory. Earlier PSE new construction efficiency programs of the late-80's and early 90's, together with other state and utility efforts, helped promote efficiency levels prescribed in these codes and for new manufactured homes (not covered by State code).

The majority of the cost-effective residential savings potential resides in "market transformation" type appliance improvements to yield lower quantities of energy to heat hot water for clothes and dish washing. This potential includes savings that could be gained by adoption of Federal Appliance Efficiency Standards in the future. The Total Resource Cost effectiveness of these measures is based on significant water savings as well as electricity savings benefits.

The majority of the energy savings potential identified in the commercial sector is from energy management controls for HVAC and lighting. PSE's commercial program experience recognizes that energy efficiency, even with short paybacks through savings on energy bills, is typically not sufficient incentive to make changes at a business facility. As a result, targeting and educating commercial customers can involve significant time and effort, as it requires an understanding of customer decision making and budget criteria, and it tends to create longer "lead times" for these projects. Streamlined operation with meaningful results, particularly for time-constrained and resource-limited small businesses, with relatively small energy savings potential, are imperative.

Cooperative working relationships with trade allies and vendors are necessary; however, this can be challenging since there are aggressive project timelines and the current economy offers opportunities to sell products independent of utility programs.

An additional 44.5aMW is included in this commercial potential assessment, consistent with NWPPC estimates that "Building Commissioning" as a measure could reduce commercial HVAC load by as much as 10%. Again program experience and evaluation have shown that installation of an energy management control device (as an example), while necessary, is not sufficient to insure energy savings. Because of the complexity and detail involved, "state-of-the-industry" is that many controls installations are not designed, installed or calibrated for optimum energy efficiency. In addition, operator and maintenance staff training is not routine, and must be reinforced over time. In line with others in the region, including NEEA, one of PSE's program goals is to achieve energy savings from commercial building commissioning projects, and to "transform" the market for this activity.

Lighting is the second major electrical end-use for commercial facilities. Successful retrofits not only address energy efficiency, but match equipment to the customer's specific lighting quality needs. Lighting retrofits have been promoted heavily in past programs; overall lighting efficiency in the market has improved in recent years. Recent efficiency levels prescribed in Washington State's commercial energy code (NREC) for lighting set the baseline new construction lighting at cost-effective levels. Energy efficient lighting beyond code level has marginal savings, leaving little cost-effective potential in new construction. Selected retrofits and improved technology in lighting and controls are the primary opportunities.

Energy conservation potential in the Industrial segment amounts to 111 aMW, or more than a third of the potential identified. In reality, savings estimates are highly site-specific, and often require special process engineering. Estimates are difficult to make as they rely on small numbers of large (sometimes very large) users. Estimates are sensitive to customer classifications and end-use model estimates used with the forecast. Program experience and evaluation verify that there is significant conservation potential, at very cost-effective levels. No changes were made to the generic measures types (mostly motors and process related equipment; some lighting) used to estimate conservation potential in the last IRP. Costs and measure saturation levels were updated as in the most recent NWPPC Plan. No energy codes effecting major uses at these facilities are in place; energy efficiency tends more to be dictated by competitiveness in energy-intensive industries. Industrial customers typically demand very short paybacks for energy efficiency projects, and the likelihood of undertaking a project is driven, among other things by production schedules. Other future drivers may be broader environmental controls (e.g. air or water quality) for selected industrial applications, which could result in changes to energy use.

Overall, the purchase of conservation resources has a significant impact on PSE's integrated resource planning. The total effect is to reduce demand by nearly ten percent and this reduction is accounted for directly in the demand forecast (see discussion in Chapter II, Section D, "Electric Sales Forecasts".) Conservation is largely responsible for residential electric sales growth under one percent. The net impact of conservation is to shift demand down so that less energy is consumed today and in the future.

E. PSE Conservation Programs

This section describes PSE's energy efficiency program offerings. As a result of the merger, PSE's conservation programs were developed as a combination of former offerings by Puget Power on the electric side and Washington Natural for gas demand-side management. While costs are tracked and recovered separately, operation of these programs is done out of one department, with staff that are trained to handle energy efficiency for both fuels. Where gas customers have a different electricity supplier (e.g. Seattle City Light), PSE makes an effort to coordinate its offerings with offerings available from other utilities.

Residential Energy Efficiency Services

The Energy Efficiency Information Program consists of three components working together to achieve cost–effective energy savings by providing information on efficiency improvements tailored to individual customer interests and energy use concerns.

<u>Personal Energy Profile</u>

The Personal Energy Profile (PEP) provides a free–service home energy audit survey, analysis and report designed to achieve cost–effective energy savings by providing customers with specific and customized energy efficiency recommendations for their home. The survey, completed by the customer, includes detailed questions on the home's construction and thermal shell components, energy use habits of the occupants, and all heating, water heating, lights and appliance use from equipment such as home entertainment, kitchen and laundry to second freezers, hot tubs and wood shop equipment. The customer returns the completed survey to PSE for analysis, which includes a computer–generated energy use profile matching the customer's survey responses to his or her actual energy use billing history. A detailed report, based on the survey responses and computer analysis, is mailed to the customer. It identifies current energy costs and consumption by end–use and provides a list of specific recommendations for energy efficiency opportunities and their associated savings estimates.

An intensive Billing Analysis Evaluation of PEP validated the savings per report and also showed additional savings for customers that request the survey and do not return it. The program continues to maintain a high response rate with approximately 50% resulting in a return and report to the customer

Energy Efficiency Hotline

The Energy Efficiency Hotline provides customers direct access, through a toll–free number (1–800–562–1482), to PSE's array of energy efficiency services for all customer sectors. Driven by the "Energy Wise" customer billing newsletter and other billing inserts, 99% of 2,000 incoming calls per month are from residential customers. Hotline services include an over–the–phone review, trouble–shooting and recommendations for evaluating personal home energy use characteristics, efficiency options, appropriate, selected follow–up brochures (sent by mail), and referral to contractors, financing alternatives and other technical assistance providers. Hotline discussions frequently lead customers to the Personal Energy Profile service or to any one or more of the 24 energy efficiency brochures described below. In addition to the direct toll–free access number, customers may also reach the Hotline via PSE's primary customer service toll–free number (888–225–5773, option #7) or by direct transfer from a Call Center Customer Service Representative.

Energy Efficiency Brochures

PSE provides brochures and how–to guides on various energy efficiency opportunities including behavioral measures, low–cost equipment and weatherization measures, major weatherization improvements and equipment upgrades. The Hotline provides over 100,000 brochures/year to gas and electric customers.

Informational brochures presently include:

- Air Sealing Your Home
- Back up Electrical
- CO Detector Brochure
- Compact Fluorescent Lighting
- Controlling Moisture
- Customer Service Offer
- Electrical Appliances & Equipment
- Energy Efficient Windows & Doors
- Energy Select Efficiency Services
- Energy Star
- Gas Water Heater Rebate
- Heat Pump Buyers Guide

- Home Solutions
- Indoor Air Quality
- Insulating Your Home
- Light Wise brochure and store list
- No Cost – Apts. And Condos
- No Cost Low Income
- No Cost – SFH
- PEP Survey
- Reading Your Electric Meter
- Saving by Degrees
- WashWise

Customer awareness of Energy Efficiency Information services for residential customers is provided through frequent energy efficiency articles in the customer billing Energy Wise newsletter and related energy efficiency services inserts, and the customer call center. Targeted PEP promotions are made via dedicated billing insert slips which customers simply fill out and return with their bill payments. Other promotional activities for informational services can include trade shows, home owner and trade ally association presentations.

Residential Low Income Retrofit

This tariff provides funding of cost–effective home weatherization measures for qualifying low income gas and electric heat customers. Funds are used for single family, multi–family and mobile home residences. This program leverages available Matchmaker funds from the Federal government, and funding can be in conjunction with non–rider/tracker funding which PSE additionally provides outside of the energy efficiency cost–effectiveness guidelines of this tariff.

PSE contracts with DCTED under the Energy Matchmaker Agreement for delivery of services, disbursement of tariff funds for completed jobs and reporting of job data to PSE. In turn, DCTED contracts with 11 local county weatherization agencies.

Gas Water Heater Rebates

Customers are eligible to receive a rebate of $25 when they purchase and install a high–efficiency gas water heater in PSE's gas service territory. Qualifying water heaters may be installed in both gas–to–gas conversions and new construction applications.

In Concert with the Environment (ICE)

In Concert is a proven environmental/ conservation education program that is changing how Washington State's secondary students (6–12th grade) and their families think about and use natural resources in their daily living. PSE, along with 26 other utilities or agencies responsible for energy, water and environmental programs in the Puget Sound area, fund the program in over 70 schools each year. ICE partners offer schools the most comprehensive energy and environmental curriculum of any ICE program in the nation. The ICE Program also teaches students how to apply these principles related to air quality, water conservation, waste management and other areas of resource management.

Residential Duct Systems Pilot

It is envisioned that a service combining both heating system diagnostics and repair with duct leakage diagnostic testing could potentially be a viable and cost–effective way to identify candidates for energy savings. Conducting the duct leakage measurements as part of a regular heating service call to the home is expected to add a modest cost to the service call.

PSE will continue this pilot under Phase II of the Duct Sealing Pilot study and work with a small number of independent heating contractors and PSE Customer Service Field Technicians to explore the potential for program expansion.

Compact Fluorescent (CF) Lighting

This program is targeted to multi–family builders, to encourage use of energy efficient CF fixtures instead of incandescent fixtures in new construction buildings. PSE promotes CF fixtures in conjunction with the NEEA residential Energy Star Fixture program. Fixtures must meet PSE/NEEA standards. Builders are offered incentives ranging from $10–$35 per compact fluorescent fixture.

PSE continues to provide educational materials (brochures, retail store lists, phone assistance) to our customers in support of Energy Star Fixture and LightWise Bulb programs. PSE also supports both programs through our PSE Hotline. Additionally, bill inserts containing program overview information is sent out to customers on a monthly basis, promoting these two programs along with other PSE programs

High Efficiency Clothes Washers

The LaundryWise program is targeted to multi–family owners and property managers. PSE, along with Seattle City Light, Seattle Water Department , and LOTT offer rebates for installing high efficiency washing machines. Both new installations and replacements are eligible. These washers save up to 60% energy and 40% water, as well as use less detergent.

Residential Duplex/Triplex Retrofit

This pilot program was designed for up to 300 existing residential duplex or triplex units that meet the following requirements:

- The unit energy consumption is 125% or more of the average consumption of all residential duplexes and triplexes. (This qualification is required to support the cost–effectiveness of the measures.)
- Electric space heating is the only source of heat and is served by PSE.

The structure has not received ceiling, or wall, or floor insulation under an earlier Puget Power program PSE provides a grant for up to 50% of the installed cost of insulation measure(s) up to an amount of $600 per dwelling unit. An initial mailing to 50 owners of potentially qualifying properties in King County yielded a response of only four owners interested in the program. Unless higher volumes of participants can be successfully recruited, the program may be recommended for suspension.

Bulk Refrigerator Purchase Pilot

This program targets low income multi–family projects to replace small standard efficiency 14–15 cu. ft. refrigerators with a high efficiency model. PSE's contribution allows the low income agencies to acquire units at a bulk purchase rate. Agencies purchase the refrigerators in truckloads and PSE pays to store the new refrigerators until they are installed in apartments. PSE also pays for costs of removing and recycling the old refrigerator, using Total Reclaim, Inc. a recycling firm in Seattle. Cost-effectiveness will depend on the volume that the agencies can move quickly.

Non-Tariff Residential Low Income Assistance

PSE provides $1.0 million per year in funding to support measures provided by low income agencies which complement and complete measures offered under the low income weatherization program. This funding provides energy efficiency, safety and educational services for low income gas and electric customers which are not otherwise provided for by tariffed conservation services meeting more stringent cost-effectiveness criteria. The availability of PSE 's non–tracker/rider funding provides the local assistance agencies with additional resources to offer a holistic approach to serving each low income weatherization job.

Commercial/Industrial Retrofit

PSE energy efficiency engineers work with commercial and industrial customers to review energy consumption at the customer's facility and assess cost–effective energy savings opportunities including HVAC and lighting equipment, building shell, industrial process and O&M improvements.

These services are provided on behalf of PSE's energy customer and, as specified by the customer, are developed for implementation by design engineers, contractors and/or other vendors. PSE also reviews third–party savings estimates and analyses. Where projects meet PSE cost–effectiveness funding criteria, PSE provides grants towards energy savings projects. Maximum grants are up to fifty percent (50%) of the incremental installed measure cost based on the Company's cost–effectiveness criteria. PSE works with the customer to help ensure that financial decision–makers at the customer's facility are aware of the cost savings opportunities, including review of energy savings projections that can help in obtaining favorable financing rates. Approximately one year post installation, PSE will review energy consumption at the facility and work with the customer to modify prior work and/or propose further energy efficiency opportunities.

Commercial/Industrial New Construction

PSE works with designers and developers of new Commercial and Industrial facilities, or major remodels, to propose cost effective energy efficient upgrades for equipment, building shell, or industrial process improvements. PSE also promotes opportunities including commissioning, operations and maintenance documentation. PSE will review and/or amend designer and/or contractors savings estimates and analyses. Where projects propose savings beyond the Non–Residential Energy Code (NREC), PSE will provide grant funding in accordance with cost–effectiveness guidelines. PSE works with the customer's design team to help ensure that financial decision–makers are aware of cost–savings opportunities, including lower overall operating cost projections that can help in obtaining favorable financing rates. Approximately one year post occupancy, PSE will review energy consumption at the facility and work with the facilities operators to review cost–efficient O&M practices.

Commercial/Industrial Motor System Efficiency Drive Power Market Transformation Program

This program provides local implementation assistance and expansion of the NEEA Motors Initiative emphasizing efficiency improvements in electric motor systems as well as considering motors as individual components. The program is targeted to medium to large–sized industrial customers that have significant electrical motor loads such as the pulp and paper, wood products, food processing and high technology market sectors.

PSE assists in recruiting customers to provide them with the opportunity to make informed energy–related decisions regarding motor replacement, motor reconditioning, inventory management, and for the sizing of motors and components in a drive system. Services include motor system efficiency awareness, education and training and specific projects such as motor reconditioning standardization. Pilot projects may also be conducted in such areas as motor inventory management and motor drive systems analysis.

Resource Conservation Manager

PSE offers its Resource Conservation Manager Service to any school district, public–sector government agency, commercial or industrial customer, with the focus on larger customers with multiple facilities. An RCM customer is one who employs, or contracts with someone, who has designated resource management responsibilities, including accounting for resource consumption and savings.

The RCM program is comprised of a "menu" of service features:

- Assist customer in designing and implementing an RCM program;
- Hiring Resource Manager;
- Resource accounting system for tracking resource use, analyzing and reporting savings relative to established baseline;
- Training for Resource Manager and other customer personnel;
- Develop resource policy guidelines;
- May provide salary guarantee or partial funding for limited period to reduce the risk for customers;
- Provide PSE billing data in electronic format;
- Provide educational materials for classroom or building occupant use;
- Training opportunities for resource managers and other customer staff such as custodians and maintenance staff. PSE's role is to facilitate customer's efforts.

Customers receive cost reductions for major resource utility bills (i.e. electricity, natural gas, water, sewer) through behavioral changes, operational improvements, facility maintenance, and attention to utility cost accounting.

Northwest Energy Efficiency Alliance (NEEA)

PSE has been a major financial supporter of the Northwest Energy Efficiency Alliance, and is represented through a position on its Board of Directors. The primary function of NEEA is market transformation for the benefit of energy efficiency at the manufacturing and retail level. The PSE Energy Efficiency Services staff have participated in review and development of NEEA funded projects. Through a number of it's own energy efficiency services, the Company has created opportunities to leverage benefits of NEEA information, products and services to PSE Customers

Small Business Energy Efficiency Program

This effort targets small businesses to optimize delivery of PSE's energy efficiency services, and improve the effectiveness with which energy efficiency actions and measures are adopted bythese customers. PSE receives numerous inquiries per year initiated by small business customers who want to better understand how energy is used at their facility and make changes that would save money on their energy bills. This program proactively reaches out to those motivated customers to help them take steps and tap into resources to cost–effectively reduce energy use. For businesses operating out of leased space, this program complements PSE's standard commercial retrofit services that apply to facility owners.

An initial offering will provide information on the top five energy savings steps for small businesses. Most recommendations will improve understanding how much energy is used by various equipment, and the major energy savings opportunities operations and practices. Criteria will also be provided to help customers decide when and how to make modest investments in energy efficiency measures. PSE will incorporate simple–to–use grant applications for prescriptive measures: efficient lighting retrofits and set–back thermostat controls. Random inspections will be used to verify installations. Based on customer input and impact evaluation results, the small business program is expected to be refined. This anticipates features such as targeted promotions, trade ally referrals, expedited rebates, financing options, and potentially community–centered field audits.

Building Commissioning

PSE will work with owners of new (or major remodels) larger commercial buildings to put a building commissioning plan in place and to carry out "commissioning" throughout the construction process. Larger commercial projects, where the owner/end–user is involved in specifying user criteria will be targeted. PSE will assist project staff in getting the owner's commitment, in selection of a commissioning agent (either an independent agent or member of the customer's design or construction team), in developing commissioning criteria which pertain to energy efficiency, and reviewing results. PSE will provide partial funding for the commissioning activity. In addition, grants which are available in the Commercial New Construction tariff may be used towards these projects. Significant additional benefits accrue in terms of thermal comfort, indoor air quality, improved system performance, improved operation and maintenance, improved documentation and training, as well as more timely project completion with reduced change orders. This program will also leverage market transformation work being done through the Northwest Energy Efficiency Alliance (NEEA) and throughout the region.

LED Traffic Signals

This program is targeted to public sector customers with traffic control authority (city, county, and state) to encourage use of energy efficient LED Traffic Signals as replacements for incandescent lights. PSE assists customers in developing economic analyses to estimate life cycle cost–savings, and, as needed, provides customers with vendor contacts and references. PSE provides rebates towards the cost of the LED lights and works through adjustments to Schedule 57 energy charges.

There is a limited market for this technology. PSE has worked with traffic engineers from various jurisdictions to review field testing results and product specifications. PSE will coordinate its efforts with the jurisdictions' replacement cycles. PSE has also been in contact with the State Department of Transportation, which maintains traffic signals in many rural areas and on highway ramps.

High Voltage and Optional Large Power Sales Customer Efficiency Pilot

This program has provided an Energy Efficiency Project Request For Proposals (RFP) to customers receiving high voltage or optional large power sales service. Qualifying large commercial and industrial customers were sent an RFP offering incentives for new energy efficiency projects or programs to be conceived, developed and implemented by the customer for their facility or facilities. Customer proposals are evaluated by PSE engineering staff for cost–effectiveness and energy code and tariff compliance. There are no anticipated restrictions on measure eligibility requirements. Innovative projects are encouraged. Eligible customers owning additional facilities in PSE service area and served under other primary or secondary service schedules may include such facilities in their project proposals to the extent funding is available.

This customer group has very specialized opportunities for energy efficiency and investments must make business sense for their operation. The incentives budget for this program will be based on the conservation program funding amounts collected from the high voltage service customers.

Local Infrastructure and Market Transformation Program

PSE allocates up to 3% of its overall energy efficiency budget to activities aimed at supporting organizations, associations, public education and awareness which can be judged to have long–term energy efficiency benefits in the local Puget Sound Region. It is not the intent to demonstrate short term kWh savings through these efforts, but rather to build broad based, multi–faceted support for energy efficiency. PSE seeks partnerships in this effort with other local utilities as well as both private and public sector energy efficiency interests.

Electric Supply

IV. ENERGY SUPPLY - ELECTRIC

This chapter provides an overview of PSE's electric power supply resource issues, opportunities and options. The existing electric resources fall into one of two categories for logical discussion: PSE owned resources, and PSE contracted resources. Following the sections on PSE's current resources is a discussion of generation resource technologies, including both central generation and distributed generation. This chapter concludes with a discussion of the electric wholesale market, a source of attractive resource opportunities.

A. EXISTING ELECTRIC RESOURCES

Puget Sound Energy generated 35% of its 1998 output, using company owned hydro and thermal resources. Purchased and interchanged power, obtained from hydroelectric generation on the Columbia River and from other long-term contracts with utility and non-utility generators, accounted for 65% of Puget Sound Energy's total energy production in 1998.

Approximately 29% of PSE's 1998 net energy output was obtained through long-term contracts with Public Utility Districts (PUDs) owning hydroelectric projects on the Columbia River. These contracts are generally on a "cost of service" basis; PSE pays a share of the annual cost of each project in direct ratio to the portion of power output it receives. These projects are financed through substantively level debt service payments.

The remainder of PSE's 1998 net electric output was purchased through long-term and short-term contracts with other utilities and long-term contracts with non-utility generators. The estimation of energy from PSE's existing conservation, contract and generation resources along with the load forecast, formed the starting point of PSE's integrated resource planning process.

Table IV.1 PSE Net Electric Output-1998

	Actual '98 MWH	Actual '98 %
<u>Hydro</u>		
PSE Owned	1,231,496	5.5%
Purchased (Mid Columbia)	6,471,295	29.0%
Purchased (other than mid-Columbia)	1,336,655	6.0%
Total Hydro	9,039,446	40.5%
Thermal		
PSE Owned Coal	5,746,536	25.7%
PSE Owned Oil & Gas	956,698	4.3%
Purchased (Net of Sales)	6,575,529	29.5%
Total Thermal	13,278,763	59.5%
Net Energy for Customers	22,318,209	100.0%
Owned Resources	7,934,730	35.5%
Purchased Resources	14,383,479	64.5%
Net Energy for Customers	22,318,209	100.0%

B. PSE OWNED RESOURCES

PSE's 1998 owned resources are listed below in Table IV.2. PSE anticipates that several changes to this list of resources could occur during the future planning period. As discussed in Chapter VI, and in Docket Nos. UE-990267and UE-991409, PSE has an opportunity to sell its interests in both the Colstrip and Centralia coal plants. Second, it is assumed that the 160 MW Encogen plant, currently a supply under a PURPA Contract, is purchased by PSE and added to the list of Company owned facilities. Also, it is assumed that the lease agreement for the Whitehorn 1 plant will expire on December 31, 1999 and will not be renewed.

Table IV.2 Company Owned and Operated Generating Facilities

NAME OF PLANT	LOCATION	FUEL	NO. OF UNITS	% TOTAL PLANT	NET (MW) CAPABILITY
HYDROELECTRIC					
Upper Baker River	Concrete	Hydro	2	100	103.0
Lower Baker River	Concrete	Hydro	1	100	71.4
White River	Dieringer	Hydro	4	100	63.4
Snoqualmie Falls	Snoqualmie	Hydro	7	100	44.0
Electron	Electron	Hydro	4	100	26.4
Subtotal					308.2
STEAM ELECTRIC					
Centralia	Centralia	Coal	2	7	91.9
Colstrip 1 & 2	Colstrip, MT	Coal	2	50	330.0
Colstrip 3	Colstrip, MT	Coal	1	25	175.0
Colstrip 4	Colstrip, MT	Coal	1	25	175.0
Subtotal					771.9
INTERNAL COMBUSTION					
Crystal Mt	Crystal Mt.	Oil	1	100	2.8
COMBUSTION TURBINES					
Whitehorn 1	Ferndale	Oil	1	100	67.5
Whitehorn 2 & 3	Ferndale	Gas/Oil	2	100	178.2
Frederickson 1 & 2	Spanaway	Gas/Oil	2	100	178.2
Fredonia 1 & 2	Burlington	Gas/Oil	2	100	247.2
Subtotal					671.1
TOTAL					1,754.0

PSE Hydroelectric Plants

PSE has the following hydro-electric plants with an aggregate net generating capability of 308.2 MW: Upper Baker River hydro project (103 MW) was constructed in 1959; Lower Baker River hydro project (71.4 MW) was reconstructed in 1960; White River hydro plant (63.4 MW) was constructed in 1911 with installation of the last unit in 1924; At the Snoqualmie Falls hydro plant (44 MW) half the capability was installed during the period 1898 to 1910 and half in 1957; One smaller hydro plant, Electron (26.4 MW), was constructed during the period 1904 to 1929.

PSE has two ongoing and one upcoming Federal Energy Regulatory Commission (FERC) licensing proceedings. The White River and Snoqualmie Falls Projects both have licensing proceedings in progress, and the Baker River Project is in preparation for re-licensing. FERC may require operating criteria that could lower the output or change the nature of the power output from these facilities.

The White River Project was developed before federal licenses were required and consequently has not operated under a FERC license. FERC requested the owners of these older plants undergo licensing for continued operation. The White River Project received a license from the FERC in December 1997 following a 14 year licensing process. However, the license contained conditions which contributed to making the project uneconomic and therefore the license is currently under appeal. Meanwhile, because the project serves many public benefits other than power production, there is great interest in resolving issues associated with the project so that it maycontinue operation. Therefore, PSE has undertaken a two-year collaborative process along with local city and county jurisdictions, state legislators, state and federal resource agencies, neighboring homeowners and other stakeholders to develop potential solutions to project economics.

The Snoqualmie Falls Project license expired in December 1993. PSE continues to operate this project under a temporary license. An application for re-license was filed in 1991 and has yet to be acted upon by the FERC pending resolution of Washington State Environmental Policy Act (SEPA) processes. These processes are ongoing and are expected to take at least one more year to complete.

The Baker River Project license will expire in April, 2006. In preparation for re-licensing, a number of processes have been initiated in anticipation of filing. These preparations include discussions with stakeholders to determine interests in the license, and development of study planning to address affected resources. The re-license proceeding will be formally initiated in the first quarter of 2000 with public meetings.

PSE Internal Combustion

PSE has a standby oil-fired internal combustion unit (2,750 KW) installed in 1969 at Crystal Mountain.

PSE Combustion Turbines

PSE installed an oil-fired combustion turbine unit (67,500 KW) in 1974 at the Whitehorn site. The lease on this plant expires at the end of 1999 and will not be renewed as renewal of the lease was not economic.

PSE installed two pairs of combustion turbines units (89,100 KW each- Whitehorn 2&3 and Frederickson 1&2) during 1981, and another pair of combustion turbine units (123,600 KW each- Fredonia 1&2) during 1984. All of these generating facilities are located in PSE's service territory. All these units may operate on either natural gas or distillate oil. Short-term supplies of distillate fuel are stored on-site. Historically, these units were used solely for winter peaking and firming hydro resources. These plants are currently operated from time to time for peaking purposes and to produce energy for sales to other utilities, either directly or through tolling arrangements, where economic to do so.

PSE Coal Plants

PSE and other utilities are joint owners of four mine-mouth, coal-fired, steam-electric generating units at Colstrip, Montana, approximately 100 miles east of Billings, Montana. PSE owns a 50% interest (330 MW) in Units 1 and 2 and a 25% interest (350 MW) in Units 3 and 4. The owners of the Colstrip Units purchase coal for the Units from Western Energy Company ("Western Energy"), an affiliate of Montana Power Company ("Montana Power") (one of the joint owners), under the terms of long-term coal supply agreements. In February 1997, PSE, Montana Power and Western Energy entered into an agreement to restructure the mines and plants. In the third quarter of 1998, Western Energy, PSE and other joint owners of Units 3 and 4 revised the coal supply contract which reduced the delivered price of coal for Units 3 and 4 and allows for the joint owners to review and approve mining plans and budgets.

In November 1998, PSE announced that it had signed an agreement to sell its interest in the Colstrip plant, as well as associated transmission facilities to PP&L Global, Inc., of Fairfax, Virginia, a subsidiary of PP&L Resources, Inc. PSE's discussion and analysis of the economics of this sale are included in Docket No. UE-990267, and are incorporated here by reference. The closing of the sale for PSE is contingent upon the PSE Board of Directors approving the sale given the conditions for the sale set forth by WUTC.

PSE owns a 7% interest (91.9 MW) in a coal-fired, steam-electric generating plant near Centralia, Washington, with a total net capability of 1,313 MW. PSE has joined with the other owners of the Centralia project in offering for sale its ownership interest in the facility. PSE and other owners have signed an agreement with TECWA Power, Inc., a subsidiary of TransAlta Corporation, to sell ownership interest in the plant and transmission assets. PSE's discussion and analysis of the economics of this sale are included in Docket No. UE-991490, and are incorporated here by reference. The sale is scheduled to close on December 31, 1999, but is dependent upon the PSE Board of Directors approving the sale given the conditions for the sale set forth by WUTC..

C. PSE Contract Resources

Mid-Columbia

The majority of PSE's hydroelectric power comes from the contractual rights on five long-term purchase agreements for portions of the output from Wells, Rocky Reach, Rock Island, Wanapum, and Priest Rapids hydroelectric projects on the middle section of the Columbia River. These five projects along with the remainder of the Columbia River projects are operated for electric power generation according to the provisions of the Pacific Northwest Coordination Agreement (PNCA) and within the conditions imposed by salmon recovery measures. Through utilization of the reservoirs, the PNCA allows parties to shape energy over time to meet their seasonal load needs.

Table IV.3 Summary of Mid-Columbia Power Purchase Contracts

PLANT	OWNER	PSE's SHARE ENERGY AMW*	PSE's SHARE CAPACITY MW*	PSE's SHARE OF OUTPUT CY 2000	CONTRACT TERMI-NATION DATE	WITHDRAWAL PROVISIONS
Wells	Douglas Co. PUD	144	263	31.3%	8/31/2018	PSE's share will remain at this level until contract expiration.
Rocky Reach	Chelan Co. PUD	275	505	38.9%	11/1/2011	PSE's share will remain at this level until contract expiration.
Rock Islandl	Chelan Co. PUD	108	124	50.0%	6/7/2012	PSE's share will remain at this level until contract expiration.
Rock Island II	Chelan Co. PUD	144	341	95.0%	6/7/2012	Beginning July 1, 2000, Chelan may begin withdrawl ofup to 10% per year, up to a maximum of 50% of the project, until contract expiration.
Wanapum	Grant Co. PUD	46	98	10.8%	10/31/2009	PSE's share will remain at this level until contract expiration.
Priest Rapids	Grant Co. PUD	36	72	8.0%	10/31/2005	PSE's share will remain at this level until contract expiration.
Total	All Projects	753	1,403			

*Based upon median water in operating year 2000.

Contracts from the Mid-Columbia are PSE's lowest priced resources and are among the most flexible. PSE continues to work closely with the Mid-Columbia Public Utility Districts to foster a cooperative environment for contract extension discussions. For example, PSE is currently engaged with Chelan Co PUD to resolve operational issues arising from the sharing of the output from Rock Island System II. PSE and Chelan PUD are also working on modifying the existing contracts to better align their interests on maintenance and improvements of the generation plant at Rock Island System I. Discussions are ongoing with Grant Co. PUD for extension of both the Priest Rapids and Wanapum power purchase agreements.

PSE's purchases of power from the Columbia River projects are generally on a "cost of service" basis. PSE pays a share of the annual debt service and operating and maintenance costs of each project in proportion to the amount of power annually purchased by PSE from each project. Payments are not contingent upon the projects being operable. These projects are financed through substantively level debt service payments, and their annual costs may vary over the term of the contracts as additional financing is required to meet the costs of major maintenance, repairs or replacements or license requirements.

The PNCA is a necessary and important agreement for realization of diversity benefits between utilities and river systems in the Northwest, and realization of benefits from Canadian storage reservoirs constructed pursuant to the Columbia River Treaty. In 1964, PSE and fifteen other utilities and agencies in the Pacific Northwest entered into a long-term coordination agreement extending until June 30, 2003. A new Coordination Agreement was negotiated in 1997 and went into effect replacing the prior agreement in February 1999. Various fishery enhancement measures, including most recently the 1995 "biological opinion" from the National Marine Fisheries Service ("NMFS"), have reduced the flexibility provided by the Coordination Agreement.

Resource Contracts with Other Utilities

In addition to the long term purchase contracts with the Mid-Columbia PUDs, PSE also has numerous power purchase and exchange contracts with other utilities as listed in Table IV.4 and further explained below.

Table IV.4 Resource Contracts with Other Utilities

PURCHASE CONTRACTS	FUEL	Yr. 2000 ENERGY AMW	Yr. 2000 CAPACITY MW	TERMINATION DATE	COMMENTS
Avista Corp.	Thermal Mix	75	100	12-31-02	May be extended to 12-31-04.
Bonneville Power Administration Sales & Exchange - SP	Hydro	75	300	06-30-01	PSE has given notice to terminate effective June 30, 2001.
BPA – Baker Replacement	Hydro	0.8	7	2-2000	Power provided in exchange for flood control operations Nov-Feb
BPA – Snohomish Conservation	Mix	6	12	2-2010	
BPA – Columbia Storage Power Exchange	Hydro	18.4	26	03-31-2003	Amount decreases gradually to 0 in year 2003. Hydro
BPA – Supplemental Capacity	Hydro	0	8	3-31-2003	
BPA – WNP#3 Bonneville Exchange Power	Hydro	42	82	06-30-17	Deliveries made during winter months only.
Canadian Entitlements	Hydro	-31.2	-54	2024	Return of power to Canada resulting from storage reservoir construction
Montana Power Company	Coal	84	97	12-29-10	Can terminate if Colstrip plants 3 and 4 are removed from service.
Pacific Power & Light	Thermal Mix	120	200	10-31-03	Variable price tied to surrogate coal plant costs
Pacific Gas and Electric Exchange	Thermal Mix	0	300	12-2004 (or 5 year notice)	PSE receives energy November-February and sends out energy June-September
Powerex – Pt Roberts	Hydro	2.4	3	Auto renewal	BC Hydro serves Pt. Roberts load
TOTAL		392.4	1081		

Avista Corporation 15 year Purchases

January 1, 1988, to December 31, 2002. This is a system delivery, not a unit-specific, purchased power contract. The rates for power under this agreement have been stable and are expected to remain so through the end of the agreement. The power is delivered at the Mid-Columbia hub or other mutually agreed upon point.

Bonneville Power Administration (BPA) Sales and Exchange

November 1, 1988, to June 30, 2001. This is a system delivery, not a unit-specific, purchased power contract for winter deliveries. The price of power is based on a fixed price adjusted by prevailing BPA rate schedules. The power is delivered to PSE's system.

BPA Baker Replacement

October 10, 1980 to September 30, 2000. This agreement calls for PSE to provide flood control for the Skagit River Valley by reducing the level of the reservoir behind the Upper Baker hydro project during the months of November through February. During periods of high precipitation and run-off during these months, the water can be stored in the Upper Baker reservoir and released in a controlled manner to reduce downstream flooding. In return for providing flood control, PSE receives power from BPA during the months of November through February to compensate for the reduced generating capability caused by the reduced head at the plant.

There are three parties to this agreement: PSE which provides the flood control service and receives power; BPA which provides the power; and the Army Corps of Engineers which pays BPA for the power. The company is presently negotiating the renewal of this agreement.

BPA Snohomish Conservation Contract

March 1, 1990, to February 28, 2010. This agreement, also called the Conservation Transfer Agreement, is a system delivery, not a unit-specific, purchased power contract. Snohomish County Public Utility District (PUD), together with Mason and Lewis County PUDs, install conservation measures in their service areas. PSE receives an equivalent amount of power saved over the expected 20-year life of the measures. The Bonneville Power Administration delivers the power to Puget Sound Energy through the year 2001. PSE will then continue to receive the power from Snohomish County PUD for the remaining life of the conservation measures. Only an energy payment, not a capacity payment, is specified in the agreement.

BPA Columbia Storage Power Exchange (Supplemental Entitlement and Capacity Purchase) Agreements

August 13, 1964, to March 31, 2003. These are system delivery, not unit-specific, power contracts between Puget Sound Energy, BPA, and various other parties. Certain utilities in the northwest United States and Canada are obtaining the benefits of additional firm power as a result of the ratification of a 1961 treaty between the United States and Canada under which Canada is providing approximately 15,500,000 acre-feet of reservoir storage on the upper Columbia River. As a result of this storage, stream-flow that would otherwise not be usable to serve firm regional load is stored and later released during periods when it is usable. Pursuant to the treaty, one-half of the firm power benefits produced by the additional storage accrue to Canada. PSE's benefits from this storage are based upon its percentage participation in the Columbia River projects and one-half of those benefits must be returned to Canada. Also in 1961, PSE contracted to purchase 17.5% of Canada's share of the power to be returned resulting from such storage until a phased expiration of the contract from 1998 through 2003.

BPA Supplemental Entitlement and Capacity Purchase Agreements

PSE also has contracted to purchase from BPA Supplemental and Entitlement Capacity in order to maximize the use of PSE's share of the benefits of the additional upstream storage. Capacity rates are fixed over the life of the agreement. The amount of Supplemental and Entitlement capacity purchased from BPA decreases gradually until contract expiration in the year 2003.

In 1997, PSE entered into agreements with the Mid Columbia PUDs which specify the amount of PSE's share of the obligation to return one-half of the firm power benefits to Canada beginning in 1998 and continuing until the earlier of the expiration of the PUD contracts or 2024.

BPA – WNP-3 Bonneville Exchange Power (BEP)

January 1, 1987, to June 30, 2017 (the maximum contract energy will be reached about April 2004). This is a system delivery, not a unit-specific, purchased power contract. Puget Sound Energy and the Bonneville Power Administration entered into an agreement settling PSE's claims resulting from BPA's action in halting construction on nuclear project WNP-3, in which PSE had a 5% interest. Under the settlement agreement, Company receives from BPA, for a period of 30.5 years beginning January 1, 1987, a certain amount of power determined by a formula and depending on the equivalent annual availability factors of several surrogate nuclear plants similar in design to WNP-3. PSE is guaranteed to receive not less than 191,667 MWh in each contract year, until receiving total deliveries of 5,833,333 MWh (expected by April, 2004)

Canadian Entitlement Return

Pursuant to the treaty between the United States and Canada, one-half of the firm power benefits produced by the additional storage accrue to Canada. PSE's benefits and obligations from this storage are based upon its percentage participation in the Columbia River projects. In 1997, PSE entered into agreements with the Mid Columbia PUDs which specify the amount of PSE's share of the obligation to return one-half of the firm power benefits to Canada beginning in 1998 and continuing until the earlier of the expiration of the PUD contracts or 2024.

Montana Power Company 20-Year Contract

October 1, 1989, to December 29, 2010. This is a unit-specific, purchased power contract. Capacity payments are specified in the contract for each year and are reduced if specific performance is not achieved. Energy payments are computed each month and set equal to the actual cost of coal burned at Montana Power Company's Colstrip Unit Four.

Pacific Gas & Electric Company Seasonal Exchange

This is a system delivery, not a unit-specific, purchased power contract. Under this agreement, 300 MW of capacity, together with 413,000 MWh of energy, is exchanged every calendar year on a one-for-one basis. PSE provides power to Pacific Gas & Electric (PG&E) during the months of June through September, and PG&E provides power to PSE during the months of November, December, January and February. (PSE is a winter-peaking utility, while PG&E is a summer-peaking utility.) There are no payments to either party under the agreement. This contract allows for reciprocal use of each utility's idle generation capacity. Either party may terminate the contract five years after issuing notice.

Pacific Power & Light Company 15-Year Purchase

November 1, 1988, to October 31, 2003. This is a system delivery, not a unit-specific, purchased power contract. Capacity payments are specified in the contract and fixed for each year. The contractual amount of power is backed by Pacific Power & Light's generation system. The energy rate is revised annually through the application of a formula that escalates the energy rate at the same rate as the DRI coal price index escalation. However, this escalation is capped at 105% of the actual change in coal fuel costs experienced at the Jim Bridger and Centralia coal plants.

Powerex 5-Year Purchasse for Point Roberts

October 1, 1996, to September 30, 2001. Powerex delivers electric power to serve the retail customers of Puget within the boundaries of Point Roberts, Washington. The Point Roberts load, which is physically isolated from PSE's transmission system, is connected to British Columbia Hydro's electric facilities. Puget pays a fixed price for the energy during the term of the contract. There is no capacity charge.

Non-Utility Cogenerators: PURPA Contracts

The five contracts listed in Table IV.5 produce power through co-generation. Most non-hydro electricity is generated by one basic process: a fuel is burned to produce steam from water, and in turn the steam drives a turbine to create electricity. The process is about 30% to 40% efficient and much of the loss is in the wasted heat. Co-generation facilities capture some of the heat that would otherwise be wasted and use it in a manufacturing or industrial process as an energy efficiency effort. The two processes, electricity generation and the manufacturing, must be located close to each other since the heat energy cannot be transported efficiently. The conservation value of the co-generation process can be calculated from the amount of heat energy that the manufacturing process uses which would otherwise have to be generated.

Table IV.5 Resource Contracts with PURPA Non-Utility Cogenerators

PURCHASE CONTRACTS	FUEL	Yr. 2000 ENERGY AMW	Yr. 2000 CAPACITY MW	TERMINATION DATE	COMMENTS
QF – Encogen	Gas/Oil	153	160	6-30-08	Potential of ownership under contract restructure
QF – March Pt 1	Gas	70	83	12-31-11	
QF – March Pt 2	Gas	57	63	12-31-11	
QF – Sumas	Gas	117	120	4-15-13	
QF – Tenaska	Gas/Oil	217	245	04-8-11	PSE supplies the natural gas
TOTAL		614	671		

Encogen Cogeneration (Gas-Fired Co-generation)

On September 26, 1990, PSE executed a 15-year contract to purchase 141 average MW of energy and 160 MW of capacity, beginning in July 1993, from Encogen Northwest L.P. ("Encogen"). Encogen is a limited partnership having a general partner that is a subsidiary of Ensearch Development Corp. Encogen owns and operates a natural-gas fired co-generation facility located at the Georgia Pacific mill near Bellingham, Washington. The contract was to have run 15 years from the commercial operation date of July 1993.

On September 30, 1999, PSE announced an agreement to purchase the plant and underlying gas supply and transportation contracts from Encogen. Ownership will significantly reduce the net cost of power from this co-generation project compared with contract costs as discussed in Docket No. UE-991498. In addition, PSE may displace generation from the project and save the difference between the cost of replacement power and the project's variable operating costs. Unlike the conditions of the existing contract, these savings are realized 100% by PSE and do not have to be shared with the developer. On October 28, 1999 the WUTC issued an Order that sets forth accounting treatment for the purchase of the project and authorizing assumption of securities for the project.

March Point Phase I & II (Gas-fired Cogeneration)

June 29, 1989, to December 31, 2011. On June 29, 1989, PSE executed a 20-year contract to purchase 70 average MW of energy and 80 MW of capacity, beginning October 11, 1991, from the March Point Cogeneration Company ("March Point"). March Point owns and operates a natural gas-fired cogeneration facility known as March Point Phase I. On December 27, 1990, PSE executed a second contract (having a term coextensive with the first contract) to purchase an additional 53 average MW of energy and 60 MW of capacity, beginning in January 1993. The power for the second contract was from another natural gas-fired co-generation facility owned and operated by March Point, known as March Point Phase II. Both plants are located at the Texaco refinery in Anacortes, Washington.

PSE pays the developer according to a predetermined escalating energy rate schedule for energy actually delivered to PSE's system. PSE may displace generation from the project and save the difference between the cost of replacement power and the project's variable operating costs. These savings are shared with the project owner.

Sumas Energy Cogeneration (Gas-fired Cogeneration)

On February 24, 1989, PSE executed a 20-year contract to purchase 108 average MW of energy and 123 MW of capacity, beginning in April 1993, from Sumas Cogeneration Company, L.P., which owns and operates a natural gas-fired cogeneration project located in Sumas, Washington. PSE may displace generation from the project and save the difference between the cost of replacement power and the project's variable operating costs. These savings are shared with the project owner.

Tenaska Cogeneration (Gas-fired Co-generation) On March 20, 1991, PSE executed a 20-year contract to purchase 216 average MW of energy and 245 MW of capacity, beginning in April 1994, from Tenaska Washington Partners, L.P., which owns and operates a natural-gas fired cogeneration project located near Ferndale, Washington. In December 1997 and January 1998, PSE and Tenaska Washington Partners entered into revised agreements which will lower purchased power costs from the Tenaska project by restructuring its natural gas supply. PSE bought out the project's existing long-term gas supply contracts, which contained fixed and escalating gas prices that were well above current and projected future market prices for natural gas. PSE became the principal natural gas supplier to the project and power purchase prices under the Tenaska contract were revised to reflect market-based prices for the natural gas supply.

Contracts with Small PURPA Renewable Resources

The Washington State Electricity System Study SB6560 defines renewable resources as electricity generation facilities fueled by; (a) water; (b) wind; (c) solar energy; (d) geothermal energy; (e) landfill gas; or (f) biomass energy based on solid organic fuels. Meeting energy requirements with renewable energy can promote greater diversity in energy resources while reducing air pollution. The operation of some renewables such as solar and wind produce no pollution or greenhouse gases; while others, such as burning landfill gas to produce electricity, use a fuel (methane and other volatile gases) that would otherwise be wasted as it seeps into the atmosphere. Table IV.6 summarizes the current level of these contracted renewable energy resources in PSE's portfolio.

Table IV.6 Contracts with Renewable Resources

Facility	Contract Expires	Energy
Biomass		
Puyallup Energy Recovery Co.	n. a.	2 aMW (est.)
Spokane Municipal Solid Waste	November 2011	16 aMW
Solar		
U.S. Environmental Protection Agency (under discussion)	Schedule 150	1 aKW (est.)
Residential Customers	Schedule 150	1 aKW ea. (est.)
Small Hydro		
STS Hydropower - Hutchinson Creek	September 2004	0.7 aMW
North Wasco	December 2012	5.0 MW
Koma Kulshan	March 2037	5.0 aMW
Port Townsend Paper	December 2003	0.3 aMW
Kingdom Energy - Sygitowicz	February 2014	0.1 aMW
Twin Falls	February 2025	8.0 aMW
Weeks Falls	November 2022	1.0 aMW
Leishman	Schedule 91	10 KW
Kahn	Schedule 91	7.5 KW
Methane Gas		
King County-Metro	(for Gas portfolio)	500 MMBtu/day

D. Energy Resource Technologies

PSE keeps abreast of the changes in technologies and costs of the many different energy resources available today. This section describes the various resource technologies, their applications, and their cost when appropriate. PSE considers both central generation and distributed resources;,as well as fossil fuels and renewable fuels. Much of the background information below is taken verbatim from the Northwest Power Planning Council, EPRI, and The Energy Journal.

Central Generation

In this report PSE relies upon the Northwest Power Planning Council for the cost comparison of different technologies for central generation: Combined-cycle combustion turbine power plants; Simple-cycle combustion turbine plants; Coal-fired power plants; Solar power plants; Wind power plants. The NWPPC generated a model of the future electricity supply system for BPA using the Aurora model, which PSE also uses for its modeling. The five technologies are described below, followed by a table for easy comparison.

Combined-Cycle Combustion Turbine Power Plants

The gas turbine-combined-cycle power plant using natural gas fuel is the technology of choice for new base load capacity in North America because of its economic efficiency. Though only about 5 percent of WSCC baseload capacity currently consists of combined-cycle plant, over 85 percent of the baseload capacity additions proposed for WSCC are combined-cycle plants. Low gas prices and low-cost, efficient, reliable and environmentally clean gas turbine-combined cycle technology have led to plants that are easily sited, quickly constructed and capable of producing power at estimated lifecycle costs of 2.5 cents per kilowatt hour, or less.

Commercially available gas turbine power plants have not approached practical limits of cost or thermodynamic efficiency. The cost of future plants is expected to decline over time as continued improvement in the technology, design, materials and manufacturing processes improve. This will reduce cost, though not directly in proportion to improvements in specific power because of the possibility that the advanced materials and processes needed to increase specific power will be more expensive than conventional materials and processes. Though these plants produce carbon dioxide, the low carbon content of natural gas and high thermodynamic efficiency of these plants make them superior to conventional coal-fired power plants from a carbon dioxide perspective.

Simple-Cycle Combustion Turbine Power Plants

Simple-cycle combustion turbine power plants are expected to operate primarily as peaking units. Eighty-megawatt class units were the majority of simple-cycle units constructed in the WSCC over the past several years. Though larger, more efficient and less costly turbines are available, very few large simple-cycle gas turbines have been constructed in the WSCC. The reason may be that peaking units often provide local system reliability in addition to system peaking service.

The capital costs of new simple-cycle gas turbines are based on equipment-only gas turbine generator set budgetary prices appearing in the *Gas Turbine World 1997 Handbook.* These prices are developed through discussions with architect/engineering firms, project developers and original equipment manufacturers. As one can see from Table IV.7, the simple-cycle gas turbine has a lower installation cost but a higher running cost based on heat rate.

Coal Fired Power Plants

Coal is the energy source for approximately 23 percent of the generating capacity of the WSCC region. Coal resources are abundant and found in many parts of the WSCC region. Major deposits are located in Alberta, Montana, Wyoming, Utah, Colorado, Arizona and New Mexico. Most of these deposits occur as thick, shallow seams, and can be produced at low cost using surface mining methods. Coal could supply the electric needs of the WSCC region for several hundred years or more. The principal uncertainties facing future development of coal-fired power plants is the cost of competing natural-gas fired combined-cycle power generation and the effects of possible efforts to control production of carbon dioxide, a greenhouse gas.

The pulverized coal-fired steam-electric plant is a mature power generating technology in use throughout the west. It is a pure steam cycle and has attained its maximum practical efficiency without substantial increase in steam pressure that would require the use of costly materials to ensure reliable operation. At this time it appears to be more economical to develop alternative coal-fired technologies using combined gas-turbine steam cycles than to attempt to improve the efficiency of steam-electric technology.

A promising alternative to steam-electric coal technology is the pressurized fluidized bed combustion (PFBC) combined-cycle power plant. In this technology, coal is combusted in a pressurized furnace. The pressurized gaseous products of combustion are cleaned and used to power a gas turbine-generator. Steam, produced both in the pressurized boiler and from the hot exhaust of the gas turbine, powers a steam turbine-generator. PFBC technology offers the advantages of higher thermodynamic efficiency, more compact size, more opportunity for factory fabrication and lower cost compliance with air emission criteria. PFBC technology is being demonstrated at several plants and is expected to be commercially available in the first part of the next decade.

Solar Power Plants

The solar power plant assumptions used for this comparative study are based on 100 megawatt central-station photovoltaic plants. Other forms solar power generation that might develop include rooftop and other distributed photovoltaic applications and solar thermal technologies such as power towers and Stirling dish power plants. Photovoltaics were chosen as the representative solar technology because the technology is commercial, current costs are known and cost trends are evident.

The highest quality solar resources in North America are centered in Nevada and Utah. Good quality resources are found in the adjacent states of the WSCC region and in New Mexico. Good daily and seasonal coincidence of solar resource and electrical load is present in the southern portion of the WSCC region. More northerly areas experience relatively poor coincidence of electrical load and solar resource availability.

Wind Power Plants

Wind power plants are more commonly known as "wind farms," where one will can see fifty to three hundred large turbines in a common area. High quality western wind power resources are assumed to be of one of three general types. "High Plains" resources are typical of the highelevation Great Plains east of the Rocky Mountains. These areas possess abundant very high-quality wind resources, but are generally distant from major load centers. Examples include Medicine Bow area of Wyoming and the Blackfeet Reservation of Montana. "Pacific Coast" resources are scattered, but of high quality and relatively close to load centers. Examples include Altamont and the Columbia River Gorge. "Basin & Range" wind resources occur on ridges running perpendicular to prevailing winds. These can be of fairly high quality, but are of limited extent and generally distant from load centers. The high plains states (NM, CO, WY, MT) have five times the potential as areas such as WA, OR, and CA.

Large wind turbines vary in size from 30 kW to 1,500 kW and costs range from $1,000 to $1,500 per kW. The cost of wind power has dropped greatly since its mass introduction in the 1970's, and there have been great technological breakthroughs which have increased it reliability, efficiency and quality. The primary benefit of centralized wind power plants is environmental, as it is not expected to be cost-competitive, on a commodity basis, with other technologies in the future.

Table IV.7 Comparison of Central Generation Technologies - NWPPC 1998 (1997$)

Technology	Nat. Gas SCCT 80 MW industrial	Nat. Gas CCCT 250 MW industrial	Coal PFBC 340 MW PFBC	Central-Station Wind 350 KW units	Central-Station Photovoltaics 100 MW array
Permitting Period (yr)	2	2	3	2	2
Construction Period (yr)	1	2	3	1	1
Unit Capacity (MW)	75	250	340	50	100
Availability (%)	87	92	81		
Capacity Factor (%)				30	21
Heat Rate (Btu/kwh)	10,860	6,910	8,216		
Capital Cost, overnight ($/kwh)	455	601	1,395	1,125	3,451
Fixed O&M ($/kw/yr)	15.78	18.4	38.73	31.86	16.17
Variable O&M ($/mwh)	0.1	0.8	1	3.5	0.8
Service Life (yr)	30	30	30	30	30

Source: NWPPC, *Analysis of the Bonneville Power Administration's Potential Future Costs and Market Revenues* (98-11).

<u>Other Central Energy Sources</u>

Geothermal power requires access to land with geothermal activity, such as the Geyserville area of northern California, parts of Iceland and New Zealand. Geothermal power utilizes a plant to capture the natural steam which drives an electric generation turbine.

Nuclear power has not been considered by PSE for the LCP. While nuclear power may be the choice of France, Japan and some utilities east of the Rockies, PSE does not currently envision its economic or political viability locally.

Wave power uses ocean waves, or tidal flows to generate electricity. The technology has not proven itself reliable and costs appear prohibitive.

Distributed Resources

According to EPRI sources, there are generally two situations where distributed generation technology can be more efficient than central power generation. The first case is when the fuel is already distributed to the remote site, such as the methane gas at an oil field, or off-shore oil drilling platform. The second case is where the cost of extending or upgrading the distribution system is greater than the cost of installing the distributed power and providing the necessary fuel and upkeep. PSE has one distributed power site at a ski resort where it is less expensive to provide a genset for winter needs than to extend the distribution line to the relatively remote area. PSE has evaluated, and will continue to evaluate the option of installation of distributed generation in areas which require distribution system upgrades as part of its process of finding the least cost solutions.

This section is an overview of the various distributed generation technologies that are commercially available today or are reaching the commercialization stage. Fuel cells are the source of much interest and speculation, and PSE continues to evaluate its participation in the technology with other companies. Also of interest is turbine technology, and distributed renewable technology. This section also discusses the more traditional genset technology.

Fuel Cells

Fuel cells are one of the most promising distributed resource technologies to be developed in recent decades. While the concept of fuel cells has been around for more than 100 years, the first practical fuel cells were developed for the US space program in the 1960's. Because of rapid technology improvements in recent years and massive investment by auto companies, utilities, NASA, and the military, fuel cells are now expected to have major applications for distributed power generation within the next few years.

A fuel cell is like a battery in that an electro-chemical reaction is used to create electric current. The major difference between fuel cells and batteries is that batteries carry a limited supply of fuel internally as an electrolytic solution and solid materials (such as the lead acid battery that contains sulfuric acid and lead plates) or as solid dry reactants such as zinc carbon powders found in a flashlight battery. Fuel cells have similar reactions, however, the reactants are gases (hydrogen and oxygen) that are combined in a catalytic process. Since the gas reactants can be fed into the fuel cell and constantly replenished, the unit will never run down like a battery (see Figure A-1).

Fuel cells promise to deliver electrical conversion efficiencies in the range of 40% to 60% and even higher total energy conversion efficiencies approaching 80% to 90% when used in cogeneration applications where both electricity and the heat of reaction are used.

Fuel cells have very low carbon dioxide emissions relative to other fossil fueled sources, and have the ability to operate quietly and reliably in a modular package. Most of the effort and commercial activity has centered around fuel cells in the size range of a few kilowatts up to a few megawatts, which can be the ideal range for distributed resource units. However, larger units up to 20 MW are also being investigated. The driving force behind fuel cell development is not just the electric power industry. It is also the automotive industry and transportation industry that sees them as a solution to the problem of developing practical electric vehicles. It is this cross-industry interest that has accelerated progress in the area and led to very rapid developments of this technology.

There are four fuel cell technologies currently under rapid development. These include Phosphoric Acid Fuel Cells (PAFC), Molten Carbonate Fuel Cells (MCFC), Solid Oxide Fuel Cells (SOFC), and Proton Exchange Membrane (PEM) Fuel Cells. The technologies are at varying states of commercialization. Fuel cells utilize hydrogen and oxygen as the primary reactants, however, they can operate on a variety of fuels depending on the type of fuel process and reformer used. Natural gas (CH4) is considered to be the most readily available and the cleanest fuel (next to hydrogen) for distributed generation applications, so most work is focused on natural-gas-powered fuel cells. Fuel cells however, need the hydrogen gas to operate so an important step is processing natural gas to separate the carbon and hydrogen atoms. The low temperature fuel cell technologies such as the PAFC and PEM require a fuel processing unit (reformer) to convert the natural gas into a hydrogen-rich mixture suitable for use in the fuel cell. The reformer uses a catalytic reaction process that creates the hydrogen-rich mixture. High temperature fuel cells such as the MCFC or the SOFC do not require the reformer since the high operating temperature of the fuel cell allows for the direct conversion to hydrogen from the natural gas molecule. For utility applications, the focus has been on natural gas, however, the transportation industry is working with gasoline and other fuel reformers to allow PEM fuel cells to use the existing gasoline distribution infrastructure.

A pure Hydrogen Oxygen Fuel Cell

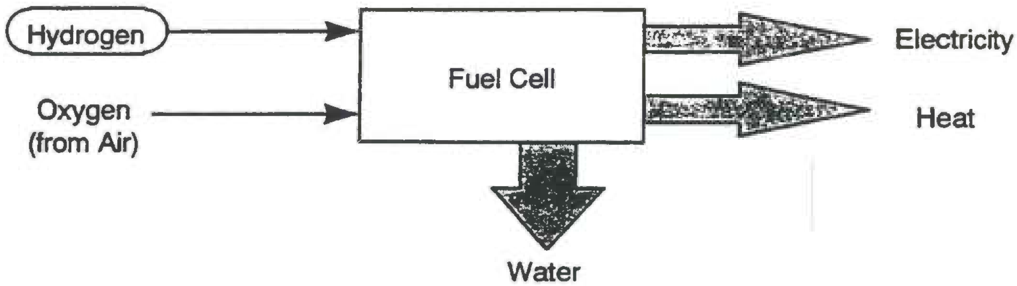


Figure A-1
Fuel cell reactions.

Phosphoric Acid Fuel Cell

The phosphoric acid fuel cell (see Figure A-2) is the most mature of the technologies; but due to system complexities and the platinum catalyst for the electrodes, the costs are staying higher relative to some of the other fuel cell technologies. Currently, this is the only commercially available fuel cell, which International Fuel Cells/ONSI manufactures in 200-kW PAFCs units at a cost of approximately $3000/kW. The Department of Energy (DOE) is also helping to promote this technology by offering a federal subsidy to the purchaser of the unit. There are well over 100 units in service and much operating experience has been obtained. These fuel cells have been installed at medical, industrial, and commercial facilities throughout the country as the 200-kW size is a perfect match for distributed generation applications and backup power for such facilities. The operating temperature is about 400° F which is suitable for low temperature steam cogeneration applications. The electrical conversion efficiencies of PAFC units have been demonstrated in the range of 35-40%. Reliability has been outstanding for many of the units in service. Significant efforts are underway to lower the cost of PAFC units to about $1,500/kW within the next few years which is a cost threshold at which studies suggest a major market develops.

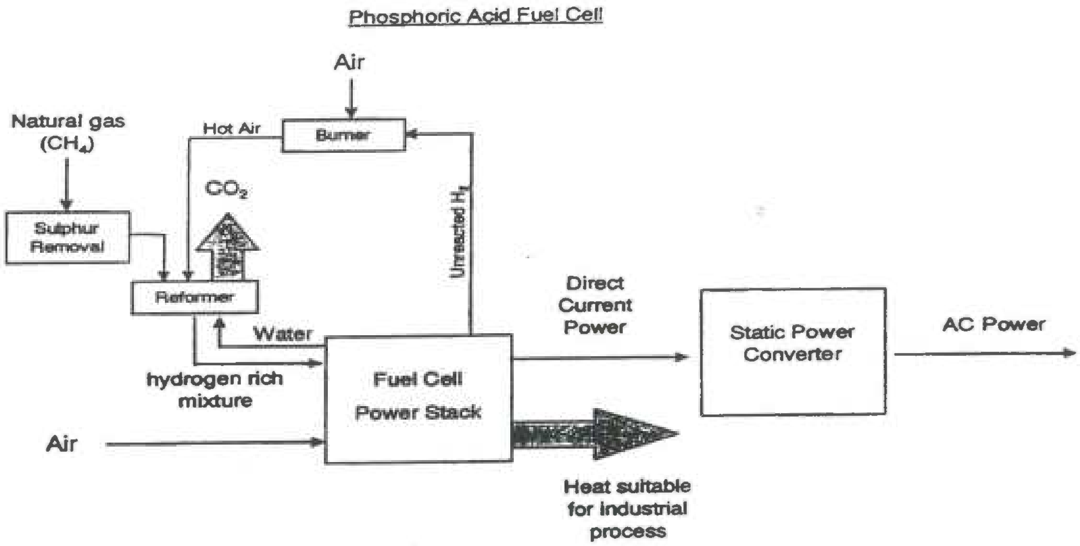


Figure A-2
Phosphoric acid fuel cell functional block diagram.

Molten Carbonate Fuel Cell

Another type of fuel cell is the Molten Carbonate Fuel Cell (MCFC) (see Figure A-3). MCFCs operate at high temperatures of about 1,200° F and are more efficient than PAFCs with electrical conversion efficiency levels in the 50 to 60% range. MCFCs are best suited to large commercial- or medium-sized industrial applications in the 250-kW to 2-MW range. A demonstration project involving a 2-MW pilot plant has been successfully implemented in Santa Clara, California by EPRI. In small volumes of production, MCFCs are predicted to cost about $2,000/kW. It is predicted that in large volume production costs could be reduced to about $1,500/kW.

Due to the high temperature of operations, MCFCs are particularly valuable in cogeneration applications involving higher grade steam heat. Also, their high temperature operation and chemical process means that they can directly be fed the natural gas fuel at ambient pressure. This saves on the cost and complexity of having a compressor to raise the gas pressure, and it saves on having a reformer to break down the methane molecules. Another cost advantages for MCFC's is the use of less expensive nickel for the catalyst. Overall, they show great promise for a wide range of distributed generation applications. PSE has held interconnection discussions with a MCFC manufacturer who is looking to field test this technology in 2001.

Molten Carbonate Fuel Cell

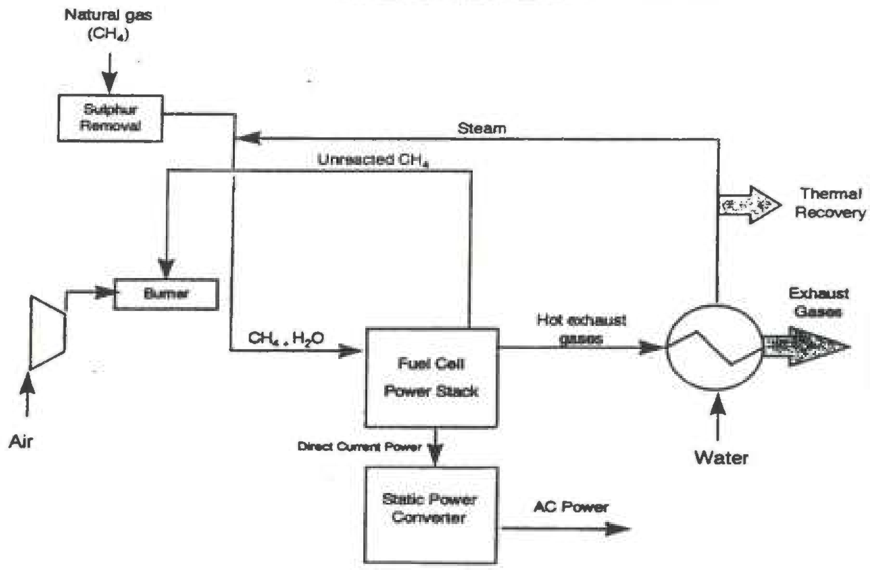


Figure A-3
Molten carbonate fuel cell functional block diagram.

Solid Oxide Fuel Cell

Yet another fuel cell is the Solid Oxide Fuel Cell (SOFC). These operate at temperatures even higher than MCFCs and have very strong prospects for becoming a widely used distributed generation technology. Like Molten Carbonate Fuel Cells, SFOCs do not require a reformer to operate on natural gas because of the high operating temperature. SOFC is the newest of the fuel cell technologies and it uses a coated zirconia ceramic as the electrolyte. There are still some manufacturing challenges to be resolved with mass production of the ceramic cells.

SOFC products are currently being developed in the size range of 2 kW and 1 MW. The US Department of Energy has been strongly promoting the development of the technology and a number of test and research projects involving them are currently under way throughout the world. Seimens and Westinghouse Electric Corporation are the leading developers of the technology and have recently constructed a 100 kW pilot plant in the Netherlands.

Solid Oxide Fuel Cell Integrated with Gas Turbine

An exciting development is the concept of an SOFC-GTs (Solid Oxide Fuel Cell- Gas Turbines). This hybrid fuel cell small gas turbine product can provide electrical conversion efficiencies of 60% to 70%. This is a breakthrough achievement exceeding the efficiency of large combined cycle steam/gas plants which peak at about 55% to 60% efficiency. One major manufacturer is planning to introduce a commercial grade 1.3MW SOFC-GT by the year 2001. The projected efficiency for the first product is 63% with later versions expecting to have electrical conversion efficiencies of 70%.

SOFC-GT concepts rely on the principle that fuel cell efficiency and reaction speed improve when the fuel-cell stack operates above atmospheric pressure. By operating the fuel-cell stack at 4 atmospheres or higher, it is possible to integrate the fuel cell with a gas turbine. In this hybrid arrangement, the gas turbine compressor is used to pressurize the fuel cell, then the hot exhaust from the fuel cell stack, which still contains 50% of the fuel's energy (as unreacted fuel and waste heat), is fed back into the turbine, combusted and expanded to extract more energy. Energy recovered from a recuperator is used to help heat inlet air for the fuel-cell stack and the compressor. The overall process can yield electrical conversion efficiencies up to 70%.

SOFC-GT is appropriate technology for industrial locations, hence many companies are working toward introducing SOFC-GT distributed generation products in the near future. Various microturbine packages may also be integrated with an SOFC fuel cell. Southern California Edison will begin a two-year testing of a Westinghouse SOFC-GT in early 2000. Some industry analysts predict that there may be several small-scale (under 200 kW) SOFC-GT products on the market which incorporate these types of turbines within 3 to 5 years.

Proton Exchange Membrane Fuel Cell

Proton Exchange Membrane Fuel Cells (PEM) are another very promising fuel cell technology. PEM fuel cells operate at a lower temperature than the other three fuel cells discussed (150 to 212 degrees F). The PEM fuel cell configuration consists of positive and negative gas diffusion electrodes (cathode and anode) containing an electrochemically active catalyst layer of platinum deposited on subplates. The anode and cathode are separated by an ion-conducting polymer membrane which allows charge carriers to migrate through the membrane. The PEM fuel cell can attain electrical conversion efficiencies in the range of 50 to 60%.

Due to their lower temperature of operation, PEM fuel cells are not applicable for high temperature or even low-grade steam applications. However, this temperature range is sufficient for residential hot-water heating and space heating using hydronic baseboard systems (circulating hot water). Many see the PEM as the ideal residential fuel cell able to provide electricity and heat. Most development efforts for PEM fuel cells are concentrated on products between 3 kW and 250 kW.

The PEM fuel cell can only accept hydrogen fuel and requires a reformer to convert natural gas into usable hydrogen fuel. Development of a practical cost-effective reformer for the PEM fuel cell has been one of the areas of focus.

A large number of companies including all of the major automobile manufacturers are involved in the development of the PEM fuel cell. Due to its light weight and small size, the PEM fuel cell is considered to be an ideal candidate for transportation applications. Already there are a number of projects ongoing in other cities where PEM fuel cell powered vehicles are being tested.

Some industry analysts believe that widespread utilization of fuel cells at industrial, commercial, and residential loads of all kinds powered first by the existing natural gas infrastructure and then later by hydrogen is only a matter of time. Already marketing studies have identified 60,000 potential sites for SOFC fuel cells alone and the total market capacity for all fuel cell types is estimated to be in the 10 to 100 GW range should a low cost system be developed. Currently the high capital cost make fuel cells uneconomic alternatives to combustion technologies for distributed generation. The two strongest selling points for fuel cells are: 1) higher efficiency, and 2) their near-zero level of emissions of nitrogen oxides, sulfur oxides, and carbon monoxide, which is an important factor in EPA non-attainment areas.

Table IV.8 Comparison of Fuel Cell Technologies

Technology	% Efficiency	NOX ppm	Size MW	Heat Byproduct
Solid Oxide SOFC	45 - 55	0.5 - 1	0.1 - 3	Steam
Molten Carbonate	50 - 60	0.5 - 1	0.25 - 10	Steam
Phosphoric Acid PAFC	35 - 40	0.5 - 1	0.2	Hot Water
Polymer Electrolyte PEM	33 - 37	0.5 - 1	0.25	Warm Water
Gas/Diesel Engines	20 - 35	100 - 2000	0.1 - 2	
Microturbines	25 - 30	9 - 250	0.04 - 0.25	

Source: MC Power, 10.21.99

Internal Combustion Gensets

Gensets represent the distributed generation technology that has been in use for many years: diesel or natural gas fueled reciprocating engines. This technology is proven, and very popular throughout the country because of its fuel flexibility, mobility, and modularity.

The technology is used primarily for backup generation and, more recently, for peak load needs. A 1.6 MW unit fits in a tractor trailer which can be moved and linked as needed. For example, at six different substations, Commonwealth Edison linked 19 units together to provide summer peaking power of 180 MW. One of the great benefits during a period of regulatory uncertainty is that the units were rented which allowed them to avoid the huge long-term capital expenditure of a new central plant.

One of the weaknesses of gensets is their noise and air pollution. In many places they can be used only for temporary power needs in order to meet EPA standards. With the improvements in technology from fuel cells and microturbines, genset manufacturers are now devoting much time and effort to the goal of improving the efficiency of the machines in order to stay competitive. For example, Caterpillar hopes to reduce it NOx emissions from 160 ppm to under 5 ppm for its gas gensets.

Turbines and Microturbines

There are basically two types of gas turbines which are already being employed or are being considered for future employment as distributed resource units. These are the conventional gas or combustion turbines in the range of 750 kW to 25 MW and microturbines (which are very small gas turbines) which are in the size range of 250 kW or less.

<u>Conventional Combustion Turbines</u>

Conventional combustion turbine (CT) generators are considered to be a very mature technology. Typical sizes range from about 0.75 kW up to 25 MW. These units are fueled by natural gas, oil, or both. CTs are either heavy frame or light frame (aeroderivative) design. The heavy frame type is the most popular one in use today. The aeroderivative type means that it basically was adapted from an aircraft engine design and has the advantage of lighter weight and higher efficiency. Modern single-cycle CT units have efficiencies in the range of 30% to 35% at full load. Efficiency will be somewhat lower at less than full load.

CT units are commonly used in cogeneration facilities with sizes of many megawatts or larger. Their quick-start characteristics make them good choices for backup power and peak shaving applications, although they are also commonly used for baseload support especially when cogeneration is included. Capital costs for smaller CT units of about 1-MW size range are around $800 to $1000/kW. Larger units can cost less than $500/kW.

<u>Microturbines</u>

Microturbines are extremely small turbines which are stirring up much interest in the electric utility and transportation industries. For transportation applications, many automotive companies see microturbines as the key to providing a light weight and efficient fossil-fuel-based energy source for hybrid electric vehicles. Meanwhile, the electric power industry sees considerable promise for smaller commercial, industrial, and even residential uses which involve cogeneration or distributed generation.

The microturbines currently under development range in size from about 10 kW up to 250 kW. Some companies involved in the development of microturbines include Allied Signal, Capstone, Elliot Energy, and Northern Research. Microturbines offer the ability to produce both heat and electricity in small scale. The fuel-energy-to-electrical conversion efficiencies of microturbines under development are in the range of 28% to 30%. These efficiencies include the use of a recuperator (a device that captures some of the waste heat to improve the efficiency of the compressor stage). While this may seem relatively low compared to some of the other technologies discussed, it is important to recognize that since the microturbine is located at the point-of-power utilization, cogeneration is also an option in many cases. The combined thermal electrical efficiency of microturbines in such cogeneration applications can reach much higher depending on the heat process requirements. Also, as was discussed in the fuel cells section of this report, a solid oxide fuel cell can be combined with a microturbine to yield electrical conversion efficiencies of 60% to 70%.

Microturbine designers hope that by utilizing low cost mass production techniques adapted from automotive turbochargers, the price for microturbines can be very competitive. Costs in the range of $300 to $500 per kW are being predicted once the technology reaches the mass production stage. Many manufacturers have already introduced beta products and are beginning rapid commercialization of the technology.

Microturbines have already established a small niche where the fuel is already distributed. For example, a remote oil drilling operation is using the methane gas to power the turbines, which produce electricity to run the oil pumps. Similarly, a large oil company plans to generate electricity for its offshore drilling platforms with otherwise wasted methane gas. Another example is that of a rural cooperative in Kentucky which is considering tapping into the wasted methane gas from coal mines, to produce power for the local towns.

Renewable Resources and Cogeneration

As illustrated in Table IV.6 of the previous section, PSE has a portfolio of small renewable resources. This portfolio may grow with the addition of solar power net metering customers and a biomass gas recovery resource. Various renewable resource technologies are discussed below along with PSE's involvement.

<u>Biomass</u>

Typically, methane gas is burned at the landfill site and the electricity is fed into the utility grid. An alternative to creating a landfill and waiting many years for the anaerobic decay of organic material to create methane gas, is to directly burn the garbage, with appropriate devices for air pollution control. PSE currently has one contract with providers who use landfill gas to produce electricity, and PSE has another contract with Spokane Municipal Solid Waste for the electricity it produces from its combustion process. PSE also expects that the agriculture sector may provide some additional electricity. For example, PSE has discussed plans with a dairy which is experimenting with electricity production using methane gas collected from the cows. This process may increase as salmon-related water standards are implemented for the agriculture industry, and the cost of waste disposal increases.

Solar

Solar radiation is often used in thermal systems where the energy is used to heat water which can be used to reduce the load on the standard water heater, or run through a heat exchanger for space heating. Using photovoltaic (PV) cells, solar energy can be directly transformed into an electric current. The cost of producing PV cells dropped greatly in the 1980's and continues to fall at this time for reasons such as improved production methods and economies of scale. PSE's customers may purchase their own PV system and hook it up to their wiring under PSE's Schedule 150, "Net Metering" tariff. If the PV system produces more electricity than the customer needs, the excess is "net-metered" into the local distribution grid for use by other customers. This process reduces the company's electricity generation and transportation needs while crediting the customer for its addition to the total supply. While solar is not economically viable as a central generating resource, it may be an option for some retail customers. PSE has a number of households who are considering net-metering contracts as well as one large governmental operation.

Wind

Wind energy can best be produced where the wind blows continuously. The preferred sites in Washington are on the coast and at some locations along the Columbia river. PSE currently buys no large scale wind-generated electricity; however, it will participate in net-metering with customers following the same guidelines as with solar energy net metering. The customer may purchase their own wind mill and attach it to their electric system, following the guidelines in a Commission approved contract (Schedule 150).

Small Hydro

Most of the state's electricity comes from large hydropower projects along the Columbia river and throughout the state. PSE receives much of its electricity from various large hydro projects; however PSE also takes advantage of independent hydro producers. Typically, these are small hydro facilities in rural areas where they produce a limited quantity of electricity, but much more than the local site can use. The producers can be "Qualifying Facilities" under the PURPA guidelines and hence are promoted as renewable. PSE currently has contracts with ten independent hydro producers. The oldest contract goes back to the 1980's; however few new projects are planned because of limited resources and environmental restrictions.

Cogeneration

Most non-hydro electricity is generated by one basic process: a fuel is burned to produce steam from water, and in turn the steam drives a turbine to create electricity. The process is about 30% to 40% efficient and much of the loss is in the wasted heat. Cogeneration facilities capture some of the heat that would otherwise be wasted and use it in a manufacturing or industrial process. The two processes, electricity generation and the manufacturing, must be located close to each other since the heat energy cannot be transported efficiently. The conservation value of the cogeneration process can be calculated from the amount of heat energy that the manufacturing process uses which would otherwise have to be generated. PSE's four cogeneration contracts save about 225 aMW annually.

Raw Digester Gas

An alternative to burning methane gas derived from organic waste to generate electricity, is to distribute the gas via the gas system. There can be a great energy benefit as it is more efficient to convert gas directly to heat than to use the gas to generate electricity, and then use electricity to produce heat. The direct use of gas requires that two obstacles are overcome: the gas must be of a certain purity, and it must be pressurized and fed into the distribution infrastructure. There is an economic trade off of these costs, such that for some sites it is more efficient to convert the gas to electricity, while at other sites the gas is acquired for direct use. PSE currently contracts with King County - Metro for raw digester gas from the Renton wastewater facility.

Summary

The table below provides a recently published cost comparison of various central and distributed technologies. In general, a combined cycle natural gas turbine is the least cost current resource technology; however, opportunities for other technologies may arise as well. As opportunities do arise, PSE evaluates the economics of the specific resource opportunity at hand and associated issues and opportunities.

Table IV.9 Costs and Efficiency Estimates of Central Generation and Distributed Resources

Technology	% Fuel Efficiency	Fuel $/MMBtu	Investment $/kW	Percent Utilization	O & M cents/kWh	Total Cost Cents/kWh
Central						
CCGT	50 - 58	2.0 - 2.5	300 - 600	> 80	0.2 - 0.5	2.5 - 3.5
SCGT	32 - 38	2.0 -3.0	180 - 350	< 20	1.0 - 2.0+	8.0 - 15.0+
Coal Plant	34 - 40	0.8 - 1.4	800 - 1,400	> 80	0.4 - 0.8	3.0 - 5.0
Distributed						
Base Gensets	30 - 40	2.5 - 6.0	700 - 1800	> 80	0.6 - 2.0	4.5 - 12.0
Peak Gensets	20 - 30	2.5 - 6.0	250 - 500	< 10	4.0 - 7.0+	5.0 - 12.0
Microturbines	20 - 30	2.5 - 6.0	500 - 700	> 50	0.2 - 0.5	15.0 - 25.0
"	"	"	"	< 10	1.0 - 2.0	17.0 - 30.0
Fuel Cells	40 - 55	2.5 - 6.0	2,000-3,000	> 80	0.4 - 1.0	8.0 - 12.0
Solar systems			3,500-5,500	20 - 40	0.1 - 0.5	15.0 - 60 0
Wind Gen			800 - 1,800	25 - 50	0.6 - 1.5	5.0 - 15.0

Source: The Energy Journal, Feb. 1998.

E. Electricity Markets in Western North America

The purchase, sale and exchange of wholesale power has occurred for a number decades in the West, and particularly in the Northwest. Participating in the wholesale market have been the traditional business entities of private and public utilities, and federal PMA's (BPA and WAPA). BPA has built 80 percent of the Northwest's high voltage transmission system, and provided access to the utilities throughout the region. Major transmission interties between the Northwest and Southwest were also developed to send excess power south in summer and bring it back in winter.

Hydro was the largest resource in the Northwest where the Pacific Northwest Coordination Agreement (PNCA) and Columbia Storage Power Exchange (CSPE) provided means for increasing overall output of the hydro system. Coordinated planning and operation of the hydro system using "critical water" assumptions, as well as fluctuations in actual hydro output and loads, provided incentives for utilities to buy and sell "secondary" power.

An organization which encompass the entire western United States was formed to develop rules that facilitate the reliable operation of the interconnected utility territories: the Western Systems Coordinating Council (WSCC). The Northwest Power Pool is the regional reliability organization. PSE is a member of both these organizations.

The Western Systems Coordinating Council (WSCC) provides coordination and reliability planning for the operations of the electric power system in the western part of the continental United States, Canada, and Mexico. The WSCC is the largest, geographically, of the ten regional councils of the

North American Electric Reliability Council (NERC). WSCC's 84 members and 17 affiliate members provide electric service to approximately 65 million people throughout the region. Over 500 executives and other personnel participate in the activities of the WSCC. The WSCC is divided into four sub-areas; the Northwest Power Pool Area (NWPP), the Rocky Mountain Power Area (RMPA), the Arizona-New Mexico-Southern Nevada Area (AZ/NM/SNV), and the California-Mexico Power Area (CA/MX).

The WSCC provides a regional forum for actively promoting regional electric service reliability through the development of planning and operating reliability criteria and policies; the monitoring of compliance with these criteria and policies; and the facilitation of a regional transmission planning process. One of the functions of the WSCC is to compile data to evaluate the adequacy and reliability of the electric system in the region.

The total summer and winter peak demand and annual energy loads for the four WSCC sub-areas are summarized in Table IV.10.

Table IV.10: Actual Peak Demand and Energy Loads in the WSCC - 1998

	Summer Peak (MW)	Winter Peak (MW)	Annual Energy (Gigawatt Hours)
NWPP	49,484	59,972	342,897
RMPA	7,975	7,740	48,066
AZ/NM/SNV	20,430	14,106	97,363
CA/MX	55,441	38,304	254,566
WSCC	131,680	120,122	742,892

The generating capacity located within the WSCC areas by type is shown in Table IV.11.

Table IV.11: Existing Generating Capacity as of January 1, 1999 - (MW)

Generation	NWPP	RMPA	AZ/NM/SNV	CA/MX	WSCC
Hydro-Conv.	46,533	2,578	2,647	9,526	61,284
Hydro-P.S.	0	362	214	3,740	4,316
Steam-Coal	17,264	6,221	9,773	3,220	36,478
Steam-Oil	0	0	160	586	746
Steam-Gas	2,292	234	2,254	18,618	23,398
Nuclear	1,170	0	3,733	4,310	9,213
Comb. Turb.	1,341	339	1,716	2,199	5,595
Comb. Cycle	743	261	1,466	1,536	4,006
Geothermal	121	0	0	2,939	3,060
Int. Comb.	160	103	4	28	295
Cogen.	1,994	479	305	5,309	8,087
Other	432	7	0	1,481	1,920
Total	72,050	10,584	22,272	53,492	158,398

Comparing the summer peak loads shown in Table VI.10 with the total generating capacity shown in Table VI.11 indicates that generating capacity exceeded peak loads by 26,718 MW (158,398 - 131,680) or approximately 20%. More detailed analyses for the four sub-areas as well as projections of future system loads and resources indicate that the WSCC area will have adequate supplies to meet loads with sufficient reserves through the year 2008. (Data from: 1999 WSCC Information Summary)

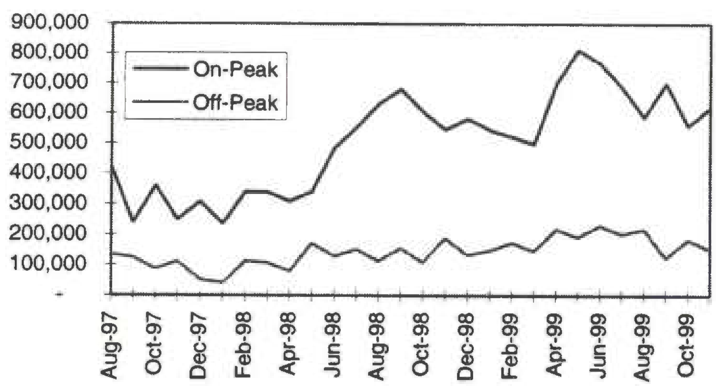
The Western States Power Pooling Agreement (WSPP) is a marketing agreement among its members designed to increase the efficiency of interconnected power system operations. WSPP provides a standardized commercial mechanism to buy and sell wholesale electricity, as an alternative to the one-of-a-kind contracts that were common at the time of its inception. The WSPP agreement establishes rules and definitions for the various transactions as well as other contractual issues such as payment terms and conditions, the relationship among parties, liability, judgments, etc. This agreement deals with wholesale market transactions for prescheduled and real-time coordinated short-term power transactions, such as economy energy transactions, unit commitment service, firm system capacity/energy sales, and transmission service by intermediate systems. All terms and conditions are consistent with FERC orders where applicable.

Parties to the WSPP agreement include public and private utilities, Independent Power Producers (IPPs), federal power marketing organizations such as BPA and power marketers. Over 170 organizations are members of the WSPP.

There are also some physical limits on the flow of electricity within the Western Interconnection based on transmission line capacity. For example, California's large summer peaking demand can be only partially satisfied by the Northwest's inexpensive hydro power because of the limited transmission capacity between the regions. The limits on transmission within the Western Interconnection prevents the attainment of a completely liquid market, which contributes to price differentials within the system. There are, naturally, price differentials within the Western Interconnection because of different costs of generation and transmission; however, greater transmission capacity would reduce the price differentials as electricity moved to the region of greatest demand.

The selling and buying of electricity in the Western Interconnection is contracted for delivery at one of several "trading points" or "hubs" located within the Western Interconnection area. The locations are: Four Corners (4-C) in New Mexico; Palo Verde (PV) in Arizona; the California Power Exchange; the California-Oregon Border (COB); and the Mid-Columbia (Mid-C). Most of PSE's trading takes place at COB and Mid-C. The chart below illustrates the increasing importance of the hubs in terms of volumes traded.

Chart IV.1 Mid-Columbia Monthly Traded Volumes



The markets in the Northwest and, to a lesser extent, throughout the Western Interconnection are heavily influenced by the precipitation, streamflow, and resulting generation from the Northwest hydroelectric generating system. In years with higher amounts of precipitation electricity prices tend to be lower while in periods of drought prices tend to be higher. Fossil fuels are significant energy sources, particularly for the Southwest, so the prices of coal and natural gas can also have great impact on the markets. The price of natural gas can also impact electric prices in the Northwest as gas-fueled combined cycle combustion turbines are expected to be the source of new electric generation.

Prices are impacted by customer demand, working in tandem with supply costs. The Northwest, which is winter peaking, can export power generated during the spring and early summer during spring water run-off to California. California, in turn, can provide power to the Northwest to meet winter heating loads. The Southwest's summer peaking demand has caused prices to spike up at times, and this has had some influence on prices at Mid-C. For example, summer quarter prices have risen about 70% while winter quarter prices have risen less than 5% over the last two years.

Another influence on the prices at the various hubs is the level of paper trades. PSE is primarily interested in buying electricity supplies to provide for its customers, while many other entities are interested in buying and selling electric contracts as they would do with any other tradable commodity. PSE and other utilities will also use electric contracts as financial hedges to provide some price stability in conjunction with contracts for the physical delivery of electric power to one's system. There are future contracts available at COB and Palo Verde; however their growth has been limited due to delivery issues and the influence of some large institutions.

Overall, the Western wholesale market is still in transition, but some observations include:

- The wholesale market has become more competitive and risky with the addition of many new players including marketers, brokers, and nonutility generators.
- The structure of the wholesale market is still evolving, but currently trading margins are thin.
- Utilities face greater price volatility and regulatory uncertainty, hence utilities are not investing in new generation and are moving away from long term supply obligations.
- Risk management products (e.g., weather derivatives) are starting to get some attention but are still relatively new and little used.
- Ancillary power products may be offered to serve retail loads, but products are not well-defined and markets for trading them have been slow to develop.
- The states' varying approaches and differing pace of implementing retail access may affect functions and liquidity of wholesale markets.
- Power prices in the Northwest generally remain lower than in other regions due in part to the Northwest hydropower system.

F. Short Term Management of PSE Resource Portfolio

On an ongoing basis, PSE manages its power supply portfolio to reliably serve its retail customer needs at overall least cost. In the short-term, this is a highly dynamic process driven by a number of factors, including:

- relatively predictable diurnal and seasonal fluctuations in PSE's retail customer requirements;

- less predictable fluctuations in PSE's retail customer requirements, due to temperature swings and other factors;
- year-to-year, seasonal and short-term variability in streamflows and hydroelectric generation;
- volatility in market prices for short-term power purchases and sales; and
- volatility in market prices for natural gas used to fuel combustion turbines.

Continuously managing PSE's power supply portfolio to serve actual retail customer requirements in real-time is a highly dynamic process, requiring careful planning, balancing of various tradeoffs and frequent fine-tuning to respond to changing conditions. This process is most effective when the power supply portfolio and the resources in it have adequate flexibility and diversity. For example, some amount of baseload generation that produces constant power output at low variable operating costs can be a useful and cost-effective component of the portfolio, especially to the extent that retail customer requirements are steady and continuous. However, because PSE's retail customer requirements vary within a broad range and are not precisely predictable, a significant portion of the portfolio must be able increase and decrease output to follow these fluctuations. Fortunately, PSE's owned hydroelectric generating facilities and its long-term Mid-Columbia purchase contracts provide substantial operating flexibility at very low incremental cost. Other resources, including PSE's combustion turbines provide added flexibility and diversity, but incur operating costs that vary with the cost of natural gas used to fuel them.

The competitive commodity market for wholesale power is another source of diversity and flexibility for PSE's power supply portfolio. PSE has traditionally purchased and sold incremental power on the spot market, both to balance its portfolio in the short-term and to achieve net cost reductions. For example, at certain times PSE combustion turbine generation may be the incremental resource available in the portfolio to serve retail customer requirements. At these times, if spot market prices for power are lower than the variable cost of operating combustion turbines, PSE may decide to capture savings by purchasing power on the spot market rather than running its turbines.

Expanded participation in wholesale commodity power markets and use of new forms of power supply transactions to supplement or replace existing resources in PSE's power supply portfolio may enhance PSE's ability to mitigate risks, reduce costs and respond to further industry changes. Accordingly, PSE is examining means to expand and enhance its ability to manage its power supply portfolio to provide reliable, least-cost service to its retail customers. As a result, PSE expects to make its power supply portfolio more diverse and flexible through expanded participation in wholesale power markets, including reducing the extent of its need to depend on long-term, fixed-cost generating resources.

Gas Supply

V. ENERGY SUPPLY - NATURAL GAS

GAS SUPPLY

This chapter covers gas supply resource options. Specifically, this chapter describes:

- The supply-side resources available to meet customer demand;
- Marketplace strategies to lower the cost of resources to core customers; and
- The environment in which gas supply decisions and transactions are made.

Approximately six years have passed since Northwest Pipeline Corporation (NWP) instituted new tariffs pursuant to FERC Order 636. New regulatory initiatives to deregulate the natural gas industry, and energy markets in general, have significantly changed the marketplace. The key changes and effects are listed below.

- Natural gas and, within certain limits, pipeline capacity are now tradable commodities and are functionally available to all market participants.
- The marketplace generates clearer price signals for producers while providing buyers greater choice and flexibility.
- The changes in the marketplace have resulted in greater price risk and more decision making in order to acquire supply at the least cost.
- Administrative costs in terms of labor and analytical tools have risen as LDCs attempt to manage supply risks and minimize the costs to consumers.
- Attempts to minimize gas costs often increase risk.

The new gas supply environment is dynamic with constantly changing gas prices. The array of supply options has expanded greatly as has the number of market participants. There is stiff competition for load and margins among buyers and sellers. Credit and credit worthiness have taken on new importance as the number of transactions and trading partners have increased. The result of all of this change has been an increase in marketplace risks. Gas price risk, upstream/downstream transport risk, supply risk, and credit risk now appear greater than in earlier periods.

PSE accesses this competitive market to meet customers needs by first assessing those needs and then responding to the market. In terms of gas supply, PSE identified 12 areas of importance in its 1995 Least Cost Plan. Each of these areas will have an impact on the portfolio of resources PSE ultimately chooses in the near term, mid term, and the long term. To understand the current and evolving gas supply environment it is necessary to identify the issues that are having the greatest impact on PSE's ability to meet its gas supply and capacity objectives:

- Selection of Supply Regions (geographical location);
- Supply Availability and Diversity of Supply (deliverability);
- Capacity/Supply Utilization (exchanges and swaps);
- Capacity Off-system (Westcoast et al, firm or interruptible);
- Canadian Regulatory (federal and provincial impacts);
- Market Competition (who are we up against, what are the costs);
- Maintaining Market Share (buying power, how to stay competitive);
- Cost of Gas vs. Reliability (spot vs. firm);
- Pricing (market related vs. fixed vs. futures related);
- Capacity Release Market (impact on gas supply and cost);
- U. S. Regulatory (federal and state impacts); and
- Load Factor Management (off-system sales and special contracts).

These issues can be more generally categorized in the following seven topics to be discussed in this chapter:

- Supply;
- Demand;
- Price;
- Pipeline Capacity;
- Regulatory Issues;
- Supply Objectives and Strategies; and
- Additional or Emerging Supply Options.

A. Supply

The overall supply picture for the near-term seems to indicate that gas will be available at generally higher costs. As was discussed in PSE's 1993 and 1995 Least Cost Plans, the gas supply availability appears to be tightening. Numerous reports and studies indicated that the perceived gas surplus was depleting and the supply/demand balance was closer to equilibrium. This supply/demand balance, particularly with respect to peak demand periods, has been further demonstrated over the past year. While firm gas supplies are readily available from all supply basins: British Columbia (B.C.), Alberta and Domestic (U.S.), peak-day supply appears to be much more closely aligned with demand. With the addition of new pipeline capacity, gas supplies from all supply basins have experienced shifts away from traditional markets. PSE continues to have the opportunity to arbitrage between a market that is short (deficit) and a market that is long (surplus) given PSE's geographical location between prolific supply basins and its capacity on NWP and PG&E Gas Transmission NW (PGT); however, price differences between supply basins have generally flattened. The result has been a general trend toward higher prices.

B.C. gas supplies, in particular, are subject to variations in availability as producers await pipeline availability to pursue better market opportunities in Canada and to the East . Many Canadian producers are availing themselves of a greater percentage of cross-provincial border trading (B.C. to Alberta and/or vice versa). In the U.S., gas flows have been directed towards the market offering the highest net-back to the producer. However, net-back prices are influenced by many things including availability of firm capacity, storage, other competing supplies, and market demand. The following is a brief summary of the various supply basins provinces and the Western U.S.

British Columbia

The B.C. supply basin is vitally important to PSE since virtually 100% of all physical gas consumed in PSE's service territory originates in B.C. In addition, from a contractual point of view, PSE must source approximately 25% of its peak day requirements at Sumas, the pipeline interconnect between NWP and Westcoast Energy Inc. (Westcoast) at the U.S./Canadian border.

<u>Alliance Pipeline</u>

Alliance pipeline is a pipeline that is currently under construction to route northeast British Columbia and northern Alberta supplies to the northeastern United States and the Chicago city gate. The initial capacity of Alliance is estimated to be 1,325 MMcf per day. The pipeline is expected to be fully operational by October 1, 2000. With increased demand for B.C. production, gas prices at the Aeco hub and at Sumas should rise. With the expectation of the pipeline's completion, we have already begun to see price increases at both of these trading points. Our perception is that the price differentials between these points will collapse as both points become more liquid. Prices at both points will more closely follow overall North American gas prices.

The results of analysis and surveys conducted by NWP reasonably depict the marketplace perception of the impact on the direction of supply basin flows once Alliance is at full capacity. Increased demand for gas supplies in the western United States due to rapid population growth and growing electric generation markets will result in the Pacific Northwest maintaining a competitive pull on B.C. production. Additionally, the increase of gas supply into Chicago may result in eventual downward pressure on Gulf Coast prices, forcing those producers to seek out more competitive market demand in the west. Permian and San Juan basin supplies will likely follow suit, and Rockies flow into the Pacific Northwest should strengthen. New drilling in B.C. is increasing in response to both higher natural gas and oil prices. The increased supply may ameliorate other price increases.

Southern Crossing

The Southern Crossing pipeline project is being developed by B.C. Gas in order to diversify their portfolio. The goal of the project is to connect gas supplies at the south end of the Alberta Natural Gas system (Kingsgate) to Westcoast pipeline at Kingsvale in B.C. in order to help alleviate winter peaking demand requirements in B.C. The total capacity for Southern Crossing Phase 1 will be 215 MMcf per day and the target in-service date is set for November 1, 2000. Southern Crossing's Phase 2 will add another delivery point at the Westcoast Huntingdon/Sumas interconnect. Increased supply at Huntingdon/Sumas should have the effect of increasing gas price liquidity at that point. Price liquidity and access to additional Canadian gas supply should effectively enhance PSE's resource portfolio by dampening peak day prices and volatility.

Alberta

Alberta gas supply is similarly important to PSE. PSE's single largest gas supply contract (9.7% of PSE's estimated 1999/2000 peak day requirements) is sourced in Alberta. The contract, with five years remaining, will be affected by the supply situation in Alberta. PSE's ability to successfully conclude annual price re-determinations under the contract or to attract other Alberta producers to various types of arrangements will be influenced by the overall supply picture in Alberta. The large increase in producer and NOVA deliverability is due to many factors: strong forward price forecasts, increased pipeline expansions to markets out of Alberta, and strong demand forecasts. Increased capacity to ex-Alberta markets and the lag in drilling and development in Alberta (due to the low prices of the last few years) has resulted in closer correlation to the higher overall North American prices.

United States

PSE has purposefully spread its U.S. gas supply acquisitions at various locations on NWP. Domestic gas supplies are delivered into NWP from numerous individual plant and gathering systems interconnected with NWP or from other adjoining interstate pipeline systems. PSE has intentionally purchased gas supplies at several different market centers. This has several benefits. Market centers create the means by which gas may flow to various demand regions through multiple interstate pipelines. Among other advantages, market centers will allow PSE to take advantage of exchange and off-system sales opportunities, resulting in the potential for core market cost savings. Market centers also provide access to gas from other pipelines increasing the opportunity for lower cost gas purchases.

Gas supply availability has been influenced by the impact of recent pipeline interconnects, expansions, and market centers. Gas that was once captive to NWP has ready access to new off-system markets. In addition, new and proposed highly efficient gas-fired electric generating facilities, including high load factor cogeneration plants, have intensified the competition for existing gas supply. The need to contract for gas at higher load factors is one result of these new areas of competition.

The western U.S. supply situation has also changed as a result of changing market dynamics. Many gas suppliers in the San Juan Basin have historically perceived the Pacific Northwest as a less attractive market than California. Gas suppliers in this region are now choosing to re-enter the Pacific Northwest market, or move their gas to Midwestern or Eastern markets. The primary motivation is that prices in the Pacific Northwest and other regions are gaining parity with other market alternatives. As discussed above, the impact of the new Alliance pipeline in midwest markets should redirect suppliers' attention back to the Pacific Northwest.

Existing Supply-Side Resources

PSE has numerous contractual arrangements currently operating to provide PSE with a portfolio of gas supplies sufficient to meet its customer gas requirements. The following describes the existing portfolio of supply side resources.

<u>Spot (1 to 30 Days Duration)</u>

Gas that is purchased for a short period of time during which neither the seller nor the buyer has a firm commitment to deliver or receive is referred to as a spot gas purchase. A spot arrangement is therefore available on an interruptible basis. The price of spot gas depends upon supply availability and prevailing demand. The price is extremely volatile and may range greatly from day-to-day and month-to-month. PSE purchases spot gas throughout the year subject to demand, prices, weather, and availability. PSE does not rely on spot gas to meet firm peak day gas requirements.

<u>Firm Long-term (1 to 15 Years)</u>

Firm long-term contracts commit both the seller and the buyer to deliver and take gas on a firm basis. From PSE's perspective, the most important consideration is the seller's contractual commitment to make gas available day in and day out, regardless of market conditions.
PSE currently has nine long-term firm gas supply agreements with third party suppliers for remaining terms ranging from one to six years. Under these contracts, gas is available at Sumas (49%), Kingsgate (45%) and various domestic points (6%). These contract options are seen as

beneficial to PSE in light of the expected near-term impact the Alliance pipeline will have on Canadian supplies.

<u>Short-term Firm and/or Interruptible (1 To 11 Months)</u>
Short-term contracts are typically negotiated for a limited period of time. Short-term supplies become available because sellers have excess gas or because expected spot market returns are not worthwhile.

An arrangement to purchase firm gas during the winter months, on a short-term basis, is often referred to as a winter peaking contract. This arrangement is similar to a firm long-term arrangement because of the sellers' and buyers' commitment, but is typically limited to a three to five month period. Sellers enter into winter peaking arrangements because gas supplies are available and not dedicated to long-term arrangements.

An arrangement to purchase interruptible or firm gas supplies on an as needed basis over any duration is referred to as a swing contract. Swing supplies may prove beneficial depending on the structure of the arrangement. The price and other contract terms vary widely and usually represent a hybrid of other supply arrangements. A variation of the swing arrangement may allow the supplier to "put" gas to the buyer under specified terms and conditions. Typically a price concession is given to the buyer.

Storage
Natural gas storage is an important and cost effective component of most LDC supply portfolios. One of the main advantages to storage is that it provides an immediate and controllable source for firm gas supply. Another advantage to storage is its use as a pooling point for volumes of gas purchased but not consumed during off-peak seasons—times of the year when gas is generally less expensive. Significant savings can be achieved if gas is bought when it is least in demand. Further, use of storage allows for year-round takes of gas and the attainment of high load factor commitments required in various gas supply agreements. Additionally, if the storage is located on the LDC's system or in the LDC's market area and connected to the LDC with a special peak season-only transportation service, it allows the LDC to purchase less year-round pipeline capacity than it might otherwise need.

PSE has contractual access to two storage projects that serve differing purposes within PSE's resource portfolio. Jackson Prairie is an aquifer storage field that has been designed to deliver large quantities of gas over a relatively short period of time. Primarily, it represents an intermediate peaking supply source. Located in PSE's market area, use of Jackson Prairie and the associated NWP storage redelivery transportation service (TF-2) minimizes the need for year-round pipeline capacity. Clay Basin is a depleted gas reservoir that has been developed to provide winter-long sustained withdrawal capabilities. Its primary role in the portfolio is as a pooling point for domestic gas supply and as a price arbitrage tool. Gas withdrawn from Clay Basin is delivered to PSE's system using year round firm transportation service (TF-1), but withdrawals can also be delivered to several other markets directly or indirectly. Clay Basin can act as a broad based winter supply source as well as a peaking gas supply source.

PSE owned Jackson Prairie Storage Service

PSE is a one-third joint owner, along with NWP and Avista Utilities, of the Jackson Prairie underground natural gas storage facility. The storage facility, located near Chehalis, WA is operated by PSE. PSE currently has firm daily deliverability of 294,667 Dth and firm seasonal capacity of 6,344,000 Dth under PSE's ownership storage rights.

An expansion of the Jackson Prairie facility was completed in November 1999, increasing the firm daily deliverability of the field by 312,000 Dth to a total of 884,000 Dth, and the seasonal capacity of the field by 3,328,000 Dth to a total of 19,032,000 Dth. PSE's one third share of the increased capacity is reflected in the numbers outlined above and below.

Best efforts service is also available to PSE from Jackson Prairie. Daily withdrawal rights of up to 52,000 Dth is available. Gas received out of Jackson Prairie storage is delivered to PSE's city gate under PSE's seasonal TF-2 firm transportation service agreement with NWP.

Jackson Prairie Storage Service, SGS-2

PSE receives firm open-access storage service under NWP's SGS-2 tariff. This service is provided from NWP's ownership storage rights. PSE currently has firm daily deliverability of 48,390 Dth and firm seasonal capacity of 1,181,021 Dth under SGS-2 storage service. The terms and conditions of service under SGS-2 generally parallel the terms and conditions of PSE's ownership storage rights.

Clay Basin

Clay Basin is a large storage field located in Northeast Utah. The field is owned and operated by Questar Pipeline. PSE has the right to withdraw up to 111,825 Dth/day associated with a seasonal quantity of 13.4 Bcf. PSE has two contracts with remaining terms ranging up to 23 years under FERC regulated rates.

Liquefied Natural Gas (LNG), Peak Gas Supply Service (PGSS) and Propane Air

LNG, PGSS and Propane Air provide firm gas supplies on short notice for a very short period of time. These sources are only used to meet extreme peak demand, that is, for the coldest few hours or days and generally only as the supply of last resort due to their relatively high cost. LNG, PGSS and propane air do not afford all the flexibility of other supply sources. All are useful to meet demands on extremely cold days.

NWP Plymouth LNG Service, LS-1

NWP owns and operates two liquefied natural gas (LNG) storage tanks located at Plymouth, Washington. LNG service is provided under NWP's LS-1 tariff. The Plymouth LNG plant is used as a needle-peak facility. LS-1 service is delivered to PSE's city gate via seasonal TF-2 firm transportation service.

PSE has a long-term contract for seasonal capacity of 241,700 Dth with NWP, which equates to approximately three and one-half days of full service at the maximum daily deliverability level of 70,500 Dth per day. Under current tariff provisions, the rate of injection is equal to 1/200th of the total capacity of 241,700 Dth, or 1,208 Dth per day. Injections and withdrawals can occur on the same day, depending on availability.

PGSS

PSE has the contractual right to call on third party gas supplies for a limited duration during peak periods. Currently PSE contracts for 50,000 Dth per day for up to twelve days during the winter season.

PSE Propane Air Facilities

PSE maintains propane storage capacity of approximately 1,400,000 gallons (130,000 Dth equivalent), and has a daily delivery capability of approximately 30,000 Dth. These facilities are utilized only to meet extreme hourly or daily peak demand. The propane air facilities are connected to PSE's distribution system, therefore no upstream pipeline capacity is required.

Miscellaneous Supplies

PSE has a gas supply arrangement with King County - Metro ("Metro") to purchase gas produced by Metro as the byproduct of its water pollution abatement processes. The quantities of gas are relatively small yet provide another source of reliable gas supply. The gas is delivered directly into PSE's distribution system. The agreement has a remaining term of approximately six years.

Other types of supply include unauthorized overrun of pipeline gas (including line-pack) and the use of gas delivered by third party transporters to an LDC's system. PSE does not view overrun gas as a workable supply source because of onerous penalties and, more importantly, the threat it poses to the pipeline system's integrity. Similarly, PSE does not consider third party transporter gas to be an acceptable supply as it is gas owned and controlled by others.

Risk Analysis

PSE has recently established a Risk Management department to analyze PSE's energy supply portfolio. With the aid of an energy consultant, PSE is also installing an energy management system which includes a comprehensive risk management module. The risk management module can allow PSE to effectively monitor financial transactions and calculate the value of various supply arrangements including parking, balancing, and lending services. For off-systems sales, the analyses may improve PSE's ability to capture additional market and increased margins, by being able to offer various pricing alternatives, with lower risk.

In addition to the new energy management system, PSE will be working with the energy consultant to develop certain analytical tools and techniques that will enable PSE to analyze the market and develop responsive risk management programs.

Information Sources

PSE is presently utilizing on-line and real time information services to provide insight into the regional and continental markets for both gas and transportation. In addition, PSE receives on a daily basis an expansive library of hard copy and faxed information bulletins.

As markets for natural gas have grown increasingly short-term in nature, the job of buying and selling natural gas has grown increasingly complex. In order to stay abreast of the dynamics in the market, PSE continues to implement technology and utilize the tools necessary to evaluate market conditions.

B. Demand

Demand is expressed as actual physical demand or demand that may materialize over time and includes markets that are either physically located on NWP or are capable of accessing NWP. PSE's end-use customer demand is an example of demand physically located on NWP while Pacific Gas and Electric is an example of off-system demand with access to NWP.

The primary geographic areas of significant demand directly competing with PSE for gas supply are:

- The western United States (the largest source of demand being California);
- The markets in the upper mid-western states;
- U. S. East Coast markets served by Transcanada and Iroquois pipelines;

- Certain southwestern states (including various markets in Texas that may access San Juan Basin gas supplies either directly or via back-haul on El Paso and Transwestern); and
- Canadian markets (all provinces).

Specific markets in the areas outlined above are similar to those found in the Pacific Northwest as they include LDCs, large industrial customers, and electric generators. In many instances, but not all, the off-system demand is often greatest in PSE's off-peak season. The counter-cyclical nature of certain markets has at times played into PSE's long-term strategy in managing load factor.

The expanding pipeline grid and new hubs have created a larger and more competitive demand for gas and provided additional means to meet existing demand requirements. The interstate pipeline grid has grown and is interconnected directly with NWP (see Capacity). Thus, there appears to be a narrowing of basis differentials between the various supply basins.

The relative attractiveness of gas supplies from one region to another is determined by factors such as the ease of contracting with suppliers, availability of capacity into and away from supply/market centers, regulatory constraints, incremental market opportunities and price expectations.

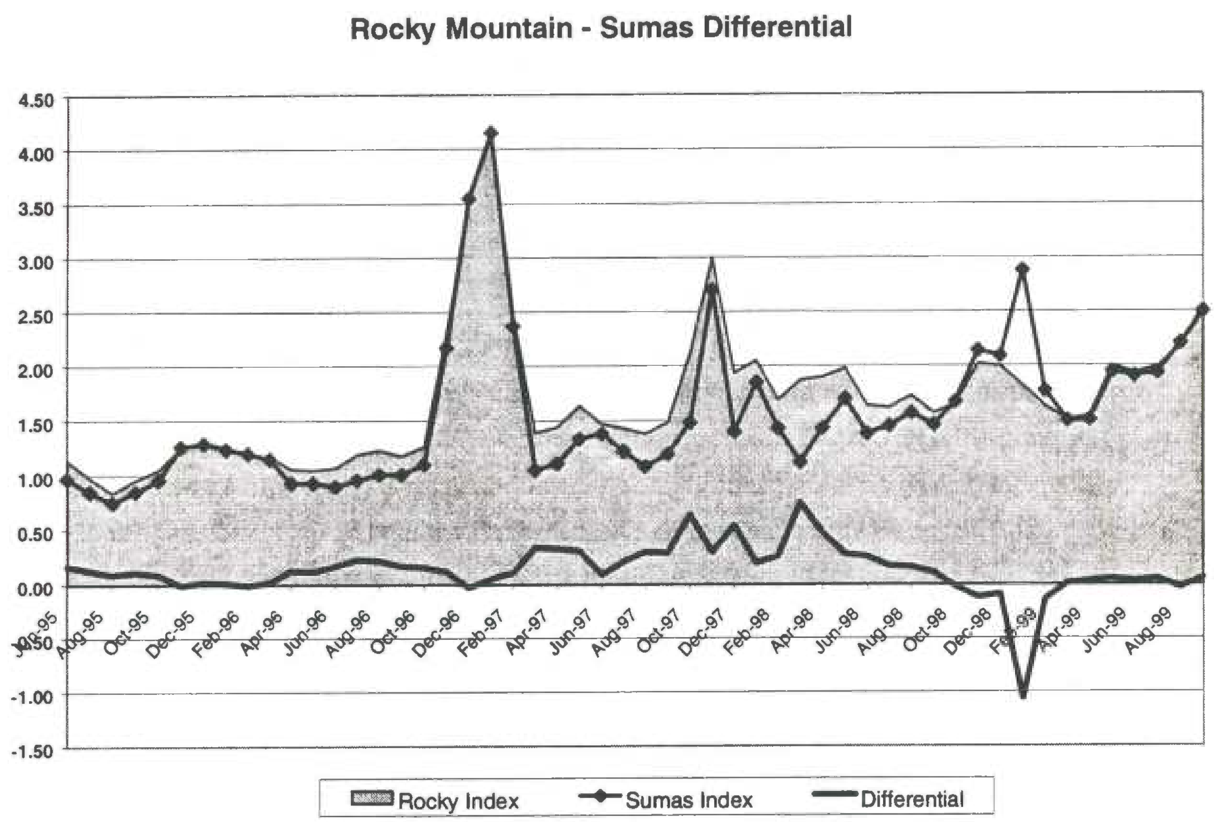
In addition to PSE's own growth, local demand has intensified as a result of rapid growth of other LDCs in the Pacific Northwest, notably in Vancouver, British Columbia and Portland, Oregon. Furthermore, a continuously growing segment of demand is gas-fired electric generation. Regardless of the final level or type of gas-fired electric generation, PSE believes that least cost synergies are possible between the gas industry and the electric industry to efficiently utilize the region's gas supply and capacity assets (see Potential Resource Strategies).

C. Price

Historically, gas price determination has been a product of a combination of three elements: availability of gas, level of demand, and availability of pipeline or transport capacity. Should the market fail to provide one or more components, or if equal access is denied by regulation, price distortions will occur. Such price distortions have persisted in the Pacific Northwest and throughout the industry for many years.

Seasonal pipeline bottlenecks on NWP (Chehalis during summer and Kemmerer during winter) have kept regional gas from accessing alternative markets. Prices have reflected the disparities in available transport. Firm shippers on NWP, on the other hand have benefited from the price distortions created by capacity constraints, by using their firm capacity as a bargaining tool to achieve lower gas costs. Note in Figure V-1 the seasonal price variations between the Rocky Mountain and Sumas index prices.

Figure V.1



PSE also tracks the index differentials from the Rocky Mountains and San Juan regions, as well as between Sumas and the San Juan basin. Figures V-2 and V-3 show a representation of these differentials since June 1995. The correlation between the indexes and the futures market appears to be strong. This price information is useful for forecasting purposes such as: predicting off-system sales activity, valuing capacity releases, and negotiating supply contracts.

Figure V.2

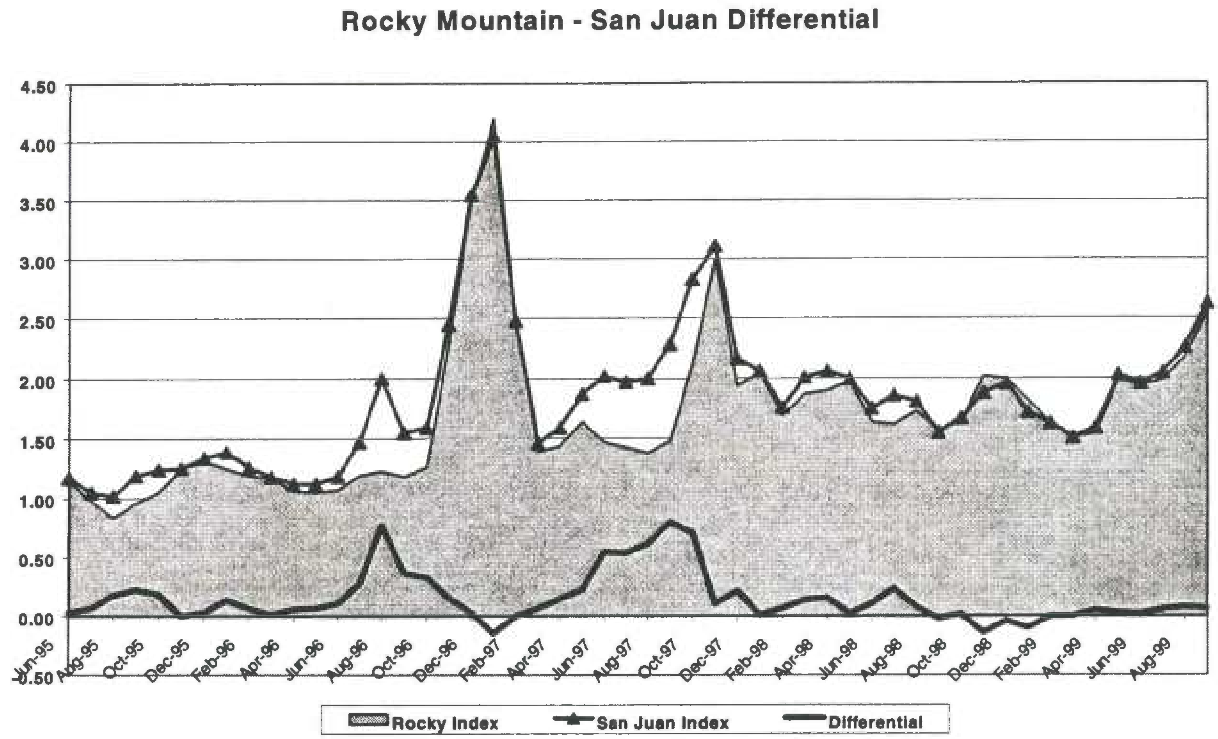
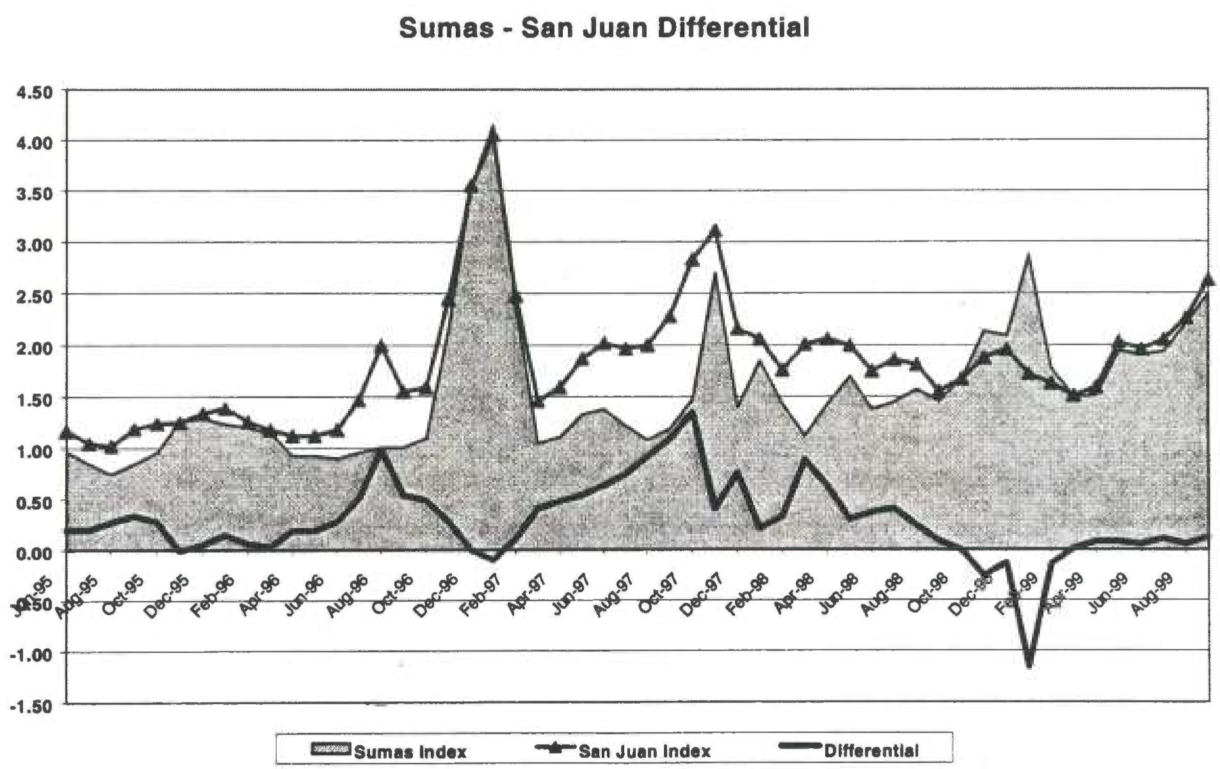


Figure V.3



Today, pipeline expansions are, to some extent, overcoming pipeline bottlenecks and FERC Order 636 facilitated capacity release opportunities. These two factors have led to less price distortion. This fact has been evident because the historical difference between B.C., Alberta and U.S. gas has decreased since late 1993, and especially during 1999. Regional gas costs may become essentially equal and subject only to the elements of supply and demand.

Gas supply costs have changed in response to the changing market conditions. Changes have occurred not only to the final delivered cost of gas but to the contractual pricing formats. Demand and reservation charges are quoted differently, as sellers and buyers seek to find equitable arrangements. Load factor commitments, length of term, flexibility of take, release mechanisms and the value of alternate markets all factor into the pricing of gas. The significance of the changes to PSE and its customers is the closer correlation between prices paid in the Pacific Northwest and the rest of the U.S.

The futures market provides a means of price discovery, a methodology to establish actual gas prices and a financial tool. Providing price certainty in a volatile market is the value-added function of futures and financial products. Other uses of these tools involve price prediction and its inherent risks.

Prices today reflect market conditions across the United States and Canada including weather, supply shortages (or over supply), and demand on a national and international level. Regional influences are still apparent and are reflected in the monthly index prices as reported in various trade publications. Index prices more than ever are considered to be the "true" market value of gas. Regardless of source, regional prices are impacted by the national futures market prices, and to some extent vice versa. Index prices will generally correlate to a futures price at any given time. However, more often than not, the regional price is equal to and is frequently quoted as a basis differential.

There usually exists a difference between the price at the Henry Hub, or the Waha Hub, and the alternate location or point of delivery. This difference is referred to as the "basis differential". The actual basis differential on a monthly basis is often considered to be equal to the difference between the regional spot index price and the futures price. Basis differentials are however far more complex. An entirely new market has developed to spread risk in the basis market.

Basis differentials are actively traded in the OTC market and will behave in a manner consistent with the trading of gas in the physical market. Managing basis differentials and positions in the basis market are essential to effectively manage price and price risk.

The use of futures in the Pacific Northwest has been slower to develop than in other regions. This is primarily due to a lack of trading data to base the NYMEX to prices in the Northwest and Western Canada. This is changing as a result of increased hub activity that allows western sourced gas to find new outlets to markets that correlate closer to NYMEX and KCBT. Furthermore, financial instruments have emerged that correlate with the NYMEX and KCBT. Participants in the Pacific Northwest and Western Canada can utilize these instruments more readily.

The creation and existence of market centers is another reason why futures are now more widely accepted. Buyers and sellers involved in a variety of markets are able to quote or ask for prices with some expectation as to prices in alternative markets. Buyers and sellers will quote basis differentials and therefore a price (price equals futures price plus a basis) to the extent that at least one of the alternate markets has an established relationship to the futures markets. It is important to note that futures prices are only an indication of what gas can be purchased for today for a future period, and do not represent a vehicle that will accurately predict gas prices.

D. PIPELINE CAPACITY

In an efficient market pipeline capacity must be readily available to deliver gas to market. The market may be an interconnecting pipeline, an LDC or a specific end user. The lack of reliable pipeline capacity tends to create dysfunction in the marketplace as market forces seek to find equilibrium. As an example of market dysfunction, systematic bottlenecks on NWP repeatedly create price disparity on a regional basis. Regional prices often display significant variations depending on the availability of pipeline capacity which either helps or hinders gas movement as it seeks the highest valued market.

Firm Transportation

Capacity may be defined as the right to occupy a stated quantity of usable pipeline space, coupled with the right to utilize that space for specific purposes and for a stated period of time. Capacity can be pipeline space or space within a storage field, or a combination of the two. Capacity may be divided into firm capacity and interruptible capacity.

Firm transportation capacity (TF-1) on NWP has been made available to LDCs since the conversion process began in 1988. This service gives the holder the right (but not the obligation) to transport a specified quantity of gas from a receipt point to a delivery point every day of the year.

Firm storage redelivery transportation (TF-2) on NWP has been available to shippers since 1994. This service allows shippers to use firm transportation from Jackson Prairie and Plymouth storage facilities, to specific delivery points. This service has an annual limit that corresponds to the storage capacity held by the shipper. While the service is limited only to gas withdrawn from storage, the cost of this service is significantly lower than firm year-round pipeline capacity.

Service from NWP

PSE currently has six TF-1 firm transportation agreements with NWP for a total of 454,533 Dth/day. The agreements provide for receipt of 204,761 Dth/day at Sumas and 173,836 Dth/day from various domestic U.S. points and 75,937 Dth/day from an interconnect with PGT's system (Alberta supply).

PSE also has TF-2 firm redelivery transportation agreements for a total of 413,556 Dth/day. The TF-2 agreements allow for receipt of 343,056 Dth/day at Jackson Prairie and 70,500 Dth/day associated with Plymouth LNG. (With the November 1, 1999 in-service date of the Jackson Prairie expansion, PSE's TF-2 increased by 104,000 Dth/day.)

Service from PGT

PSE currently has firm transportation capacity on PGT totaling 90,392 Dth/day. The transportation service originates at the international border point commonly referred to as Kingsgate. Gas received by PGT is delivered by PGT to NWP for redelivery to PSE.

Interruptible Transportation

Interruptible transportation (TI-1) is available to the extent that TF-1 customers as a whole do not fully use their respective transportation service, or to the extent that NWP may provide the service without jeopardizing the quality of firm service. As expected, the use of interruptible transportation has been virtually eliminated by firm transportation capacity released by firm shippers following full implementation of Order 636.

Service from NWP

PSE has the right to transport up to 220,000 Dth/day on NWP via an interruptible transportation agreement. Since NWP implemented Order 636, PSE has used TI-1 capacity sparingly, opting instead to more fully utilize the flexible receipt and delivery point provisions of its TF-1 capacity.

Service from Questar Pipeline

PSE has the right to transport gas supplies on Questar Pipeline via an interruptible transportation agreement. PSE utilizes the agreement to deliver gas into Clay Basin and to various off-system markets.

Service from Westcoast Energy

PSE has several interruptible transportation agreements with Westcoast Energy to deliver gas to various points on the Westcoast pipeline system.

Service from Kern River

PSE has an interruptible transportation agreement with Kern River pipeline to deliver gas to various points on the Kern River pipeline system.

Segmentation

NWP's tariff allows for the release of capacity to third parties in segments. Segmenting of capacity into discrete components permits the use of the released capacity by one party and the unfettered and continued use of the unreleased segments by the original capacity holder. The advantages are the recovery of some or all of the underlying reservation charge from one or more of the released segments and the continued use of unreleased segments for ongoing gas supply requirements. Segmentation has increased NWP's deliverability and minimized expansions. After five years, most of the operationally and economically efficient segmentations have been made.

Exchanges

Exchanges are created by diverting the physical flow of gas from its intended destination to another destination, and replacing it with other gas. An example of this is when PSE purchases gas from the San Juan basin for system supply requirements, but instead of scheduling that gas to Seattle, it is scheduled for delivery to a California market. In exchange for scheduling gas for delivery to California, PSE receives gas from Sumas that was originally destined for the California market.

Capacity Release and Capacity Swaps

PSE continues to develop the means to achieve the highest and best use of the entire portfolio of pipeline capacity. Capacity released to off-system markets, on-system markets as well as capacity swaps and trades, are all possible. Not all capacity is of equal value nor is its perceived value constant. The value of capacity will often be impacted by the risk of NWP issuing an Operational Flow Order (OFO). Under an OFO the holder of the capacity may be obligated to change the use of the underlying capacity (i.e., change receipt and/or delivery points).

Capacity swap arrangements involve the assignment of one party's firm transportation rights to another party and the simultaneous receipt of an assignment of the rights to a different firm transportation agreement. The goal of a capacity swap may be simply to align receipt and delivery points with available gas supply and market opportunities or may include various provisions such as the right to recall the assigned capacity back to the original holder.

For PSE, the alignment of receipt and delivery point options to achieve lower cost gas has been the most frequent reason for capacity swaps. As an example, PSE's inability to utilize Sumas capacity to deliver gas to points south of Chehalis has been overcome through a series of capacity swap arrangements.

The underlying goal of capacity swap activities has been to enhance PSE's competitive position in the marketplace by:

- Providing PSE with the ability to put competitively priced gas into Clay Basin and Jackson Prairie;
- Allowing PSE to purchase gas on a more competitive basis by enhancing its overall annual load factor;
- Providing PSE's capacity release effort added value through access to different markets; and
- Providing a means to create added peak day deliverability.

Capacity swaps are possible on either a short-term or a long-term basis subject to the then-current status of PSE's supply and capacity portfolios and prevailing market conditions. PSE addresses economic concerns such as the value of a secure primary receipt or delivery point versus being at risk with alternate receipt and delivery points. There have been instances when it was impossible, due to operational considerations on NWP, to receive a firm delivery point pursuant to a swap arrangement. PSE has and will continue to weigh the costs and benefits of a receipt or delivery point that may be, in essence, interruptible.

The market for capacity swap activity changes dramatically over time as market conditions change and, more importantly, as released capacity changes hands. As quickly as the demand and price for gas changes, so has the level of capacity swap activity.

PSE determines the quantity of capacity that is prudent and feasible to swap with others on a long-term basis. Consideration is given to:

- The size and scope of PSE's portfolio of gas from any given geographic region, including availability of supply and deliverability;
- Upstream and downstream capacity availability, including receipt and delivery point specifics;

- The current and the future expectations as to gas prices;
- On and off system market demand;
- Current and future expectations as to the value of capacity on a release basis both for the existing capacity and the capacity received pursuant to a swap arrangement; and
- PSE's storage injection requirements given price expectations and anticipated or known load factor commitments;
- Other prevailing market considerations.

Additional benefits are possible if PSE obtains the right to recall the capacity it assigned pursuant to the swap arrangement. PSE may also reserve a recall on the capacity it received in the swap and subsequently released to yet another party. As previously mentioned, certain costs and tradeoffs relating to recall rights must be fully understood and analyzed, including alternate fuel and environmental choices facing PSE's swap partner.

E. Regulatory Issues

Regulatory issues can have a profound effect on the supply environment. The U.S. regulations have been stable for about a decade; however Canadian national and Provincial, and State of Washington regulations have had, or will have, a direct impact on PSE's gas supply portfolio. Key issues are highlighted below to provide insight to the changes that have occurred or may occur in the near future.

Canadian Regulatory Issues

The impact on PSE of the effects of Canadian regulatory proceedings are potentially large in that PSE purchases significant quantities of gas from Canada and spends in excess of $20 million annually on firm pipeline capacity (primarily imbedded in supply contracts) in both British Columbia and Alberta. Therefore, the outcome of Canadian regulatory proceedings is potentially significant to PSE.

PSE regularly participates in Canadian regulatory proceedings. These include both intervening in federal matters before the National Energy Board (NEB) and provincial matters in British Columbia and Alberta. PSE has found it advantageous to combine its regulatory effort with other members of the U.S. export community such as other LDC's and marketers. The loosely aligned groups are known as The Export Users Group (EUP) for activities in British Columbia and variously known as the United States Northwest Group (USNG), the Alberta Export Group (AEG) or the Western Export Group (WEG) for activities in Alberta. To date the groups have intervened in pipeline rate cases as well as several pipeline expansion cases before the NEB.

Important changes have resulted in the Canadian regulatory environment, most notably the decision by the NEB to defer jurisdiction with respect to gathering and processing facilities in British Columbia. In effect all new facilities will be regulated not by the federal regulatory agencies but by the provincial regulators. Legal challenges have been brought and certain projects have been delayed or postponed indefinitely. In Alberta, the NOVA pipeline system is regulated by the Alberta Energy Utilities Board. Hearings were recently completed on a proposed revision to NOVA's rate design structure. The AEG/WEG has been involved in the proceedings to ensure that the rights of the collective members are protected.

State of Washington (WUTC) Regulatory Issues

The traditional PGA process entails gas utilities passing gas costs through to customers dollar-for-dollar. In 1997, the WUTC issued a policy statement in Docket UG-940778 that recognized the traditional PGA pass-through did not fully align customer interests for minimizing gas costs with shareholder interests. The traditional PGA includes several distorting regulatory effects; for example, with a traditional PGA, if a utility devotes financial resources to reduce gas costs, the gas costs savings are passed directly to customers while shareholders bear the additional cost in the short-run. This clearly reduces a utility's ability to devote resources to reducing gas costs. To better align customer and shareholder incentives, the policy statement included guidelines for utilities to introduce incentives for utilities to reduce gas costs into the PGA process, setting the stage for incentive PGAs.

PSE was the first gas utility in Washington to implement an incentive PGA. PSE's PGA Incentive Mechanism was approved by the WUTC to be effective for a term of three years commencing July 1, 1998. This innovative approach aligns the interests of PSE shareholders with the interests of PSE's gas ratepayers by equitably sharing rewards and risks for performance relative to a market-based cost benchmark. PSE is now financially motivated to be an even more aggressive, innovative gas purchaser on behalf of our sales customers. PSE's PGA Incentive Mechanism is clearly a win-win mechanism for customers and shareholders because PSE does not earn anything under the incentive unless the Company performs better than the benchmark. Furthermore, the benchmark is aggressive and includes significant savings that PSE is at risk to attain. The incentive PGA is balanced, in that if PSE's performance falls short of the benchmark, the Company shares the shortfall with customers.

Customers have received demonstrable benefits under PSE's PGA Incentive Mechanism. While it is still early in the experimental period, PSE is generally pleased with results of the PGA incentive. Furthermore, PSE believes there are substantial longer-term benefits to continue the PGA incentive after the experimental period, thus the Company plans to work with the WUTC, Staff, and Public Counsel to seek renewal of the PGA incentive in 2001.

F. Supply Objectives and Strategies

Many of the risks and opportunities in the current gas supply environment have been highlighted. The existing supply side resources have also been described. Realizing that options and opportunities exist, PSE will work to choose resource selections that are least cost.

A flexible strategy provides the blueprint from which to work. Underlying the strategy are key objectives outlining the initial direction and scope of the strategy. The following discussion relates to five key objectives that provide known and quantifiable benefits. The five key objectives are:

- Increasing the effective utilization of known and useful resources;
- Allocating "productive" resources to their highest and best use;
- Retaining the benefits of the high load factor market segments;
- Managing gas supply and price risk with proper application of risk management tools; and
- Maintaining an element of flexibility to react when conditions change.

These five key objectives are in furtherance of the seven strategies which PSE follows to meet the needs of PSE's customers. The seven strategies are:

- Acquire low cost, reliable gas supplies;
- Secure a diverse range of gas supplies;
- Obtain suitably flexible contract provisions;
- Secure and optimize storage options;
- Purchase spot gas as warranted;
- Secure and optimize delivery capacity options; and
- Participate proactively in regulatory arenas.

PSE believes that it must be proactive in the marketplace. Emphasis must be placed in the areas that have the greatest potential to lower the total cost of service by reducing both costs and supply risks. Value-added arrangements are possible given that different options exist in the marketplace today.

Value can be created to a large extent by PSE managing a portfolio of both gas supply and capacity options, whereby many of the individual components within the portfolio are linked either by specific contractual arrangement or as part of an overall strategy. By linking resource components, PSE has in the past achieved a higher value for released capacity and lower commodity cost for a particular gas supply.

Acquisition of Released Capacity

PSE will continue to evaluate whether to acquire capacity released on NWP, PGT, or other pipelines. Strategic acquisition of pipeline capacity, whether it be for the short term or for the long term, either on a firm or interruptible basis, will be examined as a least cost option.

Capacity Release

In order to assure that PSE's customers receive the maximum benefit for released capacity, PSE first estimates how much capacity it has available for release on a daily, monthly and annual basis and the value of that capacity on the open market. General estimates for the amount of capacity available for release have been fairly straightforward: total capacity contracted less estimated total utilization by PSE equals the total release capacity available. The quantity available for release will not be constant and will fluctuate with the seasons and the weather. The risk profile has taken into consideration numerous factors including the number of consecutive days that such capacity would be required on recall, possible revenue impacts, availability of other alternate supply, and capacity options.

An analysis of the actual capacity costs as well as estimates for the recovery of costs related to capacity release is used to assess risk. Consideration is also given to cost estimates associated with the right to recall released capacity. Capacity that is recalled may carry certain costs. The costs have typically been established as discounts to capacity that would otherwise be released on a firm basis without recall.

To a large extent the quantity of gas and the value of PSE's recall positions have been determined following the analysis of PSE's design winter demand forecast, including analysis of the number and frequency of below normal temperature days.

After five years of experience, PSE has found that the capacity release market is very seasonal. As one might expect, winter capacity typically receives a higher value. Conversely, in the summer when load factors are low, the amount of capacity available for release is large and the value is relatively low. The market for annual capacity release arrangements is highly competitive and those requiring recall are at a distinct disadvantage relative to those which do not.

PSE's prearranged capacity release efforts have been targeted to five broad markets. Each of the five markets are summarized below:

PSE's COG Customers

Interruptible customers currently transporting their own third party (COG) gas are a logical market segment for PSE's capacity. PSE intends to maximize the use of its capacity to its own COG customers in ways which optimize the cost of serving all customers. To date PSE has had limited success in releasing capacity to its own end user transporters, because most are served by independent marketers (who may purchase PSE released capacity).

On-NWP Markets

There are others with capacity needs not located behind PSE's system served directly or indirectly by NWP. This market includes large industrial customers located on NWP which may or may not be behind an LDC's system. This market segment has at times been assigned capacity and has been the largest market segment for PSE's capacity.

Off-NWP Markets

In addition to end-users and LDCs served by NWP, similar market opportunities exist with end-users and LDCs located off NWP but served from gas sources located on NWP. Examples are markets in California and the Mid-West with a desire to access Rocky Mountain or B.C. gas supplies. PSE's capacity has been utilized by these off-system markets to deliver gas to the various pipeline interconnects on NWP. This type of market is extremely market sensitive. Factors including regional gas commodity cost differentials, capacity constraints, futures market activity and the level and cost of capacity on the pipeline serving the off NWP market have a pronounced effect on PSE's ability to release capacity to these markets.

Gas-fired Electric Generation including Cogeneration Markets

Cogeneration and other gas-fired electric generating projects are ideal capacity release partners. The high load factor and fuel switching capability of many of these projects would allow PSE to place blocks of capacity with rights to recall the capacity and gas supply to meet peak day requirements. Power project development has picked up considerably in 1999 and PSE is positioning itself to be involved in any such projects within its transportation capacity corridor.

Producers, Marketers and Aggregators

Producers, marketers and aggregators have been the most frequent parties requesting capacity from PSE. These groups typically request capacity on a daily and monthly basis, however, some require capacity for longer periods. The released capacity is used to fill supply commitments that these groups have with markets on and off the NWP system.

Other

The balance of PSE's releasable capacity, that is, capacity that remains after prearranged releases have been made, is available for posting on the NWP and PGT electronic bulletin boards.

PSE continues to identify the alternative fuel capabilities available to electric generators and other end-users. This research is designed to determine the relative costs associated with recalling a specific capacity and/or gas supply. The fuel switching capability of many facilities is influenced by regional air quality rules and regulations. PSE may wish to assist capacity release partners in their effort to use alternative fuel where doing so may lower the costs of serving PSE's customers.

Futures and Financial Instruments

The futures market and financial instruments (derivatives) are used by suppliers offering gas supplies to PSE. PSE believes that prudent use of these opportunities may generate value by helping to manage the risks associated with a rapidly changing market environment and volatile pricing conditions. Prudent application of futures and derivatives may afford PSE greater opportunity to offer competitively priced sales service to non-core market segments at fixed prices regardless of the volatility in the marketplace this service, in turn, may contribute to cost recovery for core customers.

The basic issue surrounding the use of futures and derivatives is the question of how to capture value. Value could be created when the cost of a commodity is transferred to the ultimate customer at a price that is lower than the next best alternative. Near-term price stability may also have value to certain customers (i.e., knowledge that the environment is relatively stable is attractive to customers).

PSE will be investigating opportunities with prudent application of futures and risk management tools. PSE believes that benefits are possible with prudent application of financial tools given the reality that:

- Gas prices are fundamentally volatile;
- Gas prices could increase over time: and
- New gas supplies will likely be purchased under new pricing structures.

Futures and derivatives may be useful tools in three general areas: 1) Weighted Average Cost of Gas (WACOG) price stability, 2) storage costs, and 3) load factor management. Each of these areas will be addressed separately.

WACOG Price Stability

PSE files a PGA which represents the estimated average commodity cost of gas for the next succeeding twelve month period based on normal weather and demand. Included in this filing are many variables and assumptions concerning the future direction of gas prices. PSE goes through numerous iterations considering various gas price scenarios. PSE includes historical prices, current market economics, and a forward look at expected prices as indicated by futures market information. Financial market information is compiled to generate basis differentials at various gas supply and market trading locations. The basis differentials are added to the forward looking twelve month futures prices to derive an estimate of the cost of gas at the various locations. The estimated cost of gas is generally assumed to represent the future index price at a particular location. This same information is also used to formulate expected prices under long-term fixed price contracts with annual price redetermination.

Through careful study of the gas market and regional transmission system, it may be possible to develop a strategy that could increase the stability of the WACOG while lowering the overall costs. This will be investigated along with other possible applications of financial tools to achieve least cost. For example, it may be possible to contract for gas at an index price and to convert the monthly index price into a fixed price. PSE could take such a position if index prices are expected to climb to unreasonably high levels, or if (as has happened) NWP index prices exceed the monthly futures price. PSE may elect to convert portions of the index-priced gas supply to fixed-priced gas supply with a futures price swap. Price swap arrangements may help manage the risk of disproportionately high index-priced gas. If price spikes are known and quantifiable, the impact of year end surcharges may be reduced. This increases the likelihood of a stable WACOG and PGA.

As PSE's knowledge and understanding of futures and derivatives increases it may be possible to incorporate their use into broad-based strategies to lower gas costs and stabilize portfolio pricing. By blending numerous contractual pricing provisions with an aggregate of annual take requirements, and by matching the physical and financial obligations, PSE may be able to achieve lower overall gas costs.

Storage Costs

Storage injection gas costs and the value of the gas upon withdrawal from storage may similarly benefit with application of financial tools. Gas purchased for injection into storage may be purchased at an index price and converted to a fixed price as explained above. The value of the gas in the market upon withdrawal from storage may similarly benefit from a known and measurable price. That is, PSE may choose to protect against the possibility that the gas in the market is priced less than the price of gas in storage.

Storage is like an option, it provides certain price assurance. A financial option will have a price and this price must offset any savings gained by limiting the upper end of an index price or limiting the downside risk associated with a sale. Nevertheless, locking into a fixed price or purchasing an option has the effect of limiting price exposures (negative or positive) which, if left unattended, will ultimately be reflected in PSE's WACOG or in subsequent surcharges.

Load Factor Management

The opportunities for application of financial tools with regard to off-system sales are the same as for new sales service programs. New sales service programs (City gate sales) and off-system sales may allow recovery of revenues in excess of actual gas costs, in effect lowering the total cost of gas. In the past PSE has utilized its strategic position in the marketplace to make off-system sales when gas is not required for system supply or storage injection. In the past PSE's underlying gas supply portfolio had favorably priced components providing PSE with competitive advantages. In the future, it may be necessary to use financial tools to obtain core market gas cost reductions as a result of off-system sales.

G. Additional or Emerging Supply Options

Regarding the future, additional potential supply resource options and strategies are possible. The options should contribute to the lowering of cost of service once identified, explored and carefully reviewed. Some of the options PSE continues to explore include:

Strategic Alliances and Resource Pooling

The large aggregated supply pools are disintegrating and complex new relationships are forming. PSE believes that the stakes are high for both PSE and its customers. PSE must stay abreast of developments and formulate new relationships to build the foundations for long-term stability. From a customer perspective strategic alliances are beneficial for resource optimization.

The alignment of supply-side resource objectives for two or more market participants may help achieve a greater and more diverse set of supply side resource options. The pooling of resources includes not only gas supply and capacity options, but talents and ideas as well. Many of the ideas and objectives outlined herein such as capacity swaps, capacity release and off-system load factor management opportunities, may only exist to the extent PSE forms new alliances.

Strategic alliances and the pooling of strategic resources may occur in several different areas. PSE has initiated several such relationships and is exploring others. The possible alliances may occur in four general areas. PSE envisions cooperative ventures with 1) other LDCs, 2) the electric industry, 3) large industrial customers, and 4) large producers and marketers. Each of these has the opportunity to benefit PSE's overall strategy to reduce costs and risks associated with supply side resource objectives.

The following discussion concerns potential alliances with LDCs and the electric industry. The other two areas may provide additional benefits; and many such alliances are being implemented through a series of commercial arrangements.

Strategic Alliances with other LDC's

Opportunities may exist to align peak day resources and optimize pipeline capacity load factor capabilities of various LDCs. Duplicative peak day resources may create inefficiencies which are counterproductive to the LDCs collective least cost planning objectives. If it were possible for LDCs to mutually plan, construct, operate and manage a set of peak day resource options, duplicative resource building could be avoided. The obvious advantage would be a lower collective cost of preparing for the worst case peak day event. A cooperative effort among LDCs may therefore be appropriate in many instances.

It may also be possible to capture the benefits of a larger and more diverse load. By combining the collective load factor capabilities of various LDCs on a regional basis, economic efficiencies could be created. The high winter demand in the Pacific Northwest may be combined with the high summer demand in California and Arizona to create virtually 100% utilization of strategic supply side resources. Such resources may include long-term high load factor gas supply contracts or the effective cycling of several storage projects.

PSE has discussed with several LDCs the concept of a regional resource pool. Conceptually, the opportunities have been recognized and the LDCs have agreed to continue to investigate methods for implementing, on a limited scale, the sharing of peak day resources. The concept is consistent with the electric industries use of power pools and operational arrangements.
The sharing of load factor opportunities is probably easier to identify and administer. There are synergistic benefits of combining offsetting load profiles (heating and cooling) on a regional basis. PSE is pursuing several possible approaches. The offsetting load characteristics may provide PSE and its strategic partners with numerous advantages.

Strategic Alliances with the Electric Industry

Opportunities exist for the effective management of supply side resources, given the continued development of gas-fired electric generation. Proper allocation of resources should enable both gas and electric utilities to lower the cost of serving their customers. Many examples are possible, but only two will be addressed herein: efficient allocation of pipeline capacity and on-system pipe and facility enhancement.

An opportunity exists to provide the emerging gas-fired electric generating community with pipeline capacity through release agreements. If a gas-fired electric generating facility is sited at a location beneficial to PSE's distribution system, other benefits may be possible. For instance, PSE has identified in its long range forecast areas on its distribution system that require replacement or enhancement. It may be possible to combine PSE's requirement to upgrade its distribution system with the need to build facilities to serve a large high load factor cogeneration facility. A total benefit package is created by combining the cost sharing characteristics of such an arrangement with the other benefits of capacity release.

A formalized strategic alliance coupled with cooperative planning and implementation may reduce supply costs and acquisition risks for the region. The tradeoffs inherent in a formal alliance are numerous and varied. For example, the value of PSE's recall of additional gas supply and capacity may more than offset PSE's contribution of a higher percentage share of the costs associated with on-system facilities. In addition, the value that PSE brings by absorbing excess gas supply may offset the perceived obstacles faced by the cogenerator's use of alternate fuel. Each partner in the arrangement may be afforded least cost opportunities and each must evaluate them independently based on its own set of objectives.

Jackson Prairie Storage Expansion

It may be possible to expand the existing storage formations in the Jackson Prairie storage field and to develop additional formations. PSE and the other project owners will determine whether (from both an engineering and economic perspective) it is feasible to expand the Zones 2 and 9 formations. The ultimate size and scope of any expansion will be determined by, among other factors, the needs of all the co-owners including any requirements to market capacity to third parties.

Notwithstanding outside competitive issues, PSE must evaluate the costs, benefits and risks associated with any expansion of Jackson Prairie, including the physical management of gas on the pipeline and on PSE's distribution system. Issues such as balancing, load factor management, and the ability to conduct gas supply operations will be studied.

New LNG Storage

An LNG facility located directly on PSE's distribution system would have several benefits including avoidance of firm transportation costs, peak day resource capability, system balancing as well as system integrity considerations. A new LNG facility in the Puget Sound area is considered speculative at the present time due primarily to permitting requirements. Further economic analysis is required as well as additional siting and environmental analysis. However, PSE has been approached by a few parties interested in locating facilities in the greater Puget Sound area.

Satellite LNG

PSE is evaluating the suitability of installing small, mobile LNG vaporization and storage units that can be used to increase supply in constrained areas. These plants may enable PSE to reduce upstream capacity requirements and distribution system infrastructure.

Peaking Gas Supply Service (PGSS)

PSE presently has contracts providing PSE with the right to call on gas during peak periods for a limited period of time. This service is provided by an end-user, not on PSE's system, of natural gas that can either use an alternate fuel, or shut down its operations for limited periods of time. There are still opportunities available in the area which may be developed as additional peaking resources are required.

PGSS provides a supply of gas, however provisions must be made for delivery of the gas from the seller to the buyer. By taking advantage of its location on NWP, PSE can use delivery displacement agreements with other parties to cost effectively and reliably deliver peaking supplies.

Firm Gas Supply Service (FGSS)

FGSS is similar to PGSS except that the end-user is located on PSE's distribution system and, therefore can deliver firm gas supplies directly to PSE's system. PSE May negotiate a mutually beneficial arrangement

Integrated resource
Modeling

VI. INTEGRATED RESOURCE MODELING

A. Introduction

This chapter of the LCP presents the results of the analyses of the various load growth and other scenarios for both the electric and gas systems. It describes PSE's plans to meet future customer requirements reliably at the least cost, given the range of uncertainties discussed throughout this plan. While PSE's gas and electric energy systems remain different, the basic concepts and analysis approaches are similar for both.

As discussed earlier, the first step in the development of PSE's LCP is the assessment of customer gas and electricity needs. As described in Chapter II, PSE evaluates and forecasts customer end-uses and demands to project future needs. For this integrated planning process, a number of alternative forecasts or scenarios were developed that encompass the range of future customer load requirements. Consideration of a range of forecasts helps ensure that the final plan has the flexibility to respond to a wide range of possible future load growth.

A key step in the resource evaluation process is to evaluate how specific resources will affect the total cost of meeting the customer demand requirements when considered in combination with the other available resources. While a specific resource might appear to have a low cost when considered independently, it may not have the performance characteristics required to lower total costs when used in conjunction with the other potential resources. This evaluation usually requires the use of computer models to deal with the complexity of the hourly and daily dispatch requirements of a number of resource options over a multi-year time period. As discussed in this chapter, PSE uses the Aurora Electric Energy Market Model and the Uplan-G Integrated Gas Planning Model for modeling the electric and gas systems, respectively.

It is important to keep in mind that long-range forecasting of electric and natural gas prices is fraught with difficulty. Historical forecasts of energy prices have proven to be highly inaccurate. Because of this, these analyses represent only a "snapshot" of possible future outcomes based on assumptions made regarding very uncertain factors over a 20 year period. Much of the analysis in this chapter was performed from July through September of 1999. These forecasts and prices reflect PSE's estimates of the future at that point in time. Over-reliance on long term modeling data in this environment of volatile prices can be highly misleading.

B. Electricity

As discussed earlier in this report, the electric utility industry in the country as well as in Washington State is undergoing significant changes largely as a result of on-going or contemplated restructuring initiatives. Several aspects of current market conditions and potential further restructuring have direct impact on long-term utility resource planning. Four of the most important changes contemplated by PSE for purposes of this analysis include; 1) separation of generation, transmission, and distribution functions, 2) the development of active, liquid markets for buying and selling electric power, 3) the ability of utility customers to purchase power supplies from competing suppliers (open access) or to build distributed generation facilities, and 4) uncertainty regarding the specific provisions for open access in Washington State and the region.

As with other regional power planning entities such as the Bonneville Power Administration (BPA) and the Northwest Power Planning Council (Council), this study assumes a competitive pricing structure as the fundamental mechanism underlying the determination of wholesale electric prices. (This theory is discussed in the Marginal Cost Analysis Study conducted by BPA as part of the 2002 Initial Power Rate Proposal.) Two fundamental inferences for energy pricing follow from the economic theory of market pricing. First, the price in any hour will approximate the variable cost of the marginal generating resource. Second, the long-term average price will gravitate toward the full cost of a new resource.

Neoclassical economic theory concludes that in the short run a firm will continue to produce additional goods or services as long as the revenue from the sale of those units covers the marginal cost. A competitive market will produce up to the quantity where the amount consumers are willing to pay for marginal consumption is equal to the marginal cost of production. Therefore, for the electricity market, the market clearing price, in theory, translates to the variable cost from the marginal electric generator.

In the long-term, the average price will move toward the full cost of a new resource. When prices are high enough to justify additional investment, the average investment cost will be lower than the average price. Therefore, the average cost of new resources will determine the price. When the long-term average price is lower than the average cost of a new resource, new resources will not be built. In this case, demand growth will move prices up the supply curve until new investment is profitable.

Since long-term prices will gravitate toward the cost of new resources, the assumptions concerning the cost of a new resource will have an important impact on the long-term price. Recent regional studies have concluded that the bulk of new electric power generation both in the northwest as well as the WSCC area will be combined-cycle combustion turbines (CCCT). The cost of new CCCT generating plants are discussed further in the following sections.

Description of the Aurora Electric Energy Market Model

The Aurora model is used by PSE for long-range electric resource portfolio analyses and for evaluation of specific supply resources. Aurora is owned and licensed by EPIS, Incorporated, which is located in the Portland, Oregon area. PSE has a multi-year lease agreement with EPIS for the right to use Aurora. The EPIS founders who developed Aurora have over 50 years of experience in the fields of economics, engineering, planning and finance in the northwest electric power industry.

Aurora is a nationally recognized energy market model used by numerous clients both within the region and nationally. Importantly for PSE, Aurora is being used by both BPA and the Council. BPA is using Aurora in the current 2002 wholesale power rate case to forecast energy prices at the Mid-Columbia hub over the 2001 through 2006 time period.

The Council used Aurora to estimate Mid-Columbia market prices in a 1998 report entitled "Analysis of the Bonneville Power Administration's Potential Future Costs and Revenues". The time horizon of this study was from 1998 through 2022. The Council is currently using Aurora to help evaluate the future reliability of the region's energy generation and transmission system. Additional information on EPIS and Aurora are available on the EPIS website, www.epis.com. Information on the analyses done using Aurora by BPA and the Council are available at the their websites, www.bpa.gov and www.nwppc.org.

The use of Aurora by these other Northwest entities is important since it has provided for intensive review of the methodology and data used in Aurora for energy market analysis within the region. This regional review is especially important in the Northwest because of its reliance on hydro-power from the Columbia River system for energy. Due to this review, as well as the expertise of the model's developers in power planning within the Northwest, PSE has added confidence in the model structure and methodology.

As outlined by BPA in the documentation to the 2002 rate case, it is helpful to distinguish between two main aspects of the modeling the electric energy market: determination of the hourly market clearing price and the long-term optimization of the resource portfolio.

The hourly market clearing price is based upon a fixed set of resources dispatched in least cost order to meet demand. The hourly price is set equal to the variable cost of the marginal resource. Aurora sets the market clearing price using the assumptions on load and supply costs. Supply resources are defined by the cost and operating characteristics of individual generating plants including resource capacity, heat rate, and fuel price.

Aurora recognizes the effect that transmission capacity and prices have on the ability to move power between areas. In the current version, Aurora recognizes 14 areas within the WSCC, largely defined by state and provincial boundaries. California is split into northern and southern areas while Oregon and Washington are combined.

For long-term optimization, Aurora adds or retires resources based on economic profitability. Economic profitability is measured as the net present value of revenue minus the net present value of costs. A potential new resource that is economically profitable will be added to the resource data base while existing resources that are not profitable will be retired from the data base.

Aurora uses an iterative process to determine what new resources to add and which existing resources to retire. This process begins with a preliminary price forecast to evaluate existing resources and potential new resources in terms of economic profitability. If an existing resource is not profitable, it becomes a candidate for retirement. Alternatively, if a potential new resource is profitable, it is selected as a candidate to be added to the resource portfolio. In the first iteration a small set of new resources is drawn from those with the greatest profitability and added to the resource data base. Similarly, a small set of the most unprofitable existing resources is retired. This modified resource portfolio is used in the next step in the iterative process to derive a revised market clearing price forecast. In turn, the modified price will then drive a new iteration of resource changes. Aurora continues this iterative process until the difference in price between the last two iterations reaches a preset minimum.

Aurora is designed to facilitate utility portfolio analyses. A specific utility's loads and resource portfolio (both generating plants and contracts) can be defined within a specific Aurora area. Using this feature, the loads are balanced with available resources on an hour-by-hour basis. If the portfolio has surplus energy available, it is assumed to be sold at market prices. Similarly, If there is a shortfall. supplies are assumed to be purchased at market rates.

Assumptions and Inputs

The Aurora data bases used were based on the "WSCC Default" data bases developed and supplied by EPIS Inc. as part of the on-going lease agreement. Specific data for PSE resources and contracts was added to the data bases to accurately represent PSE's portfolio within the Oregon/Washington region. These resources and contracts are discussed in Electric Supply, Chapter IV.

Load Scenarios

The load scenarios used in these analyses are discussed in Demand Forecasts, Chapter II. Overall, the purchase of conservation resources has a significant impact on PSE's integrated resource planning. The total effect of current and historical conservation is to reduce demand by nearly ten percent and this reduction is accounted for directly in the demand forecast (see discussion in Chapter II, Section D, "Electric Sales Forecasts.) These sales forecasts also assume that about 5 aMW of conservation savings are achieved each year through the company's DSM activities going forward. The net impact of conservation is to shift demand down so that less energy is consumed today and in the future.

New Resource Costs

The data for cost and efficiency of potential new resources is based on the Council's study, "Analysis of the Bonneville Power Administration's Future Costs and Revenues". Much of this data was based on the Council's Fourth Northwest Conservation and Electric Power Plan. These studies, done using both Aurora and other evaluation tools, have established that natural gas fired CCCTs are expected to be the least cost supply resource in the region over the next several years. As expected, CCCT generation is the only type of new generation capacity added in any of the scenarios evaluated.

The resource capital and operating cost assumptions developed by the Council for 5 types of electrical generation resources are presented in Table VI.1 below. These resources are: natural gas-fired simple-cycle combustion turbines (SCCT), CCCTs, coal-fired pulverized fluidized bed combustion combined-cycle plant (PFBC), central station wind, and central station photovoltaics.

Table VI.1: New Electric Generating Resource Assumptions - (Council - 1998)

(costs in 1997 $)	Nat. Gas SCCT	Nat. Gas CCCT	Coal PFBC	Central-Station Wind	Central-Station Photovoltaics
Technology	75 MW industrial	250 MW industrial	340 MW PFBC	350 KW units	100 MW array
Permitting Period (yr)	2	2	3	2	2
Construction Period (yr)	1	2	3	1	1
Unit Capacity (MW)	75	250	340	50	100
Availability (%)	87	92	81	-	-
Capacity Factor (%)	-	-	-	30	21
Heat Rate (Btu/kwh)	10,860	6,910	8,216	-	-
Capital Cost, overnight ($/kwh)	455	601	1,395	1,125	3,451
Fixed O&M ($/kw/yr)	15.78	18.4	38.73	31.86	16.17
Variable O&M ($/mwh)	0.1	0.8	1	3.5	0.8
Service Life (yr)	30	30	30	30	30

The CCCT prices and performance are based on a 250 MW class industrial units which is the predominate combined-cycle unit currently employed in power plant development. The Council used the Clark Public Utilities River Road power plant a the basis for the capital cost estimates of new CCCT facilities. River Road is a 248 MW General Electric 107FA CCCT plant that entered service in late 1997. As described in previous Council and BPA analyses these prices were adjusted to reflect differences in construction costs among geographic regions as well as anticipated future technological improvements in heat rates and operating costs.

Regional Load Growth

PSE used the 1998 WSCC load as the basis for WSCC load growth. As mentioned above, this data was provided by EPIS Inc. as part of the on-going lease agreement. The long-term average annual growth rate for WSCC loads was assumed to be 1.5 percent based on previous Council studies.

Natural Gas Prices

Natural gas price assumptions are presented later in this Chapter in the natural gas planning discussion.

PSE Loads and Resources

Forecasts of PSE's loads are discussed in Chapter II and the supply portfolio in Chapter IV. The following assumptions were made regarding PSE's portfolio loads and resources over the time horizon of the analyses.

1. Schedule 48 and Special Contract loads were not included in the analysis since PSE is not required to acquire long-term resources to meet these loads.

2. All PSE owned hydro resources continue to operate at current levels of output.

3. The contracts for purchase of power from the Mid-Columbia projects are renewed upon expiration for the same amounts of power. Medium northwest hydro conditions (medium water) are assumed for all years. The impact of critical water planning on these assumptions is evaluated.

4. The lease agreements for the Whitehorn 2&3 combustion turbines are not renewed when they expire in 2004.

5. PSE retains ownership of its interest in the Colstrip Projects. This assumption is made pending resolution of this issue. (Please see WUTC Docket No. UE-990267 for the

analyses of the economics of this potential sale, which are incorporated into this plan by reference.)

6. PSE sells its share of the Centralia Project effective January 1, 2000. (Please see WUTC Docket No. UE-991409 for the analyses of the economics of this potential sale, which are incorporated into this plan by reference.)

7. The lease of the Whitehorn 1 combustion turbine is not renewed when it expires in Nov. 1999.

8. The PURPA NUG contracts are not renewed upon their expiration.

9. PSE receives 368 Mwa pursuant to the BPA Residential Exchange program beginning October 2001 and ending September 2006. This amount assumes that PSE is allocated 700Mwa of total benefits and receives a prorata share of the benefits as power (1,000Mwa / 1,900MWa).

10. All portfolio power deficits are supplied with power purchased at market prices (either short-term purchases or long-term contracts priced at market index).

11. The hourly PSE load shape was developed based on actual hourly loads for 1995, 1996, and 1997. These loads were adjusted for average temperatures and for customer load growth over the 3 year period.

Scenario Results

Each of the PSE load scenarios was evaluated based on the future resource scenarios outlined above. As indicated earlier, average water conditions have been assumed in all scenarios. An additional scenario showing the loads and resources for the medium load growth case under critical hydro condition planning is also included.

The results for all of the scenarios is summarized in Table VI.2 below. Table VI.2 includes the following information: the year that core loads exceed total portfolio energy supply, the amount and percent of core load supplied by market resources by the end of the analysis period, and the NPV of the total cost of the resource portfolio over the 20 year analysis period.

Table VI.2: Summary Results of Scenario Analyses

	Load Scenario	End of Surplus (year)	Market Resources Required in 2019 (MWa)	Market Resources Required in 2019 (% of load)	NPV Portfolio Cost ($ - million)
1.	Medium Load Growth - Average Water	2007	1,279	43	6,899
2.	Medium Load Growth - Critical Water	2006	1,420	48	-
3.	High Load Growth	2006	1,509	47	7,176
4.	Low Load Growth	2007	1,092	39	6,671
5.	Access A	2011	770	29	5,875
6.	Access B	2012	484	22	5,462
7.	5% Attrition	>2019	-	-	4,398
8.	Distributed Generation - A	2007	612	27	6,451
9.	Distributed Generation - 10%	>2019	-	-	4,399
10.	Distributed Generation - High	>2019	-	-	3,410
11.	High Gas Price	2207	1,334	45	7,471
12.	Low Gas Price	2207	1,232	41	6,527

The loads and resources for each of the scenarios are shown in Figures VI.1 through VI.12. As shown in Figure VI.1, the medium load growth scenario, PSE resources are estimated to produce approximately 600 MWa of energy in excess of core load in the year 2000 In this scenario there is a surplus of energy on an annual basis until 2007 at which time additional energy supplies are acquired at market prices. By the year 2019 market price purchase grow to approximately 1279 MWa (about 43% of core load). Under critical water planning, shown in Figure VI.2, PSE total energy from hydroelectric resources (PSE owned and Mid-Columbia) is reduced by about 156 MWa or 83%. In this scenario the end of surplus year is about one year earlier and market resources are purchased.

Figure VI.1

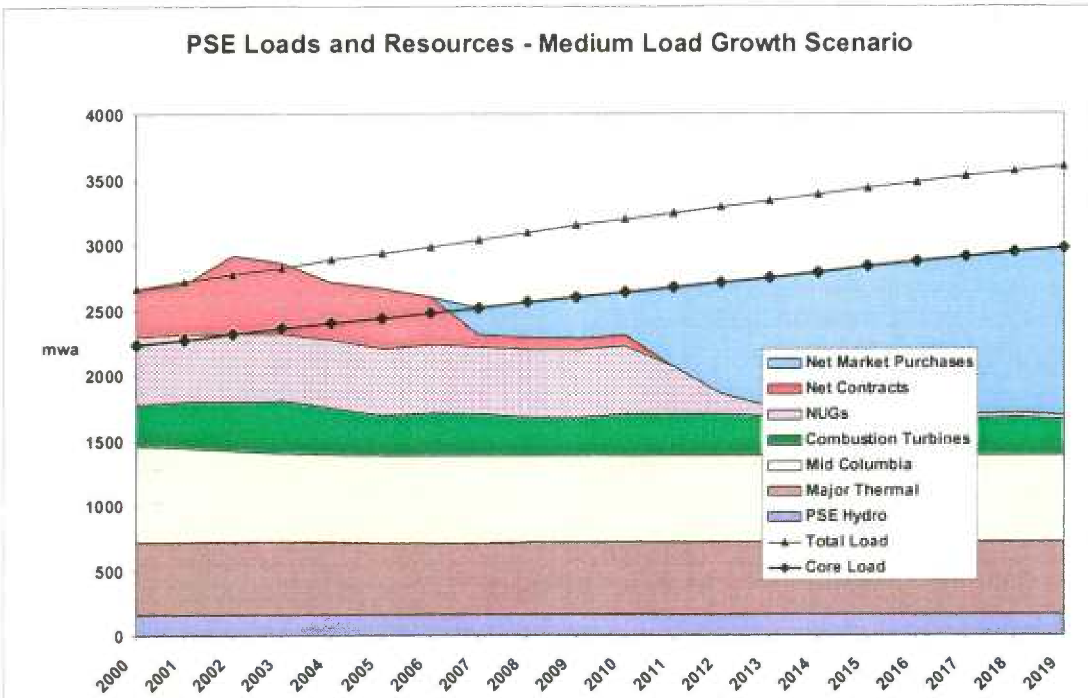


Figure VI.2

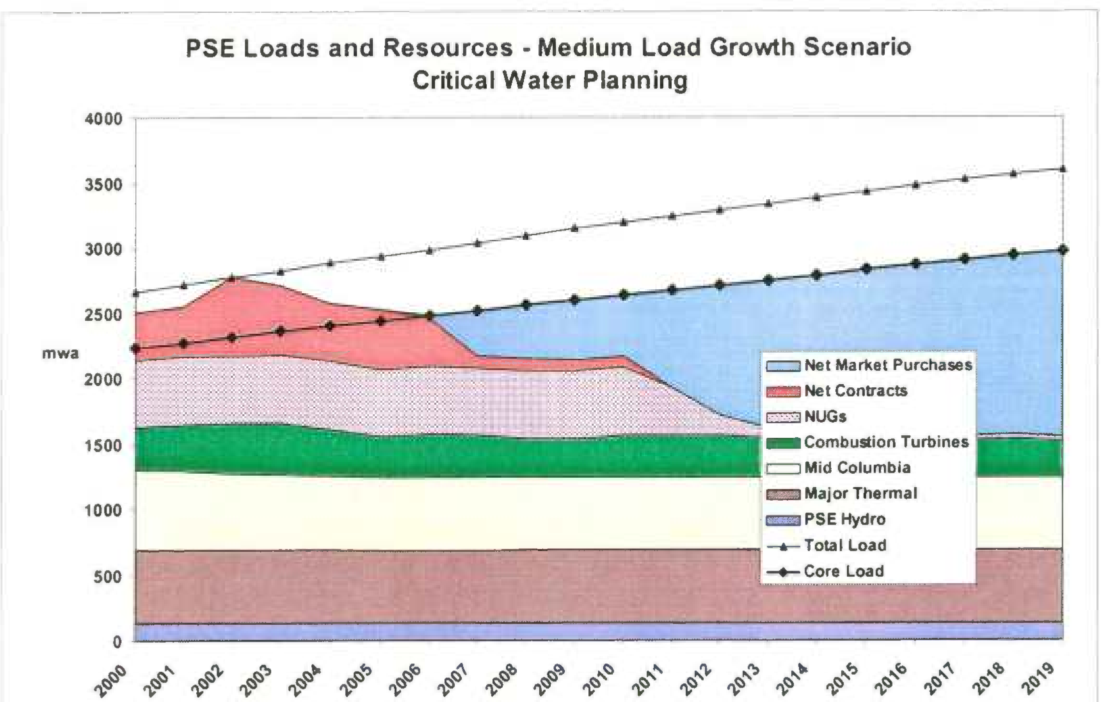


Figure VI.3

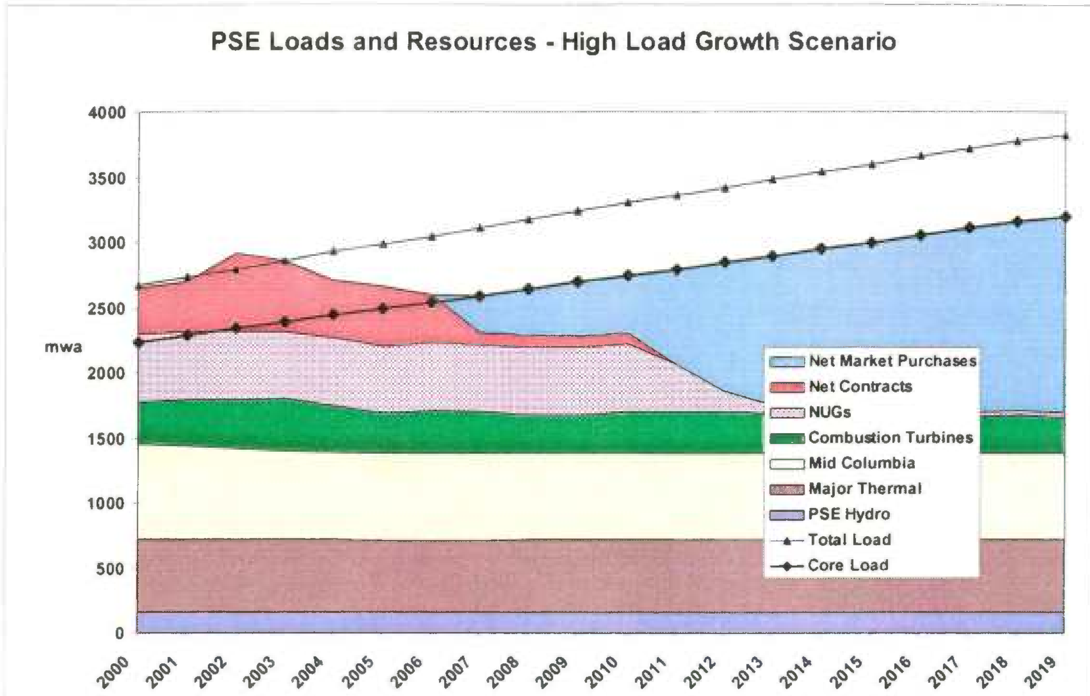


Figure VI.4

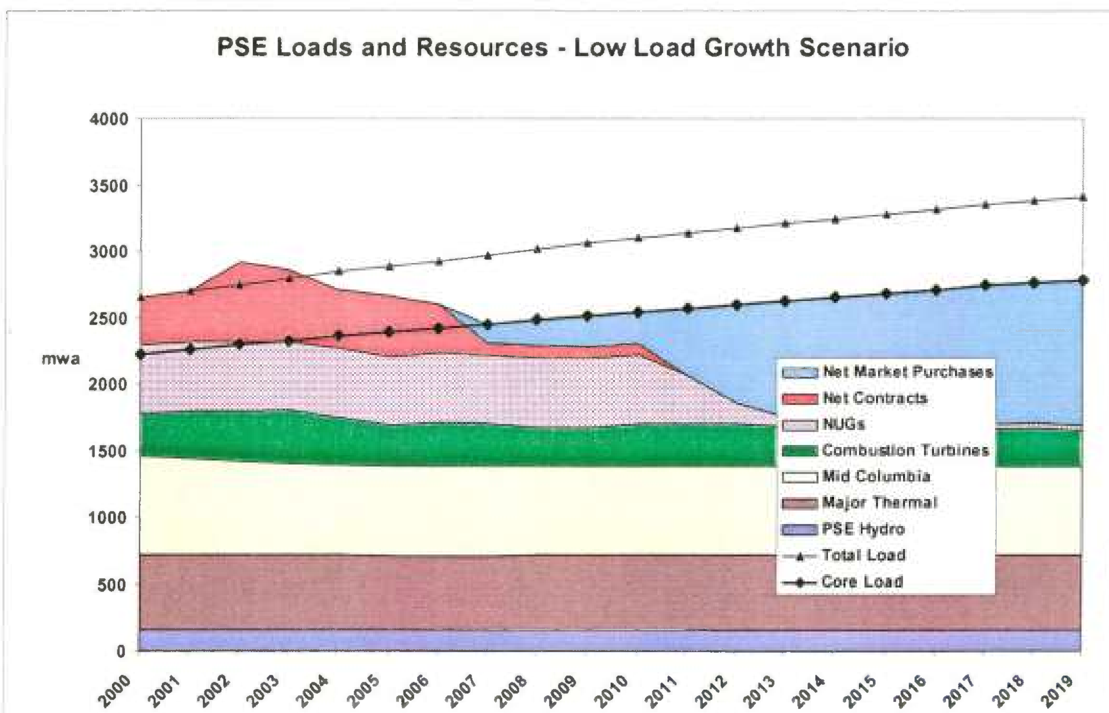


Figure VI.5

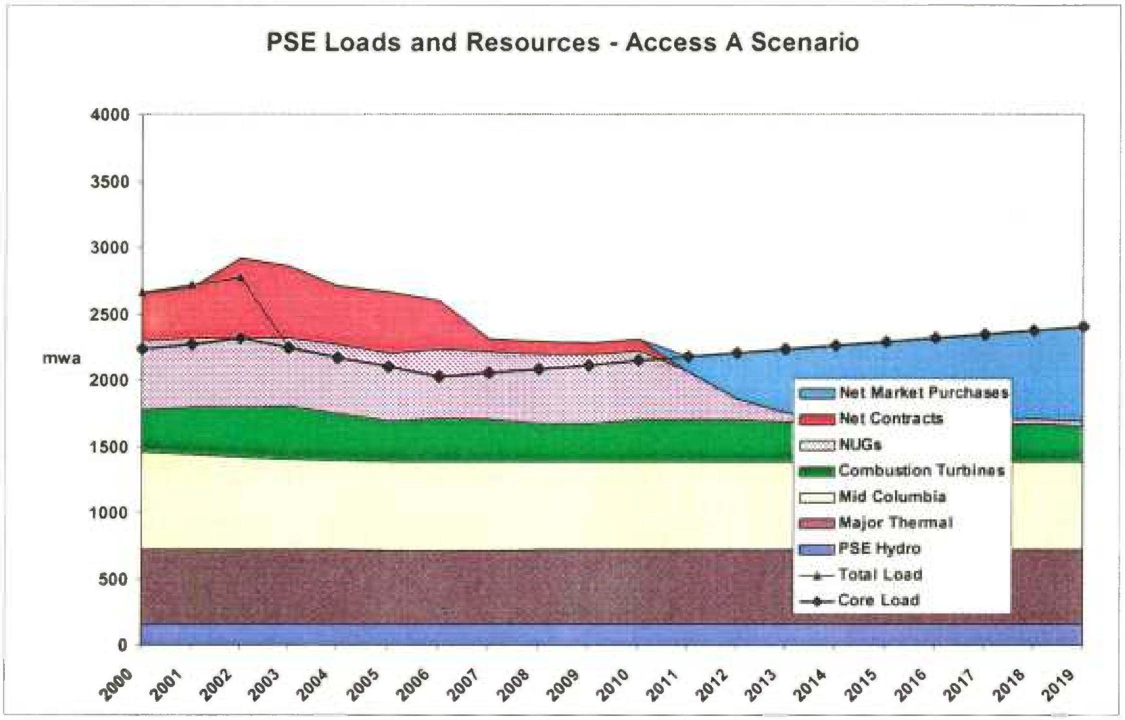
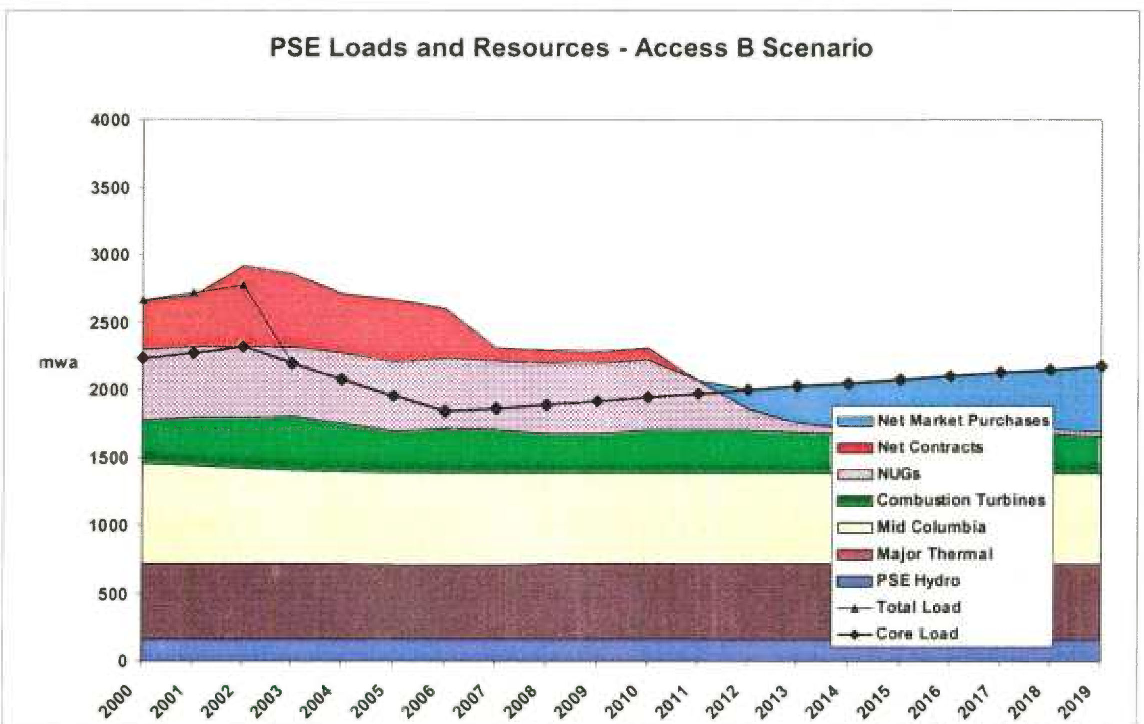


Figure VI.6



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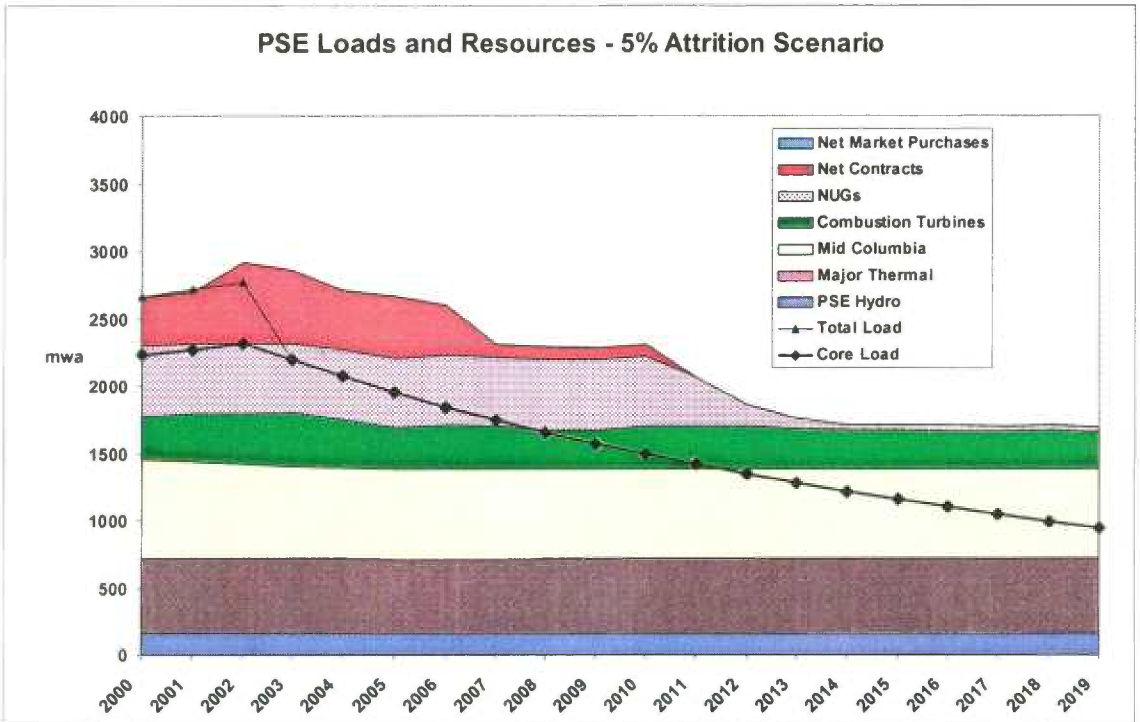


Figure VI.8

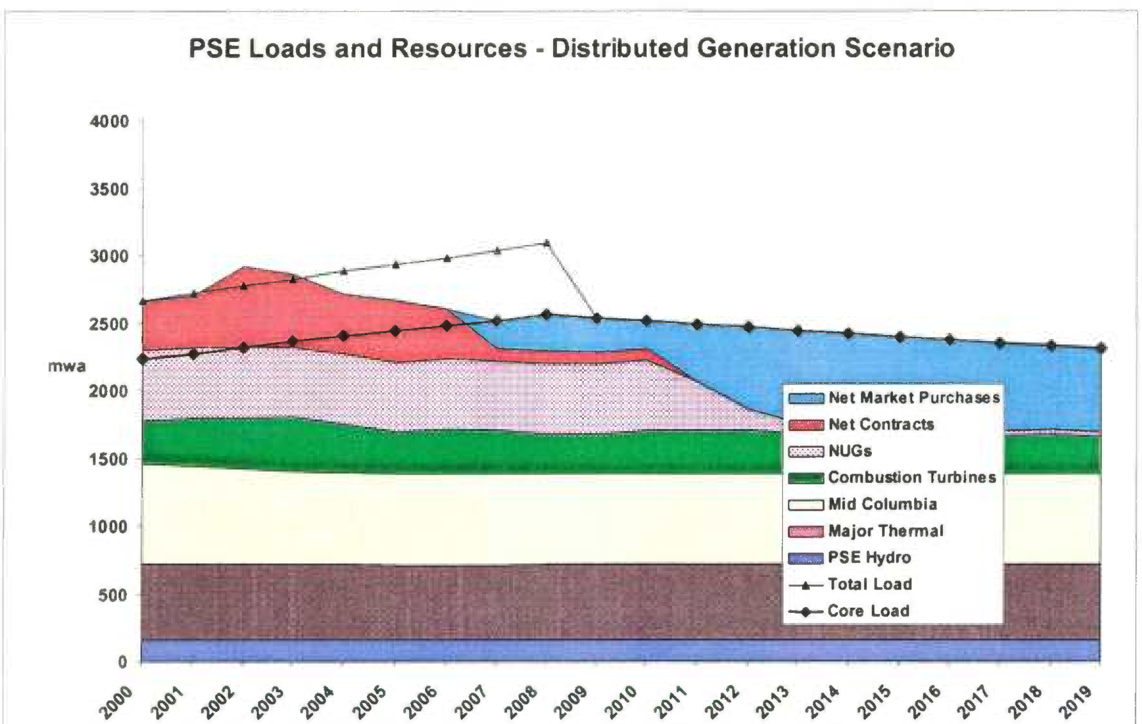


Figure VI.9

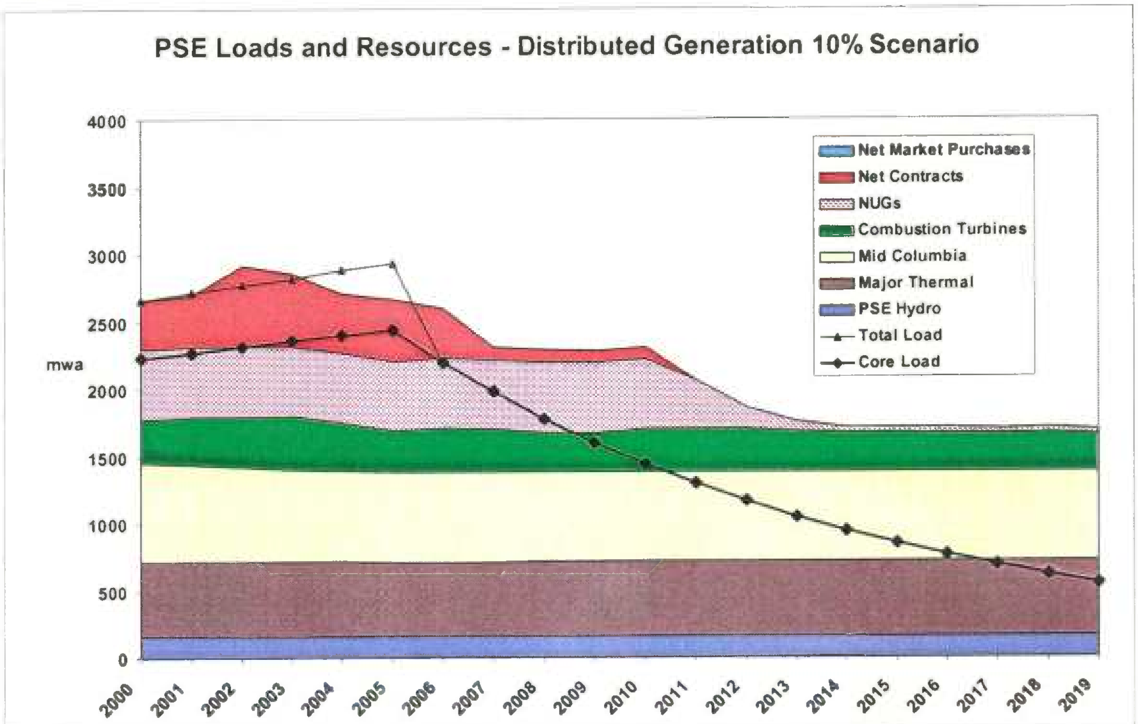


Figure VI.10

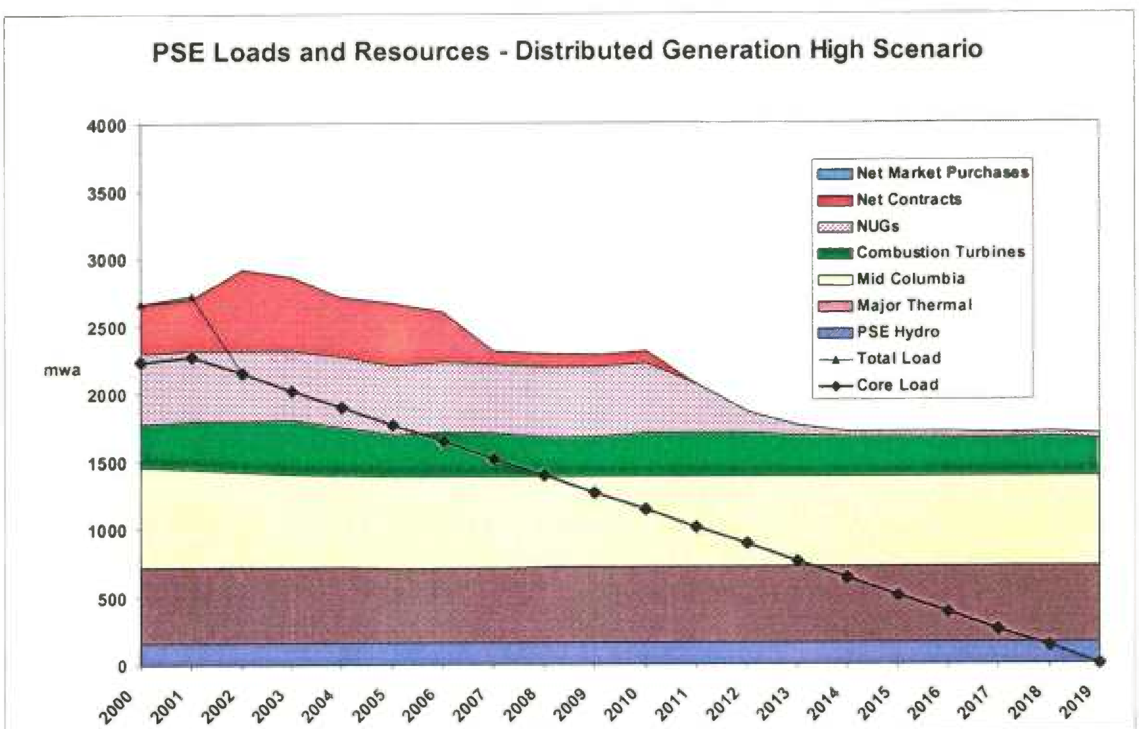


Figure VI.11

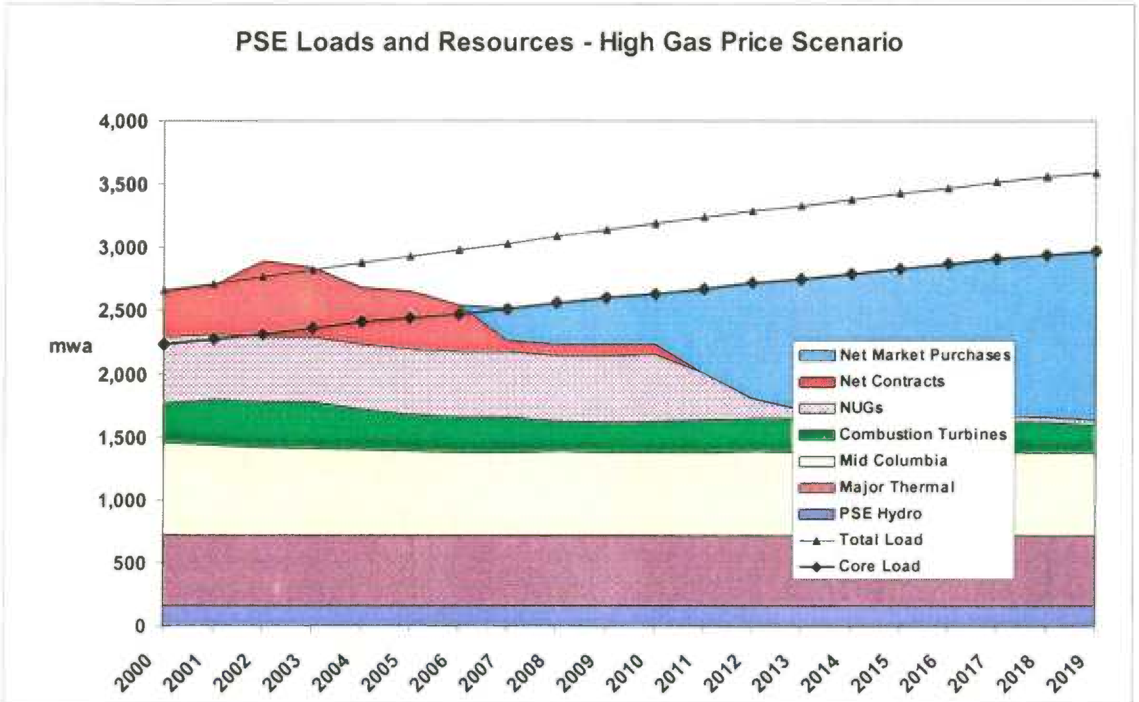
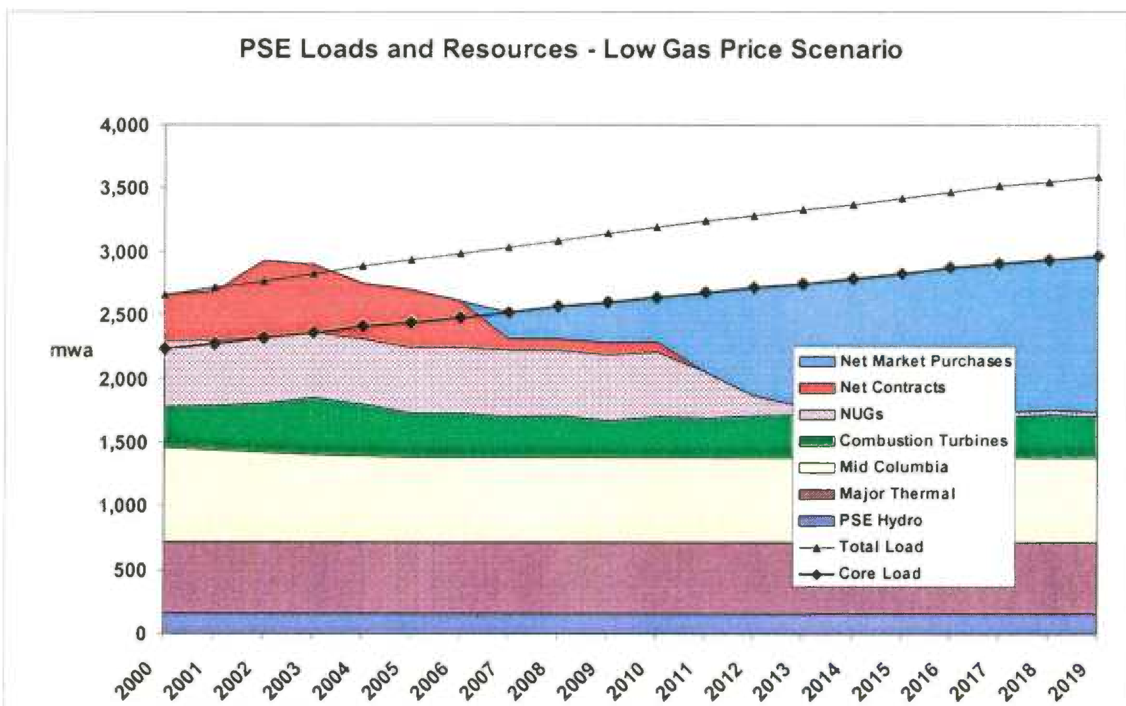


Figure VI.12



Forecasts of peak capacity loads and resources were developed assuming both "normal" and "extreme" winter peak hour loads. The normal peak hour loads are computed assuming a low temperature of 23 degrees. The extreme peak hour loads are computed assuming a low temperature of 13 degrees. Peak load forecasts were developed only for the medium load growth scenario. The normal and extreme peak loads are compared to the peak generating capacity of the PSE resource portfolio in Figures VI.13 and VI.14.

As shown in Figure VI.13, normal peak core load and portfolio resource capacity are closely balanced in 2000. Additional peak capacity resources are obtained from the market throughout the planning horizon. As shown in Figure VI.14, under extreme peak conditions loads are forecasted to exceed portfolio resource capacity by approximately 650 MW in 2000. PSE currently obtains additional capacity resources to meet winter peak loads with a purchase of a combination of firm capacity and associated energy during peak load hours as well as purchase of "call options" giving the option of calling on additional capacity if necessary.

Figure VI.13

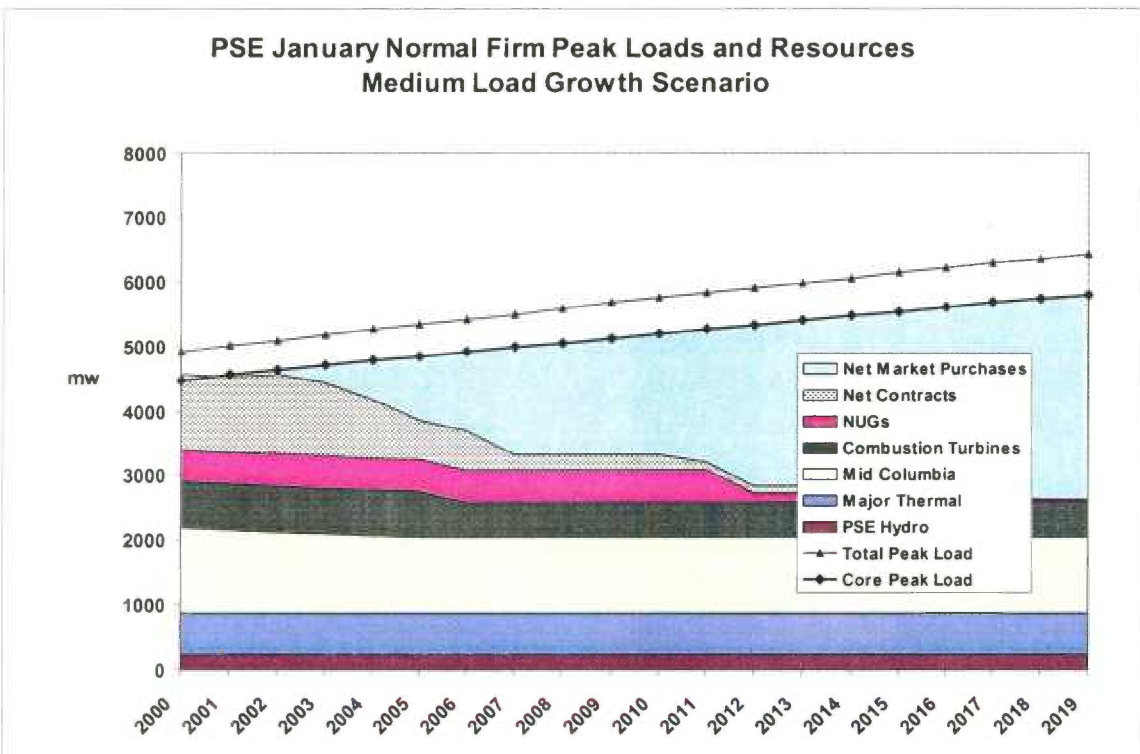
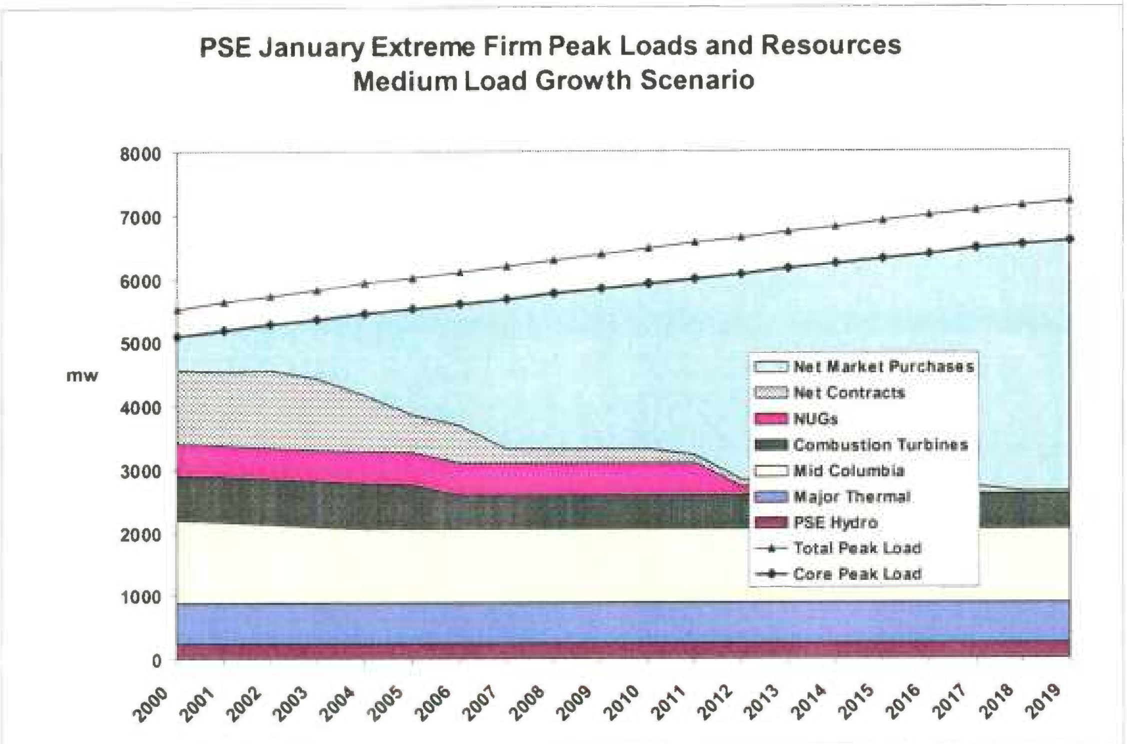


Figure VI.14



Electric Avoided Cost

Because of the emergence of competition in the wholesale electric industry and the associated development of a robust wholesale electric market in the Northwest, a regional market price index is a good indicator of "Avoided Cost." PSE's avoided cost of power is equal to the price of power at the Mid-Columbia Hub with appropriate adjustment for transmission costs between the Mid-Columbia Hub and PSE's system. Adjustments for transmission costs are based on the specific load shape of the alternative conservation or generation resource and are made as part of the calculation of the cost-effectiveness standard for the various programs. (See discussion in Chapter III).

Ideally power purchases should be priced at the actual price as of the time the power is delivered. However, for long-range planning purposes a forecast is needed on which to base decisions such as for conservation program evaluation and planning. Long-term price projections are fraught with uncertainty and are, by their nature, speculative.

The Mid-Columbia power prices shown in Table VI.3 below were calculated using Aurora based on the assumptions for the low, medium, and high gas price scenarios (using the medium load growth scenario).

Table VI.3: Annual Average Mid-Columbia Power Costs - ($/MWh)

Year	Low Gas Price Scenario	Medium Gas Price Scenario	High Gas Price Scenario
2000	24.49	24.54	24.51
2001	25.59	25.56	27.39
2002	26.04	26.95	29.76
2003	26.12	27.57	31.21
2004	26.31	27.54	31.85
2005	26.46	27.48	33.58
2006	26.82	29.80	34.58
2007	27.33	30.19	35.94
2008	27.98	29.60	34.90
2009	27.90	32.19	37.27
2010	28.56	33.43	38.08
2011	29.37	34.47	40.08
2012	30.61	35.65	41.69
2013	30.30	35.83	44.01
2014	30.42	36.30	44.59
2015	31.66	37.27	46.41
2016	31.04	38.20	48.41
2017	31.36	39.65	50.08
2018	33.61	41.04	51.91
2019	33.08	42.26	51.73

Electric Summary of Results

PSE faces a great deal of uncertainty regarding future loads because of the uncertainties surrounding both the nature and timing of ongoing national, regional, and statewide electric utility restructuring initiatives. Under scenarios assuming the structure of the industry remains similar to current practice (the Low, Medium, and High scenarios) PSE's existing resource portfolio will meet loads at least through the year 2006. Under open access scenarios (the Access A and Access B scenarios) the existing portfolio will meet loads through 2010 - 2012. Under scenarios entailing loss of even more load (the 5% Attrition, D. G. 10%, and D. G. High scenarios) existing resources meet loads throughout the 20 year planning horizon.

PSE's current resource portfolio consists almost entirely of generating resources and purchase contracts having future prices fixed based on either fixed resource construction and development costs or fixed contract purchase terms. While this portfolio is well adapted to the industry prior to the current wholesale market evolution and potential retail restructuring, it lacks the flexibility to respond to future load and price uncertainty. For these reasons PSE is seeking to diversify its resource portfolio by including a mix of both fixed and market priced resources as discussed further at the end of this chapter.

C. Natural Gas

In contrast to the wide ranging changes currently taking place in the electric industry, few significant changes are underway or anticipated in structure of the gas industry. Many of the restructuring initiatives taking place in the electric utility industry have already taken place in the gas utility industry.

Description of the Uplan-G Integrated Gas Planning Model

PSE has an on-going agreement with LCG Consulting of Los Altos, California for the rights to use the Uplan-G Resource Planning Model. LCG's PC-based models are used by numerous gas and electric utilities and Public Utility Commissions throughout the nation. (More information on LCG Consulting can be found on their website at www.energyonline.com.)

This model provides advanced features by including both a Dispatch or variable cost optimization mode and an Integrated Optimization mode. In the daily dispatch optimization mode, Uplan-G optimizes the daily variable operating cost of the supply portfolio to meet the forecast demand. The model takes into account all operational and cost implications of the contracts for gas supply, storage and pipeline capacity. The gas supply contracts are modeled on a daily basis with consideration to contract volume and contract entitlement as well as pipeline delivery and storage operation restrictions. The model also takes into account storage capacity, injection rate, withdrawal rate, inventory level, transportation losses, injection/withdrawal losses and numerous other details in order to optimize the storage operation cycle. This detail and embedded network structural representation results in a optimal dispatch for all contracts and storage operations. (Note: This portion of the model has been utilized as the basis for PSE's 1998 and 1999 PGA filings.)

In the integrated optimization mode, the model minimizes fixed and other demand charges as well as the variable components of costs. The model takes into account the complete life cycle cost of the contracts for gas supply, storage and pipeline capacity. The model thus determines the least cost resource portfolio over the planning horizon and the most economical daily dispatch simultaneously. In this mode the model develops a least cost plan which identifies not only the sizes of optimal new resources to bring on line but also the timing related issues of the new resources. The optimization is achieved by minimizing the total net present value of costs over the time horizon of the study.

Assumptions and Inputs

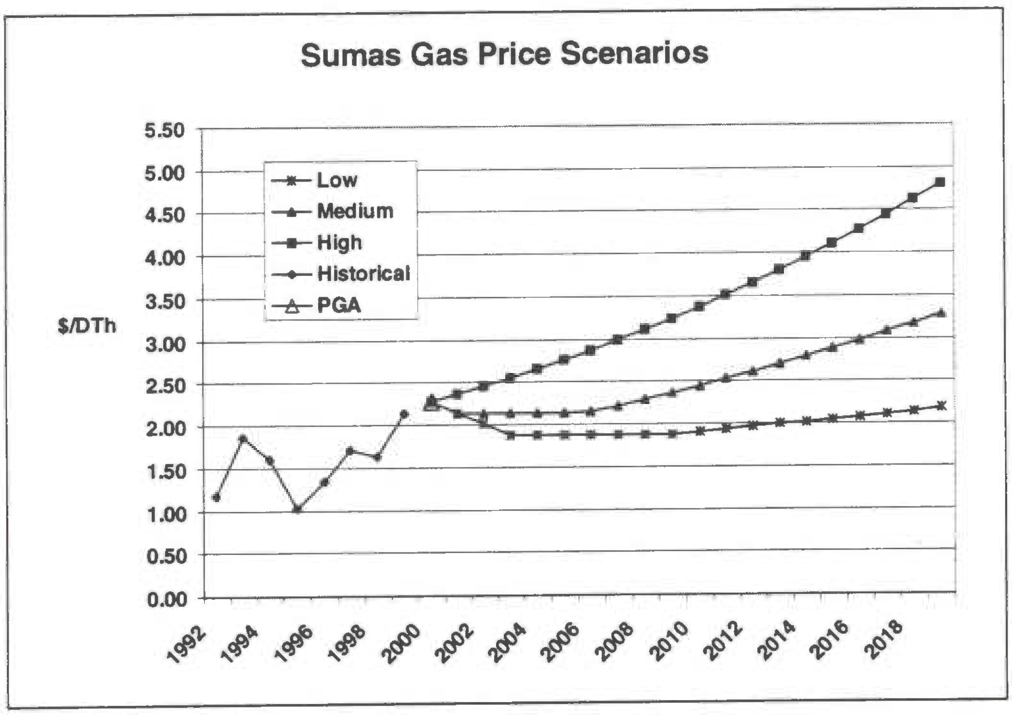
Load Scenarios

Three alternative load growth and three gas price scenarios are evaluated. The load growth scenarios are discussed in Chapter II. The impact of the low, medium, and high gas price forecasts were evaluated using the medium load growth scenario.

Natural Gas Price Scenarios

Three gas price scenarios were developed for sensitivity analysis for both the gas and electricity analyses. These forecasts all use the same year 2000 starting point but escalate at different rates over the time horizon of the analyses. PSE projected natural gas prices to average $2.27/DTh at Sumas for calendar year 2000 when developing the Purchased Gas Adjustment (PGA) submitted to the WUTC in September, 1999. This price was used as the starting point for the long-term gas price forecasts. The low, medium, and high gas price scenarios are shown in Figure VI.15 .

Figure VI.15



The price estimate of $2.27/mmbtu for the year 2000 is a relatively high price compared to historical Sumas index prices reflecting a significant increase in prices over the past several months. The medium scenario reflects the assumption that prices will go down to 1999 levels in 2001, stabilize at that level until 2006 and then escalate at 3.32%/year. The decline in prices is based on the assumption that gas exploration and development companies will react to the higher prices by developing additional supplies, bringing supply and demand back into equilibrium.

In the high case it is assumed that prices continue to escalate beginning in 2000 at 4.04%/year throughout the time horizon. In the low case it is assumed that prices continue to decline until 2004, remain constant until 2010 and then escalate at 1.48%/year. These long-range escalation rates are based on previous Council analyses.

Gas Supply

It was assumed that additional gas supplies will be available as needed over the time horizon. This assumption is based on the relatively large gas reserves identified in the various producing regions and the responsiveness of producers to higher gas prices. Gas supply contract demand and commodity pricing, load factor and entitlement provisions are similar to those currently in place are continued over the analysis period. The assumption is made that either these contracts or contracts with very similar provisions will be available throughout the time period of the analyses. Historical patterns of monthly and seasonal price variations to the annual average price are used.

PSE Peak Day Loads and Resources

PSE's existing capacity resources were discussed earlier in Chapter V. These resources and their peak delivery capacity as well as the medium forecast of peak loads for the year 2000 through 2005 are shown in Table VI.4. The peak day loads are estimated assuming an average daily temperature of 10 degrees (55 HDD) as discussed in Chapter II.

Table VI.4: Gas Peak Day Load Resource Balance 2000 - 2005 - (MDThs/day)

	2000	2001	2002	2003	2004	2005
Firm Peak Load	795	821	844	867	889	911
Resources						
Firm Pipeline - (TF-1)	454.5	454.5	454.5	454.5	454.5	454.5
Jackson Prairie	343.1	343.1	343.1	343.1	343.1	343.1
Plymouth LNG	70.5	70.5	70.5	70.5	70.5	70.5
Propane-Air & Metro	30.5	30.5	30.5	30.5	30.5	30.5
Subtotal - Existing Res.	899	899	899	899	899	899
Surplus/Deficit	103	77	54	32	10	-12

With the November 1999 expansion of the Jackson Prairie, PSE has sufficient capacity resources to meet forecasted peak day loads through the year 2004. For this reason PSE is not actively pursuing development of new delivery capacity options but is keeping abreast of on-going capacity expansion activities within the region.

New Resource Options

As outlined in Chapter V, there are several options for future capacity resource expansion beyond 2004-05. These options are summarized in Table VI.5 below.

Table VI.5: Summary of New Gas Resource Options

	Peak Gas Supply Service	PGSS Redelivery	Firm Gas Supply Service	NWP Capacity	New LNG Plant
Deliverability (MDTh/day)	50	50	10	-	100
Annual Quantity (MDTh)	600	600	30	-	1000
Days of Deliverability	12	12	3	365	10

The peak gas supply service (PGSS) option consists of an agreement with a facility using natural gas as a primary fuel having the capability to uses alternative fuels such as oil for limited periods of time. The option included in this analysis is based on an agreement with an end-user that consumes 50 MDThs/day with sufficient oil available to operate for 12 days. When called upon, the seller of the service will switch to oil thus making the gas available to the buyer. Typically the buyer of the service pays for the oil as well as a capacity based demand charge for the service.

While the PGSS option makes the gas available to the buyer, provisions must be made for delivery of the gas from the seller to the buyer. By taking advantage of its location on NWP, PSE can use delivery displacement agreements with other parties to cost-effectively and reliably deliver peaking supplies.

The Firm Gas Supply Service (FGSS) is similar to the PGSS except the seller is assumed to have firm gas transportation capacity on NWP and be located within PSE's service territory. While typically cost-effective relative to acquiring additional pipeline capacity or an LNG plant, this option may be more expensive than the PGSS in combination with a redelivery service since the buyer is called upon to pay market prices for the gas on the day it's called upon in addition to the demand charges paid for the right to call on the gas.

As discussed in Chapter V, PSE contracts for firm pipeline capacity on NWP. There are a number of separate contracts involved which were negotiated at different times (usually coinciding with major pipeline expansion projects) and with different expiration dates. Some of these contracts terminate in 2004, several terminate in 2008, and additional contracts end in 2016. PSE has the unilateral right to renew these contracts upon expiration if desired. Since other entities have similar contracts, there may be opportunity for PSE to increase its long-term pipeline capacity during these renewal years.

The final option evaluated in the analysis is a new LNG facility. For analyses purposes it was assumed the facility would be located so that PSE could use a displacement arrangement for delivery.

Scenario Results

Each of the PSE load growth scenarios was evaluated to determine the combination of capacity resources that minimize the cost of meeting customer loads. The results for all the scenarios are summarized in Table VI.6.

Table VI.6: Summary Results Of Scenario Analyses

Scenario	NPV of Resource Costs ($ - millions)
1. Medium Load Growth	3,432
2. Low Load Growth	3,357
3. High Load Growth	3,634
4. Low Gas Price	3,009
5. High Gas Price	4,310

The results for the medium load growth scenario are presented graphically in Figures VI.16 and VI.17. Figure VI.16 shows the peak day demand and delivery capacity of the various supply resources over the 20 year period. As shown, existing resources are sufficient to meet peak day loads though the year 2004. Additional resource options added include:

- small expansion of firm pipeline capacity in 2004;
- acquisition of PGSS redelivery service in 2006;
- implementation of FGSS in 2006;
- acquisition of 2nd PGSS and redelivery service agreements in 2014; and
- development of a new LNG facility in 2017.

The resource options selected to meet forecasted peak day requirements and the annual supply sources for the low load growth scenario are summarized in Figures VI.18 and VI.19 Similar results for the high load growth scenario are presented in Figures VI.20 and VI.21.

Figure VI.16

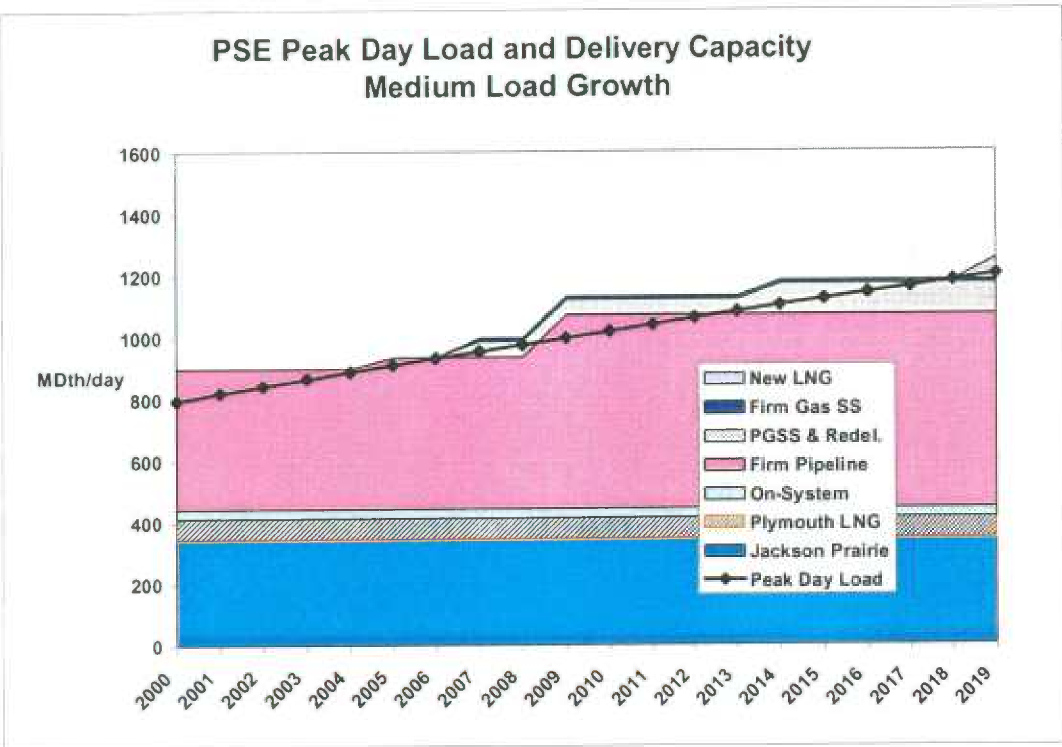


Figure VI.17

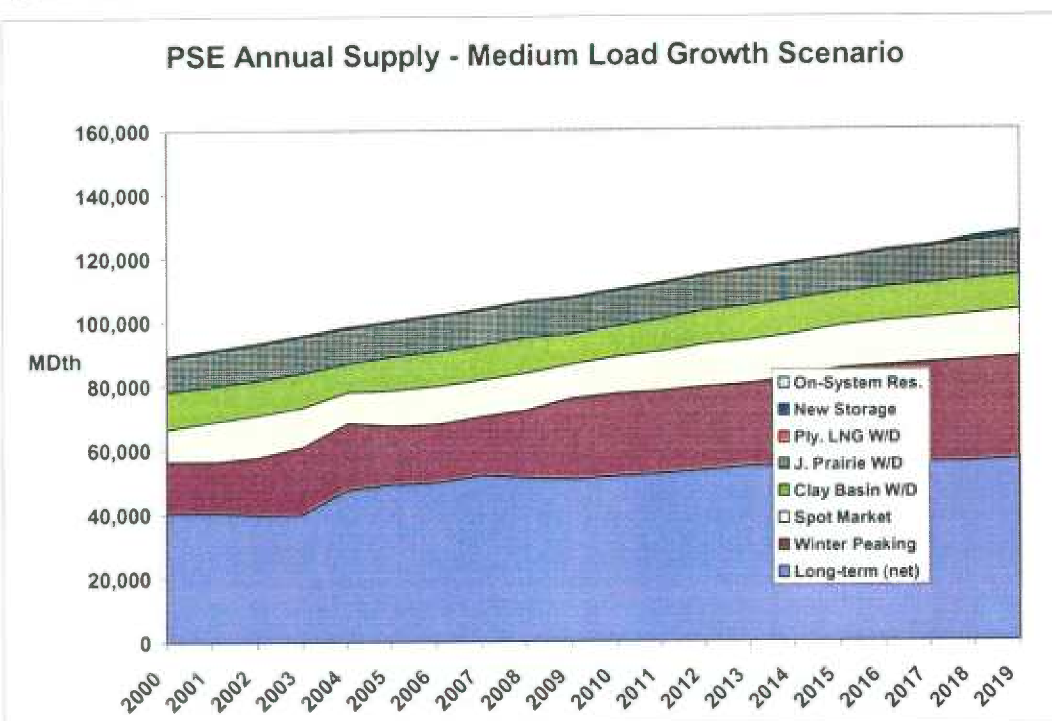


Figure VI.18

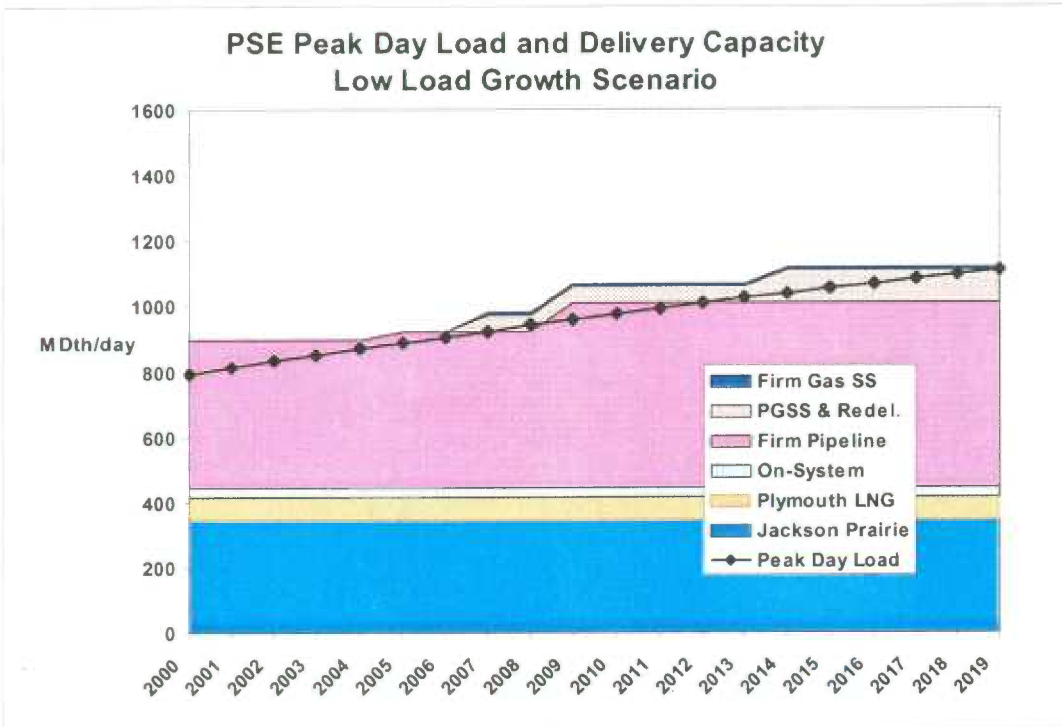


Figure VI.19

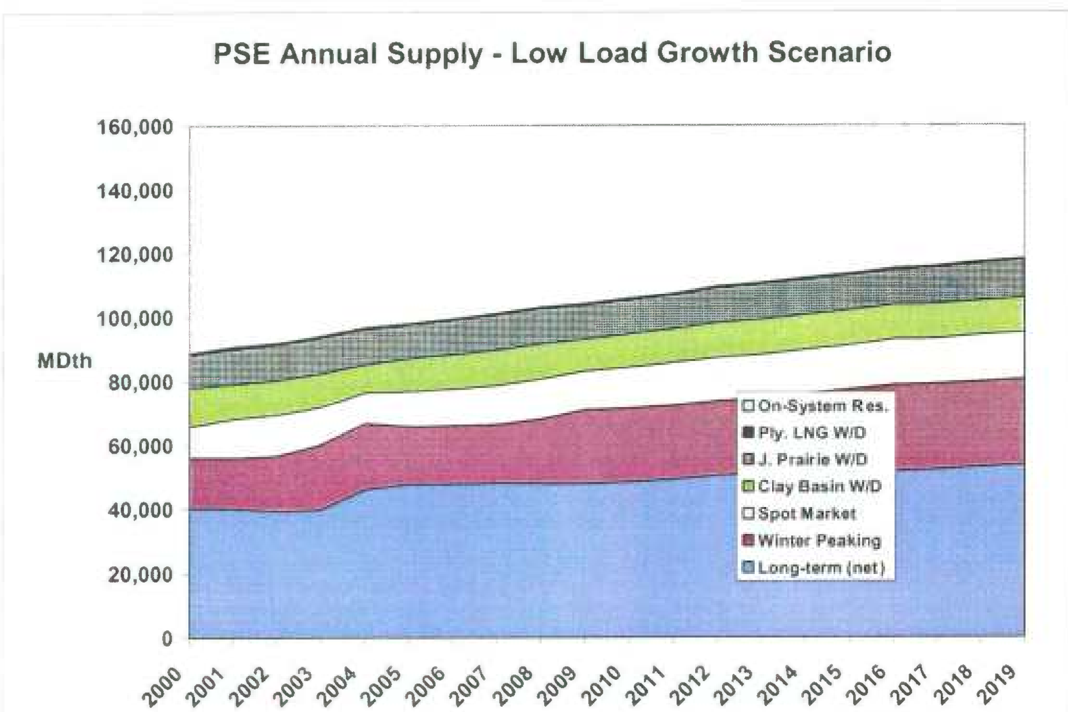


Figure VI.20

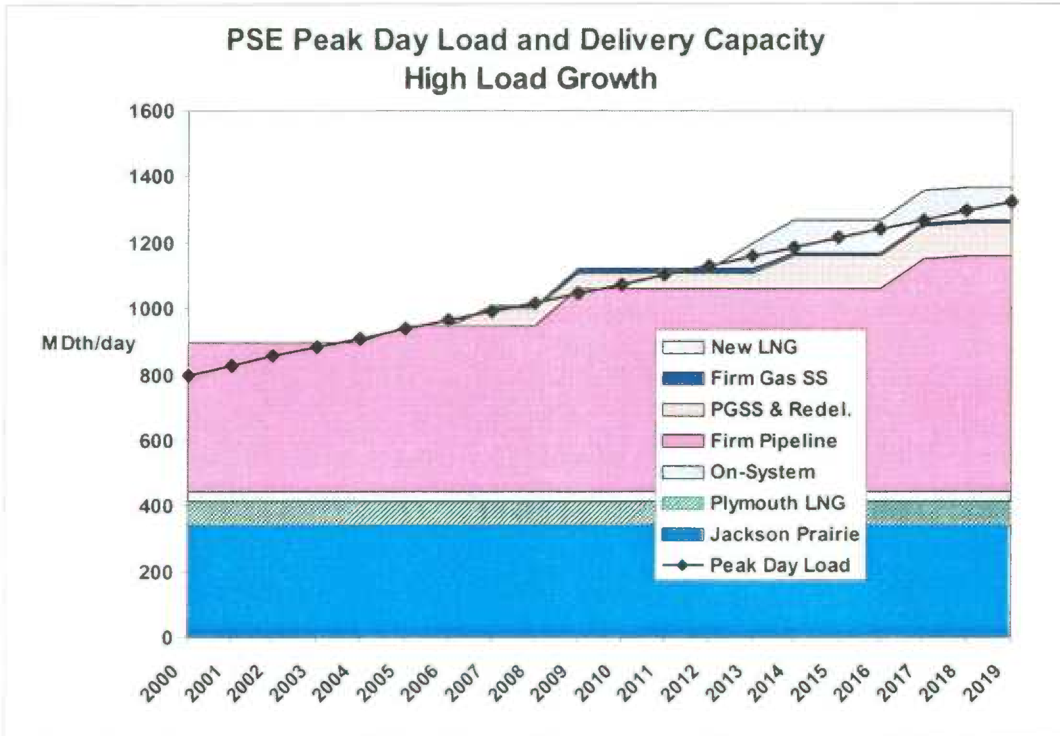
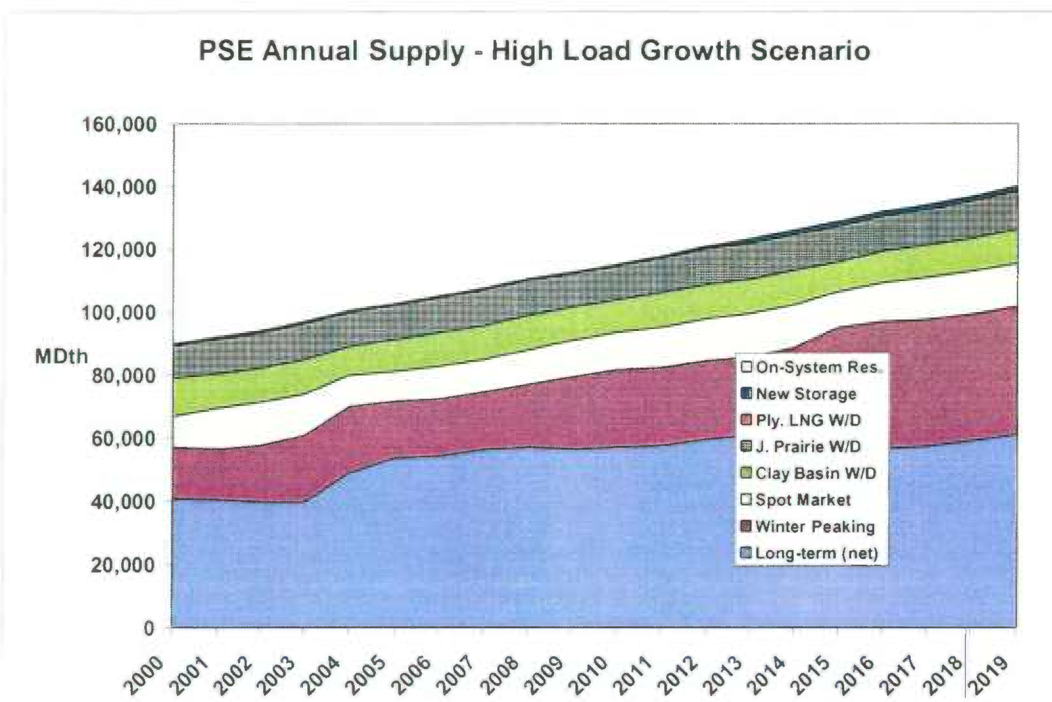


Figure VI.21



Gas Avoided Costs

As discussed in Chapter III, the avoided cost of supplying gas to the city-gate is used as the basis for the cost-effectiveness criterion for gas conservation program evaluation. Avoided costs were calculated for three different conservation program types; space heating measures, water heating measures, and process based (flat load shape) measures.

To determine the avoided cost of the various measures, the medium load growth case loads were reduced by approximately 4% for each year. Three different shapes were used, one approximating each of three program types. The difference in total annual supply cost (including gas supply, pipeline, and storage costs) divided by the difference in annual volume results in the cost of the avoided or marginal supply resources for each end use. The results are shown in Table VI.7.

Table VI.7: Avoided City-Gate Natural Gas Costs- ($/DTh)

Year	Space Heat Measures	Water Heat Measures	Process Measures
2000	1.88	1.89	1.93
2001	1.62	1.62	1.62
2002	1.88	1.84	1.89
2003	2.01	1.69	1.91
2004	2.63	2.48	2.39
2005	3.43	3.04	2.61
2006	3.38	2.89	2.71
2007	3.50	3.06	2.81
2008	3.53	3.19	2.86
2009	4.22	3.67	3.28
2010	4.34	3.82	3.37
2011	4.32	3.82	3.30
2012	4.33	3.60	3.27
2013	4.38	4.08	3.66
2014	4.23	4.10	3.63
2015	5.28	4.30	3.96
2016	4.78	4.06	3.62
2017	5.05	4.70	4.13
2018	4.81	4.50	4.30
2019	4.96	4.10	4.02

The 20 year levelized avoided cost for each end use is:

- Space heating measures: $3.28/DTh
- Water heating measures: $2.95/DTh
- Process based measures: $2.75/DTh

These values are slightly lower than the avoided costs calculated pursuant to the 1995 WNG LCP. While the forecasts of the cost of gas are higher in this plan than the 1995 plan, four factors have more than offset the effect of the gas cost increases. These are: 1) firm pipeline tariffs are slightly lower than in 1995, 2) no expansion of peak day delivery capacity is needed until 2005 following the November 1999 expansion of Jackson Prairie, 3) the PGSS, PGSS redelivery, and FGSS are less expensive than the expansion options contemplated in the 1995 plan, and 4) the revised methodology for calculating peak day loads results in lower forecasted peak day loads

Gas Summary of Results

PSE expects to have sufficient peak day delivery capacity to meet currently forecasted peak loads until the 2004-2005 heating season. As a result, no expansion of peak day delivery capacity is currently contemplated. Options for capacity expansion are evaluated on an on going basis for possible inclusion when needed.

PSE's existing and alternative future capacity options can meet future peak day loads over the 20 year planning period under all three load growth scenarios. Further, these capacity additions will enable delivery of the annual volumes of gas to meet core loads throughout the period.

The least cost resources selected by this planning process in both the low and high cases are timing variations on the resource acquisition schedule developed in the medium case. Of course, an accelerated growth pattern (such as would be seen from the high growth gas scenario, or possibly resulting from the various Distributed Generation electric scenarios) will require an adjustment of resource development plans. Since the least cost planning process in ongoing, it is expected that sufficient lead time will be available to either speed up or delay the development or acquisition of additional resources.

D. Resource Strategies and Conclusions

Based upon the results of the scenario analysis provided earlier in this chapter and in considerion of the planning issues discussed throughout this report, PSE has reached a number of conclusions regarding gas and electric resource strategies and conclusions which are discussed below. These strategies then form the basis for many of the items listed in the Two Year Action Plan provided in Chapter IX.

Gas Strategies and Conclusions

PSE will continue to utilize competitive market forces in the gas supply market to maximize benefits for our customers. PSE has developed, and will continue to develop, a portfolio of gas supply resources that are consistent with customer supply commitments and pricing provisions. PSE' gas portfolio contains a mixture of short-term and long-term contracts. Much of PSE's winter gas supplies are contracted on a seasonal basis. This provides year-to-year flexibility to optimize use of the most favorable supply basin. Contracting on a shorter-term basis can also allow an opportunity to incorporate new and innovative contracting terms as they develop in the market. PSE also utilizes some existing long term supply contracts, all of which expire by 2005. PSE's gas supply portfolio is well positioned for future demand uncertainty because contracts are priced at market and can be sold in the unlikely event that contracted supply exceeds demand. PSE's long-term contracts benefit in other ways from the competitive market. Beyond simple commodity market pricing provisions, PSE's long-term contracts contain annual re-negotiation provisions, which allow the Company to negotiate other aspects of the contract to reflect changes in the market. PSE will continue to utilize the dynamic, competitive forces in the Pacific Northwest gas supply market to benefit our customers.

Current projections suggest that additional capacity to deliver gas to PSE's distribution system will not be needed for at least 4 years, under the most liberal growth scenario. This is primarily due to additional, cost effective transportation capacity acquired in association with the recently completed expansion of the Jackson Prairie storage facility, near Chehalis, WA. To meet the needs of our firm customers on a longer term basis, PSE will continue to seek opportunities for strategic, cost effective supply and capacity resource options that match customer expected customers supply commitments.

Electric Strategies and Conclusions

It is important to recognize how electric energy markets are evolving as compared, and contrasted, to natural gas markets. While there are commonalties in the opening of gas and electric wholesale markets to competition, the structures of two industries have different histories. In natural gas markets, LDCs in most jurisdictions have not owned and operated natural gas wells, which are the supply counterparts of electric generators in electric markets. Firms that specialize in natural gas production have developed to capture upstream economies of scale and scope. Gas production firms are large (usually multinational) and optimize operations across several related petroleum markets including oil and propane. LDCs like PSE are better positioned to specialize as buyers in the competitive market place, reaping benefits of competition between firms specializing in gas production. Considering that PSE presently purchases approximately 65% of the power in its electric supply portfolio and the industry conditions discussed in this plan, PSE believes it is best positioned to meet its customer's electrical energy needs by focusing on being an effective buyer as competitive electric markets continue to evolve, and by relying less on owning and operating new generation resources.

PSE will continue to seek to structure its gas and electric supply portfolios so that they are aligned consistently with the various attributes of its expected supply commitments to customers, including term, pricing, quality and other attributes. These customer supply commitments to customers, of course, evolve within the context of national, regional, and state energy policies. As described above, such policies in the gas and electric industries have different histories, and, while becoming similar in important ways, still are markedly dissimilar in the State of Washington at this time. Correspondingly, PSE's gas and electric resource portfolios have evolved differently. PSE's gas supply portfolio has been structured to be responsive to PSE's supply commitments to its gas customers within the context of the PGA and PGA incentive pricing structures and a gas industry structure set forth by federal and state policy. These issues of pricing structure and industry structure, while resolved for now in the PSE's gas business, are enormously more uncertain for PSE's electric business. For instance, the scenarios in this plan demonstrate dramatically the degree of uncertainty faced regarding the term of customer supply commitments going forward due to the possibility of retail open access occurring at some time over the planning horizon. Further uncertainty is added to the planning process issues of electric supply pricing to customers need to be addressed.

In the absence of resolution of these issues, PSE must manage its electric supply portfolio to be responsive to its customer supply commitments as they are expected at the current time, recognizing fundamental uncertainties. This uncertainty drives a need for additional flexibility in PSE's electric supply portfolio. A noteworthy contrast between PSE's gas and electric supply portfolios is flexibility. The natural gas discussion above provides an overview of the flexibility inherent in PSE gas portfolio. This flexibility allows PSE to take advantage of rapidly evolving market opportunities, which carries over into long-term contracts. Shorter duration contracts also provide a hedge against uncertain future retail market structures, minimizing potentially uneconomic resource costs. A strategy to diversify its electric supply portfolio through adding market-responsive resources incrementally to the electric portfolio appears to provide a degree of the market and flexibility benefits similar to those of gas supply portfolio.

In the current environment where fundamental issues associated with retail access and other structural changes have not been resolved in this state, long-term resource planning over a 20-year time horizon is extremely difficult. Generally, it does not appear that making large new 20 to 30-year resource commitments today would prove to be beneficial to customers and the company under many of the scenarios identified in this plan. Consider, for instance, if PSE were to build and operate a large new central station generation resource to serve incrementally the expected loads of core customers over next 20 to 30-years. Should market prices not rise above the cost of this resource its cost may prove, in hindsight, to be uneconomic. The company and its customers would have been better off had this resource not been acquired in the first place - the company should have relied on market purchases. Further, should open access or other industry changes occur over the 20 year planning horizon, this resource may not be needed to serve core loads, and, beyond this, if market prices were to stay relatively low, the resource many become difficult to liquidate. This is an illustration of the difficulties in making large new long-term resource commitments in today's environment.

Following the path of building (or contracting for) new, inflexible long-term power supply generation facilities is risky for customers as such commitments could prove to be 1) uneconomic, due to changes in technologies or market costs, or, 2) unnecessary, due to movement of core customers to non-core status (see scenarios). In short, at this time, it is difficult to make long term capital or contractual commitments for resource acquisitions, after considering many risks to customers such commitments present. Generally, such a new resource commitment appears inconsistent with overall expected customer supply commitments.

To PSE it appears reasonable to address such risks through pursuing a strategy of increased use of flexible, short and intermediate term market responsive supply to meet incremental needs through this transition period until the context of PSE's customer supply commitments are made more clear by policymakers. However, this is not to say that under all scenarios this incremental reliance on the market will always prove, in hindsight, to be the best path. Scenarios can be constructed where market prices rise so greatly that this strategy may appear, in hindsight, best under certain sets of long-term industry assumptions. Even so, at the current time, it appears clear that, on balance, this incremental use of market purchases minimizes the risks illustrated by the scenarios in this plan.

It is important to note that PSE's existing electric supply portfolio currently contains a significant amount of long-term, (relatively) fixed price supply resources. PSE will continue to pursue opportunities, as they arise, to mitigate and streamline certain high cost resources in the existing resource portfolio. Existing long-term resource commitments may be replaced by substitute long-term commitments if overall cost savings and other benefits can be achieved. At the same time, PSE is vigorously pursuing a fair allocation from BPA of the benefits of the federal hydropower for our residential and small-farm customers and a continuation of the benefits of its very low cost Mid-Columbia power purchase ageeements. As the costs of the federal hydropower system are expected to be below market, fair access to this resource is critical for PSE's residential and small farm customers. This regional resource, in combination with PSE's Mid-Columbia contractual supplies, can form a large, stable, and very low cost resource base for PSE's customers. PSE's overall resource portfolio can then be further diversified by building in more flexible, short- and intermediate-term market-responsive power supplies, as opposed to inflexible, long-term commitments. This diversity provides protection for customers by mitigating the impact that electric market price changes would have on customers through the future.

Regulatory Issues

In order for PSE to be able to plan appropriately for meeting future customer supply commitments and to take best take advantage of the benefits for its customers of moving incrementally toward market-responsive energy supply, a regulatory mechanism is needed that can allow PSE to match the qualities of its resource supply commitments to its customer supply commitments. Under the current regulatory structure for electric energy cost recovery provided in the Merger Rate Plan, PSE absorbs market price risks as customer rates do not change in accordance with market costs. Continuation of this, or any other structure where the utility is required to absorb market price risks increase long-run costs to customers by adversely affecting the utility's cost of capital and encouraging the utility to pursue costly efforts to attempt to insulate against this risk. Conversely, it appears that customers would benefit from a regulatory policy that better encourages innovation, shares the benefits of competitive wholesale markets, encourages conservation and effective load management, and does not adversely affect the company's ability to raise capital on reasonable terms. Therefore, PSE encourages the WUTC to adopt an electric energy cost adjustment clause and incentive mechanism, generally similar to its Purchased Gas Adjustment (PGA) and PGA Incentive Mechanism, for the post-Rate Plan period.

Under such a mechanism, a yearly adjustment for changes in market costs would be made. Beyond this, customers could choose to see daily, weekly or monthly changes in market prices, which would provide real market signals to those customers providing market-based incentives for active load management and conservation. Long-term volatility would be mitigated as PSE's electric resource portfolio is very diverse as it is expected to include a mixture of incremental market purchases, BPA power provided under the subscription process, PSE owned resources, and long-term contracts. Even so, it is important to note that if current projections that gas and electric wholesale prices will rise over the long-term turn out to be true, both the current PGA mechanism and a similar electric cost adjustment mechanism would pass through these rising costs over the long term.

As the Commission considers such a mechanism, PSE urges the WUTC to consider that, the fact that wholesale energy markets have changed dramatically while retail regulation has not raises a critical issue of regulatory policy. Under the current situation, PSE, as a regulated electric utility continues to operate under cost of service regulation and a duty to serve. In doing so under the current Rate Plan structure, PSE is now effectively serving as buffer between volatile market forces and customers. Serving as this buffer is costly now, and, over the long term even more costly, as the utility's cost of capital will rise to reflect this new risk should this situation continue over time. Eventually, customers will absorb those costs.

This situation is a sharp contrast to that of the past when utilities could make long-term resource commitments under a least-cost planning framework with the assurance that all those known investments and expenditures would be recovered under a well-understood cost of service regulatory framework. Energy supply commitments and customer commitments were much more clearly and easily matched. At this time though, incremental reliance on short- and intermediate-term market-based purchases for resource acquisitions appears to be best course during this uncertain period, as discussed above. However, should the company continue to absorb the variability in market costs, customers will ultimately face significantly higher costs due to an increased cost of capital, lack of opportunities for market-based load management, and possible missed market opportunities. In this state, as opposed to others, there has been change in regulation that sets forth future customer supply commitments that fully address the changing structure electric supply markets and associated resource alternatives. It is important to note that this risk of absorbing market price volatility was largely nonexistent for utilities in the past. Puget Sound Energy believes that an alternative structure after the end of the Merger Rate Plan period is critical and looks forward to the Commission's policy guidance on this important matter.

A second, related, set of regulatory changes PSE plans to pursue regard implementation of more time-sensitive pricing in utility services for those customers who desire such service. Passing wholesale price signals to retail customers is very important for aligning market information with customer choices. At this time, PSE electric customers (aside from Schedule 48 and special contracts) see no near-term market price signals whatsoever. Generally, a disconnection between wholesale and retail prices can create very distorting signals to the generation market, which will determine when additional generation is needed. This misalignment can lead to resource decisions being made in energy supply markets that do not have the benefit of customer interests and values. Conversely, customers may be able to benefit significantly from modifying use patterns and/or using energy efficiency measures in response to market information. The closer customers come to seeing real time prices form wholesale markets, the better able they are to make choices reflective of real energy supply market economics. Market-based conservation and load management actions taken by customers in response to this information may be tremendously valuable for customers possibly enabling them to avoid market price spikes and other market costs. If broadly implemented, such load management could allow generation markets to avoid production increments when those increments are most costly, producing potential benefits to the entire system.

In the past, technological barriers have stood in the way of providing real price signals to customers with the precision necessary to enable efficient short-run customer decisions. The necessary metering and communication technology has not been available, but this is changing quickly. PSE will be completing implementation of its Automated Meter Reading (AMR) system within the next two years. PSE will be investigating how this and other enabling technologies can be used to pass through real market price signals to customers so that they can take action to manage their loads, ultimately effecting least-cost solutions. As innovative opportunities are created, PSE will work with the Commission, Staff, Public Counsel, and other interested parties to successfully implement new services based on more precise and market-reflective pricing.

PSE, for its part, is focused on flexibility in accessing competitive wholesale electricity markets in acquiring resources to serve its loads. PSE expects to increase its use of incremental short-term market responsive alternatives presented in the competitive wholesale electricity markets, rather than on long-term commitments, for resource acquisition. This flexibility is especially important because a utility's obligation to serve may change dramatically as a natural result of industry evolution and policy developments. PSE acknowledges that its obligation to serve continues unchanged until the Congress or the Washington State Legislature indicate otherwise.

Distribution Planning

VII. DISTRIBUTION SYSTEM FACILITIES PLANNING

The facilities planning process requires an effective integrated planning approach. That is, effective least cost planning for the distribution system requires that all elements of the energy delivery system be tailored to provide safe and reliable service at the lowest cost.

Within this integrated view, facilities planning establishes the guidelines for installation, maintenance and operation of the local distribution company's physical plant, balancing the economics, safety and operational requirements of the distribution system. The planning process must also consider environmental conditions and changing customer demands, review alternatives and develop contingency plans. As economics, regulations and customer needs change, so does the design of the distribution system facilities. Planning in the context of infrastructure changes, regional land-use changes and other utility construction is critical to providing least cost facilities.

This chapter addresses:

- how the gas and electric energy delivery system works,
- specific facilities which are included within the delivery system,
- system performance criteria, for both the customer and the company,
- the methods for evaluating alterations to the system,
- the types of adjustments which can be made within the system to lessen the need for additional facilities,
- the trade-off process for funding prioritization, and
- future technologies which are expected to alter the landscape of the delivery system.

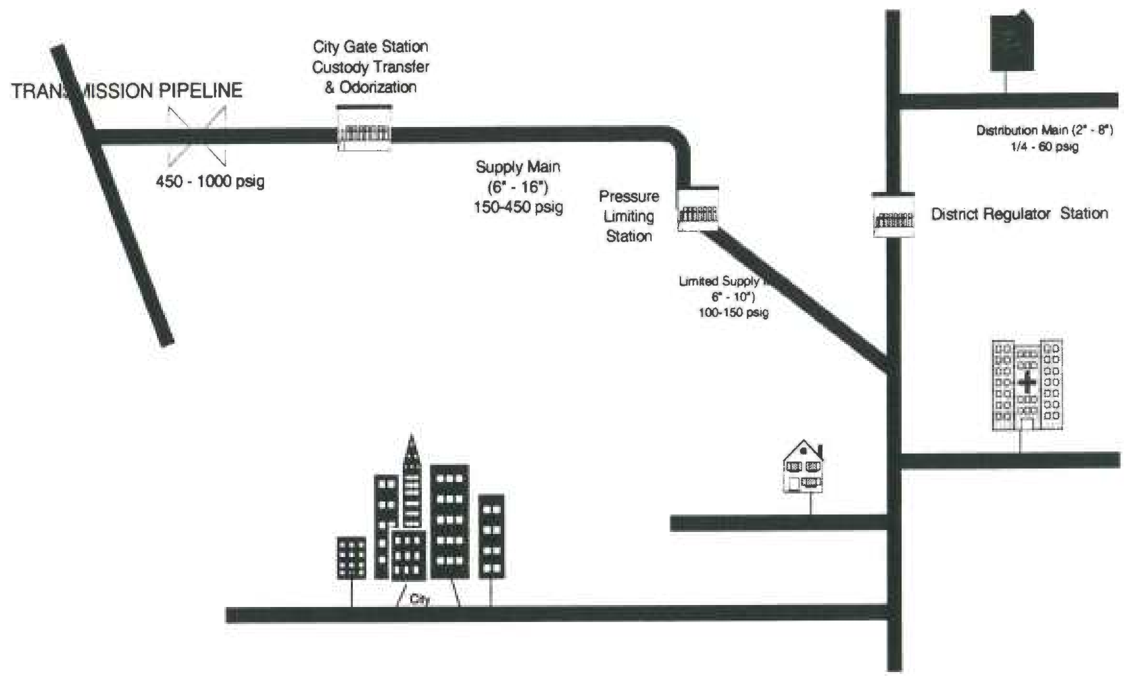
A. Science of the Energy

Gas

Gas flows as a result of differential pressures. Two chief components for consideration are the volumes being moved and the pressures as it moves. The velocity of the gas as it is moving will identify how energy is being used during that movement. It can move in a laminar or turbulent manner. This behavior is used for prediction of pressure variations within a system. Additionally, the pipe's diameter, material type and roughness, efficiency, length and the fittings used will also influence the system's pressure.

The delivery system is composed primarily of pipes, valves, regulation equipment (pressure reduction) , and measurement equipment (meters). The pressure on the transmission pipeline is typically 450-1000 pounds per square inch gauge(psig); whereas for a distribution main in a residential neighborhood the pressure will be between ¼ and 60 psig, and inside a house the pressure for a stove or space heater will be 1/4 psig. Represented schematically below is the gas local distribution system.

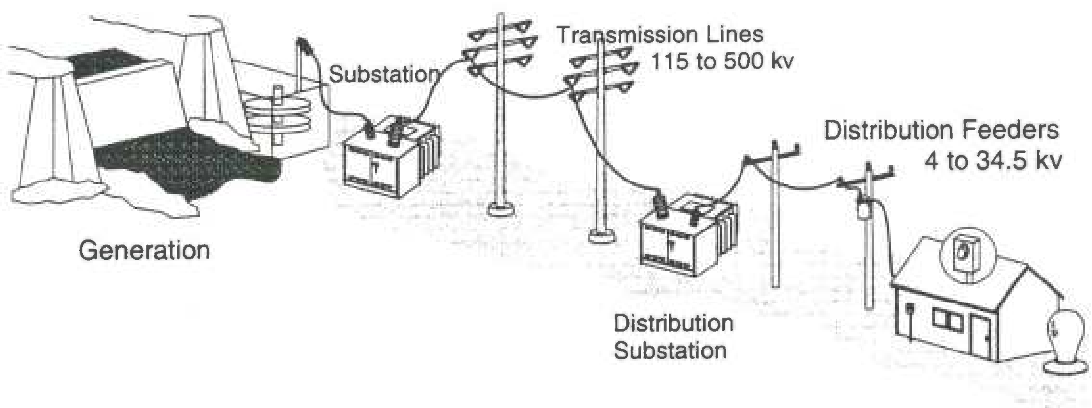
GAS SCHEMATIC
DISTRIBUTION SYSTEM



Electric

Electric energy is a unique product that is moved from electric generators to the consumers over wires and cables, using a wide range of voltages and capacities. Unlike other forms of energy, electrical energy cannot be stored. It must be continuously generated using other forms of energy, such as falling water and steam. The electrical generators and electrical network are designed to automatically regulate the flow of electricity through the system to quickly accommodate the instantaneous changes in consumer demand.

The delivery system is composed primarily of wires, circuit breakers, transformers, regulators and measurement equipment (meters). The voltage of the electricity at the generation site must be stepped up to a high voltage for efficient transmission over long distances. Generally, transmission voltages range from 115 to 500 kV. The substation reduces the voltage for local distribution, generally between 4 and 34.5 kV, and transformers reduce the voltage further for household use. Represented schematically below is the electric distribution system.



Puget Sound Energy (PSE) operates and maintains an extensive electric system consisting of generating plants, transmission lines, substations, and distribution equipment.
PSE operates approximately 300 substations, 2000 miles of transmission, 10,000 miles of overhead distribution, and 7,000 miles of underground distribution lines to serve approximately 903,000 electric customers within a nine-county, 4500 square mile_service territory.

On the gas side PSE operates approximately 45 city gate stations, 10,000 miles of high, intermediate and low pressure gas distribution lines, and numerous district regulator stations to serve approximately 560,000 natural gas customers. Approximately 288,000 customers receive both gas and electric service from Puget Sound Energy. In areas where both energies are served, additional efficiencies and lower costs have been achieved.

These complex networks of delivery facilities must be flexible enough to meet changing weather and other operating conditions as well as meeting long run service needs. Because of the significant investment in these facilities, and the important role that energy plays in an advanced society, it is important that PSE make additions and improvements as cost-effectively as possible.

B. Energy Industry Challenges

Within the energy industry, restructuring is a theme which continues to change how the utility plans for and provides service. Within the gas industry, the maturing of this new structure has created a marketplace where electric generation holds substantial rewards. This has precipitated the addition of many natural gas-fueled generation plants, which clearly impact facilities planning (both the gas distribution system to support such plants and the electric system to move the power generated must be available). The proliferation of computers and other highly sophisticated equipment are creating various needs for different qualities power than had previously been designed for and routinely delivered. These higher performance standards create additional challenges which need to be reflected in an evolving plan.

Distribution systems generally reflect the history of the area they serve. Many of PSE's long-standing service areas have seen significant growth. Growth management plans, transportation infrastructure and consumer's locational preference make some of these areas preferential, which has an effect on the infrastructure requirements (as more people are drawn to an area, more services are required). Historic systems must be enhanced as that growth occurs. A primary challenge for facilities planning is developing least cost distribution solutions that reliably serve the changing loads of existing customers as well as those of new customers. As mature communities expand, local infrastructure becomes burdened, affecting the amount of rehabilitation possible. Thus, new utility and transportation projects influence the timing and availability of access to the rights-of-way. The distribution system in newer areas could be characterized as a "fresh start," not burdened with a complex grid of existing utilities. These communities are often developed in large projects, with a clearly defined end product. However, due to the size of the projects, the timing of facilities installation may often be complex. Also, the surrounding regulatory, political and economic environment often changes, and it is imperative that the plan is modified in response to these changes.

An additional challenge which will exist for both gas and electric systems relates to the economic and operable viability of distributed generation. The distributed generation technology, primarily using natural gas as its fuel source, is one that may quickly become affordable to the average consumer. As distributed resources become more common, the impacts on gas usage will vary greatly from historical. Also, electric usage will change based on the type of generation customers site (fuel cell, microturbines, etc. as discussed in Chapter III). Each of these has a variety of operating characteristics, which pose complexity when integrating into the delivery system. As PSE moves forward, an understanding of the sophistication of customer uses, as well as the expected overall increase in firm load will need to be dealt with effectively. PSE believes many customers will begin to rely more heavily on the gas distribution system to supply some of their electricity needs.

C. Performance Standards and Operating Conditions

Performance standards concerning safety and reliability are the basis for system planning. For PSE's system these criteria include:

Gas	Electric
• the temperature at which the system is expected to perform	• the temperature at which the system is expected to perform
• the level of reliability each type of customer is contracting for	• the level of reliability each type of customer is contracting for
• the minimum pressure the system must maintain	• the minimum voltage the system must maintain
• the maximum pressure the system can accept	• the maximum voltage the system can accept
• the amount customers are willing to pay for target levels of performance	• the amount customers are willing to pay for target levels of performance

These criteria, in addition to those elements proscribed in state and federal regulations, form the basis for the company's system engineering standards and operational practices.

D. Asset Management Approach

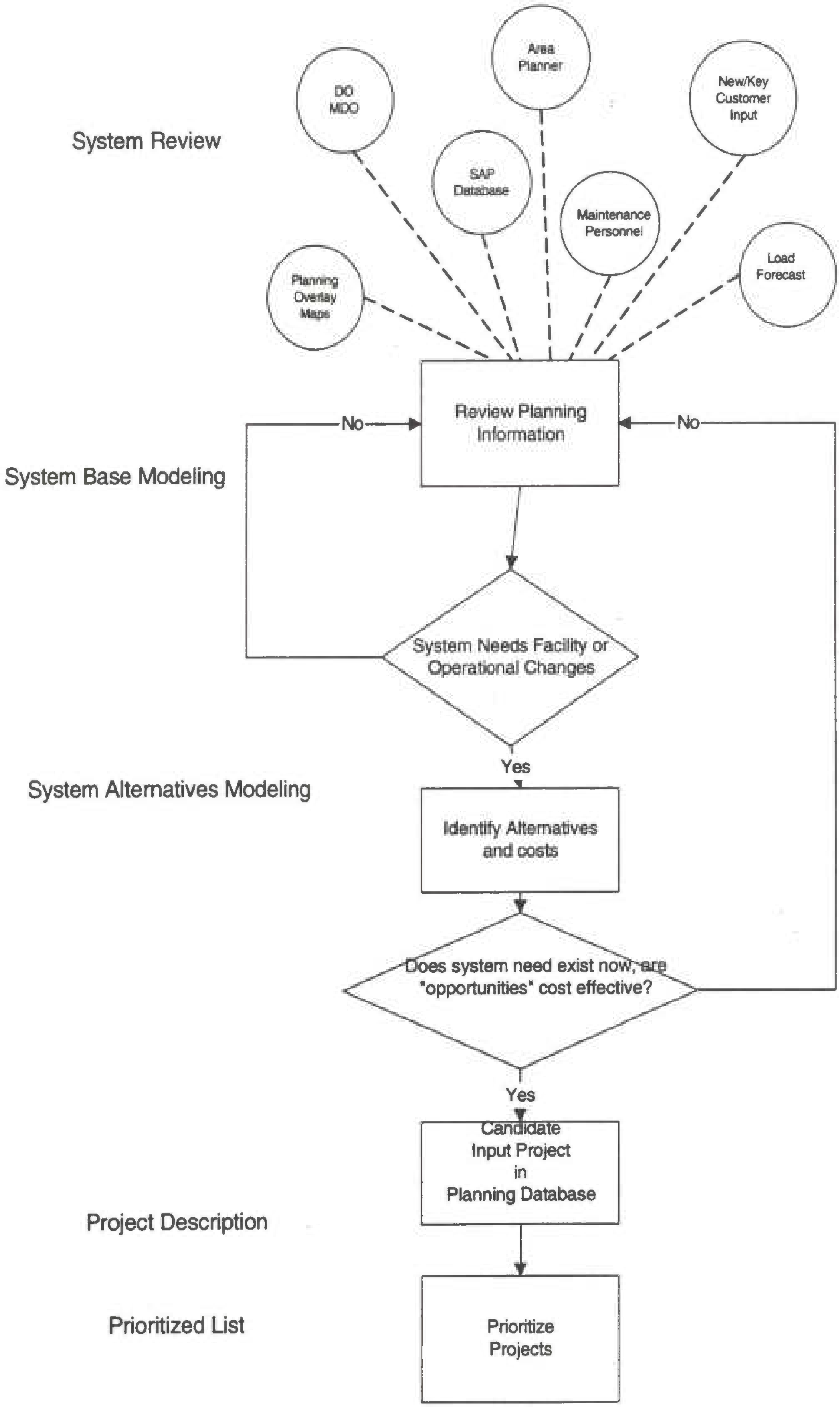
An important part of distribution planning is the concept of "asset management." The basic concept of asset management is to assure that existing facilities are being fully utilized before new facilities are added, unless the cost advantage of early installation offsets the cost of having the facility at a low level of utilization. To do this effectively, data is required that profiles existing usage as well as the system capacities under the variety of test conditions. More sophisticated modeling systems and better real-time information is helpful for optimal system planning.

Traditionally, utility planning has been very conservative. Within the gas industry deregulation has influenced many of the conservative precepts originally viewed as fundamental to system design, construction and operation. In the electric industry, the conservative approach was developed over many years of stable rates, surplus generation, and favorable public opinion related to construction of electrical supply facilities. As the electric utility industry restructures and open competition develops, the distribution planning process must become more aggressive. The utility must maximize the efficiency of its facility investments. However, this can not be accomplished by forsaking system performance, as valued by both the customer and the company. Successful asset management assures that maximum efficiency is achieved while providing acceptable reliability and safety. Planning for both gas and electric systems simultaneously can bring efficiencies and superior asset management results not yet considered by many.

E. The Planning Process

The planning process begins by analyzing the current situation, and understanding the existing operational and reliability challenges. The planner must evaluate such key parameters as load forecasts, local comprehensive plans, public improvement plans (such as road relocations), historical local area customer growth data, and known developer and customer plans. How one energy affects the other and how to optimize the whole delivery system is taken into consideration. Coordination with other utility services, including water, sewer and telephone, must be explored. All of these factors are used to develop feasible alternative methods to implement facility improvements. Each of these alternatives must be evaluated for its adherence to company and customer performance criteria. Cost estimates must be prepared for each alternative that meets the performance criteria. Lastly, the alternative which best balances customer needs, company economic parameters, and local and regional plan integration is selected and implemented. This process is graphically represented below.

Facilities Planning
Planning Process



F. Planning Alternatives

There are two alternative approaches to solving system challenges. Either facility additions and replacements, or operational adjustments, can be used to achieve optimal energy delivery. PSE utilizes both approaches to ensure least cost solutions.

Facility Alternatives

Generally speaking, both gas and electric systems have a variety of facilities which can be used to deliver an optimal energy solution, and are listed below.

Gas

- city gate station
- high pressure main
- district regulator
- intermediate & low pressure main
- capacity uprate
- regulation equipment modification
- replacement facilities
- load control equipment

Electric

- transmission substation
- transmission conductor
- distribution substation
- distribution conductor
- conductor upgrade
- substation modification
- replacement facilities
- expanded right-of-way (i.e. Tree Watch)
- load control equipment

PSE tracks the cost and viability of new technologies which will influence efficient construction of new facilities and management of existing facilities.

Operational Adjustment Alternatives

Operational management addresses operational and administrative actions the company may take to ensure reliable service to customers. These actions include ongoing and/or bridging strategies that can be used to optimize the timing of facility improvements.

Management of system performance is accomplished through controlling loads, flows, and facilities. For example, load can be managed through curtailment during peak conditions by customers who have selected interruptible tariff service. This management may also include structuring rates that make it beneficial for customers to operate during non-peak conditions, or the application of energy efficiency measures as discussed in Chapter III (as long as those measures reduce system capacity requirements).

Energy flow can be managed by adjusting equipment settings to preserve system throughput, while maintaining system flows and equipment integrity. Two examples of this are the temporary adjustment of district regulator stations (as executed through PSE's Cold Weather Action Plan) and the adjustment at substations of transformer "turns ratios" (typically done using load-tap changers) which alters the output voltage under a loaded situation. The temporary siting of equipment can infuse local capacity into a distribution system at a lower cost than a permanent upgrade. This is illustrated via PSE's historic use of mobile compressed natural gas facilities (CNG) and its evaluation of LNG trailers, as well as its historic use of the mobile substation and its evaluation of local mobile generation.

G. Value Trade-Offs

PSE has initiated using value based budgeting to improve the overall efficiency of its distribution planning operations. Value based budgeting uses a technique know as analytical hierarchy process (AHP) for the allocation of scarce resources. In order the allocate resources wisely, it is necessary to know both the cost and benefits associated with each project. The costs of a project, at least those that are in dollars or that can be readily transformed into dollars, is generally a straightforward algorithm. PSE uses a software program called Project Analyzer to calculate a wide range of financial performance indicators for each project.

A more difficult task has been to find a way to quantify the benefits of a particular project. A single project may have a wide range of benefits for many different stakeholders. AHP was developed for making decisions when trade-offs among different factors exist. For example when purchasing an automobile, trade-offs among price, durability, energy consumption, comfort, usability and reliability must be made. AHP is a tool which allows one to determine the relative importance of the factors in making the decision.

Based on the information received for a variety of areas pertinent to the evaluation, weights for each factor are computed that best reflect the relative importance the decision maker puts on the relevant factors. After their weights are developed, a score for each alternative is computed and the project list ranked. The extension of AHP to resource allocation is straightforward, and used by many highly successful and innovative organizations, including Xerox, IBM and Lucent.

H. Planning Tools and Modeling Techniques

PSE has distribution system models for both the gas and electric delivery systems. On the gas side, PSE has a mature Stoner/SCADA (System Control and Data Acquisiting) system. PSE runs the largest integrated system model in the United States. On a day-to-day basis this model is run, simulating a variety of conditions which then facilitate selection of best-cost facility and operational alternatives. On the electric side, PSE is now creating such a system model using Stoner software in companion with its Energy Management System (EMS). As the modeling tools and PSE's system models become more integrated, PSE expects that it will be able to further enhance its ability to meet customers energy needs at the lowest possible cost.

For both gas and electric modeling, the process is the same. The system is digitally created, identifying the facilities and their operational characteristics. For pipe, the diameter, roughness, length and interconnections are key. For conductor, the cross-sectional area, resistance, length, construction type and interconnections are important. Customer loads are identified on the model, either specifically (for large customers) or as block loads. Then, the models are run with varying temperatures, types of customers served (interruptible versus firm), time of day (at peak daily usage) or with various components out of service (valves closed or switches open). Thereafter, various facility or operational adjustments can be modeled in. Additionally, the output studies are compared against actual data in the SCADA and EMS systems to check the accuracy of the base model.

I. Distribution Automation

As PSE moves forward, it expects to manage its delivery systems on an improved real-time basis. This recognition has led to greater investment in sophisticated modeling and telemetry systems, as well as its decision to implement automated meter reading (AMR) technologies. Embedded within this technology is a heavy reliance on communications technologies. Telecommunications technology has long played a key role in supporting the day-to-day operations of the electric and gas utilities, linking substations, generation plants, gate stations and dispatch centers.

PSE is currently evaluating having a two-way communication with a customer's thermostat, such that under heavy load, the thermostat is ramped down, to lower the system demand and potentially defer facility investments. This capability would allow more customer choice, yet also provide a lowered cost for facilities.

Telecommunications media include wire, coaxial cable, telephone, microwave, fiber, power line carrier, packet radio, radio, satellite and optical light-beam technologies. There are a number of factors involved in selecting a telecommunications system. These include cost, distance between points of communications, location, reliability and type of information to be transported. It will be important to consider the advantages and disadvantages of various communication technologies before making long-term decisions on which communication system to use.

J. Summary

In closing, effective distribution systems facilities planning must integrate many aspects within the delivery system. The guiding principle for facilities planning is the safe and reliable delivery of gas and electricity to our customers. The planning process is rational and thoughtful, and has sound engineering, operations and economics as its foundation. The planner must have a thorough understanding of the existing system, and an accurate picture of where and when customer demand will change. Using appropriate tools, the process looks at all the available options to meet the customers' needs, it considers short-run and long-run costs, and it selects the best combination to serve the customer.

Public Involvement

VIII. PUBLIC INVOLVEMENT

A. Summary of Post–Merger TAG Meetings

Following several months of development work in late 1996 and early 1997, PSE's gas and electric conservation program tariffs went into effect on May 24, 1997. PSE then developed a joint gas and electric public involvement process for resource planning (including conservation issues). The resulting group, the Technical Advisory Group (TAG), contained the members of WNG and Puget Power's former advisory groups, the conservation "collaborative" group, a range of customers, and interested parties. PSE sought to expand the advisory group membership as broadly as possible so that a variety of opinions and suggestions could be presented to the company through this process in order to maximize the effectiveness of the process. The list below of participating organizations illustrates the breadth of participation in the company's public process.

Technical Advisory Group Represented Organizations

- Avista
- Boeing
- Bonneville Power Administration
- Building Owners and Managers Association
- Industrial Customers of Northwest Utilities
- King County Housing Authority
- Natural Resources Defense Council
- Northwest Energy Coalition
- Northwest Gas Association
- Northwest Power Planning Council
- PacifiCorp
- PG&E Gas Transmission Company
- Puget Sound Energy
- Safeway
- WSACAA Energy Project
- Washington State Attorney General Office of Public Counsel
- Washington State Dept. of Community Trade and Economic Development
- Washington Utilities and Transportation Commission
- Williams Pipeline Northwest

Additionally, on July 29 and 30, 1997, PSE and the WUTC jointly sponsored a training session regarding "mutual gains negotiation" with TAG members in order to improve the effectiveness of the resource planning public involvement process.

Below is a list of the TAG meetings held from August, 1997 through October, 1999. Each listing includes the date, location and agenda items that were discussed. The second half of 1998 and the first quarter of 1999 were devoted primarily to Demand Side Management. The product of that effort was a three-year Energy Efficiency Services program, approved by the Commissioners on March 31, 1999.

August 21, 1997
Bellevue Conference Center

- Role and Scope of the Resource Planning Process
- Structure of Public Involvement
- Key Planning Issues

October 9, 1997
WUTC offices in Olympia

- Discussion of the IRP Charter
- Distribution Planning
- Load/Resource Balance
- Scenario Discussion (phase 1—Resource Planning/Restructuring Issues)
- DSM Implementation

November 20, 1977
WUTC offices in Olympia

- Sales Forecasting
- Potential Legislation
- Scenario Discussion (phase 2—Outlining Potential Restructuring Scenarios)

January 27, 1998

WUTC offices in Olympia

- Gas Commodity Forecasting
- Gas Scenario Planning
- DSM Planning

March 19, 1998

PSE's General Office

- Distribution Planning
- Resource Planning Model Evaluation
- "Chelan" Process/Legislative Update
- Conservation Planning

July 16, 1998

Westcoast Gateway Hotel, Sea–Tac

- Reach a common understanding of our charter and the scope of this process.
- List work products/deliverables by program to meet the evaluation commitment.
- Review proposed PSE Measurement and Evaluation Plan.
- Review Personal Energy Profile evaluation results.
- Schedule Meetings needed to maintain evaluation performance, review results of evaluation work products, and develop resulting recommendations in a timely manner.

August 5, 1998

WestCoast Sea–Tac Hotel

- Review 90–day Commitment Timeline and Key Findings
- Report on Evaluation Assumptions and Concur on Directional Alignment
- Update and Feedback on Billing Analysis
- Update on Low Income Programs—What are we doing for who with what resources?
- Potential Follow–on Activity Beyond 90–day Evaluation Process

August 19, 1998

Department of Community, Trade and Economic Development, Olympia, WA

- Meeting Introduction
- Report on Conservation Program Energy–savings Estimates and Assumptions
- Discuss and Concur on TAG Directional Alignment
- Other Business, Q & A

August 31, 1998

Puget Sound Energy, Crossroads Office

- TAG 90-day Evaluation Scope Review
- Evaluation Results on Informational Programs
- Billing Analysis Results for Personal Energy Profile
- Non-Energy Program Benefits
- Recommendations for continuation, modification or replacement of programs

October 19. 1998

Puget Sound Energy, Crossroads Office

- Cost-Effectiveness
- Avoided Cost Benchmark and TRC
- Research of Utilities Throughout the U.S.
- Needs of Large Customers

December 14, 1998

Puget Sound Energy, Crossroads Office

- Consultant Report
- Program Suggestions
- Implementation Update
- Cost Allocation Issues
- Application of the Total Resource Cost Test

- Promotional Issues and Opportunities
- NEEA

February 5, 1999

Puget Sound Energy, Crossroads Office

- Proposed Program Offerings
- Cost-Effectiveness Review
- Review Outstanding Policy Issues
- Update on Program Enhancements
- Fuel Conversion

February 15, 1999

Puget Sound Energy, Crossroads Office

- Review Energy Efficiency Services Draft Filing

October 19, 1999

Puget Sound Energy, Bellevue Office

- Gas Resource Supply
- Electric Resource Supply
- Distribution Planning

October 28, 1999

Puget Sound Energy, Bellevue Office

- Demand Forecasts
- Scenarios
- Integrated Resource Plan Modeling

Action Plan

IX. TWO-YEAR ACTION PLAN

A. Progress Report of Previous Action Plans

The prior least cost plans submitted by Puget Sound Power and Light and Washington Natural Gas included short term action plans. The following is a review of PSE's efforts related to previous action plan items. The discussion is organized by the chapters of this document (starting with Chapter II, Energy Demand Forecasting) and it brings together the action items from both the electric and natural gas sides of the business. The statements in boldface font style are from the previous least cost plans.

II. Energy Demand Forecasting

Electric

Assess quarterly economic growth and determine load growth demands.

The company monitored growth trends on a quarterly and annual basis. Quarterly monitoring is done in conjunction with the New Construction Group by comparing forecasted customer additions with actual customer additions. An annual assessment is made through the regular forecast update process. Monthly comparison of actual and forecasted sales is also performed to isolate the effects of weather from non-weather factors, which include economic growth.

Natural Gas

Complete the residential end-use survey work and incorporate data into the customer demand forecast by May 1996.

A residential telephone survey was performed in July 1998. This survey data was combined with consumption data to develop preliminary analysis of consumption by building types and by end use. Key results from the survey were incorporated into the 1998 and subsequent gas sales forecasts.

Select a consultant for an industrial end-use study by January 1996. Design and conduct an industrial end-use study. Issue a final report by September 1997.

This project was not pursued further partly because of high costs. Instead, consumption and other relevant data were collected through the Key Accounts program, and relevant data were incorporated into the 1998 and subsequent sales forecasts.

Perform large volume customer needs survey and analysis. Incorporate results into forecast by May 1996.

Data from large volume customers were also collected through the special metering system, if one exists, or through the billing system. Other relevant information such as known schedule switching, plant additions or closures, or new large customer loads were obtained from our Key Accounts managers. This information is used in refining the forecasts.

Develop final annual forecast of customers, annual demand, and peak day demand requirements by August of each year.

As a result of the WNG / Puget Power merger, the annual forecast completion was moved to match the calendar year schedule for budget planning purposes. Annual forecast of customers, demand and peak day requirements are produced.

Design and implement a load research study to obtain a better understanding of consumption patterns by end-use and improve peak day estimates. If practical, data collection will begin in the Winter of 1996 - 1997.

Gas usage for 150 residential homes is currently collected using special meters. Since summer 1998, gas consumption at the 15-minute interval and outdoor temperature data have been collected. This data collection is expected to continue through Winter 2000-2001. A survey has also been performed to collect household and building characteristics data. Preliminary data will be analyzed to determine changes in use patterns at the end use level and to improve the equations for peak day demand requirements.

III. Demand Side Management

Electric

Continue to pursue cost-effective conservation opportunities.

PSE has continued cost-effective conservation programs. The company developed, and the Commission approved, a three year cost-effective DSM program on March 31, 1999. See Chapter III for discussion of this program.

Pursue 'lost opportunity' conservation.

PSE, together with other utilities in the state, helped support the development, adoption, and subsequent training for both industry contractors and code officials, for both the residential and the commercial energy codes. The energy code adoption by the state of Washington has provided a long term solution to capturing much of the "lost-opportunity" conservation involved with new construction. Additionally, several other programs including motor efficiency and multifamily lighting, strive to introduce more energy efficient products into the market, to increase future demand for them.

Increase the emphasis on commercial/industrial programs.

Approximately 70% of the estimated energy savings now comes from C/I sector. A new pilot program allows high voltage customers to self-direct conservation funding for their business. Two important programs which are aimed at the C/I sector are building commissioning, and resource conservation manager.

Increase customer participation.

The Energy Hotline answers approximately 2,000 calls per month from customers regarding their interest in energy efficiency. In addition, the Company uses billing inserts to promote energy efficiency, and routinely processes an additional 2,000 PEP surveys each month. To expand the reach to commercial customers, they are encouraged to participate in energy efficiency training and seminar opportunities.

Improve conservation infrastructure.

The company has worked with local businesses and contractors, other utilities, industry representatives, state and multi-state agencies, local public and private organizations, low income agencies, and trade associations to improve the delivery of conservation measures.

Review competitive bidding.

At the commission urging, the Company undertook a second round of demand-side competitive bidding. The second round was limited to the Commercial sector when it was agreed that the Company's own programs were significantly more cost-effective than any of the residential bids. There has been mixed success with this program.

As with the electric energy industry, the nature of businesses which engaged in utility demand side competitive bidding programs has evolved, and responded to market place changes.

Continue to develop programs to test and build the capability to acquire new conservation resources.

PSE continually looks for these opportunities. As recently as late 1998, as part of its work with the Technical Advisory Group, PSE hired an nationally recognized energy efficiency consultant to review utility (and other) energy conservation programs offered nationwide, to uncover further opportunities for PSE offerings. Results were incorporated in the 1999 programs.

Implement the evaluation plan for conservation programs.

The Company completed an extensive, 3-year, multi-million dollar DSM program evaluation. Details of the evaluation protocol were developed by the TAG Evaluation was performed for all conservation programs, and involved both process and impact evaluations. Overall findings showed most programs and most measures produced well within + or - 10% of the engineering estimated savings that had been used to report annual program performance, and that these savings persisted over time with little degradation. Detailed findings for each program have been provided to the Commission. Evaluation findings were reviewed and subject to cross examination by the Commission.

Additionally, survey research and a billing study completed in 1998 established PSE's informational energy efficiency services as cost-effective conservation programs, demonstrating energy savings through billing analysis and customer stated actions. These results were provided to the WUTC and TAG.

Recent billing analysis of the Low Income Mobile Home pilot showed savings to be approximately 12% of pre-installation consumption, with total program savings estimated at 416,000 kWh.

The Company completed telephone surveys of In Concert with the Environment (ICE) students and parents. Results indicate a positive overall impression of the program by both students and parents. Two in five households (42%) reported making changes in their home use of energy. Another 12% plan to make changes within six months.

Recent evaluation of the Duct Systems Pilot suggested cost-effective energy savings opportunities exist if the cost of identifying candidate homes can be minimized. The focus in 1999 is to explore the potential for linking duct system diagnostics and repair to existing HVAC services; developing protocol and quality control guidelines as well as training for participating HVAC contractors.

Develop information to analyze the capacity value of conservation programs and the feasibility of load management programs.

The company is currently investigating the use of AMR and other technologies to enable market-based load management.

Examine fuel switching.

The company investigated a targeted fuel switching plan as part of its most recent conservation program, and it has worked with the pollution control agency which has an interest in switching wood burning stoves to gas.

Natural Gas

Implement and maintain approved DSM programs.

PSE has continued cost-effective conservation programs. The WUTC approved a three year DSM program on March 31, 1999 which includes funding for gas conservation.

Re-design a Residential Weatherization Pilot Program and submit for WUTC acceptance by February, 1996.

The gas conservation program for residential customers currently focuses on information and recommendations through the Energy Efficiency Hotline, brochures and PEP, as well as a pilot involving space heating improvements with the residential duct systems.

Develop measurement and evaluation plans for existing programs and conduct studies as appropriate.

Survey research and a billing study completed in 1998 established PSE's informational energy efficiency services as cost-effective conservation programs, demonstrating energy savings through billing analysis and customer stated actions.

Recent billing analysis of the Low Income Gas pilot savings were found to be about 27% of pre-installation consumption, with total program savings estimated at 72,600 therms.

The Company completed telephone surveys of In Concert with the Environment (ICE) students and parents. Results indicate a positive overall impression of the program by both students and parents. Two in five households (42%) reported making changes in their home use of energy. Another 12% plan to make changes within six months.

Recent evaluation of the Duct Systems Pilot suggested cost-effective energy savings opportunities exist if the cost of identifying candidate homes can be minimized. The focus in 1999 is to explore the potential for linking duct system diagnostics and repair to existing HVAC services; developing protocol and quality control guidelines as well as training for participating HVAC contractors.

Conduct additional research and analysis on the viability of various DSM strategies to meet peak day resource requirements, including moral suasion, contracts with large customers and other potential customer programs. (While these studies will ultimately benefit from the planned load study, they will be conducted prior to its completion.) Implement viable options.

Contracts with large customers are still under consideration; however, suppliers of large transportation customers are reluctant to make supplies available ant any price less than market, which PSE can attain on its own.

Evaluate Resource Conservation Manager (RCM) program opportunities. Implement a pilot program(s), if warranted, in 1996.

The company currently operates an RCM program which includes electric and gas savings, as well as water sewer and solid waste utility costs.

Review incremental cost assumptions for high-efficiency furnaces (AFUE>90%) and the market transformation potential for this technology. Take additional action as appropriate based on findings.

The incremental cost assumptions of $500 - $1000 were reviewed and corroborated. Additional costs may be incurred for ductwork changes necessary with the installation. Maintenance and repair costs to customers for existing 90+ product (in comparison to similar costs for conventional efficiency furnaces) should be monitored however; 90+ furnaces incorporate more complex technology than conventional units and additional costs of maintenance and repair to customers may offset some portion of the energy savings benefit of the upgrade.

Conduct a study of alternative mechanisms for sharing DSM program costs with program participants. Issue final report by December 1996.

Because it was difficult to show cost-effectiveness for natural gas low-income weatherization programs, WNG initiated work with Commission Staff on the feasibility of using the "Utility Cost Test" as an alternative to the "Total Resource Cost" test for low income program funding. The change would allow the utility to pay up to the utility's value of the weatherization, and at the same time allow measures not to meet a total resource cost test. While this alternative mechanism was discussed and reviewed by TAG members, it was never formally proposed. Recent Commission adoption of revised PSE low income offerings have allowed for interpretation of the application of the Total Resource Cost test for this sector, rather than coming up with an alternative mechanism.

Work within the energy code development process to facilitate the acquisition of cost-effective resources by code.

PSE, together with other utilities in the state, helped support the development, adoption, and subsequent training for both industry contractors and code officials, for both the residential and the commercial energy codes.

Begin data collection on various DSM strategies that may have potential distribution system benefits and perform initial screening.

Distribution system benefits require morning warm-up load reduction. Towards that end, the company has a duct sealing pilot, and is investigating the use of AMR technology to enable market-based load management.

Work with other interested parties to further develop resource cost-effectiveness methodology. Consider key issues of environmental externalities and quantification of market transformation benefits.

The Company continues to use resource cost-effectiveness methodology based on natural gas avoided costs. Estimates of the value of non-energy savings benefits, both quantifiable and non-quantifiable are incorporated into measures reviewed by the energy efficiency programs. The generally accepted order-of-magnitude of these "externalities" for natural gas are significantly less than those linked with electric generation.

IV. Energy Supply - Electric

Assess competitive bidding results.

In September 1991 PSE conducted a competitive bidding process for new resource. At that time, Puget Power issued a Request for Proposals (RFP) seeking 100 to 200 average megawatts to come on-line during the 1995 through 1998 period in accordance with Chapter 480-107 WAC. This RFP included a 10% advantage for conservation and renewable generation resources. A number of resources were selected for further evaluation to a "Preliminary Award Group." These included conservation, small hydro, high-efficiency cogeneration, wood liquor, landfill gas, municipal solid waste high-efficiency cogeneration and wind resources. These generation resource opportunities from this bidding process did not come to fruition.

Monitor natural gas supply, purchases, and prices.

The company now has a person dedicated to purchase of gas for PSE turbines. Although we still paying market, with merger we have better price discovery about the actual market prices.

Monitor technological advancements.

In response to this action item, in 1993, engineers in the project management group reviewed specific emerging technology of power generation through specific course work.

Staff in many areas of the company, such as energy production and storage, conservation, facilities planning, key accounts and regulation planning, keep abreast of developments in energy supply technologies including distributed resource technology which can vary from gas turbines to fuel cells to renewable power such as solar.

Analyze feasibility of pursuing further exchange agreements.

PSE signed the PowerEx Exchange agreement in October of 1997.

Monitor emerging renewable and other resource developments.

Currently, employees in many areas of the company, such as energy supply, conservation, facilities planning, key accounts and regulation planning, keep abreast of developments in distributed resource technology which can vary from gas turbines to fuel cells to renewable power.

As reported in Chapter IV, Supply - Electric, the company has an expanding portfolio of small renewable resources. For instance, in FY1999 the company held discussions with a fuel cell developer regarding the interconnection of a new fuel cell test project.

Continue support of EPRI and encourage research on issues of special interest to the Pacific Northwest.

The company continues its membership in EPRI.

Continue to monitor and support electric vehicle research and development.

Most advances in vehicle technology are occurring because of California state laws. Various employees informally follow these developments, particularly with fuel cells.

V. Energy Supply - NaturalGas

Investigate optimum timing, cost and operating characteristics of promising supply and DSM resource options. Work with gas suppliers, DSM program development staff and resource developers to design projects that best meet WNG's needs.

PSE is the only utility in Washington with an active natural gas conservation program, which has saved over four million therms over the last two and a half years.

Continue to evaluate avoided costs for DSM and supply resource evaluation. Produce a report on avoided costs using the expected values from a number of different scenarios.

PSE updated the avoided costs using the expected costs using 3 of the scenarios developed in the 1995 least cost plan. These updated costs during the Merger process to update the conservation cost effectiveness standard. The company's current gas avoided costs are presented and discussed in Chapter VI.

Continue ongoing effort to evaluate resource needs and alternative strategies to meet customer needs. Implement resource price uncertainty modeling.

PSE has continued to evaluate resource needs and resource options. The options included in this Plan were evaluated and appear promising based on these assessments. The peak day and annual load forecast is revised annually. In response, the adequacy of current and planned resources to meet this load over the next several years is reviewed on an ongoing basis.

PSE has recently established a Risk Management Group within the Energy Supply Organization. This group is developing the tools to assess price and other resource uncertainties for both the gas and electric portfolios.

VI. Integrated Resource Planning

Electric

Continue developments and use of new analytical tools and planning approaches.

PSE models electricity with the most recent version of AURORA, which is also used by the Northwest Power Planning Council and many utilities throughout the west. HELM was also used to look at hourly load shapes.

Natural Gas

Continue working with the software vendor to enhance the capabilities of the WinUPLAN-G model to better address WNG's resource supply, customer loads and policy options. Investigate and evaluate other gas resource planning and risk assessment models for possible use.

PSE has continued working with the Uplan-G model vendor to refine the model. A significant modification to the model was the development of a new optimization algorithm which significantly reduced running time and increased model stability.

VII. Distribution Facilities Planning

Electric

Monitor and comment on transmission access legislation.

PSE has:
1. Complied with FERC Orders 888 & 889.
2. Commented to FERC on 888 & 889 and also challenged certain aspects of these orders.
3. Filed an "Open Access" tariff with FERC.
4. Developed and now operates an OASIS web site.
5. Provided comments on FERC's recent NOPR regarding RTO development.

Continue to pursue transmission access and strengthen the existing transmission system.

PSE actively participates in discussions with FERC regarding future considerations of the RTO, as well as working with BPA on strengthening and expanding the existing system. PSE also works with developers of potential new electric generation sources so that the facilities are integrated.

Explore the feasibility of using targeted conservation programs to reduce transmission and distribution system requirements in high load growth areas.

PSE has recently evaluated the use of fuel switching, from electric to gas, to reduce system upgrades, but use of the option is problematic without first addressing a number of associated regulatory issues. New growth areas have been targeted by the active support and implementation of improved building codes.

Conduct further studies to seek system efficiency improvements.

Utilities have traditionally focused efficiency improvements at the system level. For example, the installation of reduce-loss transformers, larger conductors, voltage regulation, etc.

PSE now also considers the value chain in the energy delivery business. The system efficiency model targets life cycle planning and the ownership cost associated with asset management.

Conduct coordination of transmission and distribution system planning and resource planning.

The Delivery Business Unit (distribution) works with Resource Planning (transmission) to insure that the delivery matches the system expansion. In reviewing the reliability and capacity of the electrical system, the planners work together to develop least cost solutions to resolve any system deficiencies.

<u>Natural Gas</u>

Evaluate various methods of reducing system costs through the use of new materials, procedures and tools.

PSE's efforts here include the following:
Evaluation and pilot unity crew activities.
Continuing joint construction with electric, other utilities and jurisdictions.
LNG implementation (this year/early next year) at Gig Harbor.

VIII. Regional and Public Involvement

Pursue studies on environmental externalities and monitor approaches taken by other states.

PSE's continued electric approach is consistent with provisions included in the 1980 Regional Power Act, which assigns a 10% credit for environmental "benefits" of conservation.

Participate in regional studies and analyses as appropriate (i.e., endangered species activities).

PSE has worked with numerous agencies and non-governmental organizations in various aspects of studies pertaining to the Endangered Species Act. The studies have come about as part of the licensing and relicensing process for company-owned hydro projects, as well as Mid-Columbia dams from which PSE contracts for a share of the energy. PSE has biologists on staff who can participate and provide expertise on these studies.

Participate in contract negotiations (i.e., Pacific Northwest Coordination Agreement).

The PNCA Committee continues to collectively manage the PNCA in a way which ensures that the parties achieve the economies and additional firm power in a coordinated and optimized manner. Absent the PNCA, the parties would operate on a strictly voluntary basis thereby relieving us of the opportunity to receive the maximum benefits by a coordinated operation of the resources

Continue studies of potential voltage instability in the Puget Sound Basin.

Two actions were taken to resolve this trans-Cascades issue: BPA built more transmission lines, and more generation was built in the Puget Sound area, including cogeneration resources pursuant to federal mandates under PURPA.

Continue BPA-NR studies.

PSE works with BPA and other Northwest organizations through rate cases, conservation studies, transmission issues, and the subscription process.

Participate in region-wide efforts to shorten lead times for siting, licensing and design of generation facilities.

PSE has worked with FERC for the licensing of its hydro facilities, but is otherwise not active in siting or designing new generation facilities.

IX. Regulatory Support

Continue to pursue regulation that supports least-cost integrated resource planning.

PSE continues to pursue regulation that supports the least-cost planning approaches described in this plan. For instance, the current electric conservation tariff rider mechanisms were developed during the merger process to address some of the disincentives to conservation investment under the Rate Plan.

Please see the discussion of regulatory issues in Chapter 1 for identification of important regulatory changes needed to support least-cost planning at the current time.

Analyze and pursue rate design mechanisms that support integrated resource planning goals and activities.

PSE (and Puget Power before the merger) has implemented rate schedules since the last least cost plan filing that support least cost planning goals. In October of 1993, the Company implemented experimental interruptible electric rate schedules 36 and 39, which, on a limited basis, extended interruptible service to smaller-load customers than previous interruptible schedules. A second example is Schedule 48, implemented November of 1996. Schedule 48 provides some of the Company's largest customers market-based power prices that vary daily, which provides customers a clearer, more economically efficient price signal, which can be factored into consumption decisions. Schedule 48 also unbundled the firmness of electric service, which allows PSE to plan to firm-up only load these customers wish to/are willing to pay to be firm.

Seek regulation and legislation that provides for recovery of the conservation investment where an end-use is switched to a new energy supplier.

PSE received regulatory support for it bond financing for conservation programs and for the Schedule 120 tariff rider. Under the current commercial and industrial conservation programs, contracts for grants specify that grant investments made for equipment or conservation measures at specific firms must be repaid to PSE (prorated for the remaining measure life) if the firm is no longer a PSE customer.

B. Two Year Action Plan

The following is PSE's two year "Action Plan." This includes a number of efforts that implement the least cost plan described in this document.

II. Energy Demand Forecasting

- Refine the weather adjustment methodology for billed sales to further distinguish temperature sensitivities within the year.
- Complete the analysis of gas load research data to refine peak day equations.
- Develop a forecasting module for transportation to account for the effects of business cycles and for the effects of known schedule switching.
- Implement a database to track large customer consumption and observed fuel or rate schedule switching.

III. Demand Side Management

- Investigate the use of technology and real-time pricing to enable market-based conservation and load management.
- Implement the 3-year conservation plan as described in PSE's March, 1999 conservation filing.
- Continue to pursue "fuel-blind" cost-effective conservation programs.
- Continue to support market developments of energy efficiency products and services, to promote customer-driven energy efficiency.
- Conduct evaluations for conservation programs as appropriate. Support broader-based conservation evaluation, for example at the regional level.
- In cooperation with the Puget Sound Clean Air Agency, investigate benefits of fuel-conversion from wood-burning appliances to natural gas.
- Expand customer access to energy-efficiency information using PSE's website.

IV. Energy Supply - Electric

- Continue to move, incrementally, toward more market responsive energy supply.
- Continue to develop risk analysis of PSE portfolio management.
- Develop production costing capability in AURORA or another model.

- Continue to pursue economic FERC (re) licensing of PSE owned hydro projects.
- Pursue renegotiation of the Mid-C resource agreements.
- Continue to pursue opportunities to reduce costs of existing resource commitments.

V. Energy Supply - Gas

- Investigate increased use of financial instruments for portfolio management.
- Explore city gate delivery service.
- Perform feasibility study for expanded capacity of Jackson Prairie storage.
- Increase number and scope of business relationships with suppliers, customers, other LDC's and NUG's.
- Conduct feasibility study of increased LNG capacity for peak load needs.

VI. Integrated Resource Modeling

- Continue on-going process of evaluating new gas and electricity resource options and alternative resource strategies to meet customer needs.
- Continue development of Aurora model data bases to better assess the impacts of alternative gas price scenarios, resource costs, and loads forecasts on PSE's resource portfolio.
- Continue working with the Aurora and Uplan-G software developers to better address PSE's resource and policy options.

VII. Distribution Facilities Planning

- Continue to evaluate opportunities for lower cost, innovative solutions which facilitate an appropriate level of system performance at the best long-term cost (such as the Tree Watch and Silicone Injection initiatives).
- Develop methods for cross-energy solution sets, including cost participation by the beneficiary of the system improvement (off-loading a critical substation by expanding gas usage within the affected area).
- Continue to evaluate distributed resources technologies and consider their impact to both gas and electric plant.
- Continue to evaluate historic design conditions and their impact on facility additions.

- Continue to develop system models and other technologies which facilitate more accurate, customer and time-sensitive system evaluations regarding system performance (i.e. Stoner SynerGEE implementation, SCADA, AMR).