UE-020963

PUGET SOUND ENERGY

December 30, 2002

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STATE OF WASH.
UTIL. AND TRANSP.
COMMISSION

Ms. Carole J. Washburn, Executive Secretary
Washington Utilities and Transportation Commission
P.O. Box 47250
Olympia, Washington 98504-7250

Re: Puget Sound Energy's Draft Least Cost Plan Filing

Dear Ms. Washburn:

Enclosed, please find 12 copies of Puget Sound Energy's ("PSE" or "the Company") draft Least Cost Plan ("LCP"). The purpose of this filing is to provide the Commission and other interested parties an update on the status of PSE's long-term resource planning process as of December 30, 2002. As described in the document, further process and analysis is necessary in order to develop the completed LCP. Consequently, this document is not intended to fully satisfy the requirements of WAC 480-90-238 and WAC 480-100-238, the natural gas and electric utility least cost plan filing requirements. A timeline for completing the Company's Least Cost Plan to comply with rules is included in the Executive Summary.

The Company has met with numerous external parties several times over the past few months to review and discuss resource planning issues. Feedback provided by those parties, especially Commission Staff, has been very helpful. PSE would like to thank every organization and individual that has participated in this process to date. The Company looks forward to continuing to work with all interested parties through the planning process in development of the LCP. As part of this process, PSE invites feedback on this draft document by interested parties.

Please contact me at 425-462-3727 if you have any questions or if I can be of any assistance.

Sincerely,

George Pohndorf
Director, Rates and Regulation

Enclosure

RMS

PUGET SOUND ENERGY

2002-2003
DRAFT LEAST COST PLAN

December 2002

Executive Summary

PUGET SOUND ENERGY
LEAST COST PLANNING DRAFT

INTRODUCTION

This document presents a draft of Puget Sound Energy's electric Least-Cost Plan ("LCP" or "Plan") as of December 31, 2002. As described in this document, the planning process is well underway and further process and analysis is necessary in order to develop the complete LCP. The LCP will address the Company's energy and capacity resource needs and strategies to meet those needs using energy supply resources and demand-side measures, such as conservation programs. The Plan is being developed with stakeholder input. To date, we have held a series of meetings with interested parties discussing a number of subjects and issues that influence resource planning decisions. Puget will continue to seek such input in development of the LCP. The resource decision framework that emerges from this process can have significant impacts on our customers and a number of other public interests. Accordingly, development of least-cost plans in an open and inclusive manner is very important to us.

The principal purpose of this document is to provide the WUTC and interested parties a report on the current status of the Company's least-cost planning efforts and many of the key elements, in draft form, of the next LCP. It also contains a detailed description of the activities necessary for finalizing the Plan and an expected schedule for its completion. The Company has not yet reached the stage in the planning process where a resource strategy has been finalized so this document contains few conclusions. Rather, it presents our work in this effort to date and next steps in the process. We invite feedback from interested parties.

OVERVIEW OF THE DOCUMENT

Business Environment and Planning Issues

This draft begins in Chapter 2 with discussion of a number of the key issues that impact the planning process. These are some of the overarching concerns that we believe deserve consideration as resource strategies are developed, and, ultimately, individual resource acquisitions are made. Chapter 2 includes a historical context and highlights several important business considerations that have resulted from fairly recent regulatory policies at the federal level, restructuring activity in California, and PSE specific issues. These business considerations include the utility credit crisis, collapse of merchant power plant development, collapse of the short-run electric commodity trading market, and implications of the Company's current financial situation. Some of the key findings in this section are:

Need for Resources

Determination of the Company's need for resources over the 20-year planning horizon begins with forecasting monthly energy and peak loads. The load forecasts are provided in Chapter 3. The next step is a review of the expected future availability of existing resources. Issues associated with existing resources are discussed in Chapter 5. Chapter 8 describes how PSE has used these and other key inputs to determine the Company's need for new resources. This determination of the need for new resources basically amounts to a comparison of forecasted energy loads and peak loads with future availability of existing resources (at economic levels of operation) where the "gap" represents the need for new resources.

This comparison shows significant resource needs in the near term and escalating greatly over the planning horizon. The Company has large resource needs, including annual energy, seasonal energy, and winter peak capacity. These large and growing needs reflect both forecasted growth in PSE's native loads and loss of existing resources, including expiration of power purchase agreements and power exchanges.

MEETING RESOURCE NEEDS

Chapter 8 further provides a description of the analytical process for identification and analysis of alternatives for meeting PSE's resource needs. A key part of this process it to determine planning criteria for addressing resource needs. At the outset, the Company is considering using planning criteria that include ensuring long-term firm resources to meet 100% of all projected monthly energy needs and 100% of annual energy needs on an average water basis. Through the planning process the costs and risks of application of alternate planning criteria will also be examined.

Chapter 8 further describes the process for considering various alternative portfolios of resources to meet the company's growing resource needs (and to provide for the possible replacement of any uneconomic existing resources) using a series of computer modeling techniques. This modeling process is underway but not yet complete. A schedule for completion of this modeling is presented. Further modeling will be required to assist in the development of resource acquisition strategies. Additionally, Chapter 5 provides information regarding resource alternatives and Chapter 6 describes the Company's approach to managing short-term and long-term energy supply price risk.

Chapter 4 presents the Company's strategy for securing cost-effective conservation resources to help meet resource needs. Currently the Company is implementing an expanded effort to acquire cost-effective conservation resources. The status of our conservation efforts is presented along with the process to investigate the conservation potential in our service territory and adjust conservation targets in consideration of that potential and program experience.

Finally, Chapter 9 presents a decision-making method and process the Company is considering using to determine its resource acquisition strategy.

KEY PRELIMINARY FINDINGS

Though this report is preliminary, a number of key findings have come forth through the planning process to this point. Discussed below are these findings reached to date, which are described more fully in this document.

- PSE is conducting its least-cost planning process as part of its regulated utility obligation to serve and in the context of the recent turmoil in Western power markets, including failed retail deregulation in California.
- PSE believes it will continue to be required to plan to serve its native retail load with a "least-cost" mix of resources. That is, the Company does not envision retail deregulation for its native retail load customers over the planning horizon.
- The Company has a large and growing need for new resources, partly due to load growth, but more significantly due to loss of existing resources.
- The Northwest region is currently in approximate load-resource balance under normal hydro conditions, but low hydro conditions can create regional shortages and the risk of high wholesale prices.
- Development of merchant generation has come largely to an abrupt halt in recent months. BPA's role in regional resource development has been diminished and other utilities in the region are facing needs for new resources. This poses the risk that within the next few years, the Northwest region may move to a position of becoming short on resources, even under average hydro conditions.
- PSE and its customers could be greatly disadvantaged due to extremely high wholesale power prices and other adverse effects that could result from in a situation where both PSE and the Northwest region become short of resources.
- As a result of the considerations above, PSE intends to meet its native load with firm resources and needs to acquire a significant amount of new resources to do so.
- A number of factors including the collapse of the merchant developer and wholesale markets, developer credit issues, and the Company's financial situation, make ownership of resources potentially more attractive for PSE.
- A few currently "distressed" projects in the region may present attractive opportunities for the Company and its customers.
- PSE will examine all alternatives for meeting its resource needs, including renewable resources and conservation.
- To develop its resource strategy, PSE has begun the process of assessing a wide range of resource portfolios under a structured analytical approach. This analysis includes explicit modeling of costs, environmental effects, uncertainties, and risks.

ELECTRIC UTILITY LEAST COST PLANNING REQUIREMENTS

Formal requirements for electric least cost plan submitted to the Commission are included in WAC 480-100-251. Beyond the formal requirements of the Least Cost Planning rule, the Commission, in its letter dated August 28, 2001, regarding the Company's prior Least Cost Plan, provided an additional set of expectations to be addressed in this next LCP.

This document is the Company's Draft Least Cost Plan, as described above, and is not intended to be a final document that fully satisfies the requirements of the rule or to completely address the Commission's additional expectations in the August 28, 2001, letter. This filing is to provide the Commission, interested parties, and others with an update of where the Company is in its electric resource planning process and where it is going. PSE is seeking continued feedback as it moves through the planning process.

Two additional filings will follow this Draft LCP that will fully address those requirements and expectations. First, a complete Least Cost Plan will be filed by April 30, 2003. In addition to the material presented in this draft, that LCP will include the completed resource analysis and reasoning that will help guide the Company's future supply resource acquisition decisions. The April 30 LCP filing will also include the relevant sections of the Least Cost Plan to meet the requirements of the gas least cost planning rule under WAC 480-90-238.

Second, a Least Cost Plan Update will be submitted by August 31, 2003 that includes a market assessment and analysis of cost-effective conservation and demand side resource opportunities. This timing is commensurate with the timeline for filing proposed changes to the Company's conservation programs pursuant to the Settlement Stipulation for Conservation in the Company's last general rate case filing, under Docket UE-011570. The Least Cost Plan Update will provide the conservation program update that will present adjustments to the current 15 aMW and 2.8 million therms per year savings target and proposed changes to individual programs for implementation going forward. The LCP Update will also include the analysis and reasoning used to consider the assessment of conservation potential and to modify the related savings targets. As described in the Settlement Stipulation, the August 31, 2003 filing may be delayed due to events beyond the Company's control, such as availability of information from the Regional Technical Forum. At this time, it appears August 31, 2003, will still be attainable.

PUBLIC PARTICIPATION

PSE is committed to incorporating public involvement into its planning process. To date five Least Cost Planning meetings have been held and a number of additional meetings will be scheduled in the coming weeks as LCP development continues. A number of stakeholders including WUTC Staff, consumer advocates, individual customers from industrial, commercial, and residential classes, environmental organizations, NWPPC, and CTED Staff have attended meetings held to date. Overall, these meetings have provided very helpful feedback and information. PSE is grateful for the time and energy devoted to this process by those who have attended the Least Cost Planning meetings and hope that such participation continues as the Company's planning process proceeds. The following is a summary of the Least Cost Planning meetings convened as of December 11, 2002.

Kick-off Meeting: August 26, 2002

Four primary topics were addressed at this meeting. First was discussion of the approach to initiation of PSE's planning process for this Least Cost Plan. Second was a presentation of the Company's draft electric sales forecast. Forecast assumptions and new methods were briefly touched on. Third, there was a brief comparison of the Company's sales forecast with future resources, illustrating a growing need for resources over time. Fourth, there was a review of transmission constraints and how those impact resource planning. Further, there was additional discussion around planning criteria, including the cost of meeting peak demands under normal versus dry hydro conditions.

Renewable Resource Meeting: October 10, 2002

At this meeting, several experts (non-PSE employees) presented a variety of helpful information regarding renewable resource opportunities and development issues. Specific presentations and discussions were held on wind, geothermal, and renewable resource projects on Vashon Island. Following the presentations was an informative round-table discussion.

Distribution Planning Meeting: October 16, 2002

The Company explained how it performs gas and electric distribution system planning. Topics included planning criteria and distributed generation.

Energy Risk Management and Natural Gas Supply Meeting: October 22, 2002

This meeting covered two distinct topics. First was a presentation on natural gas supply for gas sales customers. Second was an explanation of how PSE models risk and an overview of hedging for the Company's electric and gas portfolios. One key take away from this meeting was customers' sensitivity and interest in energy risk management issues and the need to keep customer and interested parties informed of the Company's actions in this area.

Updated Demand Forecast, Resource Need, Next Steps Meeting: December 11, 2002

Three topics were addressed at this meeting. First was a presentation of the Company's updated electric sales forecast, including updated forecasting methods and results. This section also included an explanation of how the Company adapts is billed sales forecast to hourly loads. The second topic was a presentation of the Company's need for resources based on robust Aurora modeling. Finally, the Company discussed with participants the screening analysis, including numerous probabilistic variables, the Company is performing on numerous resource portfolios and the decision making process for how to choose which screened portfolios to analyze further. The Company is currently open to analyzing any additional scenarios offered by participants, including some portfolios on generic demand side management programs.

Planning

Chapter 2

PLANNING ISSUES

This chapter assesses some of the overriding issues that set the present context for Puget Sound Energy's (PSE) resource planning efforts. The following first addresses recent events in the western power markets and their implications for our resource planning. A historical perspective on power markets and public policies is provided, followed by a review of the California energy crisis and its aftermath and implications. The status of the merchant supplier marketplace is then assessed followed by a discussion of issues of concern going forward. Similarly, the status of the wholesale energy marketplace is reviewed. Next, an overview of the financial condition of power companies is presented. The implications of the current financial stress in the energy sector on PSE, as well as the Company's overall financial situation, needs and objectives are discussed. This chapter ends with a discussion of uncertainties in federal policy on transmission infrastructure.

KEY FINDINGS

The past two years have been instructive to PSE in a number of ways. In terms of supply planning, events in the western region have led to a fundamental shift in the Company's view of and intended reliance on the short-term power markets. Based on a review of recent market activity and PSE's own experience in the market buying and selling resources to optimize the Company's supply portfolio, several key findings emerged:

- Resource adequacy in the Pacific Northwest region continues to mean having enough resources to meet customer needs.
- Regional interdependencies will continue to affect resource availability and price volatility.
- Reliance on hydro resources poses unique challenges for planning supply and risks to developing merchant power development in the region.
- A majority of investor owned utilities in the NW region , including PSE, will be short firm supply in the next 3-5 years without additional purchases.
- Supply planning in a resource constrained market requires being proactive to avoid recurrence of strains created by the 2000-2001 power crisis.
- Distress in the merchant sector may be providing an unexpected opportunity to secure additional firm resources, through either long-term purchases or facility acquisition.
- Corporate creditworthiness must be proactively managed to create financial flexibility and maneuverability to assure capital is available on reasonable terms to meet customer needs.
- Future of the wholesale market structure remains uncertain in the west as FERC continues to move forward with its Standard Market Design.

WESTERN POWER MARKETS

Perspective on Public Policy and the Power Markets: 1978 to Present

Since the advent in 1978 of the Public Utilities Regulatory Policy Act of 1978 ("PURPA"), the electric energy markets have been engaged in non-stop change and turbulence. Problems arising in 2000 and 2001 in the California and western power markets had its seeds sown years earlier in a variety of public policy initiatives at both the federal and state levels. The California experience is only the most recent and most widely analyzed in a long line of public policy experiments that proved unsustainable. The challenges facing all those who participate in the power industry today are great, but by no means new.

In 1978, Congress adopted the Power Plant and Industrial Fuel Use Act effectively banning the use of natural gas in new power plants because of perceived scarcity, only to repeal that act a few years later to herald in the era of large, highly efficient combined-cycle gas turbine plants. In the 1980s, gas exploration technology greatly improved access to new and more economic gas reserves. Natural gas has become the power plant fuel of choice for economic and environmental reasons. Once again, however, we read warnings of declining North American gas reserves, reduced rig counts, relatively modest drilling activity, rising gas prices and cautions about possible natural gas shortages.

Nuclear and coal fired generation continue to play a significant role in the nation's supply mix, despite the absence of permanent solutions for nuclear waste and significantly more stringent air emission and mining standards. Coal mining productivity soared in the 1990s and nominal and real prices of coal plummeted. Steady progress was made in the efficiency and reliability of wind turbine technology. Several vintages of wind technology were deployed on large-scale wind farms, some of which proved commercially successful with the aid of special tax treatment. Meaningful improvements were made in solar cell and fuel cell technology, but we still wait for their commercial promise to be realized. Conservation matured from a "movement" of a few to become building codes and fuel efficiency standards for the many. The conservation ethic is institutionalized and codified throughout the land.

More than two decades have ensued since PURPA opened the field of generation development to all-comers. Initially intended to encourage "independent" power suppliers to build small renewable resources, PURPA and its many policy off-spring at the state level induced entrepreneurs and capital providers alike to construct hundreds of small scale power facilities ("Qualified Facilities"). Some of these "QF" plants actually made economic sense, but many were little more than R&D projects made possible lucrative energy tax credits, investment tax credits and accelerated tax depreciation. Many no longer operate.

The historic approach of regulators to cost of service regulation for investor owned utilities was not applied to this new breed of power producer. Instead, access to power supply contracts with utilities was usually encouraged and sometimes mandated. Such contracts used administratively determined "long-run avoided costs" ("LRAC") as a proxy for cost of service regulation. Such prices, derived based on long-term economic assumptions that, in retrospect, turned out to be inaccurate, often proved significantly more costly than the revenue requirements associated with utility constructed generation. Beset by skyrocketing power costs driven by PURPA contracts, policy-makers again altered course and permitted utilities to abandon LRAC-type contracts in favor of "all source bidding" processes. This, in combination with advances in gas turbine technology, helped usher in the era of Exempt Wholesale Generators, larger more economic power plants, and eventually, under NEPA in 1992 and FERC orders 888, 889, and 2000, greater access to the transmission grid and the ability to wheel and trade bulk power.

The age of the lightly regulated, highly leveraged merchant generator arrived, and with it, the age of the essentially unregulated energy trader in wholesale power markets. Without the oversight and discipline of federal level cost of service regulation, merchant power companies charged whatever they could extract from the market. It is against this history and with these lessons in mind that PSE as a load-serving utility finds itself needing to address energy and capacity deficits that will grow throughout the decade ahead. Illustrative of the possible scenarios that the Company could find itself in the future is the exhibit below (See Exhibit 1). What this shows is the range of short and long positions that the Company could be in with respect to regional loads and firm supply. The color-coding in the matrix represents the severity of the situation from a cost perspective, such that the out of balance scenarios result in either opportunity costs (long in a long market) or unhedged risks (short in a short market). Where PSE finds itself over the next several years will depend on how its portfolio of resources evolves and how market prices are affected by the regional load/resource situation.

Exhibit 1

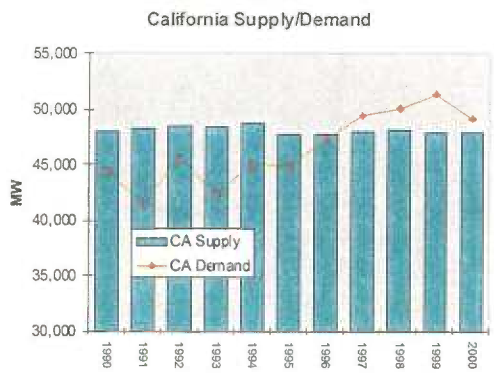
	Pacific Northwest Load-Resource Balance		
PSE Load-Resource Balance	Regional Resources Less than Loads	Regional Resources Equal Loads	Regional Resources Exceed Loads
PSE Resources Less than Loads	PSE Short in a Short Market (PSE Forced to Buy at High Prices)	PSE Short in a Balanced Market (PSE Forced to Buy, Pays Moderate Prices)	PSE Short in a Long Market (PSE Forced to Buy, But Pays Low Prices)
PSE Resources Equal Loads	PSE Balanced in a Short Market	"A Perfect World" (Theoretical Equilibrium)	PSE Balanced in a Long Market
PSE Resources Exceed Loads	PSE Long in a Short Market (PSE Forced to Sell But Gets High Prices)	PSE Long in a Balanced Market (PSE Forced to Sell, Gets Moderate Prices)	PSE Long in a Long Market (PSE Forced to Sell at Low Prices)

THE CALIFORNIA WHIRLWIND

Overview

The price spikes and rolling blackouts that occurred in California and the rest of the western region during the period 2000 to 2001 yielded important insights regarding the shortcomings of the market structure to curb opportunistic behavior. While one can point to a number of factors that are responsible for the crisis experienced in the West, including market participants, regulators, legislators, the booming economy and the weather, it is clear that the market structures adopted in the west incented perverse market behaviors by fuel suppliers, merchant power operators, and other entities. The events in California raised fundamental questions regarding the balance between regulatory oversight and the natural forces of the market. Critically, it tested the tolerance of customers and regulators for extreme price volatility in resource short markets. In terms of resource planning, it brought to the surface questions as to the financial durability of the merchant generation developer business model, and concerns about relying on the market and regulatory approval processes regarding new plant development to satisfy a company's regulatory obligation to serve retail customers in a low cost and reliable manner. For PSE, the market developments over the past eighteen months have lead the Company to reexamine fundamental assumptions used in preparing its own resource plan for meeting both short and long-term needs (described in Chapter 8).

Exhibit 2



Factors and Events

As PSE continues to review its plans for developing its resource portfolio, it is instructive to look at the conditions in California that set the stage for the emergence of the energy market crisis. In early 2000, the economy was characterized by robust load growth. In the midst of this strong economic growth in the region, supply had remained fairly stagnant with little to no additional capacity having been brought on line for almost a decade, due in part to environmental restrictions that were in place on new construction and the cumbersome approval process (See Exhibit 2). Other factors contributing to the crisis included the heavy reliance on QF capacity, the state's emphasis on conservation and efficiency initiatives, and the regional snow drought, which significantly reduced hydro resources in 2000. Market prices for electricity and gas began to skyrocket in the face of this supply/demand imbalance (See Exhibits 3 and 4). Hydro availability here in the Northwest also dropped precipitously during that same time period, severly curtailing resources that California relied upon in the Winter/Spring period (typical generation facility maintenance period) as well as the Summer (peak consumption period). This confluence of factors set the stage for the power crisis to emerge in California and spread to other parts of the western region.

Exhibit 3

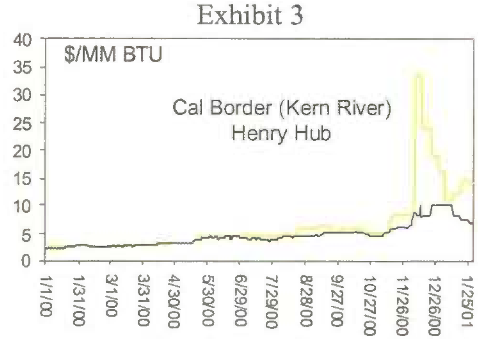
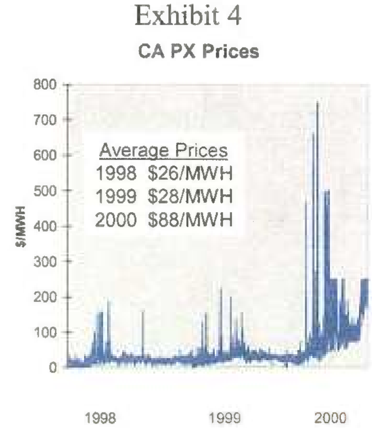


Exhibit 4



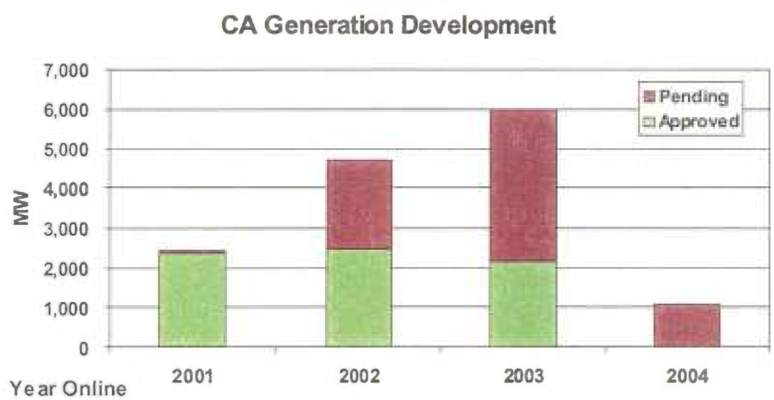
The Aftermath

The crisis that erupted in California submerged the state's largest utilities in financial turmoil. The California utilities, because of the cap on retail rates that had been in place, quickly became cash strapped in the face of rising prices on the Power Exchange (PX), from which they were required to buy. This in turn led to the rapid downward spiral of the financial health of the two largest utilities in the state – Southern California Edison and Pacific Gas & Electric – due to the heavy cash requirements of the wholesale market purchases, their inability to recover costs in their rates, and their subsequent inability to meet the terms of numerous outstanding commercial paper obligations. Regulations in California prohibited the utilities from entering into forward contracts, effectively prevented them from hedging against the risk of skyrocketing market prices and halting the downward spiral. Likewise, QFs that relied on utility credit and payment streams became uncreditworthy and some ceased operation, further exacerbating the power shortage.

Current Situation

Over the past 18 months, the market in California has returned to a more normal state thanks in part to the slowing economy, the rapid addition of new generation in the state (~5,600 MW), and relatively mild summers in 2001 and 2002 (See Exhibit 5). While the State is by no means out of the woods in terms of reforming the regulatory environment and resolving disputes over long-term power contracts that were signed at the height of the power crisis, the State is focused on attempting to return stability to the power market and revamping the supply procurement process. Beginning January 2003, the utilities will resume responsibility for procuring resources to meet their native load customer obligations, under a co-signatory arrangement between the utilities and the California Department of Water Resources. Once the utilities return their credit ratings to investment grade, all of these agreements will novate to the utilities and the DWR will exit the power supply procurement business. Until such time as the utilities are again creditworthy, the DWR and the utilities will remain wedded together in the procurement process.

Exhibit 5



Lessons Learned

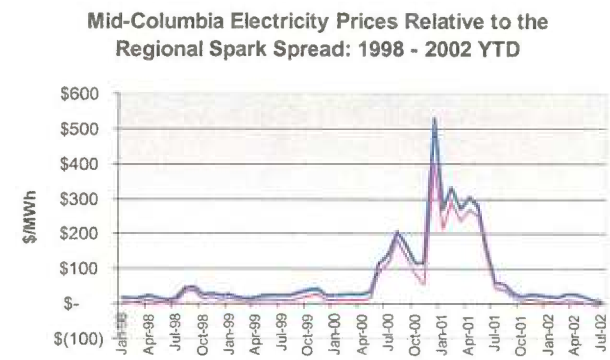
As we look forward, the primary lesson learned from the western region power crisis is the importance of taking a proactive approach to resource planning and effecting supply decisions based upon sound business and financial analyses. That means considering a whole host of resource alternatives and structures that enhance a company's ability to meets its obligation to serve in a low cost and reliable manner, under various market conditions. It also means actively monitoring the marketplace to identify opportunities and threats to that mission. For many, the recent crisis was a wake-up call to recognize that under the right (i.e., severe, adverse) conditions, the best practices employed for supply planning will be put to the test.

REGIONAL SUPPLY SITUATION

Background

Western power markets have gone through a tumultuous period characterized by supply and price volatility. While the most recent twelve months provided a reprieve from the volatility experienced over the previous two years, the concerns with supply adequacy and reliability remain. Puget Sound Energy has continued to monitor the wholesale power markets in the region to assess opportunities for meeting its resource needs, either through asset acquisitions, building its own generation, encouraging conservation, or entering into additional power purchase agreements. Whatever individual resources, or combinations of resources PSE secures, the incorporation of those resources into the Company's supply portfolio will be premised on the objectives of procuring low cost and reliable electricity supply on behalf of our customers.

Exhibit 6



Capacity Growth

Over the past decade and through the end of 2003, ~6,600 MW of new generating capacity will have come on-line in the Pacific Northwest.[1] With this development has come a temporary wholesale market supply surplus. The surplus is such that spark spreads in the region effectively dropped to zero as of July 2002, based on the contemporaneous gas prices and incremental costs of production (See Exhibit 6). However, predictions of a low water year in 2003 in the PNW has provided recent price support in the forward power markets. Until regional spark spreads return for the longer term, it is difficult to envision capital market support for merchant plants. Such market conditions raise the question whether or not an opportunity might exist to acquire a physical asset to complement PSE's portfolio of firm resources.

REGIONAL SUPPLY MIX

As of 2001, the four-state region of Idaho, Montana, Oregon and Washington had nearly 68,000 MW of installed capacity (See Exhibit 7).[2] What is unique about the region's supply mix is the heavy dependence on hydro resources. Approximately 53% of the installed capacity in the region continues to be hydro based. This heavy dependence is a double-edged sword. On one side it provides a powerful means of keeping energy prices low, but in off years, where hydro availability is much below average, the price effects in the merchant market can be devastating for consumers as experienced during the 2000 to 2001 power crisis.

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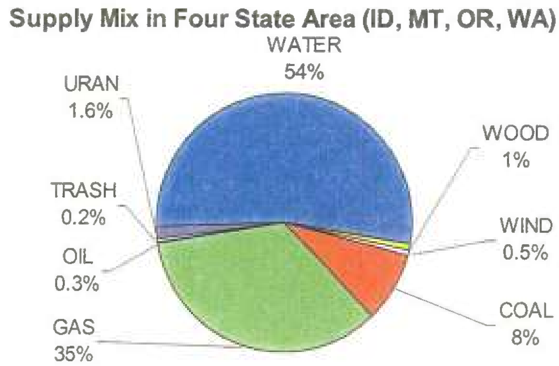
[1] The Pacific Northwest region consists of ID, MT, NV, OR, UT, WA, and WY

[2] Source: PowerDat. RDI, October release

Exhibit 7



	Installed Capacity (MW)
WATER	36,235
GAS	23,516
COAL	5,772
URAN	1,107
WOOD	650
WIND	324
OIL	182
TRASH	140
Total	67,926

The new fuel of choice for power plant developers over the past five years has been natural gas. While gas prices hovered in the $2 to $3/MMBtu range during the late 1990s, indications were strong that gas-fired combined-cycle capacity should be the technology of choice given its quick construction turn around, its high level of efficiency, and its reliance on, at that time projected low-cost, gas. Although the preference appears to hold true today across most parts of the country, the fundamentals of the North American gas market bear close scrutiny. Basin depletion rates, pipeline delivery capability, environmental developments, and exploration and production economics are all dynamic and can significantly affect short-term prices and availability in certain regions in certain seasons. Some have begun rethinking how the growing reliance on gas affects profitability, overall risk exposure and the best means for managing that risk. For those relying on gas-fired generation, the key to managing short-term gas price risk has been the ability to leverage physical assets such as gas storage and pipeline capacity. Over the long-term, gas price risk is a little more challenging, as there are limited market offerings of long-term financial hedging products.

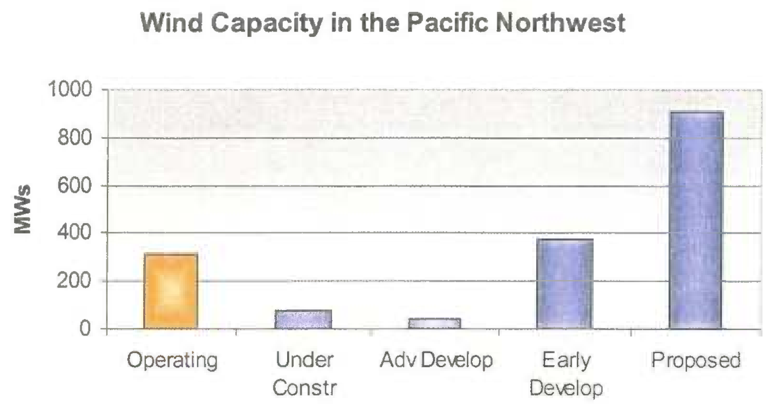
The second largest piece of the generation mix in the region is coal-fired, the majority of which is installed in Wyoming. The current resurgence in coal plant development in states like Wyoming, Illinois, and Kentucky has been driven in part by the concern about gas price volatility and the relative price stability of coal. For a company like PSE whose interest in supply reliability and cost stability remain paramount, owning or contracting with a coal facility is potentially attractive relative to gas, due to the availability of long-term fuel contracts that can be used to lock-in fuel prices. While coal facilities are of interest for these reasons, siting challenges in the Puget Sound basin are considerable. Moreover, transmission challenges to plants east of the Cascades remain unmet by BPA. Nevertheless, a coal based resource could well be attractive to PSE in the intermediate term once transmission bottlenecks are addresssed.

On the renewable front, wind energy appears to have substantially grown in the level of interest that developers have been showing in and around Washington. In the Pacific Northwest, more than 1,400 MWs of wind capacity are at varying stages of development, with over 300 MWs currently installed (See Exhibit 8). According to RDI, there are approximately 16 individual wind projects, which represent the identified MWs under development.[3] An important note to keep in mind with the growth in wind resources is that the average availability capacity for a wind resource is closer to one-third of the installed capacity. When looking at the total installed wind capacity numbers for the region, as compared with other installed capacity, one would

[3] Source: NewGen, RDI

multiply the number by one-third to derive a comparable figure to other installed generation in the region.

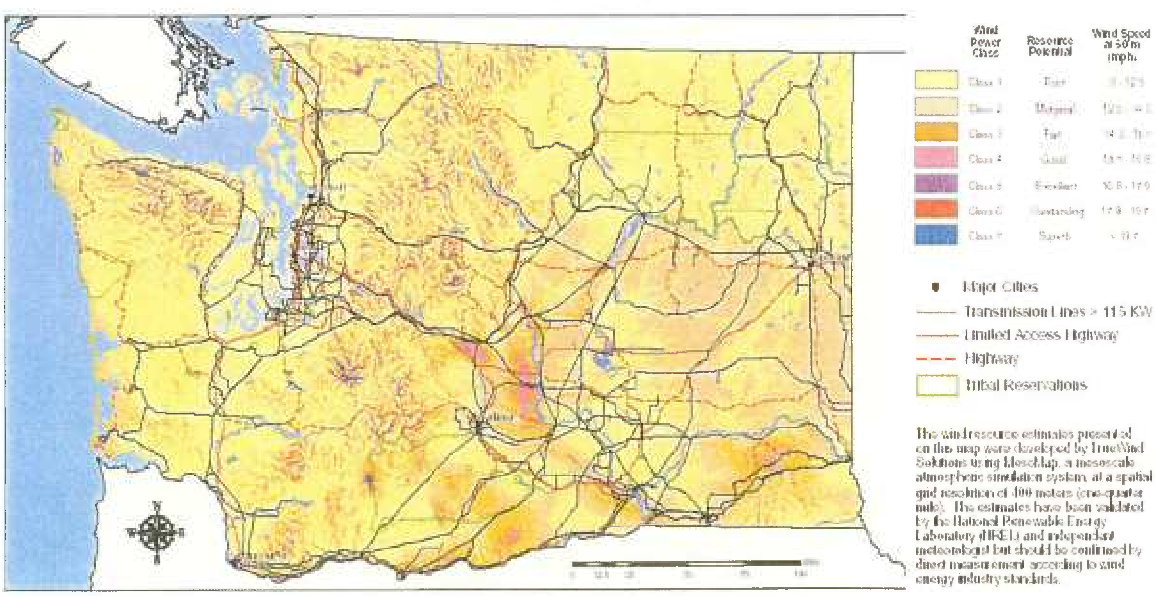
Exhibit 8



Wind resources offer an attractive resource alternative because of their mitigation of fuel price risk, their declining costs of production, and the absence of emission effects (See Quantifying the Value that Wind Power Provides as a Hedge Against Volatile Natural Gas Prices, LBNL, June 2002). Continued growth in wind applications will draw on these benefits. The challenges facing further wind development are not so much with the power production process, but the commercial feasibility of such projects. In particular, wind developers still face a number of challenges: (1) renewal of the production tax credit; (2) modest forward price curves; (3) procurement of financing; (4) physical integration and interconnection; and (5) the reportedly modest wind regime here in Washington. Given its intermittent nature, it is challenging to integrate wind on a large scale into a company's portfolio in the same manner as fully dispatchable stand-alone facilities using coal or gas. One way that it can be effectively integrated is through a shaping of wind resources with another resource such as hydropower to create a load following resource. As an example, BPA and Pacificorp are coupling hydro resources with wind power from FPL's Stateline facility to create a load following product.

Another key challenge for wind is its interconnection with the transmission system. As illustrated on the map, Washington does have a modest number of excellent wind resource locations, but they are not necessarily located in areas adjacent to existing transmission lines or lines with available capacity (See Exhibit 9). On-going wind development projects have been addressing such issues to enhance the technology's attractiveness. As PSE moves forward with its resource planning, it will look to wind as a potential resource alternative.

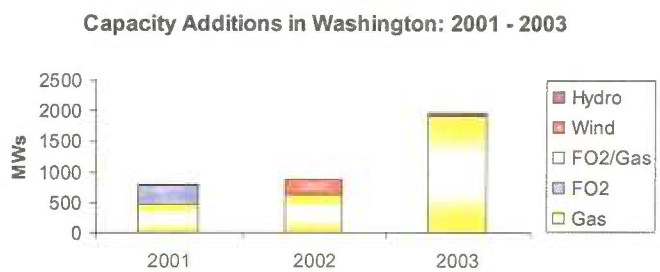
Exhibit 9



Issues Going Forward

As the Company evaluates the supply situation over the next few years, it recognizes the need to consider the impact that the region's hydroelectric resources have on electricity prices and the economic incentive to bring more generation on-line. According to NPPC, the region's hydro resources can vary 4,000 MWs above or below the historical average of 16,000 average MWs in a given year. At the average level, the hydro resources satisfy over 70% of the region's annual average load of 22,000 aMWs. Under conditions where an additional 2,000 MWs of hydro is available, that figure jumps to over 80%. When conditions emerge that provide for either an average year or an above average year for hydro, the economics of merchant generation can be severely undermined. In light of this uncertainty regarding merchant gross margins, a shadow is cast over the incentive to build more generation in the region if it is not tied, at least in part, to a long-term power purchase agreement that is based on a utility's credit. The dampening effect that strong hydro availability can have on market prices will affect the amount of new generation being built in the region. Because of the decline in the merchant sector, lenders may have to step into the role of plant owner, as developers default on projects. Since the capital markets are dominating the merchant sector today, how they respond to existing market conditions and their expectations for the future market will be a powerful determinant of the supply situation that takes shape over the next several years. As we have seen over the last few years, high prices attract development. Indeed, high prices are critical to developers needing to overcome the hydro and price volatility described above. In Washington alone, high prices contributed to the addition of nearly 3,700 MWs between 2001 and 2003 (See Exhibit 10).

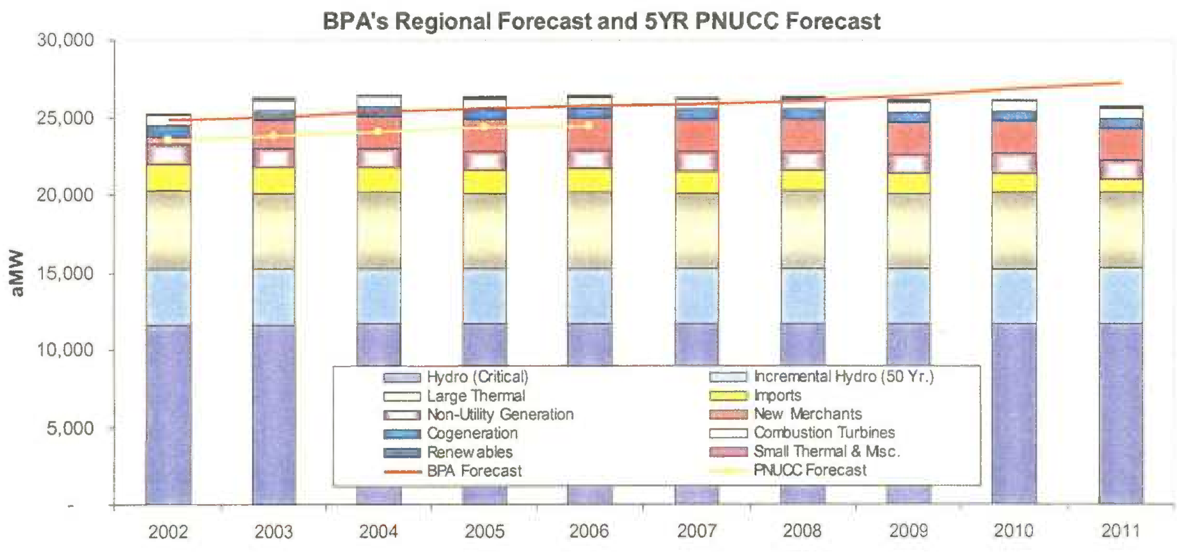
Exhibit 10



Note: Above figures do not include tabled or cancelled capacity

From the perspective of consumers, price weakness in 2002 offered a welcome respite. For entities responsible for planning supply to meet future loads, recent price increases driven by forecasts of low water condtions is a solemn reminder of the adversity consumers can expect

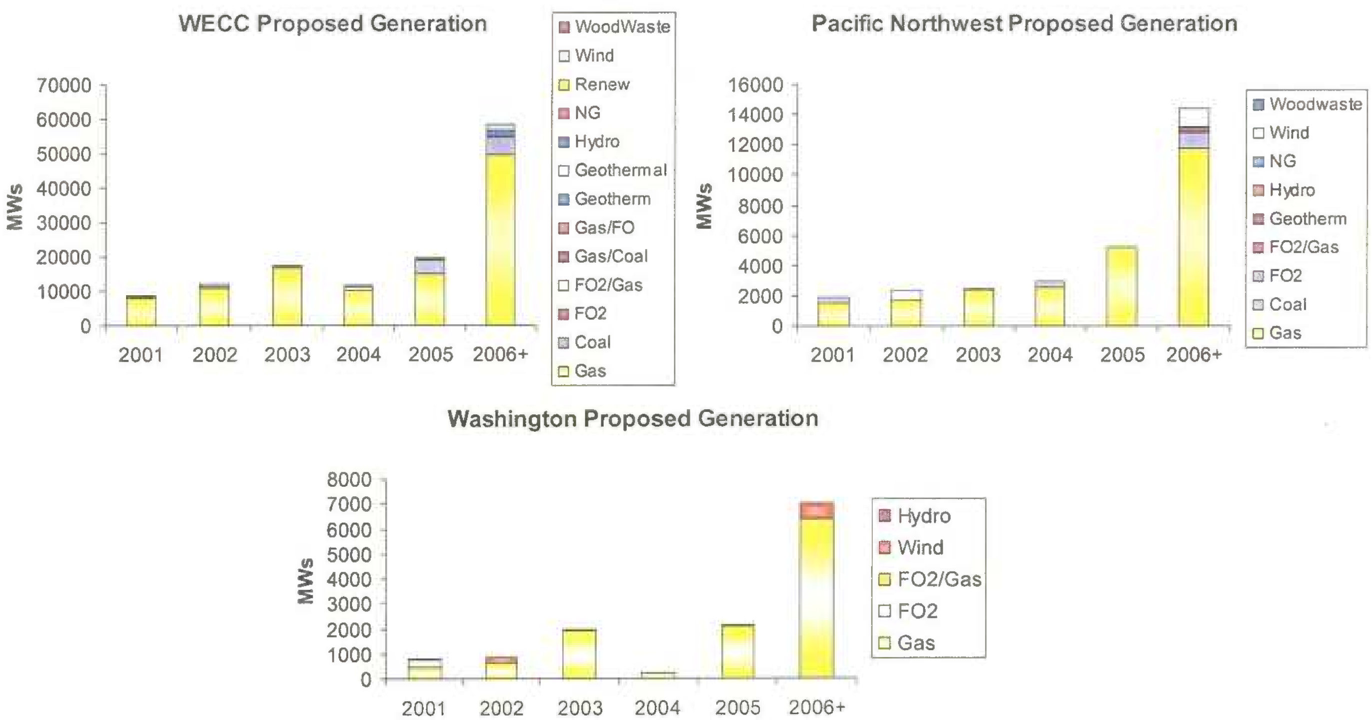
Exhibit 11



when resources to serve native load must be acquired from a tight market.

There is no evidence that retail markets will be opening up any time soon in Washington State, though wholesale market competition will continue to move forward under Federal policies. However, it remains uncertain what that wholesale market structure will look like and how companies operating within that structure will finance resources to meet their on-going supply commitments. In light of this uncertainty, PSE sees the current surplus of merchant generation as an opportunity to identify and potentially acquire competitvely priced supply that would strengthen the Company's portfolio of firm resources. According to PNUCC data, it appears that the majority of investor owned utilities are going to be short firm resources beyond the 2004 time frame. For the region as a whole, PNUCC projects that the firm resource deficit will grow to over 4,700 MW at peak load (3,800 MW on an annual energy basis) by 2006 (See Exhibit 11).[4] One might conclude that there could be significant competition for the resources that are currently being built and that are coming on-line over the next couple of years. As the economy returns to strength and the recently added supply is absorbed by load growth, energy prices will recover. PSE believes it is important to examine a range of options available to it to moderate the effects of volatility and potential supply/demand imbalances in the electricity market.

Exhibit 12



Source: California Energy Commission, WECC Proposed Generation Database, updated November 13, 2002

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[4] Source: 2002 PNUCC Northwest Regional Forecast; See also December 11, 2002 press release from NWPPC

THE STATUS OF MERCHANT POWER

Merchant Retrenchment

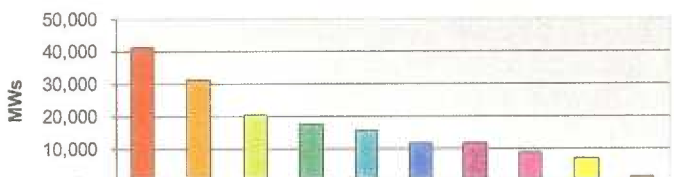
Since January 2001 and through August 2002, over 160,000 MWs of proposed new generation have been either tabled or cancelled nationally. Nearly 25% of this capacity was projected to be developed in the WSCC (See Exhibits 13 and 14). The majority of these delays and cancellations occurred during the first six months of 2002. Merchant plants being developed in the Pacific Northwest and around the country are being delayed or canceled. Despite this activity, some developers of gas-fired projects are loath to admit their projects might not make sense and to relinquish their place in queue for gas pipeline upgrades and transmission studies and improvements. It will be diffucult for developers that do not have adequate cash or corporate support to continue the facility permitting and development process that includes such costly outlays as design development, detailed engineering, permitting, turbine deposits, gas transmission deposits, electric interconnect studies and deposits, land acquisition and environmental studies. Developers of wind projects report they have encountered a less robust wind resource than initially hoped for in the Pacific Northwest, and in some cases, more environmental opposition than anticipated. Most importantly, developers of wind projects are trying to keep their projects alive in the face of the scheduled expiration of production tax credits at the end of 2003, low merchant market prices and tight credit markets. Developers of all sorts are endeavoring to keep development period and construction period financing flowing, but it appears this may be an uphill battle as lenders and equity investors alike retrench to reconsider the business and financial models inherent in merchant power markets.

Exhibit 13

Cancelled or Tabled Capacity in the U.S.
(January 2001 to August 2002)

Exhibit 14

Cancelled/Tabled Capacity by NERC Region
(Jan. 2001 to Aug. 2002)



	WECC	SERC	ECAR	MAIN	FRCC	ERCOT	NPCC	SPP	MAAC	MAPP
Total	41,143	31,495	20,558	17,520	15,615	11,874	11,638	8,614	6,760	1,140

Decline in Merchant Valuations and Credit Ratings

Merchant companies have lost an enormous amount of market capitalization. Loss of 90% or more of market value from peak valuations is common. The past twelve months have been intensely volatile for operators in the merchant sector. The market overall turned dramatically bearish, leaving most merchant operators at a fraction of their original valuations (See Table 15). Among the largest merchant operators, valuations have dropped over 75% since July 2001. Once high-flying merchant developers are now struggling to raise much needed capital to meet existing debt obligations as well as future growth plans (See Exhibit 16). A little over a year ago, the picture was quite different with valuations steadily climbing for the majority of pure play merchants (See Exhibit 18).

Exhibit 15

Merchant Valuations 12 Months Ago

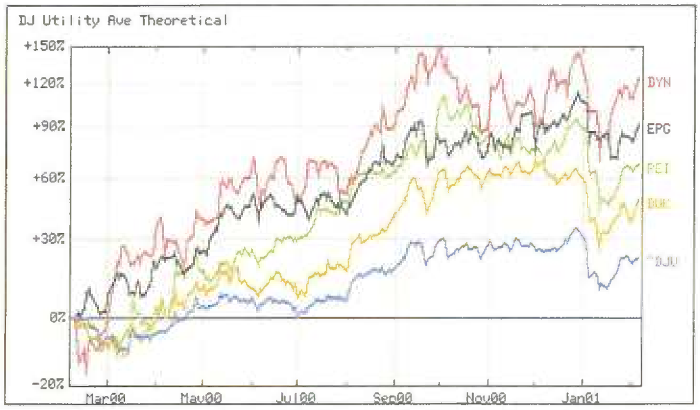


Exhibit 16

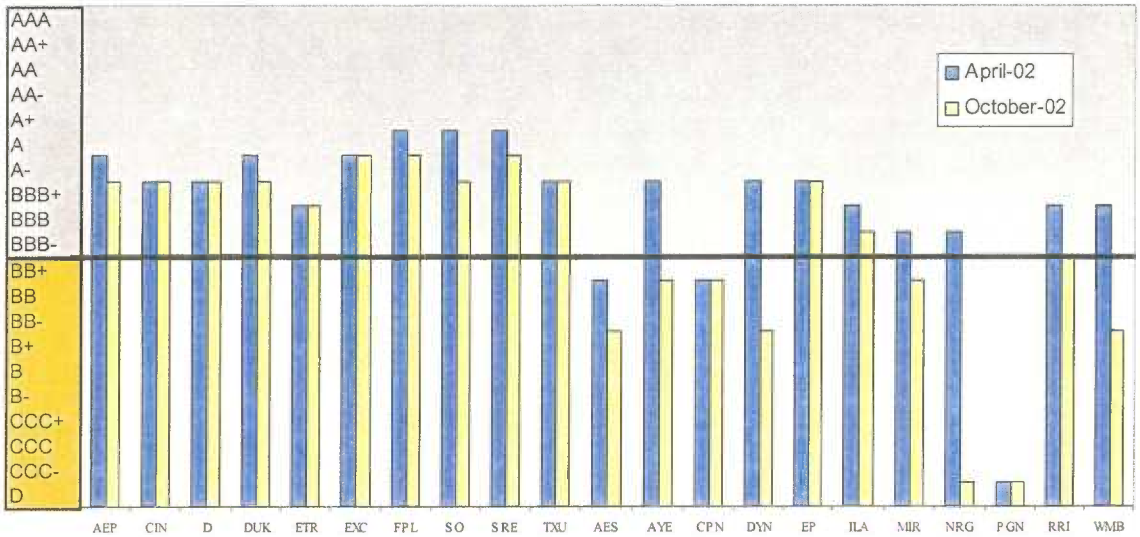
Company	Symbol	Closing Share Price 7/2/2001	Closing Share Price 12/6/2002	Change	Shares (000,000)	Market Capitalization 7/2/2001	Market Capitalization 12/6/2002	Change
AEP	AEP	$ 44.43	$ 26.55	-40%	338.83	$ 15,054	$ 8,996	$ (6,058)
AES	AES	$ 43.78	$ 2.59	-94%	543.80	$ 23,808	$ 1,408	$ (22,399)
Allegheny	AYE	$ 46.66	$ 6.30	-86%	125.69	$ 5,865	$ 792	$ (5,073)
Aquila	ILA	$ 29.09	$ 1.91	-93%	181.62	$ 5,283	$ 347	$ (4,936)
Calpine	CPN	$ 37.39	$ 3.49	-91%	378.00	$ 14,133	$ 1,319	$ (12,814)
CMS	CMS	$ 26.08	$ 8.70	-67%	133.47	$ 3,481	$ 1,161	$ (2,320)
Dominion	D	$ 65.20	$ 50.23	-23%	307.22	$ 20,031	$ 15,432	$ (4,599)
Duke	DUK	$ 38.01	$ 19.67	-48%	891.59	$ 33,889	$ 17,538	$ (16,352)
Dynegy	DYN	$ 44.80	$ 1.05	-98%	369.32	$ 16,546	$ 388	$ (16,158)
El Paso	EP	$ 50.01	$ 6.80	-86%	598.97	$ 29,954	$ 4,073	$ (25,881)
Mirant	MIR	$ 33.44	$ 1.75	-95%	402.92	$ 13,474	$ 705	$ (12,769)
Reliant	RRI	$ 24.60	$ 2.28	-91%	290.44	$ 7,145	$ 662	$ (6,483)
TXU	TXU	$ 47.21	$ 14.79	-69%	278.14	$ 13,131	$ 4,114	$ (9,017)
Williams	WMB	$ 31.50	$ 2.37	-92%	516.67	$ 16,275	$ 1,225	$ (15,051)
Xcel	XEL	$ 26.71	$ 10.30	-61%	398.71	$ 10,650	$ 4,107	$ (6,543)
			Average	-76%	Total	$ 228,718	$ 62,266	$ (166,453)

*Closing price as of July 1, 2001

The credit ratings of many merchant companies and traders are below investment grade, making access to the public capital markets either impossible or prohibitively costly. In addition to the decline in equity valuations, the debt ratings of most of these market players have dropped precipitously (See Exhibit 17). AYE, DYN, MIR, NRG, RRI, and WMB all dropped to junk status since April. As noted in the discussion regarding the on-going credit crisis, merchants have endured sequential downgrades during the past year that have made it difficult to not only refinance existing debt, but also to secure additional financing to fund on-going development projects. The cost of senior debt to some developers now exceeds 20% if it can be obtained at all.

Exhibit 17

Change in S&P Credit Ratings: April 2002 - October 2002



Capital Markets Pullback

It is clear from a review of the financial press and conversations with bankers to the energy industry, that access to capital has essentially been shut off to developers of merchant projects and trading firms. So severe is the lack of capital and so dramatic is the loss of credit ratings, that bankruptcy and near bankruptcy is a common condition among both subsidiary merchants/trading firms and their parent companies.

Many of the companies involved in the merchant sector space founded their business plans on continued access to capital. During the late 1990s and on into 2001, much of the growth that was seen in the merchant sector was built on the capital of choice – low cost debt. The ready access to debt made the execution of growth plans that much easier. Coupled with this ready access to capital was the positive treatment that these plans received from both credit rating agencies and the investment community. The problem with this one-dimensional view was the need for supportive market fundamentals that came in the form of high market prices for electricity, liquid wholesale markets, and a continuing supply deficit. Over the past two years, these conditions, while once prominent attributes of the wholesale market creating enormous profits for some and large cost burdens for others, were temporary and premised on a cyclical confluence of variables. The absence of these supportive market fundamentals has thrust the majority of pure-play merchants into a chaotic state. Merchants must now focus on strengthening their balance sheets, refinancing outstanding debt positions, and persuading Wall Street as well as the rating agencies that they have a viable business model going forward and that they are focused on profitability. They are also working to improve their credit ratings by improving financial disclosure and working with the bank lending and financial markets to restore confidence.

Pressure to Sell Assets

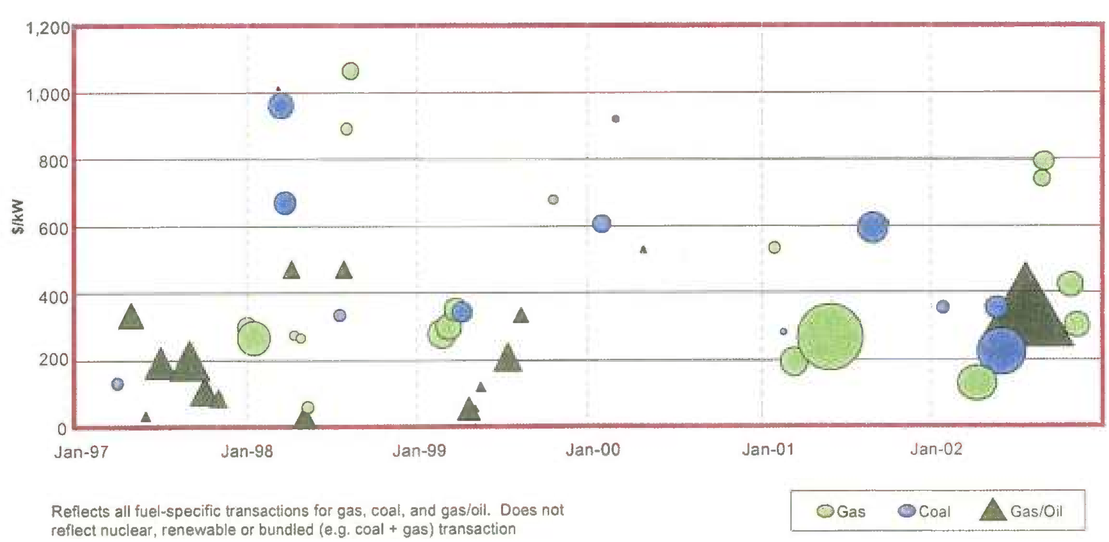
Since access to the capital market has been restricted and the commercial banking community has severely curtailed bank credit support, asset sales and development project cancellations have been forced upon such companies in the past few quarters in order to raise cash to stave off liquidity crises; accordingly, there is a glut of assets available around the country; but given the dreadful condition of the capital markets generally and the energy industry in particular, there are few adequately financed buyers for generating assets or the residue business of the trading companies. Some analysts offer the view that foreign buyers with large balance sheets such as Scottish Power, National Grid, Suez, E.ON etc., will seek to acquire more US power assets. In fact, the speculation that these overseas players will come to the U.S. to "bargain hunt" has been running rampant for the past few years. However, no activity has been seen suggesting that even these parties are willing to place their balance sheets and credit ratings at risk to invest in a sector so terribly tarnished. In the near term, some merchants' fates will be determined by the lenders that are assuming asset management responsibilities for merchants going through bankruptcy or that have defaulted on various generation asset related financial obligations.

Also, while many assets are "on the market" even the few potential buyers cannot support values anywhere near the asking price of these sellers – resulting in a dramatic difference in the bid/ask price spreads in the generation asset market. Worse yet, many sellers cannot sell at drastically reduced prices for fear of creating a market transaction value that may cause external accountants to force a further write-down of their remaining impaired portfolio of assets. Further, sellers are reluctant to execute an inefficient tax transaction that creates a capital loss against which they may have no capital gain offset.

Looking at the value of recent transactions, it would appear that they have clearly trended back down toward replacement values (See Exhibit 18). Under such conditions, it may be difficult for merchant sellers to obtain book value for their assets. As mentioned above, however, the sale of any assets below book value may result in a requirement to record the impairment of additional assets. Such discounted sales may effectively put the merchants in a Catch-22 position. Selling an asset would provide much needed capital, but if the asset is sold below book it creates a capital loss and may imply broader asset impairment than owners are presently representing to their accountants and the investment community. Such is the quandary that merchants find themselves in today.

Exhibit 18

Generation Asset Transaction History 1997-2002



Future of the Merchant Sector

In the post merchant era, liquidity in the energy trading model has been assumed by well capitalized entities like commercial banks and strong balance sheet operating companies with strategically situated operating assets in trading, generation, and fuel. Companies are also pulling back from the national merchant model to a more regional or asset management focus. AEP, for example, has stated that it will focus its trading and marketing activities primarily on areas where it has assets. In another case, NRG has indicated that it will return to an "asset management" basis for its business.

Bank of America analysts express a view that the merchant power market will survive, more reliant on traditional two party agreements and re-defined along regional lines and players who have strategically situated assets or "logistical sophistication." They also posit the entry into the power markets of non-traditional participants like commodity trader Cargill, insurance broker AIG, and financial hedge funds like Citadel and D.E. Shaw.[5]

FERC initiatives in the area of Standard Market Design (SMD) and Regional Transmission organizations purport to accelerate FERC's vision of a seamless national wholesale electric market. However, FERC has yet to address in any meaningful way the collapse of the merchant business and financial model or to offer its own views on what business and financial models may ultimately work in the new market places that it envisions. In the Pacific Northwest, numerous public officials and entities are adamantly opposing such initiatives, making their timing, design and ultimate impact on the functionality of electric markets in the Pacific Northwest unknowable at the present time. At least in the intermediate term (3 to 5 years), regulatory experimentation and volatile energy and capital markets will continue to add uncertainty and opacity to the marketplace for power plant construction and power trading. Whatever structure is ultimately put in place it will need to take into account the unique physical attributes of the region – reliance on hydro, the dispersed nature of plant locations relative to loads, and existing transmission constraints – before implementing the final SMD for the Pacific Northwest.

WHOLESALE ENERGY COMMODITY TRADING MARKET

Background

Commodity trading in the electric and gas markets grew rapidly over the past decade as competition in the gas and electric markets began to take root. Growth in electricity trading moved almost in lockstep with the increase in merchant generation development. Merchant developers, in order to take advantage of emerging market opportunities, used a number of different electric commodity trading approaches. Some traded around the physical assets in their portfolio, while others took more speculative positions betting on forecasted market movement. Still others relied on the commodity market to lock in prices for themselves and their customers. Regardless of the approach taken, the commodity markets provided a means of hedging risks and creating liquidity for those in long and short positions in the market. The commodity markets were an integral part of the development of the merchant sector. For fuel, the markets provided a means for the merchants to lock-in their fuel price risk. For electricity output, it provided the

[5] Outlook for the Merchant Energy Sector, Bank of America, September 2002.

means by which the merchants could take advantage of market volatility to capture additional revenue. For some this was (and still is in some cases) their primary source of revenue.

One of the theories behind the competitive wholesale markets has been a belief that market forces would drive development of new generation. Over time it was widely believed that market signals in the form of spark spreads and marginal generation additions would determine when and where additional capacity would be added to the system. The vehicle for providing these market signals has been the commodity trading markets. While by no means perfect, without these markets, we would not have seen the level of growth we have over the past three years across the country with nearly 150,000 MWs of new capacity added to the grid. In light of the slow pace of generation growth that occurred in the 1990s, this influx of development was welcome to those short on firm supplies.

Impact on the Sector

For the merchants, the current economic stagnation and the surplus of generating capacity in the market have been sending bearish signals to the sector. At some point, this trend will reverse itself, but the big question remains "when?" In anticipation of this eventual reversal, some companies with load obligations are moving away from the short-term commodity markets and relying more on bilateral contract arrangements for their supply. Companies on the opposite side, those with capacity and energy for sale, are also pulling back from the commodity trading markets as a means for clearing their resources in the market. Many national energy trading and marketing entities are reducing trading activity in various regions that they have an existing market presence. In some cases, companies have announced plans to retreat to trading around just their core assets, while others have announced that they will exit trading entirely. We have also seen reduced volumes of trading activity across electric and gas commodity trading markets, which has in turn reduced liquidity and price transparency in the market. Several entities recently announced a complete exit from the wholesale non-regulated trading business (e.g., Aquila, Allegheny, and Dynegy).

Counterparty Credit Decline

Along with the implosion of the merchant sector has come a sharp decline in the number of creditworthy counterparties that PSE can transact with in commodity markets. The decline in the sector has made transacting more difficult by not only reducing the number of counterparties, but also eliminating commodity products that PSE has relied on to manage its supply risks. Compared to one year ago, many of PSE's counterparties no longer exhibit investment grade credit. Below is a summary of PSE's counterparties in various categories, and an estimate of the remaining marketer-trader companies.

- Physical Gas- 16 are no longer investment grade out of a group of 44. Approximately 7 of PSE's current gas counterparties are marketers. Three of these are small marketers without assets or large balance sheet
- Physical Power- 24 out of a group of 70 are no longer investment grade. There are approximately 7 power marketers remaining in this group.
- Financial derivatives- Of the 8 counterparties, three no longer meet investment grade criteria.[6]

[6] Source: PSE Integrated Credit Report

Only a few firms have newly entered the marketplace. The scope and scale of trading activity is hard to predict at this time, particularly with respect to their trading in the Pacific Northwest, as it is a relatively small and illiquid region.
The most notable include:

- Bank of America has received FERC approval to trade in physical power markets and now awaits OCC approval.
- Louis Dreyfus Energy LLC has received permission from FERC to commence trading physical power, capacity and ancillary services.
- J Aron announced the opening of a physical power-trading desk in September 2002.
- A private hedge fund based in Chicago, Citadel, has recently hired a few senior people from Aquila, and the chief research person at Enron, with an eye toward investing in the energy sector.

DISTRESSED ASSETS

In spite of the financial duress that the merchant sector is currently under, some projects are still moving forward with development. Some facilities have quietly been put on hold and have not been officially tabled or cancelled, while others are still progressing with the permitting and facility development processes. As part of its overall least cost resource planning efforts, PSE is gathering information about a variety of supply alternatives, one of which is the acquisition of a physical unit operating or under development by a merchant. It remains unclear at this point if this is the least cost alternative, but it seemed appropriate to PSE to collect information about asset acquisition options in order to give this alternative earnest and timely consideration.

Exhibit 19 is an alphabetical list of all the merchant projects, which are being developed in the State of Washington over the next several years, as identified by RDI. Assuming all of these projects moved forward, it would provide an additional 9,800 MWs in-state. As we have seen over the past year, the pace of development project tabling and cancellation has continued, so PSE fully expects that additional projects on this list will fall by the wayside over the next 12 to 24 months. It is important to note that this project list neither represents facilities that are of interest to PSE nor all the facilities from which it has collected information. It represents an inventory of projects around the state that are in various stages of development. With respect to asset acquisitions PSE is evaluating both in-state and out-of-state alternatives as well as investigating possible Purchased Power Agreements ("PPA").

In addition to the development projects, there are a number of facilities that have come on-line in the past 24 months that are also worth noting. Since June 2000, over 900 MWs of additional capacity has become operational in the State of Washington (See Exhibit 20). The majority of this capacity is gas-fired combined cycle, although it consists of just two facilities, both 248 MW each. The largest number of facilities are the gas combustion turbines which will likely be used by their owners for peaking purposes.

Exhibit 19

Facilities in Washington Under Development

Project Name	Company	Facility Type	Project Size (MWs)	Status
BP Cherry Point Refinery	BP Cherry Point Refinery	CC/Cogen	750	Early Develop
Chehalis Power Station	Tractebel Power, Inc.	Comb Cycle	520	Under Constr
Darrington	National Energy Systems Co. (NESCO)	Boiler/Cogen	15	Proposed
Everett Delta Power Project	FPL Energy, Inc.	Comb Cycle	248	Advan Develop
Frederickson (USGECO)	PG&E Generating Co.	Combust Turb	100	Advan Develop
Frederickson (Tahoma)	Tahoma Energy	Comb Cycle	270	Early Develop
Frederickson Power	Frederickson Power	Comb Cycle	290	Proposed
Goldendale	Calpine Corp.	Comb Cycle	248	Under Constr
Goldendale Smelter	Westward Energy Llc	Comb Cycle	300	Early Develop
Horse Heavan	Washington Winds Inc.	Wind	150	Early Develop
King County Fuel Cell Plant	Fuel Cell Energy Inc	Other	1	Proposed
Klickitat	Columbia Wind Power	Waste	80	Proposed
Moses Lake	National Energy Systems Co. (NESCO)	CC/Cogen	306	Proposed
Nine Canyon Wind Project	Energy Northwest	Wind	50	Under Constr
Plymouth Energy LLC	Plymouth Energy Llc	Combust Turb	306	Early Develop
Rainier	National Energy Systems Co. (NESCO)	Comb Cycle	306	Proposed
Richland (COMPOW)	Composite Power Corp.	Combust Turb	2500	Early Develop
Roosevelt (SEENGR)	SeaWest Energy Group, Inc.	Wind	150	Proposed
Roosevelt Landfill	PUD No. 1 of Klickitat County	Intern Combust	13	Proposed
Satsop Combined Cycle	Duke Energy North America	Comb Cycle	530	Early Develop
Satsop Combined Cycle	Duke Energy North America	Duct Firing	120	Early Develop
Six Prong	SeaWest Energy Group, Inc.	Wind	150	Proposed
Sumas Energy 2, Inc.	Sumas Energy 2, Inc.	Comb Cycle	530	Early Develop
Sumas Energy 2, Inc.	Sumas Energy 2, Inc.	Duct Firing	130	Early Develop
Sumner (PG&E)	PG&E Dispersed Generating Co., Llc	Combust Turb	87	Advan Develop
Tacoma (Mscg)	Morgan Stanley Capital Group, Inc.	Combust Turb	324	Early Develop
Waitsburg	SeaWest Energy Group, Inc.	Wind	50	Proposed
Wallula	Newport Northwest	Comb Cycle	1000	Early Develop
Wallula	Newport Northwest	Duct Firing	300	Early Develop
Washington (Elcap)	El Cap I	Combust Turb	10	Proposed

Exhibit 20

Recently Operational Facilities in Washington

Project Name	Company	Facility Type	Project Size (MWs)	On-line Date
Bellingham Division	Georgia Pacific Corp.	Intern Combust	40	3/1/2001
Boulder Park	Avista Corp	Intern Combust	24.6	5/31/2002
Centralia (TRAENE)	TransAlta Energy Corp.	Comb Cycle	248	8/12/2002
Columbia Peaking Facility	Columbia River Peoples Utility District	Combust Turb	77	7/15/2001
Finley	Benton Public Utilities District	Combust Turb	27	12/21/2001
Frederickson Power	EPCOR	Comb Cycle	248	8/19/2002
Fredonia (PSPL)	Puget Sound Energy, Inc.	Combust Turb	100	7/1/2001
Fredrickson	Pierce Power Llc	Combust Turb	150	9/30/2001
Pasco (Franklin)	PUD No. 1 of Franklin County	Combust Turb	22	12/31/2001
Roosevelt Landfill	PUD No. 1 of Klickitat County	Intern Combust	2.1	6/1/2000

BUY VS. BUILD

When a utility determines it needs new resources one of the fundamental issues it faces is a choice between building/owning its own generating plant, or buying power from another utility or other provider. The choices have changed somewhat during the past year such that the options available during the past year are not the same as the choices available at the end of 2002. The discussion below focuses on the choices that the Company faces today.

Build and Plant Ownership

When a vertically integrated utility requires more energy, the historical supply-side solution has been to build a new generating plant, which would typically be fueled by natural gas, coal, or fuel oil. For PSE to build a new plant, numerous issues must be considered and included in a cost effectiveness analysis including: size, location and zoning of the site; access to fuel, water and sewer; and interconnection to the existing transmission and distribution systems. A review of the zoning can eliminate many potential sites before any financial analysis is performed. When one considers sites that are away population centers, analysis will often show higher costs associated with extending the infrastructure (e.g. water, sewer, gas system, etc.) In general, there are no perfect sites sitting idle and waiting for a plant to be built. Each site has unique costs that require appropriate engineering studies and cost estimates before a selection can be made.

PSE at this time also has non-traditional ownership choices because of developments in the merchant energy market as described earlier. PSE may make an equity investment in an existing plant, or a partially completed plant. An advantage of this strategy is that zoning and permitting issues have been resolved, saving a year or more vis-a-vis a "greenfield" site project. There are numerous financial and operational details that need to be agreed upon when one plant has more than one owner. Cost effectiveness analyses will determine the competitiveness of each these options.

Buy

There are two choices when considering the "buy" option today: the purchase of a market product; or a tolling arrangement whereby PSE would pay for the right to use an existing resource and provide its own fuel.

The opportunities to make a long-term power purchase agreement have changed considerably with the collapse of the energy market. Many entities that PSE would have considered have either left the energy marketing business or have low credit ratings such that PSE cannot do business with them. Today, a preferred contract would be with a company that owns generating assets to ensure their capability to deliver the energy.

A tolling arrangement is usually linked to a specific power plant. The owner of the resource may have excess capacity and would look to recover fixed and variable costs in a capacity payment through the "rental" of the project. The purchaser of the tolling agreement has control over the resource, and is also responsible for the purchase and delivery of fuel.

Financial Considerations of Buy vs. Build

As discussed in the section below entitled, "PSE's Financial Condition and Policy," payments under long-term purchased power agreements are viewed by both S&P and Moody's as financial obligations, resulting in debt imputed on these obligations when those agencies assess creditworthiness. This means that, in practice, when such long-term power purchase obligation are made, utilities need to maintain sufficient equity capital to achieve adequate capitalization ratios when this imputed debt is taken into account. Therefore, an additional cost to long-term purchased power agreements is the incremental cost of the additional equity that would need to be issued to offset the impacts of this imputed debt on the Company's capitalization ratios. The Company's analysis of specific resource will reflect this cost when such purchased power resource options are considered.

Credit rating agencies view payments on long-term purchase power agreements (PPA) as financial obligations and impute debt related to these payments. The typical methodology for determining the debt related to a PPA is to discount the capacity (fixed) portion of the payments using a 10% discount rate and a half-year convention. When the PPA does not specify a capacity payment, 50% of the total payment is used. This present value amount is then multiplied by a risk factor to determine the imputed debt. S&P has published a range of risk factors used in their calculations of imputed debt. The S&P range is from 10% to 50% for take-and-pay contracts and from 40% to 80% from take-or-pay contracts. In 2002, Standard and Poors assigned risk factors of 15% and 40% to PSE's take-and-pay and take-or-pay contracts, respectively.

Once the debt related to a purchased power agreement has been imputed, the cost of the PPA must include the incremental cost of the equity needed to balance the imputed debt at the desired capital structure. For example, if the imputed debt is $50 million and a capital structure of 55%/45% debt/equity is targeted, the PPA must include the annual cost of an additional $41 million in equity.

PSE'S FINANCIAL CONDITION AND POLICY

PSE has defined in this Least Cost Plan a need for energy and capacity of approximately 456 MW in its most deficient month (December) of 2003. Such need grows to an estimated 1,563 Megawatts by 2013. The following table identifies a range of the implied capital required to meet this need and the magnitude of this investment relative to the capitalization of both PSE and Puget Energy Inc (PEI). This range was developed assuming a capital cost per kW that starts at $620/kW for combined cycle gas fired projects, and rises to $1,400/kW for coal fired projects (2002$).[7]

[7] Source: NWPPC

Exhibit 21

	CCGT	Coal
Capital per kw	$620	$1,400
Total Capacity Acquired	456 MW	456 MW
Total Capital Investment Required	$283 million	$638 million
% of Book Equity PSE (PEI) (1) (2)	22.1% (20.5%)	49.7% (46.3)
% of Total Book Capitalization PSE (PEI) (1)	7.6% (7.2%)	17.1% (16.2%)

(1) Based on September 30, 2002 10Q report
(2) Excluding amounts associated with preferred shares

To meet this 456MW resource need, PSE would need to spend between $283 million and $638 million depending on the technology used if the plant were owned by PSE, see discussion above for implications of a purchased power contract. This represents approximately 22% to almost 50% of current book equity of the regulated utility.

For most of the last decade, the Company has not generated sufficient cash flow from operations to cover its both its capital expenditure requirements and its cash dividends. It obtained funds for those purposes by selling more debt and increasing the financial leverage on the Company. Debt as a percent of total capitalization increased from about 50% at the end of 1992 to about 60% at the end of 2001. The Company in February 2002 reduced its annual cash dividend to $1.00 per share from $1.84 per share thus reducing the net cash outflow from the business and retaining more primary capital to rebuild the balance sheet. It also applied for and was granted modest increases in its base electric and gas rates in mid-2002 that will improve the generation of cash from operations. In November 2002, the Company issued 5.75 million shares of common stock and raised net cash proceeds of $115 million. The proceeds of such sale were used to pay down debt and provide working capital and further improve the Company's common equity ratio. A regulated company's common equity ratio is an indirect indicator of its ability to generate cash flow from operations to cover the interest due on its debt; i.e. the times interest coverage ratio is looked to by rating agencies and debt investors alike as a key indicator of creditworthiness.

For example, Standard & Poor's (S&P), a prominent credit rating agency, publishes financial benchmarks used to rate credit worthiness. A company's earnings base, rate of return, and its capital structure are the key determinants of its ability to generate cash coverage of its required interest payments and other fixed charges.

With respect to purchased power agreements (PPA), the credit rating agencies treat a portion of the costs associated with PPAs as an alternative form of debt. This alternative or "imputed" debt is included by the agencies when assessing capitalization ratios and the interest on this imputed debt is included when assessing coverage ratios. As a result, PPAs create the need for additional equity in the capital structure to offset this imputed debt and the cost of a PPA must include the cost of this additional equity. The Company is very sensitive to taking actions that adversely affect its creditworthiness.

Given its obligation to serve, the many great uncertainties surrounding federal and state policy toward the merchant energy marketplace and the upsets in the capital markets, it is the Company's financial policy to increase its common equity ratio and improve its credit ratings.

UNCERTAINTY OF FEDERAL POLICY ON TRANSMISSION INFRASTRUCTURE

PSE's transmission system, along with the regional high voltage transmission system, is undergoing fundamental restructuring mandated in large part by the Federal Energy Regulatory Commission (FERC).

In May 1996, FERC issued Orders 888 and 889 that required all public utilities, including PSE, to file open access transmission tariffs that would make utilities' electric transmission systems available to wholesale sellers and buyers on a nondiscriminatory basis. PSE complied with Order No. 888 and gained FERC approval of its open access transmission tariff.

On December 20, 1999, FERC issued Order 2000 to encourage transmission-owning utilities, such as PSE, to turn operational control of their high voltage power lines over to independent entities called Regional Transmission Organizations (RTOs), while still maintaining ownership of their power-grid assets and receiving revenues from their use. In addition to FERC's stated goals to promote efficiency in wholesale electricity markets and to reduce electricity prices, FERC expressly intended RTOS to eliminate utilities' ability to use operational control of transmission facilities to gain a competitive advantage over other power providers. This regulation required each public utility that owns, operates or controls facilities for the transmission of electric energy in interstate commerce to file with FERC by October 15, 2000 plans for forming and participating in an RTO.

Pursuant to Order 2000, PSE is participating with nine other utilities in the Pacific Northwest in the possible formation of RTO West, a non-profit organization. The filing utilities, which include BPA, have made several filings as RTO West has developed and have received limited approval from the FERC of its initial plans. The filing utilities anticipate many more months of discussion before a more fully developed proposal for RTO West will be filed at FERC for approval. Thereafter, the respective company boards would have to decide to proceed and ask state commissions, such as the WUTC, for requisite approvals. Depending on regional support, RTO West could be operational in early 2006 at the earliest.

On July 31, 2002, the FERC issued a Notice of Proposed Rulemaking proposing a Standard Market Design (SMD) that would significantly alter the markets for wholesale electricity and transmission and ancillary services in the United States. The new SMD would establish a generation adequacy requirement for "load-serving entities" and a standard platform for the sale of electricity and transmission services. Under the new SMD, Independent Transmission Providers would administer spot markets for wholesale power, and ancillary services and transmission congestion rights.Electric utilities, including PSE, would be required to transfer control over transmission facilities to the applicable Independent Transmission Provider. Public meetings were held during the fourth quarter of 2002 and the comment period for certain issues has been extended to January 10, 2003 with the final SMD expected to be issued during the first half of 2003. Once the final SMD is issued, a phased compliance schedule will begin with final implementation expected to take effect by the end of 2004. PSE is currently in the process of determining the impact the proposed SMD would have on its operations as well as how the SMD would impact the RTO West proposal. Once again, PSE recognizes that it is subject to state regulation in Washington. State regulatory agencies, such as the WUTC, are actively involved in the SMD rulemaking process.

This same uncertainty about transmission markets, rates and operations, in addition to the recent volatility in wholesale power markets in the West, has severely limited investment in the region's transmission system. Limited regional transmission system investment has exacerbated congestion problems that affect how PSE satisfies its electric power requirements.

As a consequence of this changing regulatory environment, the terms, costs, and rates of PSE's continued use of its own transmission system, as well as that of BPA and other regional utilities, is uncertain at this time, making some aspects of planning for obtaining and transmitting power for PSE's load obligations more difficult than in the past. For purposes of this Least Cost Plan, however, PSE has assumed that it will be entitled to maintain its use of its transmission system (and that of other utilities) in about the same manner as it currently does, recognizing that at some point the actual entity operating its transmission system may be an independent transmission operator. This assumption is grounded in a current understanding of the pricing, planning, and operational structure currently set forth in the RTO West proposal. PSE recognizes that there is no certainty in how transmission service will be regulated, how much it will cost, and how it will be operated.

Chapter 2 – Appendix

The Financial Situation of Power Companies

As of October 2002, S&P reported that credit pressures are persisting for electric and gas utility companies:

- During Q1 and Q2 of 2002, 78 individual company downgrades were made and just 6 upgrades
- 57 downgrades occurred among holding companies and their operating subsidiaries since July 2002 and just 8 upgrades were issued (3 of which are related to Northern Natural Gas Co.)
- During the same period in 2001, there were 9 downgrades and 5 upgrades
- 49% of the industry now falls in the BBB category
- 11% of the industry is rated below investment grade, with 5 D rated companies (these figures were 40% and 5%, respectively in 2001)
- Only 40% of the industry carries an A rating or above (55% one year earlier)
- Downgrades for the three quarters totaled 135 with just 14 upgrades

S&P reported that energy companies have $90 billion in Medium-Term debt that must be refinanced between 2003 and 2006

The reasons for financial turmoil in the sector are many, and often company specific, but some widely held reasons include:

- Surplus generating capacity is some regions brought about by delayed plant retirements, easy credit and aggressive capacity additions
- Overall weakened financial profile
- Recession and lower than predicted demand for power
- Moderately high gas prices combined with weak electric prices to create a "low spark spread" environment
- Unproved merchant business models and loss of investor confidence
- Excessive use of debt and complex financial structures for merchant companies

In an August 2002 publication, S&P states that there are specific signs that they recommend investors look for before coming to the conclusion that the merchant company is possibly making a turnaround:

- Asset Sales,
- Cancellation or delay of construction plans,
- Winding down or eliminating certain lines of businesses,
- Capital restructuring,
- Debt repayment, and Equity issuance.[8]

[8] Source: Is Time Running Out For U.S. Energy Merchant Companies? S&P, Part 1, August 29, 2002

Load Forecasting

Chapter 3

LOAD FORECASTING

This section describes the methods and results of PSE's billed sales forecast, which is primarily driven by macroeconomic assumptions affecting customer growth and energy usage. Also included is a description of the updates to the billed sales forecasting methodology adopted since the Company's last Least Cost Plan filing. This billed sales forecast is used for financial planning and as the basis for estimating loads. Resource planning, however, requires a more detailed time resolution than the monthly billed sales forecast provides. Thus, the Company prepares a load forecast (as opposed to billed sales forecast) for supply planning and portfolio management. This chapter includes an explanation of the load forecasting procedure along with an explanation of the tie between the billed sales and load forecast.

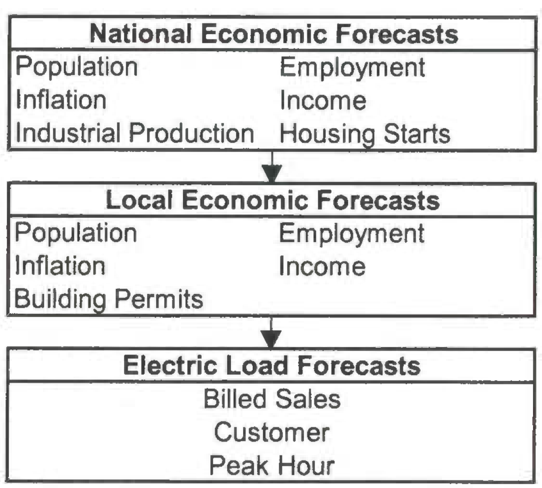
CUSTOMER, SALES, AND PEAK DEMAND FORECAST

Introduction

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

Forecast Methodology

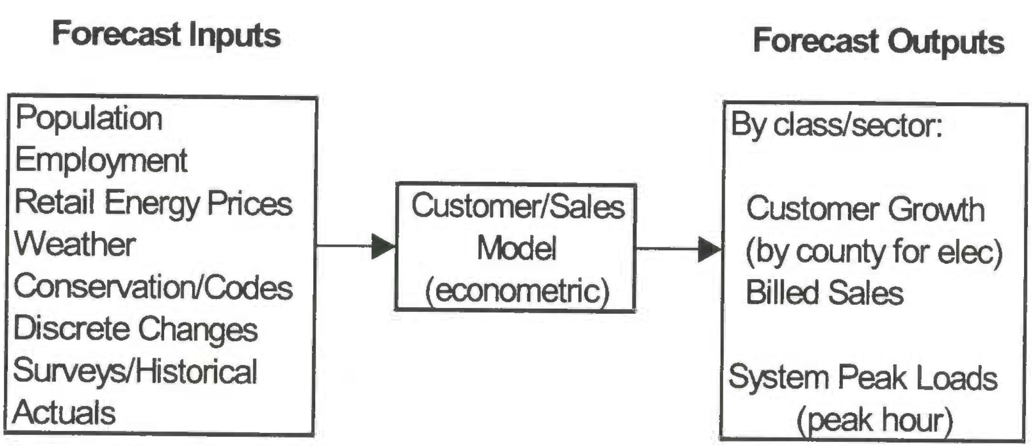
<u>Billed Sales and Customer Counts Forecasts</u> - The forecasting process is designed to provide monthly forecasts of customers and billed sales at the customer class and service territory levels. The five customer classes for electric are residential, commercial, industrial, streetlights and resale. The service territory covers the nine counties in the state (Whatcom, Skagit, Island, King, Kittitas, Pierce, Thurston, Kitsap and Jefferson) accounting for about two-thirds of the state's



population. The basic premise behind the electric forecasting model is that electricity is an input into the production of various outputs. In the case of the residential sector, the output is "home comfort" which includes the different end uses such as space and water heating, lighting, cooking, refrigeration, dish washing, laundry washing and various other plug loads. In the case of the non-residential sector, these outputs are HVAC, lighting, computers, and other production processes. Thus, the demand for electricity is dependent upon the economic and demographic conditions both locally and at the national level. Below is a general overview of the forecasting model.

In the previous least cost plan, PSE has used a mixed end-use and econometric models to develop the long term billed sales forecasts. Specifically, sales forecasts from the residential and commercial sectors were developed by using end-use models (RHEDMS and CEDMS, respectively) while those in the industrial sector were developed by an econometric model at the two-digit SIC level. A new approach was implemented in developing this year's billed sales forecasts for the least cost plan. An econometric approach is used to develop the relationship between electricity demand and the economic and demographic factors at the customer class level for several reasons. First, the end use models required end use surveys which are very costly to implement, hence, were not done in several years. Second, it was found that many SIC codes were either outdated or missing when the billing system was replaced, so distinguishing between single-family vs. multi-family customers or by standard industrial classification codes would have produced inaccurate results. Third, large industrial and commercial electric customers moved to transportation or "retail wheeling" schedules and left only a small amount of industrial sector that would have made it difficult to model at the two-digit SIC level.

Other factors affect the use of energy as well. Below is a more detailed diagram of the forecasting model as estimated in the econometric model.



The estimated equations have the following forms:

Use per Customer by Class = f (Weather, Prices, Economic/Demographic Variables)
Customer Count by Class = f (Economic/Demographic Variables)
where: Use per Customer - monthly billed sales/customers
Weather - cycle adjusted HDDs (base 60,45,35) and CDDs (base 75)
Prices - $/kwh (constant 2000$)
Econ/Demo Variables - Income, Household Size, Population, Employment Levels/Growth,
Building Permits
(variables entered depend on class and whether it is use/customer or customer counts equation and by class)
Peak Hour Load (System) = f(Peak Temperature, Weather Sensitive Load, Peak Temperature*SeasonDummy, El Nino Dummy)

Different functional forms were used depending on the customer class. For residential use per customer equation, a semi-log form is used with the explanatory variables (prices and demographic variables) entering in polynomial distributed lagged form. The length of the lag depends on the customer class equation with residential having the longest lags. A double log form is used for the other sectors, again with explanatory variables entering in a lagged form. The reason for using lagged explanatory variables in the equations is that changes in prices or economic variables have both short term and long term effects on energy consumption.

The equations were estimated using historical data from January 1993 to March 2002 for residential, commercial, streetlights and resale sectors. Billed sales from the data centers in the commercial sector were not included in the commercial equations. The forecast of billed sales from the data center is based on discussions with the customers and their planned capacity additions in the next few years. The industrial equations were estimated using data from January 1996 to March 2002. Note that the industrial use per customer and customer counts equations pertain only to industrial customers which did not go to Schedule 449 or 459 (transportation or "retail wheeling" schedules). It was only possible to go back to January 1996 to isolate the billed sales of these customers from the total industrial billed sales. However, a separate equation is used to forecast billed sales for the non-core Schedule 449/459 customers using manufacturing employment and Mid-Columbia prices as explanatory variables. The forecast for resale also accounted for the Seatac airport leaving the system.

Based on the estimated coefficients for the retail prices in the use per customer equations, below are the computed long-term price elasticities for the major customer classes:
Residential = -0.19
Commercial = -0.21
Industrial = -0.17
All of the estimated price coefficients are statistically significant also.

Customer forecasts by county is also generated by estimating an equation relating customer counts by class/county and population or employment levels in that county. The adding up restriction is then imposed so that the sum of forecasted customers across all counties is equal to the total service area customer counts forecast. This projection is an input into the distribution planning process.

Billed sales forecast is further adjusted for discrete additions and deletions that are not accounted for in the forecast equations. These adjustments include the company's forecast of new programmatic conservation savings for each customer class, known large additions/deletions or fuel switching, and schedule switching. Finally, total system loads are obtained after accounting for own use and losses from transmission and distribution.

Peak Hour Forecast – The normal or expected peak load forecast is obtained using an econometric equation relating observed hourly system peak loads in the month with weather sensitive sales from both residential and non-residential sectors, with deviations from normal peak temperature for the month, and with unique weather irregularities such as El Nino. Because the historical data includes periods when large industrial customers left the system, the equation also account for this change in historical series. Finally, the impact of peak temperature on peak loads is allowed to vary by season. This specification allows for different effects of residential and non-residential loads on peak demand by season. The functional form of the equation is displayed below:

Peak MW = *a**Resid aMW + *b**Non-Resid aMW
+ *c**(Deviation from Normal Peak Temp)*(Weather Sensitive aMW)*SeasonDummy
+ *d**Sched48Dummy + *e**ElNinoDummy

where *a,b,c,d,e* are coefficients to be estimated.

The equation is estimated using monthly data from 1991 to 2001 resulting in coefficients which are statistically significant from zero. The normal peak load forecast is obtained by using the appropriate design temperature into the equation. For Puget Sound Energy, the design temperature is 23 degrees for the normal peak, which occurs in January.

Key Forecast Assumptions

The forecast of electricity use is dependent on inputs into the model. Major inputs into the model are economic activity and fuel prices. Regional economic growth increases employment and the demand for electricity. Economic growth also increases the number of customers by attracting more in-migration. Retail energy prices affect the type of fuel used in appliances, their efficiency and utilization levels. Conservation and other rate programs instituted by the company also affects energy consumption. This section will present the assumptions and forecast of economic and demographic variables and retail prices, conservation savings and other key assumptions 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 national economic outlook is drawn from the DRI-WEFA's Spring 2002 Long Term Trend Projections (25 Year Focus). As the name suggests, the forecast exhibits only mild variations in growth over the next 25 years. After recording its first recession in about 10 years, the national economy is expected to grow at about 2.3% in 2002, after which it is expected to follow its underlying historical growth rate of about 3.2% in the next 20 years. Annual real GDP growth is about 3.1% between 1970 and 2000. The major factor contributing to this result despite declining labor force participation as the percent of population of working age declines is the assumption of higher productivity growth due to efficiencies induced by technology.

United States

	2002	2003	2005	2010	2015	2020	Aarg
GDP(Bils,96$)	9548.2	9909.3	10569.3	12300.0	14450.8	16895.1	3.2%
Employment(mils)	131.7	133.8	138.4	146.4	154.8	161.9	1.2%
Population(mils)	279.1	281.3	285.9	297.7	310.1	322.7	0.8%

Where aarg – average annual rate of growth

Near term, the national economy is expected to recover albeit at a very slow pace. While consumer spending has been propping up the economy, business and state/local government spending are expected to be flat or negative. Federal spending is expected to grow but not enough to offset declines in other sectors. The Federal Reserve Board has recently reduced the federal funds rate by another 50 basis points in an effort to jump start the economy. The uncertainties in the near term consist of potential war with Iraq, whether consumers have enough confidence to continue spending, and whether companies can become really more profitable and overcome accounting anomalies to help turn the stock market around.

Regional Economic Outlook - During the next two decades, employment growth in the electric territory is expected to grow at a slower rate (1.6%) compared to it 30 year historical growth of 3.3% per year. But even at that rate, local employers are expected to create about 580,000 jobs between 2002 and 2020 or more than one third of the jobs we have today. During the same period, the area is expected to add about 730,000 residents raising the population to about 4.1 million. The regional economy is currently experiencing one of its worst recessions in the last 20 years. Employment is expected to decline in 2002 by about 2%. This is in large part due to the 30,000 company wide layoffs at Boeing, and layoffs in the high technology and telecom sectors. Near term, employment is expected to grow only modestly by about 1% in 2003 before jumping by about 4% in 2004. The decline in employment in 2002 is such that the region is not expected to reach the peak employment level reached in 2000 until mid to late 2004. The slower growth in employment in the long term is due in part to the current recession and the assumption that aerospace jobs is not expected to go back to their historical highs in 2000 as Boeing becomes more efficient in its production processes.

Electric Service Area

	2002	2003	2005	2010	2015	2020	Aarg
Employment(thous)	1695.5	1718.6	1795.9	1972.9	2124.2	2277.2	1.6%
Population(thous)	3351.2	3373.5	3438.7	3659.1	3859.5	4078.9	1.1%

Most of the long term 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.
Retail Energy Prices

PSE's electric demand models require predictions of various retail energy prices. Energy prices affect the choice of fuel for the new appliances, the efficiency levels and the utilization rates of existing and new appliances. The following table shows the forecasts of retail rates for electric and gas for the three major customer classes.

Forecast of Retail Rates (nominal)	2002	2003	2005	2010	2015	2020	Aarg
Residential							
Electric, cents/kwh	6.14	6.18	6.18	7.36	8.36	9.72	2.6%
Natural Gas,cents/therm	85	67	71	74	83	93	.5%
Commercial							
Electric, cents/kwh	6.67	6.66	6.65	7.38	8.38	9.75	2.1%
Natural Gas,cents/therm	80	60	65	65	73	82	.1%
Industrial							
Electric, cents/kwh	6.15	6.13	6.14	6.82	7.74	9.01	2.2%
Natural Gas,cents/therm	75	55	61	63	70	79	.3%

The forecast of electric rates accounts for the 6.5% rate case settlement increase effective July 2002. It also assumes a deferral of the BPA residential exchange credit, implying slightly higher rates near term but lower rates long term. The long term retail rates are based on DRI-WEFA's forecast of electric rates for the state after adjusting DRI-WEFA's rates so that the starting points are similar to PSE's retail rates. Real electricity prices will fall over time, driven by a variety of changes: competitive pressures is expected to bring costs down, additional capacity in supply-short regions, declining coal prices, and efficiency improvements for new generation technologies. Based on DRI-WEFA's model, the Northwest is expected to add more generation but almost all of it is expected to be gas fired facilities, a small amount of coal, and a small amount of wind due to government mandates. As most of the region continue to rely on gas for new generation, the prices are likely to become more similar to the average for the region. The table above shows that electric rates are expected to grow by between 2% and 2.6% in the next 20 years which means that real electric rates are declining given an inflation rate of about 3%.

Gas retail rates forecast accounts for the 5.8% rate case settlement increase effective September 2002. It also accounts for an increase in gas conservation rider in March 2002. Finally, adjustments were made due to lower projections of gas costs and the refund of deferred gas cost in 2003 and 2004. As a result, gas retail rates are projected to decline in 2003 from 2002 levels. From 2003 to 2020, gas rates are expected to increase at about 2% per year, again lower than the long term rate of inflation. Gas retail rates are therefore expected to decline or not change much in real terms.

Conservation Savings

The new forecast accounts for the 15aMW of new savings per year for the next 20 years. This amount is about 0.6% of total billed sales. About 82% of the savings are expected to come from the commercial and industrial sectors. In contrast, only about 5.5aMW of savings was assumed in previous forecasts. The savings were adjusted for measure life and price overlap assumptions.

Other Key Assumptions

1. Data Center Loads – Given the current economic background for high tech industries, loads from data centers are expected to be flat in the future.

2. Lake Youngs Water Treatment Plant – Seattle Water Department's water treatment plant is expected to complete this addition early in 2003 and is expected to add about 2.3aMW by the middle of the year.

3. King County Sewage Treatment Plant – Due to the development of fuel cell as their alternative power source, their consumption is expected to decline by about 8aMW by 2005.

4. Mt. Star Development – This residential development in Kittitas county is expected to add about 150-250 residential customers per year in the next few years.

5. The effects of either real time pricing or time of use pricing were not included in this forecast.

6. The forecast of billed sales is based on normal weather defined as the average weather using the most recent 30 years ending the first quarter of 2002.

Electric Sales and Customer Forecasts

Base Case Electric Billed Sales Forecasts - Puget Sound Energy's electric sales are expected to grow at an average annual rate of 1.4% per year in this forecast, from 2,181 aMWs in 2002 to 2,891 aMWs in 2022 with conservation savings. Without conservation savings, billed sales are expected to grow at about 1.7% per year in the next 20 years. Compared to the historical growth rate of 2.1% per year, the new forecast of sales growth is lower as a result of the ramp up in savings from conservation programs, slower growth in population and employment in the near term, and increasing share of multifamily units in new construction in the service territory which have lower use per customer.

F2002 Sales Forecasts by Class in aMWs							
	2002	2005	2010	2015	2020	2022	aarg
Total - Base w/ Conservation	2,181	2,243	2,390	2,574	2,798	2,891	1.4%
Residential	1,102	1,135	1,230	1,334	1,445	1,493	1.5%
Commercial	903	930	988	1,070	1,177	1,221	1.5%
Industrial	165	166	156	152	154	155	-0.3%
Others	11	13	15	18	21	23	3.9%
Total - Base w/o Conservation	2,182	2,291	2,508	2,713	2,936	3,030	1.7%
Residential	1,102	1,144	1,251	1,354	1,466	1,514	1.6%
Commercial	904	959	1,061	1,158	1,265	1,309	1.9%
Industrial	166	176	181	182	184	184	0.5%
Others	11	13	15	18	21	23	3.9%

The pattern of growth is such that growth until 2010 is slower (about 1.1% per year) compared to the growth beyond 2010 (about 1.6% per year). The primary reason for this result comes from the assumption that most of the conservation measures implemented have an average measure life of 8 to 10 years.

With more than 80% of new conservation savings coming from the non-residential sector, the growth in commercial sales is expected to be about 1.5% per year while industrial sales is expected to decline slightly at about 0.3% per year. Without conservation, commercial and industrial sales are expected to grow by about 1.9% and 0.5% per year, respectively. Historically, commercial sales have grown at slightly more than 2% per year in the last 10 years. Growth in industrial sales is driven by growth in manufacturing employment which is not expected to grow significantly in the next 20 years. As a result, the share of commercial and industrial sales to total sales declines from 49% in 2002 to 47.5% in 2022. Residential billed sales are expected to grow by about 1.5% per year with conservation. Given the declining amount of developable land for single family housing, sales growth in single family homes will slow down but sales growth in multifamily housing units is expected to increase. However, the average residential use per customer is expected to decline with more multifamily units being built and with more conservation programs. Consequently, the share of residential sector in total sales is expected to increase modestly by 1% from about 50.5% in 2002 to 51.5% in 2022.

Base Case Electric Customer Forecasts - Electric customers are expected to grow at an average annual rate of growth of 1.7% per year between 2002 and 2022, or from 958,147 in 2002 to 1,354,784 customers by 2022. This growth rate is slightly lower than the average growth rate of about 1.9% per year in the last five years. Customer growth is slightly lower than the historical average in the next five years then rises slightly to 1.8% per year thereafter, consistent with the pattern of growth in population and employment. The long term projected growth rate of 1.7% 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.

F2002 Customer Counts Forecasts by Class (Year End)

	2002	2005	2010	2015	2020	2022	aarg
Total	958,147	1,006,365	1,100,176	1,199,495	1,308,581	1,354,784	1.7%
Residential	848,405	890,981	972,659	1,060,085	1,155,907	1,196,599	1.7%
Commercial	103,845	109,049	120,475	131,602	143,872	148,920	1.8%
Industrial	3,880	3,946	4,069	4,083	4,129	4,146	0.3%
Others	2,017	2,389	2,973	3,725	4,673	5,119	4.8%

Currently, the residential sector accounts for 88.5% 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. Thus, its share in the total customer base is not expected to change in the next twenty years.

Electric Peak Hour Forecast (Normal or Expected) – The Peak load forecast is also based on the system sales forecast. The annual normal peak load is assumed to occur at 23 degrees, which occurs in January.

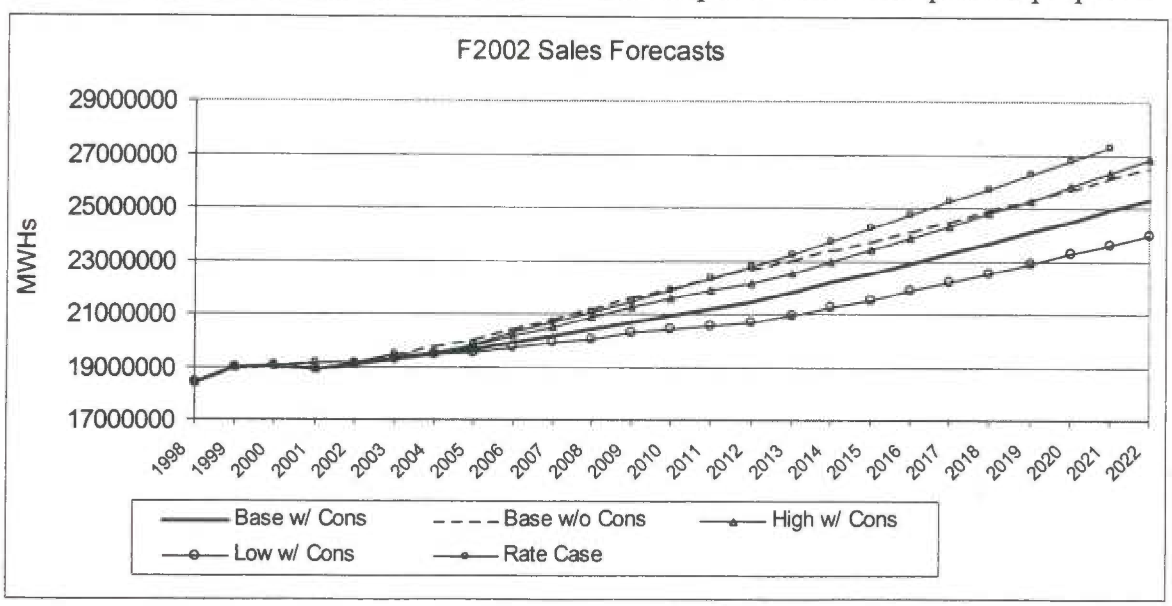
F2002 Peak Forecast in MWs (w/ Conservation)							
	2002	2005	2010	2015	2020	2022	aarg
Normal Peak Load	4,670	4,862	5,251	5,702	6,182	6,384	1.6%

Peak loads are expected to grow by 1.6% per year in the next twenty years. Peak load grows slightly faster than total sales. The peak forecasting model is based on an econometric equation that allows for a different effects of residential versus non-residential energy loads. Since the residential energy load is growing slightly faster than the non-residential energy loads(commercial and industrial), and since residential energy has a larger contribution to peak than non-residential energy, the system peak load grows slightly faster than the system energy loads and more similar to the growth rate in residential sales.

Sales Forecast Scenarios

There are always risks to the forecasts. The base case long term sales forecast assumes that the economy grows smoothly over time and that there are no major shocks or disruptions to the economy. In order to capture the range of economic possibilities in the forecast of billed sales, a high and low sales forecast scenarios are developed in order to capture the upper and lower bandwidths where the forecast of sales is likely to fall with 50% probability. As an example, the high case forecast assumes a GDP growth rate of 3.6% while the low case assumes a 2.6% average growth rate compared to 3.1% in the base case scenario. The high case also assumes a low inflation rate, and vice versa for the low case scenario. The other key assumption is that growth in productivity is higher in the high case compared to the base case scenario.

In actual implementation, the high and low case sales forecasts were developed using 1999 forecasts of base, high and low population and employment variables, the key drivers in the forecast. High to base and low to base ratios were developed and applied to the current base case forecast of population and employment. The forecasting model is then run with the new set of population and employment forecast scenarios. No changes were made in other inputs. Below are a table and a figure comparing the base case forecast with conservation against the high and low case forecasts. The rate case forecast and base case forecast without conservation are also presented for comparison purposes.



F2002 Sales Forecast Scenarios in aMWs							
Scenarios	2002	2005	2010	2015	2020	2022	aarg
Base Case with Conservation	2,181	2,243	2,390	2,574	2,798	2,891	1.4%
High Case with Conservation	2,182	2,260	2,459	2,672	2,945	3,063	1.7%
Low Case with Conservation	2,181	2,233	2,329	2,458	2,659	2,737	1.1%
Base Case - No Conservation	2,182	2,291	2,508	2,713	2,936	3,030	1.7%
F2001 - Rate Case	2,189	2,268	2,497	2,766	3,054		1.8%

Note that the rate case forecast of sales shows the highest forecast because the growth in employment assumed in that forecast is more optimistic in the long run, even though a decline in employment growth is assumed in 2002. The rate case forecast is slightly lower for the next 10 years than the base case forecast without conservation because the rate case forecast still contains the conservation savings from PEM/TOD and existing programs. The high case forecast is even lower than the rate case forecast over the twenty-year period. The high case forecast is about 3% higher while the low case forecast is about 2.6% lower than the base case forecast by 2010.

CONVERSION OF MONTHLY BILLED SALES FORECAST TO LOADS (GPI)

Historically, the Financial Planning department at PSE has produced an annual KWh (and more recently a monthly KWh) forecast of Billed Sales. This Billed Sales forecast needs to be converted into a monthly total Generated, Purchased and Interchanged amount ("GPI") in order to be used in Power Supply related load/resource models.

Summary of Methodology

Monthly GPI is forecast through a system of hourly multivariate regressions utilizing historical temperatures and GPI loads. This method does not convert or allocate Billed Sales forecasts to GPI: it forecasts monthly GPI "from scratch" using real GPI loads. The statistical techniques are similar to the process by which Billed Sales is forecast. To capture conservation and load growth assumptions the GPI forecasts are adjusted to match up with annual forecasted Billed Sales.

Input Data and Assumptions

- An annual Billed Sales forecast for the upcoming calendar year.
- Seven years of historical, hourly actual (i.e. non-temperature normalized) loads.
- Historical hourly Sea-Tac temperatures.
- An assumed annual distribution loss factor.

Validity of Methodology

Stationarity of the GPI load data:

- *Stationarity* ensures that the data generating process for the series is itself not dependent on time.
  - Measurement of the variance of GPI load data reveals no significant change over the sample period. Thus the series is stationary in variance.
  - Although the raw GPI load data clearly exhibits trend in mean over time (customer growth) the data has been de-trended to allow accurate specification through the addition of a linear trend variable (Equation Details).

Alternative methodology - temperature splines:

- It is common to use splines to help identify the separate relations between temperature and load depending on the level of temperature. For the calculation of this model the inclusion of splines was rejected in favour of the quadratic equation form. This was done for two reasons:

1) Temperature splines require arbitrarily chosen temperatures to act as boundaries (e.g. <60 F to 60 F , 61 F to 70 F , >71 F).
With the changing energy demands of our customers (air conditioning load) over recent years the arbitrary selection of spline boundaries and the linearities they impose on the model would serve to reduce its explanatory power vis-à-vis the quadratic specification. This is particularly true with hourly data.

2) To assist with a generalized format across all hourly equations, the quadratic format is superior to the use of temperature splines as the equation is able to self select the appropriate balance point between heating and cooling for every hour of the day.

Equation Details

$aMW_h = \alpha_w + \beta_1(aMW_{h-i}) + \beta_2(\Sigma(aMW_{h-i})/3) + \beta_3((Month_m)Temp_h) + \beta_4((Month_m)Temp_h^2) + \beta_5(Holiday) + \beta_6(Trend)$

where: h=1-24 (hour)
w=1-7 (weekday)
i= 2-4 (lagged hours)
j= 1-12 (months)

Holiday includes all NERC holidays. Trend is a linear function $y=\alpha + x$.

Discussion of Load Forecasts

To determine the amount of power that needs to be generated to supply the forecasted billed sales, the billed sales forecast must be increased to account for transmission and distribution losses (6.4% of generation) and the time lag associated with the billing cycle. For example, assuming a monthly billing cycle, power bills reflect the power consumed and generated in the previous month.

To do this the annual billed sales forecast is first increased to account for the transmission and distribution losses and then shaped or allocated among the 12 months based upon the methodology outlined above. The base, low and high load forecasts are shown in table below.

PSE Load Forecasts (MWh/year)

	Base	Low	High
2003	20,623,609	20,616,264	20,663,433
2004	20,818,940	20,782,992	20,907,983
2005	20,994,755	20,900,232	21,154,277
2006	21,252,369	21,082,274	21,524,529
2007	21,527,009	21,260,599	21,909,439
2008	21,816,085	21,445,549	22,297,612
2009	22,128,117	21,658,193	22,697,310
2010	22,365,522	21,793,254	23,012,717
2011	22,650,883	21,958,722	23,362,312
2012	22,937,946	22,124,724	23,686,149
2013	23,303,207	22,390,372	24,092,860
2014	23,694,736	22,689,911	24,543,722
2015	24,088,851	23,004,458	25,003,781
2016	24,493,362	23,357,857	25,485,107
2017	24,900,901	23,727,627	25,986,039
2018	25,312,603	24,096,313	26,488,900
2019	25,741,711	24,483,757	27,010,223
2020	26,183,871	24,882,072	27,559,282
2021	26,616,016	25,250,955	28,102,829
2022	27,058,693	25,615,816	28,662,113
2023	27,508,734	25,985,949	29,232,527

Peak Capacity Forecast for Resource Planning

The econometric equations discussed above in the load forecasting section are utilized to forecast peak loads (on a GPI basis).

PSE uses the expected peak load for long-term capacity planning. The expected peak load is the maximum hourly load expected to occur when the hourly temperature during the winter months (November through February) is 23° at SeaTac Airport. Based on historical temperature data at SeaTac, there is a 50% probability of the minimum hourly temperature during the winter months being 23° or lower. The maximum expected peak load for the year is expected to occur in January of each year given PSE customer use profiles.

PSE's expected peak loads for the 2003 through 2023 time period are shown below. The peak loads are forecasted to increase over time as the number of customers increase. As discussed earlier, the growth in the peaks (about 1.6%/year) is slightly higher than the growth in energy (about 1.4%/year) since residential energy load is growing faster than non-residential energy loads and the residential sector has a larger contribution to peak.

	Expected Peak Load mw
2003	4,773
2004	4,819
2005	4,862
2006	4,929
2007	5,004
2008	5,089
2009	5,182
2010	5,251
2011	5,336
2012	5,421
2013	5,514
2014	5,608
2015	5,702
2016	5,794
2017	5,888
2018	5,983
2019	6,081
2020	6,182
2021	6,282
2022	6,384
2023	6,490

Conservation and Efficiency

Chapter 4

CONSERVATION AND ENERGY EFFICIENCY

INTRODUCTION

This chapter will discuss PSE's conservation programs, including how the Company arrived at its current commitments regarding conservation efforts and plans for how it will proceed with future conservation analysis. Additionally, this chapter also briefly touches on the Company's experience with price-responsive demand programs under its Time of Use ("TOU") pilot program that was recently concluded. Finally, Chapter 4 also includes a description of all of PSE's current conservation programs.

CURRENT POSITION OF PSE'S CONSERVATION EFFORT

PSE recently increased its commitment to conservation by doubling its annual conservation targets. In August 2002, PSE filed new conservation tariffs with WUTC. About 20 programs were expanded, and another 10 new programs and pilot projects were initiated. The scope and size of programs are a result of a collaborative effort through the Company's Conservation Resource Advisory Committee ("CRAG") that was created in the settlement of the Company's recent general rate case in Docket UE-011570. Under the settlement agreement, during the 16-month period from September 2002 through December 2003, PSE's portfolio of conservation programs and services expect to achieve 20.2 aMW and 2.9 million therms of cost-effective energy savings. At the same time, an additional annual 2.5 aMW electrical savings is targeted, using C&RD Program Funding available through BPA agreements.

This same plan establishes a framework for future conservation programs beyond 2003. Market research is underway to better understand customer preferences, motivations and barriers to conservation. New technologies are under review in cooperation with NEAA and NPPC. Revised conservation supply curves, outlining the amount of cost-effective energy savings achievable in PSE customers' facilities, will be developed by May 2003. An evaluation plan has been prepared. New measures and program proposals will be evaluated using the avoided cost forecast developed through the Least Cost Planning process. The effectiveness of PSE's latest conservation initiatives, market research findings and conservation potential will all be used to develop new program offerings and targets and the best strategies for achieving energy efficiencies going forward.

HISTORICAL CONTEXT

PSE has been offering energy efficiency programs to customers for over 20 years. Utilities throughout the Pacific Northwest have a unique legacy. Despite some of the lowest electricity rates in the country, PSE and others in the region have made some of the most significant investments in conservation programs, encouraging customers to use electricity efficiently. Utility new construction programs run in the late 80's can be attributed to resulting in Washington State's current energy codes, among the country's strongest for encouraging energy efficiency in housing and the commercial building stock. PSE has consistently offered programs targeted to its low-income customers, and over the years has developed a good working partnership with the Community Action Agencies in the communities it serves.

PSE has provided conservation services for its electricity customers since 1980, saving approximately 2,108,995 MWh (cumulative, annual) or 241 aMW (cumulative load reduction) through 2001. These energy savings, over 10% 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 7,482,060 therms (cumulative, annual) through 2001. In terms of investments in energy efficiency, the Company has invested approximately $300 million in electricity conservation since 1989 and approximately $5.9 million for natural gas conservation since 1995. 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.

RECENT HISTORY

During the mid '90s, uncertainty about future deregulation in the electricity industry made it difficult for utilities to invest in demand-side resources at levels previously achieved. Electric and gas avoided costs were significantly lower than they had been up until that time, with the anticipation of falling prices as electricity markets opened up. Most conservation incentives for residential end-uses were no longer cost effective, and residential programs came to rely primarily on information, education and referral services to encourage efficiency. PSE grants and rebates, in addition to information and technical services, continued for the more cost-effective commercial and industrial sector programs. At the same time, Energy Service Companies (ESCOs) were making some in roads in the commercial building sector. These independent contractors could package services and equipment together with favorable financing by using the energy bill savings generated by the project. Of particular note, the Washington State General Administration Office promoted ESCO financing for public facilities, and the State Treasurer's office made very low interest financing available for public projects. The largest industrial customers were pursuing the option to purchase power on the open market in regulatory and legislative forums. A period of uncertainty ensued wherein the future requirements for utilities to acquire resources for some customer classes might be changed through legislative or regulatory actions.

At the same time, improved energy codes were adopted in Washington State, making new construction and major remodels more energy efficient from the "get-go", thus requiring less future investment for retrofits to homes and buildings.

While national interests were promoting deregulation of the electric industry, the governors of the four Pacific Northwest States convened the Comprehensive Review of Northwest Energy System were weighed with business interests, particularly of very large consumers who viewed deregulation as a way to lower energy costs for their "bulk" purchases. An important portion of the Review was the committee that wrestled with "public purpose" issues, including conservation, low-income assistance and renewable resources.

"Market transformation"(MT) emerged from the public purpose recommendations as another potentially cost effective method to get customers to invest in efficiency on their own. By undertaking MT activities now, market prices of efficiency equipment or practices could drop in the future, making them more rapidly attractive for end-use consumers. Northwest Energy

Efficiency Alliance ("Alliance") was created by regional utilities, with PSE as a major funding provider. Notable of the Alliance's recent efforts has been accelerating consumer adoption of compact fluorescent lamps and horizontal-axis washing machines.

The merger of PSPL and WNG, effective 1997, gave PSE the opportunity to offer "fuel-blind" conservation/energy efficiency programs. Instead of being sent to the "other" company, customers could now benefit from a one-stop, comprehensive conservation service. PSE became "indifferent" to whether a customer upgraded efficiency of an electric heating system or converted to natural gas.

Initially, Puget's cost-recovery of cost-effective conservation resources had been added to rate base, and amortized over 10 years. Rates allowed for a premium +2% on the allowed rate of return for all unamortized conservation balances. It become clear that this financing method, creating an outstanding debt, could be an obstacle as the industry faced deregulation. Washington State passed legislation to allow conservation investments to be financed using bonds, and in 1995 PSE became the first utility to issue and obtain favorable financing terms for over $200 Million in conservation bonds. A second bond offering of $35 Million was issued two years later. WNG, by comparison, relied on a "tracker" mechanism; costs spent on conservation were collected as an expense in the year following the year expended. After the merger, PSE retained the "tracker" mechanism for gas conservation and added a similar "rider" mechanism to allow for cost-recovery of electric conservation. The rider recovers costs for conservation in the same year as expended.

In 1999, PSE submitted a three-year, joint electric and gas conservation program. The Commission approved the program effective April 1 of that year. The program was extended beyond March 31, 2002 for an additional period during the course of the General Rate Case. Three-year savings and costs for that program were 31.6 aMW and 5,084,019 therms, for a combined electricity and natural gas cost of $30,484,713.

No one accurately predicted the events and electricity wholesale price escalations of 2000. Price impacts hit the recently de-regulated California market, complete with rolling blackouts. The Pacific Northwest has long had close electricity interties with California, and an "energy crisis" for this region was inevitable. BPA and many of the region's utilities immediately sought to raise rates, and quickly imposed significant rate increases, mostly in the form of surcharges. This included the three large public utilities adjoining PSE's service territory. Rate increases of this magnitude, particularly hitting in the middle of winter (peak load periods for the NW), were packaged with dramatic near-term increases to conservation efforts to help manage utility and customer costs. More broadly, there was a societal need to heavily encourage conservation to help manage energy costs throughout the region, and PSE joined others to ramp up its efforts. One of the most successful efforts was a broadly promoted, time-limited 10% bonus to commercial conservation grants. This effort in conjunction with daily news headlines of the energy situation no doubt aided customer readiness to adopt efficiency measures.

PSE had another tool at its disposal. Having installed new metering throughout the service territory, and with a new billing system in place, the Company worked with the Commission to launch a Time-of-Use pilot program to over 300,000 residential customers. Subsequently, and additional 20,000 business customers were added to the pilot. While the program set out to reward customers who use energy efficiently, the Company determined in fall 2002 that further analyze and restructuring of the program was need to add customer value. The WUTC recently approved PSE's request to terminate the program.

Most recently, PSE filed new conservation programs developed with the CRAG on August 1, 2002. The WUTC approved programs effective September 1, for 16 months.

GOING FORWARD

As part of the Least Cost Plan filing to be made by April 30, 2003, PSE plans include some hypothetical conservation portfolio scenarios. This portfolio analysis will be performed integrated with the same modeling PSE is applying to supply side resources through the screening stages of analysis described in Chapter 8. Because hourly load shapes for many conservation resources will be difficult to obtain, the Company will use load shapes similar to those underlying the avoided costs used to justify the current programs.

PSE has agreed to work closely with the NWPPC in the development of Regional Conservation Supply Curves for the Fifth Regional Power Plan. Development of these estimates is underway. Results are expected throughout the early parts of 2003. PSE plans to use the Power Council's methodology and many of the same conservation measure data inputs, and apply to PSE's customer base and forecasts. This work is anticipated to be completed by May 2003, as discussed at the end of this chapter. As additional conservation supply curve becomes available, PSE will update the Least Cost Plan with the improved information for the August 30, 2003 update filing.

During the spring and summer of 2003, PSE anticipates using best available information, conservation supply curves, and program experience to work with the Conservation Resources Advisory Group (CRAG) in the development of conservation targets for 2004 and beyond.

THE TIME-OF-USE PILOT, AN EXAMPLE OF A PRICE-RESPONSIVE DEMAND PROGRAM

The Time-of-Use rate program began in May of 2001 for approximately 300,000 residential customers. At the time, the West Coast energy crisis was still in effect, and, under this program, customers were provided financial incentives to shift their electric consumption to off-peak times of the day in an effort to reduce energy supply costs as well as other system costs. The total length of the pilot program for residential customers extended over 15 months. This program included an "opt-off" mechanism whereby customers could choose to exit the program. Over the first year of the pilot program less than one percent of customers chose to voluntarily leave the program; during the last few months of the program about eight percent of customers chose to leave the pilot program. All of the customers on the pilot had been receiving time-of-use consumption information regarding their energy use for nearly six months prior to being placed on time-of-use rates (this was part of PSE's Personal Energy Management information program). During the course of the pilot program a group of tens of thousands of customers continued to receive individualized time-of-use consumption information. This group proved to be a useful sample to compare to the customers on actual time-of-use rates as well as customers on traditional "flat" rates. As a result of the settlement of the Company's recent general rate case, a few changes were made to the program, effective July 1, 2002. These included a slight reduction in the on- and off-peak prices charged to customers and a provision to collect many of the incremental costs of the program from it participants. In the fall of 2002, many of the residential customers were paying slightly more on time-of-use rates than they would have on flat rates.

Quantitative Analysis of Load Impacts by the Brattle Group

A quantitative analysis of energy load shifting between time periods by customers participating in the Time-of-Use rate program has been conducted by the Brattle Group. This analysis covers the months of June 2001 through June 2002. The analysis statistically compares actual consumption under the Time-of-Use rate program with the consumption that would have been used if the program participants continued to be charged the current flat rate and received time-of-use consumption data on an information-only basis.

The Brattle Group's analysis indicate that the results of the load shift analysis indicate that significant shifting behavior occurred throughout the course of the pilot program. On average, Time-of-Use rate customers decreased their usage by about 5.5% in the more expensive morning peak period and decreased their usage by about 5.0% in the more expensive evening peak period. The Time-of-Use rate customers decreased their usage between 2% and 3% during the mid-day period when prices were the same as the flat rate. Energy use increased by about 5.3% during the lowest price period (Economy) in effect at night and all day Sunday (and NERC Holidays). It is estimated that during the wintertime this shifting effect help move over 30 aMW off of PSE'd peak demand. The Brattle Group's analysis confirm that the strong shifting behavior persisted over a period of more than twelve months despite many changes in several exogenous factors during the same time period. The price-elasticity exhibited by PSE's residential customers is consistent with the response of other residential customers on various other time-of-use programs.

The Brattle Group also conducted an analysis of whether or not the Time-of-Use customers consumed less energy than customers who were not on the Time-of-Use rates and customers who had access to time-of-use consumption information. This was termed the "conservation effect" in the Brattle Group study. The Brattle Group's analysis tends to indicate that there was some conservation effect for the customers on Time-of-Use rates. However, there is currently no consensus among external stateholders as to the degree or existence of this "conservation effect." On average, the Brattle Group estimated that Time-of-Use rate customers consistently conserved 1% more electricity than flat-rate customers conserved. While the overall conservation effect for all customers did decrease over the course of the pilot program the Time-of-Use customers appeared to continue to conserve 1% more than customers on flat rates. The analysis indicates, that while there was some variation in the conservation effect across various housing types, the estimated overall effect of a time-of-use rate applied to all of PSE's residential customers appeared to be a 1% effect of more conservation. The Brattle Group's analysis tends to indicate that some conservation behavior persisted over a period of more than twelve months despite many changes in several exogenous factors during the same time period.

Participant Survey and Customer Advisory Panels

The Company conducted a survey of 821 time-of-use rate customers was conducted during the month of July. More than 120 customers responded to PSE's request to serve on customer advisory panels for the Time-of-Use rates and Personal Energy Management programs. Three customer advisory panels held 4 weekly meetings in July and August 2001. There were 16 participants on each panel and each member spent 12 hours studying and debating the program. Recruitment and panel selection practices made every attempt to have a wide-representation of PSE's customer sectors. As a result the panels included seniors, working and stay-at-home customers, as well as disabled, low and fixed income and various education levels.

Current Collaborative Study

Currently the cost-effectiveness of the time-of-use rate program is being studied by a collaborative group. Demand-side programs, including time-of-use rate programs, must demonstrate that they improve resource efficiency and that they must reduce total resource costs. This analysis will use the standard practice methodology. The standard practice methodology was developed in 1983 to evaluate demand-side programs and projects. The methodology looks at costs and benefits from multiple perspectives, thereby answering the question of who benefits and by how much. The test results depend on the interplay between avoided costs, prices and program costs. Currently, the Company and a collaborative group of stakeholders are conducting this analysis of the program using Charles Rivers Associates to model the cost-effectiveness of this program under these standard practice tests. As of December 31, 2002, development of assumptions for this analysis is ongoing.

DESCRIPTION AND STATUS OF CURRENT CONSERVATION PROGRAMS

PSE is currently offering conservation programs under tariffs that are in effect from September 1, 2000 through December 31, 2003. Programs provide for efficiency savings from all customer sectors, and for both electricity and natural gas. The majority of the programs are funded using electric "rider" and natural gas "tracker" funds, collected from all customers. A small portion is funded through arrangements with the Bonneville Power Administration to provide Conservation and Renewable Discount (C&RD) Credits. Based on best current estimates of costs and savings projections, these conservation programs provide a cost-effective resource.

1. Energy Efficiency Information Services

The program consists of four components:

A. Personal/Business Energy Profile
The Personal/Business Energy Profile is a free energy audit survey, analysis, and report that provides customers with specific and customized energy efficiency recommendations. 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.

Marketing highlights to date: The Personal Energy Profile and Business Energy Profile are routinely promoted in bill inserts, and in customer subscriber editions of the residential e-newsletter and Business e-newsletter.

Recent notes: The Personal Energy Profile was recently added in an "online" format. PSE customers can now complete the analysis online, and receive a report "instantly". The paper format is still available.

B. Personal Energy Advisors
Specially trained and dedicated phone representatives provide customers of all sectors direct access to PSE's array of energy efficiency services and programs through a toll-free number. Personal Energy Advisors discuss with customers, one-on-one, the potential benefits of various conservation programs and related products and services including contractor referrals. Personal Energy Advisors answer approximately 3,000 customer inquires per month, including approximately 150 e-mail messages.

***Marketing highlights to date*:** PSE's Energy Efficiency Hotline serves are regularly featured in bill inserts, on all brochures and written materials, and in most print advertising.

Recent notes: In the past few months, PSE has added the capability for customers to email energy efficiency questions, applications and brochure requests. These are fulfilled on a 24-hour turn-around.

C. Energy Efficiency Brochures

PSE provides brochures and how-to guides on various energy efficiency opportunities, including behavioral measures, low-cost equipment, weatherization measures, major weatherization improvements, and equipment upgrades. This information includes investment and savings estimates where appropriate. These brochures are available to both residential and commercial customers in paper form and online at the PSE Web site.

Marketing highlights to date: New brochures are now available for the several new offerings in the current year's programs.

Recent notes: With the new programs in effect, most brochures are being updated, as appropriate. Commercial brochures were updated as of October 2002.

D. On Line Services

Sections of PSE's web site are dedicated to energy efficiency and energy management for customers that prefer to get information on-line. The site includes an online version of the Personal and Business Energy Profile, tools and download-able brochures. Additional services include periodic e-newsletters, an e-mail box for customer questions, and links from a customer's Personal Energy Management information/graphs to energy efficient tips and ideas.

Marketing highlights to date: One residential e-news and two business e-newsletters have gone out in fall '02. Subscribers are nearly 8,000 for the residential newsletter, and 1,000 for business.

Recent notes: Energy Efficiency Libraries for both residential and for business customers have been added. Energy efficiency pages are being reviewed to add additional programs, rebate forms and information. Navigation and links are to be enhanced.

2. Efficient Natural Gas Water Heater

The Efficient Gas Water Heater Program provides a $25 rebate to partially offset the extra cost of an efficient gas water heater (.60 or higher Energy Factor; 20-100 gallons of storage).

***Marketing highlights to date*:** The program is advertised to customers through the PSE Web site, Personal Energy Advisors, bill inserts, the *Energy Wise* Newsletter, referrals from other PSE Departments, Energy Efficiency Program materials, and a network of contractors, builders, and retailers.

Recent notes: New DOE efficiency standards for gas water heaters have been approved and will go into effect January 2004. These increased efficiency levels (ranging from .51-.59 EF depending on tank size) are still lower than the program threshold of .60 EF. If the water heater rebate program continues in 2004, the .60 EF qualification level might need to be re-evaluated.

In 2002, we will also review the rebate amount in light of the revised gas avoided cost and consider the inclusion of tankless models and condensing water heaters.

3. High Efficiency Gas Furnace

The high efficiency gas furnace program is a rebate program offered to all residential and new construction customers in the PSE service area. Customers receive a $150 rebate when a qualifying furnace is installed.

Marketing highlights to date: To launch this program at the beginning of the heating season, PSE promoted the program heavily. PSE was able to negotiate with dealers to add an additional $150 from the manufacturers, making a total of $300 rebate for customers. A program brochure and rebate form includes benefits and projected energy savings for different furnace efficiencies. It also includes rebate information for related programs, such as efficient water heaters.

Recent notes: Customers who request contractor referrals can receive no obligation bids from participating contractors on PSE's contractor referral program.

4. Residential Energy Efficient Lighting Program

The program offers rebates to residential customers and builders in the PSE electric service area. A portion of the program is funded using CR&D funds.

Retail Incentive Program
Residential customers receive incentives through direct mail or bill inserts. With the rebate, participating retailers and lighting showrooms (approximately 350 retail stores) deduct $3 from the cost of Energy Star CFL's or $10 from the fixture price at the time of purchase.

New Construction/Remodelers
Builders receive rebates on the installation of CF fixtures in new residential applications. PSE works with builders to identify high-use lighting areas in homes that would benefit from the installation of three dedicated CF fixtures.

Cross Promotional/WEB Incentive
CFL rebates will be offered as a customer incentive to participate in other programs such as PSE's online energy-use analysis tools. Customers use the tools to learn about energy efficient products, determine the energy efficiency of their homes, identify how much appliances cost to operate, and evaluate which efficiency solutions to install in their homes. Once customers register and complete an online home analysis or view their energy consumption using the Energy View graph, they can receive the CF rebate through the retail program or purchase a bulb online.

Marketing highlights to date: Rebate coupons have been mailed in customer bills and distributed through the hotline. Advertising has appeared in local newspapers, including Seattle Times. Home Depot elected to run its own advertising, citing PSE's coupons.

Recent notes: Plans include securing additional mailing and advertisement avenues and developing retail programs with partners such as Costco.

5. Energy Efficient Manufactured Housing

This program provides a $150 rebate to the buyers of qualifying NC/ES manufactured homes in the PSE gas service area.

Marketing highlights to date: The promotional focus will be toward the dealer showrooms, manufactured home sales people, and trade and product communications. Work is underway with the Washington Manufactured Housing Association (WMHA) to publicize the program in manufacturer and dealer trade communications, and to make sure program brochures are in the hands of dealers in new manufactured housing communities.

On September 30th, program bulk supplies of brochures/rebate forms along with supporting program information were mailed to 58 dealers selling homes into the PSE gas and electric service areas. Brochures and program information were also mailed to the general managers of 19 home manufacturers whose products are sold to customers within the PSE service area so that they are able to reinforce the availability of the rebate with their dealer networks.

Recent notes**:** A mailing is being prepared to a list of 2700 prospective new manufactured home buyers that have responded to the manufactured home purchase advertising campaign sponsored by the Washington Manufactured Housing Association.

6. LED Traffic Signals

This program provides rebates to public sector customers installing red, green and walk/crossing LED traffic signals. Customers with unmetered accounts must document all connected load at the intersection.

Marketing highlights to date: PSE will continue to partner with the Association of Washington Cities, send direct mailings, and make personal contacts with customers to promote the program. Examples: Energy Advisors perform cross selling of other PSE energy efficiency commercial programs along with LED program. Association of Washington Cities has promoted the LED rebates in their quarterly publication. PSE sent letters to over 70 cities to encourage them to switch to LED signals.

Recent notes: PSE did a presentation on LED traffic signals and the rebates at a recent AWC meeting.

7. Small Business Energy Efficiency Program

The program offers a variety of fixed-incentives that streamline the delivery of energy-saving measures for a variety of small usage commercial businesses and building types. Eligibility is limited to Schedule 24 and Schedule 8 electric customers. Rebates cover efficient incandescent and fluorescent lighting conversions, lighting controls, programmable thermostats, and vending machine controllers.

Marketing highlights to date: A new brochure has been developed to promote lighting rebates. There are enhancements to "Your Business" on PSE's Web site underway. These include new pages with participation guidelines, and new downloadable rebate forms. Customers may also receive contractor referrals to get no-obligation bids.

Recent notes: Review and increases to the dollar amounts on most lighting rebates. Some additional lighting measures have been included and rebates for vending machine controllers have been increased.

8. Commercial and Industrial Retrofit Program – both Electric and Gas

PSE works with C/I customers to review energy consumption at the customer's facility, and to assess cost-effective energy savings opportunities from equipment, building shell, industrial process, or O&M improvements. Where the project meets PSE cost-effectiveness funding criteria, PSE will provide grants toward energy savings projects. Projects must be approved for funding prior to installation/implementation to be eligible.

An additional part of this program will be the development and evaluation of a new small-scale commercial HVAC Premium Service to optimize the efficiency of packaged HVAC units that serve smaller commercial establishments throughout the PSE service territory. Trained mechanical contractors will perform more rigorous testing of equipment and settings to maximize energy efficiency. Customers will enter either a three or five-year Premium Service agreement with their contractor. PSE's incentive will cover 50% of the cost for the first year of the multi-year agreement. This pilot is being conducted by NEEC, the trade association for energy efficiency contractors.

All Electric C/I customers are eligible except Electric Sch. 46, 49, and Sch. 449 Retail Wheeling customers (See Conservation Sch. 258). All Natural Gas C/I customers are eligible excepting those receiving transportation services only.

Marketing highlights to date: In October, PSE hosted 5 trade ally meetings throughout the service territory, involving nearly 450 contractor participants. The purpose was to announce new offerings and funding levels, and encourage contractor support and marketing of the program to eligible PSE customers. Promotion materials are under development in support of the Premium Service Pilot.

Recent notes: Maximum grants for hardware changes will be based on the company's cost-effectiveness criteria. Projects with a simple payback (before applying the grant) of up to 8 years will be eligible for a grant of up to 50 percent of the installed measure cost. Projects with a payback over 8 years before grant will be eligible for grants of up to 70% to a maximum of Full Avoided Cost. Projects with a simple payback of one year will not be eligible for grants. Prescriptive rebates are available to larger C/I accounts for a limited number of items, including selected lighting measures, occupancy sensors, programmable thermostats, and variable-frequency drives. A contract has been signed with NEEC to conduct the Premium Service Pilot. Four mechanical contractors have been recruited to participate; three have completed contractor training. Contractors are currently undergoing in field work reviews on their initial set of three projects.

9. Commercial and Industrial New Construction Efficiency - both Electric and Gas

PSE works with designers and developers of new C/I facilities, or major remodels, to propose cost-effective energy efficient upgrades for EMS programming and building equipment, including Energy Star transformers, and industrial process improvements. PSE also promotes opportunities to include commissioning, operations, and maintenance documentation.

The first approach is a prescriptive measure approach, similar to meeting code using the prescriptive path. PSE recommends and reviews measures beyond what is included in the proposed design. Where the project proposes savings beyond the applicable local Energy Code, PSE provides grant funding in accordance with cost-effectiveness guidelines. Measures must be at least 10% more efficient than code to receive an incentive.

In the second, whole building approach, similar to meeting the code using a performance path. PSE will work with designers to attempt to incorporate measures that go 10% beyond the applicable local energy code in buildings. Given the time frame of new construction planning to completion, these projects may not be complete in the first year.

PSE works with owners of new larger commercial buildings to put a building commissioning plan in place and to carry out commissioning through the construction process. Major remodels also qualify. Larger commercial projects, where the owner/end-user is involved in specifying user criteria, are targeted.

All C/I customers are eligible, as described for the CI Retrofit program. Customers provide PSE with project costs and estimated savings. Customers assume full responsibility for selecting and contracting with third-party service providers. Projects must be approved for funding prior to installation/implementation to be eligible.

Marketing highlights to date: New Construction efforts were highlighted during presentations to contractors at recent CI Retrofit meetings. Plan to work further with Architects and Developers. Despite the fact that economic situation in the region has slowed the number of project starts, there are several projects currently underway with PSE funding.

Recent notes**:** PSE is working with ECOTOPE, a local consultant to determine feasibility of "prescriptive" rebate amounts for selected new construction measures. Standard rebates could overcome the barrier of getting reliable incremental cost and savings information from designers, contractors, and owners. Currently 10 potential measures under consideration. Reviewing process and procedures used by SCL to work a program with Seattle Energy Code.

10. Large Power User Self-Directed Program (Electricity Only)

This program provides an Energy Efficiency Project incentives up to 87% of the Sch. 120 Conservation Rider revenues contributed to PSE's Conservation Program, for C/I customers receiving high-voltage electrical service under Schedules 46, 49, or 449. Projects are conceived, developed, and implemented by customers for their facilities. Customer proposals are evaluated by PSE engineering staff for cost-effectiveness and for energy code compliance. All projects will be field-verified by PSE as completed and operating before the grant payment is made.

Marketing highlights to date: Twenty-five companies representing 30 high-voltage customers have been notified of the opportunity via direct mailing of an introductory letter and RFP package. Two meetings have been held to review program requirements and procedures as well as answer customer questions.

Recent notes: Customers will be able to use their 16-month, Sept 2002 – Dec 2003 contribution for projects submitted for approval prior to December 2003.

11. Resource Conservation Manager (RCM) Program

An RCM customer employs or contracts with an individual designated to perform resource management responsibilities. The RCM implements low-cost/no cost energy saving activities with building occupants and facility maintenance staff. RCM responsibilities include routine accounting and reporting of resource consumption (electricity, gas, water, sewer, recycling, etc.), costs and savings estimates.
PSE offers Resource Conservation Manager Services (RCM) to any school district, public-sector government agency, and commercial or industrial (C/I) customer, with a focus on larger customers with multiple facilities. PSE assists in designing and setting up tracking for a RCM program tailored to the customer. Depending on individual customer needs, PSE may provide additional services or assistance, including resource policy guidelines, a resource accounting system, PSE billing data, and other training and informational materials. PSE hosts a quarterly forum for resource conservation managers to exchange information, ideas, and techniques for controlling utility costs. Training opportunities are available for RCMs and corollary staff such as custodial and maintenance personnel. Salary guarantees are available for RCMs. In some cases, PSE provides a grant to partially fund a start-up RCM position, provided there is a mutual agreement that if the program generates dollar savings, funding by the customer will continue after "start-up" funding support terminates.

Any grants for retrofits are coordinated through PSE's C/I retrofit or new construction programs.

PILOT PROGRAMS

12. Fuel Switching Pilot

This service will be available to customers in certain targeted areas where providing electricity to customers is more costly than the cost of making natural gas available to customers. Eligible customers will be offered financial incentives to convert electric space and/or water heating appliances/systems to appliances/systems fueled by natural gas. PSE will individually notify customers of their eligibility to receive service under this schedule.

Marketing highlights to date: The program is still under development, expected to launch sometime during the first quarter, 2003.

Recent notes: As of December, PSE has identified three areas with PSE electric capacity constraints and natural gas availability. The program was reviewed with the CRAG at its December meeting. Prior to discussing this program with customers, the Company will further review program goals, targets and policies with the Conservation Resource Advisory Group.

13. Residential Duct Systems Pilot

This program targets residential customers living in a) manufactured homes with central forced air electric heating systems and b) single family homes with ducted and gas furnaces in PSE's electric and gas service areas.) Climate Crafters offers the Performance Tested Comfort Systems^{TM} (PTCS) program. PSE has contracted with Climate Crafters to provide diagnostic testing, duct sealing and data reporting for 180 existing manufactured homes. Climate Crafters has contracted with Comfort Zone, Inc. an experienced weatherization contractor, for delivery of the field services and field data collection. Participating customers will receive the duct diagnostic measurement services and sealing services from the certified contractor at no cost. This program provides technical support, contractor training and marketing assistance to contractors.

Marketing highlights to date: Mobile Home Duct Sealing Pilot: Initially, Comfort Zone experienced some difficulty recruiting mobile home participants, but this has been resolved with experience in approaching the mobile home park management and a printed program description/scheduling form provided by PSE.

Recent notes: Climate Crafters trained and certified the Comfort Zone technicians on September 10-11, 2002. Production work began in September. The single-family, gas-heat portion of the pilot has been temporarily deferred in order to launch the mobile home pilot. A contractor has agreed to participate in this portion of the duct pilot. Contractor is also a certified Aeroseal® duct-sealing contractor. The Contractor will offer PSE's pilot duct diagnostics /sealing rebates ($50/$250) to qualifying participating customers who are contracting for new gas furnace installations. Recruitment will be accomplished by presenting the pilot program information/questionnaire to prospects seeking new heating system installations. The first customer offers will be made in December.

14. Commercial and Industrial Boiler Tune-up Pilot

This pilot program will consist of working with mechanical contractors to design a pilot that provides sufficient incentive to persuade customers to have their boilers tuned up for the first time, so that they can see the resulting energy savings immediately on their bills. The incentive will be 50% of the cost for the tune-up, up to $300 per boiler.

All firm, non-transportation PSE gas C/I customers with gas boilers that can be tuned are eligible. Funding will be limited to one time per boiler per site.

Marketing highlights to date: Contacts with mechanical contractors qualified to perform boiler tune-ups have been initiated. Targeted mailings directed to customers of the size and type that may have a gas boiler is under review. There may also be a mailing list available through appropriate sources, e.g., from the state, listing boiler owners.

Recent notes: Program expected to launch in January 2003.

MARKET TRANSFORMATION PROGRAMS

15. NW Energy Efficiency Alliance

Puget Sound Energy has been a major financial supporter of the Northwest Energy Efficiency Alliance, and is represented through a position on NEEA's Board of Directors. The primary function of NEEA is market transformation for the benefit of energy efficiency at the manufacturing and retail level. PSE staff participates in review and development of NEEA funded projects. PSE leverages NEEA information to develop energy efficiency programs for the benefit of PSE Customers.

Recent notes: PSE has provided additional funding in support of the Small HVAC Maintenance Pilot program. PSE is also committed to providing additional funding for the Commercial Buildings Initiative.

16. Local Infrastructure and Market Transformation and Research

PSE funds specific energy efficiency initiatives and/or organizations committed to accelerating the adoption of energy efficiency in the marketplace. This includes research activities for which PSE may not have a related program in place. This category also includes funding for local organizations that help PSE promote programs. An example is PSE's annual membership dues for E-Source.

PUBLIC PURPOSE PROGRAMS

17. Energy Education 6–9th Grade Environmental Education

Powerful Choices (formally called "In Concert with the Environment") is a proven environmental conservation education program that is changing how Washington State's middle school students and their families think about and use natural resources in their daily lives. PSE, along with 26 other utilities, cities, and agencies responsible for energy, water, and environmental programs in the Puget Sound area, fund the program in over 70 schools with a reach of over 12,000 students. Powerful Choices offers Puget Sound area schools the most comprehensive energy and environmental curriculum in the nation. The program teaches students how to apply principles and make informed choices related to energy use, air quality, water conservation, and solid waste.

Eligible customers are PSE gas and electric territory school districts

Marketing highlights to date: PSE partners with school districts and a variety of municipalities and public agencies to help gain access to classrooms and improve teaching materials.

Recent notes: Staff is updating the current curriculum to better align with state WASL and ELR requirements and environmental education requirements. In 2002–2003, the program aims to reach more middle-school age students, develop an education plan to include elementary and high school students, obtain more funding from partners, and install a new database. Information technology will help the program keep up with education trends such as e-learning,

18. Residential Low-Income Retrofit

This program provides funding of cost-effective home weatherization measures for low-income gas and electric heat customers. Funds are used for single-family, multifamily, and mobile home residences.

Program participation takes place through referrals from low-income and crisis service agencies. PSE customers who are having difficulty paying heating bills are also referred to the appropriate serving agency when they apply for energy bill payment assistance. Income qualification for the low-income weatherization program takes place at the local weatherization agency or other designated agency. Local agencies assume responsibility for getting permission from rental property owners to install weatherization measures. The elderly, disabled, and households with very young children receive priority in scheduling of the weatherization work. In addition to the structure audit and measures installation, agencies might provide energy use education to participants.

Marketing highlights to date: PSE provides a weatherization program brochure, which explains the program and basic eligibility requirements, and lists the agencies contact phone numbers. This brochure is normally available to customers during many public events in which PSE participates. The brochure has been distributed by OCD to local agencies and to other State agencies serving the low-income population.

Recent notes: Work will begin shortly on modification to a partially completed PSE Access database that will allow more accurate calculation and reporting of measure energy savings for the program. Contract services have been recently authorized for this purpose. When these modifications are complete, it will permit a more detailed picture of the program results and should provide the basis for an initial program evaluation.

C&RD PROGRAMS

19. Green Power

PSE customers can decide to purchase green power directly on their monthly energy bill. PSE's Green Power Plan is purely optional, but many customers indicate they are willing to pay 10% more on their electric bill for green power, which for the residential customer is approximately $6 per month. The plan starts at an additional $4 per month, which allows PSE to buy 200 kilowatt hours of energy from renewable sources in the Northwest. Customer elect to purchase any number of additional blocks of 100 kilowatt-hours at $2 each.

Marketing "It's Easy Being Green": Signing up for the Green Power Plan is easy. Just fill out the online enrollment form or call the PSE Hotline at 1-800-562-1482.

20. Farm Motors and Processes

Refer to Commercial/Industrial Retrofit program. Evaporative Plate Coolers and VSD on pumps are added measures that can be funded under this program.

21. New Manufactured Housing

Refer to Program Write-up #5.

22. Energy Star Appliances

Offerings will be developed early in 2003.

23. New Construction Lighting Fixtures

Under development.

24. Residential Energy Efficient Lighting

Refer to Program Write-up #4

ISSUES UNDER CONSIDERATION OF CRAG

i) Electric Transmission and Distribution Avoided Costs
ii) Gas Transportation and Distribution Avoided Costs

PSE plans to refine Conservation Cost-effectiveness standards later next year, in conjunction with development of conservation supply curves. Currently, PSE is using avoided costs developed earlier in 2002 as the cost-effectiveness test for demand-side conservation programs.

DESCRIPTION AND ANALYSIS OF SUPPLY CURVES

Description

PSE will assess conservation potential for the development of new energy management programs targeted for summer 2003. Conservation supply curves will be developed by May 31, 2003. These assessments will be made in cooperation with the regional supply curves under development by the NW Power Council for the upcoming 5th Power Plan. Once the NW Power Council work is developed PSE plans to "Pugetize" the regional model with PSE-specific customer data, end-use estimates, forecasts, and financial parameters.

PSE will also undertake selected market research projects designed to improve understanding of the market potential for selected market segments and efficiency technologies. Data should provide a deeper understanding of customer preferences, motivations and barriers to energy efficiency. It is commonly held that the greatest gap in market insight is within the commercial/industrial sector; thus research activities are more heavily weighted there. PSE will take full advantage of existing research and opportunities to partner with other active research initiatives. Results will be available September 2003 for setting program targets in 2004 and beyond.

Market research topics include:

- Small Commercial Customer Needs
- Medium/Large Business Customer Needs
- Residential New Construction
- Residential Gas Conversion
- Online Delivery of Efficiency Services

Schedule

Market research plans developed	Summer 2002
Undertake selected PSE studies	Fall 2002
Support regional studies	Fall 2002–Spring 2003
Supply data to Power Council	Summer–Fall 2002
"Pugetize" supply curves	Fall 2002
Develop supply curves	May 2003
Complete conservation potential assessment	May 31, 2003
Complete all research activities	Summer 2003

Recent notes:

PSE has provided funding for E-source multi-client energy efficiency/load management market studies for Residential, Small Commercial/Industrial, and Medium-to-Large Commercial/Industrial Markets. The objectives for each study were to identify market segments within each market, assess the segment interest in demand-side products/technologies and utility programs, and to identify the most appealing marketing themes by segment. The most sought-after benefits of energy efficiency are saving money, no hassles, and protecting the environment. Concerned businesses, especially, want to be able to demonstrate their concern to their customers

PSE has also recently conducted interviews with residential builders about new construction efficiency offerings. The most desired features for these contractors are: make it easy to participate, reimbursement for additional costs, and training on best practices to meet the Energy Code.

Fieldwork is starting in early December for the NEEA-sponsored NW Commercial Building Stock Assessment Study. PSE contracted with Xenergy to over-sample PSE customers in conjunction with this study, targeting 200-300 PSE customers with phone surveys and site visits. Deliverables including customer characteristics data and Energy Use Indices should be completed in February 2003. These results will help support work for the conservation supply curves. On the residential side, relatively recent data is available from the 1998 Residential Characteristics survey. Efficient Appliance and lighting saturations will be augmented with program evaluations and other regional findings. Information for the industrial sector will be supplied by ICNU, in conjunction with work being done for the NWPPC regional curves. The industrial potential for PSE will need to address forecasting of self-served loads in the future.

Energy Supply

Chapter 5

ENERGY SUPPLY RESOURCES

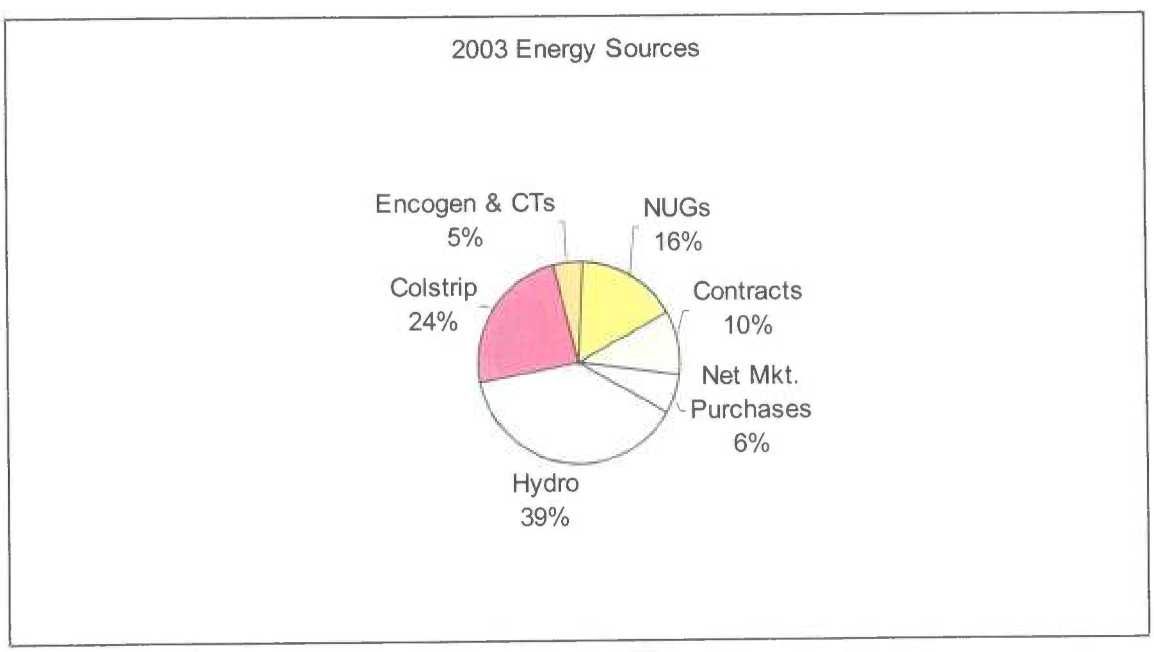
INTRODUCTION

This Chapter provides a detailed description of PSE's existing energy supply portfolio, along with a description of generic generating resources that are available and are considered in Chapters 8 and 9. A key item identified in this section is that several of the Company's power supply contracts will be expiring in the relatively near future. Table 5-5 illustrates that approximately 580 MW of capacity under contract will no longer be available by the end of 2006. The loss of these contracts is a key contributor to the Company's resource needs, more fully described in Chapter 8.

As part of its resource planning effort, PSE is also assessing the relative merits of three primary means of acquiring long-term firm base load electric resources: (1) purchasing power supply under a power purchase agreement; (2) buying and completing a partially developed generation project; and (3) developing a greenfield project. Accordingly, In 2002, PSE enlisted Tenaska to evaluate the prospects of building new generation by PSE. The topics study include: identification of potential sites; cost estimates for various technologies and sizes; and estimation of a benchmark to compare other resource alternatives with. A discussion of Tenaska's preliminary findings is provided as an appendix to Chapter 5.

OVERVIEW OF EXISTING RESOURCES

PSE currently has a balanced portfolio as the chart below illustrates.



The chart represents expected energy under average hydro conditions (40 year) and with natural gas and energy prices from PSE's long run analyses. Each of the sections is discussed in greater detail below.

DESCRIPTIONS AND CURRENT ISSUES

Hydro

Hydroelectric plants provide about forty percent of PSE's energy needs. Hydro includes both PSE-owned dams and long term contracts with dams on the Columbia. PSE-owned hydro resources are much smaller than the dams on the Columbia River where PSE has its long term contracts. Other hydro resources include many small dams which are included in the Contracts section as Qualifying Facilities, and "Net Market Purchases" which are contracted for at the Mid-C and will include significant levels of hydro produced energy.

The primary benefits of hydro is the low cost and its use as a load following resource during the day. The last decade saw high precipitation on average which provided most northwest utilities with most of their power. However, during years of drought expected hydro energy needs to be replaced on the market with more expensive sources which are produced from natural gas or fuel oil. Table 5-1 lists the PSE hydro resources.

Table 5-1

Plant	Owner	PSE Share %	2003 Energy (amw)
Upper Baker River	PSE	100	39
Lower Baker River	PSE	100	45
White River	PSE	100	29
Snoqualmie Falls*	PSE	100	48
Total PSE-Owned			**161**
Wells	Douglas Co. PUD	31.3	146
Rocky Reach	Chelan Co. PUD	38.9	285
Rock Island I	Chelan Co. PUD	50.0	106
Rock Island II	Chelan Co. PUD	95.0	126
Wanapum	Grant Co. PUD	10.8	48
Priest Rapids	Grant Co. PUD	8.0	34
Mid-C Total			**745**
Total Hydro			**906**

* Includes "Electron" and other small PSE hydros.

Colstrip

PSE's coal based energy is limited to the plant in Colstrip, Montana as the company's interest in the Centralia, WA coal plant was sold two years ago. Colstrip provides important baseload energy and about twenty-five percent of overall needs. Colstrip has four units which are operated by Pennsylvania Power and Light-Montana, and owned by PPL-M, PSE, and other northwest utilities. Table 5-2 lists the expected energy from Colstrip for 2003.

Table 5-2

Units	PSE Ownership	Nameplate Capacity	2003 Energy (amw)
Colstrip 1 & 2	50%	614 mw	257
Colstrip 3 & 4	25%	1480 mw	316
Total			**573**

Non-Utility Generators – NUG's

The NUGs are the cogeneration plants that PSE contracted with under the PURPA regulations. The plants use natural gas and have "hosts" that use the steam energy in their production processes. All three of the plants are in the northern part of PSE's service territory, the Skagit and Whatcom Counties. The primary problem with the NUG contracts is that they are very expensive.

Table 5-3

Name	Contract Expiration	2003 Energy (amw)
March Point I	12/31/2011	85
March Point II	12/31/2011	51
Tenaska	12/31/2011	151
Sumas	12/31/2012	90
Total		**377**

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.

Encogen and CT's

This segment contains a former NUG, Encogen, which has been purchased by PSE, and a number of simple cycle gas turbines for peaking and market needs. The peaker plants provide important capacity although they are expected to operate only a few months each year. The lease for the Whitehorn units expires in 2004; however it may be extended to 2011. Fredonia 3 & 4 were purchased in 2000 but the financing was arranged as a long term lease which expires in 2011.

Table 5-4

Name	Plant Capacity (mw)	2003 Energy (amw)
Encogen	160	95
Fredonia 1 & 2	202	2
Fredonia 3 & 4	108	12
Whitehorn 2 & 3	134	3
Frederickson	141	0
Total	745	**112**

Contracts

This section includes about 20 long term contracts that range in capacity from a few megawatts to three hundred megawatts. The group is a mix of QF's and contracts with other utilities, and the fuel sources include hydro, gas, waste products, and unidentified sources from outside the area. Most of the contracts will expire by 2011.

Note that short term contracts (less than one year) are procured by the Risk Management group, and discussed elsewhere.

Table 5-5

Contract	Type	Expiration	Capacity (mw)	2003 Energy (amw)
Avista	Thermal	12/31/2002	33	0
CSPE	Hydro	3/31/2003	20	4
Supplemental & Entitlement Capacity	Hydro	3/31/2003	10	0
PacifiCorp	Thermal	10/31/2003	200	97
Port Townsend Paper	Hydro-QF	12/31/2003	0.4	< 1
Powerex/Pt.Roberts	Hydro	9/30/2004	8	2
Hutchison Creek	Hydro-QF	9/30/2004	0.9	< 1
Baker Replacement	Hydro	9/30/2006	7	1
PG&E Seasonal Exchange-PSE	Thermal	12/31/2006	300	0
Puyallup Energy Recovery Co.(PERC)	Biomass-QF	4/15/2009	2	2
Conservation Credit - SnoPUD	Hydro	2/28/2010	10	10
Montana Power	Colstrip	12/29/2010	97	82
Spokane Municipal Solid Waste	Biomass-QF	11/1/2011	22.9	16
North Wasco	Hydro-QF	12/31/2012	5	4
Kingdom Energy-Sygitowicz	Hydro-QF	2/2/2014	0.4	< 1
BPA- WNP-3 Exchange	Various	6/30/2017	50	45
Weeks Falls	Hydro	12/31/2022	4.6	1
Canadian EA		12/31/2025		1
Koma Kulshan	Hydro	12/31/2025		4
Twin Falls	Hydro	12/31/2025		8
Total				**280**

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.
PG&E defaulted on the contract in 2000. Subsequently, PSE notified PG&E with a termination notice. Currently, PG&E is under Chapter 11, so the outcome of the termination procedure is uncertain.

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 Purchase 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.

Future Issues

PSE Energy

PSE faces two load resource balance issues over time: increasing load combined with expiring contracts for energy. PSE has a current annual average energy need for about 200-300 megawatts, and will need another 300 megawatts or so in the second half of the decade. The degree of need is much greater in the winter months where PSE needs 400-500 average megawatts now through 2006. From 2007 to 2011 the need grows by another 400-500 average megawatts to provide energy for the winter months (December, January, February) Chart 5-2 illustrates the long run situation for energy on an average annual basis while Chart 5-3 illustrates the monthly average energy need for the year 2007. (Determination of need is discussed in greater detail in Chapter 8.)

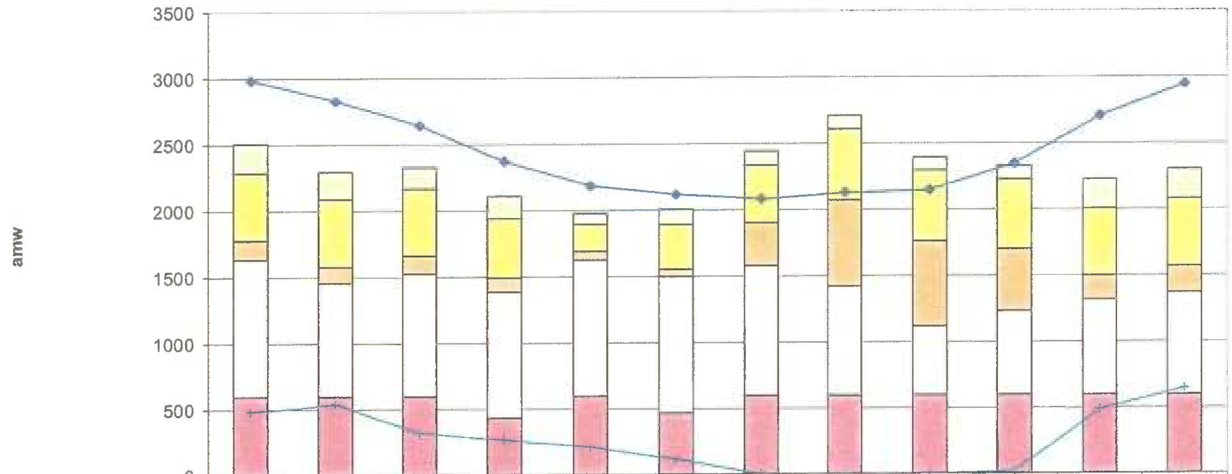
PSE Capacity

PSE has been short of capacity for many years, especially for winter peaking and for the extreme peak (Chart 5-4). As with energy the situation gets worse over time as contracts expire. Capacity needs are correlated to winter peaking energy needs rather than average energy needs. While peaking energy indicates a need for an additional 1,000 average megawatts by 2011, the capacity addition by 2011 is 1,400 megawatts for the expected peak. (Further discussion can be found in Chapter8.)

Regional Issues

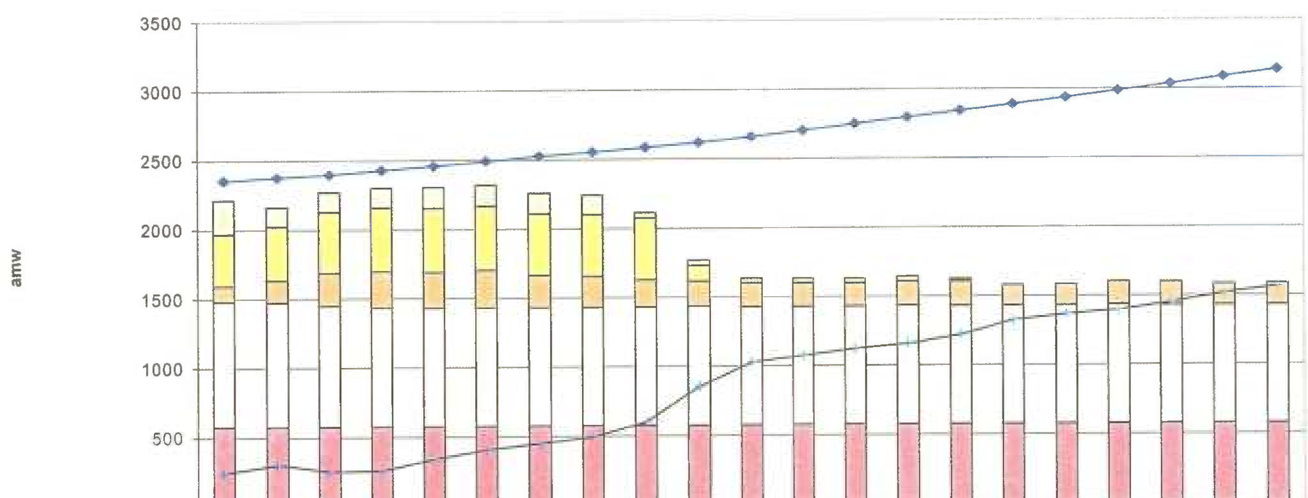
The most recent analysis from the Northwest Power Planning Council (December 11, 2002) suggests that the region will face increasing probability of electricity shortages if plans for new power plants and conservation initiatives are not implemented. In the short run the northwest is still highly dependent on hydro-power and is vulnerable to the risks of drought in any given year. In the long run, demand side management and supply side resources may not keep up with growing regional demand leading to significant high prices by 2005.

Chart 5-3 Average Monthly Need: 2007



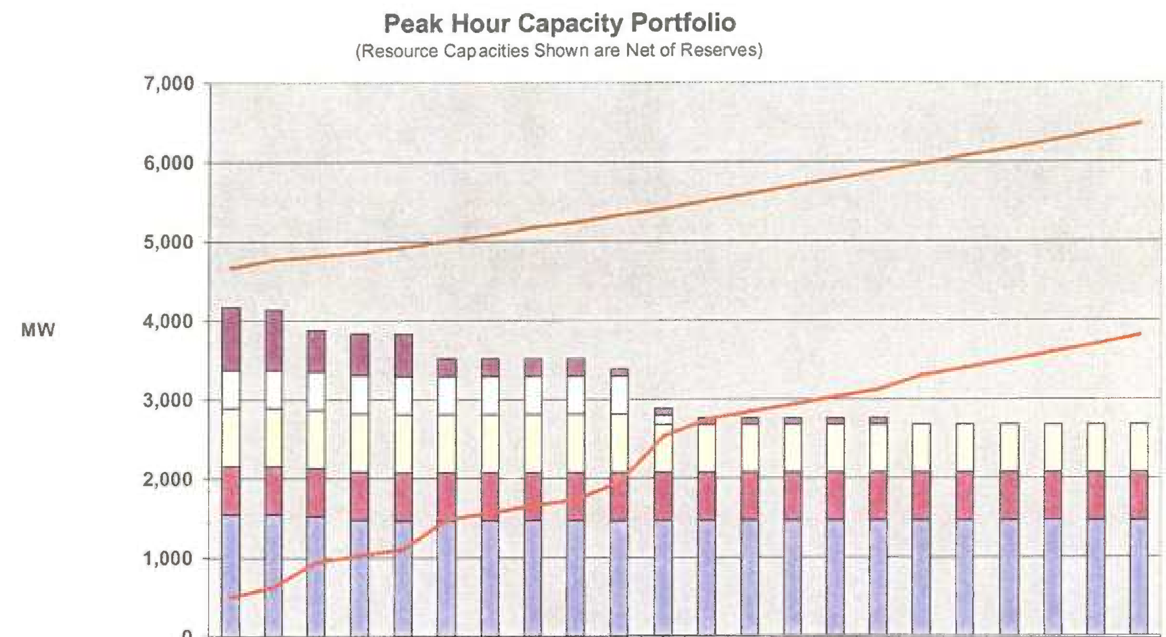
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Contracts	221	209	161	171	81	115	108	101	96	101	219	225
NUGs	510	509	510	446	206	337	434	535	535	528	510	512
Encogen & CTs	146	123	134	108	65	58	326	651	641	466	180	196
Hydro	1,033	857	926	952	1,027	1,031	977	822	521	635	718	771
Colstrip	598	598	598	433	598	464	598	598	598	598	598	598
Need- Pct.of Load	16%	19%	12%	11%	10%	5%	0%	0%	0%	1%	18%	22%
Need	481	536	318	263	210	115	0	0	0	20	485	646
Load	2,988	2,831	2,646	2,373	2,187	2,120	2,083	2,129	2,149	2,348	2,709	2,948

Chart 5-2 Annual Resource Balance



	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Contracts	245	140	141	144	150	150	150	142	40	38	34	34	34	34	17	-8	-8	-8	-8	-8	-8
NUGs	377	392	442	460	464	465	445	446	448	111	0	0	0	0	0	0	0	0	0	0	0
Encogen & CTs	113	160	238	260	259	269	233	224	196	183	171	168	166	173	176	146	151	167	167	153	156
Hydro	905	897	876	863	856	859	856	856	856	859	856	856	856	859	856	856	856	859	856	856	856
Colstrip	573	575	573	573	573	575	573	573	573	575	573	573	573	575	573	573	573	575	573	573	573
Need Pct.	10%	13%	11%	11%	14%	16%	18%	19%	23%	33%	39%	40%	41%	41%	43%	46%	47%	47%	48%	49%	50%
Load	2354	2377	2397	[illegible]	[illegible]	2490	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	2705	[illegible]	2796	2843	2890	2939	2989	3038	3089	3140
Need	247	302	253	261	342	405	449	496	596	856	1,029	1,076	1,124	1,158	1,223	1,326	1,370	1,400	1454	1518	1,566

Chart 5-4 Annual Capacity Balance



	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Contracts	793	760	523	523	523	223	223	223	221	85	85
NUGs	484	484	484	484	484	484	484	484	484	484	118
Encogen + CTs	737	737	737	737	737	737	737	737	737	737	605
Colstrip	612	612	612	612	612	612	612	612	612	612	612
Hydro	1,540	1,540	1,519	1,475	1,464	1,464	1,464	1,464	1,464	1,464	1,464
Expected Peak Load	4,670	4,773	4,819	4,862	4,929	5,004	5,089	5,182	5,251	5,336	5,421
Expected Peak Deficit	503	639	945	1,032	1,110	1,485	1,569	1,663	1,734	1,954	2,537

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Contracts	80	80	80	80	80	-2	-2	-2	-2	-2	-2
NUGs	0	0	0	0	0	0	0	0	0	0	0
Encogen + CTs	605	605	605	605	605	605	605	605	605	605	605
Colstrip	612	612	612	612	612	612	612	612	612	612	612
Hydro	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464
Expected Peak Load	5,514	5,608	5,702	5,794	5,888	5,983	6,081	6,182	6,282	6,384	6,490
Expected Peak Deficit	2,754	2,847	2,941	3,034	3,127	3,304	3,402	3,503	3,603	3,705	3,812

GENERIC OPPORTUNITIES

There are four technologies readily available for new, central generation to fill PSE's needs. The purpose of this section is to describe some of the basic characteristics of the technologies. Detailed descriptions are provided in Appendix 5 which come from the Northwest Power Planning Council's Draft of its Fifth Power Plan (2002), and slides from Navigant Consulting.

Wind

A wind generation site typically must have a capacity of 100 mw or greater in order to achieve reasonable economies of scale. The individual generators are now one to 1.5 megawatts, based on recent project proposals; however turbines of 2 mw and greater have been introduced. The primary economic benefit of wind power is that it avoids the volatility of the fuel market. However availability of wind is volatile. Typical average capacity for a wind project is 30-35 percent, with a range of output from zero to 100. Raw wind energy needs to be either small enough to be absorbed into the control area without adversely affecting operations, or have firming from a dispatchable resource.

Wind energy projects currently operate under a unique business model. The developer identifies the site and procures the necessary permits. The developer then contracts with a utility for the energy, which allows them to get bank financing. Subsequently, the developer sells the project to a larger entity that can benefit from the federal tax credit. O & M can be contracted back to the developer or another qualified entity. Currently, the federal tax credit is critical to the economic viability of wind power projects.

Much of the wind power development in the northwest is along the Columbia River, which is outside PSE's territory. Power from this area requires a transmission wheel for the full capacity. The power can be delivered to Mid-C either raw or firmed and shaped. PSE service territory extends into Kittitas County along the I-90 corridor. There are some wind power developments under consideration which could interconnect directly to PSE transmission lines; however, upgrades would be necessary as the transmission capacity is finite.

Coal

Currently twenty-five percent of PSE's energy comes from part ownership of coal plants in Colstrip, Montana. Development of new coal burning plants west of the Cascades is unlikely because of the economics and environmental issues. Developers of new coal plants focus on "mine mouth" operations to avoid the expense of shipping the coal. Mine mouth generation implies greater expense and reliance on high voltage transmission.

Coal generation is typically baseload with a large capacity factor. The plants are relatively large, 400 mw or greater, to benefit from the economies of scale. The capital cost of coal generation is higher than that for large natural gas fueled plants; however the cost of coal is much less on a per mmbtu basis.

Natural Gas Combined Cycle Gas Turbines

Most of the new generation proposed and under development in the Northwest is combined cycle turbines. The typical plant design uses one to three gas turbine generators (about 250 mw each) in combination with a steam turbine of 20-60 mw. Heat from the gas turbines is captured through a heat recovery system to create the steam for the secondary steam turbine system. Additional peaking capacity can be achieved with duct firing where the heat recovery system is augmented with gas combustion to create more steam energy.

A new combined cycle gas turbine could be located in or near PSE's service territory. The plant's primary need is access to natural gas which can be delivered via the Northwest Pipeline or PSE's system. Local generation provides an economic benefit by minimizing the need for long distance high voltage transmission. Local generation may require upgrades in the water and sewer infrastructure in addition to possible upgrades of the gas lines and transmission and distribution systems.

Simple Cycle Gas Turbines
Simple cycle turbines are less efficient than combined cycle generators. Simple cycle turbines are used for peaking and backup needs because of their operational flexibility: they can be shut down and started up more quickly. In the long run, simple cycle machines can be adapted with a heat recovery system and the plant can be converted into a combined cycle plant for baseload needs.

The attached Appendix 5 provides more description of the generic resource opportunities from the Northwest Power Planning Council.

RESOURCE-SPECIFIC CONSIDERATIONS: TRANSMISSION

Transmission is an important consideration for new resources, for several reasons. First, siting new generating resources at certain locations may create new constraints or aggravate existing constraints on one or more portions of the transmission system; and siting new generating resources at other locations may relieve existing congestion on the transmission system. Second, siting new generating resources at different locations can affect the cost of transmission to PSE and therefore affect the resulting costs for new resources.

For example, new generation opportunities at locations that would allow direct interconnection with PSE's central or southern transmission system would not require payment of transmission charges for use of the BPA system, and may improve power flows within the PSE transmission system.

The following portion of this section describes constraints on the PSE transmission system. Following that is a discussion of constraints on the regional transmission system, along with information about regional efforts to address transmission constraints.

Additional discussion of transmission considerations affecting new resource opportunities, including FERC's Standard Market Design (SMD) proposal is provided in Chapter 2, "Planning Issues".

Constraints on Puget Sound Energy's Electric Transmission System

The following evaluation provides a narrative assessment of some aspects of the performance of the transmission system of Puget Sound Energy, Inc. (Puget) in future time periods based upon the application of Puget's reliability criteria. While an exhaustive list of such aspects is not possible, and each instance of potential transmission must be evaluated in light of the unique facts and circumstances pertaining thereto, many likely future transmission constraints are described in this Part 6.

System Overview

Puget owns transmission facilities in its control area and, in connection with the Colstrip generating facility, in Montana. Puget's control area transmission system is composed primarily of 115 kV facilities, which are operated in parallel with the Bonneville Power Administration (BPA) main transmission grid. BPA's facilities mainly consist of 500 kV and 230 kV transmission facilities. While Puget's system may have capacity for new generation in certain locations, transmission constraints on BPA's system may not permit additional generation in or around Puget's control area without new construction by BPA or Puget. Puget's control area transmission system constraints arise from thermal limitations, while its Montana facilities are stability limited.

Identified Puget System Constraints

Whatcom County
Puget has a 230-115 kV transformer at Portal Way Substation and a Portal Way-Arco Central 115 kV line in Whatcom County. Under high Canadian transfers, local generation, and local load conditions, these facilities can overload during outage conditions. A transformer was added at BPA's Bellingham Substation, but it does not mitigate these overloads.

Whatcom County - Skagit County
Puget has two 115 kV lines between these two counties, the Bellingham-Sedro Woolley Nos. 3 & 4 lines, and owns 1/2 the transfer rights on a double circuit 230 kV line. These lines are operated in parallel with two BPA 500 kV transmission lines. BPA and Puget use those lines to transfer power from Canada to the Northwest. When imports from Canada are high, an outage on one of the BPA lines can cause sufficient additional loading of Puget's 115 kV lines for them to reach their thermal limits. Furthermore, Puget currently is using all of its thermal transmission capacity in its Nos. 3 & 4 115 kV lines, and its transfer rights on the 230 kV lines to transfer its share of Canadian power, and power from its generation resources in Whatcom County to Skagit County.

Mid-Columbia Area - Puget Sound Area
Puget has a 230 kV line and a 115 kV line running between the Mid-Columbia and Puget Sound areas. BPA has agreed with Puget that the combined capacity of the two lines is 450 MW. Due to the amount of output from generation resources that Puget has under contract in the Mid-Columbia area and elsewhere, however, Puget's transmission capacity on the two lines already is fully utilized. Puget has had to contract with BPA for an additional 1136 MW of transmission capacity between these two areas.

Internal King County
Puget's 230 and 115 kV system through King County is strongly affected by power transfers from and to Canada. Outages on BPA's system result in overloads on Puget and BPA's system to such an extent that the transfers from and to Canada must be curtailed below the full ratings. Puget facilities that are most affected include the Bothell-Sammamish 230 kV line, and the Sammamish 230-115 kV transformers.

King County - Kitsap County
Puget has a single 115 kV line running between King County and Kitsap County. This line must be operated with one end open because outages on BPA's main grid can cause the line's thermal overload. BPA will have to construct additional facilities in the future to mitigate this problem.

In addition, there are several problems within the Kitsap County system. In the event of an outage among one of the three transmission lines from BPA's Kitsap substation that serve Puget's load and the U.S. Navy's load in Kitsap County, the remaining two transmission lines could be overloaded. Finally, Puget has two transmission lines between its Bremerton substation and its Foss Corner substation in Kitsap County. An outage of one of these two lines could result in the remaining line becoming overloaded.

Pierce County – Thurston County
Puget has two 115 kV lines, and one 57.5 kV line between Pierce and Thurston Counties. These lines can overload following an outage of a BPA 500 kV line that is in a parallel path with them. To mitigate the amount of overloading, large blocks of generation north of this path are tripped when the 500 kV line outage occurs. For the highest transfers, the 57.5 kV line may trip due to overload. These lines and BPA 230 kV lines limit the transfers that can reliably be accommodated between these counties.

BPA Paul Substation - Puget Tono Substation Interconnection
Puget has contracts for the delivery of 441 MW of electrical output from the Centralia Generation Project to BPA's Paul Substation where the power enters Puget's system. Puget's interconnection with the Paul Substation has a thermal rating of only 400 MW, however, and BPA has required Puget to purchase an additional 167 MW of transmission capacity from BPA.

South King County - Thurston County
BPA has a single 500 kV line and two 230 kV lines between the two counties. Puget has several 115 kV lines that are operated in parallel. An outage of the single 500 kV BPA line could overload BPA's 230 kV lines and Puget's 115 kV lines. Both utilities are jointly investigating how to address this transmission constraint.

Colstrip Transmission System
The Colstrip transmission facilities are located in Montana and are jointly owned by PacifiCorp, The Montana Power Company, The Washington Water Power Company, Portland General Electric Company, and Puget. The capacity of these facilities is fully utilized to transfer Colstrip Project output to points west of Montana. The Colstrip transmission facilities limitations arise from stability limits.

Resource-Specific Considerations: Gas Transmission Capacity

Another resource specific consideration is the availability and cost of gas transmission (pipeline) capacity to deliver natural gas fuel to a gas-fired power plant.

The Pacific Northwest is served primarily by 3 pipelines:
Duke Energy Gas Transmission-Canada (formerly Westcoast Pipeline) receives supplies in northern British Columbia for delivery in southern B.C. and to the US border at Sumas, Washington. From there, a dedicated project-controlled short-haul pipe or service provided by a LDC (Local Distribution Company) utility can be used to deliver supplies to a power-plant site in Whatcom County.

Williams Companies' Northwest Pipeline can make deliveries to locations along the I-5 corridor in western Washington and Oregon. Gas delivered by Northwest originates from B.C. (via Westcoast at Sumas) or from the Rocky Mountain states. Project dedicated laterals or service provided by a LDC utility could be used to move gas to locations not immediately adjacent to the pipeline.

Locations in eastern Washington and Oregon are served by PG&E Gas Transmission-Northwest with supplies originating in Alberta. Project dedicated laterals or service provided by a LDC

(Local Distribution Company) utility can be used to move gas to locations not immediately adjacent to the pipeline.

Pipelines will generally expand their systems (both mainline and laterals) to deliver additional gas when requested by customers willing to sign binding contracts. Recent trends suggest, however that new capacity will be priced at the higher of rolled-in or incremental cost. For example, Northwest's Evergreen Expansion project, which will add capacity from Sumas to Chehalis WA. is expected to be priced at over 40 cents a Dth. This is significantly more than the 32-cent price of existing capacity. Such incremental pricing will provide great incentive for new generation loads to seek synergies with other users to more fully utilize existing capacity.

The cost to construct and operate a pipeline lateral or the payments to an LDC (needed to deliver gas to a power plant off the mainline) must be weighed against the cost of additional electric transmission needed to move the plant closer to the pipeline.

Expansions by pipelines generally require a 2-3 year lead-time, but often, small amounts of surplus capacity can be consolidated to bridge to the availability of the new capacity.

Capacity additions by both Westcoast and Northwest in 2003 are expected to increase the capacity to deliver B.C. originated gas to western Washington in the amount of about 200,000 Dth/day. Sponsors of the many proposed, but not completed, power plants have contracted the majority of this capacity.

Because of the many potential power plant locations relative to the existing and planned pipeline capacity, the viability of each project should include a detailed review of the cost, availability, timing and potential synergies relative to gas transmission capacity.

Appendix 5

Detailed Resource Type Descriptions

Wind Power Plants

August 27, 2002

This paper describes the technical characteristics and cost and performance assumptions to be used by the Northwest Power Planning Council for new wind power plants. The intent is to characterize a typical facility, recognizing that actual facilities can differ from these assumptions. This is particularly true of wind power projects. Energy production is sensitive to the quality of the wind resource and costs are sensitive to location and size of a wind farm. The value of energy from a wind power plant is a function of the seasonal and daily variations of the wind. The assumptions that follow will be used in our price forecasting and system reliability models and in the Council's periodic assessments of system reliability. The Council may also use these assumptions in the assessment of other issues where generic information concerning wind power plants is needed. Others may use the Council's technology characterizations for their own purposes.

Wind energy is converted to electricity by wind turbine generators. A wind turbine generator is a tower-mounted electric generator driven by rotating airfoils. Because of the low energy density of wind, bulk electricity production from wind power requires tens or hundreds of wind turbine generators arrayed in a wind power plant. A wind power plant (often called a "wind farm") includes meteorological towers, strings of wind turbine generators, turbine service roads, a control system interconnecting individual turbines with a central control station (often remote), a voltage transformation and transmission system connecting the individual turbines to a central substation, a substation to step up voltage for long-distance transmission and an electrical interconnection to the main transmission grid. On-site service buildings may be provided.
The typical wind turbine generator being installed in commercial-scale projects is a horizontal axis machine of 600 to 1500 kilowatts capacity with a three-bladed rotor 150 to 250 feet in diameter. The machines are mounted on tubular towers currently ranging to over 250 feet in height. Trends in machine design include improved airfoils; larger machines; taller towers and improved controls. Improved airfoils increase energy capture. Larger machines provide economies of manufacturing, installation and operation. Because wind speed generally increases with elevation above the surface, taller towers and larger machines intercept more energy. Turbine size has increased rapidly in recent years and multi-megawatt (2000 - 2750kW) machines are being introduced. These machines are likely to see initial service in European offshore applications.

Many of the issues that formerly impeded the development of wind power have been resolved in recent years, clearing the way for the significant development that has occurred in the Northwest. Concerns regarding avian mortality, aesthetic and cultural impacts have been alleviated by the choice of dry land agricultural areas for project development. The resulting land rent revenue has also garnered political support from the agricultural community. The impact of wind machines on birds, which has been significant at certain wind development sites has been reduced by better understanding of the interrelationship of birds, habitat and wind turbines. The resulting improvements in turbine design (e.g., tubular towers), choice of project locations and siting of individual turbines have resulted in low rates of avian mortality at recently developed projects.

Though per-kilowatt installed costs of wind power plants have not greatly declined in recent years, turbine performance, reliability, site selection and turbine micro-siting have improved. This has increased the efficiency of energy conversion and thereby reduced energy production costs. The resulting busbar energy production costs at the better sites are in the range of **4 to 5** cents per kilowatt-hour. However, because wind is an intermittent resource, to these costs must be added the costs of shaping and firming, and, if the site is remote from load centers, the cost of long-distance transmission, which can be especially high for wind because of its relatively low capacity factor.

Though the cost of energy from wind power plants is not yet economically competitive with the average energy production costs of gas-fired combined-cycle plants, wind power has benefited from a variety of economic incentives, leading to unprecedented development of wind power in certain regions, notably Minnesota, Texas and the Pacific Northwest. The most important incentive is the federal production tax credit, currently about $18/MWh, available for the first ten years of project operation. Complementing the production tax credit have been energy premiums resulting from the robust market for "green" power that has developed in recent years. This market is driven by retail green power offerings, utility efforts to diversify and "green up" resource portfolios, green power acquisition mandates imposed by public utility commissions as a condition of utility acquisitions, renewable portfolio standards and system benefits funds established in conjunction with industry restructuring.

In spite of the recent wind power development activity, issues affecting continued development of the resource remain. Wholesale power costs are currently low and are anticipated to remain so for several years. The cost of firming and shaping wind farm output to serve load are not well understood and can be substantial. While it appears possible that several hundred megawatts of wind power can be shaped at relatively low cost using the Northwest hydropower system, the cost of firming and shaping additional amounts of wind energy are uncertain, pending further operating experience and analysis. In addition, wind power, because of its intermittency, has been subject to generation imbalance penalties intended to constrain gaming by operators of schedulable thermal resources. The Bonneville Power Administration has recently exempted wind power from imbalance penalties for a period of one year. The issue has received considerable publicity and is likely to be addressed in federal energy legislation and discussions of future transmission management. Northwest wind development to date has not required expansion of transmission capacity, which can be expensive for wind because of its relatively low capacity factor. However, the availability of prime sites with easily accessible surplus transmission capacity is limited. Finally, the competitive position of wind power remains dependent upon the federal production tax credit

The first commercial-scale wind plant in the Northwest using contemporary technology is the 25 MW Vansycle project in Umatilla County, Oregon. Since Vansycle entered service in late 1998, four additional wind projects have been placed in service or are under construction. Now in operation or under construction within the region are 412 megawatts of wind capacity, producing about 130 average megawatts of energy. In addition, Northwest utilities have contracted for 110 megawatts of capacity, producing about 44 megawatts of energy from the Rock River and Foote Creek projects in Wyoming. Northwest wind farms range from 25 to 265 megawatts capacity. These projects are comprised of 16 to nearly 400 machines, ranging in size from 600 to 1500 kilowatts capacity. Several of the project sites are capable of expansion and additional sites have been proposed for development.

Wind

- Status and Trends
- Economics
- New Asset Development
- Value of Recent Transactions

Trends in the wind sector point to an improving competitive position for the technology

Wind power technology has matured significantly in the last decade, with next generation turbines targeting 3-5 MW

Industry Trends

- Wind power is more often being thought of as "conventional" technology
  - Costs are nearly competitive with best fossil fuel options
- Offshore (coastal wind power development is accelerating, spurring development of larger size turbines (3-5 MW)
- Larger wind systems are dominating the industry
  - Small systems for off-grid applications represent a niche market
- In some cases, wind power development is being supported by customer demand for green power

Technology Trends

- Technology advances are driving further cost reductions
- Turbines are getting larger
- Elimination of gearboxes with use of direct drives and advanced electronics
- Variable speed operation
- Taller and stronger towers (to exploit higher wind speeds/sheers)

Typical Size

- 750 – 1,500 kW per turbine
- 1,000 kW average size installed in 2001
- Larger turbines targeted for offshore (coastal) applications
- Wind farms range from <10 to 200 MW

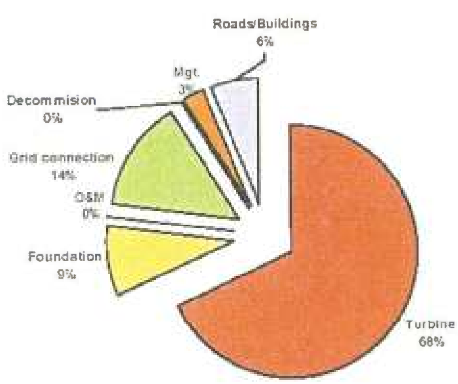
The wind generation market is poised for growth over the next several years

There are several key factors driving growth in the wind generation market

- Tax credits and state incentives
  - The federal tax incentive that subsidizes wind power generation at 1.7 cents per kwh for a ten year period is scheduled to end in 2003, however, it is probable that the credit will be extended
  - Individual states offer a variety of other incentives
    - California offers additional tax credits
    - Illinois provides grants to developers in amounts ranging from $60K to $1000K range for new systems
    - Minnesota offers property tax breaks and equipment sales tax exemptions to developers
    - Texas offers tax deductions on corporate income tax to reduce taxable capital or corporate income
- Utilities required to buy renewable energy
  - One example is BPA which is seeking to buy 1,000 to 2,500 MW in new windpower before the end of 2002 (BPA is already buying or has under consideration nearly 300 MW of wind)
- Green pricing programs
  - 321 Municipal and investor owned utilities in 32 states offer green pricing programs that are founded on renewable technologies, including wind
- Cost of wind-generated electricity
  - Technology has been improving and decreasing the costs of producing energy via wind farms
    - Capital costs are expected to decline from $1,300/kw to $750/kw as a result of new technology (GE Wind)
  - According to NREL, costs of production, on an unsubidized basis, have dropped to 4 cents/kWh for specific projects (e.g., NSP's 107 MW Lake Benton, MN project)

The economics of wind facilities are among the most favorable for renewable fuel sources

Typical Cost Components of Land-Based Wind Facilities



Source: *Review of Offshore Wind Energy Ready to Power a Sustainable Europe, Final Report*: Concerted Action on Offshore Wind Energy in Europe, December 2001

- Capacity factors for wind are typically 1/3 that of baseload units because of the dependence on weather which is highly variable
- Capital costs are / will be declining in the near future
  - Capital costs have ranged from $1,200 - $1,500 / kW but are expected to drop to $750/kW very soon with the development of new technology (GE)
- Production costs are lower than several other renewable sources
  - Generation costs are $5-10 cents/kwh and expected to levelize around $5-6 cents/kwh in the near term
- Environmental benefits
  - Wind plants do not produce any emissions and will also benefit from emissions credits

Wind costs continue to improve relative to other technologies

Assuming no tax credits or electricity feed-in rate incentives, wind energy cost of electricity can be very attractive.

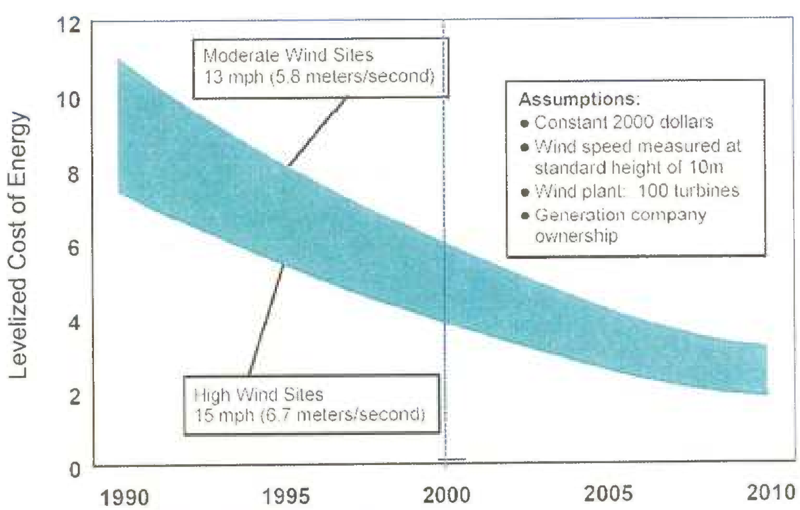
	2002	2005	2010
Average Turbine Size (kW)	1,000	1,500	1,500–2,500
Installed System Price ($/kW)[3]	$1,000	$800–900	$700–800
O&M Cost ($/kW-yr)[3]	$12	$10	$9
System AC Output (kWh/kW-yr) High Wind Speed Area[1] Moderate Wind Speed Area[2]	 3,330 2,450	 3,500 2,800	 3,765 3,065
Electricity Cost (c/kWh)[3,4] High Wind Speed Area[1] Moderate Wind Speed Area[2]	 3.0–5.0 5.0–7.0	 2.6–4.4 3.2–5.5	 2.1–3.6 2.6–4.5

Utility Financing (low cost of capital)   Private Developer Financing (higher cost of capital)

Notes: 1. Capacity Factor for Class 6 Winds (8m/s or 17.9mph @ 50m hub height) = 35% 2002, 40% 2005, 40% in 2010.
2. Capacity Factor for Class 4 Winds (7m/s or 15.7mph @ 50m hub height) = 30% 2002, 32% 2005, 35% in 2010.
3. Real 2002 $.
4. Capital Recovery Factor = 15% After Taxes. The low end of the range assumes a 10% capital recovery factor. No tax incentives assumed

Source: Capital Recovery factor and system price— NCI estimates based on industry interviews 2002.

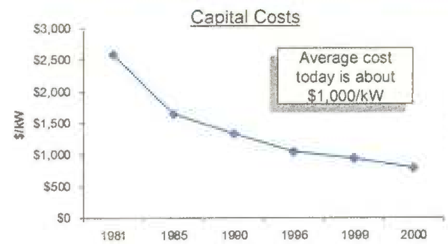
Production costs from wind have continued to decline from the 8 to 11 cents/kWh range down to 3 to 4.5 cents/kWh*

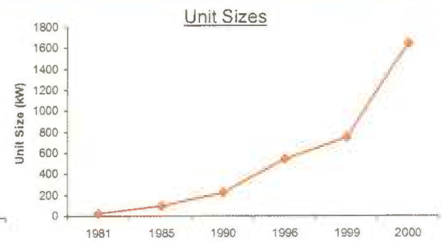


Source: NREL; in most cases this includes subsidies

Over the past 20 years turbine sizes have continued to increase while costs have declined

	1981	1985	1990	1996	1999	2000
Rotor (Meter)	10	17	27	40	50	71
kW	25	100	225	550	750	1,650
Total Cost	$65	$165	$300	$580	$730	$1,300
Cost/kW	$2,600	$1,650	$1,333	$1,050	$950	$790
MWh	45	220	550	1,480	2,220	5,600

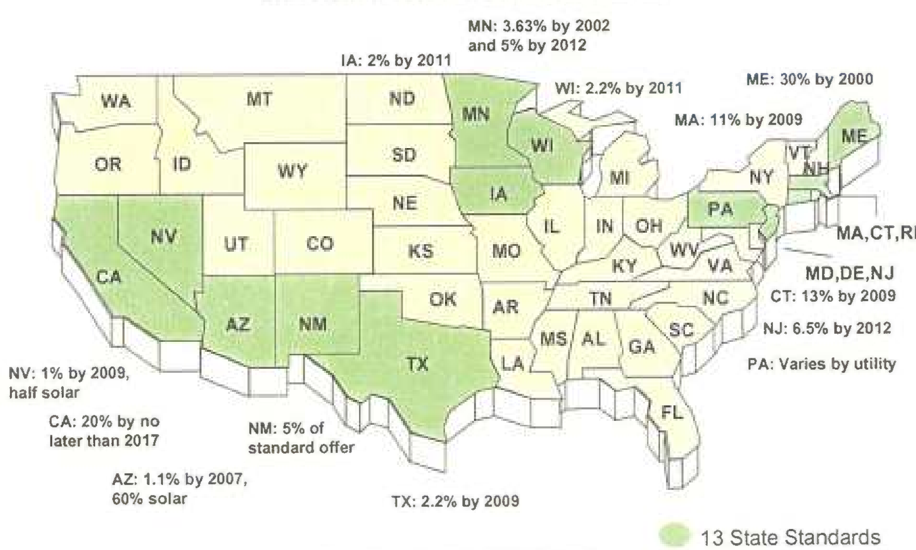




Source: GE Wind Energy

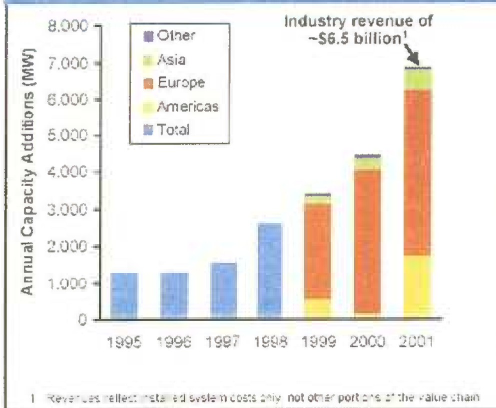
Renewable energy portfolio standards are stimulating a significant US market for wind energy systems

U.S. Renewable Portfolio Standards



The compound annual growth rate of wind power capacity additions over the past five years was ~ 40% (~50% 2000 to 2001)

Annual Worldwide Wind Power Capacity Additions

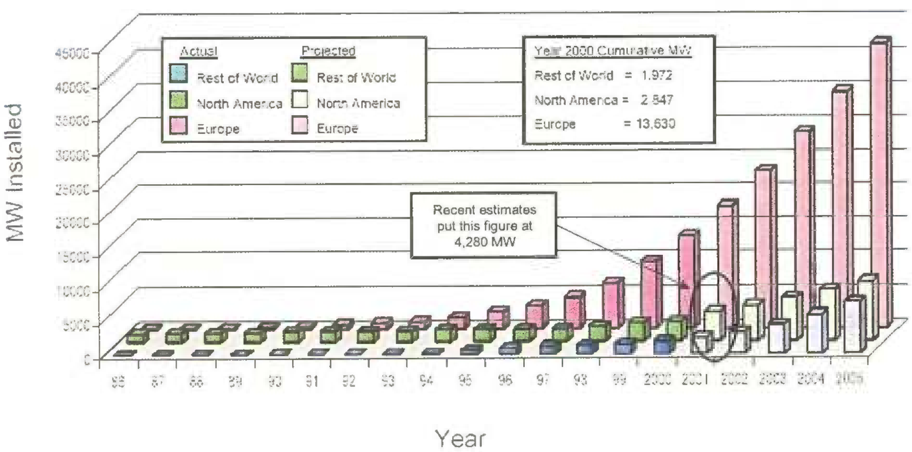


	2001 MW Sold	Total MW Sold
Vestas	1,646	4,983
Enercon	1,036	3,205
NEG Micon	874	4,510
Enron (GE)	865	2,286
Gamesa	646	2,125
Bonus	593	2,306
Nordex	461	1,473
MADE	191	783
Mitsubishi	178	558
Repower	133	379
Other	448	3,482
Total	**7,075**	**25,090**

1 Revenues reflect installed system costs only, not other portions of the value chain

Majority of worldwide wind installation growth has occurred and is projected to continue in Europe

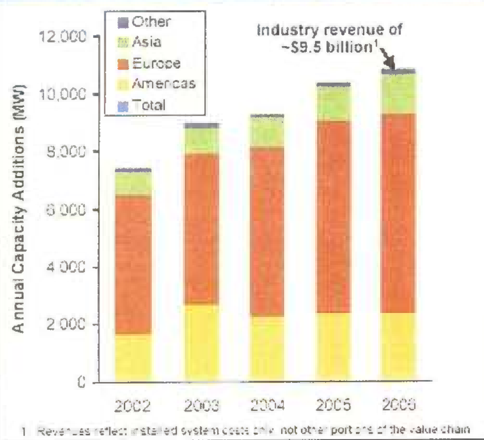
Installed wind capacity in North America was projected to reach just over 5,000 MW by 2005, but based on recent activity will likely be closer to 6,000 MW



Source: NREL

Future growth of wind power in the US will be affected by a probable extension of the Production Tax Credit beyond 2003

Annual Worldwide Wind Power Capacity Additions Forecast



1. Revenues reflect installed system costs only, not other portions of the value chain

- Production Tax Credit of $.018/kWh applies to installations through 12/31/03 (wind, closed loop biomass, and chicken waste)
- Currently House and Senate Energy Bills (HR4 and S517) in conference would extend PTC through 12/31/06
  - Would also expand to include PV, geothermal, open loop biomass
- Europe is expected to have continued steady growth with countries like Germany moving toward offshore installations

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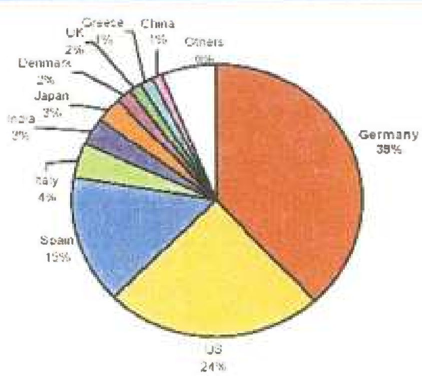
Germany, U.S, and Spain represented 78% of total annual capacity additions in 2001

Wind Markets in 2001 – Annual Capacity Additions



2001 Capacity Additions = 6,819 MW
2001 Installed Capacity = ~25,000 MW

Source: NCI estimates based on *International Wind Energy Development: World Market Update 2001*, BTM Consult ApS, March 2002 and BWE, 2002.

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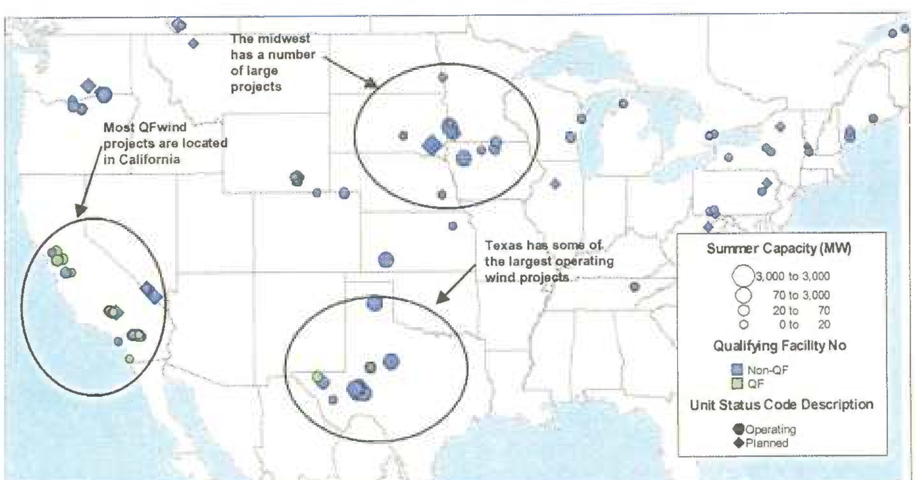
US wind power capacity reached ~4,260 MW in 2001 --roughly a doubling of capacity since 1998

U.S. Installed Wind Power Capacity (MW)

Source: NREL

There are currently numerous operating and planned wind facilities spread across the United States



Wind power is a maturing technology with industry standards continually being adopted. Many improvements are still possible

Common Standard	• Three bladed, upwind, active yaw (mechanisms used to turn wind turbine rotors against the wind) with or without gearbox is becoming the industry standard
Turbine Size	• Average turbine size is 1,000 kW for onshore facilities • Average turbine size is between 2-4 MW for offshore
Blades	• Full-span or partial-span pitch capability of turbines most common installation enabling the system to turn blades slightly out of the wind when power output becomes too high
Materials	• Advances in composite materials is leading to lighter weight designs and ability to manufacture larger rotors • Constant balance between strength/stiffness and dampening properties
Rotation Speed	• Constant speed turbines are most common • However, semi-variable and variable speed concepts are successful and popular from European and U.S. suppliers; made possible by lower cost increased capability of power electronics
Regulation of Power Input	• Simple stall or more sophisticated active stall, which allows you to more accurately control power output (less than half the current market)
Duty Cycle	• Intermittent • High wind areas (8 m/s) at hub height ~ 3,330 hrs/year • Medium wind areas (7 m/s) at hub height ~ 2,450 hrs/year
Lifetime	• 20-30 years
Maintenance	• Periodic component overhauls (e.g., gearbox, yaw mechanism, blades, after 12 to 18 years) • According to NREL, the average O&M cost for wind facilities is ~ 0.5-0.7/kWh

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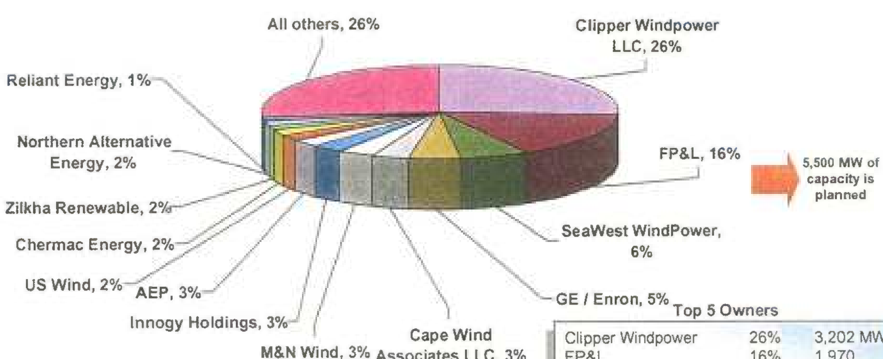
There are a number of players in the wind generation market...

...however, the top 5 players have over 56% of the market

North American Wind Plant Owner Percentages
100% = 12,315 MW Installed



Top 5 Owners

Clipper Windpower	26%	3,202 MW
FP&L	16%	1,970
SeaWest WindPower	6%	739
GE (Enron)	5%	615
Cape Wind Associates	3%	369
Total	56%	6,895 MW

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Northwest Power Planning Council
New Resource Characterization for the Fifth Power Plan

Coal-fired Power Plants

August 19, 2002

This paper describes the technical characteristics, cost and performance assumptions used by the Northwest Power Planning Council for new coal-fired power plants. The intent is to characterize a reasonably typical facility, recognizing that any actual new plant could differ from these assumptions in many respects. These assumptions will be used in our price forecasting and system reliability models and in the Council's periodic assessments of system reliability. The Council may also use these assumptions in the assessment of other issues where generic information concerning coal-fired power plants is needed. Others use the Council's technology characterizations for their own purposes.

Coal-fired steam-electric power plants are a mature technology in use for over a century. Coal-fired power plants are the major source of power in the east and the second largest power supply component of the western grid. Currently, over 36,000 megawatts of coal steam-electric power plants are in service on the western electricity grid, comprising about 23% of generating capacity. In recent years the economic and environmental advantages of combined-cycle gas turbines, low load growth and promise of advanced coal-based technologies with superior efficiency and environmental characteristics eclipsed coal-fired steam-electric technology for new resource development in North America. Since 1990, less than 500 megawatts of coal-fired steam electric plant entered service on the western grid.

The future prospects for coal-fired steam-electric power plants may be changing. The economic and environmental characteristics of coal-fired steam-electric power plants have greatly improved and show evidence of continuing evolutionary potential for improvement. These factors, combined with the prospect of stable or declining coal prices may reinvigorate the competition between coal and natural gas and lessen the near-term prospects for revolutionary coal-based technologies.

The capital cost of coal-fired steam-electric plants has declined about 25% in constant dollars since the early 1990s with little or no sacrifice to thermal efficiency or reliability. Environmental performance has improved. This reduction in cost is attributable to plant performance improvements, automation and reliability improvements, equipment cost reduction, reduced construction schedule, and increased market competition (DOE, 1999). Coal prices also have declined during this period as a result of stagnant demand and productivity improvements in mining and transportation. By way of comparison, the Council's 1991 power plan estimated the overnight capital cost of a new coal-fired steam-electric plant to be $1775/kW and the cost of Powder River coal at $0.68/MMBtu (year 2000 dollars). The comparable capital and fuel costs proposed for the Fifth Power Plan are $1230/kW and $0.71/MMBtu, respectively.

Though the economics have improved, many issues associated with development of coal-fired power plants remain. The issues cited in the Fourth Power Plan - air quality impacts, carbon dioxide production, water impacts, solid waste production, site availability, coal transportation, electric power transmission and impacts of coal mining and transportation - remain significant

A conventional steam-electric coal-fired power plant consists of coal handling equipment, a steam generator, a steam turbine-generator, flue gas treatment equipment and stack, ash handling system, condenser cooling system, switchyard and transmission interconnection. Typically, two to four units of similar design will be located at a site to take advantage of economies of design, construction and operation. In the west, coal-fired plants have generally been sited near the mine-mouth, or at intermediate locations between mine-mouth and load centers having good rail and transmission access.

The proposed reference plant is a 400megawatt pulverized coal-fired unit of subcritical steam cycle design, co-located with several similar units. The plant would be equipped with low-NOx burners and selective catalytic reduction for control of nitrogen oxides. The plant would also be equipped with flue gas desulfurization, fabric filter particulate control and activated charcoal injection for additional reduction of mercury emissions. Because the Council forecasts delivered coal prices for specific geographic areas, some of which could host mine-mouth plants and others that would require rail delivery of coal, the base case does not distinguish between fuel supply methods. The estimated costs include a shared local switchyard and transmission interconnection, but do not include dedicated long-distance transmission facilities that might be required for some plant sites (the cost of long-distance transmission is captured elsewhere in the Council's models).

The base case plant uses evaporative (wet) condenser cooling. Dry cooling uses less water, and other factors equal, might be more suitable for arid areas of the West where new coal-fired power plants might be located. But dry cooling reduces the thermal efficiency of a steam-electric plant by about 10 percent, and proportionally increases per-kilowatt air emissions and carbon dioxide production. The effect is about three times greater for steam-electric plants than for gas turbine combined-cycle power plants, where recent proposals have trended toward dry condenser cooling. For this reason, we assume that the majority of new coal-fired power plants, if developed, would be located in areas where water availability is not critical and would use evaporative cooling.

Specific proposals for new coal-fired power plants could differ substantially from this case. These differences can significantly affect the cost and performance. Important variables include the steam cycle, method of condenser cooling, transmission interconnection, the level of equipment redundancy and reliability desired, unit number and size, level of air emission control, the type of coal used and method of delivery.

Advanced coal technologies, including supercritical steam cycles, atmospheric fluidized bed combustion, pressurized fluidized bed combustion and coal gasification offer higher thermal efficiency, improved control of air emissions and reduced water consumption. Supercritical units are widely used in Europe and Japan. Many were installed in North America in the 1960s and 70s but more recent installations are uncommon because of low coal costs and poor reliability associated with early units. Recent European and Japanese experience has been satisfactory (World Bank, 1999). Atmospheric fluidized bed technology is in commercial use, but has been generally limited to smaller units using waste or low-grade coal. Coal gasification has been commercially employed in the petrochemical industry, but electric power applications are in the demonstration phase. Both coal gasification and pressurized fluidized bed combustion designs would offer the benefits of highly-efficient gas turbine combined-cycle technology, but to date have been limited by lack of cost-effective and reliable product gas cleanup technology. The generally superior competitive position of natural gas has been a major factor impeding more widespread adoption of advanced coal technologies. If more aggressive attempts at reducing carbon dioxide production are made, advanced coal technologies will be increasingly attractive because of superior energy conversion efficiency.

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Coal

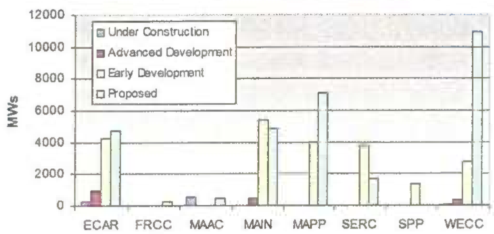
- Status and Trends
- Economics
- New Asset Development
- Value of Recent Transactions

After Years Of Dormancy, New Coal-Fired Generation Has Seen A Recent Boost In Activity

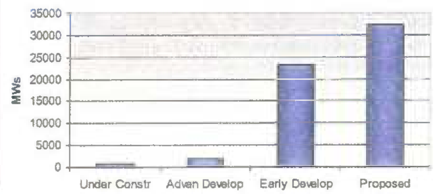
- The announcement of numerous (43 projects) new coal-fired generation projects (≈ 24 GW) has been driven by several key factors
  - Development of "clean coal" technologies
    - These technologies, including circulating fluidized bed and coal gasification, allow higher-sulfur coals to be burned more cleanly—and in some cases allow low-quality (waste) coal once considered useless to be burned
  - Favorable federal and state initiatives
    - In August '02, the Bush administration announced its intention to promote the use of domestic energy sources
    - In its current form, this plan includes $33.5 billion in tax breaks for energy producers over the next 10 years, including $2 billion earmarked for the continued development of clean coal technology
    - Developers have also received significant state aid—in the form of tax credits and tax-exempt bonds—in order to finance construction and boost sagging coal industry employment (particularly in Pennsylvania and Illinois)
  - Economics—coal remains cheap relative to other viable fuel sources
- Despite environmental uncertainties, select coal projects around the country are attractive growth opportunities for plant developers
  - Development of "clean coal" generation in close proximity to low (commodity) cost supplies, such as significant waste coal stores at former mine-mouth facilities, appear to be the most attractive
  - Coal producing areas have significant local and state support – provides rural areas with jobs, new modular coal technologies (80 MW) have shortened the on-line lead time (e.g., Wygen I in WY) to 24 to 36 months

There are over 54,000 MWs of new coal projects in various stages of development – Proposed and Early Development

New Coal Projects by Stage of Develoment, NERC Region



New Coal-Fired Capacity in the U.S.



New Coal Projects by Stage of Develoment, NERC Region (New Capacity in MWs)

	Under Construction	Advanced Development	Early Development	Proposed	Total
ECAR	268	950	4,260	4,750	10,228
FRCC				300	300
MAAC	520			500	1,020
MAIN	18	500	5,400	4,841	10,759
MAPP			4,000	7,100	11,100
SERC			3,755	1,700	5,455
SPP			1,350		1,350
WECC	80	350	2,770	10,950	14,150
Total	886	1,800	21,535	30,141	54,362

NOTES:

- If all projects eventually became operational, this would lead to an increase in installed coal capacity of approximately 16.8%
- However, the likelihood of completion of any particular project not yet under construction or in advanced development is low
- EIA estimates that 74 GW of additional coal fired generation will be added between now and 2025

The economics of new coal facilities are expected to be similar to existing coal-fired units

- Many coal facilities in construction or advanced development will utilize circulating fluidized bed technology
  - This technology allows the coal to be burned at lower temperatures
  - Limestone is used to reduce SO2 emissions; the reduction is ~92% in some facilities
  - Planned CFB units are generally expected to be base load units with capacity factors of ~90%
- Projected capital costs are significant ($950 - $1,500 / KW), however, many developers are getting sizeable subsidies under various federal and state programs
  - Reliant received $400 million of financing (50% of total costs) for its Seward facility from tax-exempt bonds through Pennsylvania's Economic Development Financing Authority
  - JEA received $74 million of total projected costs of $309 million for its 275 MW CFB repowering project from the DOE's Clean Coal Technology Demonstration Program
  - EnviroPower took advantage of two KY bills providing incentives to coal-fired plants sited in coal producing counties, including a $2 / ton tax credit for generators using KY coal
- Fuel costs are generally expected to be low
  - CFB technology allows for the use of lower quality, but cheaper, coal
  - Heat rates for planned CFB units are comparable to existing coal units (9,300 – 10,000)
- Environmental costs
  - Emissions rates for CFB units are only slightly higher than other coal units with pollution control equipment (I.e., SCRs)
    - SO2 rates: ~.15 - .57 lbs / mmbtu
    - NOx rates: ~.09 lbs / mmbtu
  - However, potential federal regs classifying ash and other byproducts as hazardous wastes would impact CFB plants significantly due to the volume of ash they generate

However, the realized value of a given facility are largely driven by unit-specific factors—such as type / availability of the coal commodity, transportation options, local / regional environmental issues

The type of coal used impacts fuel / non-fuel operating expenses and costs to comply with emissions standards

- There are four general classifications of coal (ranked by order of decreasing heat content)
  - Anthracite
    - Highest heat value of any coal at ~15,000 BTU / lb
    - Very small segment of the U.S. coal market; there are approximately 7.3 billion tons of anthracite reserves in the U.S., found mostly in 11 northeastern counties in Pennsylvania
    - Most frequently associated with home heating
  - Bituminous
    - The most plentiful form of coal in the United States and the most widely used in generation
    - Found throughout Eastern and Mid-continent coal fields
    - Heat value ranging from 10,500 to 15,500 BTU / lb
  - Subbituminous
    - Ranks behind bituminous coal with a heat value between 8,300 and 13,000 BTU / lb
    - Reserves are located mainly in a half-dozen Western states and Alaska and includes PRB coal
    - Although its heat value is lower, this coal generally has a lower sulfur content than other types, and therefore, burns more cleanly
  - Lignite
    - Geologically young coal with a heat value between 4,000 and 8,300 BTU / lb
    - Sometimes called brown coal, it is mainly used for electric power generation
- In addition to the four general coal classifications, new generation is increasingly utilizing "waste coal" supplies as a fuel source

Proposed legislation calls for significant reductions in emissions over the next decade

Status of regulations

NO_X

- State is regulated by the Clean Air Act of 1990 to cap emissions during summer season cap (May – Sept) and must comply by 2004
- There are ongoing lawsuits that challenge restrictions
  - Minimum emission levels could increase or decrease
  - Recent rulings have been in favor of utilities
- Additional legislation proposes to reduce emissions 15-20% more in 2007

SO_2

- SO2 caps have been enforced since 1995
- Proposals to further reduce emissions an additional 25-50% in 2007 are on the table (3 Senate bills, 3 House bills)

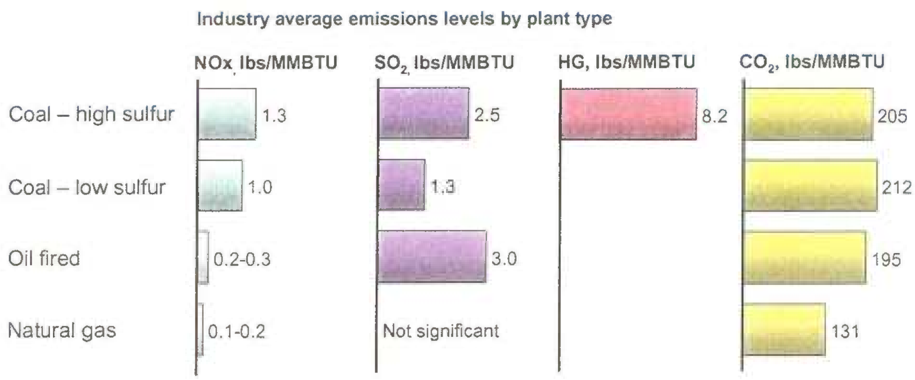
CO_2

- Emissions are presently not enforced
- Potential restrictions vary from reducing emissions levels 50-75% in 2007 but are very uncertain
- Senator Jeffords (VT) has significant Democratic support as well as some Republican support on the Environment Committee to enforce regulation
- MA is the only state that is already moving ahead with CO2 controls

HG

- Some states (WI, MA) already moving forward with regulatory plans
- EPA proposals to regulate HG due in December 2003
- HG is specifically addressed in President Bush's energy plan
- Final rule due by 2004 with initial compliance by 2007

Since coal plants are heaviest producers of all types of emissions, coal plants will remain vulnerable to future regulations



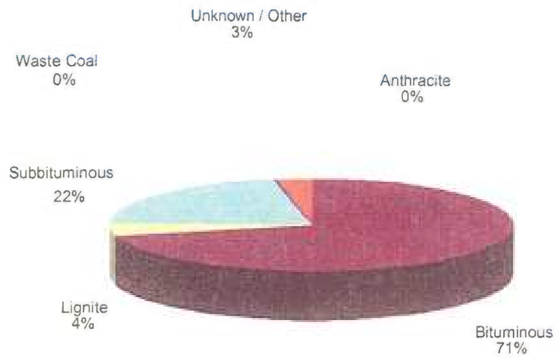
Source: EIA 1999; EPA; IPM Data, and ICF

More than two-thirds of all coal-fired generation in advanced stages of construction / development[1] are waste coal facilities

- Waste coal is generally used to describe low-grade mined coal which was previously considered unsuitable for use
  - Some Illinois mines estimate that only 65% of mined coal can be burned as fuel using traditional coal burning technologies
  - Most new waste coal facilities utilize CFB technology
- Due primarily to the recent developments in coal burning technologies, the capacity of announced waste coal projects exceeds the current installed base
  - In the U.S. there is currently ~1,000 MW of waste coal generation
  - In excess of 2,300 MW of additional waste coal generation is in various stages of permitting, development and construction, including more than 500 MW under construction and more than 600 MW in advanced development
- Plants are located by long-standing sources of coal
  - Long-operating mines have large stores of coal mining byproduct
  - Due to lower heat content, waste coal has higher transportation costs than other coal
  - Coal-mining states with rising unemployment have offered attractive financial incentives to developers

[1] – Represents facilities currently under construction or in advanced development

Total existing U.S. coal-fired generation by coal type



	Capacity (MW)
Anthracite	346
Bituminous	233,419
Lignite	13,756
Subbituminous	71,168
Waste Coal	1,014
Unknown / Other	8,679
	328,382

The types of coal used in generation are primarily dictated by proximity to fuel sources

Sources of Coal Supplies

Capacity by Coal Type, by State[1]

Bituminous		Subbituminous	
OH	24,393	TX	8,722
PA	18,084	WI	5,693
IN	17,877	IL	5,554
KY	14,724	MN	5,404
WV	14,536	IA	5,039
GA	13,369	WY	4,986
Other	130,435	Other	35,770
Total	233,419	Total	71,168

Lignite		Waste Coal[2]	
TX	8,735	PA	586
ND	4,231	WV	212
LA	673	OH	112
MN	66	UT	51
MT	44	MT	39
SD	8	CA	15
Total	13,756	Total	1,014

[1] - All Anthracite capacity is located in Pennsylvania
[2] – Waste coal sites are typically located near large stores of (primarily bituminous) waste coal at mines, former minemouth facilities

Northwest Power Planning Council
New Resource Characterization for the Fifth Power Plan

Natural Gas Combined-cycle Gas Turbine Power Plants

August 27, 2002

This paper describes the technical characteristics and cost and performance assumptions to be used by the Northwest Power Planning Council for new natural gas combined-cycle gas turbine power plants. The intent is to characterize a facility typical of those likely to be constructed in the Western Electricity Coordinating Council (WECC) region over the next several years, recognizing that each plant is unique and that actual projects may differ from these assumptions. These assumptions will be used in our price forecasting and system reliability models and in the Council's periodic assessments of system reliability. The Council may also use these assumptions in the assessment of other issues where generic information concerning natural gas combined-cycle power plants is needed. Others may use the Council's technology characterizations for their own purposes.

A combined-cycle gas turbine power plant consists of one or more gas turbine generators equipped with heat recovery steam generators to capture heat from the gas turbine exhaust. Steam produced in the heat recovery steam generators powers a steam turbine generator to produce additional electric power. Use of the otherwise wasted heat in the turbine exhaust gas results in high thermal efficiency compared to other combustion-based technologies. Combined-cycle plants currently entering service can convert about 50 percent of the chemical energy of natural gas into electricity (HHV basis[1]). Additional efficiency can be gained in combined heat and power (CHP) applications (cogeneration), by bleeding steam from the steam generator, steam turbine or turbine exhaust to serve direct thermal loads[2].

A single-train combined-cycle plant consists of one gas turbine generator, a heat recovery steam generator (HSRG) and a steam turbine generator ("1 x 1" configuration). Using "FA-class" combustion turbines - the most common technology in use for large combined-cycle plants - this configuration can produce about 270 megawatts of capacity at reference ISO conditions[3]. Increasingly common are plants using two or even three gas turbine generators and heat recovery steam generators feeding a single, proportionally larger steam turbine generator. Larger plant sizes result in economies of scale for construction and operation, and designs using multiple combustion turbines provide improved part-load efficiency. A 2 x 1 configuration using FA-class technology will produce about 540 megawatts of capacity at ISO conditions. Other plant

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[1] The energy content of natural gas can be expressed on a higher heating value or lower heating value basis. Higher heating value includes the heat of vaporization of water formed as a product of combustion, whereas lower heating value does not. While it is customary for manufacturers to rate equipment on a lower heating value basis, fuel is generally purchased on the basis of higher heating value. Higher heating value is used as a convention in Council documents unless otherwise stated.

[2] Though increasing overall thermal efficiency, steam bleed for CHP applications will reduce the electrical output of the plant.

[3] International Organization for Standardization reference ambient conditions: 14.7 psia, 59° F, 60% relative humidity.

components include a switchyard for electrical interconnection, cooling towers for cooling the steam turbine condenser, a water treatment facility and control and maintenance facilities.

Additional peaking capacity can be obtained by use of various power augmentation features, including inlet air chilling and duct firing (direct combustion of natural gas in the heat recovery steam generator). For example, an additional 20 to 50 megawatts can be gained from a single-train plant by use of duct firing. Though the incremental thermal efficiency of duct firing is lower than that of the base combined-cycle plant, the incremental cost is low and the additional electrical output can be valuable during peak load periods.

Gas turbines can operate on either gaseous or liquid fuels. Pipeline natural gas is the fuel of choice because of historically low and relatively stable prices, deliverability and low air emissions. Distillate fuel oil can be used as a backup fuel, however, its use for this purpose has become less common in recent years because of additional emissions of sulfur oxides, deleterious effects on catalysts for the control of nitrogen oxides and carbon monoxide, the periodic testing required to ensure proper operation on fuel oil and increased turbine maintenance associated with fuel oil operation. It is now more common to ensure fuel availability by securing firm gas transportation.

The principal environmental concerns associated with gas-fired combined-cycle gas turbines are emissions of nitrogen oxides (NOx) and carbon monoxide (CO). Fuel oil operation may produce sulfur dioxide. Nitrogen oxide abatement is accomplished by use of "dry low-NOx" combustors and a selective catalytic reduction system within the HSRG. Limited quantities of ammonia are released by operation of the NOx SCR system. CO emissions are typically controlled by use of an oxidation catalyst within the HSRG. No special controls for particulates and sulfur oxides are used since only trace amounts are produced when operating on natural gas. Fairly significant quantities of water are required for cooling the steam condenser and may be an issue in arid areas. Water consumption can be reduced by use of dry (closed-cycle) cooling, though with cost and efficiency penalties. Gas-fired combined-cycle plants produce less carbon dioxide per unit energy output than other fossil fuel technologies because of the relatively high thermal efficiency of the technology and the high hydrogen-carbon ratio of methane (the primary constituent of natural gas).

Because of high thermal efficiency, low initial cost, high reliability, relatively low gas prices and low air emissions, combined-cycle gas turbines have been the new resource of choice for bulk power generation for well over a decade. Other attractive features include significant operational flexibility, the availability of relatively inexpensive power augmentation for peak period operation and relatively low carbon dioxide production. Combined-cycle power plants are an increasingly important element of the Northwest power system, comprising about 87 percent of generating capacity currently under construction. Completion of plants under construction will increase the fraction of gas-fired combined-cycle capacity from 6 to about 11 percent of total regional generating capacity.

Proximity to natural gas mainlines and high voltage transmission is the key factor affecting the siting of new combined-cycle plants. Secondary factors include water availability, ambient air quality and elevation. Initial development during the current construction cycle was located largely in eastern Washington and Oregon with particular focus on the Hermiston, Oregon crossing of the two major regional gas pipelines. Development activity has shifted to the I-5 corridor, perhaps as a response to east-west transmission constraints and improving air emission controls.

Issues associated with the development of additional combined-cycle capacity include uncertainties regarding the continued availability and price of natural gas, volatility of natural gas prices, water consumption and carbon dioxide production. A secondary issue has been the ecological and aesthetic impacts of natural gas exploration and production. Though there is some evidence of a decline in the productivity of North American gas fields, the continental supply appears adequate to meet needs at reasonable price for at least the 20-year period of the Council's power plan. Importation of liquefied natural gas from the abundant resources of the Middle East and the former Soviet states and could enhance North American supplies and cap domestic prices. The Council forecasts that US wellhead gas prices will escalate at an annual rate of about 0.9% (real) over the period 2002 - 21. Though expected to remain low, on average, natural gas prices have demonstrated both significant short-term volatility and longer-term, three to four year price cycles. Both effects are expected to continue. Additional discussion of natural gas availability and price is provided in the Council issue paper Draft Fuel Price Forecasts for the Fifth Power Plan (Document 2002-07). The conclusions of the paper with respect to natural gas prices are summarized in Appendix A of this document.

Water consumption for power plant condenser cooling appears to be an issue of increasing importance in the west. As of this writing, water permits for two proposed combined-cycle projects in northern Idaho have been recently denied, and the water requirement of a proposed central Oregon project is highly controversial. Significant reduction in plant water consumption can be achieved by the use of closed-cycle (dry) cooling, but at a cost and performance penalty. Over time it appears likely that an increasing number of new combined-cycle projects will use dry cooling.

Carbon dioxide, a greenhouse gas, is an unavoidable product of combustion of any power generation technology using fossil fuel. The carbon dioxide production of a gas-fired combined-cycle plant on a unit output basis is much lower than that of other fossil fuel technologies. The reference plant, described below, would produce about 0.8 lb CO2 per kilowatt-hour output, whereas a new coal-fired power plant would produce about 2 lb CO2 per kilowatt-hour. To the extent that new combined-cycle plants substitute for existing coal capacity, they can substantially reduce average per-kilowatt-hour CO2 production.

The proposed reference plant is based on the General Electric 7FA gas turbine generator in 2 x 1 combined-cycle configuration. The baseload capacity is 540 megawatts and the plant includes an additional 70 MW of power augmentation using duct burners. The plant is fuelled with pipeline natural gas using a firm gas transportation contract with capacity release provision. No backup fuel is provided. Air emission controls include dry low-NOx combustors and selective catalytic reduction for NOx control and an oxidation catalyst for CO and VOC control. Condenser cooling is wet mechanical draft. Specific characteristics of the reference plant are shown in Table 1

Navigant

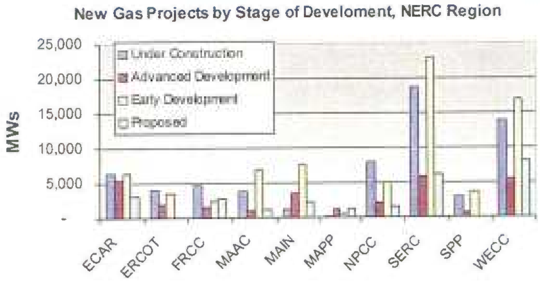
Gas

- Status and Trends
- Economics
- New Asset Development
- Value of Recent Transactions

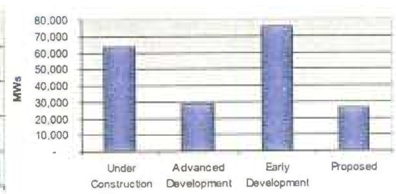
Navigant

There are over 184,000 MWs of new gas projects, with nearly 50% of that coming on-line in the next 5 years

New Gas Projects by Stage of Develoment, NERC Region



New Combined-Cycle Capacity in the U.S.



New Gas Projects by Stage of Develoment, NERC Region (New Capacity In MWs)					
	Under Construction	Advanced Development	Early Development	Proposed	Total
ECAR	6,315	5,429	6,295	3,020	21,059
ERCOT	3,979	1,830	3,500		
FRCC	4,647	1,547	2,435	2,750	11,379
MAAC	3,855	1,100	6,851	1,150	12,956
MAIN	1,168	3,376	7,644	2,250	14,438
MAPP	118	1,140	515	1,279	3,052
NPCC	7,965	2,025	5,085	1,520	16,595
SERC	18,553	5,820	23,006	6,180	53,559
SPP	2,896	770	3,560		7,226
WECC	13,870	5,579	16,973	8,120	44,542
Total	63,366	28,616	75,864	26,269	184,806

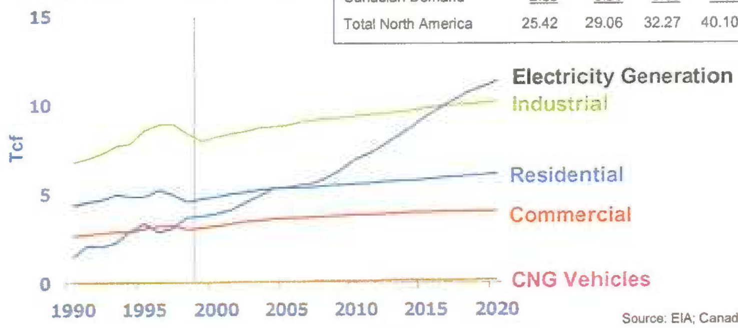
According to EIA, the share of all U.S. generation produced from natural gas will increase to 29% by 2025 from the 17% level recorded in 2001

North American Gas Demand Forecast by Sector 2000-2020

Highlights

- Over the 20 year period, gas consumption used for power production nearly triples
- 90% of North American demand is driven by the U.S.
- Growth in gas demand for electricity production outpaces other sectors by more than 4 to 1

Quadrillion BTU	2000	2005	2010	2020	Average Annual Growth
Residential	4.97	5.46	5.69	6.30	1.3%
Commercial	3.27	3.71	3.88	4.13	1.3%
Industrial	9.66	10.43	11.11	12.34	1.3%
Transportation	0.66	0.75	0.86	1.09	2.4%
Electric Generation	3.98	5.45	7.07	11.55	5.4%
Total US	22.54	25.80	28.61	35.41	2.3%
Canadian Demand	2.88	3.26	3.66	4.69	2.5%
Total North America	25.42	29.06	32.27	40.10	2.3%



Source: EIA; Canadian Natural Resources

A number of factors in both the long and short term will continue to shape the North American natural gas market

	Short Term	Long Term
Weather	☑	–
Economic Conditions	☑	☑
Underground Storage Levels	☑	–
Production Cost	–	☑
Pipeline Capacity	☑	☑
Market Demand	☑	☑
Operational Difficulties	☑	–
Technology	–	☑
Policy	–	☑
Environmental Issues	–	☑
Competitive Fuels	☑	☑

- The North American gas market is not a single market but is comprised of regional markets each with different supply, demand and price dynamics
- Important structural changes are taking place in North American gas markets including changes in consumption patterns, market pricing and sources of supply
- In order to meet demand a number of changes will be required in the North American gas industry, including significant increases in production capacity and infrastructure development
- The gas market is moving toward balance with the addition of new pipeline capacity throughout North America

On-going supply and demand issues will drive the cyclicality of natural gas as a fuel source for generation

Natural gas remains the fuel of choice among the vast majority of plant developers in North America

- Natural gas consumption is projected to grow at a rate in excess of 2.3% annually, faster than any other major fuel source – driven largely by demand from power generators
- More than half of the growth in future gas consumption is projected to come from the use of gas for power generation
- This trend in unlikely to abate as long as the technology retains its low capital cost, its high efficiency ratings, and its short construction and start-up cycle and gas stays cheap
- Over the last decade, natural gas demand continued to outstrip domestic production capabilities, imports of gas increased, and seasonal consumption dynamics have become much more complex
- The natural gas industry will continue to be plagued by boom and bust cycles given the lumpiness of production investments
- The irreversibility of (or high cost of reversing) equipment decisions by power developers will add to the cyclicality of the sector
- The existing market downturn in most regions will likely be prolonged until shortages return and create price spikes thereby attracting new development

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A simple-cycle gas turbine generator set consists of a gas compressor, fuel combustors and a gas turbine. Air is compressed in the gas compressor. Energy is added to the compressed air by combusting liquid or gaseous fuel in the combustor and the hot, compressed air is expanded through the gas turbine. The gas turbine drives both the compressor and an electric power generator.

Gas turbine power plants are available as heavy-duty "frame" machines specifically designed for stationary applications, or as aeroderivative machines - aircraft engines adapted to stationary applications. Because of higher rotor speeds and pressure (compression) ratios, aeroderivative machines are more efficient and compact than frame machines, but are more costly to purchase than frame machines. Aeroderivative machines exhibit excellent operational flexibility with superior black start capability, short run-up periods, capability for overpower operation (at a shortening of maintenance intervals, however) and ability to trade off higher power operation at low ambient temperatures for overpower operation at high ambient temperatures (constant power operation). Aeroderivative machines are highly modular and major maintenance is often accomplished by swapping out the engine for a replacement, shortening maintenance outages. Both frame and aeroderivative stationary gas turbine technology development is strongly driven by developments in military and aerospace gas turbine applications.

A typical simple-cycle gas turbine power plant consists of one to several gas turbine generator sets. The generator sets are typically equipped with inlet air filters and exhaust silencers. Water or steam injection, intercooling or inlet air cooling can be used to increase power output. Steam injection requires a heat recovery steam generator. Increasingly, exhaust gas catalysts are used to reduce nitrogen oxide and carbon monoxide production. Other plant components may include a switchyard for electrical interconnection, fuel gas compressors (if line pressure is inadequate for the gas turbine generator) a water treatment facility (if units are equipped with water or steam injection) and control and maintenance facilities. Simple-cycle gas turbine generators are often co-located with gas-fired combined-cycle plants to take advantage of shared site infrastructure and operating crew.

Gas turbines can operate on either gaseous or liquid fuels, however pipeline natural gas is the fuel of choice because of historically low and relatively stable prices and low air emissions. Though still occasionally used, distillate fuel oil is has become less common as backup fuel in recent years because of environmental concerns, the periodic turbine testing required to ensure proper operation on fuel oil and increased maintenance associated with fuel oil operation. It is now more common to ensure fuel availability by securing firm gas transportation. A few plants have used propane as backup fuel.

The principal environmental concerns associated with simple-cycle gas turbines are emissions of nitrogen oxides (NOx) and carbon monoxide (CO). Noise has been a concern at sites near residential and commercial areas. Fuel oil operation may produce sulfur dioxide. Within the past decade, the commercial introduction of "low-NOx" combustors and high temperature selective catalytic controls for NOx and CO, has enabled the control of NOx and CO emissions from simple-cycle gas turbines to levels comparable to combined-cycle power plants. Water is required for water or steam injection but is not usually an issue for simple-cycle machines because of relatively low consumption. Gas-fired simple-cycle plants produce moderate levels of carbon dioxide per unit energy output because of the moderate thermal efficiency of the technology and the high hydrogen-carbon ratio of methane (the primary constituent of natural gas).

Because of the ability of the Northwest hydropower system to supply short-term peaking capacity, simple-cycle gas turbines have been a minor element of the regional power system. As of January 2000, about 900 megawatts of simple-cycle gas turbine capacity were installed in the Northwest, comprising less than 2% of system capacity. The power price excursions, threats of shortages and abnormally poor hydro conditions of 2000 and 2001 sparked a renewed interest in simple-cycle turbines as a hedge against high power prices, shortages and poor water. About 360 megawatts of simple-cycle gas turbine capacity has been installed in the region since 2000, primarily by large industrial consumers exposed to wholesale power prices and by utilities with direct exposure to hydropower uncertainty (including Bonneville "Slice" customers).

The proposed reference plant is generally based on a large aeroderivative gas turbine generator such as the General Electric LM6000, Pratt & Whitney FT-8 or Rolls-Royce RB211. The rated capacity of these machines ranges [up to] 48 megawatts. Recently-developed simple-cycle projects in the Northwest have tended to use smaller machines, though this is believed to be an artifact of machine availability and permitting requirements. Fuel is assumed to be pipeline natural gas. A firm gas transportation contract with capacity release capability is assumed, in lieu of backup fuel. Air emission controls include dry low-emissions combustors plus selective catalytic reduction for NOx control and an oxidation catalyst for CO control. Costs are representative of a machine located at an existing gas-fired power plant site, or two or more machines located at a greenfield site. Fuel gas delivery pressure is assumed to sufficient to not require additional compression.

References:

GE (2000): General Electric Power Systems. *GE Aeroderivative Gas Turbines - Design and.*

Risk Management

Chapter 6

MANAGING ENERGY RISK

INTRODUCTION

Following PSE's previous Least Cost Plan, the Washington Utilities and Transportation Commission (WUTC) issued a comment letter dated August 21, 2001, with the following remarks on energy risk management:

Risk Management: *The least-cost planning rule requires utilities to develop integrated resource plans that meet "current and future needs at the lowest cost to the utility and its customers." In fulfilling this rule, PSE must balance price, supply, and weather risks against the directive to minimize costs. The recent energy debacle revealed price and supply risks that few utilities or energy consumers had heretofore recognized. The Commission is keenly interested in the procurement and other strategies utilities use to manage these risks (e.g., acquisition of additional generating capacity, long- and short-term power purchases, fixed and floating price derivatives, and other hedges and risk management instruments.) A detailed description of risk-management strategies and how those strategies advance the twin goals of low and stable rates should be a critical component of PSE's next plan. Moreover, the plan should empirically support the chosen strategies with a short-term evaluation of their economic effects.*

For this Least Cost Plan, PSE is addressing energy risks and their implications for:

- Planning PSE's long-term energy resource portfolio,
- Acquiring new energy resources, and
- Managing PSE's energy resource portfolio

PORTFOLIO PLANNING

Portfolio planning involves developing a long-term resource strategy that identifies the Company's preferred mix, or portfolio, of resources to meet is customers' needs. Setting the preferred portfolio mix includes making choices among resource technologies. It also requires determining what proportion of the portfolio should be composed of long-term resource commitments (e.g., owned generation and long-term contracts), and what remaining proportion (if any) of the portfolio should rely on short-term resources.

As noted in the WUTC comments, the long-term resource strategy and preferred resource portfolio must balance tradeoffs between the objective of minimizing costs and the objective of protecting against undesired variability in costs due to price, supply and weather risks. These issues and activities are the primary focus of the Least Cost Planning process. In particular, Chapters 8 and 9 of this report describe the methods and approach that PSE is using to address energy risks as they relate to development of the long-term resource strategy and the preferred resource portfolio. Chapter 2 also addresses a number of topics that involve energy-related risks and that bear upon determination of the resource strategy.

RESOURCE ACQUISITION

Resource acquisition involves obtaining specific new energy resources that are consistent with the long-term resource strategy. In essence, acquisition of new resources is an implementation activity that carries out the desired configuration of the energy resource portfolio. However, because new resource opportunities tend to be situation-specific, PSE's resource acquisition activities must be responsive and take into consideration the actual circumstances (including changes in conditions from the previous Least Cost Plan) that exist at the times when resource acquisition decisions are being made. Chapter 2 of this report identifies and discusses various factors that are affecting the risks and opportunities for PSE to acquire new resources.

PORTFOLIO MANAGEMENT

Management of PSE's energy resource portfolio entails managing, at any given point in time, an existing mix and level of long-term and short-term resource commitments – along with the resulting short-term risk exposures. Portfolio management activities include hedging the portfolio against many of the risks that are addressed in long-term resource planning and acquisition. However, portfolio management is a comparatively more dynamic process, involving anticipating and protecting against shorter-term risks and taking actions based on actual circumstances such as observed hydro reservoir levels or shifts in forward market prices for electricity and natural gas.

Resource Planning, Resource Acquisition and Portfolio Management All Involve Risk Management

Determination of PSE's preferred resource strategy, acquisition of new resources and management of the existing portfolio all involve the management of energy-related risks.

For example, development of the long-term resource strategy includes determining how much of the portfolio should be composed of a particular type of resource whose availability may vary with short-term changes in weather conditions or whose cost may vary with fluctuations in market prices. As a result, decisions on the resource strategy typically result in configuring the resource portfolio to accept a certain degree of remaining exposure to such risks. As noted above, decisions like this involve balancing tradeoffs between minimizing costs and minimizing undesired variability in costs. However, these same decisions should also reflect an assessment of how well the resource portfolio can then be managed, including the current – and future – viability and cost-effectiveness of hedging the portfolio's remaining risk exposures using financial derivatives or other short-term instruments.

IMPACT OF RECENT DEVELOPMENTS

Over the last several years, PSE has made significant advances in its understanding of various risks associated with its existing energy resource portfolio. The Company has also developed and implemented effective hedging strategies to help mitigate risks. However, ongoing changes and upheavals in the energy industry, including those discussed in Chapter 2, are making it increasingly difficult to use short-term hedging transactions to manage risk exposures in PSE's existing resource portfolio. Therefore, the remainder of this Chapter addresses management of PSE's existing energy resource portfolio, with particular emphasis on the outlook for the viability and economic effects of hedging the existing portfolio's risk exposures.

PORTFOLIO RISK MANAGEMENT

PSE's near-term portfolio risk management philosophy is to protect its energy portfolios from commodity price risk exposure and counterparty risk exposure. Its risk management practices are based upon the following principles: 1) identify risk exposure in the energy portfolio 2) measure the degree of the risk exposure 3) develop and test risk management strategies designed to reduce risk exposure 4) implement risk management strategies that minimize energy cost volatility and 5) implement the risk management strategies approved by the Risk Management Committee. The energy risk management function is focused on risk mitigation and value protection of the portfolio.

PSE manages its energy supply portfolio to achieve three primary objectives:

- ensure that physical energy supplies are available to serve retail customer requirements;
- manage portfolio risks to serve retail load at overall least cost while limiting undesired volatility on customer bills and PSE financial results; and
- optimize the value of PSE energy supply assets.

PSE manages the physical and financial positions and exposures through real-time trading, daily pre-scheduling, hedging, supply portfolio management, and optimization. Specifically PSE may purchase and sell energy in the spot and forward markets and dispatch or displace generation units and nominate storage injection or withdrawal, both to balance the supply portfolio and to achieve net cost reductions.

PSE manages financial exposures associated with price and volumetric risks consistent with the following:

1. PSE manages the price and volumetric risks associated with its retail and wholesale energy sales with a diverse supply portfolio of resources that includes hydro, coal-based generation, combustion turbines, non-utility generation contracts, long-term purchase and exchange contracts, gas supply contracts, gas transportation and electric transmission, storage and peaking options and physical and financial wholesale energy and options on energy purchases and sales.

2. At times when PSE's energy supply resources may exceed its sales customer obligations, PSE manages the price risk associated with the excess resources by entering into forward energy sales transactions or options on energy sales transactions. For example, PSE may forward sell energy at fixed prices or purchase put options at fixed strike prices.

3. At times when PSE's sales obligations exceed available resources, PSE manages the price risk associated with deficit resources by entering into forward energy purchase

transactions or options on energy purchase transactions. For example, PSE may enter into energy purchases at fixed prices or purchase call options at fixed strike prices.

4. PSE manages the location risk associated with the anticipated energy resource sales by entering into purchase and sales transactions that have the same delivery point, term, and volume as the anticipated transaction. At times PSE may tie purchases and sales together by acquiring firm transmission rights to deliver energy associated with purchase or sale transactions to the point of receipt/delivery for the anticipated transactions.

5. PSE enters into other derivative products such as weather, hydro, and plant outage derivatives for purposes of managing exposure in the energy portfolio. These instruments and their strategic application to the portfolio shall be approved by the Risk Management Committee.

Management of PSE's wholesale energy portfolio is a highly dynamic process driven by a number of factors, including:

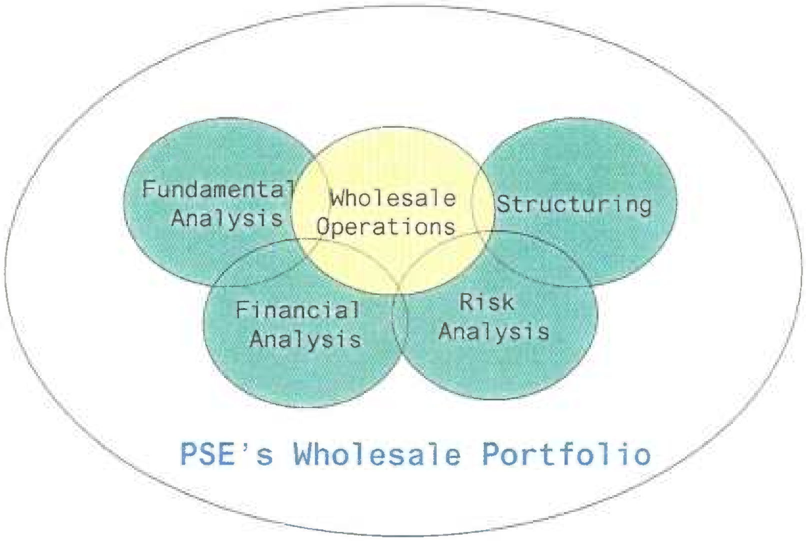
(a) relatively predictable diurnal and seasonal fluctuations in PSE's retail customer requirements;
(b) less predictable fluctuations in PSE's energy supply requirements due to temperature swings, economic conditions, system outages and customer growth;
(c) year-to-year, seasonal, and short-term variability in stream flows and hydroelectric generation and short term supply demand imbalance in gas supply markets;
(d) forced outages of generation;
(e) volatility in market prices for energy; and
(f) constraints in electric transmission, gas transportation capacity and storage injection/withdrawal capability.

PSE manages a complex energy portfolio that requires careful measurement of volumetric and financial exposures. Specifically, PSE monitors financial positions on a daily basis, analyzes physical and financial variability, conducts portfolio and scenario analysis, develops risk management strategies and executes risk management strategies while giving consideration to financial reporting requirements and accounting treatment under FASB Statement No.133.

RISK MANAGEMENT PERSPECTIVES

Within Energy Risk Management, the company employs several analytical disciplines to cover different facets of portfolio management. It is important that the various functions inter-relate, so that the overall effort is coordinated and models and theories are used consistently for multiple purposes (Figure 1).

Figure 1



Fundamental analysis is the study of supply and demand factors that are influencing the price of energy in a given market for a certain time frame. PSE applies both a top-down and bottoms-up approach to fundamental analysis. The company uses some tools such as stacking models to replicate market behavior. This provides both a base expectation, as well as other scenarios that might result in different market prices. Having a range of possible outcomes enables the risk management group to get a sense for potential risks, and to identify what are the single largest uncertain factors.

COMMODITIZATION OF ENERGY MARKETS

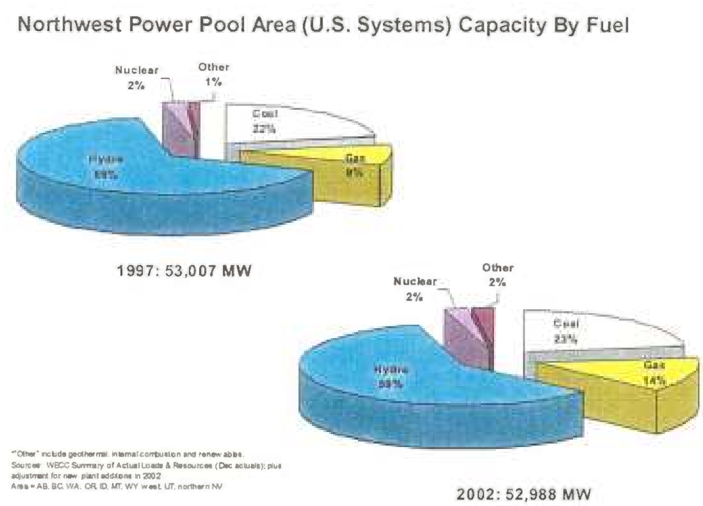
Supply/Demand fundamentals are the primary drivers to commodity prices. Over the last five to ten years, natural gas and electric markets have become 'commoditized' through FERC deregulation of the natural gas pipeline industry and electric power sector. Today, the indicators that power and natural gas are commodity markets are:

- Price discovery through numerous market buyers and sellers electronic exchanges and broker markets.
- Development of liquid pricing locations at central trading hubs such as Mid C for power and Sumas, WA for natural gas.
- Standardization of contractual terms for physical power, natural gas and associated financial derivatives.
- Development of a parallel financial markets and new structured products around physical power and natural gas markets.

POWER MARKET DRIVERS

With respect to understanding the underlying supply/demand factors, the company looks at a number of leading indicators. In power, the key variables in the Pacific Northwest are weather (temperature and precipitation), economic conditions, fuel costs, plant heat rates, plant availability, transmission and intertie capacity, hydro energy and storage, biological opinion

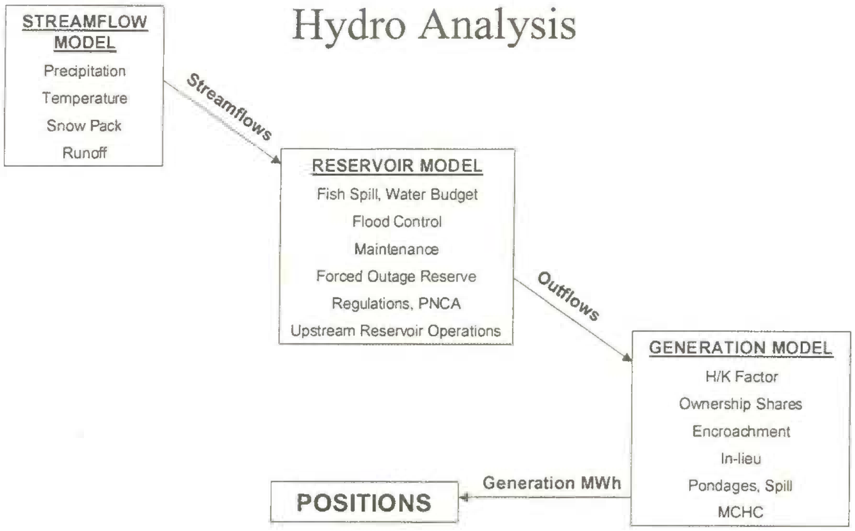
Figure 2



affecting flows on the river system and spill requirements, new generation capacity and other neighboring regional power market dynamics.

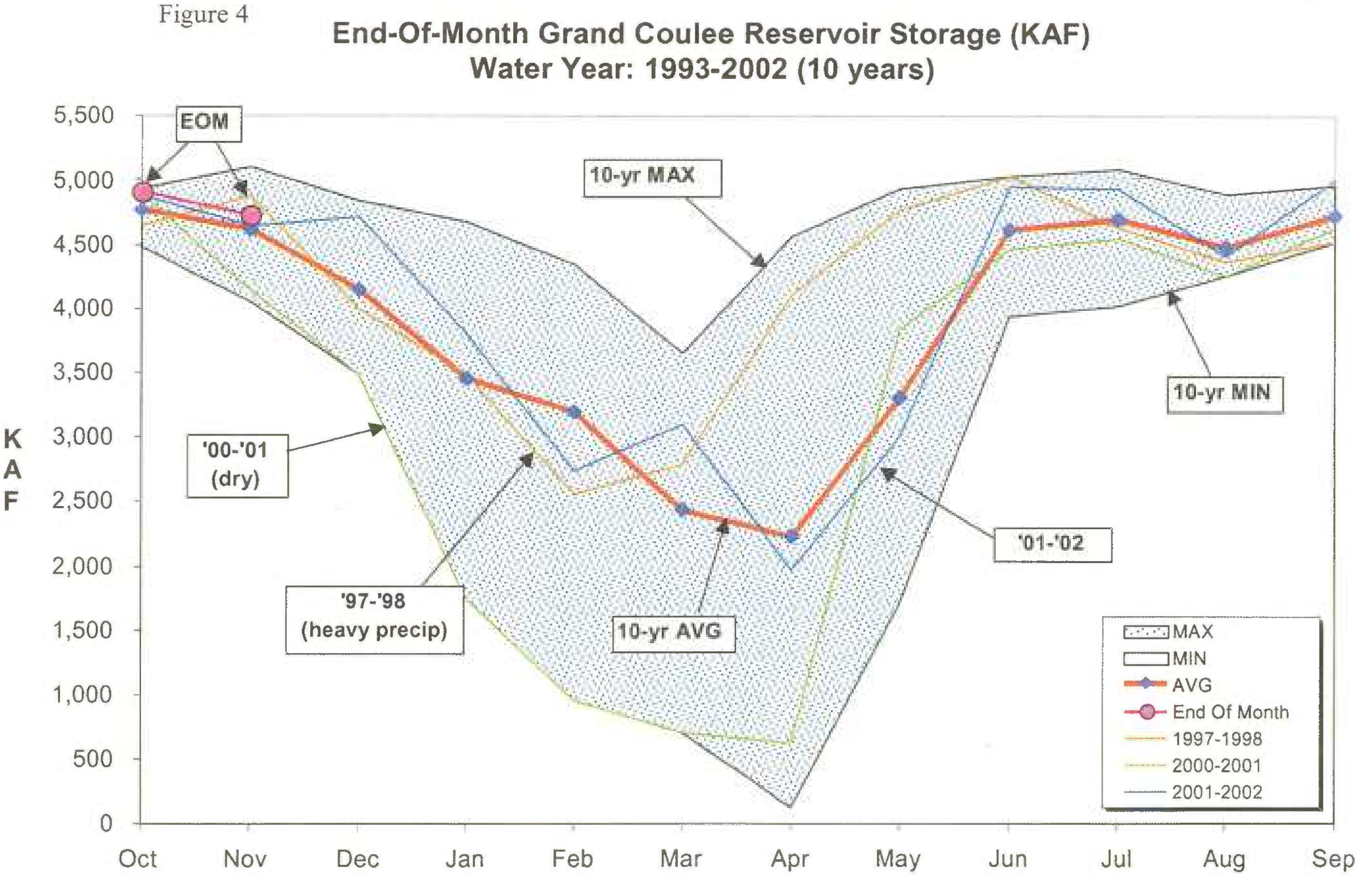
Hydro energy is the largest share of power generation in the Pacific Northwest (Figure 2). Hence, hydro energy availability is the single largest source of variability in PSE's energy portfolio. This is because the cost of the energy is extremely low, relative to market-based replacement power. Additionally, the percentage change in any given year from normal hydro output is a meaningful number in PSE's portfolio (between 5,600,000 and 9,800,000 MWh). As a result, hydro analysis is very important. Forecasting energy out of the hydro system is highly complex. As a result, PSE conducts analysis internally, and supplements the analysis with two outside consultants. Information is gathered on precipitation at critical locations that mimic the Company's West Side hydro facilities and which correspond to the rainfall into the federal river system. See Figure 3. shows a schemata of PSE's hydro modeling. The precipitation information feeds a "Streamflow Model" which feeds a "Reservoir Model" that subsequently models fish spill, flood control, forced outages, regulation and other factors affecting outflows of water. The last piece of the modeling effort is the Generation Model, from which PSE forecasts available energy for the base case position. The final stage, which the company is just now completing, it to take the base case forecast and run scenario tests based upon historical years. This allows the Energy Risk Management group to project a range of possible energy outcomes as a result of the scenario testing.

Figure 3



Hydro reservoir storage is a short-term market indicator, in addition to elevation levels on the federal system above Grand Coulee dam, and MAF (million acre-feet) streamflow levels. These, in addition to plant outages, weather reports, and spot fuel prices help PSE understand what energy is coming into the market, and understand the relative changes by day and through the current month of energy costs. Figure 4 illustrates graphical representation of historical reservoir levels.

Figure 4

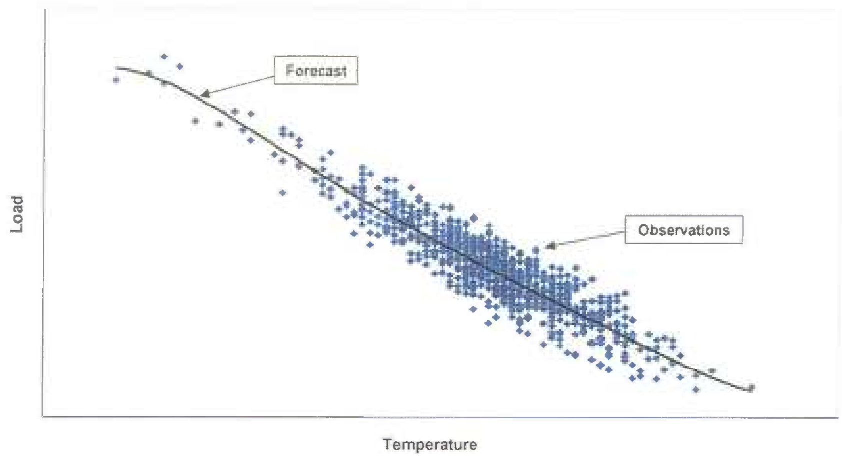


Source: USBR

The next largest source of variability in PSE's Power portfolio is load, which is driven by customer count, temperature and economic conditions. The Energy Risk Management group models expected average load, and then develops a forecast range for minimum and maximum loads that is needed to model variability for exposure testing. The challenge is to have enough energy to serve the peak loads, but to have some flexibility to back down supplies in off-peak periods in order to mitigate costs.

Figure 5

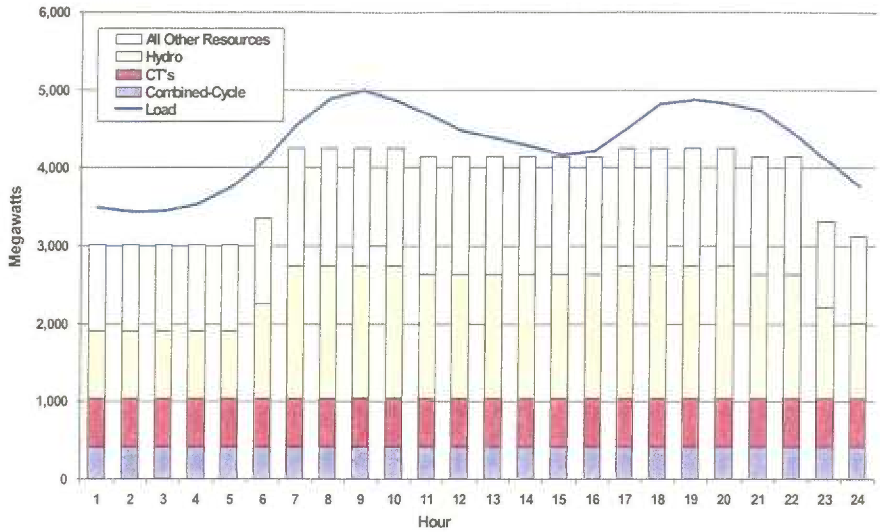
Load versus temperature relationship



The nature of PSE's load is that it has hourly variability, as well as diurnal and seasonal variability. At any given time, the company must plan to meet that load, especially in an extreme winter peak condition. The hourly management is further complicated because the load profile has a double peak. Figure 6 shows a typical load picture over a twenty four-hour period. PSE's hydro storage is a very important resource for balancing the resource and loads on a short-term basis. The company has storage both at its Baker facilities and through its Mid C contracts.

Figure 6

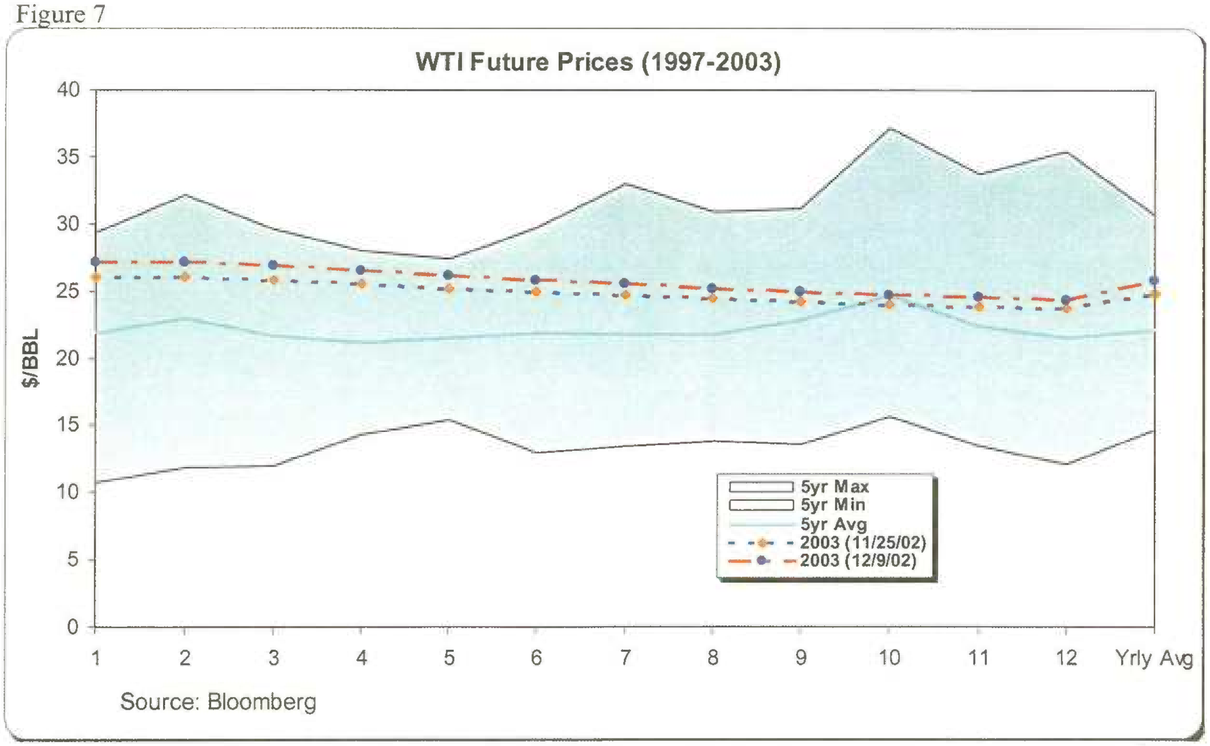
Peak Load Analysis and Planning



NATURAL GAS MARKET DRIVERS

Natural gas market drivers are similar, for natural gas is a growing part of the generation mix in the Pacific Northwest (Figure 2). Therefore power market factors, particularly the relative surplus or deficit of hydro energy, can have a large impact on regional natural gas demand. Significant movements in natural gas market prices will also affect power prices.

Figure 7



Oil prices are strongly linked to natural gas prices for a couple of reasons (Figure 6). In the fuel consumption area, natural gas competes with two refined products, residual fuel and distillate fuel which are burned in older fossil fuel plants as an alternate fuel to natural gas. In the exploration

& production sector, natural gas and crude oil are sometimes found together ("associated oil"), or at times have to compete for exploration budgets. An indicator of natural gas drilling activity is 'rig counts', and there can be an eight to eighteen month lag time between drilling and gas coming to market. PSE tracks rig counts to monitor the longer term increasing or decreasing supply trends.

An important gauge to natural gas supply/demand imbalances is the storage inventories. The natural gas industry uses salt caverns and depleted oil wells as underground storage facilities. The relative level of inventory is an important determinant of relative surplus or deficit in the short-term markets. PSE tracks the weekly and monthly storage inventory levels nationally, as well as in the western US and Canada.

As with power markets, weather and economic factors are important determinants in price volatility. PSE's gas load is predominantly heating load-based, and is extremely sensitive to variations in load on account of changing weather patterns. PSE monitors weather patterns from several sources including local weather stations, national weather service and through a weather subscription with Weatherbank.

CREDIT RISK MANAGEMENT

The company faces significant constraints executing wholesale transactions in short-term and medium-term power and gas markets. There are several factors at work. One, the markets are much less liquid with fewer parties transacting, and the forward time frame is shrinking to shorter-term delivery periods. Two, the industry is extremely concerned about default risk, given the recent bankruptcy filing of Enron, NRG, and TXU Europe. Therefore credit requirements have risen dramatically. Three, the higher rated companies command a 'premium' in their power and natural gas prices to transact with them. That increases operating costs significantly for PSE since its credit rating is only just above investment grade.

In both power and gas markets, there has been a huge decline in forward market activity by traditional investor owned utilities and municipal load serving entities. Moreover, the large energy marketing companies have either exited the Pacific

Northwest markets have scaled back for strategic purposes, have stopped trading altogether in North America (Aquila, Dynegy), or simply cannot transact because of their weak credit rating There are several implications to the liquidity concerns. Forward hedging is much more difficult, and the company is in an uncomfortable position of having to ration credit across multiple needs and activities (power, gas, weather derivatives, peaking capacity, regional exchanges to improve reliability). In Core Gas, PSE has ample storage and pipeline capacity, but because of market illiquidity, the company cannot optimize its assets fully, but must hold open capacity or inventory for significant changes in load. Another implication to the market liquidity problem is that the Company is challenged in displacing and dispatching its generation units to respond to all price opportunities.

In addition to liquidity concerns that hamper hedging, short-term balancing and asset optimization, PSE faces serious credit concerns from counterparties. Entities who would have transacted with PSE a year ago, are now concerned about our credit rating. By example, a surprising number of natural gas producers are reluctant to sell fixed price to us because they are concerned about PSE's credit rating.

TOOLS AND METHODS

Portfolio Management

PSE utilizes an energy transaction capture and risk management system ("system") to capture, monitor, manage, and control physical positions, exposures, and variances. The system monitors volumetric positions and financial exposures and variability. Additionally, PSE uses proprietary models to conduct portfolio and scenario financial analysis of the energy supply portfolio. These models are analytical applications incorporating industry- models and third party software. The Energy Risk Management and Risk Control groups perform specific analyses to quantify volumetric and financial exposures with internal written procedures. Risk Control is responsible for deal capture, data integrity, and reporting from the system. Figure 8 gives the KWI explanation for the Risk Analysis module.

Figure 8.

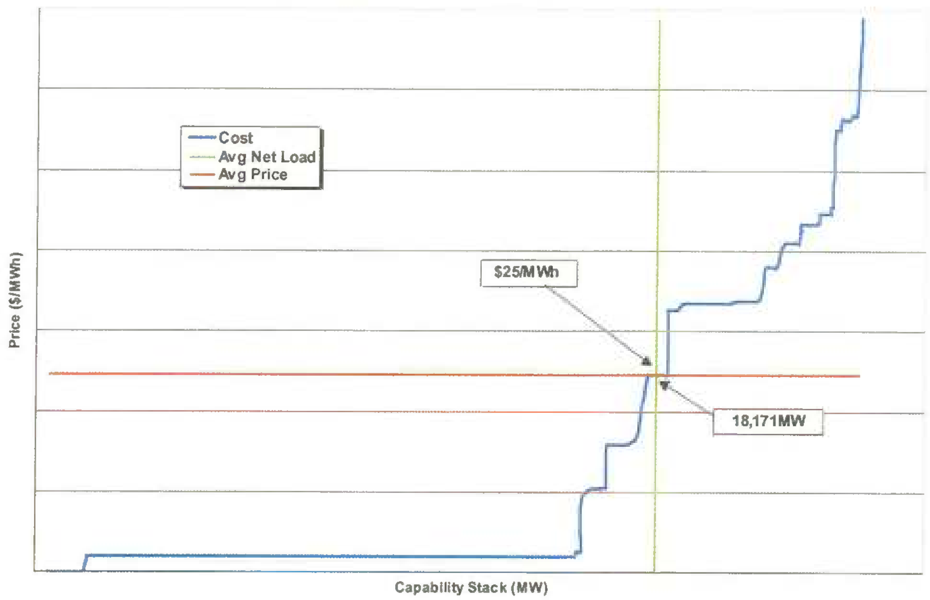
Module Name
Risk Analysis
kWRiskAnalysis.exe
The objective in using this module is to find a strategy that best improves the profit/risk trade-off in a portfolio or sub-portfolio of the company. In this module the Risk Manager (or similar person) can carry out detailed risk analysis to ascertain the expected profitability of the total portfolio or any part of the portfolio in the potential profit at risk. Risk managers can see the effect of adding a new trade or trades and then can assess how their position relates to a variety of categories such as Production, Bilateral purchases, Futures (or Standard Product) purchase, Spot purchases, End user sales, etc. This data can also be viewed in a graphical manner. Risk managers are then able to perform sensitivity analysis in order to evaluate the impact on ratio between profit and risk of any trading, production or sales strategies. This is used to develop hedging strategies that create a portfolio including physical assets (such as generation plant and retail customers) that is robust to changes in the market.

Fundamental Analysis Tools

To model the Pacific Northwest region's power supply/demand dynamics, the company utilizes the Aurora model. Energy Risk Management staff have adapted the long-term forecasting tool to simulate economic dispatch throughout the region in short-term market scenarios.

Figure 9

Fundamental Analysis Example:
Forecasting Regional Supply and Demand



The intersection of projected load and the resource stack gives the theoretical market-clearing price. PSE does not use the model so much for a point estimate for price, but more as a tool to give an indication of market price direction, and the scale of that potential market price move, given changes to inputs in the model. This tool is used to give a sense of relative change in market prices given different assumptions for regional load and estimated generation availability.

To model its natural gas portfolio, PSE utilizes a model called "U Plan G". This model enables the energy risk management staff to simulate the gas portfolio using estimated loads and capacity utilization. The model is loaded with assumptions about estimated load, transportation requirements, storage requirements, and an estimated market value for unused capacity.

APPROACH TO MANAGING PRICE RISK

PSE's goals in hedging and managing price risks in the power and gas portfolios are to:

- Provide price certainty and to lock down risks (Gas and Power)
- Keep prices stable and minimize costs (Gas and Power)

PSE has internal risk management processes to help bring focus and order to the energy risk management function. For power, Energy Risk Management staff develops position reports based upon probabilities load, generation output, and unit availability. The probabilities position is driven by several important inputs. First, the analysis centers on current market prices for fuel and power, and price dispersion around those base prices. Next, each plant's operating characteristics are modeled, and a resulting fuel need and estimated power output results. Plants with lower heat rates (better conversion costs of fuel to power) will typically be economically dispatched more often in the models feeding the position, whereas, peaking units have less impact and contribution to position. Lastly, dispatchable contracts are modeled to be fully optimized for a given set of price assumptions and load/resource balances.

The resulting information is a position report that illustrates the net open position for every month for power and natural gas. The positions are generated for 12-24 months out in time. Next, the energy risk management staff evaluate the forward positions, and explore which of them have significant forward risks associated with them. There is a prioritization process of focusing on these items that can be hedged, and which have the greatest risk associated with them.

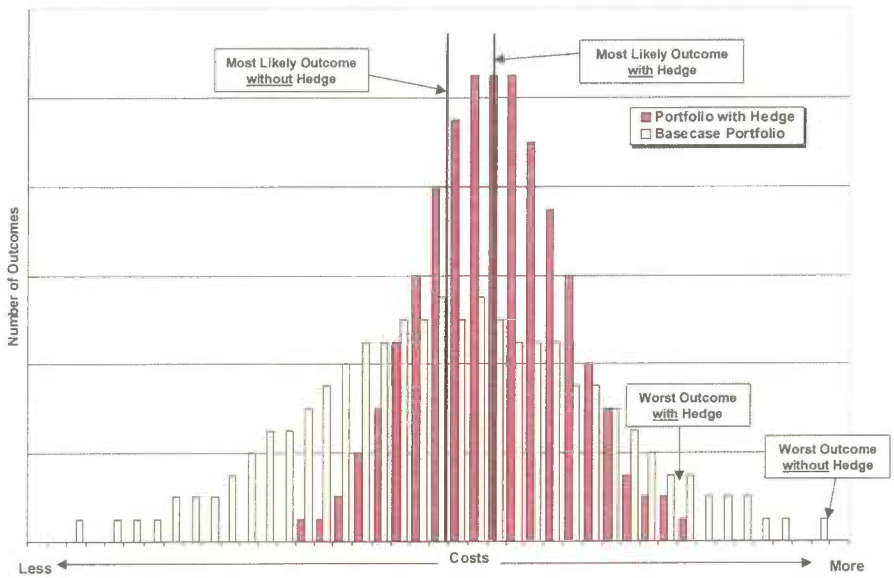
Hedge strategies are developed. A wide range of deal structures is evaluated. The hedge might be a straightforward fixed price purchase or sale of fuel or power. It might be a seasonal exchange, or a buy/sell at different locations. Still other common instruments are options, such as a call (option to purchase) or a put (option to sell). Calls and puts can be valuable instruments, *depending upon their cost,* to offset the risks PSE has in a load that is highly weather-related.

Strategies are tested, not only against the current probalistic position, but also for the portfolio in numerous other market scenarios (different hydro, load, energy prices, etc.). The goal is to identify a strategy not only the base case, but also for other scenarios. Sometimes the 'winning' strategy is not the immediately obvious strategy, but one that takes significant risks out of the portfolio under a range of conditions.

PSE has just begun to utilize the new KW 3000 tool to measure how hedging strategies take out risks in different scenarios. Figure 10 shows a histogram of what a hedge strategy ideally does in terms of reducing outlyer risks and not moving expected outcome (the mean) too much as a result of the hedged cost.

Portfolio Risk Analysis

Measuring cost of Hedging versus Risk Reduction



PSE monitors how the hedge cost affects the bottom line costs. PSE sets a budget for power costs at the beginning of the year. This includes hedging costs, as well as operating costs. Hedge costs need to be taken into consideration so the hedge costs don't move the expected value or outcome too much in a negative fashion.

Integration of Optimization with Hedging and Risk Management

PSE strives to find a healthy tension between removing price exposure, but doing it so as to not assume large hedging costs. In addition, in both the power and gas portfolios, the company seeks to optimize idle capacity and maximize the operational flexibility of its assets and contracts. The optimization is a cost mitigation function, as it helps defray some of the fixed costs associated with transmission, transportation, storage and inventory costs.

Distribution Planning

Chapter 7

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.

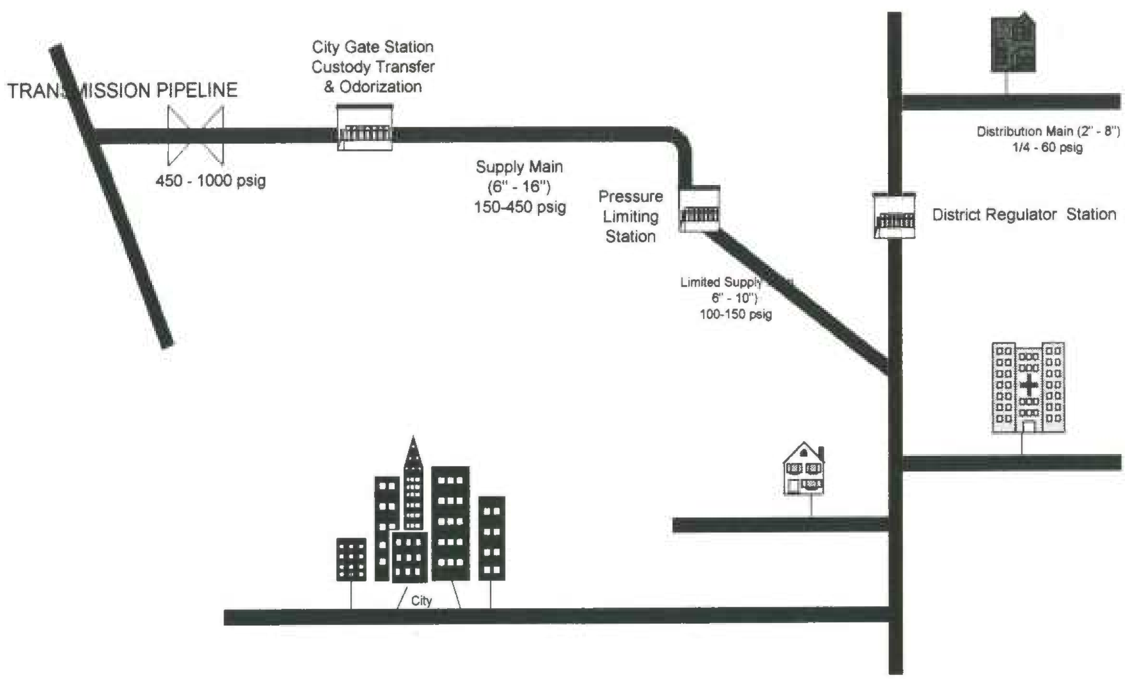
SCIENCE OF THE ENERGY

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.

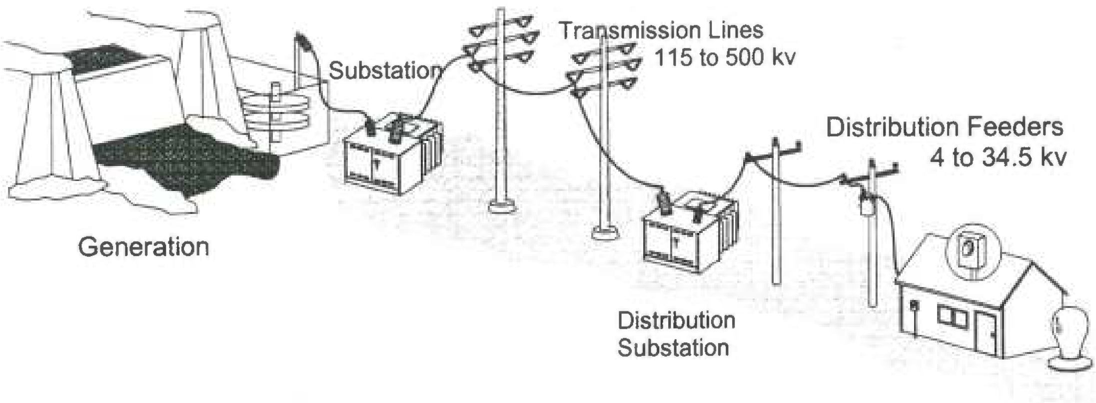
GAS SCHEMATIC
DISTRIBUTION SYSTEM



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 303 substations, 2901 miles of transmission, 10,523 miles of overhead distribution, and 8,224 miles of underground distribution lines to serve approximately 941,697 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 624,463 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.

ENERGY INDUSTRY CHALLENGES

Within the energy industry, restructuring is a theme which continues to change how the utility plans for and provides distribution 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 diverse quality power needs than that had previously been designed for and routinely delivered. These higher performance standards create additional challenges and costs 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.

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

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

Electric

- the temperature at which the system is expected to perform
- the level of reliability each type of customer is contracting for
- the minimum voltage the system must maintain
- the maximum voltage the system can accept
- 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.

ASSET MANAGEMENT APPROACH

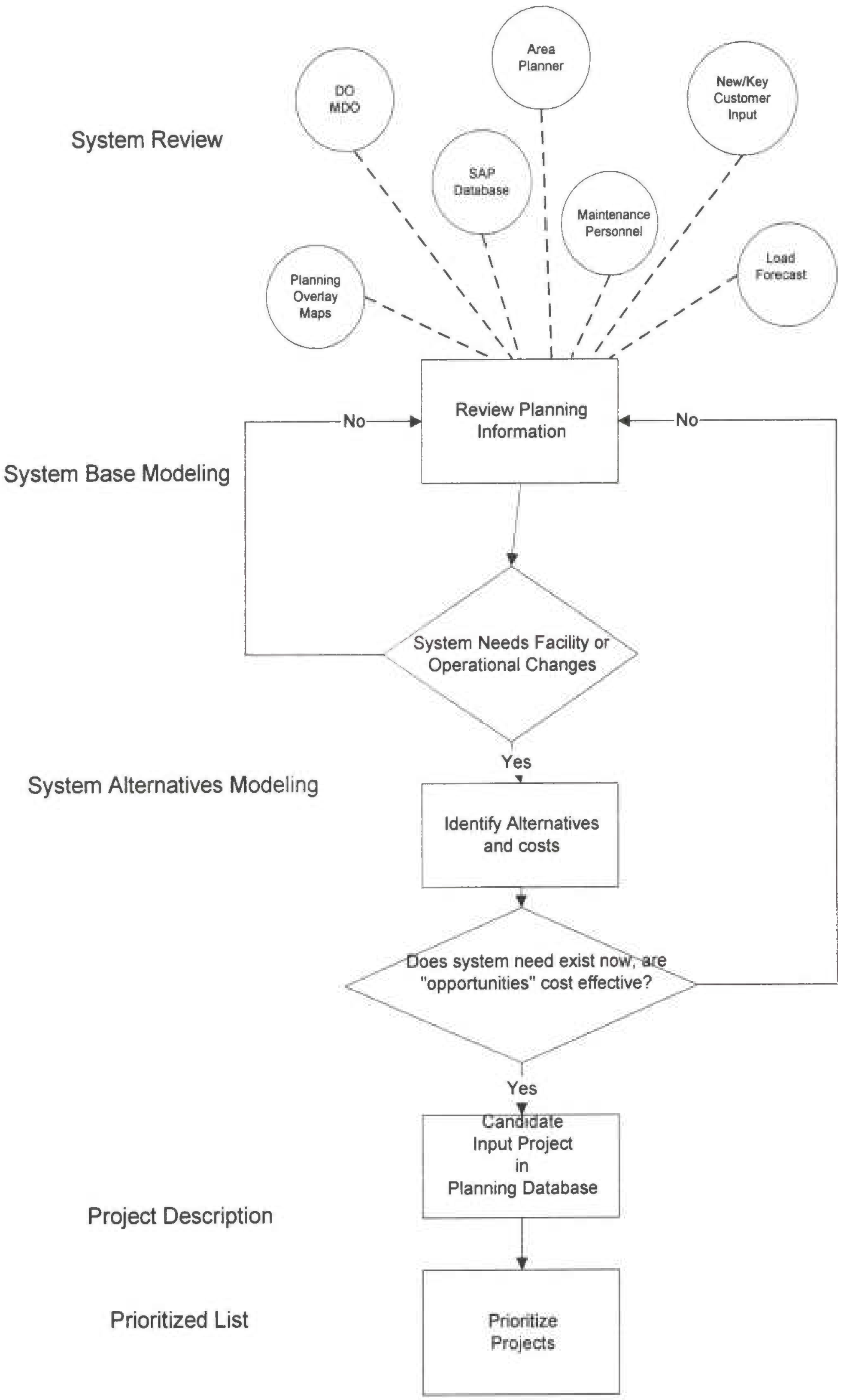
An important part of distribution planning is the concept of "asset management." The basic concept of asset management is to assure that existing facilities are being fully utilized before new facilities are added, unless the cost advantage of early installation offsets the cost of having the facility 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.

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



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.

PSE uses a combination of methods to produce a load forecast for a particular area of study of the distribution system. From a historical perspective, a trend of actual system peak load readings is used which reflects the loading levels of the system components within the study area. The future near term forecast tracks permitted construction activity which will result in new loads added to the system within the next 2 years. Longer term forecasting comes from PSE's corporate econometric forecasting method which includes growth due to population and employment data by county (see Section II. Energy Demand Forecasting). Together, these resources provide a 5 year history and 10 year forecast which acts as one of the inputs to the planning process.

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 services. 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.

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.

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.

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.

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.

Electric Load-Resource Analysis

Chapter 8

Electric Load-Resource Analysis

INTRODUCTION

This chapter describes the electric load-resource analysis that PSE is performing for the current least cost plan, including the analytical process, modeling tools and major input assumptions that are being used.

This chapter presents the determination of PSE's need for new electric resources, including annual energy needs, monthly energy needs and winter peak capacity needs. As discussed further in section 8.e., PSE faces a large and growing need for new electric resources. The need for new electric resources includes annual energy, monthly energy and winter peaking capacity. These needs for new electric resources are driven in part by projected growth in PSE's retail customers' electrical demands; however they are also reflect significant losses of existing resources from PSE's portfolio, including expiration of power supply contracts and retirement of other existing resources.

Various alternative resource portfolios that are being evaluated are also described, along with key uncertainty factors that are being used to perform an initial screening and risk analysis of the alternative resource portfolios. A description is also provided of PSE's plans to perform further, more detailed analysis of the screened resource portfolios in early 2003, followed by integrated load-resource analysis using updated conservation resource assessments, which are scheduled to become available in mid-2003.

The electric load-resource analysis for this Least Cost Plan will also address potential revisions to PSE's resource planning standards. In addition, the load-resource analysis will identify and evaluate possible modifications to existing resources (beyond those existing resources that are already known or assumed to drop out of the portfolio), including resources whose costs or fuel-conversion efficiencies may make it preferable to modify or remove them from the portfolio.

OVERVIEW OF ANALYTICAL PROCESS

Compared with PSE's previous least cost plan, the Company is using a significantly revised and updated the analytical process for this least cost planning cycle. In part, this process seeks to respond to comments that were received following PSE's previous least cost plan. The process is also structured to reflect and respond to major changes that have occurred and are ongoing in the energy utility industry. Accordingly, the new analytical process now being used is designed to provide a more rigorous, yet flexible, approach for meeting the objectives described in Table 8.1:

Table 8.1 Analytical Process Objectives	
1.	Comprehensive analysis of long-term energy resource planning issues and alternatives, using consistent methods and assumptions
2.	Explicit assessment of key uncertainties, including probabilistic analysis of major risk factors and associated tradeoffs
3.	Formulation and testing of a broad variety of potential resource portfolios
4.	Use of defined criteria to guide the analysis and to provide results that facilitate open, well-documented decision-making that includes both quantitative and qualitative factors
5.	A responsive, iterative process that promotes timely, useful results at each major stage and ultimately results in full integration of energy supply resources and demand-side management

To accomplish these objectives (including balancing tradeoffs among them), PSE has organized the least cost plan analytical process to proceed in several stages, as listed in Table 8.2:

Table 8.2 Major Stages in the Least Cost Plan Analytical Process	
1.	Development of Major Input Assumptions and Forecasts
2.	Forecast of Market Prices for Electricity in the Pacific Northwest
3.	Determination of PSE's Need for New Resources
4.	Resource Portfolio Screening Analysis
5.	Detailed Analysis of Resource Portfolios
6.	Integrated Analysis Using Updated Conservation Resource Estimates

The remaining sections of this chapter focus on each major stage of the analytical process identified in the table above.

DEVELOPMENT OF BASIC INPUT ASSUMPTIONS AND FORECASTS

Forecasts of PSE's retail customer electrical loads are of course a major input to the electric load-resource analysis. These forecasts, including the base case and alternate scenario forecasts of energy and peak demands, are presented in Chapter 3 of this report.

Information about PSE's existing power supply resources represents another key set of input assumptions, along with information about costs and other characteristics of available new resources. PSE's existing electric resources and potential new resources are discussed in Chapter 5 of this report.

Another key input to the resource analysis is a forecast of market prices for natural gas. The base case gas price projections that PSE is using for the analysis are based on a long-term forecast of market prices for natural gas at Sumas produced by the PIRA Energy Group in September 2002.

The PIRA Energy Group is an international energy consulting firm that serves more than 350 companies located in 33 countries. Results of the gas price forecast are shown in Chart 8.1 and Table 8.3. The prices for 2003 and 2004 reflect forward market prices as of Fall 2002, and are changed from the PIRA forecast for those two years.

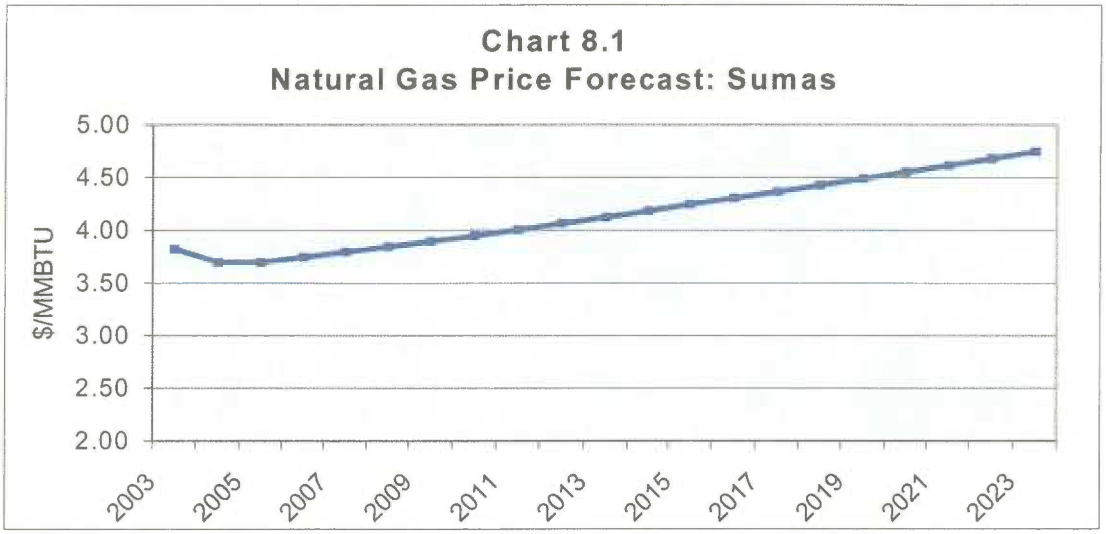


Table 8.3
Long-Term Forecast of Market Prices
For Natural Gas at Sumas
(Dollars per MMBtu)

YEAR	PRICE
2003	3.83
2004	3.70
2005	3.70
2006	3.75
2007	3.80
2008	3.85
2009	3.90
2010	3.95
2011	4.01
2012	4.07
2013	4.13
2014	4.19
2015	4.25
2016	4.31
2017	4.37
2018	4.43
2019	4.49
2020	4.55
2021	4.62
2022	4.68
2023	4.75

Finally, the electric load-resource analysis requires input assumptions about market prices for wholesale electric supplies. Preparation of the market electricity price forecast is described in the following section of this chapter.

FORECASTS OF MARKET PRICES FOR ELECTRICITY IN THE PACIFIC NORTHWEST

To develop the base case projection of market prices for electricity, PSE prepared a region-wide market forecast using the AURORA model to simulate long-run market prices for wholesale power supply in the Western Electric Coordinating Council area, including prices at the Mid-Columbia trading hub.

The AURORA model was developed and is owned and licensed by EPIS, Inc., which is located near Portland, Oregon. AURORA is a nationally recognized energy market simulation model used by numerous clients of EPIS, including BPA and the Northwest Power Planning Council. Use of AURORA by these and other Northwest entities is important since it has resulted in extensive review of the methodology and data used in the model. This regional review is especially important in the Northwest because of the large role that hydroelectric generation plays in the region. Further information about the AURORA model are available on the EPIS website at www.epis.com.

To produce the AURORA-based forecast of market prices for wholesale power supply, a number of assumptions were made. These assumptions included forecasts of regional load growth, completion of new generating resources that are under construction, costs and operating characteristics of new resources, costs of capital (including debt, equity and capitalization ratios) and the types of entities (investor-owned utilities, publicly-owned utilities and non-utility developers) who may develop new generating resources. The PIRA forecast of natural gas prices described above was also used. Further detail about these assumptions is provided in Appendix 8.1.

A summary of the results from the forecast of Mid-Columbia power supply prices is shown in Chart 8.2 and Table 8.4.

Chart 8.2
Forecast of Annual Average Mid-Columbia Wholesale Power Price
Nominal Dollars per Megawatt-Hour

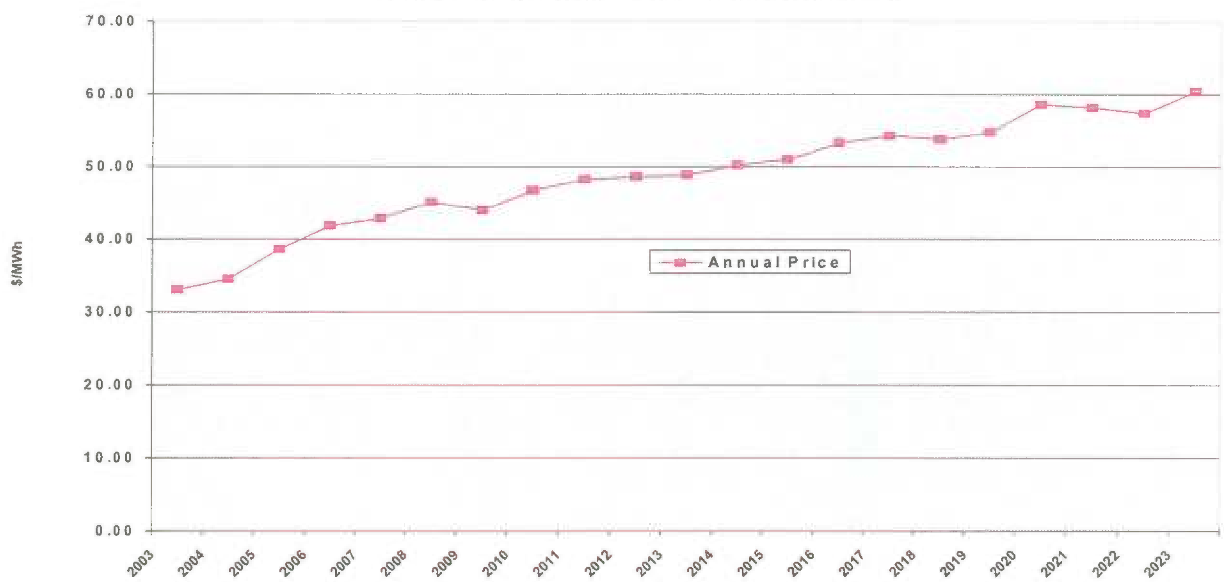


Table 8.4
Results of AURORA Forecast of Wholesale Market Power Supply Prices (Annual Average) Nominal Dollars per Megawatt-Hour

Year	Price
2003	33.16
2004	34.60
2005	38.67
2006	41.91
2007	42.94
2008	45.17
2009	44.01
2010	46.78
2011	48.31
2012	48.72
2013	48.97
2014	50.28
2015	51.06
2016	53.36
2017	54.31
2018	53.81
2019	54.83
2020	58.64
2021	58.22
2022	57.43
2023	60.46

DETERMINATION OF PSE'S NEED FOR NEW ELECTRIC RESOURCES

Determination of PSE's need for new resources is a major step in the development of the Company's Least Cost Plan. The magnitude of PSE's projected need for new resources, including the growth over time and the seasonal "shape" of the need for new resources has direct implications for the amount of new resources that PSE should acquire, as well as the types (e.g., energy and capacity) of resources it should acquire and at what points in time it should be making new resource acquisitions. In other words, PSE's need for new resources is one of the most important drivers for development of the Company's electric resource strategy.

As discussed in Chapter 2, it is important to assess PSE's need for new resources in the context of the Pacific Northwest region's overall load-resource balance. To the extent that PSE and the region both may face the prospect of resource deficits, the risks to PSE and its customers are magnified.

Need for New Electric Energy Resources

Accordingly, PSE performed a detailed assessment of its need for new electric resources, beginning with the energy component of its need for new resources.

The AURORA model was also used to prepare this portion of the analysis. However, rather than simulating the overall regional market (as was done to produce the market power price forecast described in Section 4. d. above), the analysis at this stage focused specifically on simulating the use of PSE's existing portfolio of electric resources to serve its customers' forecasted retail electric loads.

The AURORA model was used to determine how much of the retail customer energy requirements (net of new conservation energy savings accumulating at a rate of an additional 15 average megawatts each year) would be met by cost-effective use of PSE's existing portfolio (net of expiring contracts and other resource losses as they are scheduled to occur over the 20-year planning horizon). The amounts of the shortfalls in the ability of the existing portfolio to serve the forecasted loads were then computed for each time period in the planning horizon. These shortfalls, or energy deficits, then represent PSE's need for new resources.

Key inputs to this portion of the analysis included the assumptions described in earlier sections of this chapter, including the market price forecasts for natural gas and electricity.

It is important to note that the AURORA model results to determine PSE's need for new energy resources include projections of energy produced on an economic basis from PSE's existing co-generation and simple-cycle combustion turbine facilities (i.e., during periods when market prices for power are higher than combustion turbine operating costs, including market prices for natural gas). However, the AURORA results indicate that the majority of the energy generation from PSE's combustion turbines would occur during summer months when other existing resources in the portfolio are sufficient to serve PSE's retail customer loads and PSE would be making surplus power sales from its portfolio. As a result, the combustion turbine generation amounts included in the results do not significantly affect PSE's need for new energy resources. Because PSE's combustion turbines play a critically important role in providing generating capacity to help meet winter peak loads, it is important not to assume that they can also be used extensively to meet energy requirements during those same winter months.

Need for New Electric Resources – Annual Energy

Annualized results of the analysis to determine PSE's need for new electric energy resources are provided in Chart 8.3.

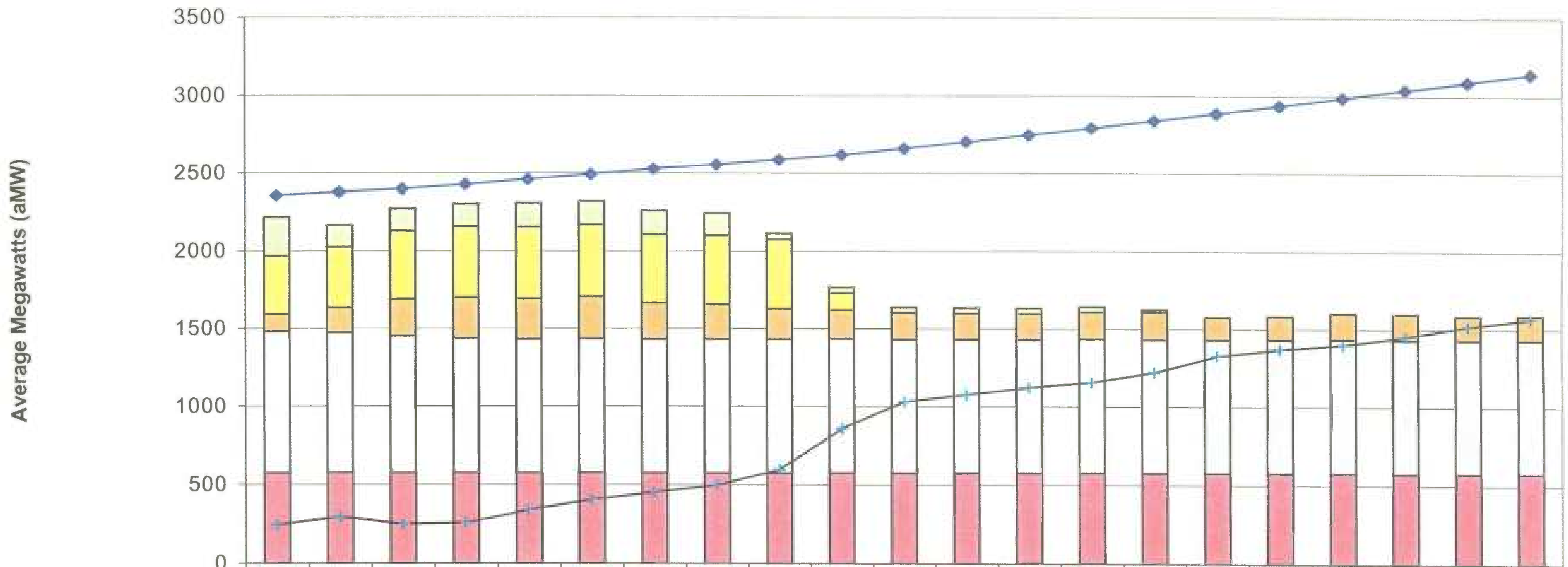
Looking at PSE's projected need for new energy resources on an annual basis, Chart 8.3 indicates a need for 247 average megawatts (aMW) of energy in 2003, increasing to 302 aMW in 2004. By 2007, the annual need increases to 342 aMW and in 2010 to 496 aMW. The annual need is projected to reach 1,029 aMW in 2013, eventually increasing to 1,566 aMW in 2023.

Need for New Electric Resources – Monthly Energy

However, looking at PSE's need for new energy resources on an annualized basis provides only a partial view of the Company's actual need for energy. Viewing the results on a monthly basis provides a more accurate and detailed assessment of the seasonal "shape" and magnitude of the need.

Table 8.5 and the charts in Appendix 8.2 provide monthly results from the analysis of PSE's monthly need for new energy resources. The table and corresponding charts show that PSE's need for new energy resources is larger during the winter months and lesser during the summer months. These results include a projected need of 456 average megawatts (aMW) of energy during December 2003, and 450 aMW of energy in December 2004. By December 2007 the monthly need increases to 646 aMW and in 2010 to 768 aMW. The mothly need is projected to reach 1,563 aMW in December 2013, eventually increasing to 2,246 aMW in December 2023.

Chart 8.3
PSE Need for New Resources -- Annual Energy



	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Contracts	245	140	141	144	150	150	150	142	40	38	34	34	34	34	17	-8	-8	-8	-8	-8	-8
NUGs	377	392	442	460	464	465	445	446	448	111	0	0	0	0	0	0	0	0	0	0	0
Encogen & CTs	113	160	238	260	259	269	233	224	196	183	171	168	166	173	176	146	151	167	167	153	156
Hydro	905	897	876	863	856	859	856	856	856	859	856	856	856	859	856	856	856	859	856	856	856
Colstrip	573	575	573	573	573	575	573	573	573	575	573	573	573	575	573	573	573	575	573	573	573
Need Percent	10%	13%	11%	11%	14%	16%	18%	19%	23%	33%	39%	40%	41%	41%	43%	46%	47%	47%	48%	49%	50%
Load	2354	2377	2397	2426	2457	2490	2526	2553	2586	2618	2660	2705	2750	2796	2843	2890	2939	2989	3038	3089	3140
Need	247	302	253	261	342	405	449	496	596	856	1,029	1,076	1,124	1,158	1,223	1,326	1,370	1,400	1454	1518	1,566

TABLE 8.5
PSE NEED FOR NEW ELECTRIC RESOURCES -- MONTHLY ENERGY
Average Megawatts (aMW)

YEAR	January	February	March	April	May	June	July	August	September	October	November	December
2003	165	409	292	267	-	59	-	-	135	124	314	456
2004	433	586	359	279	168	268	-	-	58	138	278	450
2005	278	406	265	167	124	325	-	-	-	6	264	440
2006	260	388	280	204	171	290	-	-	-	6	280	473
2007	481	536	318	263	210	115	-	-	-	20	485	646
2008	509	564	333	302	248	114	-	-	-	-	503	668
2009	654	740	421	390	285	227	-	-	-	55	565	707
2010	683	749	506	480	316	239	-	-	-	113	607	768
2011	821	933	599	603	398	356	-	-	163	405	756	923
2012	1,216	1,232	1,015	905	572	621	365	340	663	804	1,177	1,358
2013	1,405	1,443	1,220	1,047	703	729	466	544	851	1,014	1,362	1,563
2014	1,457	1,489	1,261	1,115	735	778	522	586	881	1,086	1,415	1,594
2015	1,519	1,548	1,299	1,151	771	814	549	635	931	1,138	1,478	1,658
2016	1,575	1,546	1,356	1,193	805	833	588	650	965	1,164	1,510	1,713
2017	1,611	1,637	1,394	1,244	852	881	646	691	1,007	1,186	1,665	1,863
2018	1,804	1,811	1,518	1,329	909	942	695	765	1,116	1,328	1,746	1,951
2019	1,844	1,867	1,551	1,389	950	984	701	806	1,164	1,342	1,800	2,037
2020	1,901	1,828	1,605	1,425	961	1,022	731	865	1,176	1,387	1,859	2,038
2021	1,975	1,942	1,658	1,480	1,039	1,047	792	886	1,181	1,431	1,898	2,114
2022	2,031	2,007	1,717	1,531	1,065	1,106	885	935	1,291	1,488	1,968	2,190
2023	2,092	2,079	1,777	1,578	1,122	1,138	911	993	1,349	1,499	2,007	2,246

Need for New Electric Capacity Resources

The determination of PSE's need for new electric capacity resources is based on a comparison of forecasted peak capacity needs with the estimated supply capability of the Company's existing generating and contract resources.

The assumptions about the expiration of existing contracts and resource retirements over the 20-year planning horizon are outlined in Chapter 5. The peak hourly capacity available from each of these supply resources is determined based on the peak hourly generating capability (for generating resources) and the maximum available capacity as specified in the purchase and sale agreements (for contracts).

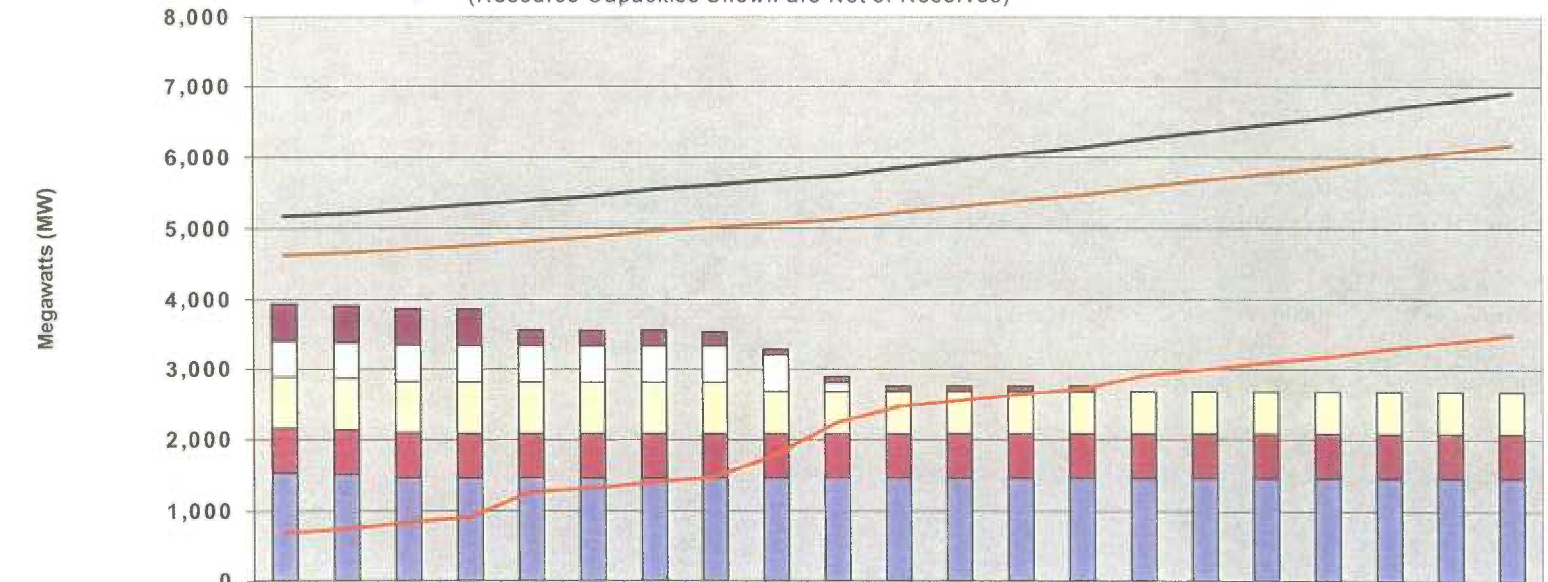
For long-term resource capacity planning purposes, PSE has traditionally used the expected peak load. The expected peak load is the peak load that can be expected to occur (or be exceeded) for at least one hour with a probability of 50 percent during any year, based on historical temperature profiles. The maximum expected peak load for the year is in January of each year.

PSE's expected peak loads and supply resources for the 2003 through 2023 time period are summarized in Chart 8.4. The columns show the peak hourly capacity of PSE's supply resources. As shown, the total capacity supply decreases over time as resources are retired and contracts expire. The resource capacities shown are net of operating reserves (5% of hydro resources and 7% of thermal resources) and required regulating margin.

The peak loads are forecasted to increase over time as the number of customers increase. As discussed earlier, the growth in the peaks (about 1.6%/year) is slightly higher than the growth in energy (about 1.4%/year) since residential energy load is growing faster than non-residential energy loads and the residential sector has a larger contribution to peak.

As the Northwest region becomes more capacity constrained, winter peak capacity planning is becoming a topic of greater significance. This presents challenges that PSE intends to address further in the analysis for this Least Cost Plan. For example, there is an important tradeoff between seeking to meet extreme temperature peak loads (defined as having a 5 percent probability of occurring for one hour or more during a year) and the cost to meet such peak loads (also shown on Chart 8.4). In particular, it can be very expensive to maintain peaking generation to protect against such low-probability events. Because of the complexities involved in the tradeoffs, PSE intends to assess the costs, benefits and risks that may be associated with planning to more conservative standards such as an extreme peak load criterion. PSE will also seek to identify creative approaches to cost-effectively meet winter peaking requirements.

Chart 8.4
Peak Hour Need for Capacity
(Resource Capacities Shown are Net of Reserves)



	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Contracts	523	523	523	523	223	223	221	201	85	85	80	80	80	80	-2	-2	-2	-2	-2	-2	-2
NUGs	520	520	520	520	520	520	520	520	520	127	0	0	0	0	0	0	0	0	0	0	0
Encogen + CTs	737	737	737	737	737	737	737	737	605	605	605	605	605	605	605	605	605	605	605	605	605
Colstrip	612	612	612	612	612	612	612	612	612	612	612	612	612	612	612	612	612	612	612	612	612
Hydro	1,540	1,519	1,475	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464
Normal Peak Deficit	692	745	841	910	1,271	1,323	1,408	1,481	1,794	2,237	2,465	2,553	2,641	2,717	2,905	2,997	3,094	3,177	3,290	3,389	3,490
Extreme Peak	5,177	5,212	5,271	5,335	5,404	5,462	5,555	5,615	5,686	5,743	5,850	5,948	6,047	6,132	6,251	6,355	6,462	6,555	6,682	6,793	6,906
Expected Peak	4,625	4,656	4,708	4,766	4,827	4,879	4,962	5,015	5,079	5,130	5,226	5,313	5,402	5,477	5,584	5,676	5,772	5,855	5,968	6,068	6,169

Hydro Colstrip Encogen + CTs NUGs Contracts Expected Peak Extreme Peak Normal Peak Deficit

RESOURCE PORTFOLIO SCREENING ANALYSIS

Introduction

To begin analyzing alternatives to meet its need for new electric resources, PSE is performing a screening analysis of alternative resource portfolios. This screening analysis is designed to allow testing of a broad range of combinations of potential new resources on a consistent basis. The screening analysis will also include explicit consideration of major sources of uncertainty, through an initial risk analysis. The portfolio screening and initial risk analysis builds upon the steps described in the previous sections of this chapter, using the results from those sections as inputs.

In preparing for the portfolio screening and initial risk analysis, PSE determined that it needed a flexible, responsive model that can be used to test the impacts of various alternatives and assumptions relatively quickly and easily. PSE also wanted to use a relatively comprehensive model to address both its energy needs and its capacity needs, and that incorporates both fixed and variable costs. This is in contrast with more focused resource planning models that can provide greater precision and analytical rigor, but that tend to focus in greater detail on specific topics. These more detailed resource planning models also tend to require more extensive time and effort to produce results.

PSE intends to perform more detailed modeling later in the least cost planning process. This will be particularly useful after the range of alternative resource portfolios has been narrowed. However, for the purposes of the portfolio screening and initial risk analysis, PSE has selected a somewhat simpler and more flexible modeling tool. Appendix 8.3 provides a detailed description of the screening model.

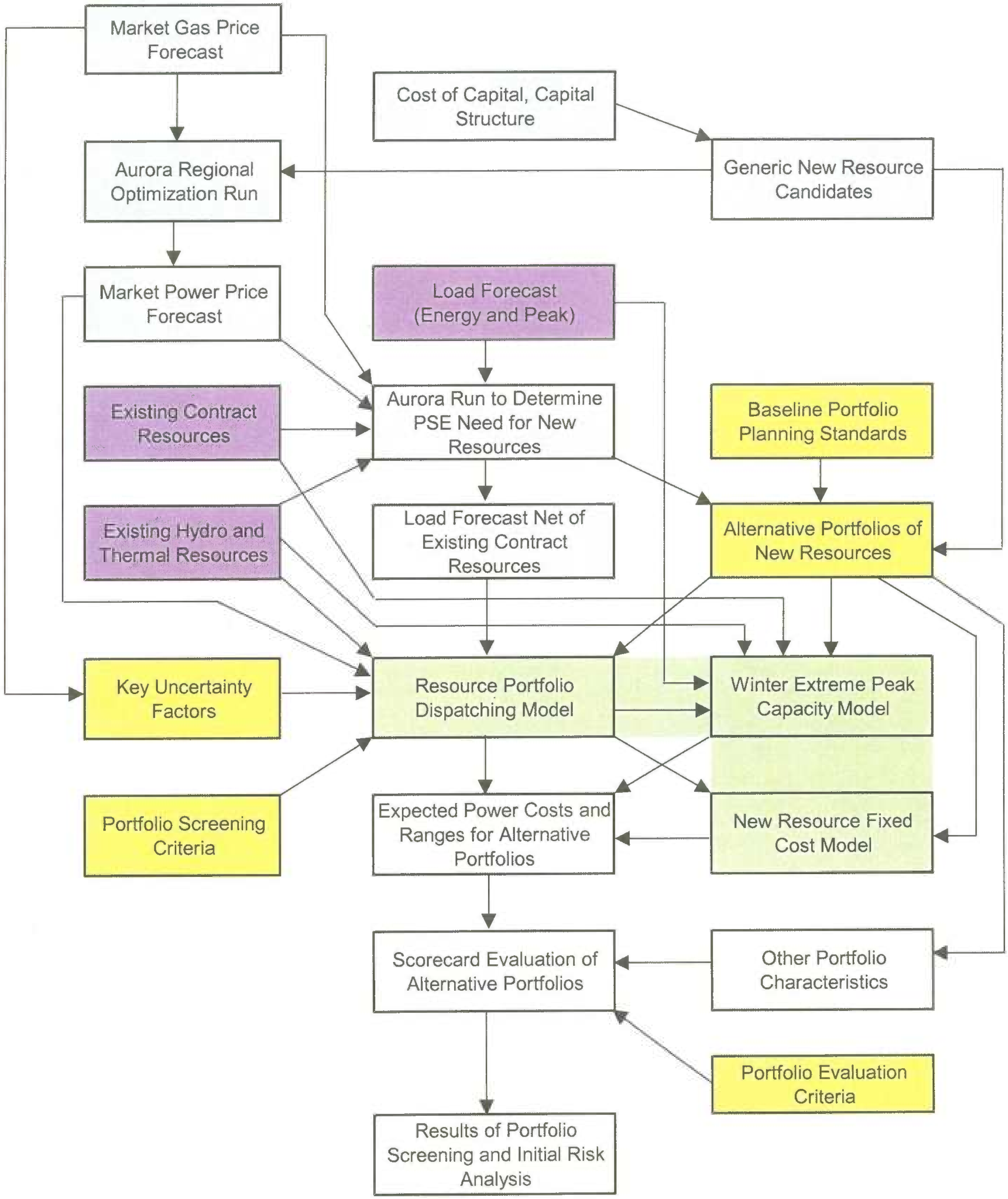
Figure 8.1 is a flow chart that illustrates the portfolio screening and initial risk analysis process. The flow chart represents the logical relationships and the process flow, including the basic input assumptions and the forecasts described in previous sections of this chapter. The flow chart also shows the flow of information into the portfolio screening model, including a number of "defining assumptions". These defining assumptions are key assumptions that will be used to define, or structure, the portfolio screening and initial risk analysis. The following sections 8. f. ii), 8 f. iii) 8. f. iv and 8. f. v). describe the "defining assumptions" for the portfolio screening and initial risk analysis.

Baseline Portfolio Planning Standards

Purpose:
Baseline Portfolio Planning Standards are basic criteria that will be used to guide formulation of the initial set of resource portfolio alternatives to be evaluated in the screening analysis.

Figure 8.1

Portfolio Screening and Initial Risk Analysis Process Flow Diagram



Legend: Completed Tasks (Light Blue), Defining Assumptions (Yellow), Base Input Assumptions (Lavender)

The set of resource portfolio alternatives to be evaluated using the screening model should be sufficiently broad to encompass a full range of resources and resource strategies. In addition, the set of resource portfolio alternatives should focus on resources and strategies that appear feasible. Finally, each resource portfolio alternative to be evaluated should be relatively distinct and the total number of alternatives should be manageable.

Baseline Portfolio Planning Standards:

1. Portfolios to be evaluated will include long-term energy resources sufficent to meet annual energy requirements (based on 40-year average hydro generation).
2. Portfolios to be evaluated will include long-term energy resources to meet at least 100 percent of each month's energy requirements (based on 40-year average hydro).
3. Portfolios to be evaluated will include sufficient long-term capacity resources to meet expected winter peak hour requirements.

PSE is using these Portfolio Planning Standards for its screening and initial risk analysis on a provisional basis. However, PSE will also evaluate costs, benefits and risks of more or less conservative portfolio planning standards, including to address risks associated with lower than average hydro conditions and extreme winter peak loads.

Alternative Portfolios Evaluated

Resource portfolio alternatives can be built along the following three dimensions:

- level of commitment to new resources
- types and mixes of new resources
- timing of commitments to new resources

For the portfolio screening and initial risk analysis, PSE is formulating a wide range of resource portfolio alternatives, including portfolios that can be generally categorized as follows:

A. Do Nothing Alternative (no new resource commitments)
B. All Gas
C. Max Coal
D. Strong Wind
E. Mixed Thermal
F. Mixed Thermal and Wind

NOTE: Structured transactions (purchases, sales, exchanges), and partnership approaches will be added to various resource portfolio alternatives shown above.

Table 8.6 provides an example that illustrates how the resource portfolios will be represented.

Further Notes on the Load-Resource Analysis:

In addition to the portfolios described here, PSE intends to evaluate resource portfolio alternatives that assume "retirement" or restructuring of existing resources in PSE's power supply portfolio, beyond those existing resources that are already known or assumed to expire. This approach will facilitate evaluation and identification of opportunities to address existing resources that may have comparatively higher costs or that are relatively less efficient.

As discussed in Chapter 2, the load-resource analyses for this Least Cost Plan will explicitly incorporate imputed debt effects associated with resources that may be acquired under long-term purchased power agreements.

TABLE 8.6
SUMMARY OF NEW RESOURCE PORTFOLIOS

se ber	Portfolio Case Title		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
1	All Gas Sample Portfolio	CCGT SCGT Coal Wind Asset Based Contract Market Based Contract	THIS SECTION TO BE FILLED IN WITH TIMING AND AMOUNTS OF NEW RESOURCE ADDITIONS (MW)										
2	Max Coal Sample Portfolio	CCGT SCGT Coal Wind Asset Based Contract Market Based Contract	THIS SECTION TO BE FILLED IN WITH TIMING AND AMOUNTS OF NEW RESOURCE ADDITIONS (MW)										
3	Strong Wind Sample Portfolio	CCGT SCGT Coal Wind Asset Based Contract Market Based Contract	THIS SECTION TO BE FILLED IN WITH TIMING AND AMOUNTS OF NEW RESOURCE ADDITIONS (MW)										
4	Mixed Thermal Sample Portfolio	CCGT SCGT Coal Wind Asset Based Contract Market Based Contract	THIS SECTION TO BE FILLED IN WITH TIMING AND AMOUNTS OF NEW RESOURCE ADDITIONS (MW)										
5	Mixed Thermal & Wind Sample Portfolio	CCGT SCGT Coal Wind Asset Based Contract Market Based Contract	THIS SECTION TO BE FILLED IN WITH TIMING AND AMOUNTS OF NEW RESOURCE ADDITIONS (MW)										
6	Mixed Thermal & Market Sample Portfolio	CCGT SCGT Coal Wind Asset Based Contract Market Contract	THIS SECTION TO BE FILLED IN WITH TIMING AND AMOUNTS OF NEW RESOURCE ADDITIONS (MW)										

Portfolio Screening Criteria

Purpose:
Portfolio Screening Criteria will be used to eliminate less cost-effective resource portfolio alternatives from further consideration and select more cost-effective portfolios for further evaluation.

Portfolio Screening Criteria will be applied to the initial quantitative results of the PC-based dispatch model – i.e., before risk analysis of key uncertainty factors. As such, the criteria will focus primarily on power costs. Qualitative criteria will not be used at this stage, but will be applied later in the Scorecard Evaluation.

Portfolio Screening Criteria:

1. Expected power costs, measured on a net present value basis, including all costs (fixed and variable) for new resources and variable costs for existing resources.

Key Uncertainty Factors

Purpose:
Uncertainty Factors for Risk Analysis are key sources of variability that affect power costs and the ability of the portfolio to effectively serve retail customer loads.

There is an important need for PSE's least cost planning to analyze major risks using probabilistic methods. A generally-accepted method for risk analysis involves identifying key factors that have a large influence on power costs and that are difficult to predict or are subject to significant variability. Probability distributions can be assigned to these uncertainty factors and Monte Carlo analysis can then be performed by taking a large number of samples from the probability distributions, power costs are calculated for each. Results are then displayed in the form of histograms that illustrate the range and shape of impacts that can be caused by the uncertainty factors. For some uncertainty factors, the analysis can be performed more effectively using scenarios with expected-case, high-case and low-case projections of the uncertainty factor.

Uncertainty Factors for Risk Analysis:

1. Market prices for natural gas (probability distributions)
2. Market prices for electricity (probability distributions)
3. PSE hydroelectric generation (probability distributions)
4. PSE retail load growth (scenarios) – energy and winter peak
5. Carbon taxes (scenarios)
6. Production tax credits for wind (scenarios)
7. Unit outage risk (probability distributions)

Results of Portfolio Screening and Initial Risk Analysis

This section will be completed when results of the portfolio screening and initial risk analysis become available. Table 8.6 provides an example illustrating the types of information that will be developed and a representative format that may be used to present the results.

Detailed Analysis of Portfolios

Following completion of the portfolio screening and initial risk analysis, PSE will perform additional, more detailed analysis of the screened portfolios. This analysis will be performed using the AURORA model, possibly supplemented with additional analysis using other modeling tools and methods.

Integrated Analysis Using updated Conservation Resource Estimates

Under the settlement agreement reached in PSE's last General Rate Case, a schedule was established that is expected to result in development of updated conservation resource assessments in or shortly after May 2003. PSE anticipates that it will use these results to conduct additional load-resource analysis during the second half of 2003, including more complete integration of the analysis of both supply-side and demand-side resource alternatives.

ANALYSIS RESULTS SUMMARY FOR NEW RESOURCE PORTFOLIOS

Portfolios	NPV Incremental Cost to Customer	NPV Revenue Requirement	Electricity Price Exposure	Gas Price Exposure	Hydro Exposure	Emissions Exposure
Sample Portfolios						
oal Sample Portfolios						
nd Sample Portfolios						
Thermal Sample Portfolios						
Thermal & Wind Sample Portfolios						
Thermal & Market Sample Portfolios						

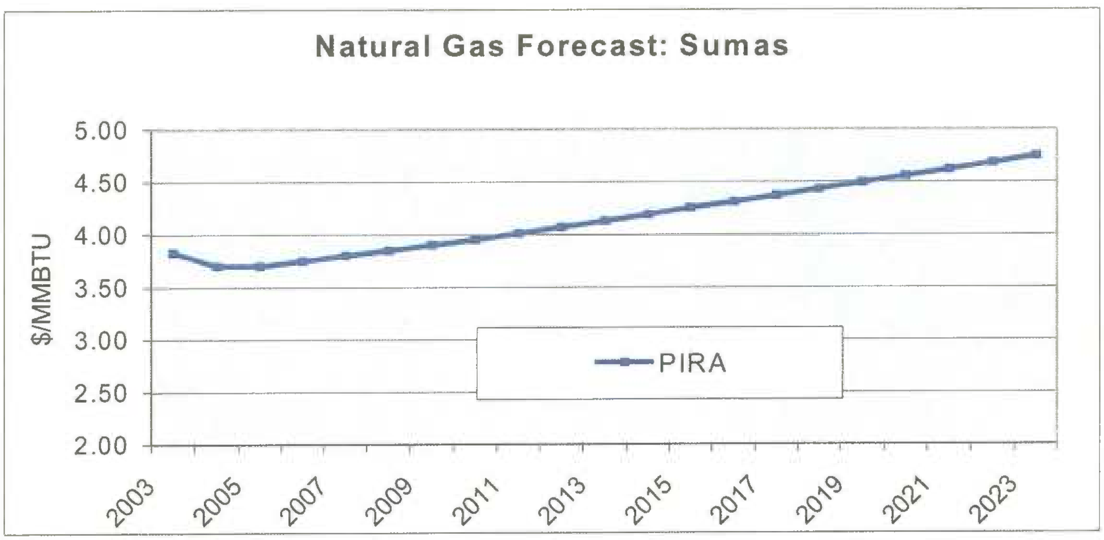
Appendix 8.1

Key Assumptions for Aurora Market Power Price Forecast

November 11, 2002

Gas Prices:

PIRA forecasts for the Sumas gas trading hub near the U.S.-Canada border were used. The PIRA forecast is from September, 2002. The prices for 2003 and 2004 reflect forward market prices as of Fall 2002, and are changed from the PIRA forecast for those two years.



Electricity Demand:

Aurora divides the WECC into 13 subregions with individual growth rates. Table 1 below lists the regions along with the New and Previous assumed **long run** regional growth rates. The new growth rates were adopted from the NPPC, " Draft Forecast of Electricity Demand of the 5th Pacific Northwest Conservation and Electric Power Plan," August 2, 2002. **Short run** demand was adjusted downward to take into account the current recession, following the assumptions in the NPPC's 5th Draft of Wholesale Electric Price Forecast. Intermediate term growth rates were increased so that the long run growth rate was unchanged.

Table 1

Region	New Demand (%)	Previous (%)
OR / WA / No. ID	1.50	1.53
No. California	1.71	1.63
So. California	1.87	1.63
British Columbia	1.53	1.53
Idaho South	1.71	1.53
Montana	0.90	1.53
Wyoming	0.23	2.37
Colorado	1.22	2.37
New Mexico	2.43	2.45
Arizona / So. Nevada	1.39	2.45
Utah	2.32	1.53
No. Nevada	1.65	1.53
Alberta	1.53	1.53

New Northwest Resources:

We assumed that 2,055 MW of new natural gas fired resources currently under construction will be completed and on line by mid-2003. Table 2 below lists those plants:

Table 2

Plant	Owner/Developer	Capacity (MW)	Online Date
Coyote Springs II	Avista-Mirant	260	Q1/03
Hermiston	Calpine	530	Online
Goldendale	Calpine	248	Online
Centralia	TransAlta	248	Online
Frederickson I	EPCOR	249	Online
Chehalis	Tractebel	520	Q2/03

Other well known gas fired resources that were expected to be developed, such as the Duke Grays Harbor plant, have not been assumed into the model.

Wind resources that could be built in 2003, or later, were not assumed to be built. 473 MW of wind generation which are listed by their developers as online in 2002 are included.

New Resources:

There are three aspects of new resource costs that need to be considered: the debt/equity ratio and their corresponding costs; assumptions about who will be building plants in the future; and the fixed and variable costs for each technology. In general, PSE used values that are currently known or expected; otherwise PSE defaulted to assumptions made by the NPPC.

Cost of Capital

Table 3 below presents the cost of capital assumptions for PSE. The company expects that the spread between the return for debt and equity for the IOU's should be 4% to 5%, consistent with recent practice. The debt/equity ratio and the corresponding rates of return are used to determine a weighted cost of capital for each developer segment.

Table 3

	Cost of Capital		
Return %	Public	IOU's	IPP's
Debt	6.5	7.5	8.5
Equity	0	11.5	17
	Debt/Equity Ratio		
Debt	100	55	40
Equity	0	45	60
	Total Cost (%)		
Weighted	**6.5**	**9.3**	**13.6**

New Resource Development

The second set of assumptions consider which entities will be building new generation for each technology over the next twenty years. PSE used the developer mix assumptions made by the NPPC listed in Table 4 below.

Table 4

	Developer Mix (%)			Mix Weighted Cost of Capital
Technology	Public	IOUs	IPPs	PSE
CCCT	15	15	70	**11.9**
SCCT	40	40	20	**9.0**
Wind	20	20	60	**11.3**
Coal	25	25	50	**10.8**
Solar	50	25	25	**9.0**

The developer mix percentages were applied to the weighted cost of capital for each developer segment (i.e. 6.5%, 9.3%, 13.6%) to produce a mix weighted cost of capital (values in bold font under PSE in Table 4) for each technology. The mix-weighted cost of capital was then applied to the investment costs discussed in the following section.

Cost of Various Technologies

The estimates for future costs of developing new generation projects was adapted from NPPC with some modifications. PSE used the same values as NPPC for the capacity, the all-in cost, variable O&M, forced outage rate, maintenance rate, and minimum capacity. NPPC also included part of the natural gas transportation costs as fixed O&M since a new resource would require pipeline capacity. PSE used that technique, taking the average of the thirteen areas, and applied it as well. Table 5 below lists the assumptions that go into determining the overall cost of new resources.

Table 5

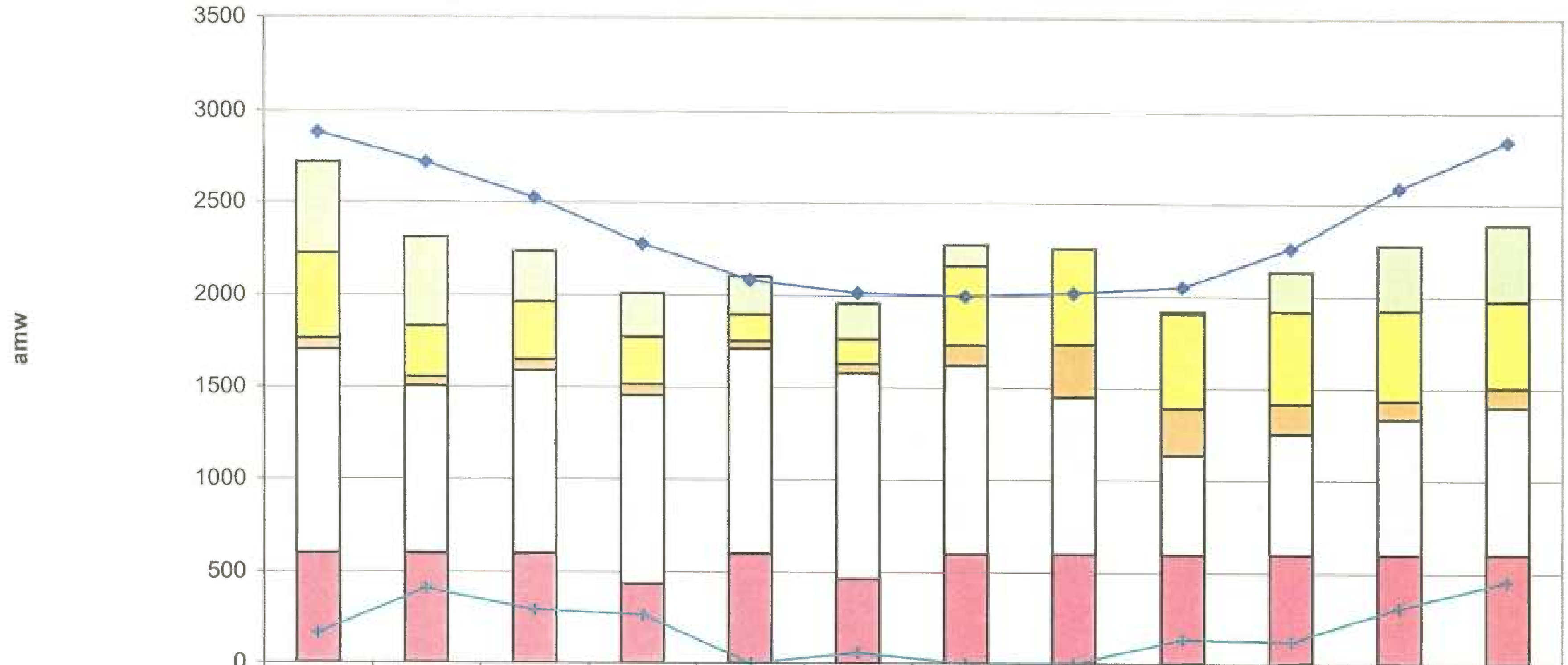
Technology	Capacity (mw)	All-In Cost ($/kw)	Fixed O&M ($/kw)	Fixed Fuel ($/kw)	Variable O&M ($/mwh)	Forced Outage (%)	Maint. Rate (%)	Min. Cap. (%)
CCCT	540	621	8.55	15.55	2.80	5.0	5.0	40
SCCT	94	730	8.00	15.74	8.00	3.6	2.8	25
Wind	100	1,030	20.0	0	1.00	32-35	32-35	5
Coal	400	1,400	25.00	0	1.75	7.0	9.6	50
Solar	20	6,000	24.00	0	0.80	37.5-42.5	37.5-42.5	5

Appendix 8.2
Monthly Energy Needs

Key to Following Sheets

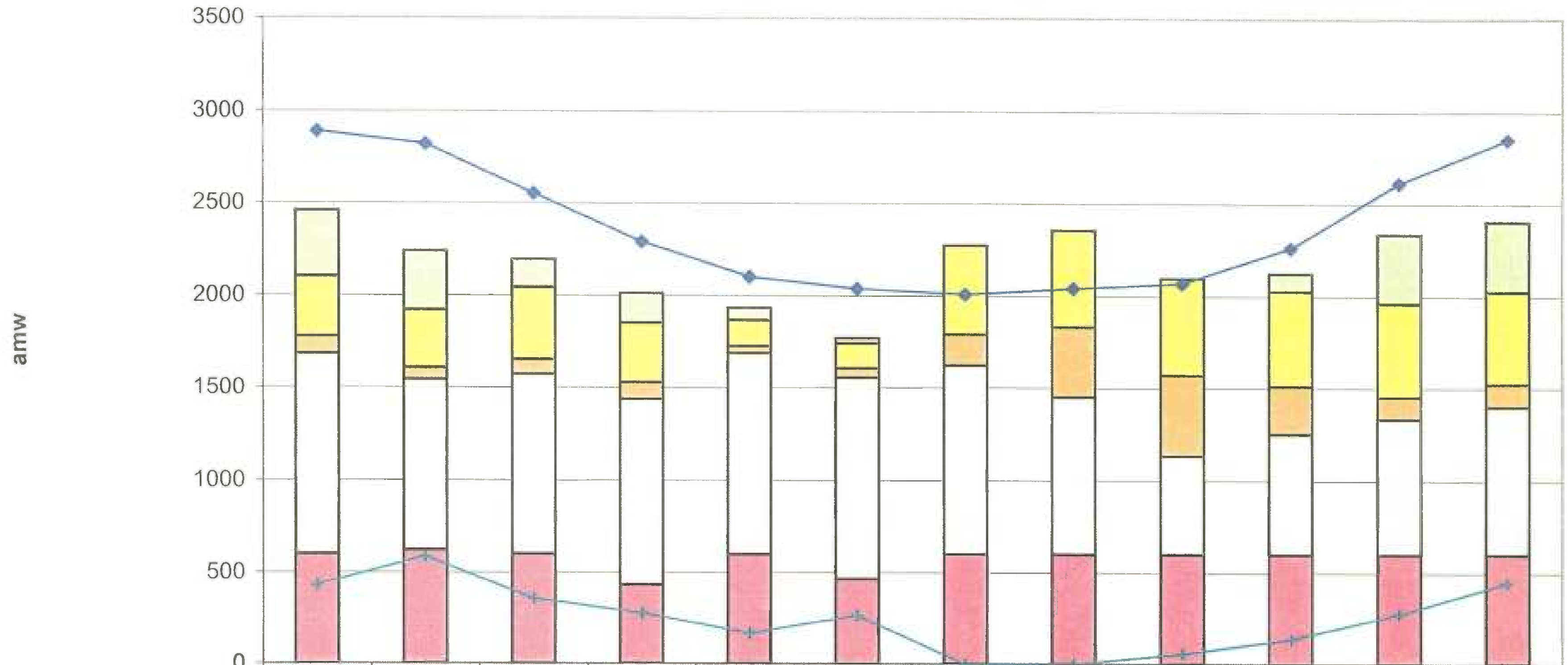
Contracts	Numerous contracts with other utilities and small QF's. Most of the contracts expire by 2011 Small QF's within PSE territory have contract extensions assumed.
NUGs	The three large PURPA contracts: March Point, Sumas, and Tenaska. March Point and Tenska contracts expire with 2011, while Sumas expires with 2012
Encogen & CT's	All resources continue to 2025 except for Whitehorn 2 & 3 which terminates in 2011.
Hydro	PSE owned hydro, plus contracts at Mid-C. Assumes licenses and contracts are renewed at time of expiration.
Colstrip	50% ownership of 1 & 2; 25% ownership of 3 & 4.
Load	Base Case Load: Final Forecast, October, 2002.
Need	Difference between Load and sum of dispatched resources.

2003



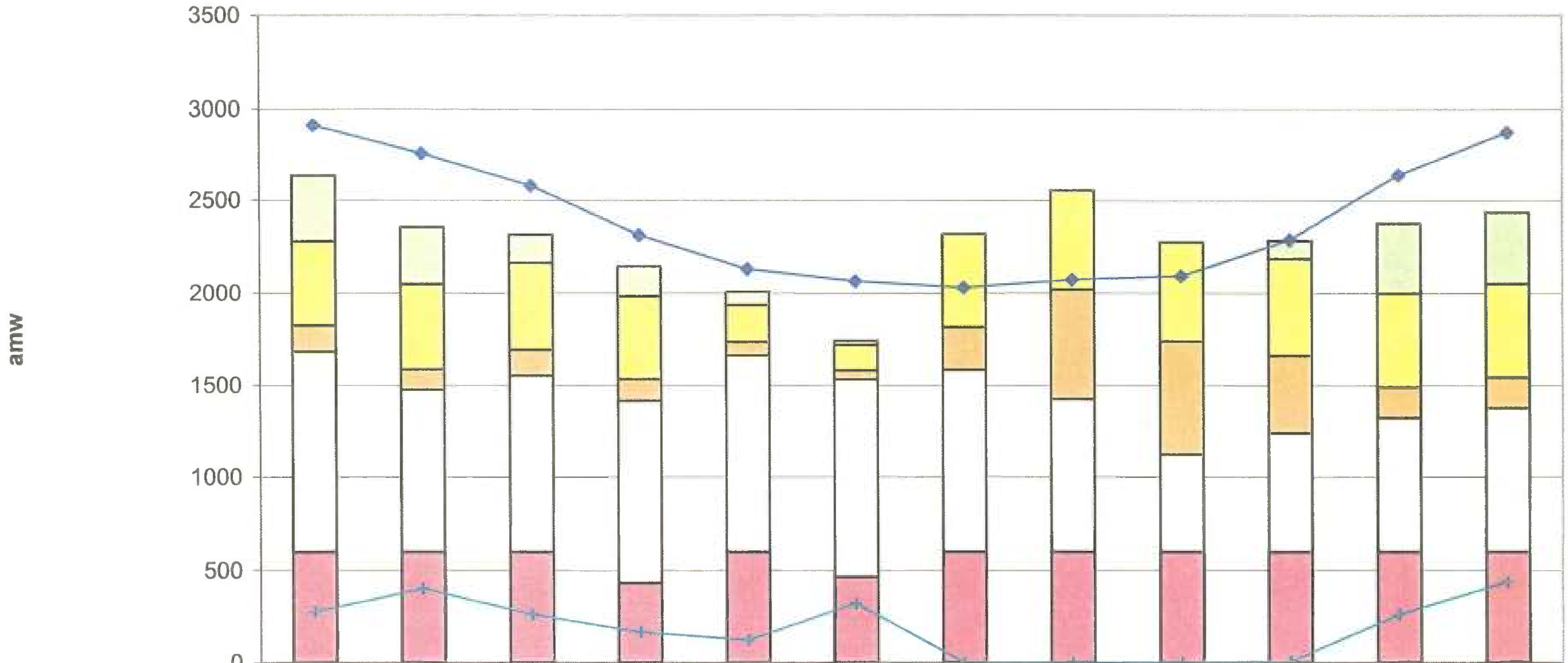
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Contracts	500	481	270	236	210	193	114	(31)	11	216	350	412
NUGs	457	276	313	256	140	135	427	518	520	504	495	473
Encogen & CTs	60	50	60	63	43	50	111	287	254	165	101	105
Hydro	1,106	906	993	1,022	1,114	1,116	1,026	852	536	652	732	800
Colstrip	598	598	598	433	598	464	598	598	598	598	598	598
Need- Pct.of Load	6%	15%	12%	12%	0%	3%	0%	0%	7%	6%	12%	16%
Need	165	409	292	267	0	59	0	0	135	124	314	456
Load	2,884	2,720	2,526	2,277	2,086	2,017	1,999	2,018	2,052	2,259	2,588	2,844

2004



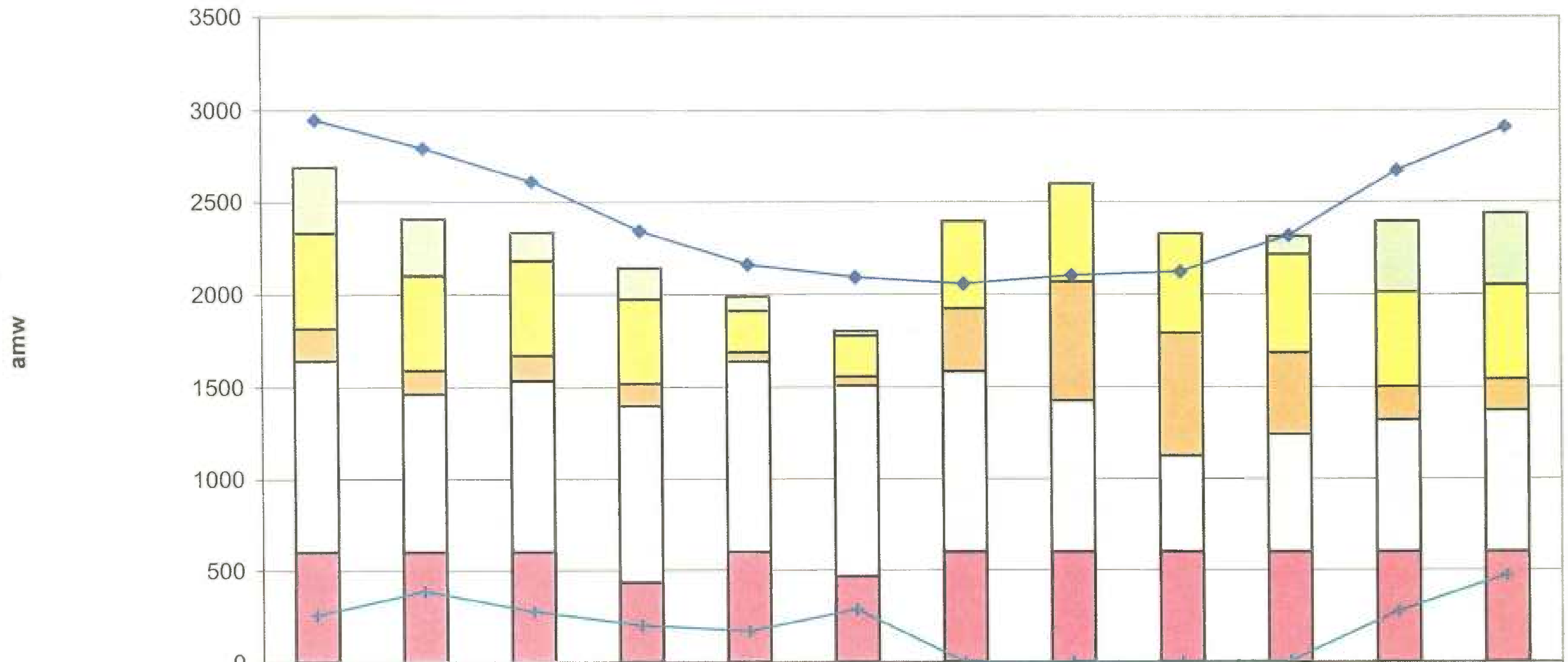
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Contracts	358	317	151	162	68	30	(79)	(78)	(85)	95	375	379
NUGs	325	313	391	323	140	135	483	526	525	517	510	502
Encogen & CTs	93	65	80	92	37	50	167	380	437	262	122	125
Hydro	1,085	924	974	1,002	1,090	1,092	1,026	852	536	652	732	800
Colstrip	598	619	598	433	598	464	598	598	598	598	598	598
Need- Pct.of Load	15%	21%	14%	12%	8%	13%	0%	0%	3%	6%	11%	16%
Need	433	586	359	279	168	268	0	0	58	138	278	450
Load	2,891	2,823	2,552	2,292	2,101	2,038	2,010	2,042	2,069	2,261	2,614	2,854

2005



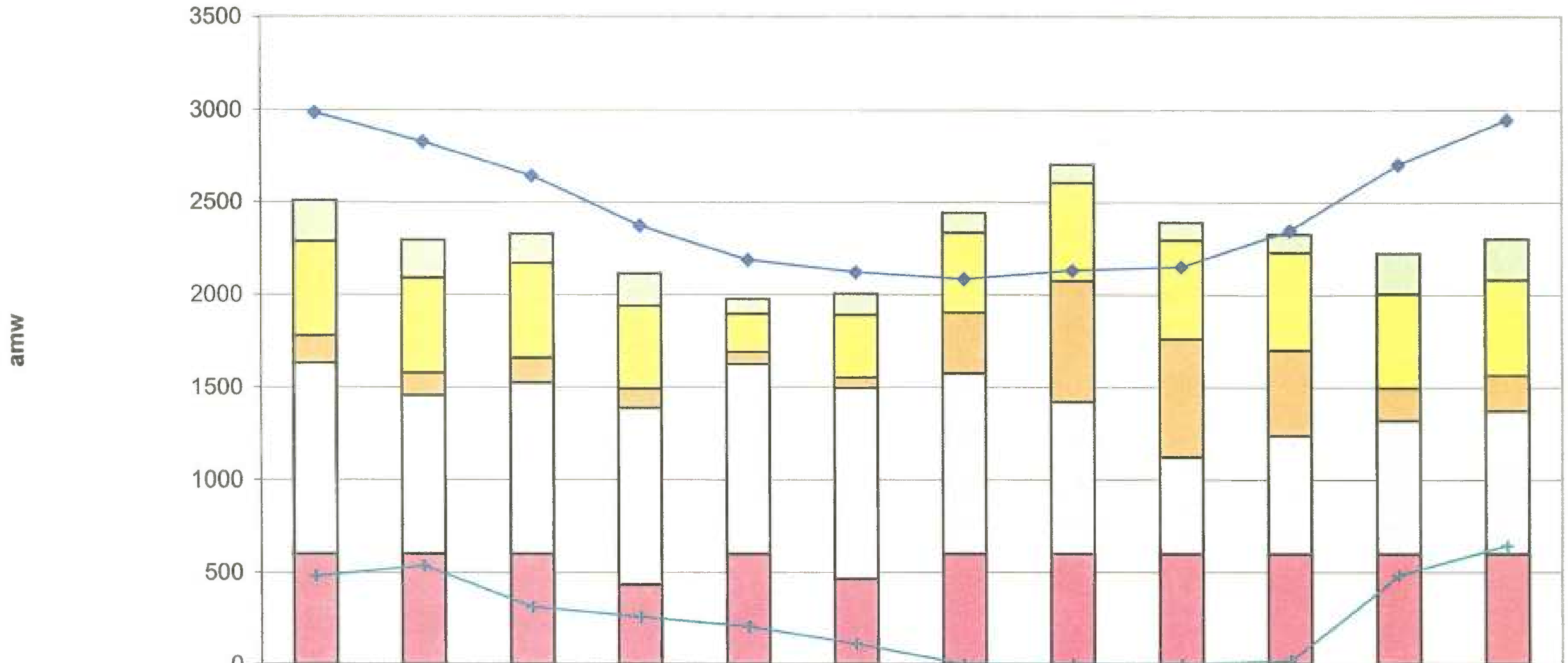
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Contracts	358	306	151	163	75	23	(78)	(73)	(83)	97	379	383
NUGs	456	464	471	450	198	137	506	535	536	525	510	510
Encogen & CTs	139	110	141	119	74	50	230	594	619	426	171	168
Hydro	1,085	878	955	982	1,065	1,068	987	828	524	638	721	777
Colstrip	598	598	598	433	598	464	598	598	598	598	598	598
Need- Pct.of Load	10%	15%	10%	7%	6%	16%	0%	0%	0%	0%	10%	15%
Need	278	406	265	167	124	325	0	0	0	6	264	440
Load	2,914	2,761	2,581	2,314	2,133	2,067	2,032	2,076	2,095	2,290	2,642	2,875

2006



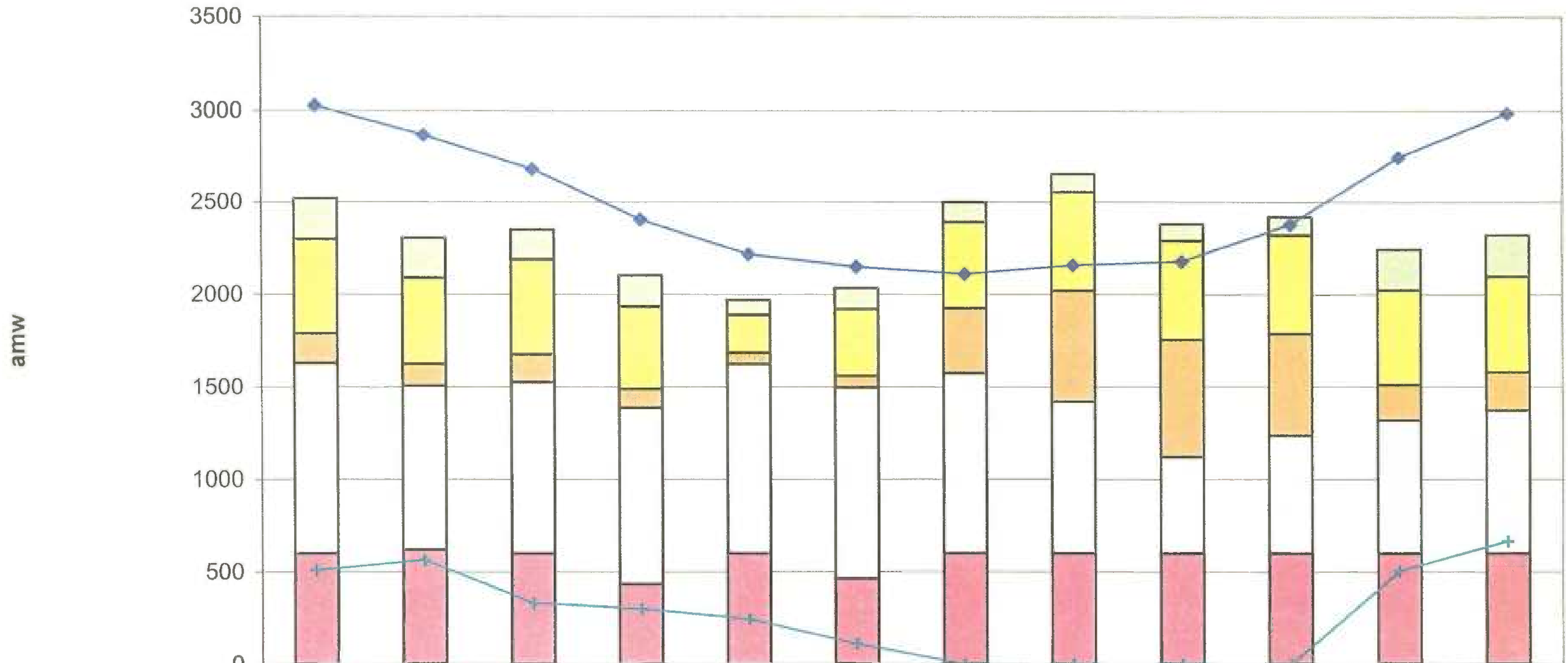
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Contracts	362	309	155	167	79	27	(75)	(73)	(77)	100	383	387
NUGs	515	509	510	453	222	219	472	534	538	528	510	510
Encogen & CTs	172	128	135	124	50	50	338	640	668	449	186	172
Hydro	1,044	864	936	962	1,040	1,043	987	828	524	638	718	771
Colstrip	598	598	598	433	598	464	598	598	598	598	598	598
Need- Pct.of Load	9%	14%	11%	9%	8%	14%	0%	0%	0%	0%	10%	16%
Need	260	388	280	204	171	290	0	0	0	6	280	473
Load	2,950	2,795	2,612	2,343	2,159	2,093	2,056	2,102	2,121	2,318	2,674	2,911

2007



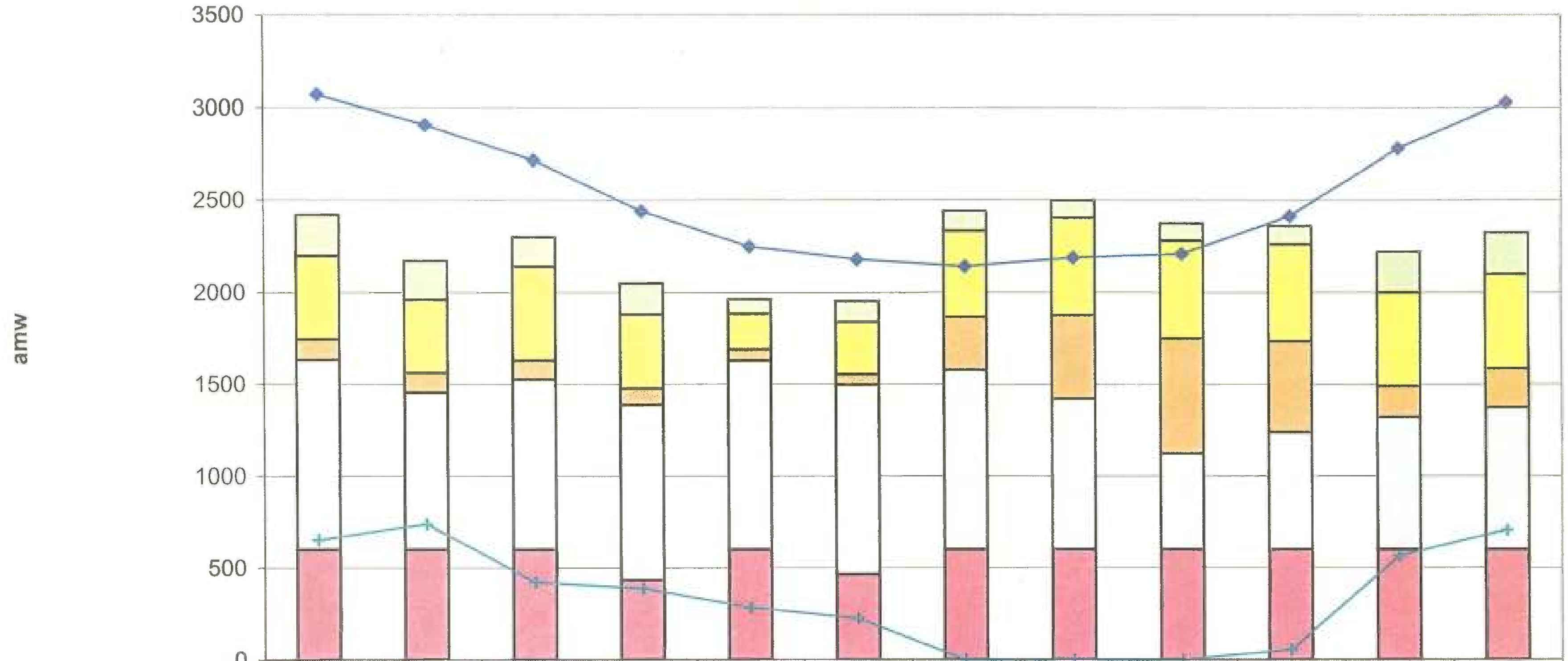
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Contracts	221	209	161	171	81	115	108	101	96	101	219	225
NUGs	510	509	510	446	206	337	434	535	535	528	510	512
Encogen & CTs	146	123	134	108	65	58	326	651	641	466	180	196
Hydro	1,033	857	926	952	1,027	1,031	977	822	521	635	718	771
Colstrip	598	598	598	433	598	464	598	598	598	598	598	598
Need- Pct.of Load	16%	19%	12%	11%	10%	5%	0%	0%	0%	1%	18%	22%
Need	481	536	318	263	210	115	0	0	0	20	485	646
Load	2,988	2,831	2,646	2,373	2,187	2,120	2,083	2,129	2,149	2,348	2,709	2,948

2008



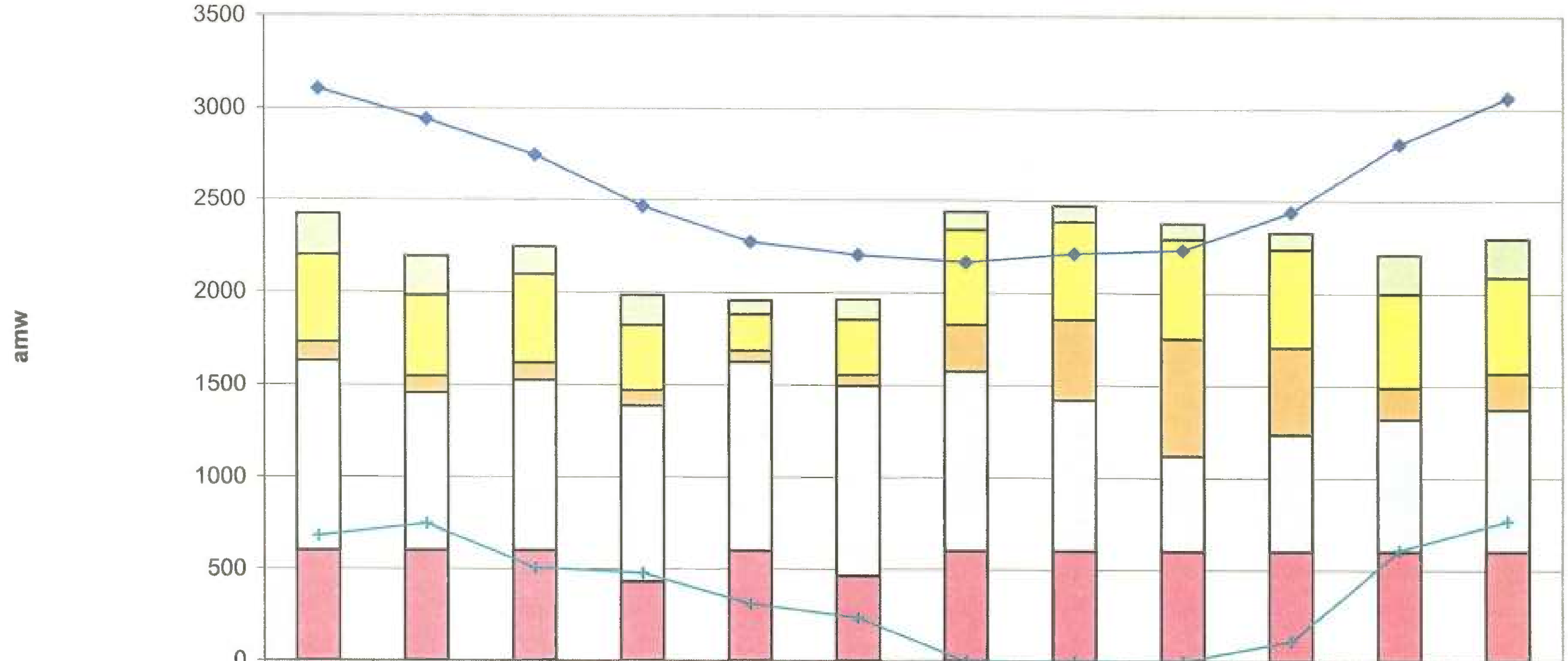
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Contracts	221	217	161	171	82	116	109	101	91	98	219	225
NUGs	510	462	510	444	200	358	466	534	534	531	513	515
Encogen & CTs	157	119	154	102	62	65	348	601	638	556	195	212
Hydro	1,033	887	926	952	1,027	1,031	977	822	521	635	718	771
Colstrip	598	619	598	433	598	464	598	598	598	598	598	598
Need- Pct.of Load	17%	20%	12%	13%	11%	5%	0%	0%	0%	0%	18%	22%
Need	509	564	333	302	248	114	0	0	0	0	503	668
Load	3,028	2,869	2,682	2,405	2,217	2,148	2,111	2,158	2,177	2,379	2,745	2,988

2009



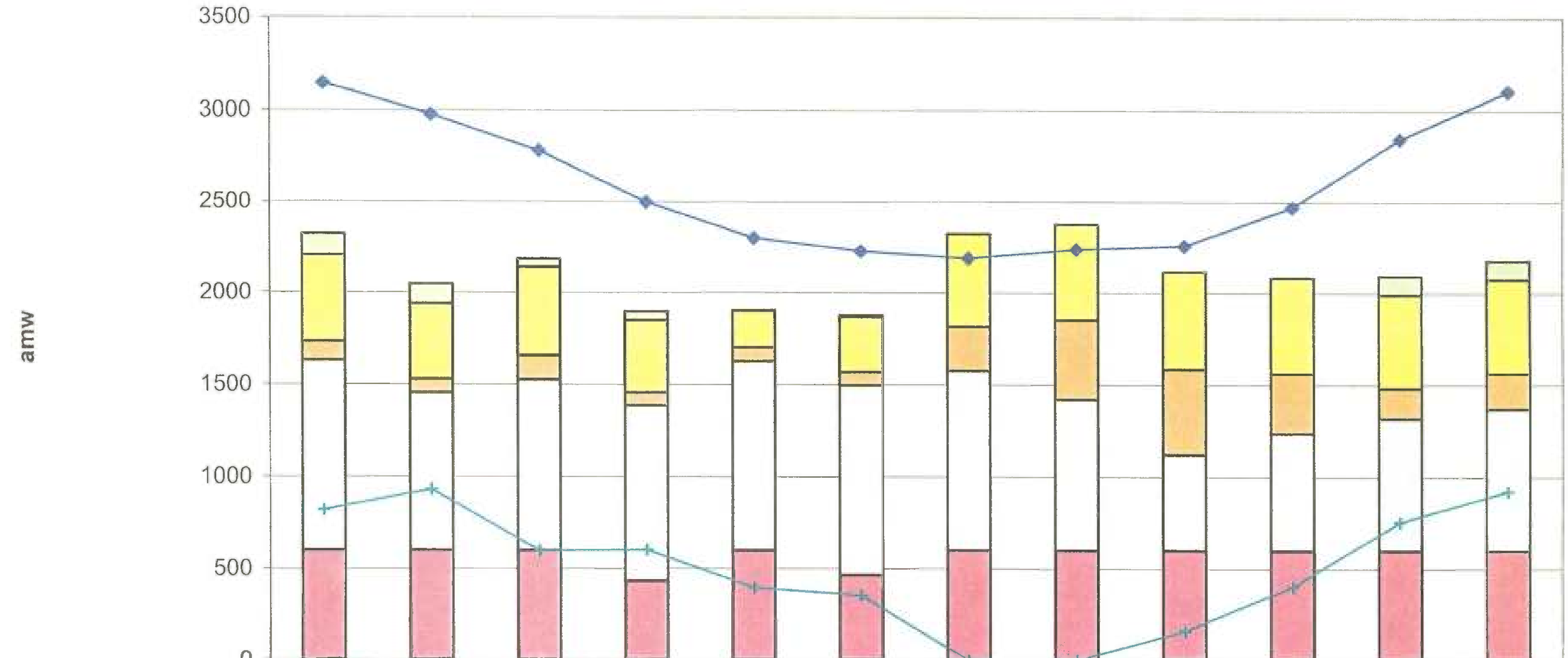
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Contracts	221	210	161	171	80	114	107	96	95	99	220	226
NUGs	454	400	510	403	198	287	467	526	531	528	513	515
Encogen & CTs	112	105	104	90	61	55	291	456	629	499	171	214
Hydro	1,033	857	926	952	1,027	1,031	977	822	521	635	718	771
Colstrip	598	598	598	433	598	464	598	598	598	598	598	598
Need- Pct.of Load	21%	25%	15%	16%	13%	10%	0%	0%	0%	2%	20%	23%
Need	654	740	421	390	285	227	0	0	0	55	565	707
Load	3,071	2,910	2,720	2,439	2,248	2,179	2,141	2,188	2,209	2,413	2,784	3,031

2010



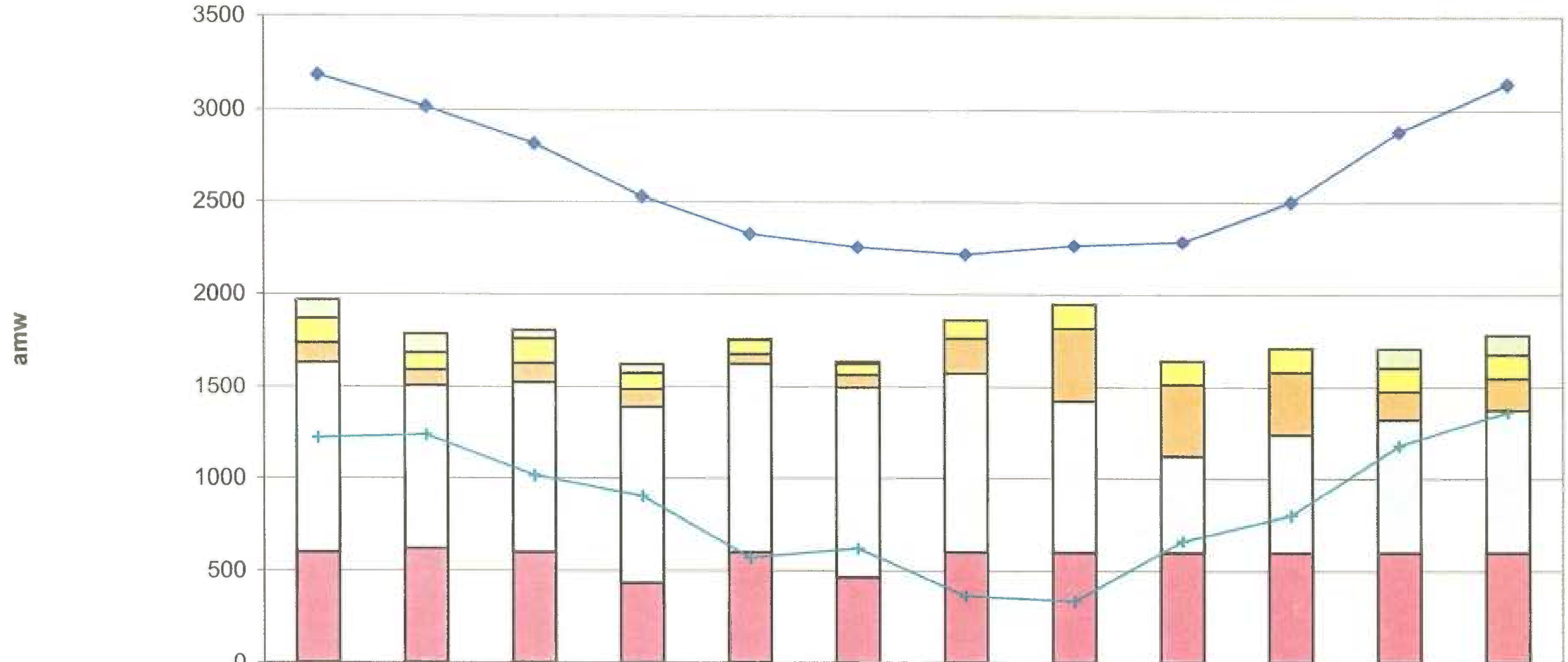
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Contracts	222	211	150	162	74	109	100	86	86	91	209	210
NUGs	468	435	474	353	195	299	511	526	535	526	510	515
Encogen & CTs	100	92	95	85	63	60	253	439	636	476	173	200
Hydro	1,033	857	926	952	1,027	1,031	977	822	521	635	718	771
Colstrip	598	598	598	433	598	464	598	598	598	598	598	598
Need- Pct.of Load	22%	25%	18%	19%	14%	11%	0%	0%	0%	5%	22%	25%
Need	683	749	506	480	316	239	0	0	0	113	607	768
Load	3,104	2,941	2,749	2,465	2,273	2,202	2,164	2,212	2,232	2,439	2,814	3,063

2011



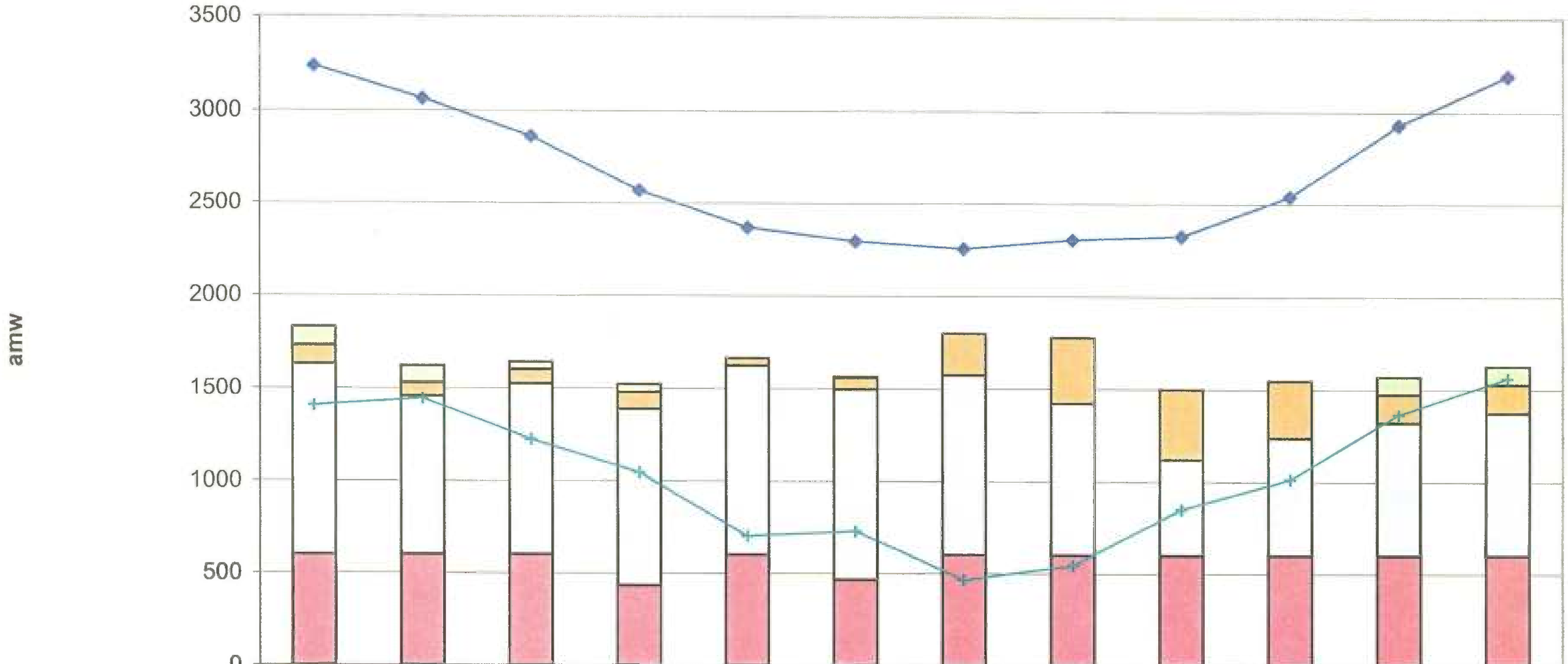
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Contracts	118	108	45	49	5	10	(5)	(17)	(18)	(18)	103	104
NUGs	475	411	485	390	200	296	513	528	532	522	510	513
Encogen & CTs	100	73	133	70	74	73	237	429	465	329	166	194
Hydro	1,033	857	926	952	1,027	1,031	977	822	521	635	718	771
Colstrip	598	598	598	433	598	464	598	598	598	598	598	598
Need- Pct.of Load	26%	31%	21%	24%	17%	16%	0%	0%	7%	16%	27%	30%
Need	821	933	599	603	398	356	0	0	163	405	756	923
Load	3,144	2,979	2,784	2,497	2,302	2,230	2,192	2,240	2,261	2,470	2,850	3,102

2012



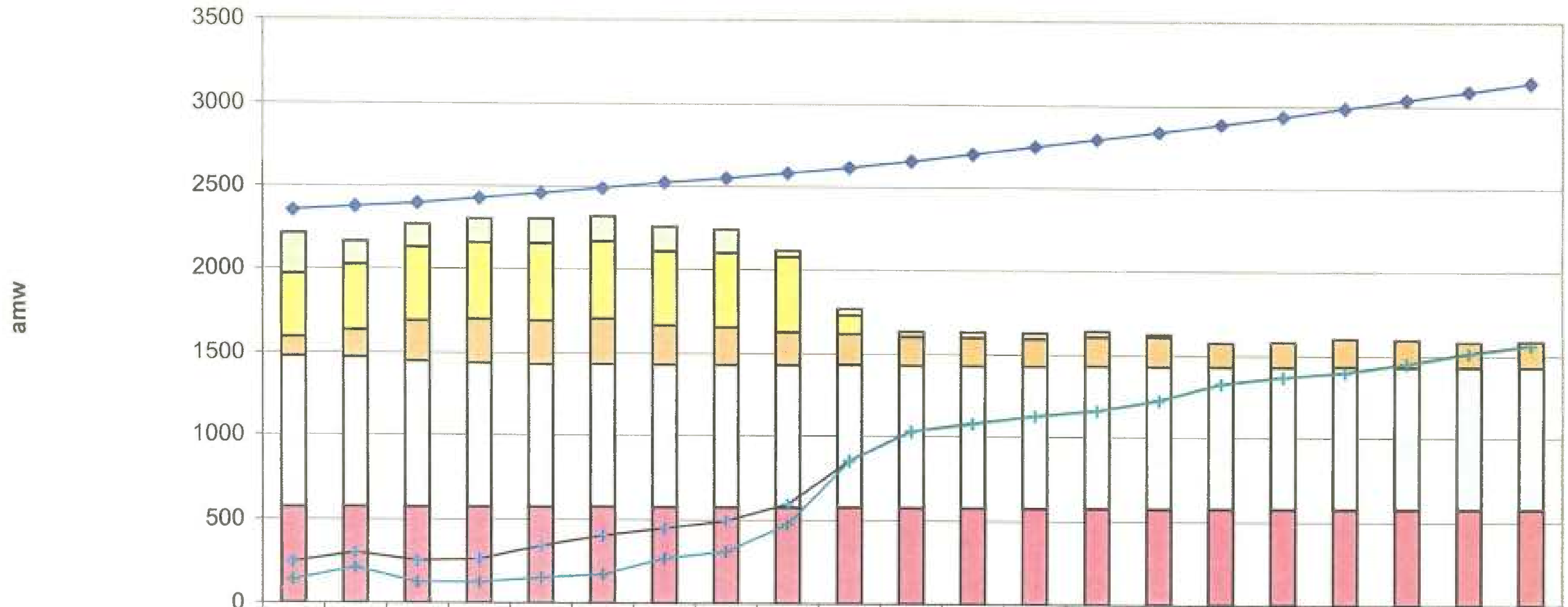
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Contracts	102	100	45	49	5	10	(5)	(17)	(18)	(15)	103	104
NUGs	131	92	131	89	76	62	98	129	131	129	131	131
Encogen & CTs	104	86	105	100	53	70	187	397	396	351	160	179
Hydro	1,033	887	926	952	1,027	1,031	977	822	521	635	718	771
Colstrip	598	619	598	433	598	464	598	598	598	598	598	598
Need- Pct.of Load	38%	41%	36%	36%	25%	27%	16%	15%	29%	32%	41%	43%
Need	1,216	1232	1015	905	572	621	365	340	663	804	1177	1358
Load	3,184	3,016	2,819	2,528	2,331	2,259	2,220	2,268	2,289	2,501	2,886	3,142

2013



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Contracts	98	93	40	44	0	5	(10)	(19)	(23)	(20)	98	102
NUGs	-	-	-	-	-	-	-	-	-	-	-	-
Encogen & CTs	100	74	80	93	40	65	224	360	380	315	156	158
Hydro	1,033	857	926	952	1,027	1,031	977	822	521	635	718	771
Colstrip	598	598	598	433	598	464	598	598	598	598	598	598
Need- Pct.of Load	43%	47%	43%	41%	30%	32%	21%	24%	37%	40%	46%	49%
Need	1,405	1443	1220	1047	703	729	466	544	851	1014	1362	1563
Load	3,234	3,064	2,864	2,569	2,368	2,295	2,255	2,305	2,326	2,541	2,932	3,192

Annual Resource Balance



	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Contracts	245	140	141	144	150	150	150	142	40	38	34	34	34	34	17	-8	-8	-8	-8	-8	-8
NUGs	377	392	442	460	464	465	445	446	448	111	0	0	0	0	0	0	0	0	0	0	0
Encogen & CTs	113	160	238	260	259	269	233	224	196	183	171	168	166	173	176	146	151	167	167	153	156
Hydro	905	897	876	863	856	859	856	856	856	859	856	856	856	859	856	856	856	859	856	856	856
Colstrip	573	575	573	573	573	575	573	573	573	575	573	573	573	575	573	573	573	575	573	573	573
Need- Pct.of Load	6%	9%	5%	5%	6%	7%	11%	12%	18%	33%	39%	40%	41%	41%	43%	46%	46%	47%	48%	49%	50%
Need (2) Pct.	10%	13%	11%	11%	14%	16%	18%	19%	23%	33%	39%	40%	41%	41%	43%	46%	47%	47%	48%	49%	50%
Load	2354	2377	2397	2426	2457	2490	2526	2553	2586	2618	2660	2705	2750	2796	2843	2890	2939	2989	3038	3089	3140
Need	141	213	128	125	155	173	269	312	472	853	1026	1073	1121	1155	1220	1323	1366	1397	1450	1514	1562
Need (2)	247	302	253	261	342	405	449	496	596	856	1,029	1,076	1,124	1,158	1,223	1,326	1,370	1,400	1454	1518	1,566

PUGET SOUND ENERGY

PRELIMINARY DRAFT FOR DISCUSSION ONLY

Assessment and Report on Self-Build Generation Alternative for Puget Sound Energy's 2002-2003 Least Cost Plan

Prepared by Tenaska, Inc.
Omaha, Nebraska

December 2002

Tenaska, Inc.
Assessment and Report on
Self-Build Generation Alternative
for Puget Sound Energy's
2002-2003 Least Cost Plan

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Section 1 – Introduction

Tenaska, Inc. (Tenaska) is pleased to provide this document for use in Puget Sound Energy's (PSE's) 2002-2003 Least Cost Plan. As part of its resource planning process, PSE retained Tenaska to prepare an assessment and report on alternatives for generation project self-development by PSE. Tenaska has extensive knowledge and experience as a developer of new electric generating facilities, including siting, permitting, design, major equipment procurement, and construction management for over 9,000 megawatts (MW) of project capacity. Tenaska also provides operations and maintenance services for all six of its domestic, operating projects and will provide similar services for three more domestic projects which are currently under construction. This experience includes development, ownership and operation of a combined-cycle facility near Ferndale, WA.

Natural gas-fired, combined-cycle combustion turbine technology is the most common type of new electric generation resource now being developed in North America. PSE could potentially acquire long-term power supplies from this type of resource under several alternative mechanisms, including: (a) self-building a project at a greenfield site; (b) purchasing and completing a project that is partially-developed; or (c) purchasing power output from a project that is owned by a third party. Comparison of the advantages and disadvantages of these three alternative resource acquisition methods is beyond the scope of this report. However, information provided in this report may be useful for comparing the self-build alternative with other methods of acquiring power from natural gas-fired, combined-cycle resources.

Following this Introduction, the discussion provides more detailed information on various aspects of self-development including project design, siting, permitting, equipment procurement, project construction, startup, operation and maintenance. Estimates of project development costs and time schedules are also provided. A brief overview of current market conditions affecting the price and availability of combustion turbines and other prime mover equipment, as well as similar information for EPC (engineering, procurement and construction) contractor services is also provided.

Section 2 – Report Approach

Tenaska's assignment for this report can be summarized as follows:

- identify and screen a range of potential sites;
- narrow the potential sites to a short list of leading candidates;
- describe possible project configurations;
- estimate project permitting and construction costs and schedules;
- estimate non-fuel project operating costs; and

- finally integrate all project performance and cost characteristics to estimate total resource costs of a hypothetical self build option.

For costing purposes, the primary focus of this report is to identify representative "reference" costs under market conditions that are relatively stable. Tenaska also discusses recent industry events that have caused actual EPC and equipment prices to vary from "equilibrium" levels. The report uses a bottom-up approach to develop cost estimates, including breakout of costs into major categories. A standardized format, or "template" is used to present the cost estimates for "generic" plants. Actual costs are very project-specific; we have used our experience and judgment to customize these generic estimates to several project configurations for two PSE sites possibilities. This template can then be used to evaluate specific self-build project development opportunities in a systematic, consistent fashion as such opportunities arise in PSE's ongoing resource identification and evaluation process.

The focus for this report is to develop estimates of capital costs and non-fuel operating and maintenance costs for the self-build alternative. Topics such as capital structures that might be used to finance a self-build project and forecasts of costs for natural gas supply to fuel a project do not receive extensive attention in this report. While total power, or PSE "resource," costs are estimated at several points, many of financial, macro economic and energy market parameters need to be consistent with those used in the analysis of other PSE resource alternatives before final least cost comparisons can be reached.

Finally, this report does not draw conclusions about which site or sites PSE might actually select to construct a generating project. Instead, the purpose of this report is to assess and develop reasonable estimates of costs, permitting, schedules and other project development considerations. Any decision to proceed with self-build development of a generation project by PSE would require more specific and detailed analysis. As indicated above, such a project would also have to be shown to be consistent with PSE's least cost electric resource plan and preferable to other available alternatives.

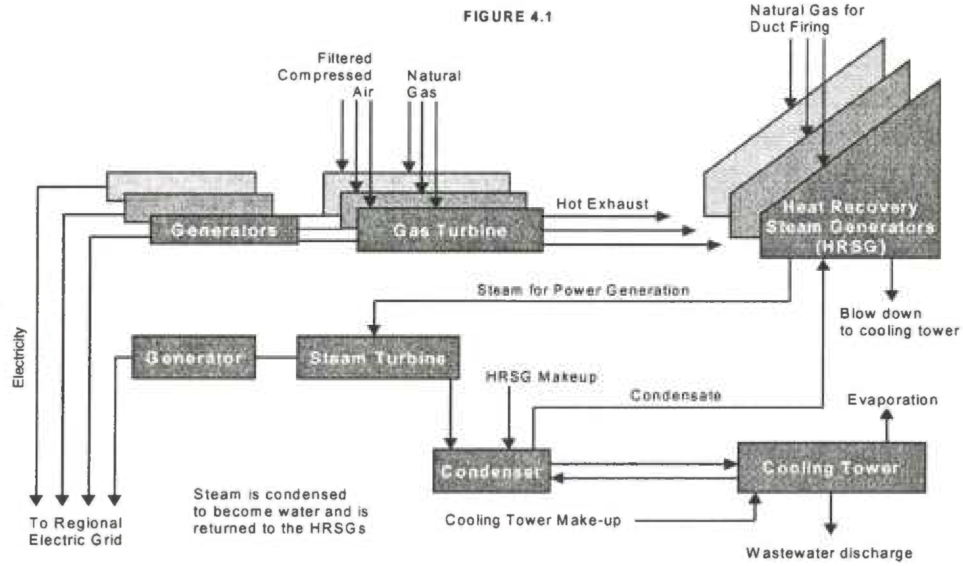
Section 3 – Basic Project Configurations

Gas-fired power plants can be separated into two basic types depending on their intended market service. "Peaking units" operate and produce electricity only during periods of high electricity demand. These peak demand periods generally occur during the extreme hot spells of summer and extreme cold spells in the winter. "Baseload units," on the other hand, generally operate full time. For gas turbine (GT) power plants, peaking units are usually comprised of simple cycle GT's and baseload units are usually comprised of GT's operating in combined cycle with one or more steam turbines (ST's).

A simple cycle gas turbine is a combustion engine with three major parts: an air compressor, burner(s), and power turbine. In the air compressor, a series of bladed rotors compresses the incoming air from the atmosphere. A portion of this compressed air is then diverted through the burners (also called combustors), where fuel (usually natural gas at pressures of 325 to 500 psig) is burned raising the temperature of the compressed air. This very hot gas is mixed with the rest of the compressed air and directed to the power turbine at temperatures up to 2350°F. In the power turbines, the force of the hot compressed air as it expands pushes another series of blades, rotating a shaft. Greater than 50 percent of the mechanical energy produced by the power turbine is consumed to drive the air compressor. The balanced of the mechanical energy turns a generator and makes electricity. The cycle efficiency, defined as a percentage of useful shaft energy output to fuel energy input, is typically in the 30 to 35 percent range.

The difference between simple cycle and combined cycle is that in combined cycle, the hot exhaust gases from the GT do not directly go to the atmosphere. Instead, the hot exhaust gases, which are typically above 1000°F, are ducted through a waste heat boiler (a heat recovery steam generator, or "HRSG") to generate steam. This steam is then used to drive a steam turbine generator (or "ST") to make additional electricity. The recovery of the heat energy in the exhaust of a gas turbine in this manner can increase the cycle efficiency of a combined cycle plant to 50 percent or more. The additional electricity that can be produced by a combined cycle installation is accompanied by additional capital costs for the HRSG, ST and a cooling system. However, the operating cost per unit of electricity produced is usually lower compared to that of simple cycle turbines due to the higher energy recovery. Figure 4.1 illustrates the basic components of a combined cycle facility.

FIGURE 4.1



Because it appears that a portion of PSE's need for new resources could be met with base load generation, Tenaska focused on combined cycle plant designs, or "configurations." The cost and performance of combined cycle plants is very dependent on the size and number of the basic GT unit(s) around which the overall plant is designed. These plants are commonly referred to by the number of gas turbines and steam turbines they feature. A "one by one" (1 X 1), for example, represents one gas turbine, paired with one steam turbine/HRSG. Larger plants can be designed as "3 X 1" (three GT's and three HRSG's paired with one larger ST), "4 X 2," and so on.

Initial Results

In June of 2002, Tenaska provided basic performance and cost information for five generic or "reference" combined cycle plants based on two standard General Electric (GE) frame gas turbines (FA's and EA's). Refer to Table 4.1. As indicated, these five plants cover a range of combined cycle capacity from 146 MW (1 X 1 EA) to 893 MW (3 X 1 FA).

The capital and operating costs associated with these plants were our first estimates and feature only very high-level detail. The initial estimates were based on Tenaska's experience with similar projects. The capital and operating costs were "inputs" to an economic model which also added the various financial parameters and assumptions necessary to determine an all-in costs of electricity expressed in $/MWh. PSE provided many of the financial assumptions such that the results reflect a utility's analytic approach and determination of total project cost and revenue requirement rather than that of an IPP developer. The all-in cost shown on Table 4.1 represent the price of electricity needed per MWh, over the number of annual operating hours indicated, to cover fuel, all fixed and variable operating costs, debt service and to earn a return on invested equity. A summary of the results follows:

Table 4.1

Gas Turbine Type	Configuration	MW	Total Capital MM$	Total Capital $/kW	All-In Cost $/MWh
GE 7FA	1 X 1	294	216.4	735	43.07
	2 X 1	593	367.8	620	40.25
	3 X 1	893	490.4	549	38.81
GE 7 EA	1 X 1	146	158.0	1081	53.73
	2 X 1	295	234.4	794	46.91

Figures 4.2 and 4.3 graphically show the results from this high level analysis for all five generic plant configurations. These graphs clearly show how project size impacts cost. Capital costs range from about $1100/kW for the smallest EA-based plant (about 146 MW) to just under $600/kW for the largest FA-based plant (about 893 MW). All-in costs in $/MWh range from about $54 to about $38, respectively, over the same range (given the noted financial assumptions and fuel cost). FA-

FIGURE 4.2
Generic Combined Cycle Plants - All In Cost
June 2002 Results

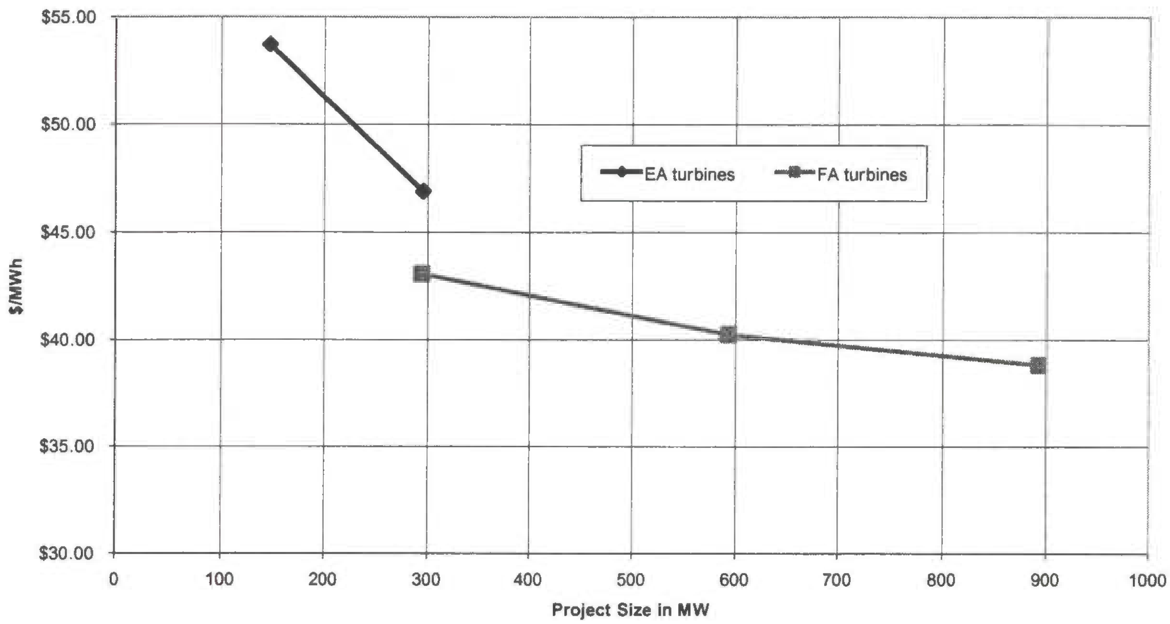
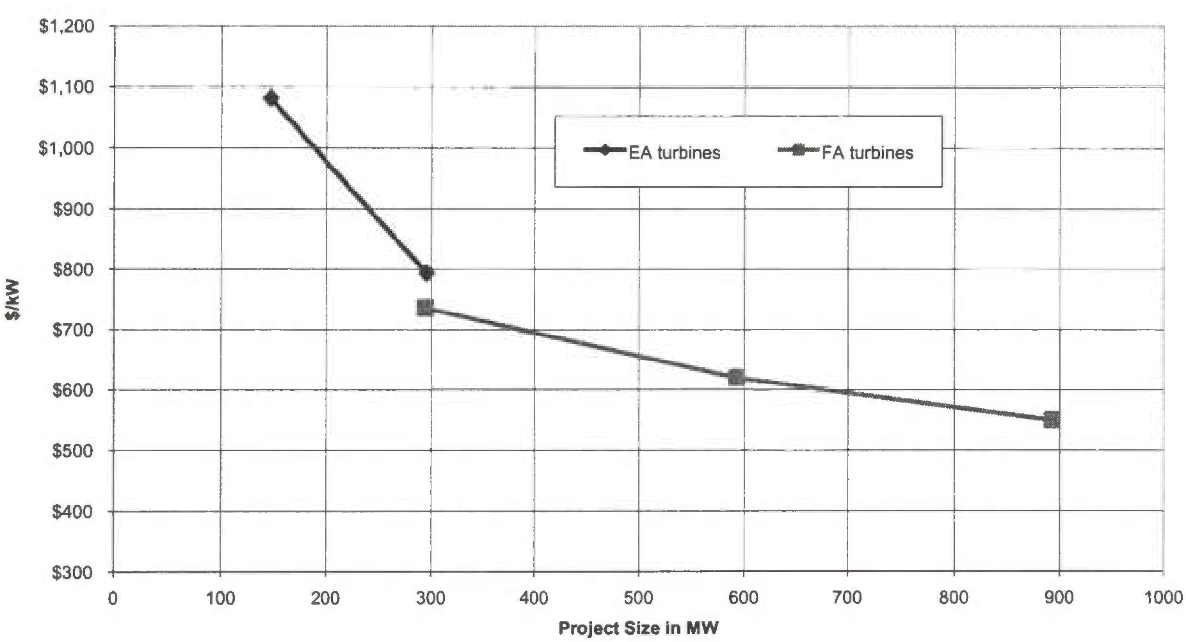


FIGURE 4.3
Generic Combined Cycle Plants - Capital Cost
June 2002 Results



based plants are also clearly more economic than EA technology if resource requirements match this plant size.

Revised and Updated Results

These high level results formed the basis for more detailed analysis of PSE's self-build options and some of the plant design trade-offs which need to be considered. Subsequent to Tenaska's initial work for PSE, which was highlighted above, we increased the level of technical and cost detail for the five original generic plants during a second phase of our assignment which was conducted in November and December of 2002. This analysis includes more detail on the components of capital and operating costs and indicates many of the physical requirements of each generic configuration (fuel use, water requirements, site size, etc.). Once again this data was combined with the requisite economic parameters in a financial model to estimate all-in project costs and revenue requirements, the results of which are discussed in later sections.

Two design issues should be mentioned at least briefly. First is cooling. Refer back to Figure 4.1. When steam exits the steam turbine it is condensed back into water and further cooled to be re-circulated through the steam cycle or discharged. "Wet" cooling uses large open towers and evaporation to cool process water while "dry" or "air" cooling condenses steam and passes hot water through large radiator-like facilities in a closed system. Wet cooling has a large raw water requirement, approximately 2 million gallons per day for a generic 1 X 1 on Table 4.1 depending on climatic conditions and technical configuration. Typically more than 80% or so of this raw water is "consumed" due to evaporation. For the same 1X1, dry cooling uses only a small fraction of the daily raw water volume of wet cooling, typically less than 10%, but suffers two disadvantages: efficiency is lower (hence project capacity is reduced by 2-3% or about 6-8 MW at summer conditions) and capital costs are higher (15% more EPC cost or about $10MM). Dry cooling can be an important option, however, if water is not physically available in the quantities required or if environmental or community circumstances restrict its use. Municipal wastewater, if available, is another source of make-up water for a wet cooling system. Additional pretreatment may be required and typically more wastewater is produced also due to the lower quality raw feedwater. The fact that this water is often very low cost (often free), usually offsets the incremental treating and wastewater discharge costs.

The second design issue is duct firing. When ambient temperatures increase gas turbine output and overall plant output decrease. This loss of output can be more than offset by adding supplemental firing, via "duct burners," to the hot gases passing through the HRSG's into the steam turbine. Typically, combined cycle steam turbines are "over-sized" to accommodate duct firing during such ambient conditions. Over-sized steam turbines do suggest a small cost and efficiency penalty when duct firing is available but not in use. The overriding benefit, however, is that although duct firing adds capital cost, the cost per incremental MW added is quite attractive. For a generic 1 X 1 on Table 4.1, duct firing adds 38 MW of capacity from 256 MW to

294 MW) and about $6MM, or about $150/kW. Simple cycle peaking plants typically cost about twice this per kW. The incremental heat rate for duct firing is also much lower than the simple cycle peaking alternative (say 9,200 btu/kWh versus 11,000 to 12,000).

Additional output over and above duct firing can also be derived on hot days by inlet air cooling either by evaporative cooling or mechanical refrigeration. Evaporative cooling (or fogging) is the most cost effective technique but gas turbine compressor inlet temperatures are of course limited to the ambient wet bulb temperature. Typically inlet cooling is not placed in service unless ambient dry bulb temperatures exceed 59 degrees F.

Section 4 – Current Status of Equipment and EPC Markets

The largest portion of a combined cycle plant's capital cost is the EPC contract (Engineering, Procurement and Construction) and the cost of the major equipment components. Contracting practices obviously vary by project and from developer to developer, but a common approach is to negotiate a single EPC contract with one construction firm to serve as the "general contractor" and to provide all construction materials, labor and supervision and all "balance of plant" components. Developers/owners often independently provide the major equipment components and "turnkey" contracts for the interconnects (power, fuel and water). Some or all of these latter items can also be assigned to the EPC contractor contractually. Contractor fees vary depending the scope of services and materials provided and the amount of project risk, both in terms of schedule and dollar budget, the EPC contractor takes on.

EPC costs and fees and equipment prices vary with market conditions. In general, both have fallen with the 2002 down-turn in the energy sector. Making generalizations can be difficult because both can be very project-specific; however, we viewed a change in EPC and equipment costs during 2002 between our initial (June) and final (December) work based on Tenaska's judgment and conversations with industry sources, contractors and equipment vendors. EPC differences are the most difficult to determine because so few new contracts have been announced or awarded recently. The reduction has generally been 5 to 10%. Appropriately scaling these changes up or down with project size is also project specific. EPC costs have fallen; this reflects a revision in our scaling factor for smaller projects not an increase in price.

Changes in equipment prices are much easier to observe. Gas turbines have a high degree of interchangeability and hence a "secondary" market exists were GT's are bought and resold. The price of gas turbines rose quickly in the late 1990's and early 2000's with the surge in gas-fired plant development. Waiting periods for delivery reached "years." The opposite has occurred this year. FA turbines peaked at about $40MM each in early to mid 2001. Today's manufacturer price is perhaps $30MM;

prices on the secondary market are perhaps $20MM. Steam turbines and HRSG's are less "commodity-like" and a larger number of manufacturers exist than for GT's. Hence prices have not been as volatile as prices for GT's, but in our view some softening has occurred.

Occasionally, very distressed pricing can be observed in the secondary market, usually through equipment brokers which protect the identity of the actual owner/seller. The lowest price Tenaska has observed has been a package of three 1 X 1 FA power islands for about $60MM (or about $10MM each for a GT, ST and HRSG). We do not recommend basing an investment decision in a resource planning context on such numbers. Availability of this pricing on an ongoing basis is very uncertain and such sales are "as is, where is." Significant costs can be associated with relocating and reusing such equipment components.

Section 5 – Potential Sites

Selection of a suitable site is a major step in the development of a new power generation facility. A number of site-specific factors can significantly influence a particular location's feasibility and attractiveness. Some factors are 'knockout' factors, such as when zoning for a prospective site would prohibit its use for power generation. Other factors influence the cost of development, including availability or accessibility of electric transmission.

It should be noted that discussion of potential sites in this report is primarily for the purpose of illustrating various factors that need to be considered and estimating representative costs associated with particular sites. Nothing in this report should be interpreted to mean that a particular site has been selected for development, or that other sites would be excluded from future consideration.

In the site review, transmission constraints and regulatory uncertainties, as discussed elsewhere in this document, were of primary concern. Early in the process it was determined that the company should avoid building new generation in locations where the ability to deliver the power to the company's retail loads was uncertain. This first meant that new generation sites should focus on west of the Cascades as there are already trans-Cascades constraints on the regional transmission system. West of the Cascades, there are some south-north constraints as well, which removed Whatcom and Skagit counties from consideration. After eliminating some geographic areas, the search focused on PSE's service territory in King, Pierce and Thurston counties.

Map A-6-1 shows the location of twenty-four sites that were considered. None of the sites were ideal. For example, some substation sites were large enough, but they were not close to a gas supply line, while other sites had become encumbered with suburban growth. For a first cut, it was determined to remove the sites with non-economic constraints: zoning and public acceptance. A group of PSE municipal land planners reviewed the sites and identified a "short list" of sites which could provide the appropriate zoning environment (Map A-6-2). The process led to a fundamental paradox: the further a site was located from its customers, the greater the cost for gas, transmission and water.

PSE personnel and Tenaska conducted on-site inspections of the short list properties before initiating financial analyses. The on-site inspections allowed for discovery of developments and other locational issues that did not show up on inspection of maps. These issues were further investigated by direct contact of local authorities, and PSE personnel who were knowledgeable of specific sites and processes.

The financial analysis will focus on two sites: Dieringer, which is a substation near the White River hydro plant; and Frederickson, which currently holds two gas turbine peakers. The Dieringer site could contain a "one-on-one" 250+ megawatt combined cycle turbine with a steam generator as it is limited by size. The Frederickson site has more room for expansion and could be used for either a "one-on-one" or a "two-on-one" (250+ mw and 500+ mw, respectively).

The evaluations of these sites by Tenaska included many important issues such as power system upgrades and fuel and water availability and costs. Nevertheless, this report is still a rough cut to be used as a benchmark for comparison with other alternatives. A detailed analysis would still require engineering reports for construction, OASIS-based transmission upgrade studies, and negotiations with municipalities for services and taxes

Section 6 – Site Specific Project Description and Cost Estimates

Table 7.1, based on the technical characteristics of the generic combined cycle plants detailed on Table 4.2 and the specific attributes of PSE's two main site alternatives listed on Table 6.1, summarizes Tenaska's view of the capital cost of a 1 X 1 and a 2 X 1 project at Frederickson and a 1 X 1 project at Dieringer. Two scenarios are provided for each configuration to highlight the impact of possible equipment price differences. As discussed previously for the initial June results, these capital costs were added to an economic model that calculated "soft costs" and then total installed project cost. A summary follows using "Base" equipment pricing:

Table 7.1

	Units	Frederickson 1 X 1	Frederickson 2 X 1	Dieringer 1 X 1
Capacity	MW	294	593	294
EPC Cost	MM$	76.0	137.4	75.6
Equipment	MM$	54.8	102.5	53.6
Interconnects	MM$	31.2	75.3	14.4
Soft Cost	MM$	68.3	105.7	65.4
Total Cost	MM$	230.4	420.8	209.0
	$/kW	784	710	711

The economies of scale associated with larger plants usually suggest declining capital cost per kW as plant size increases as is evident with the two Frederickson cases ($784/kW falling to $710/kW using higher equipment pricing). Notice that the Dieringer 1 X 1 shows about the same capital cost as the Frederickson 2 X 1. Interconnect costs at Frederickson are a significant issue. This location may have offsetting system benefits to PSE, but all other things equal, Frederickson appears to be a higher cost site.

Section 7 – Project Permitting

The construction and operation of a new project will require approvals from certain federal, state, and local authorities. The following information characterizes the process of obtaining these approvals and the costs and schedule associated with completion of the permitting process.

Requirements

PSE would need to self-certify under the requirements of the Power Plant and Industrial Fuel Use Act of 1978. A Certificate of Compliance would be filed with the Office of Fuels Programs, Department of Energy. Publication of a Public Notice by the Department of Energy would also be required.

Stationary thermal power plants to be sited in Washington with a net electrical generating capacity greater than 350 MW are included within the definition of Major Energy Facilities and subject to licensing review by the Washington State Energy Facility Site Evaluation Council (EFSEC or Council) and case-by-case approval by the governor. The state's energy facility license is obtained in the form of a Site Certification Agreement. The licensing process includes application to the Council, evaluation of the application, and recommendation by the Council to the governor to approve and sign a Site Certification Agreement. The Council will apply its regulatory standards to subject facilities, and is currently in the process or reviewing those standards.

Smaller projects (i.e., less than 350 MW) that do not meet the definition of a Major Energy Facility do not require a Site Certification Agreement or governor approval, but are subject to applicable state and local permitting requirements, including federal air quality and water quality reviews that are delegated by the United States Environmental Protection Agency (USEPA) to the State of Washington or local jurisdictions. Such requirements include air quality permits, wastewater discharge or pretreatment permits, and local land use or zoning and building construction permits.

The State Environmental Policy Act (SEPA) process provides broad interdisciplinary environmental review and will be lead by EFSEC for Major Energy Facilities or by other state or local agencies for smaller projects. In the event that there is a material federal environmental review required by the National Environmental Policy Act

(NEPA), the lead agency under SEPA may conduct a coordinated review with federal agencies whose action with respect to the Project is subject to NEPA.

Notable federal jurisdiction is that of the U.S. Army Corps of Engineers (USACE) over certain construction activities in waterways and wetlands. If such construction is necessary, including interconnecting water, gas, and electrical infrastructure, some form of permit may be required from the USACE. Review of permit applicability and compliance by the USACE also includes review of cultural resource issues under the requirements of the National Historic Preservation Act as well as review of potential impacts to threatened and endangered species required by the Endangered Species Act. The USACE will coordinate the reviews of state and federal agencies with expertise in these areas, or coordination will be provided by the lead agency under NEPA. A detailed delineation of wetlands and other waters of the United States must be developed to help avoid jurisdictional waters and to determine potential USACE requirements.

The potential site alternatives include discharge of cooling water and minor volumes of other process effluents to the collection systems of publicly owned wastewater treatment works. Storm water drainage, retention, and discharge facilities will also comply with the treatment requirements and approvals established by local ordinances, State of Washington regulations, and the National Pollutant Discharge Elimination System.

Given available emissions control technology, combined cycle combustion turbine projects subject to EFSEC are also likely to be subject to federal new source review or Prevention of Significant Deterioration (PSD) permit requirements. Smaller project alternatives may not necessarily be subject to PSD depending on final equipment and emissions control selection decisions. Federal land management agencies, such as the National Park Service and U.S. Forest Service, must be consulted in the PSD permitting process with respect to air quality impacts on certain public lands that they administer, such as national parks and wilderness areas. Detailed air quality modeling, potentially including emissions from other sources as well as the Project, may be required to address federal land manager concerns.

The air quality permitting process includes a review of applicable construction standards, assessment of potential project impacts to ambient air quality, and a determination of best available control technology. An air quality construction permit will establish operating and emission limits for project equipment, requirements for initial emissions testing, as well as monitoring and reporting requirements.

New projects must also apply for a permit under the Clean Air Act acid rain prevention program at least 24 months prior to the date when electricity is first provided to the grid system. The acid rain prevention program includes additional monitoring requirements for emissions of sulfur dioxide, oxides of nitrogen, and carbon dioxide. Projects must certify and operate a continuous emissions monitoring system in accordance with the requirements of the acid rain prevention program.

After completion of construction, projects will also apply for an operating permit. When issued, the operating permit will identify applicable regulatory requirements including a requirement to regularly certify compliance with all applicable air quality regulations and conditions of the operating permit. The acid rain permit is issued as one part of the operating permit.

Unless site conditions dictate otherwise, new projects generally will not require hazardous waste transfer, storage, or disposal permits or underground storage tank registration (no underground storage tanks are included). Projects will be required to submit to the USEPA and Ecology a Facility Response Plan detailing contingency plans for oil spills and a Risk Management Plan governing hazardous materials contingencies.

Estimated Costs

Budgetary cost estimates for permitting range from $0.8 to $1.7 million exclusive of preliminary design engineering that may be required to support permitting efforts. In addition to costs directly associated with project permitting, new EFSEC global warming mitigation costs could be imposed as a result of currently ongoing regulatory rulemaking. One of the regulatory options for such mitigation is based upon Oregon Energy Facility Siting Council (EFSC) requirements. Under the Oregon program, these mitigation costs are paid lump-sum prior to commercial operation (i.e. the fee would be treated as another up-front capital cost). For the size range of projects Tenaska evaluated for PSE, the fee would range from about $4MM for a small 146 MW project to over $14MM for a 3 X 1. Given the status of the debate on this subject, however, no mitigation costs have been included in Tenaska's project cost estimates.

Schedule

EFSEC's web site provides a generalized siting process timeline EFSEC suggests a potential schedule involving four to eight months of preliminary site study plus an additional 14 months for the various other steps for development of air and water permits and the Site Certification Agreement as well as public hearings and other procedural steps. A smaller project not subject to Council requirements could anticipate a permitting timeline of 10 to 14 months, depending upon procedural options selected by the lead SEPA agency and assuming no significant federal involvement.

Section 8 – Project Construction

As an example, Table 9.1 lists the major components of the cost to construct a 1 X 1 at the Frederickson site. At this level of detail, construction costs (often called total installed cost) are highly site-specific. The EPC contract reflects all balance of plant requirements (i.e. non-equipment requirements) such as buildings, cooling towers, site preparation and excavation, footings and foundations, installing utilities and all piping, fans and control systems. The EPC contract also includes the contractor's fees and profit and is reflective of the amount of risk the contractor assumes. One important risk is related to labor (both hours and wage rates). With fully loaded wage rates of say $50/hour and 600,000 total man-hours the Frederickson 1 X 1 would have about $30MM of labor cost, or almost 40% of the total EPC contract. Typically EPC contracts also contain premium/penalty provisions that set out the cost or benefit of achieving or missing key schedule milestones and/or equipment performance.

Table 9.1

Example of Total Installed Project Costs ($2002)		
	$1,000	Percent of Total
EPC contract	$ 76,000	33.0%
Equipment	$ 54,840	23.8%
Interconnects	$ 31,190	13.5%
Subtotal	$ 162,030	70.3%
Interest During Construction	$ 11,479	5.0%
Contingency	$ 10,238	4.4%
Sales Tax	$ 9,512	4.1%
Development Costs	$ 7,000	3.0%
LTSA-related and Spares	$ 5,782	2.5%
Startup Including Fuel	$ 5,639	2.4%
Project Management	$ 5,500	2.4%
Lender-related	$ 5,472	2.4%
Insurance-related	$ 2,900	1.3%
Land- related	$ 2,500	1.1%
Working Capital	$ 1,750	0.8%
All Other	$ 591	0.3%
Subtotal	$ 68,363	29.7%
Total Installed Cost	$ 230,393	100.0%

This example suggests that costs other than EPC, equipment and interconnects (commonly called "soft costs") comprise about 30% of total installed costs. These costs are very dependent on what type of company sponsors and builds a project (regulated utility or independent power producer) and how it is financed. The costs related to bank financing (interest during construction and lender-related fees and reimbursables) total about $17MM. The philosophy on contingency and spare parts also varies from sponsor to sponsor.

A schedule should reflect site and project specific characteristics, but in Tenaska's experience a general rule of thumb for a 3 X 1 configuration is 24 months. 2 X 1's and 1 X 1's might be one month less each (i.e. 23 months and 22 months). This particular schedule also assumes a two or three month "Limited Notice To Proceed (LNTP)" during which the contractor and sometimes subcontractors get a "head start" on certain site-preparation and engineering items. The permitting and construction timelines, of course, are additive. The following table summarizes the total timeline for a new gas-fired project. 1 X 1's might range from 33 to 39 months; 2 X 1's might range from 40 to 48 months. Some of the individual activities can be accomplished concurrently. In our experience the regulatory process is highly uncertain; it is critically important to gain local community support and communicate regularly with all of a project's stakeholders.

Configuration	Site Study Permit Preparation	EFSEC?	Regulatory Approvals	Construction
1 X 1	2 – 4 mos	No	10 – 14 mos	21 mos
2 X 1	4 – 8 mos	Yes	14 – 18 mos	22 mos

Section 9 – Operating and Maintenance Requirements and Cost Estimates

Non-fuel operating and maintenance ("O&M") costs are typically broken into two categories. The first category, "fixed" costs, generally does not vary with a plant's level of output. Fixed costs include plant labor, ongoing utilities and building/grounds upkeep, usually some allocated corporate overhead and fees paid to the operator. Operator fees of course are eliminated if Puget self operates.

Variable costs generally change with a plant's annual hours of operations. Water treatment, chemicals, environmental controls and catalyst replacement, etc. all are directly related to hours of operation. The largest single item in the variable category is major maintenance of the gas and steam turbines. Scheduled, routine maintenance occurs on a very carefully managed timeline related to annual hours and the number of starts per year, typically as follows:

Table 10.1

Activity	Operating Hours Between Each Activity
Combustion Inspection	8,000
Hot Gas Path Inspection	24,000
Major Overhaul	48,000

Although some plant owners/operators manage and conduct these major maintenance activities themselves, others opt to contract with third parties for these services, frequently with the manufacturer of the equipment. In such cases Long Term Service Agreements (LTSA's) describe these maintenance practices and include all the parts and labor needed. LTSA's usually levelize annual maintenance costs using a charge per fired hour and an annual fixed minimum fee ($435/fired hour and about $1MM/year for a 1 X 1). In this fashion, the manufacturer assumes all of the risks associated with parts availability, premature wear, equipment performance, etc.

Section 10 – Summary of Results

As discussed in previous sections, Tenaska looked at two Puget self-build site alternatives for Frederickson (1 X1 and 2 X 1) and one for Dieringer (1 X 1). Table 11.1 integrates all of these estimates for plant performance, capital and operating cost, permitting and construction schedules as well as all of the necessary financial modeling assumptions to calculate total installed capital cost (in MM$ and $/kW) and all-in power costs (in $/MWh). Capacity cost in $/kW-month estimates the fixed payment that a plant owner needs to receive to support the full cost of new capacity. This payment covers all fixed costs including repayment of debt and earns the project owner a minimum "profit." The capacity payment is independent of hours of operation (i.e. it's "take or pay"). The all-in cost in $/MWh covers the capacity payment as well as fuel and all variable costs (i.e. all of the costs which are incurred based on hours operated). The all-in cost is clearly very dependent on the assumption about annual hours of operation. A summary of the results using "Base" equipment pricing follows:

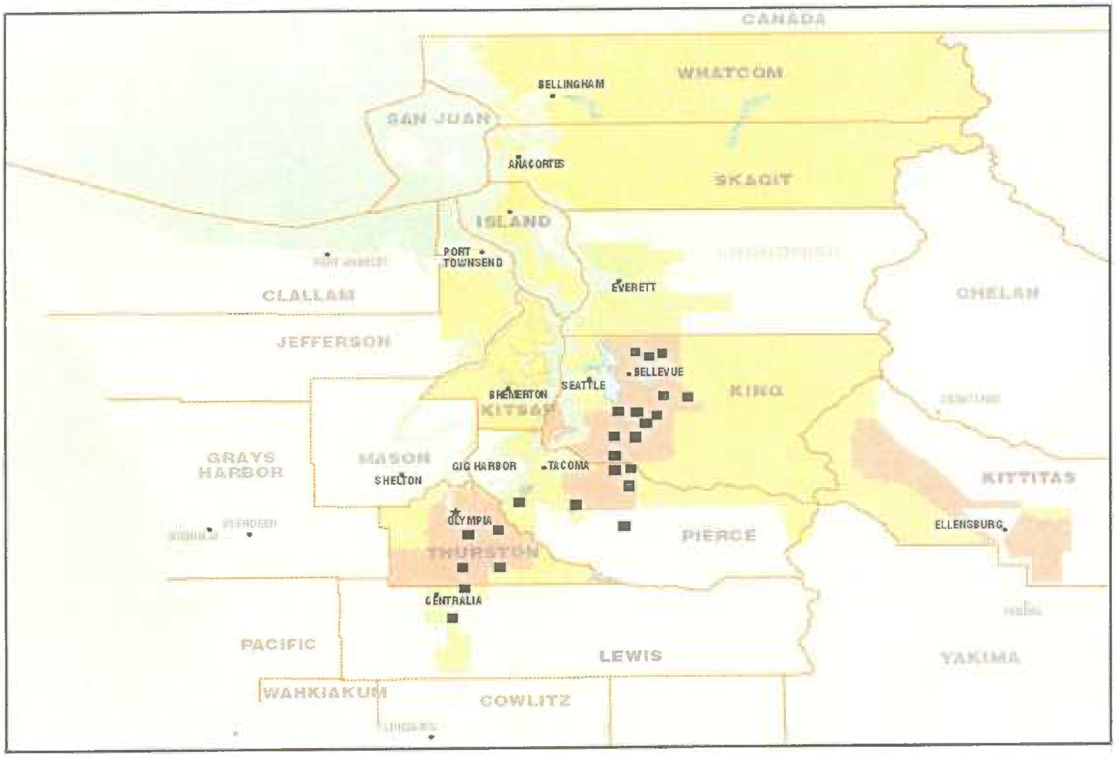
Table 11.1

	Units	Frederickson 1 X 1	Frederickson 2 X 1	Dieringer 1 X 1
Capacity	MW	294	593	294
Capital Cost	MM$	230.4	420.9	209.0
	$/kW	784	710	711
Capacity Cost	$/kW-mon	8.36	7.17	7.68
All-In Cost	$/MWh	44.48	42.18	43.41

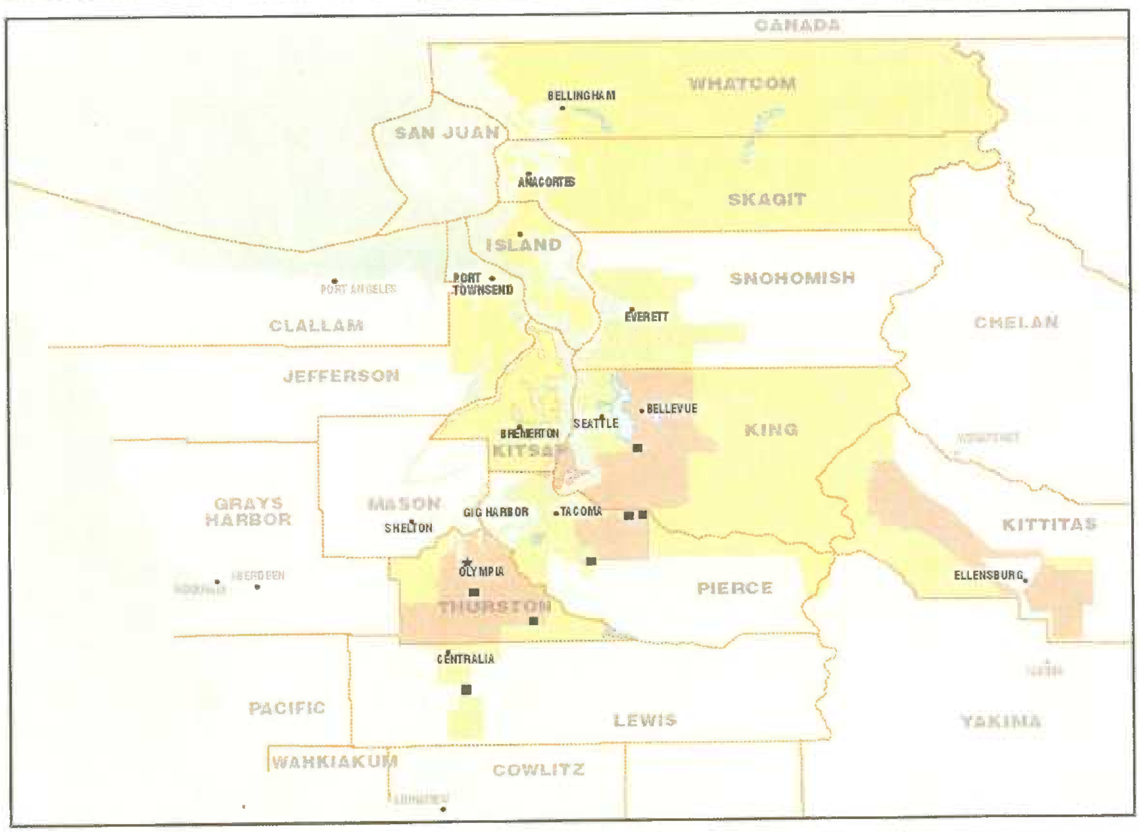
Capital costs for the 1 X 1's range from $711/kW at Dieringer to $784/kW at Frederickson. Interconnect costs account for the vast majority of the difference. Notice that interconnect costs for a Frederickson 2 X 1 are substantially higher than for a 1 X 1, but the scale of a larger plant offsets the increase. If lower priced equipment is available, capital costs for the lower cost sites fall to about $660/kW. The only difference in non-fuel operating costs is water and wastewater cost at Dieringer (less cycles of cooling concentration due to water quality). All-in costs, based on 90% capacity factor, $3.63/mmbtu fuel, and other financial assumptions, range from about $42/MWh for a Frederickson 2 X 1 to about $44.50/MWh for a Frederickson 1 X 1. Lower equipment prices and hence capital cost push the all-in costs down about $.80/mWh.

Maps A-6-1, A-6-2

PUGET SOUND ENERGY SERVICE TERRITORY



PUGET SOUND ENERGY SERVICE TERRITORY



Decision Process

Chapter 9

DECISION PROCESS ON RESOURCE STRATEGY

Note to readers:

This chapter provides an overview of a decision-making approach that PSE is considering using for this Least Cost Plan. The method described here is currently undergoing further consideration and development. As a result, certain portions of the following are subject to revision. Also, additional details remain to be specified.

Therefore, PSE is interested in receiving comments on the basic approach it is considering, including suggestions for its implementation.

INTRODUCTION

This Chapter describes the decision-making method and process that PSE is considering using to formulate its updated long-term electric resource strategy. This approach is intended to facilitate consideration of a full range of relevant factors while also documenting how the Company is applying judgment to reach conclusions about its long-term electric resource strategy. This method will also allow PSE's decision-making process to take into account the results of the analysis presented in Chapter 8 (which tend to focus on more quantitative factors), along with other qualitative considerations (including issues discussed in Chapter 2) that may not lend themselves as easily to quantification.

The next section of this chapter provides an overview of the decision process, beginning with an overview flowchart and a summary of the requirement that PSE document the factors it considers and how it weighs various considerations in determining its long-term electric resource strategy. Also included is a description of the need to include quantitative and qualitative factors in the decision process, as well as the necessity for applying judgment in order to balance tradeoffs between multiple goals and constraints.

Section c. of this chapter lays out a structured decision process that PSE is contemplating using for its current least cost planning process. Five basic criteria that PSE is using to evaluate alternative resource portfolios are presented. Next, a "scorecard", or decision matrix based on the five decision criteria is presented. This is accompanied by a description of how the matrix can be used to evaluate a number of alternative resource portfolios, incorporating the results of the resource analyses and the application of judgment to quantitative and qualitative considerations.

Section d. describes how PSE intends to test the use of the scorecard evaluation methodology using results from the portfolio screening analysis. This section will provide interim results from application of the scorecard, along with a discussion of benefits and limitations that become apparent through the Company's initial application of the methodology.

Section e. will present results from the second round of the resource strategy determination process. This will include results of the more detailed evaluation of screened resource portfolios, using results that are expected to become available in March 2003.

Section f. will identify key tradeoffs that PSE anticipates will be identified through the decision process, including during the initial application to portfolio screening results and during the subsequent application to results of the more detailed portfolio evaluation.

Section g. will identify considerations related to implementing PSE's updated long-term electric resource strategy.

Section h. will provide a proposed plan and schedule for implementing the Company's updated long-term electric resource plan.

Section i. will describe PSE's plans to continue reviewing its long-term electric resource strategy, including to incorporate any major changes that could affect PSE's need for new resources or the types and amounts of resources that it should include in its resource acquisition plan. This section will also set forth PSE's plan to incorporate updated conservation resource assessments (expected to become available in May 2003) in its resource analysis and plan.

OVERVIEW OF DECISION PROCESS

Deciding upon PSE's preferred long-term electric resource strategy is an important and challenging process that must take a variety of factors into consideration. Some of these factors can be evaluated in quantitative terms, allowing a range of resource strategy alternatives to be compared relatively directly on the basis of such factors. However, the resource strategy also must incorporate other important factors that do not lend themselves to quantitative measurement, making relative comparisons more difficult and less precise. Further complexity is created by the need to include these multiple factors, both quantitative and qualitative, in making decisions about the long-term resource strategy. As a result, determination of a preferred long-term resource strategy is not a purely objective process, but also includes subjective evaluation. In other words, PSE must apply judgment in the decision-making process.

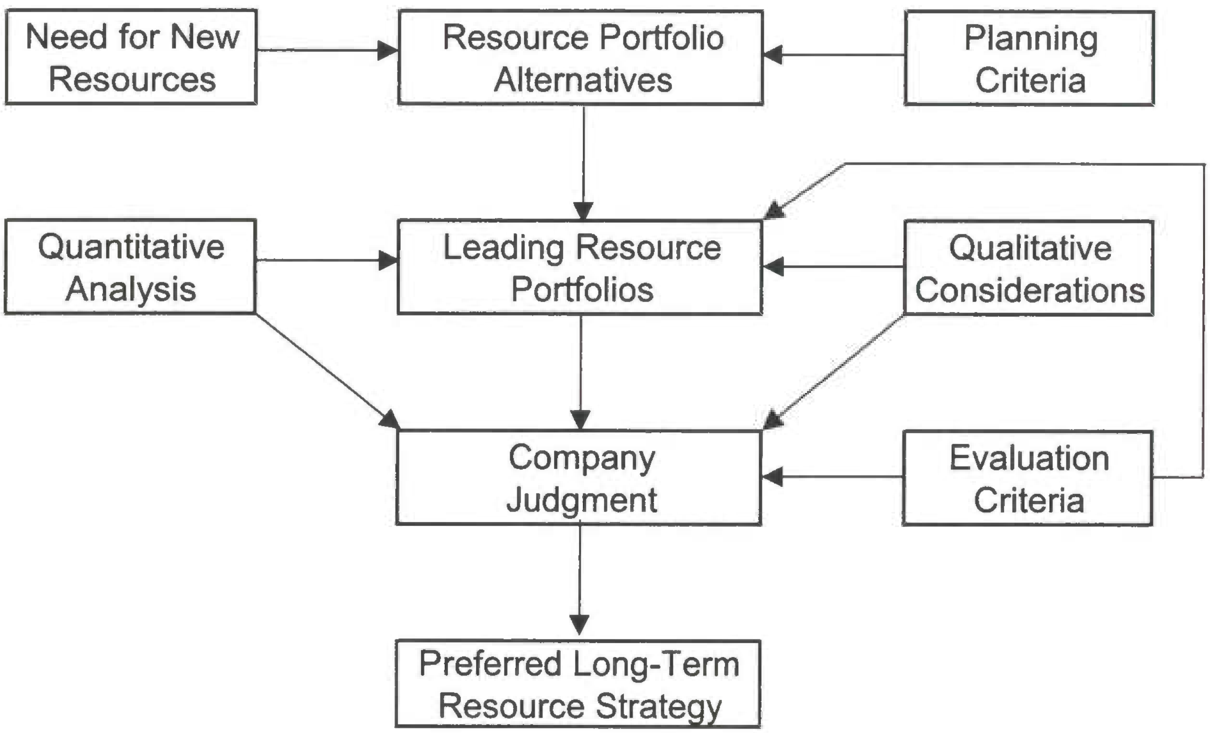
Notwithstanding the challenges in deciding upon a long-term resource strategy (or perhaps in recognition of these challenges), PSE is required to document the methods and assumptions that it uses to develop its Least Cost Plan. This documentation must include a demonstration that PSE has considered a range of resource alternatives and made its decision based on consistent evaluation of the alternatives. The process that the Company uses to formulate its long-term resource strategy must also be documented, including its application of judgment in the decision-making process.

Documenting the decision-making process that results in PSE's long-term electric resource strategy also helps to make the Least Cost Plan an action-guiding document. Specifically, the long-term electric resource strategy can assist the Company as it makes specific resource acquisitions and carries out other implementation actions on a consistent, well-founded basis.

For the reasons discussed above, PSE is considering using an open and structured approach to assist in decision-making for the resource strategy and to document the assumptions, method and results of the decision process.

Figure 9.1 provides a simplified flowchart representing the long-term resource strategy development process that PSE is using for this Least Cost Plan. The flowchart illustrates how the Company intends to determine its preferred resource strategy, including the consideration of both qualitative and quantitative factors and the application of judgment in its decision-making process.

Figure 9.1
Overview of Resource
Strategy Development Process



As mentioned above, resource planning involves both quantitative analysis and incorporation of qualitative considerations. In addition, load-resource analysis frequently identifies tradeoffs between different objectives. For example, one possible resource portfolio may have the lowest expected cost, but may exhibit significant variability in cost due to hydro uncertainty, gas price risk or other factors. Meanwhile, a second possible resource portfolio may have slightly higher expected costs, but with much less variability in costs due to lower or mitigated risk exposures. Since low cost and low variability in costs are both desired objectives, the choice between one portfolio and the other involves a key tradeoff.

For this Least Cost Plan, PSE is considering using multiple decision criteria at two stages in the process depicted in Figure 9.1. The first application of this method would be to identify leading resource portfolios using results from the portfolio screening and initial risk analysis. Then, following more detailed analysis of the screened resource portfolios, the method may be used again to determine the Company's preferred long-term resource strategy.

SCORECARD EVALUATION METHODOLOGY

Each resource strategy (or resource portfolio alternative) has certain characteristics that can be quantified (e.g., NPV of power costs) and other characteristics that are somewhat more qualitative (e.g., portfolio diversity). Selection of preferred resource portfolio alternatives requires application of judgment in a way that that considers both quantitative and qualitative factors. Further, judgment must be applied using a process that allows documentation of the factors that were weighed and their relative importance. While no method perfectly satisfies the competing needs for flexibility and rigor, use of a scorecard with both quantitative and qualitative criteria can be a useful means to facilitate the comparison of alternatives and documentation of the judgment process.

Evaluation Criteria

The following criteria cover a broad range of quantitative and qualitative criteria:

1. Compatibility with resource need (e.g., effect on load-resource balance, timing, firmness, flexibility)
2. Cost minimization (NPV power costs, price-to-value, fixed/variable cost structure)
3. Risk management (cost volatility, dispatchability, availability, commercial risk)
4. Public benefits (environmental impacts, effect on regional resource adequacy)
5. Strategic/financial benefits (capital structure, PSE credit rating, counterparty credit exposure, regulatory objectives)

Scorecard Matrix

An example scorecard matrix is provided as the following Table 9.1.

PSE PUGET SOUND ENERGY

Table 9.1

Scorecard Matrix

Draft Example for Illustrative Purposes

Resource Portfolio	Compatability with Resource Need	Cost Minimization	Risk Management	Public Benefits	Strategic/Financial Benefits	Portfolio Ranking
Portfolio 1						
Portfolio 2						
Portfolio 3						
.						
.						
.						
Portfolio N						

Interim Scorecard Results Based on Portfolio Screening

This section will be completed following the portfolio screening analysis.

Scorecard Results to Develop Resource Strategy

This section will be completed following further analysis and determination of PSE's updated long-term electric resource strategy.

Key Tradeoffs

This section will be completed following further analysis and determination of PSE's updated long-term electric resource strategy.

Implementation Considerations for the Resource Strategy

This section will be completed following further analysis and determination of PSE's updated long-term electric resource strategy.

Resource Strategy Implementation Plan and Schedule

This section will be completed following further analysis and determination of PSE's updated long-term electric resource strategy.

Ongoing Review and Re-Evaluation of Resource Strategy

This section will be completed following further analysis and determination of PSE's updated long-term electric resource strategy.