XI

XI. ANALYTICAL RESULTS AND APPLICATION OF JUDGMENT

This chapter details the analytical results, describes the judgment that PSE has applied to interpret the results and incorporate additional considerations, and creates a roadmap for the electric resource strategy that PSE is adopting with this Least Cost Plan. The analytical results, including analysis of cost and risk, support balancing the portfolio with enough resources to meet retail customer energy needs on an expected monthly basis. For capacity planning, resource adequacy is addressed in terms of customer needs, and in terms of meeting those needs in the least cost manner available. A third major conclusion reached is that the Company should plan to meet its customers' needs for new energy and capacity resources with a diversified portfolio that includes conservation, renewable resources, and thermal generation. Additional analytical results and conclusions are presented for several topics, including shaping new electric energy and capacity resources to match the seasonal profile of the need, and risks associated with deferring the addition of new resources.

A. Analysis of Planning Levels

The first major area of analytical results focuses on identifying the level of resource adequacy the Company should plan upon to meet its customers' electrical needs at least cost and within an acceptable degree of risk. As described in Chapter X, the Company analyzed this topic by identifying and evaluating a wide range of planning levels for both energy and capacity.

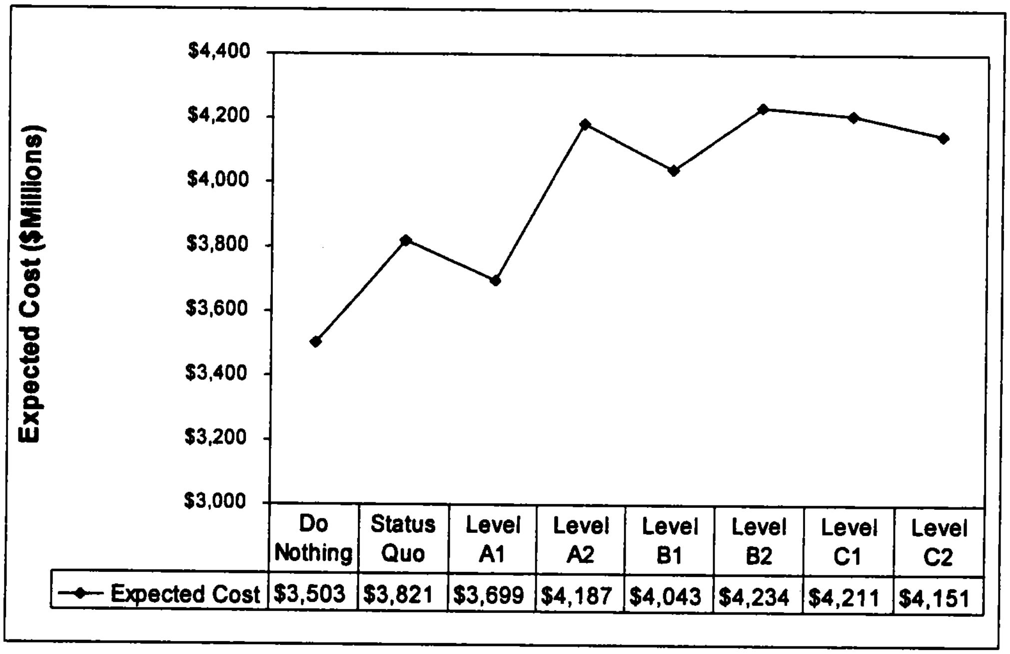
Combined Energy and Capacity Planning Levels

PSE considered a total of eight planning levels, including (in addition to Do Nothing and Status Quo cases), six combinations of different levels of energy resource adequacy and capacity adequacy.

It is important to note three key things about the eight planning levels that were considered in this stage of the analysis. First, each planning level is composed of a planning level for energy and a planning level for capacity. Second, moving from lower planning levels to higher planning levels generally, but not uniformly, involves moving from lower to higher levels of resource adequacy for energy and higher levels of resource adequacy for capacity. Third, the eight planning levels do not include all combinations of the five energy planning levels and the five capacity levels.

In the analytical process, the Company modeled expected costs to customers for the eight combinations of energy and capacity levels. Results of this expected cost analysis of the eight planning levels are shown in Exhibit XI-1.

Exhibit XI-1
Expected Cost to Customer by Planning Level



	Do Nothing	Status Quo	Level A1	Level A2	Level B1	Level B2	Level C1	Level C2
Expected Cost	$3,503	$3,821	$3,699	$4,187	$4,043	$4,234	$4,211	$4,151

The Expected Costs shown in Exhibit XI-1 apply to the average of four different mixes of resource technologies at each planning level: (1) All Gas; (2) Gas and Coal; (3) 5% Wind Plus Gas and Coal; and (4) 10% Wind Plus Gas and Coal.

These results show that as the overall level of resource adequacy is increased, including both energy and capacity together, expected costs generally tend to increase as well. However, since the eight planning levels considered at this stage of the analysis reflected combinations of energy planning levels and capacity planning levels, the analysis then turned to a distinct evaluation of energy planning levels (holding the capacity planning level constant), and a distinct evaluation of capacity planning levels (holding the energy planning level constant). The expected cost results for the five energy planning levels are discussed next, followed by results of the evaluation of five capacity planning levels.

Energy Planning Levels

Exhibit XI-2 shows expected cost results for five different levels of energy resource adequacy, holding capacity resource adequacy constant at the A1, or Status Quo capacity planning level.

Exhibit XI-2
Expected Cost Across Energy Levels Holding Capacity Levels Fixed

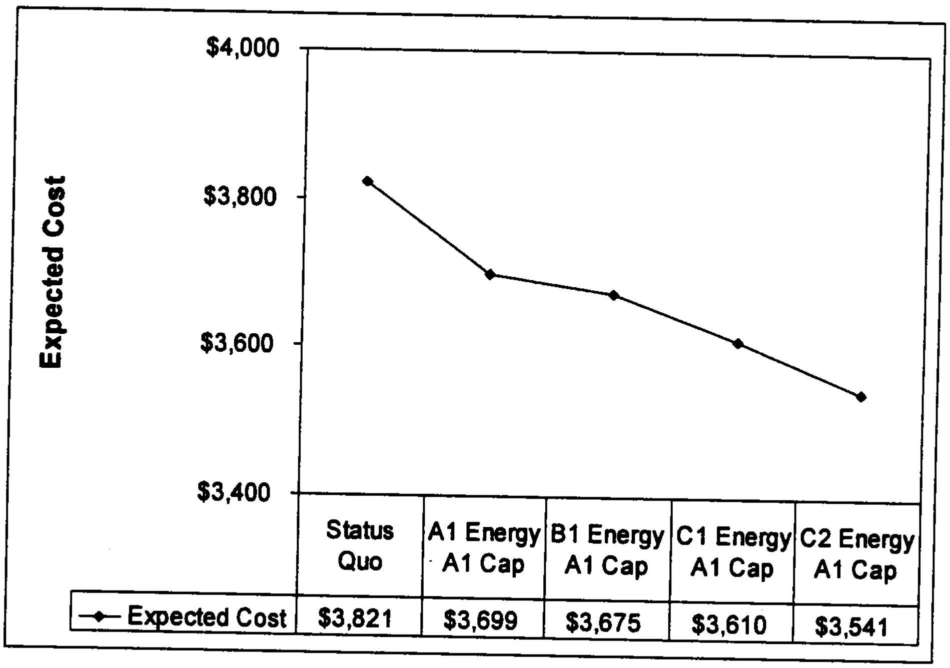


Exhibit XI-3 shows that with increases in the energy planning level (i.e., as more long-term resources are added), the 20-year net present value cost to customers declines.

At first glance, this exhibit might imply that on a purely expected cost basis, the Company should acquire as many long-term baseload energy resources as possible, even to the point of acquiring more resources than needed to serve its retail customers' needs. However, such an 'over-build' resource strategy would create surpluses that the Company would have to sell into the wholesale power market. The revenue volatility associated with market sales of this surplus energy would cause the Company and its customers to take on a risk profile more akin to a merchant than a vertically integrated utility.

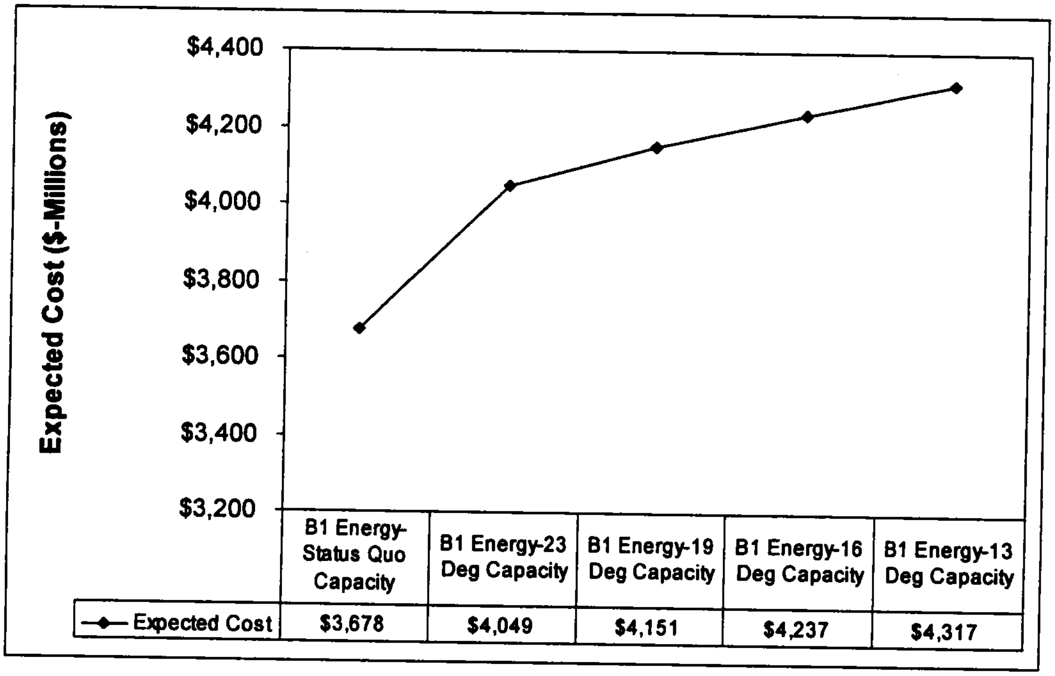
Accordingly, consideration of costs and risks points toward adopting a balanced energy planning level, or one that includes enough long-term firm resources to meet each month's expected customer needs. Specifically, this is the B energy planning level.

Capacity Planning Levels

Planning to meet peak capacity needs proves to a somewhat more challenging process than planning to meet customer energy needs. The process must consider more than just expected costs, as resource capacity needs are related to the Company's obligations to serve customer peak electrical needs during cold winter weather periods. The character of the Company's temperature-dependent loads further complicates the analysis, since PSE must plan for winter needle peaks that may occur only for comparatively short periods of times (from one day up to several days). Further, these temperature-dependent loads may not reach extreme peak levels during years that severe winter cold conditions do not materialize. In other words, capacity resources may only be needed for relatively brief periods of time and may or may not be fully needed in any given winter. As a result, tradeoffs exist between (1) the costs of acquiring and keeping long-term capacity resources ready to meet peak loads, and (2) consequences of not being able to fully serve extreme peak loads when they do occur.

While keeping these considerations in mind, PSE performed an analysis of the expected cost to meet various capacity planning levels while holding the energy planning level constant. The expected cost to customer results of this analysis for five capacity planning levels at the "B" energy planning level are shown in Exhibit XI-3. This exhibit shows that the expected cost to customers increases with the addition of more peaking resources to meet progressively higher capacity planning levels.

Exhibit XI-3
Expected Cost Across Capacity Levels Holding Energy Levels Fixed



In large part, the increased costs at higher capacity planning levels reflect the generic nature of Least Cost Plan analysis, which typically identifies SCGT generation as the primary, extensively-available resource technology available to meet such loads. However, SCGTs are a high-cost solution, particularly given the short and infrequent amount of time that they would be needed to meet winter peak load requirements.

While Exhibit XI-3 indicates increasing costs to meet higher capacity planning levels, the Company also recognizes that its analysis has not yet fully considered potential winter peaking power supply contracts or demand-side alternatives that might be used to help meet these needs in a more cost-effective manner than by adding only SCGTs. Accordingly, the Action Plan found in Chapter XVI lays out a commitment to further explore a broader range potential resource alternatives to meet these capacity needs.

Further, peaking capacity needs also relate to issues of regional resource adequacy. In January 2003, the Northwest Power Planning Council, the Northwest Power Pool, representatives of regional utilities and representatives of state regulatory commissions began a process to investigate this topic, including possible development of a regional resource adequacy standard. Accordingly, PSE intends to actively participate in this regional process.

However, given the assumptions used for this analysis, the conclusion remains that meeting increasing capacity needs for a given energy need is an increasingly costly requirement, but one that also reflects the Company's obligations to meet its customers' peak demands on cold winter days.

Risk Analysis of Combined Energy and Capacity Planning Levels

Cost and risk tradeoffs for each of the eight portfolio planning portfolios were also assessed. Exhibit XI-4 shows a scatter plot of expected cost versus risk (measured as standard deviation of expected cost) for each of the planning levels.

Exhibit XI-4
Expected Cost vs. Risk

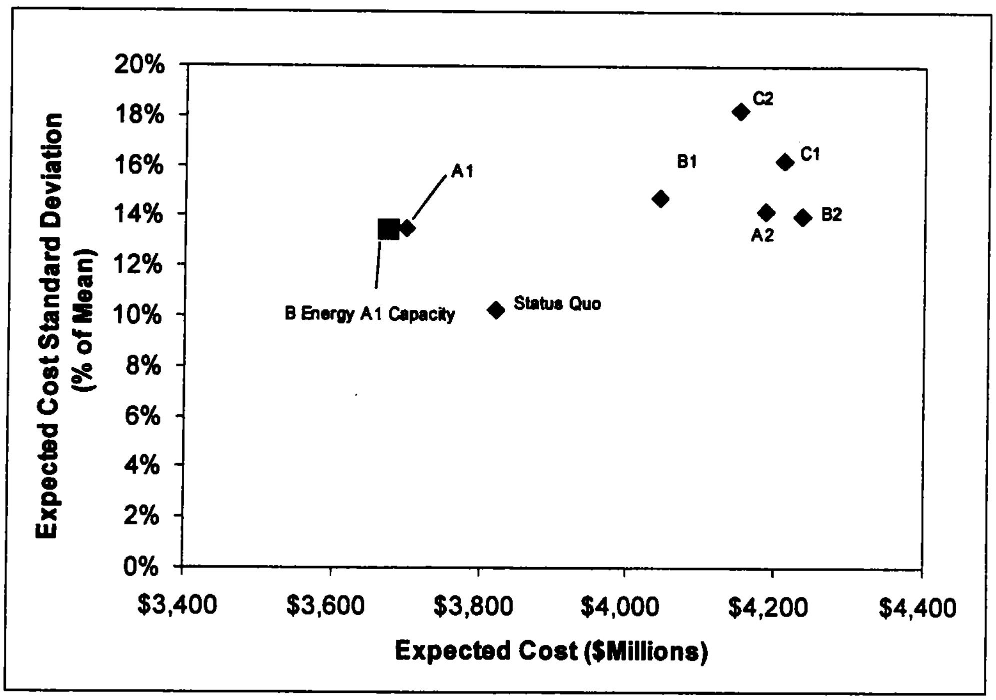


Exhibit XI-4 shows that moving from the A1 planning level to higher levels of B1, A2 and B2, the additional costs of the higher capacity planning levels more than offsets the reduction in cost from the higher energy planning levels. Additionally, the risk profile across these planning levels is similar.

Exhibit XI-4 also shows that further increases in energy for planning levels C1 and C2 lead to increased risk as the portfolios become surplus and exposed to market price risks associated with dependence on revenue from market sales.

Lastly, Exhibit XI-4 illustrates the results of an analysis of the impact of combining the B planning level energy with the A1 capacity level. This result indicates a small reduction in expected cost from the higher amount of energy and a negligible change in risk. This leads to a major conclusion that a balanced planning level that provides an adequate amount of energy resources to meet each month's expected customer energy needs proves to be attractive on the basis of cost and risk.

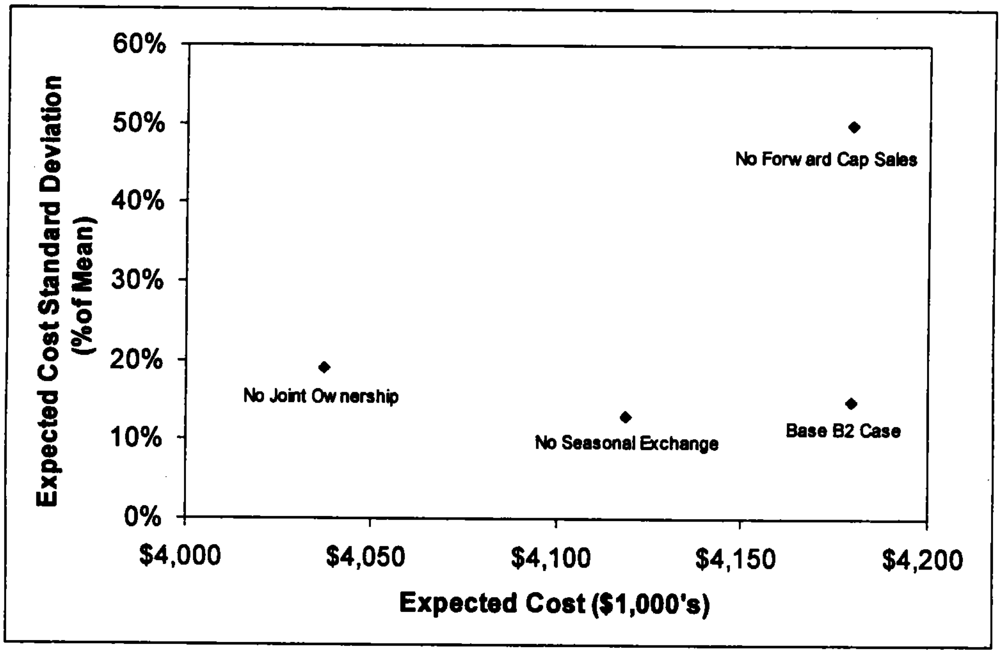
B. Portfolio Shaping Results

Chapter X provided a detailed description of the techniques used to seasonally shape both energy and capacity resources to balance the portfolio within each year. The techniques described in Chapter X are:

1. Joint Ownership of base load resources
2. Forward Capacity sales of new Single Cycle Gas Turbines (SCGTs)
3. Seasonal Exchanges

Exhibit XI-5 summarizes an the impact of these three shaping techniques under the B2 planning standard and using the Aurora Case III market price forecast.

Exhibit XI-5
Impact of Shaping Techniques on the B2 Planning Level



The results of using Joint Ownership for new long-term resources is two-fold. First, as discussed earlier, PSE's resource portfolio generally does not need energy in the summer months. The result of using a Joint Ownership-like approach will be to help balance the portfolio seasonally and thereby avoid the need to make significant spot energy sales in summer periods. However, the Case III AURORA market price forecast underlying the analysis shows the highest spot market power prices occurring during the summer months. Expected cost to customers, therefore, is increased by about $150 million (on a 20-year net present value basis), due to the foregoing of revenues from sales of surplus energy into the spot market in the summer months. The second impact involves risk. By avoiding the reliance on making spot energy sales in the summer periods, the use of a Joint Ownership-like approach produces a significant reduction in risk, over 25 percent. PSE's consideration of this tradeoff between expected costs and risks leads it to conclude that shaping new long-term resource acquisitions using Joint Ownership arrangements is merited. In other words, the potential upside in net revenues from holding summer surplus energy for sale into the spot market is outweighed by the risks associated with such a strategy.

Exhibit XI-5 also demonstrates the impact of seasonal Forward Capacity Sales of new capacity resources from SCGTs. The forward sale period (May-October) is estimated to return fixed revenues very close to the more volatile revenues that the model estimates would be realized from spot energy sales in the same seasonal period. The cost difference, therefore, between the case where SCGT capacity is sold forward and the case where SCGT capacity is retained and used for spot market sales is small. However, a significant difference exists with risk exposure. The volatility of power prices can cause wide differences in the amount of economic dispatch the new SCGT resources experience from a probabilistic perspective. The risk associated with exposure to spot sales is over triple that in the case where PSE sells capacity forward at a fixed price. (It is important to note that this effect is muted at lower capacity planning levels and magnified at higher capacity planning levels.) Therefore, the analysis justifies the forward sale of peaking capacity resources during the May-October period on the basis of cost and risk.

Lastly, Exhibit XI-5 demonstrates the impact of Seasonal Exchanges. Under the AURORA Case III market price forecast, adding baseload energy resources (with Joint Ownership) has a lower cost than the forecasted cost of purchasing power from the spot market. PSE evaluated this by creating a set of new resource portfolios that removed System Exchanges and replaced them with a roughly equal amount of long-term resources instead. As shown on Exhibit XI-5, replacement of Seasonal Exchanges with seasonally shaped long-term firm resources reduces expected cost to customers (on a 20-year net present value basis) by over $100 million. In addition, removal of Seasonal Transactions produces a slight reduction in risk. Therefore, the Company has tentatively concluded on the basis of cost and risk that Seasonal Exchanges are not a preferred approach.

C. Deferral of Resource Acquisition

PSE also analyzed the issue of deferring acquisition of new long-term firm resources.

Before presenting the results of the deferral analysis, it is useful to address some of the practical considerations that would be associated with such a strategy. In the aftermath of the collapse of the merchant generation sector of the electric business, PSE has few creditworthy counterparties available to transact with. Additionally, the credit support requirements that the remaining counterparties in the market would impose on PSE would become quite onerous. Given PSE's current credit position, it is unlikely that the deferral strategy described below could practically implemented.

To explore the impact of deferring the acquisition of long-term firm resources, the Company evaluated costs and risks for two sets of resource portfolios:

(1) portfolios composed of various technology mixes where energy and capacity needs are met starting in 2004 using long-term firm resources; and

(2) portfolios that include the same resource technology mixes as in the first set, but that defer resource acquisitions until 2008. For these deferral portfolios, energy and capacity needs during 2004-2007 are assumed to be met with market-priced power purchase contracts.

Exhibit XI-6 shows the result of this analysis run with the AURORA Case I market price forecast.

Exhibit XI-6
Deferral Analysis

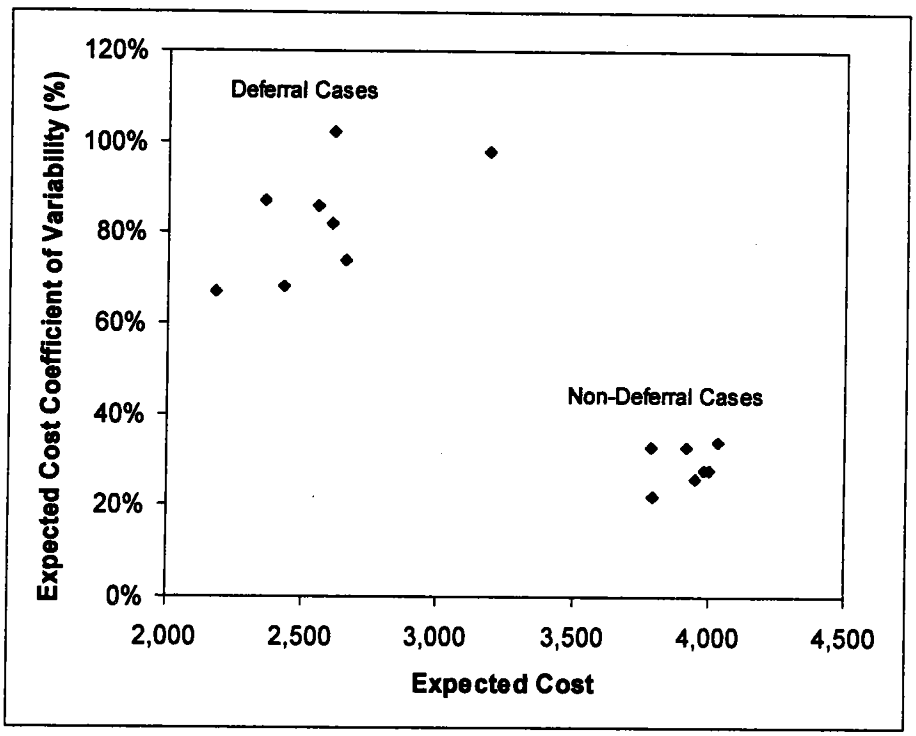


Exhibit XI-6 shows significantly higher risk levels under the deferral strategy, nearly doubling the risk associated with the non-deferral strategy. This increase in risk, in addition to the difficulties in executing such a strategy, has caused PSE to look for other solutions to its energy and capacity need. Therefore, PSE reaches the conclusion that a deferral strategy is not merited.

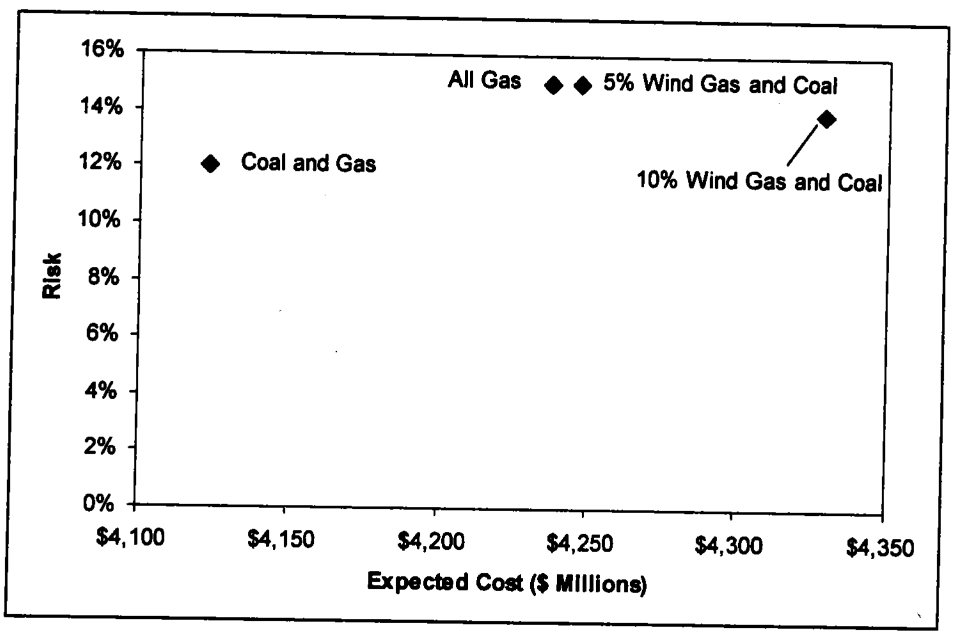
D. Analysis of Portfolio Diversification

Section B of this chapter discusses the use of Joint Ownership of baseload resources and forward summer-season sales of peaking capacity resources to help mitigate risks. Another important approach to managing risk involves diversification across multiple resource technologies. This section summarizes results of the analysis of resource portfolio diversification across various generating resource technology alternatives.

As described in Chapter X, the Company evaluated resource portfolios with various combinations of resource technologies. All of these portfolios included 150 aMW of conservation resource acquisition.

Exhibit XI-7 illustrates the different cost and risk profiles for four generating resource technology mixes at the B2 planning level.

Exhibit XI-7
Impact of Technology Mix on Expected Cost and Risk



Under an assumption of no CO2 costs, these results indicate that a portfolio composed of gas-fired generation and coal-fired generation is attractive on the basis of both cost and risk. Other resource technology mixes have higher expected costs and higher risk.

A similar pattern can be seen at the other planning levels evaluated. The All Gas portfolios are typically the highest risk portfolios, due to their increased exposure to volatility in market prices for natural gas. Adding coal to the portfolio technology mix both lowers cost and risk. (Coal fuel prices are assumed to have no volatility in PSE's analysis.) From a cost perspective, the higher capital cost of coal is more than offset by lower fuel costs and higher economic dispatch relative to gas resources. As PSE adds wind to the coal and gas mix, cost and risk go back up. Two factors drive the increase in cost – higher capital costs for wind resources and the assumed need for additional SCGT capacity to back up the wind energy with capacity. This additional SCGT capacity also leads to a slight increase in the risk profile, initially offsetting the benefit of adding an energy resource with no fuel price volatility. Notice that in the 10 percent wind case that while the cost goes up as expected, the risk is slightly lower.

There are several additional factors that need to be brought into an analysis of the appropriate mix of resource technologies. The primary factors that PSE considered were emissions associated with fossil-fueled generation, production tax credits for wind resources and market price volatility for natural gas. Under new emissions regulations for NOx and/or CO_2, coal and to a lesser extent gas resources could become far less competitive than implied under the assumption of no new costs for NOx or CO_2. (See Chapter X for a full analysis of the impact of potential emissions regimes on coal and gas-fired assets). Also, as demonstrated in Chapter X, without the production tax credit, wind would become far less competitive on the basis of cost. Lastly, market prices for natural gas are subject to significant volatility. Gas prices are subject to a number of influences, including changes in crude oil prices. Thus, gas prices may introduce sources of risk that do not currently affect a major base load portion of PSE's existing resource portfolio. Consideration of these factors, in conjunction with the economic and risk characteristics of the technologies, points toward a diversified portfolio strategy. This not only avoids putting "all the eggs in one basket", but allows flexibility for mid-course corrections should one or more of the factors described above change unexpectedly.

E. Application of Company Judgment

This section addresses several additional considerations that the Company has factored into development of its Least Cost Plan and the resource strategy in particular. The section begins by noting several relevant guiding principles as stated in the recent Washington State Energy Strategy update. A discussion of the Company's role in contributing to regional load-resource balance follows. Then, the capabilities and limitations of using economic dispatch models for load-resource analysis are described. Next, this section discusses the need to watch out for inconsistencies that may be created when input assumptions to the load-resource analysis assume overall market equilibrium (i.e., 'perfect' resource adequacy at the macro level), but the results of such load-resource analysis indicate taking actions that could lead to different market outcomes (i.e., shortages that could result from insufficient resource development). Finally, the section closes with a discussion of additional judgmental factors that the Company considered in its identification of a diversified resource strategy that includes a mix of various electric resources.

Washington 2003 Biennial State Energy Strategy

In February 2003, the State of Washington issued its biennial update to the State Energy Strategy (SES). The SES addresses a number of the same topics that are also addressed in this Draft Least Cost Plan. The SES also sets forth 13 Guiding Principles as developed by the SES Advisory Committee. Several of these Guiding Principles are directly relevant to PSE's Least Cost Plan, including the following two principles that focus on utility obligations regarding provision of resource adequacy and protection of customers from market price volatility and other risks.

Guiding Principle	Detailed Annotation
#1 Encourage all load-serving entities to adopt and implement resource plans to ensure they have adequate resources to meet their obligation to serve their customers' projected long term energy and capacity needs	"...underscore the continuing obligation that the state's utilities have to serve their customers' load requirements and to acquire the resources necessary to do so." "...Recognize that current and future electricity markets are likely to experience greater price volatility, and supply risk than has historically occurred prior to 2000. "

#4 Preserve and promote Washington's cost-based energy system to benefit the end use consumer by providing reliable power and reduce the consumers' vulnerability to supply shortage and price volatility. At the same time, the state should promote policies that harness market forces in the wholesale energy market to reduce customer costs and increase reliability while protecting the environment	"...Washington continues to be extremely cautious about increasing its reliance on market forces to provide for its electric supply......the main question for Washington is the extent to which our load-serving utilities rely on market purchases or their own resources to serve their loads."

These two Guiding Principles send a clear message that load-serving entities, including PSE, have significant obligations and responsibilities to plan and acquire resources to meet their customers' needs reliably, cost-effectively and without excessive exposure to risks of supply shortage and market price volatility. PSE recognizes these obligations and responsibilities and has factored them into the development of the resource strategy identified in this Draft Least Cost Plan. In particular, PSE has factored them into its consideration of the results of its analysis of energy and capacity planning levels.

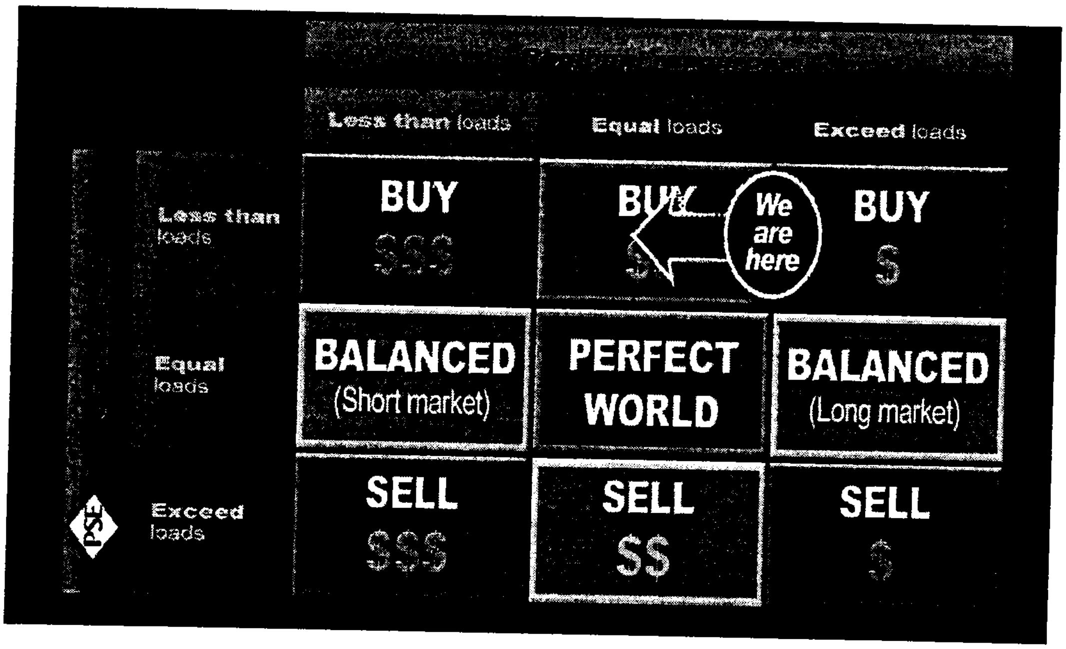
PSE Contribution to Regional Load-Resource Balance

Historically, regulators in many states have defined utility obligations to maintain sufficient capacity reserves to meet extreme peaks. Reliability organizations such as NERC also prescribed regional reliability standards. However, recent events in California and other areas that have attempted regulatory restructuring have underscored the dangers of a load-serving entity not having access to sufficient resources to meet customer needs in a deregulated market where prices are free to rise to meet what is essentially an inelastic demand. While price caps can dampen these impacts to a limited extent, the consequences of resource inadequacy have proven to be much more severe than was anticipated when deregulation regimes were being developed.

It is not enough to assume that market forces alone will ensure the availability of sufficient, cost-effective electric resources and that the goals set in the SES Guiding Principles described above will be achieved through such an approach. In other words, a utility cannot assume that it would be able fall back upon the regional market at any time to correct imbalances in the utility's portfolio without exposing itself and its customers to substantial price risk and potential impacts on reliability.

Therefore, it has become very important for PSE to consider its load-resource balance in the context of the regional load-resource situation. The interactions between PSE's load resource balance with the Pacific Northwest region as a whole can be seen in Exhibit XI-8.

Exhibit XI-8
PSE and Regional Load Resource Balance



This exhibit illustrates that the greatest adverse consequence to PSE and its customers would occur when PSE's resource portfolio is out of balance and the Company must either purchase power from the regional market to cover shortfalls in its own resources, or sell power into the regional market to dispose of resources surplus to its customers' needs. While it may be tempting to try to "time" the market by staying short-during periods when the regional market appears to be surplus, or by going long during periods when the regional market appears to be deficit, this is highly risky, both in terms of execution and in terms of potential consequences. Accordingly, PSE believes that a more robust strategy is to plan adequate electric resources to meet its customers' needs without excessive reliance on the regional market. Again, this supplements the results of the Company's analysis of energy and capacity planning levels. In addition, it further validates the analytical results that indicate significant risks would be associated with deliberately delaying acquisition of new resources.

Evaluating Energy and Capacity Needs with Economic Dispatch Models

The utility industry has developed various resource planning models to evaluate and select preferred resource strategies to meet a utility's projected loads. These models provide the analytical capability to evaluate resources and alternatives under a variety of assumptions. They also provide a useful perspective of the future under a market that is often assumed to continuously remain in equilibrium over the long run. The models assume that when existing resources are no longer adequate to serve loads and market prices begin to increase, unspecified market participants will anticipate this change and respond by constructing new generation facilities in time to mitigate the tightened conditions. One outgrowth of this modeling approach is that most dispatch models focus on the evaluation of the energy component of a utility's resource planning decision and will tend to undervalue the expected value of the utility's capacity resources. Due to this underlying assumption of a well-functioning market that always remains in equilibrium, extreme peak demand-supply imbalances will not occur in the model.

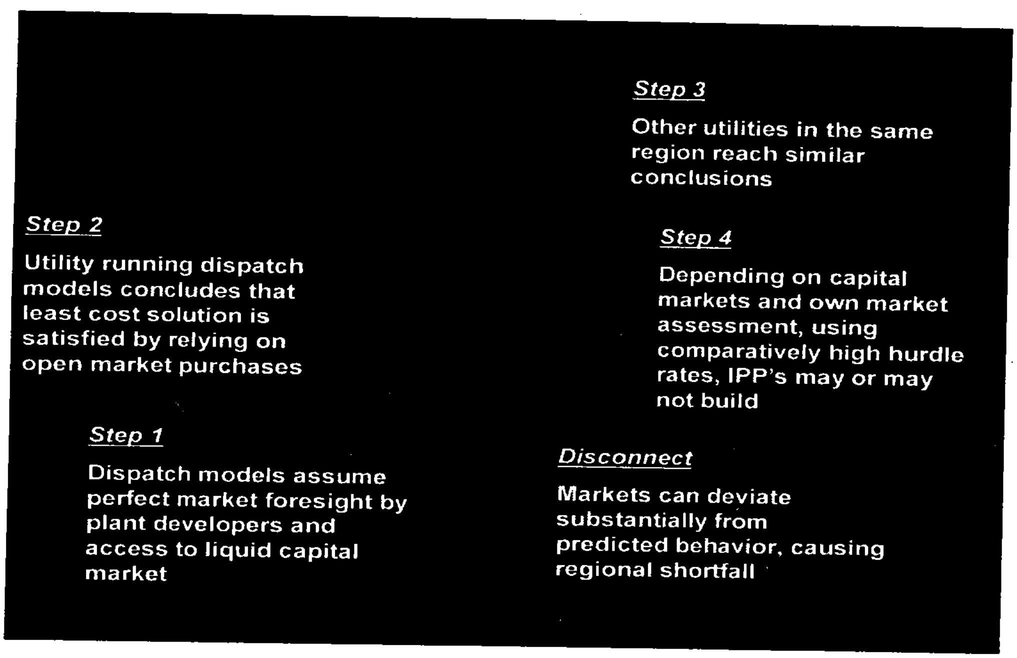
However, recent experience has shown that energy markets are subject to extreme variability. The merchant generation and marketing sector observed the magnitude of market price spikes that can be caused by capacity constrained conditions and soon modified their use of dispatch models based on equilibrium assumptions. Many merchants and marketers shifted to use of option valuation models that explicitly reflect the impacts of market price volatility under market disequilibrium conditions. While such models are perhaps a better reflection of the dynamics of price volatility in deregulated markets, they also highlight the potential disconnect that can be created by basing a utility's resource plan on a foundation assumption that the regional marketplace will continuously remain in equilibrium over the long run. This disconnect is addressed further below.

Bridging the Disconnect in Dispatch Models' Analysis

It was noted earlier that economic dispatch models assume a long-run equilibrium condition in which extreme supply-demand imbalances do not occur in the model. In the real world however, capacity shortfalls can and do occur. They can result from below-normal hydroelectric conditions, unforeseen outages at large generating facilities, inadequate transmission facilities, transmission line outages, or a variety of other reasons. When capacity shortfalls do occur, a "disconnect" can be created between a dispatch model's view of long-run equilibrium market prices, and the impacts of market price spikes that can occur if market equilibrium is disturbed.

This same type of disconnect can occur in what the model assumes for the industry's and the region's response to long-term market price signals and other conditions. In the real world, if market price projections are perceived by developers to be too low, or if access to capital needed to finance new resources is constrained, then market participants will not build new facilities. Meanwhile, if utilities assume that other entities will develop new resources to maintain balance in the regional market where the utility is planning to buy power to meet its customers' needs, this can lead to an actual outcome of regional supply shortfalls and higher market prices. This potential disconnect obligates utility planners to increase the importance of resource capacity adequacy beyond what might be indicated by a strict interpretation of dispatch model results that are based on an assumption of market equilibrium. The cycle that could result from this disconnect is shown Exhibit XI-9.

Exhibit XI-9
Disconnect in Dispatch Models' Analysis



Regulators have also recognized that capacity can be undervalued in competitive markets and therefore have attempted to develop mechanisms such as ICAP pricing to assign an explicit premium to those assets needed to meet capacity needs in order to encourage their development. FERC has recognized the impact of this disconnect in its development of its Standard Market Design (SMD) where it states:

> ...Some market participants depend on government intervention during severe shortages as an alternative to paying their share of the cost of developing adequate regional resources. ***As long as regional reserves are made available to all, a load-serving entity can reduce its own reserve resource costs and rely on the resources of others. The result is that all load-serving entities will tend to follow this strategy, leading to a systematic under-investment in resources needed for reliability.*** ....
>
> .....This is the well-known "free rider" problem for public goods, those for which consumption cannot be limited to those who paid for them (such as parks and national defense) and that are available to all users even if only some users pay for them. See, e.g., Lee S. Friedman, The Microeconomic of Public Policy Analysis, Princeton University Press (Princeton, NJ 2002), which states at pages 597-598: If their provision were left to the marketplace, public goods would be under-allocated. The reason is that individuals would have incentives to understate their own preferences in order to avoid paying and free-ride on the demands of others. Thus, public goods provide one of the strongest arguments for government intervention in the marketplace: not only does the market fail, but it can fail miserably.
>
> ***emphasis added***

The requirement for PSE to apply judgment to its analytical results leads to the development of a resource strategy that balances the Company's responsibility to minimize the cost of meeting its customer's needs with its responsibilities to contribute to maintaining regional load-resource balance and not become a "free rider" dependent upon other market participants during peak demand periods. This consideration further supplements the results of the Company's analysis of energy and capacity planning levels and supports a resource strategy that maintains a balanced portfolio to meet customer needs for both energy and winter peak capacity.

PSE has seen how dispatch models based on inputs that assume continuous market equilibrium tend to undervalue capacity resources. It has also been seen how the current analysis and assumptions considered a limited set of available capacity resources, which can be quite expensive when only used for those rare, extreme peak periods. This has led to identification of a need for more analysis and research by the Company to develop additional supply- and demand-side resource solutions to help meet extreme winter peaks.

As also discussed earlier in this chapter, the Company has a significant role in contributing to the regional load-resource balance for energy and capacity. PSE intends to actively participate in regional efforts that have recently been initiated to address this topic. Utility obligations, as well as the methods and criteria that they use to balance tradeoffs between costs and risks, represent important elements of the overall topic of regional resource adequacy. In addition, opportunities to consider regional load diversity, and to develop collaborative regional approaches merit serious review and appear to offer considerable potential.

Additional Judgmental Factors Supporting A Diversified Resource Mix

As discussed in Section D, each major resource technology type has a unique combination of favorable features, as well as risks and uncertainties. For example, coal-fired generating resources offer potential benefits of comparatively low and stable costs, but they also produce emissions that raise environmental concerns and may become subject to increased costs (e.g., CO_2). Natural gas-fired resources are currently the predominant source of new generation in the region and nation, but they involve risks associated with volatility of market prices for natural gas. Wind power generation produces no air emissions and is not subject to market fuel price risks, but its economic viability is highly dependent on extension of federal production tax credits.

In other words, no single electric resource technology has a clear and obvious advantage in meeting all of the Company's need for new resources. Further, it is not possible to predict with any degree of certainty the future outcomes of the particular uncertainties associated with each of the generating resources discussed above. In recognition of this, PSE is committed to its existing 10-year, 150 aMW goal for conservation resource development, and will evaluate the potential for further revisions to this goal by August 2003. In addition, the Company has concluded that a diversified long-term resource strategy that identifies several forms of generating resource technologies provides an effective way to spread out and mitigate the risks associated with each specific technology type.

F. Summary

PSE's Least Cost Plan is designed to identify the best long-term resource strategy to meet its retail customers' needs at least cost consistent with acceptable risk. To accomplish this, the Company has reached the following conclusions on the basis of its analysis and its application of judgment:

- The Company will plan to acquire long-term firm energy resources sufficient to ensure that customer energy needs are met on an expected monthly basis.
- To meet its customers' winter peak demands, the Company will plan to maintain adequate capacity resources to meet its obligations to serve peak loads, contribute to regional load-resource adequacy and do so at least cost. The Company plans to meet a capacity planning level associated with loads at a minimum hour temperature of 16 degrees F and will seek lower-cost approaches than relying only on SCGTs to meet this capacity planning level.
- The Company will develop a diversified portfolio of multiple resource technologies to meet its customers' future energy and capacity needs, including a goal of meeting 10% of its retail customers' energy needs with renewable resources by the year 2013.

Each of these conclusions is described in greater detail below.

Energy

To meet its energy needs, the earlier discussion demonstrated that adding resources was the least cost approach. The analysis also shows that beyond a certain amount of new resource additions, the overall portfolio would become surplus to customer needs and the Company would become more exposed to market price risk as a seller and would take on a risk profile more like a merchant. Energy level "A" meets the November-February energy needs, but relies on market purchases to meet some remaining needs in the year. Energy level "B" meets the expected deficit needs for each month of the year, while energy level "C" provides additional energy needs above the highest deficit month. The Company's selected planning level is therefore "B", which meets the highest deficit month. The Company also plans to pursue Joint Ownership for new resources to dispose of energy in those parts of the year when it does not have resource needs, so as to reduce its overall exposure to market price risks. The "B" energy level involves adding approximately 400 aMW energy in 2004, growing to 1,600 aMW in 2013.

Capacity

To meet its capacity needs, the Company must balance the increased costs of adding new capacity with the obligation to meet customer peak needs without imprudently relying on non-specific market resources to meet future needs. The "A" planning levels would appear to be less expensive under strict evaluation of base case assumptions. However, there is considerable risk exposure to a regional under-build scenario and the resultant high prices which would put the Company in the same situation the region recently experienced during the Western Energy Crisis. Furthermore, the Company has a responsibility to avoid a "free-rider strategy". Instead, it recognizes that by planning adequate capacity resources to meet its customers' needs, it can also help maintain resource adequacy in the Northwest region. Therefore, an increase beyond the "A" capacity level is warranted.

The B1 and B2 planning levels both provide the improved level of reliability that the Company and its customers require. However, the analysis conducted during this least cost planning process has indicated that current planning assumptions make the "B" levels a higher cost option. This is largely result of the assumed use of SCGT's as the primary resource technology to meet the higher peak demand levels. Even with seasonal shaping transactions to lower the net costs of SCGT resources, the Company recognizes that it still needs to find lower cost options to meet capacity needs at the B1 or B2 level. The primary areas that appear to offer the most potential would be greater use of winter capacity purchase agreements and greater use of demand response programs oriented toward extreme peak circumstances. Moving to the higher "C" capacity levels would meet the peak demand requirements, but would also entail an inordinate cost and would not be cost-justified, given current results of analysis. Therefore, the Company has selected planning level "B2", with a commitment to identify lower cost options than just adding SCGTs. The B2 capacity level involves adding approximately 1,050 MW of capacity resource in 2004, growing to 1,887 MW in 2013.

Technology Mix

The analysis of alternative resource technologies demonstrates that diversified portfolios can offer reduced exposure to major uncertainty factors. There are a variety of uncertainties associated with the available resource technologies, ranging from emissions costs for thermal resources to extension of Production Tax Credits for wind. Exposures to these risks can be mitigated with a diversified portfolio of new resources. The analysis also demonstrates the benefits of a portfolio that would include renewable resources to meet a portion of customer energy needs. Portfolios with higher amounts of renewables (modeled as wind energy) indicate higher costs however, which is primarily a result of the Company's assumption that wind resources would need to be backed with SCGTs for firming requirements.

The Company is adopting a policy that incorporates renewable energy into its portfolio where possible. Portfolios that meet 10 percent of customer energy needs with renewable resources by 2013 are not strictly justified on a least cost basis given today's limited knowledge of the cost to integrate wind into the Company's existing resource portfolio. However, the Company is committed to performing further work to identify more effective approaches to integrate wind resources into its portfolio. PSE also intends to seek specific resource acquisition opportunities for other types of renewable resources beyond just wind power. On this basis, PSE has established a goal of meeting 10 percent of its customers' energy needs with renewable resources by 2013.

XII. ELECTRIC RESOURCE STRATEGY

Chapter XII presents PSE's long-term electric resource strategy. PSE recognizes an opportunity to establish a balanced long-term resource strategy that meets customers needs, while keeping rates low and protecting customers against market and price risks. To realize this vision, PSE has established a goal of meeting 10 percent of its resource needs through renewable resources by 2013. The resource strategy also reflects a commitment to acquire 150 aMW of new conservation resources over the next 10 years, possibly updating this commitment based on the outcome of the region's current collaborative developing new conservation potential assessments. To meet the rest of its need over the planning period, PSE will look to a diverse mix of other resources, including combined cycle gas-fired generation, coal-fired generation, market purchases, Joint Ownership or other seasonal resource shaping approaches, and winter peaking resources.

A. Conclusions Supporting PSE's Electric Resource Strategy

As mentioned in Chapter XI, PSE's analysis demonstrates that diversified portfolios offer customers reduced exposure to various risks, including gas price volatility and potential emissions impacts and costs. PSE acknowledges this factor, and has adopted the objective of maintaining a balanced portfolio of firm resources to meet its retail customer needs. To serve customer energy needs, PSE will plan adequate long-term firm resources to serve each month's energy load under average hydro conditions. In order to ensure that PSE meets its winter energy deficit, without creating summer energy surpluses, PSE will seasonally shape its new energy resources. To serve customer capacity needs, PSE has established a goal of adequate resources to serve retail load during winter peaks at temperatures as low as 16 degrees Fahrenheit. Again, PSE seeks to fill its winter capacity deficit, without creating a summer capacity surplus. To reach this goal, PSE will seasonally shape its capacity resources and also seek lower-cost resource alternatives than relying exclusively on new SCGTs.

B. Conservation

PSE recognizes the significant value of conservation in a long-term electric resource strategy. PSE has committed to 150 aMW of new conservation over the next 10 years. In the analysis for this Draft Least Cost Plan, PSE assumes the conservation savings will be proportional to the seasonal shape of customer loads. In August 2003, PSE will incorporate results from the regional conservation resource potential collaborative into an update of its April Least Cost Plan. At that time, PSE will revisit its 150 aMW assumption and may revise this number.

It is important to note that other elements of PSE's long-term resource strategy do not "preempt" further commitments to conservation. As detailed in Chapter IX, PSE there are adequate avenues for further conservation initiatives. As detailed in PSE's two-year action plan in Chapter XVI, PSE has made commitments to further explore conservation and demand response opportunities. A decision by PSE to acquire a new generation resource will not come at the expense of its commitment to conservation's role in meeting PSE's long-term resource needs.

C. Renewable Resources

PSE intends to meet a five percent goal (133 aMW) of meeting customer energy loads by 2013 through wind resources. PSE believes a greater potential for the use of renewable resources exists, and has stated a goal of meeting 10 percent, or 266 aMW, of its customers' energy needs through the use of renewable resources. As exemplified in PSE's draft renewable policy in Appendix L, PSE has made a corporate commitment to renewable resources. PSE's two-year action plan details specific steps the Company will take toward reaching this 10 percent goal. Appendix M provides an overview of PSE's preliminary thinking and direction on one of the first renewable resource issues the Company faces – the integration of wind into its portfolio.

D. Diversified Mix of Other Resources

PSE's existing resources – including hydro, coal, gas and both power supply and NUG contracts – will continue to play an important role in meeting PSE's resource needs. As loss of a portion of these resources occurs, and power supply contracts expire, PSE will not only look to conservation and renewable resource opportunities, but also to a diversified mix of other resources. Combined cycle gas-fired generation and coal-fired generation both have potential roles. PSE will include combined cycle generation in its near-term mix, and will shape this resource to meet monthly energy needs. New coal-fired generation will not be included in PSE's near-term resource mix, however, PSE will monitor development and acquisition opportunities. While coal may not be the first fuel of choice for PSE, the Company recognizes this technology offers benefits in terms of long-term costs and mitigating gas and market price risk. However, the environmental costs of coal must be taken into consideration as well. As such, PSE will monitor opportunities for coal, but makes no near-term commitment to this resource.

PSE also plans to seasonally shape new baseload generating resources and acquire winter peaking resources to meet its growing needs.

E. Other Considerations

PSE's Least Cost Plan focuses mainly on "generic" resource technologies. Currently, PSE is monitoring the market for attractive resource acquisition opportunities, considering both asset ownership and power contracts as possibilities. New conservation resource potential assessments will be available in May 2003, serving as the basis for PSE's August 31, 2003 update. PSE will continue to investigate seasonal shaping techniques and wind integration issues, as outlined in its two-year action plan in Chapter XVI, and will include these issues in its August 2003 update.

F. Summary

PSE believes it has an opportunity to pursue a balanced resource portfolio strategy that meets customer needs, keeps rates low and protects against market risks, such as those recently experienced in the region. Several key components drive PSE's long-term electric resource strategy:

- Energy resources will be adequate to serve each month's expected customer energy needs under average hydro conditions.
- PSE has a goal of having capacity resources adequate to meet customer peak loads of 16 degrees Fahrenheit.
- Both new energy and new capacity resources will be shaped to fill winter deficiencies, without creating summer surpluses, to the extent feasible.
- PSE will acquire at least 150 aMW of new conservation resources over the next 10 years.
- PSE will serve at least 5 percent of its load with wind resources, and will strive to meet 10 percent of its load requirements through renewable resources by 2013.
- A diverse mix of other resources, including combined cycle gas-fired generation in the near-term and possibly coal in 2006, in addition to market purchases provide options for meeting the rest of PSE's resource needs.
- PSE will continue to monitor the market for acquisition opportunities and power contracts, but not at the expense of its commitment to conservation.

XIII. EXISTING GAS PORTFOLIO RESOURCES

Chapter XIII provides an overview of PSE's existing gas resource portfolio. The chapter begins with background on PSE's gas conservation and efficiency approach, providing details on specific conservation and efficiency programs. Next, this chapter turns to the supply side and details PSE's pipeline capacity, storage capacity, other capacity resources and gas supplies. The chapter ends with an assessment of PSE's existing gas supply/demand balance.

A. Conservation and Efficiency

Overview

PSE has provided conservation services for natural gas customers since 1993, saving approximately 5,916,258 therms (cumulative) through 2002. These energy savings were captured through energy- efficiency programs primarily serving residential and low-income customers from 1993 through 1998. Beginning in 1999, PSE recognized nearly three-quarters of the savings from commercial and industrial customer facilities. In terms of investments in energy efficiency, the Company has invested close to $6 million in natural gas conservation. All savings have been cost-effective relative to the company's avoided cost in place at the time the measures were implemented. Annual energy savings recur for 10 to 20 years for most heating equipment measures, while certain water heating measures may have shorter measure lives.

As discussed previously in Chapter VII, PSE recently increased its commitment to conservation by doubling its annual conservation targets in August 2002. When PSE filed new conservation tariffs with WUTC, 11 programs were expanded, 3 new programs were added and 3 pilot projects were initiated. The scope and size of programs resulted from a collaborative effort through the Company's Conservation Resource Advisory Committee ("CRAG"), a committee 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 natural gas conservation programs and services expect to achieve 2.9 Million therms of cost-effective energy savings, at a utility cost of $3.9 Million.

Current PSE Natural Gas Conservation Programs

PSE currently offers conservation programs under tariffs, effective from September 1, 2000 through December 31, 2003. Programs provide for efficiency savings from all customer sectors. PSE funds these programs through natural gas "tracker" funds collected from all customers. The scale and scope of PSE's natural gas programs have been smaller than its electric programs. The variety of applicable natural gas end-uses primarily include space, water and process heating – a list of measures more limited than those available to electric customers. Within PSE's joint electric and gas service territories, the Company offers customers all applicable conservation programs – including both electric and gas. Since the natural gas territory has significant overlap with neighboring electric utilities which offer their own programs for electric savings, PSE carefully tracks these programs to avoid PSE electric offerings for those non-PSE electric customers. Conversely, in areas of the service territory where another utility serves natural gas, PSE will only offer programs according to the electric rate schedule which it serves at a given location.

Exhibit XIII-1 provides an overview of current PSE's current gas conservation and efficiency programs. See Appendix E for more detailed information on these programs.

Exhibit XIII-1
PSE Existing Gas Conservation Programs

PROGRAM NAME	DESCRIPTION Sept. 2002 – Dec. 2003 Conservation Programs	EXPECTED ANNUAL ENERGY SAVINGS
Energy Efficiency Information Services – Personal / Business Energy Profile	• Free energy audit survey, analysis, & report providing customers with specific & customized energy efficiency recommendations	• No energy savings currently credited
Energy Efficiency Information Services – Personal Energy Advisors	• Phone representatives provide customers direct access to PSE's energy efficiency services & programs through a toll-free number	• No energy savings currently credited
Energy Efficiency Information Services – Energy Efficiency Brochures	• Brochures on program participation guidelines & how-to guides on energy efficiency opportunities	• No energy savings currently credited
Energy Efficiency Information Services – On Line Services	• Sections of PSE's web site dedicated to energy efficiency & energy management information, program details & application instructions	• No energy savings currently credited
Efficient Natural Gas Water Heater	• $25 rebate towards purchase of an energy-efficient gas water heater served with PSE natural gas	• 170,667 therms • 7-year resource
High-Efficiency Gas Furnace	• $150 rebate toward the purchase of a high-efficiency gas furnace, offered to residential customers for existing homes & new construction	• 224,667 therms • 15-year resource
Energy Efficient Manufactured Housing	• $150 rebate to the buyers of qualifying Natural Choice/ Energy Star labeled manufactured homes with natural gas heat	• 12,720 therms • 20-year resource
Small Business Energy Efficiency Programs	• Rebates for energy-efficient fluorescent lighting upgrades & conversions, lighting controls, programmable thermostats, & vending machine controllers	• 93,308 therms • 10-year resource
Commercial & Industrial Retrofit Program	• Incentives to commercial and industrial customers for cost-effective energy-efficient upgrades	• 1,406,033 therms • 15-year resource

Exhibit XIII-1
PSE Existing Gas Conservation Programs

PROGRAM NAME	DESCRIPTION Sept. 2002 – Dec. 2003 Conservation Programs	EXPECTED ANNUAL ENERGY SAVINGS
Commercial & Industrial New Construction Efficiency	• Incentives to commercial & industrial customers for cost-effective energy-efficient building components or systems	• 100,000 therms • 20-year resource
Resource Conservation Manager (RCM) Program	• PCM to implement low-cost/no-cost energy saving activities with building occupants & facility maintenance staff	• 266,667 therms • 3-year resource
PILOT Programs – Residential Duct Systems Pilot	• Participating customers receive the duct diagnostic measurement services & sealing services from the certified contractor at no cost	• 10,667 therms • 10-year resource
PILOT Programs – Commercial & Industrial Boiler Tune-up Pilot	• Pilot provides incentives of 50% of the cost of the tune-up for customers to have older boilers tuned up for the first time	• 377,000 therms • 1-year resource
Public Purpose Programs – Energy Education 6-9th Grade Environmental	• Conservation education program funded by PSE, along with 26 other utilities, cities, and agencies responsible for energy, water, & environmental programs in the Puget Sound area	• 80,756 therms • 10-year resource life
Public Purpose Programs – Residential Low-Income Retrofit	• Funding for installation of home weatherization measures for low-income gas & electric heat customers	• 120,800 therms • 20-year resource life

B. Pipeline Capacity

Puget holds 456,381 Dth/day and 413,557 Dth/day of firm TF-1 and TF-2 transportation capacity, respectively, on the Northwest Pipeline (NWP). PSE also holds 90,392 Dth/day on PG&E's Gas Transmission Northwest (GTN) in order to deliver gas received at Kingsgate, British Columbia, to NWP in eastern Washington. PSE has recently acquired capacity on Duke Transmission (formerly Westcoast) from Station 2 to Huntingdon / Sumas in British Columbia. A further discussion of this acquisition appears in Section B of Chapter XIV, *Upstream Pipeline Capacity*. Exhibit XIII-2 provides a summary of PSE's pipeline capacity position.

Exhibit XIII-2
PSE Pipeline Capacity Position
(Dth/Day)

	TOTAL	**EXPIRATION DATE**		
		2004	**2008**	**Other**
Pipeline/Receipt Point				
NWP – Sumas TF-1	196,705	128,705	58,000	10,000 (in 2016)
NWP – GTN Interconnect	75,936	75,936	-	-
NWP – Rockies TF-1	183,740	131,836	43,848	8,056 (in 2016)
Total TF-1	***456,381***	***336,477***	***101,848***	***18,056***
NWP – Jackson Prairie TF-2	343,057	343,057	-	-
NWP – Plymouth LNG TF-2	70,500	70,500	-	-
Total TF-2	***413,557***	***413,557***	-	-
Total Capacity to City-Gate	***869,938***	***750,034***	***101,848***	***18,056***
GTN – Kingsgate to Starr Road	75,936	-	-	75,936 (in 2023)
GTN – Kingsgate to Stanfield	14,456	-	-	14,456 (in 2023)
Duke Transmission to Sumas (beginning 11/03)	40,000	-	-	25,000 (in 2014) 15,000 (in 2019)

Note: all NWP and GTN contracts have automatic renewal provisions, but can be canceled by PSE upon one year's prior notice. The Duke contract contains a right of first refusal upon expiry.

Firm pipeline transportation capacity carries the right, but not the obligation, to transport up to a maximum daily quantity (MDQ) of gas from one or more receipt points to one or more delivery points.[1] This transportation activity is conducted in accordance with the pipeline's published tariff, as approved by the Federal Energy Regulatory Commission (FERC). The tariff defines the scope of service, which defines the number of days that the transportation service is available, along with the rates and other operating terms and conditions.

The NWP TF-1, and GTN and Duke transportation contracts are firm contracts, available for use 365 days each year. The NWP TF-2 firm transportation contract have annual contract quantities (ACQ) that corresponds to the storage capacity held by the shipper. While the annual contract term limits TF-2 service to a quantity equal to the storage ACQ, the cost of this service proves to be significantly lower than holding firm pipeline capacity for the entire year.

PSE may also use interruptible transportation, sometimes referred to as "best-efforts" agreements, from NWP under rate schedule TI-1. This service allows NWP to provide a transportation service that is subordinate to the rights of the shippers holding and using firm transportation capacity. To the extent that the firm shippers do not use their pipeline capacity, they may receive interruptible capacity. Since TI-1 transportation service can be interrupted, PSE does not rely upon it to meet peak demand, thus it serves a limited role in PSE's gas resource portfolio.

Additionally, firm transportation capacity on NWP and GTN may be "released" and remarketed to third parties under the FERC-approved pipeline tariffs. PSE aggressively releases capacity during time periods when it has identified surplus capacity. The capacity release market can also provide PSE with access to additional firm capacity, when available.

Consistent with the pipeline's service obligation, the rate for firm transportation capacity requires a fixed payment, regardless of whether or not PSE uses the capacity. The rate for interruptible capacity is negotiable, and typically billed as a variable charge.

C. Storage Capacity

PSE' s natural gas storage represents an important and cost-effective component of its capacity portfolio due to the many advantages it offers. Primarily, storage offers an immediate and controllable source of firm gas supply. Storage also proves advantageous as it can be used as a

[1] From a risk management perspective, pipeline capacity can be viewed as an option that provides the contract holder with the right, but not the obligation, to buy gas at one location and sell it at another.

pooling point for the quantities of gas purchased, but not consumed during off-peak seasons, or times of the year when gas prices tend to be less expensive. PSE can achieve significant commodity price savings if they buy gas during the relatively low demand period of the summer. In addition, coupling the market storage area and peaking facility located near PSE's system (Jackson Prairie and Plymouth LNG) with the TF-2 transportation service, allows PSE to purchase less year-round pipeline capacity than it might otherwise need.

Further, storage allows PSE to use its annual transportation and gas supply contracts at a higher load factor, minimizing the average cost of gas to its customers. Operationally, PSE uses underground storage for daily balancing on the interstate pipeline. If PSE's loads run higher or lower than the forecasted amount, PSE will use its storage to handle operational imbalances throughout the day, and minimize any balancing or scheduling penalties.

PSE also uses storage to balance its city-gate gas receipts with actual loads of its Gas Transport customers. The industrial and commercial customers who elect gas transport service (as an alternative to gas sales service) make nominations directly or through marketer-agents to move city-gate gas deliveries to the their respective meters. The customers, or marketer providing services to customers, often have daily imbalances since their scheduled gas deliveries do not match their actual gas consumption. On a daily basis, PSE provides balancing services in connection with its transportation tariff, and relies quite heavily upon storage to manage these imbalances.

PSE has contractual access to two storage projects, each of which serves a different purpose in PSE's resource portfolio. Jackson Prairie storage is an aquifer storage field that has been designed to deliver large quantities of gas over a relatively short period of time. PSE's other storage facility, Clay Basin – a depleted reservoir storage field – provides supply area storage and a winter gas supply. PSE has 343,057 Dth/day of TF-2 transport capacity from Jackson Prairie and can use its Rockies-originated TF-1 transport capacity from Clay Basin. Exhibit XIII-3 provides more details on PSE's storage capacity.

Exhibit XIII-3
PSE GAS STORAGE POSITION

	STORAGE CAPACITY (DTH)	INJECTION CAPACITY (DTH/DAY)	WITHDRAWAL CAPACITY (DTH/DAY)	EXPIRATION DATE
Jackson Prairie – Owned	6,344,000	144,600	289,216	N/A
Jackson Prairie – NWP SGS-2F[2]	1,181,021	26,900	53,841	2004
Clay Basin	13,419,000	55,900	111,825	2013/19
Total	**20,944,021**		**454,882**	

Located in PSE's market area in Chehalis, WA, PSE uses Jackson Prairie and the associated NWP TF-2 transportation capacity to meet seasonal load requirements, and eliminate the need to contract for year-round pipeline capacity to meet winter-only demand. PSE primarily uses Jackson Prairie to meet the intermediate peaking requirements of core customers.

PSE operates and owns one-third (with NWP and Avista Utilities) of the Jackson Prairie storage facility. PSE currently holds firm daily deliverability of 343,057 Dth and firm seasonal capacity of 7,525,021 Dth – of which PSE owns 6,344,000 Dth and holds the right under the contract for SGS-2F storage service from NWP to 1,181,021 Dth until October 2004. PSE holds the unilateral right to this contracted capacity. PSE has access to best efforts withdrawal rights of up to 82,000 Dth, and interruptible transportation service from Jackson Prairie.

Questar Pipeline owns and operates the Clay Basin storage facility in Daggett County, Utah. This depleted gas reservoir was developed to allow gas to be stored during the summer and withdrawn all winter. PSE holds the right, under two contracts, to store up to 13,419,000 Dth, and withdraw up to 111,825 Dth/day. FERC regulates the terms and conditions, including rates, of this agreement.

PSE also uses Clay Basin as a pooling point for purchasing gas, and as a partial supply backup in the case of well freeze-offs, or other supply disruptions in the Rocky Mountains during the

[2] Jackson Prairie leased contract has an auto-renewal provision, but can be cancelled by PSE upon one year's prior written notice.

winter.[3] As such, gas stored at Clay Basin provides a reliable source of available gas throughout the winter, including on-peak day. Gas withdrawn from Clay Basin is delivered to PSE's system, and to other markets directly or indirectly, using firm, TF-1 transportation. Similar to firm pipeline capacity, firm storage arrangements require that a fixed charge be paid regardless of whether or not the storage service is used. PSE pays a variable charge for gas injected or withdrawn from storage.

D. Peaking Capacity Resources

PSE has firm access to other resources that provide capacity and gas supplies to meet peaking requirements or short-term operational needs. Liquefied natural gas (LNG), Peak Gas Supply Service (PGSS), and vaporized propane-air (LP-Air) provide firm gas supplies on short notice for relatively short periods of time. PSE typically uses these sources to meet extreme peak demand during the coldest few hours or days, and generally only as the supply of last resort due to their relatively higher variable cost. LNG, PGSS, and LP-Air do not afford all of the flexibility of other supply sources. Exhibit XIII-4 provides an overview of PSE's peaking gas capacity resources.

Exhibit XIII-4
PSE PEAKING GAS RESOURCES

	STORAGE CAPACITY (DTH)	INJECTION CAPACITY (DTH/DAY)	WITHDRAWAL CAPACITY (DTH/DAY)	TRANSPORT TARIFF
Plymouth LNG	241,700	1,208	70,500	TF-2
Swarr LP-Air	128,440	16,680[4]	30,000	On-system
PGSS	NA	NA	48,000	City-gate delivered
Total	370,140		148,500	

NWP owns and operates an LNG facility located in Plymouth, Washington, and provides a gas liquefaction, storage, and vaporization service under its LS-1 tariff. PSE holds a long-term contract that provides for seasonal storage with an ACQ of 241,700 Dth, liquefaction with an

[3] From a risk management perspective, Clay Basin provides value as an arbitrage tool, and serves as a partial hedge to price spikes in the Rockies supply basins.
[4] Swarr holds 1.24 million gallons. At a refill rate of 111 gallons/minute, it takes 7.7 days to refill Swarr. This equates to 16,680 Dth/day.

MDQ of 1,208, and a withdrawal MDQ of 70,500 Dth. The ratio of injection and withdrawal rates to the storage capacity means that it can take PSE over 200 days to fill the capacity, but only three and one-half days to empty it. Due to these operating characteristics, PSE uses the LS-1 service to meet its needle-peak demands, and is delivered to PSE's city gate using firm TF-2 transportation.

Under its PGSS agreements, PSE has the contractual right to call on third party gas supplies for a limited duration during peak periods. Currently, PSE has the right to purchase up to 48,000 Dth/day at a price tied to the replacement cost of distillate oil for up to twelve days during the winter season.[5]

PSE maintains an LP-Air facility with a net storage capacity of 128,440 Dth equivalent, and has the ability to vaporize approximately 30,000 Dth per day. At the maximum vaporization capacity, this provides a little over four days of supply. Since the propane air facilities connect to PSE's distribution system, PSE requires no upstream pipeline capacity. PSE typically uses this LP-Air facility to meet extreme hourly or daily peak demand, or supplement distribution pressures in the event of a pressure decline on NWP. Some of PSE's peak shaving resources require that a fixed charge be paid regardless of whether or not the resource is used. The LNG service is billed to PSE pursuant to a FERC-approved tariff, while the cost of service associated with the on-system LP-Air plant is recovered from customers through base rates. PSE pays a variable charge on gas injected or withdrawn from LNG storage.

E. Gas Supplies

By maintaining pipeline capacity to various supply basins, PSE gains access to supplies of natural gas. Gas supply contracts tend to have a shorter duration than transportation contracts. The price and delivery terms across supply basins tend to be very similar, although the price levels from one day to the next can vary significantly. While the gas supply contract terms ensure the gas suppliers' performance, PSE's firm transportation capacity grants access to supply basins that offer the greater likelihood of availability and liquidity. In the event of a supplier default, PSE can always use its pipeline capacity to buy gas from other suppliers or marketers at market locations along the pipeline. PSE primarily focuses on the reliability of its pipeline delivery capacity and the long-term outlook for natural gas .

[5] In essence, this is a call option with a variable strike price equal to the then-current, delivered price of distillate oil.

PSE has a mix of long-term (+three years), medium-term (one to three years) and short-term contracts (less than one year) to meet average loads during different months, and PSE uses storage to meet intermediate peak load requirements. Long-term contracts and medium term contracts are typically baseload supplies delivered ratably over the year. Additionally, PSE can contract for seasonal baseload firm supply, typically for the winter months. The company enters into forward month transactions to supplement the baseload transactions, particularly for the months of November-March. During "bid week" – the week prior to the beginning of the upcoming delivery month – PSE estimates the average load requirements for the upcoming month and enters into month-long transactions to balance load. On a daily basis, the company does not plan to be long or short going into any day, but instead balances the position using storage and day ahead purchases and sales transactions. During the gas day, the company uses its Jackson Prairies storage for balancing. Exhibit XIII-5 provides an example of the weighting between different contract terms in 2002.

Exhibit XIII-5
Percentage Mix of Winter Supplies for 2002-2003

TERM	PERCENTAGE
Long-term (+3 years)	15%
Medium-term (1-3 years)	26%
Short-term (less than 1 year, includes storage)	54%
Bid Week	5%
Total	100%

Due to the number of long-term contracts expiring in the next few years, the weighting in Exhibit XIII-5 may change if Puget elects to change the ratio of long-term, medium-term and short-term supply. PSE will consider both costs and reliability issues when developing the portfolio strategy.

PSE also has a contract with King County - Metro ("Metro") to purchase the gas produced by Metro as the byproduct of its water pollution abatement processes. The gas is delivered directly into PSE's distribution system. The agreement has a remaining term of approximately three years.

PSE Participation in the Gas Futures Market

The Company commenced hedging in its core gas portfolio as of September 2002. The Company utilizes hedge instruments such as fixed-price physical transactions and fixed-price financial swap transactions. These were determined to be the most effective means of hedging at the time. In its power portfolio, the company has entered into similar transactions for natural gas hedging.

The Henry Hub futures market has a delivery point in Henry Hub, Louisiana. There can be a significant price dislocation between Henry Hub and the physical locations from which PSE sources its physical supply (from the Rockies, British Columbia and Alberta). In order for a futures hedge to be fully effective, PSE would need to enter into an Exchange for Physical (EFP) basis transaction with another counterparty to effectuate local delivery. In this way, PSE could enter into a fixed price hedge that transpired into physical delivery.

A futures account necessitates opening an account with a clearing firm and establishing commercial relationships with floor brokers who can execute transactions for its customers on the New York Mercantile Exchange (NYMEX). The clearing firm would require PSE to post margin call, and there would be a daily settlement into and out of the PSE account, depending upon the size of PSE's futures position and the daily direction of futures prices. Then, with respect to entering into an EFP, PSE would enter into a transaction with a counterparty who would agree to physical delivery at the agreed upon location, and the two parties would exchange futures at the NYMEX as part of the EFP transaction. The level at which the futures are exchanged, combined with the basis price of the EFP contract, sets the price for the physical delivered gas.

While the EFP mechanism provides a viable means to hedge, PSE has been able to enter into fixed price physical agreements directly with regional suppliers. These transactions prove to be far more simple and remove the need for opening and managing a futures account with a clearing firm engaging in futures trades and then entering into an EFP with a regional supplier.

In addition, a liquid market has developed for the over-the-counter financial derivatives for fixed price and basis transactions. These transactions are similar to entering into futures trades and EFP's from a pricing perspective, but requires a simpler process as transactions do not require the intermediary of clearing firms, floor brokers and the NYMEX. A master agreement, or an ISDA agreement, governs these transactions, and the parties negotiate a range of contractual items including credit, netting and cross-collateral terms. These transactions have worked well for PSE since they can be combined with physical index purchases. Moreover, many of PSE's long-term and medium-term contracts are index-based contracts, thus the financial derivatives work well within the company's portfolio.

On a going forward basis, the company will continue to evaluate the hedging mechanisms available in the market to weigh the benefits of each mechanism to determine its applicability in PSE's portfolio.

F. PSE Gas Supply/Demand Balance

PSE holds firm pipeline transportation and vaporization capacity that allows it to transport or otherwise deliver gas, on a firm basis, from points of receipt to its customers. This capacity ensures that PSE can provide its customers with reliable and cost-effective gas supplies during the coldest expected weather, and over a range of expected scenarios. In addition, PSE maintains on-system resources that assist in meeting peak demands and contribute to the reliability of the distribution system.

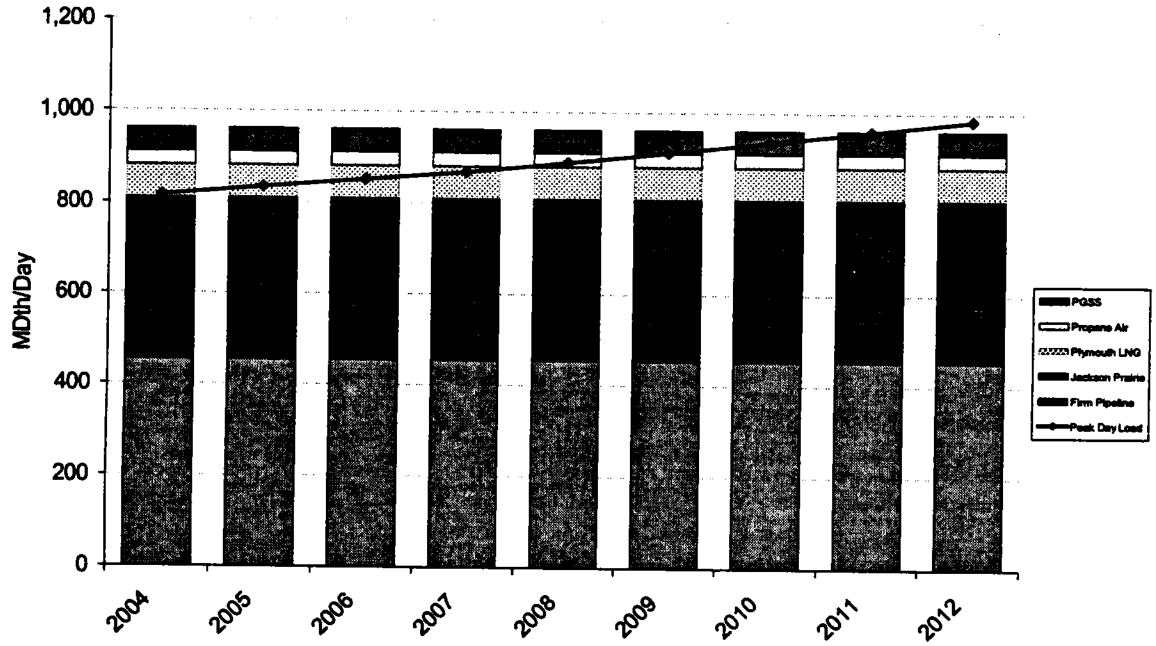
Based on the current base case forecast, PSE does not anticipate requiring additional firm capacity until around 2010. Until that time, PSE has adequate capacity to meet the expected requirements of its firm customers. Exhibit XIII-6 summarizes PSE's capacity position.

G. Summary

PSE relies upon a variety of resources – including both conservation and efficiency, and supply resources – to serve its gas customers. Currently, PSE does not anticipate requiring additional firm capacity until sometime around 2010. Other key highlights include:

- PSE recently increased its commitment to conservation, agreeing in August 2002 to double its annual conservation target. During the 16-month period from September 2002-December 2003, PSE's portfolio of natural gas conservation programs and services expect to achieve 2.9 million therms of cost-effective energy savings, at a utility cost of $3.9 Million.

Exhibit XIII-6
Summary of PSE's Gas Capacity Position
(Dth per Day)



- PSE holds a total of 869,938 Dth/day of pipeline capacity to its city-gates – 456,381 Dth/day and 413,557 Dth/day of firm TF-1 and TF-2 transportation capacity of the Northwest Pipeline, and additional upstream capacity on other pipelines.
- PSE has contractual access to two storage projects, providing a total storage capacity of 20,944,021 Dth. PSE utilizes storage capacity to provide an immediate source of firm gas supply, allow for less expensive, off-peak purchases of gas, for load balancing, and to use its transportation and gas supply contracts at a higher load factor.
- PSE's peaking resources include Liquefied Natural Gas (LNG), Peak Gas Supply Service (PGSS) and vaporized propane-air.
- This Least Cost Plan focuses more on the reliability of its pipeline capacity and the outlook for natural gas supplies than it does on supply contracts.
- PSE holds a total of 960,330 Dth/day of pipeline capacity – 456,381 Dth/day and 413,557 Dth/day of firm TF-1 and TF-2 transportation capacity of the Northwest Pipeline, and 90,392 Dth/day of PG&E's Gas Transmission Northwest pipeline.
- PSE has contractual access to two storage projects, providing a total storage capacity of 20,925,021 Dth. PSE utilizes storage capacity to provide an immediate source of firm

gas supply, allow for less expensive, off-peak purchases of gas, for load balancing, and to use its transportation and gas supply contracts at a high load factor.

- PSE's other gas resource options include Liquefied Natural Gas (LNG), Peak Gas Supply Service (PGSS) and vaporized propane-air.
- PSE has a mix of long-term (+ three years), medium-term (one to three years) and short-term (less than one year) contracts to meet average loads during different months, and PSE uses storage capacity to meet intermediate load.
- PSE participates in the gas futures market, primarily through fixed-price physical transactions and fixed-price financial swap transactions. On a going forward basis, PSE will continue to evaluate the hedging mechanisms available in the market to weight the benefits of each mechanism to determine its applicability in PSE's portfolio.

XIV

XIV. NEW GAS RESOURCE OPPORTUNITIES

Chapter XIII provided an overview of PSE's existing natural gas resources including conservation and efficiency, and supply portfolio resources. This chapter examines potential new gas resource opportunities for PSE. Gas resource portfolio opportunities exist when PSE can vary the structure of its existing capacity resource portfolio. These opportunities arise either when capacity contracts expire or additional capacity opportunities become available. Under some situations, it might also be desirable for PSE to buy out of an existing capacity contract in order to meet PSE's least cost objectives. Over the forecast period, PSE has a number of opportunities to modify the structure of its gas resource portfolio.[1] The NWP transportation contracts expire over the next 13 years, sponsors are considering new pipeline projects, underground storage expansions are proceeding, conservation continues, and peak shaving resources could be expanded. This chapter not only describes natural gas conservation and efficiency opportunities, but also these other opportunities.

A. Conservation and Efficiency

The amount of conservation and efficiency in the Company's gas resource portfolio depends heavily upon actions and decisions made by consumers, policies set by government agencies, and customer feedback related to current programs and offerings. As part of the current effort to develop new supply curves, PSE is reviewing new and emerging measures anticipated to become cost-effective over the 5 to 10 years. In the residential sector, there will likely be more emphasis on high-efficiency heating appliances, duct sealing, better controls and potentially higher-efficiency windows. Space heating primarily drives gas energy use in the commercial sector, with water heating loads significant only in certain business segments. Higher-efficiency equipment, better control schemes, demand controlled ventilation, and more attention to commissioning and O&M represent major potential for space heat savings. Certain measures, such as variable speed devices, will yield both electric and gas savings at facilities. These become more cost-effective for PSE customers when PSE serves both fuels at the site; thus PSE has sought to co-fund measures with neighboring utilities which serve electricity to a PSE gas customer. Industrial process heating improvements tend to be site-specific, and primarily include waste heat recovery.

[1] These opportunities are permanent capacity changes, as opposed to capacity optimization techniques such as capacity release, interruptible sales, off system sales, and other portfolio management activities used by PSE to minimize the average cost of gas to its customers.

The settlement agreement stemming from PSE's rate case in 2002 established a framework for future natural gas conservation programs beyond 2003. Data collection for natural gas measures to be used in development of the natural gas conservation supply curves will be complete in May 2003. Energy efficient natural gas end-use technologies will be compared with those being used by other gas and dual-fuel utilities in the region, and will focus on space, water and process heating applications. The gas supply curve, outlining cost-effective gas energy savings achievable in PSE customers' facilities, will be developed by early summer 2003. At this time, PSE anticipates adapting the models it uses for electric supply curves for use with natural gas. PSE will evaluate new measures using natural gas avoided cost forecasts developed through this Least Cost Plan process. The effectiveness of PSE's latest conservation initiatives, market research findings and the conservation potential will be tools for developing new program offerings and targets, and the best strategies for achieving gas energy efficiencies going forward.

B. Pipeline Capacity

PSE has a number of opportunities to modify its capacity position on interstate pipelines. As detailed in Chapter XIII, a number of the NWP contracts expire in 2004, 2008, and 2016. PSE retains the unilateral right to cancel these contracts upon one year's notice, otherwise the contracts renew automatically In essence, the pending expirations coupled with PSE's renewal rights, create opportunities, at those points in time, for PSE to make alternative resource decisions.

While NWP is the only pipeline that directly connects to PSE's city-gates, other pipeline projects have developed initial plans to offer transportation alternatives, some of which might connect directly with PSE. To date, those pipeline projects have not aggregated enough anchor tenants to make a project feasible. However, PSE continues to monitor their progress toward aggregating load, since, as stated earlier, the Company has some flexibility with respect to the expiration of transportation contracts with NWP and the roll-over terms of those contracts.

New pipeline capacity tends to be more expensive than existing capacity. For example, NWP's current Evergreen expansion is expected to cost approximately $0.42 per dth/day versus NWP's existing rate of $0.32. PSE will evaluate the cost of incremental capacity, weighing other transportation alternatives from a cost and reliability perspective, with diversity benefits from access to other supply basins. To the extent that core loads and/or incremental capacity costs change, PSE believes it important to maintain this analytical perspective in order to structure its gas resource portfolio on a least cost basis.

C. Storage Capacity

PSE has a number of opportunities to modify its storage capacity positions over the next eight years. As detailed in Chapter XIII, the Jackson Prairie lease expires in 2006. The Clay Basin contract continues through 2013 and 2020.

A capacity expansion is currently underway at Jackson Prairie, anticipated to add an additional 1,750,000 Dth of storage capacity to the facility every summer (April – October) for six summers, eventually expanding the total capacity by 10,500,000 Dth. Of this capacity, 40 percent will be cushion gas – gas that is injected and used to prevent ground water from seeping into the storage space. The remaining 60 percent -- or 1,050,000 Dth each year for a total of 6,300,000 Dth – will be used to provide working storage capacity. PSE holds the right to use one-third of this working capacity, or 2,100,000 Dth (350,000 each of six years). While the exact time frame for completing the Jackson Prairie expansion has not yet been determined, PSE anticipates the owners will elect to expand the deliverability of the project by 300,000 dth/day of delivery (100,000 dth/day for PSE) for the next decade. Jackson Prairie may well represent the least cost way of meeting this firm load requirement.

D. Gas Supplies

The Company manages its supply portfolio to maintain supply diversity, and the pricing terms reflect at least three regional markets: the U.S. Rockies, British Columbia, and Alberta. Over long periods of time, a tendency exists toward equilibrium pricing among the three regions. Over shorter-time frames, however, one basin will be lower cost than the others - a difference that can be more pronounced on a daily basis. PSE's capacity rights on NWP allow it some flexibility in buying from the lowest cost basin. This arbitrage opportunity can mitigate the price volatility and serves to mediate prices between the various supply basins.

PSE has always purchased its supply at market hubs or pooling points. In the Rockies, the transportation receipt point is Opal but alternate points such as gathering system interconnects with NWP allow for some purchases directly from producers as well as from gathering & processing firms. In fact, the Company has a number of supply arrangements in the Rockies with major producers. Thus, the Company has the ability to purchase supply at or close 'to the wellhead' or point of production.

With respect to Canadian supply, NWP's receipt points interconnect with upstream pipelines (Duke Transmission at Sumas / Huntingdon, BC) or at a lateral (GTN at Starr Road). The Company's upstream GTN transportation capacity allows PSE to source supply at the Kingsgate British Columbia interconnect with Alberta Natural Gas (ANG). In British Columbia, the Company has entered into an agreement with Duke Transmission to hold firm transportation from Station 2 to the Sumas market (called T-south capacity). Station 2 is a pooling point, and producers move their gas supply from the wellhead and gas processing facilities to the Station 2 pooling point. The upstream transportation arrangements are explained in more detail later in this chapter.

From a supply-planning perspective, continued diversification of its natural gas purchases among the three supply basins provides some measure of reliability and price protection for PSE by avoiding a concentration in any single market. PSE expects to maintain this approach to contracting for gas supplies in the Rockies, British Columbia, and Alberta.

Pipeline projects add capacity in stepwise fashion, while load growth and production increases tend to happen more gradually. New pipeline projects can suddenly increase the take-away capacity from one supply basin, shifting the supply-demand dynamic across the network. As a result, large price shifts can result from a pipeline expansion project. While the pricing data illustrate the relative equilibrium among the western basins, the imbalance lies between these basins and the market areas. When that differential becomes large enough and persists over time, new pipeline capacity is proposed to re-balance the market. Rockies prices are relatively depressed in comparison to other production basins, however, the price differentials between the Rockies and Sumas areas have grown more pronounced. New pipeline projects such as the Kern River expansion (summer 2003) will tend to narrow these price differentials.

With respect to planning future gas purchases by basin, PSE will diversify its portfolio to match the transportation take-way capacity it holds at the primary receipt points in its long-term pipeline transportation contracts. Over time, as the market differentials spur pipeline capacity expansions, PSE could have an opportunity to diversify to other supply basins. However, the expansions might also serve to bring prices closer together.

Outlook for Future Natural Gas Supplies

Natural gas reserves in the United States and Canada are estimated to be 2,189 trillion cubic feet (Tcf). This estimate includes gas reserves that are proved (236 Tcf) and unproved (1,953 Tcf). Proved reserves are those estimated to be commercially recoverable, with reasonable certainty, under current geologic, commercial, and technical conditions. Unproved reserves include all other reserves, including those calculated to exist, but not yet discovered. Under these definitions, the level of gas reserves depends, in part, on the expected price of gas. At higher expected gas prices, the potential quantity of recoverable gas also increases.

Since 1994, US gas reserve additions have exceeded production in all years except 1998.[2]. While Canada has seen a gradual decline in provides reserves, continued exploration and development of natural gas reserves in the U.S. Rockies, British Columbia and Alberta will provide production adequate to meet most of the projected demand. Increasingly, the development and re-opening and expansion of LNG import projects will likely play a role in meeting incremental capacity and gas supply requirements in certain regions of the US

Over longer periods of time, as reserve and gas production levels change, the development of gas reserves in other regions might take on greater significance to PSE. Given the continued development of gas reserves accessible from Duke Transmission, GTN, and NWP, PSE does not expect shifting purchases to other supply areas to be a material consideration in the foreseeable future.

US Reserves

As noted earlier, additions to natural gas reserves in the US have exceeded production in every year but one prior to 2001. Existing gas reserves in the lower-48 are estimated to be 183 Tcf. At current production levels, these reserves will be adequate to supply approximately nine years of gas demand at current consumption levels. As with Canada, significant amounts of gas reserves remain unproved. The average of the estimates from industry sources of North American gas reserves is 1,186 Tcf, or almost 60 years of demand at current levels. See Exhibit N-1 in Appendix N for more details.

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[2] According to the EIA, this year [1998] was characterized by extremely low energy prices and accounting adjustments that affected reserve calculations.

Canadian Reserves

Canada is a major producer of natural gas and oil, and the largest exporter of natural gas to the United States. In 2001, Canada produced 17.4 Bcf per day (6.4 Tcf per year) of gas, with year-end, proved reserves at 60.1 Tcf. Exports to the United States were 10.6 Bcf per day (3.9 Tcf per year).

Alberta, the largest natural gas producer in Canada, produces almost 5 Tcf (13.6 Bcfd) in 2001. Estimated, proved reserves at year-end 2001 stood at 40.5 – 45.2 Tcf. British Columbia produced a little over one Tcf (2.9 Bcfd) in 2001, the second largest gas producer in Canada behind Alberta. Gas reserves are concentrated in northeastern part of the province, with a recent, significant find (Greater Sierra - 2002) estimated to contain five Tcf. As the frontier gas development progresses, new pipelines (from Alaska, Mackenzie Delta, or both) will likely tie into existing systems in Alberta, finding a ready market for the gas at the AECO Hub for markets south and east. PSE's capacity position on PGT provides strategic access to current and future gas supplies from Alberta and points north. For more details on Canadian reserves, please see Appendix N.

Reserve Growth

When evaluating published accounts of gas reserves, it is important to note that a significant portion of reserve growth comes from the re-evaluation and continued development of existing reserves. The USGS observes that " ... reserve growth is expected to contribute at least twice as much oil and natural gas to the Nation's reserves as new discoveries."[3] For PSE, this implies that gas reserves currently accessed by their transportation contracts should be expected to grow. And given the relative early development stage of the gas reserves in British Columbia and Rockies, the potential for reserve growth could be substantial. Further, applying the same logic to Alberta's reserves suggests that additional gas reserves await further development.

In summary, the pipeline transportation contracts held by PSE position it well to maintain access to adequate gas supplies in producing areas well-positioned for further development. These supplies will likely remain price competitive due to the focus on development of these reserves. PSE finds itself in a strong position to seek additional pipeline capacity when needed to meet incremental load requirements with reliable and economical gas supplies.

[3] See USGS Fact Sheet FS-119-00, October 2000.

Upstream Pipeline Capacity

In some cases, a trade off exists between buying gas at one point or buying capacity to enable gas to be purchased at another upstream point, closer to the supply basin. PSE faces this situation with its purchase of gas at Sumas and Kingsgate. Many of its Canadian supply arrangements have upstream transportation values embedded in the contract price. At Sumas, upstream transportation values from Station 2 on Duke Transmission are embedded in the gas supply pricing PSE has in several, long-term contracts expiring in 2003. Moreover, owning upstream capacity can help insulate the Company and its customers from price volatility at the downstream location (in this case, Sumas).

PSE initiated this strategy by acquiring 40,000 Dth/d of capacity on Duke Transmission from Station 2 to Huntindon, BC starting November 2003. PSE can take advantage of a growing re-seller market at Station 2 with this transportation capacity, minimizing its cost and risk by contracting for a portion of this upstream transportation, and serving as a hedge against potential price spikes at the Sumas market. PSE will continue to evaluate its upstream transportation, and re-evaluate its position to ensure a balance of market diversity, liquidity, volatility and least cost.

PSE also holds GTN capacity from Kingsgate (Canadian border) south to NWP. The Company has had a long-term supply arrangement, through aggregators, with the Alberta Pool at Kingsgate. Transportation costs for ANG and Nova pipelines are included in the pricing formula. Since that supply contract will soon be up for renewal, the Company will seek to explore both supply arrangements at Kingsgate and upstream at AECO, providing upstream transportation capacity on ANG and Nova is available. If transportation upstream on ANG and Nova is available so that PSE could transport gas from AECO to its city-gate, then this would open opportunities to procure gas supplies directly at AECO. Therefore the Company will review options to renew the contract at Kingsgate, procure gas from alternate suppliers at Kingsgate, and evaluate the possibility of holding upstream transportation and purchasing from AECO suppliers.

With respect to making those decisions, the Company will review a host of factors including price risk, currency risk, pricing and other contract conditions, fixed cost exposure, market liquidity, security of supply issues, other transaction costs, and counter-party creditworthiness.

E. Summary

Over the 20-year planning period, PSE has a number of opportunities to explore new conservation and efficiency initiatives, and modify the structure of its resource portfolio. These opportunities arise as capacity contracts expire or additional capacity opportunities become available. Other key highlights include:

- PSE has access to a variety of cost-effective gas conservation and efficiency resource opportunities in each of the customer sectors to help meet gas energy needs.
- PSE expects newer, more efficient technologies will allow increased precision with which users are able to monitor, operate, maintain and manage natural gas energy consumption.
- Several of PSE's pipeline capacity contracts expire between 2004-2016. These pending expirations, coupled with PSE's renewal rights and proposed new pipelines, create opportunities for PSE to make alternative gas resource decisions.
- Along with the expiration of its pipeline capacity contracts, PSE has a number of opportunities to modify its gas storage capacity positions over the next eight years.
- PSE expects to maintain its current approach to making diversified purchases among the Rockies, British Columbia and Alberta supply basins in order to provide reliability and price protection.
- The average of the estimates from industry sources of North American gas reserves is 1,186 Tcf, or almost 60 years of demand at current levels.
- Reserve additions in the basin's tributaries to PSE's firm transportation receipt points indicate growing exploration and production activity.
- Pipeline and producers have demonstrated a willingness to develop the facilities to bring gas into the Northwest region as necessary.

XV

XV. GAS RESOURCE ANALYSIS AND STRATEGY

Chapter XV focuses on the analysis process used by PSE to develop its gas Least Cost Plan. The chapter begins by stating the objectives guiding PSE's gas Least Cost analysis. Next, this chapter details the steps taken in the analytical process. The chapter ends with a presentation of the resource analysis results and a discussion of the implications of the results. Specific actions for the recommended long-term gas resource strategy can be found in PSE's two-year action plan in Chapter XVI.

A. Analytical Process Overview

PSE's gas portfolio analysis seeks to identify the combination of gas resources that minimizes the average cost of gas to firm customers, over time, under a given set of assumptions and constraints. While mainly quantitative in nature, the analysis has a strong qualitative dimension. It relies on forecasts of annual and peak day gas demand; projected costs for gas capacity and commodity; contract quantities, terms and conditions; and other known or expected operating constraints.

This process also identifies those points in time when changes to the portfolio can or must be made, evaluates the costs or benefits of making those changes, and assists PSE in re-structuring its portfolio to select the appropriate resource mix. Finally, PSE conducted and evaluated various sensitivities.

PSE evaluated three portfolios that correspond to three demand scenarios – Base Case, High Growth and Low Growth. The sensitivity of the Base Case portfolio to hypothetical changes in gas prices was also evaluated and there were two scenarios with different gas commodity price assumptions – High Gas and Low Gas. In all, five different model runs were conducted and evaluated. The three different growth scenarios produced different portfolio structures, while the price scenarios tested the sensitivity of the Base Case scenario at two, alternative hypothetical price levels.

Once the optimal portfolio structure has been selected, it remains the same. However, managing the portfolio to minimize cost and price volatility constitutes a dynamic and continuous activity as discussed in Chapter III. PSE's assessments of the potential opportunities to enhance the value of the portfolio comprise a significant part of the qualitative dimension of the gas portfolio analysis process. These include assessments of the potential risks associated with various resource selections when making portfolio restructuring decisions, including risks associated with supply reliability, price, and resource diversity.

As detailed in Chapter IV, meetings with stakeholders, and public input only enhances the analytical process. PSE believes its portfolio analysis process supports its ability to design and manage a gas resource portfolio that meets the objective of providing customers with a reliable, least-cost supply of natural gas.

B. Analytical Process Stages

The analytical process consists of the following six stages.

1. Defining and validating all data inputs (e.g., demand forecasts, contract quantities, gas costs and transportation rates, etc.);
2. Identifying those gas resources that can be varied and when;
3. Pre-screening resources to streamline modeling time;
4. Running the planning model to evaluate various resource configurations, under Base Case, Low, and High gas demand scenarios;
5. Running the Base Case demand scenarios under High Price and Low Price scenarios; and
6. Evaluating the model results.

Data Validation

PSE considered a combination of available and potential capacity and commodity, and their respective costs. Capacity includes pipeline transportation capacity; supplemental (LNG and LP-Air) vaporization capacity; injection, storage, and withdrawal capacities of storage facilities; conservation measures; and firm, third-party delivered gas. Commodity includes the gas supplies available or avoided due to holding the capacity positions. Each of these resources has one or more costs associated with it, and those costs can be fixed and/or variable. Further, the costs and capacities can also change over time and as a function of other inputs. All of these data, plus the demand data, must be verified and input into the model.

In the base case, PSE used the same forecast of gas prices as used in the electric analysis. It is important to note that the costs used by PSE in its analyses reflect its long-term view of the magnitude and direction of natural gas commodity costs, and may be lower than the costs currently seen in the market. PSE believes that the current market volatility reflects short-term factors that will dissipate over time and does not believe it appropriate to evaluate long-term resource decisions in light of short-term market aberrations.[1]

Identifying Gas Resources to Vary

The structure of the portfolio can change only when a capacity resource can be changed. Capacity contracts that have renewal dates, incremental capacity requirements, and options to increase or decrease capacity positions all represent examples of changes that can affect the portfolio structure. Some of these changes may prove to be material and require more detailed analysis, others occur so far into the future, obviating the need for a decision, while some are obvious to the point of requiring minimal analysis.

The decision whether to meet incremental demand with new pipeline capacity, storage capacity, conservation, supplemental capacity, or a combination of all four requires a complex analysis. The fact that capacity additions occur in large, discrete quantities, available only at certain points in time, and not necessarily available year-round further complicates this decision. Since modeling all of the possible combinations can be time-consuming and redundant, screening the various resources prior to the modeling activity allows for a more efficient selection of the resources to analyze. Exhibit XV-1 illustrates how the screening process could quickly identify that storage and LP-Air should be included in an analysis of how best to meet a 30-day gas requirement, while pipeline and conservation resources seem better suited to meet demands of longer duration. The analysis also illustrates how LNG competes with pipeline as a resource to meet short duration, peak winter demands. Each resource faces limits, however, due to operational constraints such as the available amount of storage capacity, injection and withdrawal rates, interchangeability limits on LP-Air injections, or the difficulty in siting a new LNG facility. Of course, this represents only a snapshot, and aids in refining the resource selection process. This approach does substitute for the long-term, least-cost modeling of the resource portfolio, nor does it reflect the best resource selection over time. The long-term modeling effort described below provides greater insight to addressing that issue.

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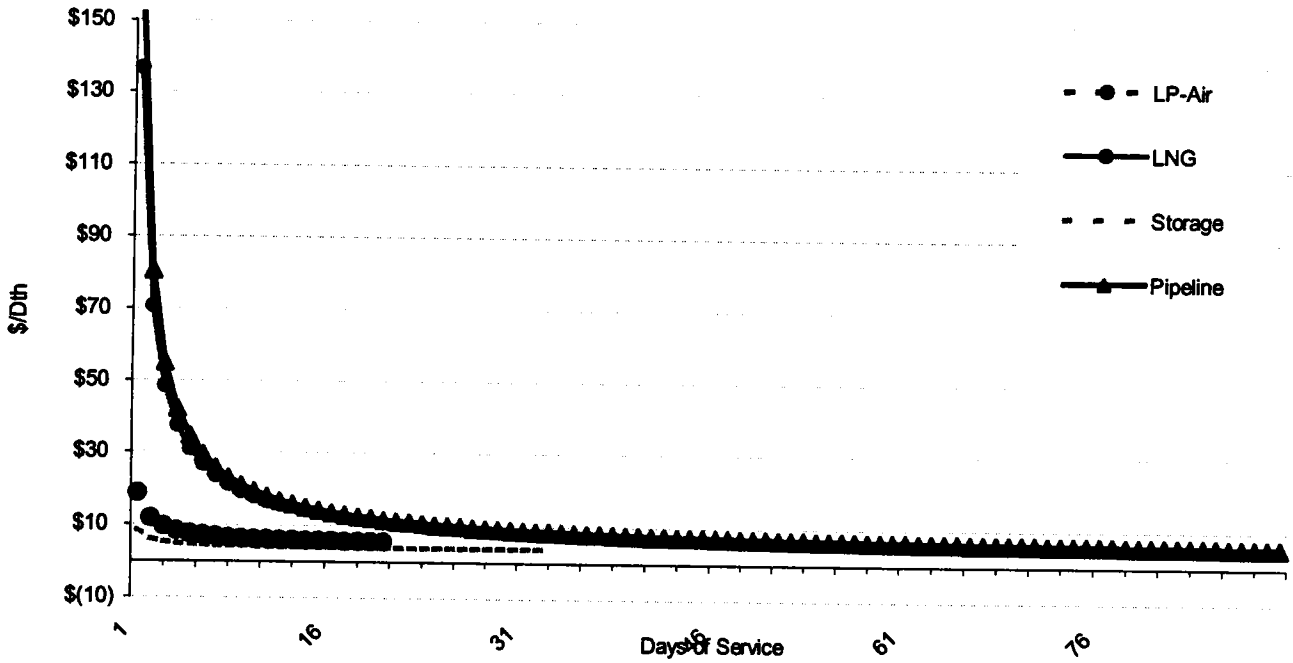
[1] The factors pushing up gas prices this year include sustained cold weather in the eastern US; larger-than-normal storage withdrawals; high storage refill demand; growing evidence of low hydro levels in the West and Northwest; projected warmer-than-normal temperatures for the Southwest; oil prices pushed very high due to the instability in the Middle East; and trading activity by fund mangers in commodity markets.

Exhibit XV-1

Preliminary Resource Screening
Average Cost per Dth Over 90 Days of Service
($/Dth)



While the existing NWP capacity contracts could be varied, they are maintained in this analysis because the existing TF-1 contract is approximately $0.10 per Dth per day less expensive than a new firm transportation contract. Accordingly, PSE recognizes that it has the contract cancellation options available but models its existing NWP contracts as being available for the forecast period because it simplifies the modeling process and does not compromise the results.

Gas Resource Portfolio Model

PSE used a least-cost planning model (Uplan-G Resource Planning Model) that calculated the net present value (NPV) of the costs of the gas resources selected to meet specified load requirements under the terms of the various capacity and commodity contracts. The model uses a time period of twenty years beginning in 2004 and a discount rate of 8.95 percent. The Uplan-G model specification for this Least Cost Plan used the data, described above, as inputs to a network representation of the systems that supply natural gas to PSE.[2] The model then ran daily dispatches for 20 years including a planning criteria peak day each year to calculate the annual cost of serving PSE's firm load under the Base Case, Low Case, and High Case demand scenarios.

PSE has the option of using Uplan-G to minimize either the variable costs of its portfolio or the total costs.[3] For the purposes of its long-term plan, PSE used the model in the mode of minimizing total costs. In this mode, the analysis took into account the complete life-cycle costs of contracts for gas supply, storage, pipeline, and LP-Air capacity, minimizing the fixed costs, as well as the variable costs. Given the planned expansion of the Jackson Prairie storage field, this storage capacity was modeled to be available at assumed points of time that varied by scenario.

From this analysis, PSE identified that mix and timing of gas resource additions that would be expected to minimize the cost of gas to its customers under the given sets of price and load forecasts, and capacity assumptions.

Evaluating Model Results

The model results were evaluated to ensure the following:

- All of the firm customers' requirements were met each year over the planning period.
- The model dispatched resources in a least-cost fashion.
- What, and if, any resource decisions were required.

The year-to-year changes in gas costs, as calculated by the model, also were examined for continuity and reasonableness to understand the timing effect of resource changes.

C. Modeling Approach and Results

In developing its current Gas Least Cost Plan, PSE analyzed three portfolio configurations and two additional price scenarios, generating five model runs.[4] The three portfolio configurations corresponded to Base Case, High Growth and Low Growth demand scenarios. Since each of these scenarios had different projections of gas demand, Uplan-G identified a different optimal

[2] Consistent with accepted modeling practice, Uplan-G is configured to provide an abstract representation of PSE's resource portfolio and supply system.

[3] PSE regularly uses the variable cost optimization mode of Uplan-G for calculating its PGA.

[4] One model run included both Base Case load growth and Base Case price forecasts.

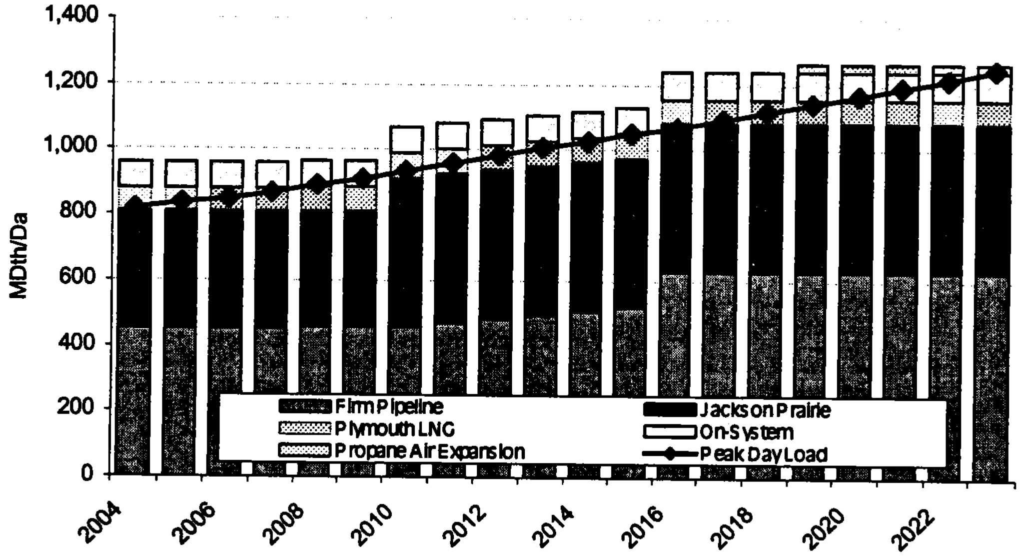
mix of resources, or portfolios, for each scenario. To understand the impact of different gas price levels on the Base Case portfolio, PSE ran it against two hypothetical price scenarios, generating High Price and Low Price scenarios. In these two price analyses, the resource mix did not change from the Base Case but the impact on the average cost of gas under different price levels was calculated. In all of the analyses, there was a need to add resources, however the mix and timing varied. More importantly, the timing of the required resource additions indicated that PSE would not have to make a resource acquisition decision at this time. The results of each of these runs are discussed below.

Base Case

Exhibit XV-2 illustrates the current gas resource portfolio has sufficient resources to meet the expected Base Case demands of PSE's firm customers through 2009. Additional underground storage deliverability is assumed to be available in 2010. After that point in time, pipeline capacity is added from 2011 through 2016, and propane air capacity in 2019. While the model identifies the need for relatively small, annual additions of pipeline capacity, in practice the required capacity would be added in larger amounts but less frequently.. Contemporaneously, the peak day demand is expected to grow at an annual rate of 2.27 percent, moving from 817 MMBtu in 2004 to 1,246 MMBtu in 2023. The total load served over the 20-year forecast period is 2.2 Tcf.

Exhibit XV-2

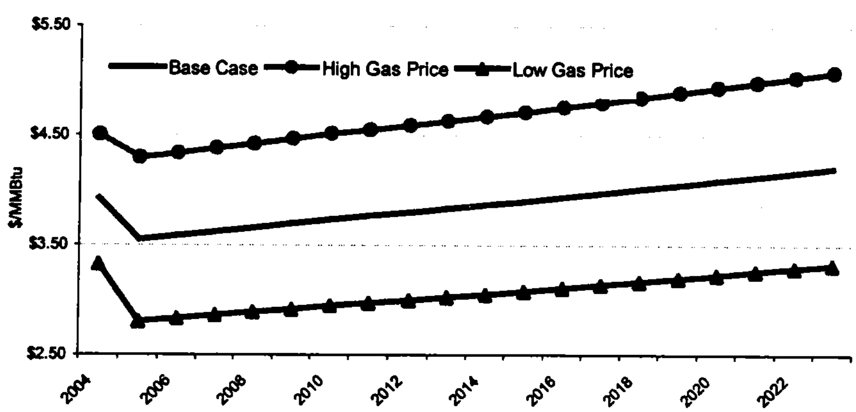
PSE Peak Day Load and Delivery Capacity
Base Case Load and All Price Scenarios



The High Gas Price and Low Gas Price scenarios used hypothetical price forecasts for gas purchased at Sumas, AECO Hub, and the Rockies to evaluate the sensitivity of the Base Case portfolio to changes in gas prices. Exhibit XV-3 illustrates the different price levels. These different gas commodity prices flow through the models, affecting the costs used for storage gas and Plymouth LNG. As will be seen later, the impact of different gas prices on the average costs of the various portfolios is larger than changes in capacity.

Exhibit XV-3

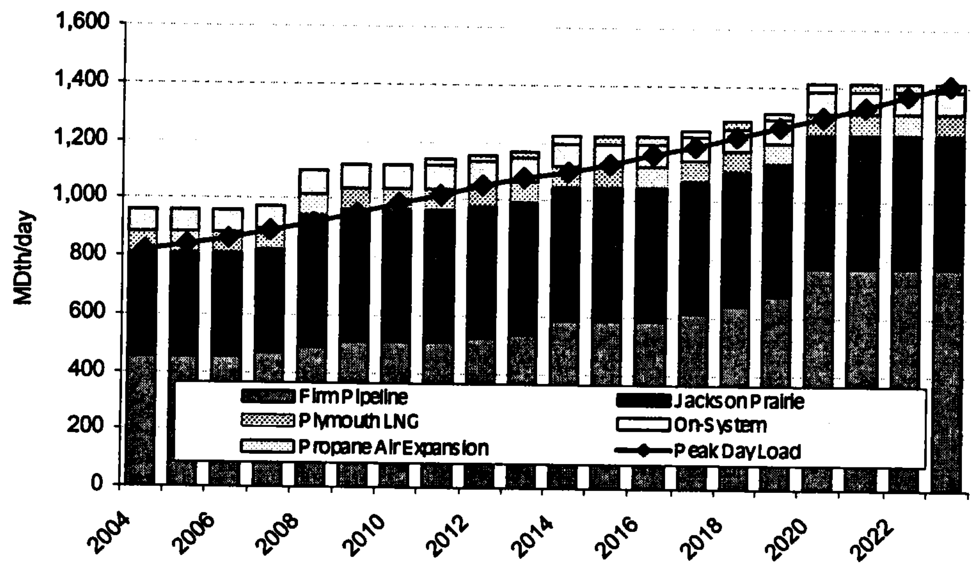
PSE Natural Gas Price Scenarios



High Growth

Exhibit XV-4 illustrates the current gas resource portfolio has sufficient resources to meet the expected needs of PSE's firm customers through 2007. Due to the higher growth rate, additional storage deliverability is assumed to come on be available in 2008. After that point in time, pipeline capacity is added from 2008 through 2020, and LP- Air capacity in 2011. At the same time, the peak day demand is expected to grow at an annual rate of 2.89 percent, moving from 819 MMBtu in 2004 to 1,408 MMBtu in 2023. The total load served by this portfolio over the forecast period is 2.4 Tcf.

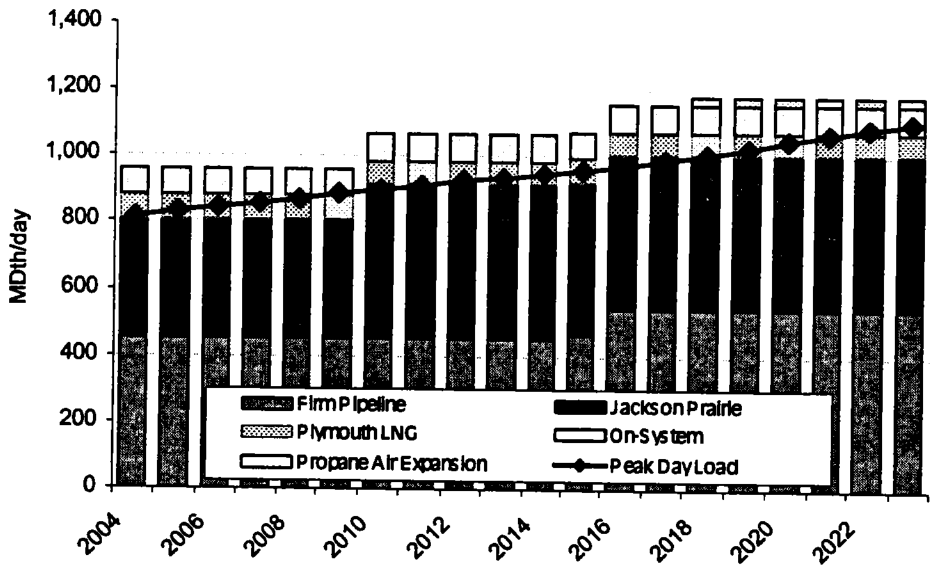
Exhibit XV-4
PSE Peak Day Load and Delivery Capacity
High Load Growth



Low Growth

The Low Growth scenario models a significantly lower growth in annual and peak day gas demand. Exhibit XV-5 illustrates that the lower growth pushes out the time when additional capacity would have to be added. As modeled, the current portfolio has sufficient resources to meet the expected needs of PSE's firm customers through 2009. Reflecting the lower growth rate, storage deliverability was assumed to be available in 2010. After that point in time, pipeline capacity is added in 2015 and 2016, and LPAir capacity in 2018. Under this scenario, the peak day demand is expected to grow at an annual rate of 1.60 percent, moving from 816 MMBtu in 2004 to 1,104 MMBtu in 2023. The total load served by this portfolio over the forecast period is 2.1 Tcf.

Exhibit XV-5
PSE Peak Day Load and Delivery Capacity
Low Load Growth



D. Analysis of Model Results

The model results were reported and compared in terms of the net present value (NPV) of each portfolio. To standardize for the different sales quantities under the three different growth scenarios, an average cost of gas ($/Dth) was calculated for each growth and price scenario. To understand these results, they were evaluated from an investment perspective and an expense perspective by using discount rates of 8.76 percent and 3.00 percent, respectively. The 8.76 percent rate represents PSE's weighted average cost of capital. The second discount rate represents a portfolio evaluation from the perspective of an investor in PSE. This second discount rate characterizes the effect that may be experienced by a PSE firm customer. Viewing the results through these two perspectives allowed PSE to ensure that the results did not differ materially from either perspective. Exhibits XV-6 and XV-7 summarize these results.

Exhibit XV-6
Summary of Portfolio Analysis Results at 8.76 Percent

MODEL RUN	FIRM DTH (MM)	NPV ($MM)	$/DTH
P1 – Base Case	2,215.8	$4,645	$2.10
P2 – High Growth	2,386.1	$4,972	$2.08
P3 – Low Growth	2,055.5	$4,362	$2.12
P1 – High Gas Price	2,215.8	$4,384	$2.18
P1 – Low Gas price	2,215.8	$3,858	$1.74

Exhibit XV-7
Summary of Portfolio Analysis Results at 3.00 Percent

MODEL RUN	FIRM DTH (MM)	NPV ($MM)	$/DTH
P1 – Base Case	2,215.8	$7,846	$3.55
P2 – High Growth	2,386.1	$8,519	$3.57
P3 – Low Growth	2,055.5	$7,291	$3.55
P1 – High Gas Price	2,215.8	$8,195	$3.70
P1 – Low Gas price	2,215.8	$6,519	$2.94

These model results were compared to determine which portfolio had the lower NPV, the lower average cost per Dth, and the likely lower level of risk. The first two steps required straightforward calculations, while the latter relied upon more qualitative and subjective analysis.

To approximate the sensitivity of the average cost of gas to changes in firm requirements (for any one portfolio), PSE calculated the cost per Dth by dividing the NPVs from the Base Case, Low Case and High Case by their respective demand quantities. This resulted in average costs per Dth that varied by $0.04 per Dth and $0.02 per Dth using the respective 8.76 and 3.00 percent discount rates. The High Gas Price and Low Gas Price scenarios illustrated that the average costs per Dth were more sensitive to changes in commodity gas costs than to changes in the fixed costs, portfolio structure, or the level of gas demand.[5] This also underscored the important role played by portfolio optimization in minimizing the average cost of gas.

Under the 8.76 percent discount rate, the results indicated that the High Growth portfolio resulted in an average cost that was lower than the Base Case portfolio by $0.02 per Dth. From the 3.00 percent perspective, the average costs under the Base Case and Low Growth scenarios were equal, and lower than the High Growth Scenario by $0.02 per Dth. This

[5] Generally, this holds true as long as the (variable cost) > (unit fixed costs)/(firm load factor).

comparison demonstrated two points. First, the low disparity in the average costs of the portfolios illustrates relatively stable portfolios. Second, the change in the relative order of the average costs suggested that the timing of resource additions could have an effect on the average cost of gas. Accordingly, PSE evaluated the average cost of the portfolios over time.

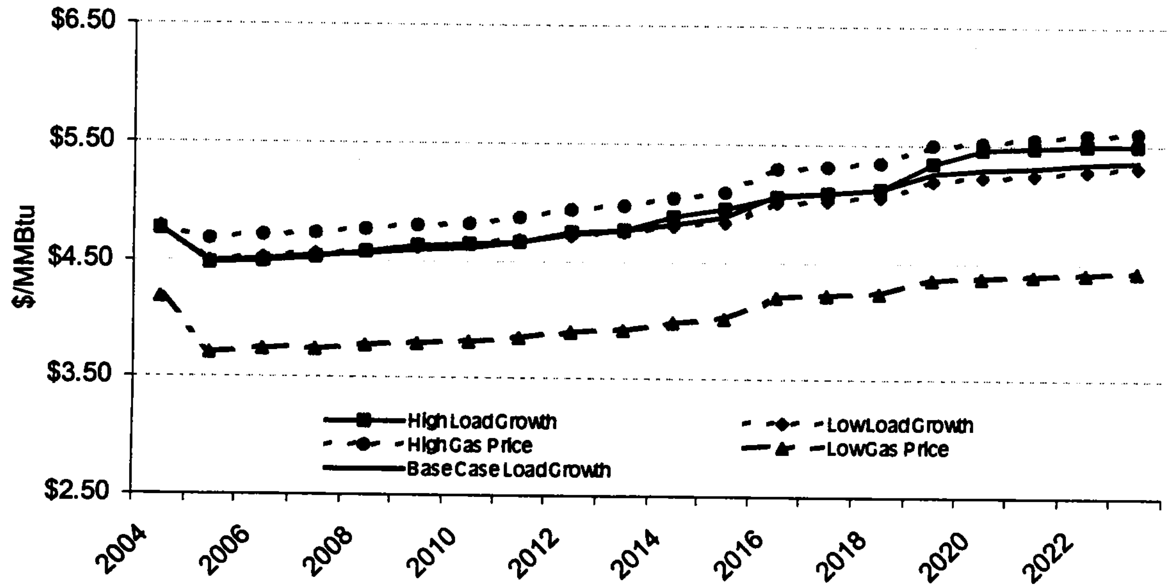
Exhibit XV-8 illustrates the average cost paths over time for each model run. Exhibit XV-9 shows the percent deviation of the average costs under each model run from the average cost under the Base Case. The average costs under the three different growth scenarios track closely until 2011, when the average costs under the High Load Growth and Low Load Growth scenarios begin to diverge. Prior to that point in time, the High Growth Scenario results in a lower average cost than the average costs under the Low Growth Scenario, and, in some years, the Base Case.

This pattern illustrates two key points. First, the higher growth results in the existing portfolio being used at a higher load factor during the earlier years, lowering the average cost of gas. As new capacity is added in the later years, the average cost begins to increase. Second, the average cost under the lower load growth portfolio is higher than the average cost under the Base Case portfolio until 2012. These two points illustrate the following:

- PSE faces little risk from growing as expected or more quickly over the next four to eight years,
- The resource additions having the greatest impact on the average cost of gas are expected to be required around 2012.
- Since average costs in the short-term are not very sensitive to the structure of the portfolio, the larger benefit to firm customers will come from optimizing the existing portfolio.

This temporal analysis also identified the point in time that resource additions would be expected to have a larger effect on average gas costs.

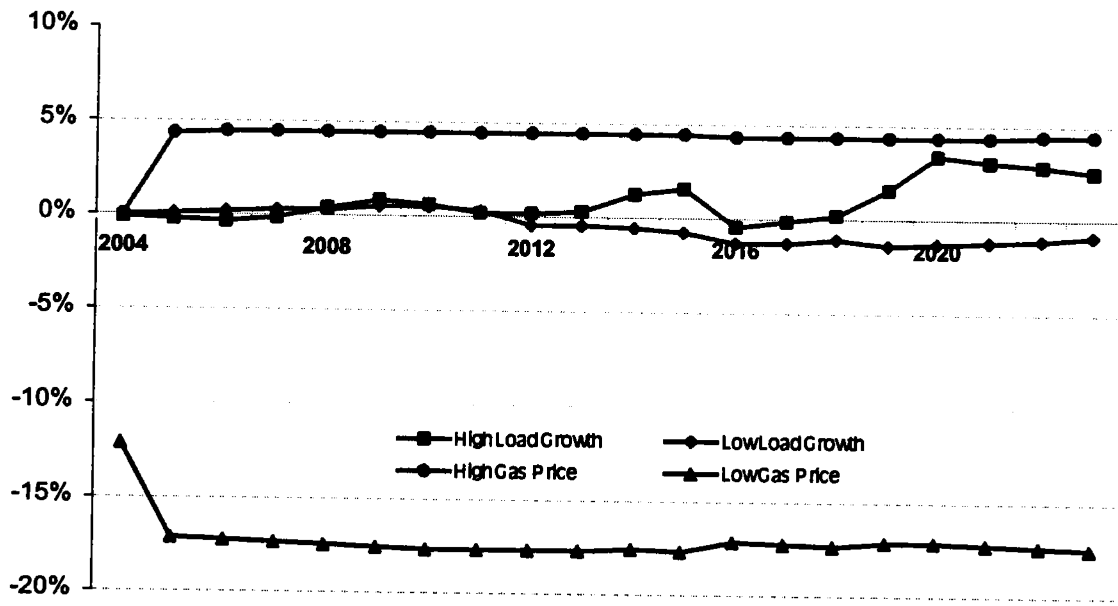
Exhibit XV-8
Comparison of Average Cost of Gas
Under the Various Portfolios



Exhibits XV-9 and XV-10 illustrate that the average cost of the portfolio is more sensitive to market forces than to structural changes. Due to the fixed cost component of gas resource portfolios, PSE expected this result since average costs are much more sensitive to changes in variable rather than fixed costs. This also illustrates and confirms the earlier conclusion that optimizing the portfolio on a day-to-day basis will more likely have a greater impact in the near-term, pending the more significant resource decisions required toward the end of the decade.

Taken together, these two graphs also illustrate that PSE currently holds and manages a least cost gas resource portfolio. They further illustrate that PSE could optimize the value of this portfolio through growth (or capacity release/optimization) in the short-term and the addition of selected resources around 2010. Since PSE faces no compelling capacity resource decisions in the next few years, PSE did not evaluate the portfolio with the lowest NPV in 2010. Over the next few years, PSE has the opportunity to carefully evaluate and select those resources that will contribute to the least cost portfolio in the latter part of this decade.

Exhibit XV-9
Percent Deviation of Average Cost of Gas
Under the Various Portfolios
From the Base Case Average Gas Cost



To evaluate the sensitivity of these various portfolios to different assumptions, PSE used the model results to develop relative comparisons. PSE did this for the results across the growth scenarios and then the price scenarios. While this analytical approach tends to overstate the near-term risk and understate the long-term risk, it proves useful for illustrating the portfolio sensitivities.[6] Exhibit XV-10 illustrates the variability in the model results for the three growth scenarios using the estimated upper and lower bounds for the projected results.[7] Exhibit XV-11 contains the corresponding illustration for the gas price scenarios. Not surprisingly, PSE found the sensitivity of the average cost in the growth scenarios to be relatively lower than that for the price scenarios.[8]

[6] There were insufficient data points to make calculating standard deviations meaningful, so the total results for the three portfolios were combined.

[7] These bounds were determined for each year as: Base Case \$/MMBtu +/- 1.96(Std. Dev.)

[8] The standard deviations of the average costs of gas for the growth and price scenarios were \$0.315/MMBtu and \$0.605/MMBtu, respectively.

Exhibit XV-10
Sensitivity of the Average Cost of Gas Under Base Case, High Growth, and Low Growth Scenarios

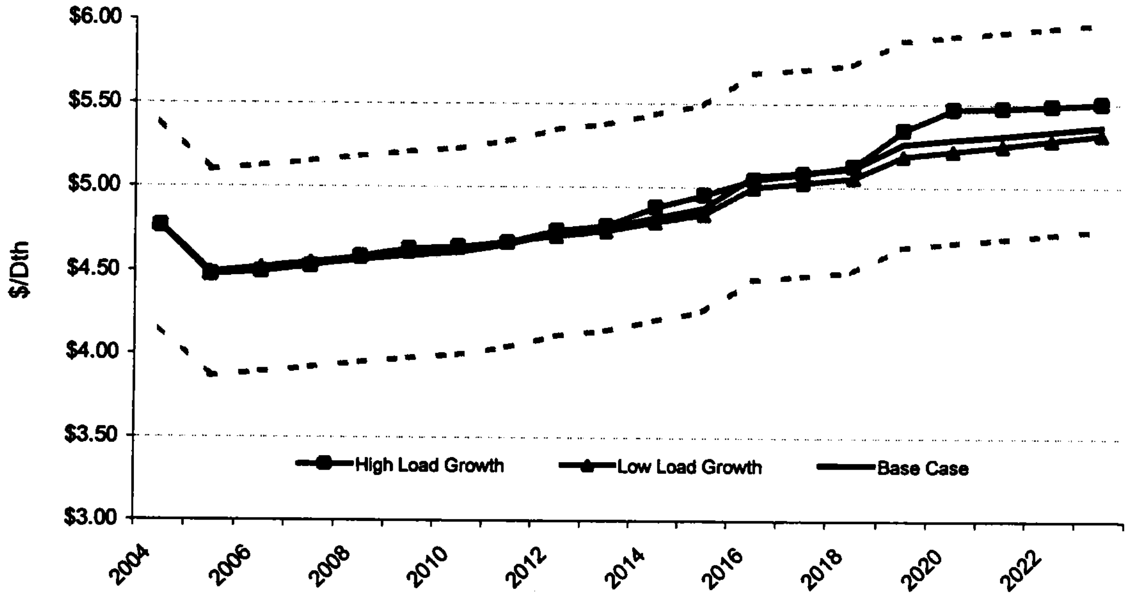
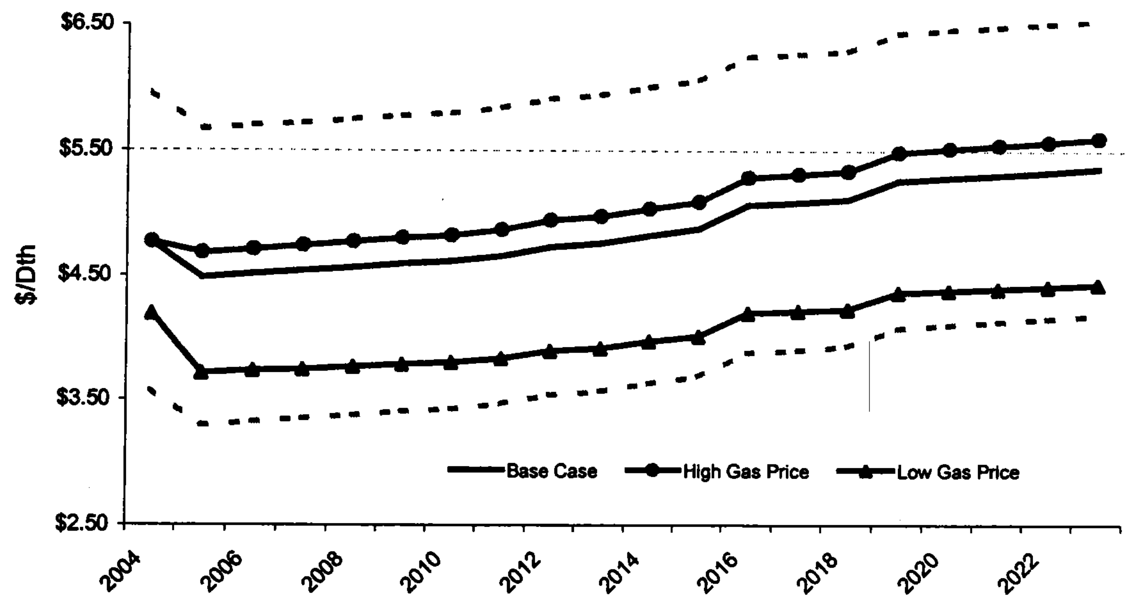


Exhibit XV-11
Sensitivity of the Average Cost of Gas Under Base Case, High Price, and Low Price Scenarios



D. Summary

PSE analyzed its resource portfolio in light of expected changes and under a variety of assumptions. This evaluation demonstrated that PSE has developed and maintains a portfolio of gas resources that provides a reliable supply of natural gas to its customers at least cost. Other key highlights include:

- The analysis demonstrated that there is relatively low risk in the near term due to the portfolio structure, but opportunities exist to enhance the value and reduce the effect of price risk on the portfolio.
- Within the next few years and depending on the growth in firm loads, PSE will face decisions regarding resource acquisitions that change the structure of its portfolio.
- In the interim, it is not cost-effective to terminate any of its pipeline capacity contracts since new capacity is 30 percent higher than existing capacity.
- Further, PSE's demonstrated ability to optimize the gas resource portfolio provides additional benefit to its customers by reducing the risk in the average cost of gas, and extracting the maximum benefit for its customers.
- PSE does not need to make any resource acquisition decisions in the near-term. PSE continues to refine its analysis of resource requirements to ensure that its customers have a reliable, least-cost supply of gas.
- The modeling exercise identified an "ideal", least-cost portfolio structure. Because this portfolio structure relied upon assumptions and forecasted data, PSE understands that the selected portfolio serves as a reference point for its gas resource procurement and management strategy.

XVI

XVI. TWO-YEAR ACTION PLAN

Chapter XVI addresses PSE's two-year action plans, including a review of the action plan from its previous Least Cost Plan, and its new two-year action plan. The chapter begins with a progress report on PSE's previous two-year action plan, providing a status of efforts to date on each of the implementation items identified in the 2000-2001 Gas and Electric Least Cost Plan. Next, PSE provides a two-year action plan to implement the recommended resource strategies found in this current Least Cost Plan.

A. Progress Report of Previous Action Plans

The Least Cost Plan submitted by PSE in 1999 included short-term action plans. The following is a review of PSE's efforts related to previous action plan items. The statements in boldface font style are from the Least Cost Plan filed in 1999.

I. Energy Demand Forecasting

- **Refine the weather adjustment methodology for billed sales to further distinguish temperature sensitivities within the year.**
  The econometric models used to develop forecasts for the current Least Cost Plan account for differences in the effects of weather by season in the case of electric, and by month in the case of gas. This equation specification holds true for residential electric only, and for all gas sectors. Seasonal variation in temperature sensitivity for commercial electric was tested, but the results did not show significant improvement in the equation.

- **Complete the analysis of gas load research data to refine peak day equations.**
  The gas load research data collection process was interrupted by the installation of AMR meters, and the resources devoted to the data collection process were later needed to address general rate case issues. As a result, the gas load research data were not used in refining the gas peak day equations. However, the gas peak day equation was tested for accuracy using more recent observations, and demonstrated that the percent error was within +/-2 percent, about equal to the tolerable meter error in pipeline tariffs.

- **Develop a forecasting module for transportation to account for the effects of business cycles and for the effects of known schedule switching.**

  This task is postponed because the Company's billing system was changed from the Oasis Data Extract Mechanism (ODEM) to Consumer LinX (CLX). Historic billing data are not readily retrievable. Accordingly, PSE decided to wait until the CLX system is completed and new means of extracting data from CLX is developed using the new Client Data Analysis and Retrieval System (CDARS).

- **Implement a database to track large customer consumption and observed fuel or rate schedule switching.**

  This task is postponed because the Company's billing system was changed from the Oasis Data Extract Mechanism (ODEM) to Consumer LinX (CLX). Historic billing data are not readily retrievable. Accordingly, PSE decided to wait until the CLX system is completed and new means of extracting data from CLX is developed using the new Client Data Analysis and Retrieval System (CDARS).

II. Demand Side Management

- **Investigate the use of technology and real-time pricing to enable market-based conservation and load management.**

  PSE's Time-of-Use rate program began in May of 2001 for approximately 300,000 residential customers, and expanded to include 20,000 business customers (primarily on Rate Schedule 24, less than 50 kW demand) in the fall of 2001. PSE terminated the program in the fall of 2002 when recent changes in the program resulted in many Time-of-Use customers paying slightly more in energy bills than they would have on flat rates. Further details on PSE's Time-of-Use program may be found in Chapter IX.

- **Implement the 3-year conservation plan as described in PSE's March, 1999 conservation filing.**

  In 1999, PSE submitted a three-year, joint electric and gas conservation program and received Commission approval in April 1999. 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 33 aMW and 5,645,085 therms, for a combined electricity and natural gas cost of $37,281,352.

Exhibit XVI-1
Energy Efficiency Services Program Results

Year/period	Kwh	therms
1999	35,896,091	916,494
2000	63,863,530	1,785,874
2001	149,452,752	2,381,651
Jan-Aug 2002	42,623,632	561,066
Total	**291,836,005**	**5,645,085**

Few accurately predicted the events and electricity wholesale price escalations of 2000 and 2001. The period of extremely low market prices that initially resulted from deregulation in California gave way in 2000-2001 to extremely high prices, volatility, shortages and blackouts. With close interties with California, an "energy crisis" for the Pacific Northwest also emerged. BPA and many of the region's utilities immediately sought to raise rates, and quickly imposed significant rate increases. 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 significant near-term increases to utility conservation efforts to help manage utility and customer costs.

More broadly, a policy need developed to heavily encourage conservation to help manage energy costs throughout the region. PSE, while not raising electric rates, joined others to ramp up its conservation efforts. One of PSE's most successful tactics was a "time-limited", 10 percent bonus available on commercial conservation grants. This effort in conjunction with daily news headlines of the energy situation no doubt aided customer readiness to adopt efficiency measures during the 2001 period, resulting in a marked, corresponding rise in natural gas efficiency investments.

PSE instituted another company-wide program for five months in 2001. Customers who converted or adapted efficiency measures such that their monthly use was 10 percent less than energy use for the same monthly period in the prior year were offered an incentive of five cents per kwh beyond the 10 percent saved. As the crisis began to moderate, the Commission approved termination of the program.

- **Continue to pursue "fuel-blind" cost-effective conservation programs.**
  PSE, with regulatory support, continues to serve customers by proactively addressing their questions and concerns on energy efficiency and energy management. Customers, whether receiving electricity or natural gas, benefit from a one-stop, comprehensive conservation service. When a customer receives both electric and natural gas service from PSE, the Company informs the customer of eligibility for efficiency services and potential funding for both electric and natural gas end-uses, as appropriate.

- **Continue to support market developments of energy efficiency products and services, to promote customer-driven energy efficiency.**
  PSE routinely reviews findings of the Northwest Energy Efficiency Alliance's Market Research Reports and Baseline Characteristic Studies to help with designing delivery of its local energy efficiency programs. Most recently, PSE has incorporated findings into its lighting, appliances, manufactured housing and new construction offerings. PSE is supplementing funding of the Commercial Sector Baseline Study now underway in the region, with additional sampling underway from commercial buildings in PSE service territory.

  PSE has worked with Northwest Energy Efficiency Council (NEEC) to investigate potential savings from improved maintenance on unitary roof-top systems in medium size commercial facilities. NEEC's membership is comprised largely of mechanical contracting firms interested in promoting energy efficiency to its clients. Three firms expressed interest in participating in a pilot to develop standards, test procedures and demonstrate savings from improved maintenance practices to be offered as a "premium" level service contract. PSE is continuing its investigation in 2003, and comparing its approach with the Alliance's Small Commercial HVAC O&M service Pilot program.

- **Conduct evaluations for conservation programs as appropriate. Support broader-based conservation evaluation, for example at the regional level.**
  Two surveys of Personal Energy Profile participants were completed in March of 2002. Results were consistent with previous findings that found significant numbers of participants were pursuing energy conservation actions. These included energy efficient behavior (e.g. shorter showers), installing low-cost measures (e.g. compact fluorescent

lamps) and using energy efficiency as a purchase criterion for appliances (e.g. clothes washers) and/or home remodeling (e.g. insulation). This survey was conducted during the time PSE's Time-of-Use pilot was in operation and nearly half of the respondents reported shifting energy use to off-peak periods as well as conserving energy use.

PSE conducts follow-up feedback phone surveys for Energy Efficiency Hotline callers and customer feedback continues to qualitatively measure high customer satisfaction with the program. The surveys also enable PSE to make process improvements, specifically to identify additional training for hotline staff. In addition, PSE routinely asks commercial and industrial customers receiving grant funding for Commercial/Industrial Retrofit conservation measures to provide feedback on their satisfaction with the retrofit program, and on the level of service received. PSE's decision in 2002 to significantly increase incentive levels for small business lighting rebates resulted directly from customer and contractor feedback.

PSE supports regional evaluation work by the Northwest Energy Efficiency Alliance, and has used evaluation findings to help assess the energy savings impacts of select measures and market transformation activities. Examples include evaluations of Building Operator Certification, Motor Management, Energy Star Products, EZSim, Magna Drive and the Lighting Design Lab. The Company is represented on the Regional Technical Forum and has adopted many of the regionally developed findings regarding conservation measure energy savings.

- **In cooperation with the Puget Sound Clean Air Agency, investigate benefits of fuel-conversion from wood-burning appliances to natural gas.**
  PSE explored options for offering this program, and presented information to Least Cost Plan stakeholders early in 1999. This program was not pursued.

- **Expand customer access to energy-efficiency information using PSE's web site.**
  PSE's web site has significantly increased the amount of content regarding energy efficiency and energy management. The site includes an online version of the Personal and Business Energy Profile, calculator tools and brochures. Energy Efficiency Libraries for both residential and for business customers have been added. PSE periodically

updates the energy efficiency pages to add additional programs, rebate forms and information. Moreover, PSE plans to enhance navigation and links within the web site.

Additional electronic services include both a quarterly residential (8,000 subscribers) and bi-monthly business (1,100 subscribers) e-newsletters. PSE maintains an email box, energyefficiency@pse.com for customer questions, providing response within 24 hours. PSE provides links from a customer's Personal Energy Management information/graphs to energy efficient tips and ideas.

III. Energy Supply – Electric

- **Continue to move, incrementally, toward more market responsive market supply.**
  Since no new long-term resources were added during the period, PSE had a defacto reliance upon short-term markets. Out of necessity, the Company entered into short-term purchases and sales to balance its portfolio. Relying on the short-term market provided some flexibility and had lower costs than purchasing long-term supplies since long-term supplies carried a premium to current market pricing.

  Prior to 2002, the "market" was more robust, made up of numerous creditworthy counterparties offering an array energy instruments. During this time, new forward market hedge products were being introduced, and there was market liquidity (ability to forward transact 3 to 18 months in the future).

  During this time frame, the Company entered into both market-sensitive contracts and fixed price/cap contracts. PSE purchased market-responsive energy supply under index pricing arrangements for winter delivery period to supplement its portfolio. These index contracts were matched specifically with financial hedge instruments to protect against an extreme winter temperature event causing a price spike. Coupling index-related physical supply with financial price caps allowed PSE to have physical supply on hand to serve customers as well as price insurance of the financial hedges.

  PSE combined index-priced physical natural gas purchase contracts with financial derivatives to pair financial hedges and physical contracts that use the same index as a benchmark price. By separating the physical supply from the financial supply, the company was able to purchase the financial hedge from one party and the physical supply from another. That allowed the company to enter into agreements at the same or at different times, and to purchase from the best supplier in each respective market.

Following the bankruptcy of Enron in late winter 2001 and other developments, there has been significant retrenchment of the "market" as numerous marketers and merchant power producer companies have either gone out of business, or ceased to transact in the Pacific Northwest regional markets. Since then, market liquidity has suffered significantly. PSE's weak credit rating combined with the credit issues of remaining market participants make entering into forward commitments to purchase extremely challenging for PSE. As a result, reliance upon the short-term market, with a growing short position and limited ability to forward hedge, leaves the company and its customers vulnerable to short-term price volatility. As part of this Least Cost Plan, the Company has highlighted the degree of the company's deficit position and explored the benefits of procuring supply for its deficit positions using long-term power purchase agreements and acquisition of resources with much less cost volatility.

- **Continue to develop risk analysis of PSE portfolio management.**
  In 2002, PSE implemented a portfolio screening-testing tool – KW 3000, which is now used to help the Company identify risk exposure in its portfolio. This risk management tool allows the Company to enhance its portfolio analysis. The risk management system is integrated with PSE's physical trade capture and scheduling systems for power and natural gas.

  The risk management group use this system for numerous portfolio management purposes. Outside of risk control needs for deal capture, credit risk management, billing and position reporting, the staff has developed the portfolio management capability of the system so that dynamic position and exposure reports can be generated. The risk system allows PSE to develop a "probabilistic" base case, using certain percentage probabilities and correlations that are inputs to the model. PSE can test its portfolio, not only in a base case environment, but also in scenarios driven by variability unique to its portfolio and the region.

  In order to fully model the portfolio, PSE has integrated external models incorporating hydro risks, wholesale price variability, load changes, plant outage risks, flexible supply contacts, and heat rate valuations of combustion turbines and cogeneration plants. These new models, developed in 2002, give the Company additional tools to test hypotheses and explore the impact of volumetric and market price changes on different parts of its portfolio.

The integration of KW 3000 with the scheduling systems greatly reduces manual data entry, and provides a more stable reporting platform for physical and financial volumetric and price risks.

- **Develop production costing capability in AURORA or another model**
  PSE continues to use AURORA for electric portfolio production costing. AURORA was used to estimate portfolio power costs for the 2001-02 General Rate Case (GRC). A number of enhancements were added during the GRC to the AURORA software and associated databases to extend the ability of AURORA to accurately represent PSE's resource portfolio. These capabilities were used and extended during the preparation of this LCP. The more significant modeling enhancements include: 1) development of software and databases to model PSE's hydro resources under the 60 years of record for the Northwest Power Pool's hydroelectric regulations; 2) added logic to model power purchase agreements unique to PSE; 3) developed data to allow hourly shaping of PSE's power purchase agreements and generating resources; and 4) developed databases and capability to do risk analyses of PSE's resource portfolio.

- **Continue to pursue economic FERC (re)licensing of PSE-owned hydro projects.**
  PSE is currently pursuing the relicensing of three of its hydroelectric projects. The "uneconomic" relicense issued for the White River project has been stayed at PSE's request, and the Company is conducting a collaborative project to identify possible solutions to the economic, recreational and fisheries aspect of the project. PSE has begun a relicensing effort around its Bake River projects utilizing FERC's alternative/collaborative process, and expects to file its license application in 2004.

- **Pursue re-negotiation of Mid-Columbia resource agreements.**
  Late in 2001, PSE finalized new long-term agreements for cost-based purchases of power from the Priest Rapids and Wanapum projects, operated by Grant PUD. PSE's current Priest Rapids and Wanapum purchase contracts expire in 2005 and 2009,

respectively. PSE continues to work with the Chelan and Douglas PUCs toward extension or renewal of its other long-term Mid-Columbia purchase contract, which expire in 2012 and 2018, respectively.

- **Continue to pursue opportunities to reduce costs of existing resource commitments.**

  PSE continues to evaluate its long-term supply contracts to determine cost reduction opportunities in its existing supply commitments. PSE is currently renegotiating a price re-opener in the fuel supply for Colstrip Units 1 & 2 to provide long-term fuel stability and operational cost reductions for these units.

IV. Energy Supply – Gas

- **Investigate increased use of financial instruments for portfolio management.**

  PSE uses financial instruments for gas hedging in both the power and natural gas core portfolios. The most common instrument that PSE enters into is a fixed price financial swap for the physical location that approximates the receipt points under the Company's pipeline transportation contracts. As an example, the Company entered into fixed price hedges for the period of November 2002-October 2003 for the natural gas core portfolio. The hedges were both fixed-price physical transactions and fixed-price financial swap transactions.

  At times there is not a fixed-price financial swap available as a single instrument for the geographical location PSE seeks to hedge. In this case, the Company will enter into a fixed-price financial swap at Henry Hub, and a basis swap contract to lock in the basis for the Pacific Northwest region. Combined, they simulate a fixed-price financial swap.

  Additionally, the Company has entered into some daily price options struck at the first of the month index price, using its storage as a backstop to reduce price exposure. The Company has also entered into basis swaps at two locations to act as a hedge for off-system stales that lock in transportation values for the gas portfolio.

- **Explore city-gate delivery service.**

  There are very few occasions when PSE can release capacity and procure city-gate gas supplies from a third party at a cost savings to using its transportation capacity to move supply from supply source to city-gate. However, there are occasions when PSE can enter into an economically attractive exchange agreement to supply a third party at their requested city gate while that party supplies PSE at its city-gate. PSE has been able to earn a premium for providing baseload supplies (using secondary transport rights), while the counterparty has made baseload deliveries of the same service to one of PSE's system city-gates.

Some holders of long-term NWP capacity have offered end-users and LDCs a fully bundled service of supply, capacity and delivery to the city-gate for limited periods in the winter months. In the future, the option of city-gate delivery service may be a least cost alternative for meeting peak requirements relative to acquiring more storage and/or pipeline capacity assuming consistent availability over time. PSE will continue to evaluate all resource options and select those that meet the Company's least cost and reliability criteria.

- **Perform feasibility study for expanded capacity of Jackson Prairie storage.**
  PSE and other Jackson Prairie owners completed a feasibility study, and have embarked on a further expansion of the storage capacity of Jackson Prairie by removing additional water from the aquifer storage field. This storage capacity expansion is expected to be developed over a period of approximately seven years. The owners are also evaluating the feasibility, economics and timing of further increasing the gas injection/withdrawal capability of Jackson Prairie. (see Chapter XIII for more details on Jackson Prairie).

- **Increase number and scope of business relationships with suppliers, customers, other LDC's and NUG's.**
  PSE seeks to expand its group of gas physical and financial counterparties. In 2001, the Company added 12 counterparties to its list of suppliers for physical and financial gas transactions. In 2002, there have been significant changes in the gas marketing and trading sector in which PSE dropped 10 of its counterparties due to weak financial conditions, and the net number of counterparties added in 2002 totaled 21, increasing PSE's total number of gas physical and financial counterparties to 54. The large number of counterparties is due to the fact that in each discrete region, there are utilities, merchant power producers and NUGs, producers, aggregators, marketers, and

gathering and processing companies. Only some of PSE's counterparties transact in all regions and for all products.

- **Conduct feasibility study of increased LNG capacity for peak load needs.**
  PSE has monitored LNG capacity in wholesale markets but there are no projects currently in Washington, Oregon or British Columbia expected to be placed in service anytime soon.

  For its distribution system, PSE is installing LNG capacity during 2003 at Gig Harbor to increase pressures and delivered volumes to PSE's customers during peak periods. Additionally, the Company has installed compressed natural gas (CNG) to relieve constraints on its system. Approximately 35 sites exist throughout Snohomish, King, Pierce, Thurston and Lewis Counties. PSE can utilize 13 of these sites during a peaking event.

V. Integrated Resource Modeling

- **Continue on-going process of evaluating new gas resource options and alternative resource strategies to meet customer needs.**
  As discussed earlier in this LCP, PSE has continued to review pipeline expansions as well as gas storage and propane-air alternatives to meet future needs. However, since PSE currently has sufficient capacity to meet forecasted needs for several years no new developments are recommended.

- **Continue development of AURORA model databases to better assess the impacts of alternative gas price scenarios, resource costs, and load forecasts on PSE's resource portfolio.**
  As discussed earlier in Section III of this chapter, a number of enhancements have been developed for the AURORA software and the associated data bases to extend the ability of AURORA to accurately represent PSE's resource portfolio.

- **Continue working with AURORA and Uplan-G software developers to better address PSE's resource and policy options.**

An update of UPLAN-G Version 5.01 was provided by LCG Consulting, the software developers, in March 2002. This update corrected some "bugs" in the software. PSE staff have discussed the possibility of extending the risk analysis capabilities of UPLAN-G with LCG Consulting but no firm plans have been made.

VI. Distribution Facilities Planning

- **Continue to evaluate opportunities for lower cost, innovative solutions, which facilitate an appropriate level of system performance at the best long-term cost (such as the TreeWatch and Silicone Injection initiatives).**

  PSE continues to evaluate opportunities for low cost solutions that facilitate system performance. For example, PSE has recently piloted a cost-effective method to reduce animal-related distribution outages in targeted areas.

- **Develop methods for cross-energy solution sets, including cost participation by the beneficiary of the system improvement (off-loading a critical substation by expanding gas usage within the affected area).**

  PSE continues to evaluate fuel switching of customers to address capacity constraints as part of its total energy system planning process. As a long-term strategy where possible, PSE locates new gas and electric facilities nearby to facilitate future fuel switching and distributed generation opportunities.

- **Continue to evaluate distributed resources technologies and consider their impact to both gas and electric plant.**

  As discussed in Chapter VI, PSE has continued to evaluate distributed resources and has developed distributed resource screening tools that identify those projects that facilitate deferral of capital expenditures in a least cost manner.

- **Continue to evaluate historic design conditions and their impact on facility additions.**

  PSE continues to review the historic and continued loading on equipment under design conditions. PSE has begun to review a plan for an increase in facility additions due the impact of loading under design conditions on the aging equipment.

- **Continue to develop system models and other technologies which facilitate more accurate, customer and time-sensitive system evaluations regarding system performance (i.e. Stoner SynerGEE implementation, SCADA, AMR).**

  As discussed in Chapter VI, PSE utilizes distribution system models for both its gas and electric delivery system. PSE's has a mature gas system model that is regularly updated to reflect system changes and new customer additions. PSE's electric system model has been recently created and models the distribution feeder system.

B. Two-Year Action Plan

The following is PSE's two-year "Action Plan" organized by topic area. This lists the steps to be taken over the next two years to implement PSE's recommended long-term resource strategy.

I. August 2003 Update

- Modify Northwest Power Planning Council models and run with PSE data assumptions.
- Provide a detailed measure-by-measure summary of results.
- Assess the practicality of pursuing specific cost-effective measures based on the analysis.
- Incorporate the above results into a revised integrated analysis of supply and demand-side resource alternatives.
- Update PSE resource strategy accordingly.

II. Conservation and Efficiency

- Achieve average annual target of 15 aMW and 2.1 million therms of conservation savings per year for the next 20 years.
- Achieve an additional 2.5 aMW electricity savings from residential and farm customers, supported by Conservation & Renewable Discount (C&RD) credits to electricity supply-side purchases from BPA.
- Promote information, education and training efforts for energy efficiency products, services and practices, in order to support customer decision-making in selecting, purchasing, maintaining and efficiently using equipment, which consumes electricity and natural gas.
- Support local energy efficiency market infrastructure in the communities PSE serves, in addition to continuing support for activities at the regional level through the Northwest Energy Efficiency Alliance.

III. Demand Response Management

- Conduct a fuel-conversion pilot to investigate the cost-effectiveness of residential space and water heating conversions from electric resistance units to high-efficiency natural gas, in order to defer the need for electric distribution system capacity upgrades.
- Investigate the use of natural gas for multi-family units.

- Provide an update of the role of price responsiveness once the Time-of-Use Collaborative has completed its work and provide an update of the outcome of the Time-of-Use collaborative in August 2003 Least Cost Plan update.
- Participate in the Regional CVR pilot program as a demonstration utility, to examine cost-effectiveness of energy savings benefits for the customer and the utility, and well as other impacts.

IV. Renewable Resources

- Continue to study the issues associated with integrating wind resources into PSE's distribution system. In particular, identify and evaluate lower-cost alternatives to the use of new SCGTs to back up intermittent wind generation.
- Explore the feasibility of other renewable resources such as biomass, solar and geothermal energy.

V. Peaking Resources

- Look for lower-cost alternatives to simple-cycle gas turbines (SCGTs), including peaking power supply contracts; and peak-oriented demand response programs.
- Actively participate in regional processes focusing on electric resource adequacy.

VI. Supply-Side Resource Acquisition

- Continue to monitor market opportunities for acquisition of generation assets or power contracts.
- Issue RFP for supply from a large-scale, commercially feasible renewable resources.

VII. Energy Supply – Gas

- Perform detailed analysis of expected long-term supply basin pricing differentials to assist in determination of preferred pipeline alternatives.
- Develop further refinement of the Propane Air options and cost estimates.
- Analyze specific new pipeline projects.
- Explore additional storage options.
- Evaluate the cost and benefits of upstream pipeline capacity.
- Perform feasibility study on expandability of Jackson Prairie storage capacity and deliverability (beyond the current project).

- Examine feasibility of gas reserve ownership as an alternative or supplement to fixed price hedges.

VIII. Energy Demand Forecasting

- Develop more detailed load shape and duration data to facilitate greater optimization of resources and potential for further gas/electric synergies.
- Analyze results of electric to gas conversion pilot program to determine impacts on gas and electric load, and implication for regulatory policy.

IX. Distribution Facilities Planning

- Participate with other EEI utilities in the FERC NOPR process for distributed generation. The FERC NOPR for distributed generation will be issued in the spring of 2003.
- Seek opportunities to deploy distributed generation for least cost capacity deferral.
- Continue the collaboration with the DOE/NREL/GE Universal Interconnect project.
- Track distributed generation technologies and applications that can impact and improve the distribution gas and electric planning process.

X. Integrated Resource Modeling

- Continue on-going process of evaluating new gas and electricity resource alternatives and development of integrated resource strategies to meet customer needs.
- Continue development of databases to support modeling and better assess the impacts of alternative gas price scenarios, resource costs, and loads forecasts on PSE's resource portfolio.
- Continue working with software developers of resource planning models to better address PSE's resource planning issues, resource alternatives and policy options.

A

APPENDIX A
REGIONAL GENERATION PROJECT DEVELOPMENT

In spite of the financial duress currently impacting the merchant sector, a few developers continue to complete projects. Many projects have been put on hold and several have been tabled or cancelled. As part of its overall least cost resource planning efforts, PSE has examined a variety of supply alternatives, including the acquisition of a physical unit operating or under development by a merchant.

Exhibit A-1 provides an alphabetical list of merchant projects proposed in the State of Washington over the next several years. Assuming all of these projects moved forward, they would provide over 10,000 MW. As has been witnessed 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. PSE notes that this project list neither represents facilities of interest to PSE nor all the facilities from which it has collected information, rather it represents an inventory of projects around the state in various stages of development, provided by RDI. With respect to asset acquisitions, PSE has evaluated both in-state and out-of-state alternatives, as well as investigating possible Purchased Power Agreements ("PPAs").

In addition to the development projects, a number of facilities have come on-line over the past 24 months. As illustrated in Exhibit A-2, in 2002, over 1,100 MW of additional capacity has become operational in the State of Washington. Gas-fired capacity comprises a majority of the newly installed capacity.

Exhibit A-3 lists the three plants currently under construction with their expected commercial operation dates.

Exhibit A-1
Proposed Generation Projects in Washington

Facility	Developer	Facility Type	Size (MW)
Bickleton	PacifiCorp Power Marketing, Inc.	Wind	200
Big Horn	PacifiCorp Power Marketing, Inc.	Wind	200
BP Cherry Point Refinery	BP Cherry Point Refinery	CC/Cogen	720
Columbia River 1	Nordic Electric, Llc	Combust Turb	100
Columbia River 2	Nordic Electric, Llc	Combust Turb	100
Cowlitz Cogneration	Weyerhaeuser Co.	CC/Cogen	405
Darrington	National Energy Systems Co.	Boiler/Cogen	15
Everett Delta Power Project	FPL Energy, Inc.	Comb Cycle	248
Frederickson (USGECO)	PG&E Generating Co.	Combust Turb	100
Frederickson (Tahoma)	Tahoma Energy	Comb Cycle	270
Frederickson 2	EPCOR	Comb Cycle	290
Goldendale Smelter	Westward Energy Llc	Comb Cycle	300
Horse Heavan	Washington Winds Inc.	Wind	150
King County Fuel Cell Plant	Fuel Cell Energy Inc	Other	1
Kittitas Valley	Zilkha Renewable Energy	Wind	250
Klickitat	Columbia Wind Power	Waste	80
Longview (MIR)	Mirant Corp.	Comb Cycle	286
Mercer Ranch	Cogentrix, Inc.	Comb Cycle	850
Moses Lake	National Energy Systems Co.	CC/Cogen	306
Plymouth Energy LLC	Plymouth Energy Llc	Comb Cycle	306
Port Of Washington	Continental Energy Services, Inc.	Combust Turb	290
Rainier	National Energy Systems Co.	Comb Cycle	306
Richland (COMPOW)	Composite Power Corp.	Combust Turb	2600
Roosevelt (SEENGR)	SeaWest Energy Group, Inc.	Wind	150
Roosevelt Landfill	PUD No. 1 of Klickitat County	Intern Combust	13
Satsop Combined Cycle	Duke Energy North America	Comb Cycle	530
Satsop Combined Cycle	Duke Energy North America	Duct Firing	120
Seattle (Globaltex)	Globaltex Industries Inc.	Coal	249
Six Prong	SeaWest Energy Group, Inc.	Wind	150
Stateline Wind Project [Wa]	FPL Energy, Inc.	Wind	40
Sumas Energy 2, Inc.	Sumas Energy 2, Inc.	Comb Cycle	530
Sumas Energy 2, Inc.	Sumas Energy 2, Inc.	Duct Firing	130
Sumner (PG&E)	PG&E Dispersed Generating Co.,	Combust Turb	87
Tacoma (Mscg)	Morgan Stanley Capital Group, Inc	Combust Turb	324
Underwood	PacifiCorp Power Marketing, Inc.	Wind	70
Waitsburg	SeaWest Energy Group, Inc.	Wind	50
Wallula	Newport Northwest	Comb Cycle	1000
Wallula	Newport Northwest	Duct Firing	300
Washington (Elcap)	El Cap I	Combust Turb	10

Exhibit A-2
Washington/Oregon Generation Facilities Online in 2002

Facility	Developer	Facility Type	Size (MW)	On-Line Date
Boulder Park	Avista Corp	Intern Combust	25	5/31/2002
Centralia (TRAENE)	TransAlta Energy Corp.	Comb Cycle	248	8/12/2002
Frederickson Power	Frederickson Power (EPCOR)	Comb Cycle	248	8/19/2002
Hermiston	Calpine	Comb Cycle	630	6/1/2002
Klondike	Northwest Wind Power	Wind	25	4/30/2002
Nine Canyon Wind Project	Energy Northwest	Wind	50	9/25/2002

Exhibit A-3
Washington Generation Facilities Currently Under Construction

Facility	Developer	Facility Type	Size (MW)	On-Line Date
Chehalis Power Station	Tractebel Power, Inc.	Comb Cycle	520	Q3/2003
Coyote Springs 2	Avista	Comb Cycle	260	Q3/2003
Goldendale	Calpine Corp.	Comb Cycle	248	Q2/2004

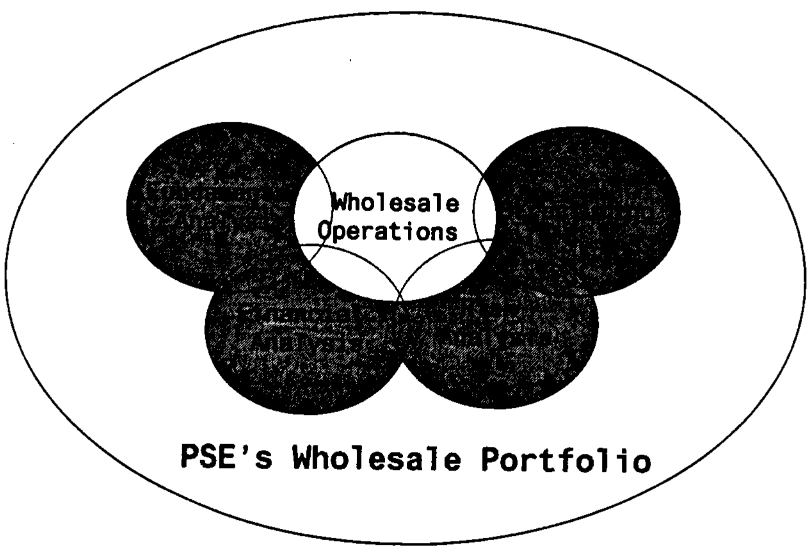
B

APPENDIX B
PORTFOLIO MANAGEMENT PERSPECTIVES

Once PSE has configured its portfolio with a mix of long-term resources, the focus of activity shifts toward the task of near-term operation of the portfolio. These near-term operational functions include portfolio hedging and optimization of the Company's resources. This appendix describes PSE's portfolio management activities more in detail.

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 to ensure a coordinated overall effort with the consistent use of models and theories for multiple purposes. Exhibit B-1 illustrates this dynamic.

Exhibit B-1
Portfolio Management Perspectives



Fundamental analysis pertains to the study of supply and demand factors that influence 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 the single largest uncertainty factors.

Commoditization Of Energy Markets

Supply/demand fundamentals primarily drive commodity prices. Over the last 5 to 10 years, natural gas and electric markets have become 'commoditized' through FERC deregulation of the natural gas pipeline industry and electric power sector. Factors indicating the commoditization of power and natural gas markets include:

- 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-Columbia for power and Sumas, WA for natural gas.
- Standardization of contractual terms for physical power, natural gas and associated financial derivatives.
- Development of 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 include weather (temperature and precipitation), economic conditions, fuel costs, plant heat rates, plant availability, transmission and intertie capacity, hydro energy and storage, biological opinion affecting flows on the river system and spill requirements, new generation capacity and other neighboring regional power market dynamics.

As Exhibit B-2 illustrates, hydro energy comprises the largest share of power generation in the Pacific Northwest, making hydro energy availability the single largest source of variability in PSE's energy portfolio. The cost of hydro energy is extremely low, relative to market-based replacement power. The percentage change in any given year from normal hydro output provides a meaningful number for PSE's portfolio (between 5,600,000 and 9,800,000 MWh). As a result, hydro analysis proves important. However, 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. PSE gathers information 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.

Exhibit B-2
Northwest Power Pool Area (U.S. Systems) Capacity By Fuel

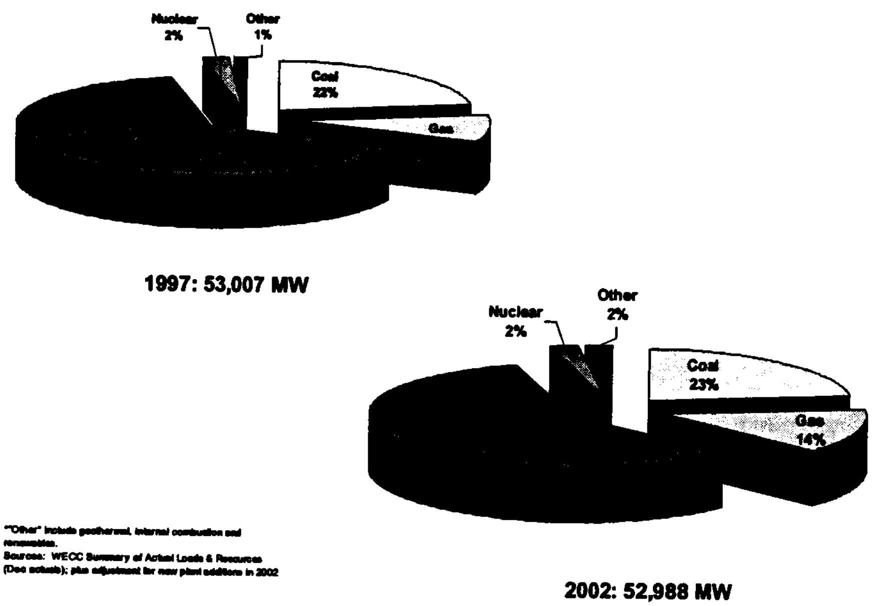
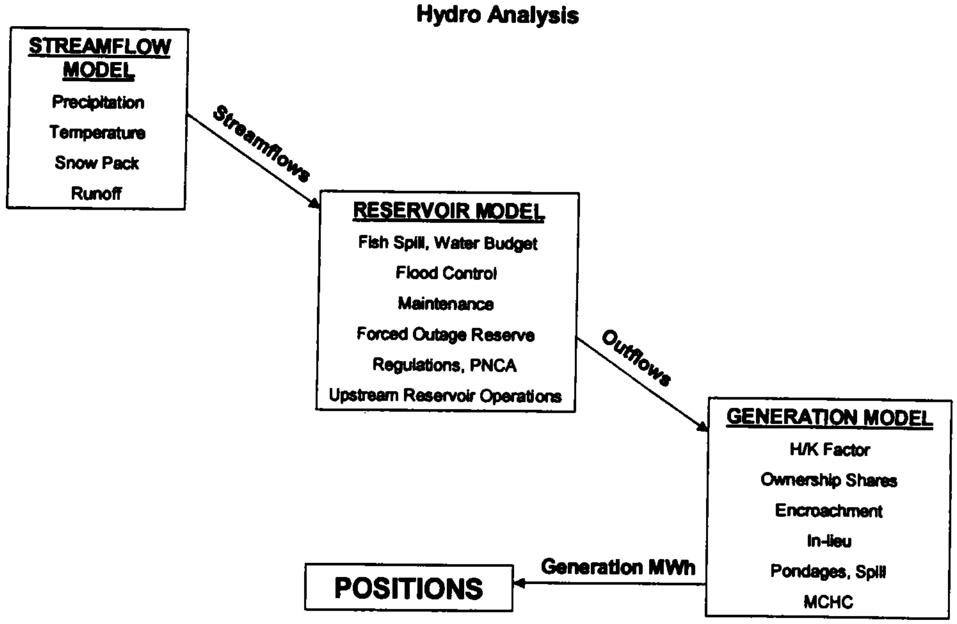


Exhibit B-3 illustrates PSE's hydro modeling process. The precipitation information feeds a "Streamflow Model" which feeds a "Reservoir Model" that subsequently models fish spill, flood control, forced outages, regulation and other factors affecting outflows of water. The Generation Model – the last piece of the modeling effort – allows PSE to forecast available energy for the

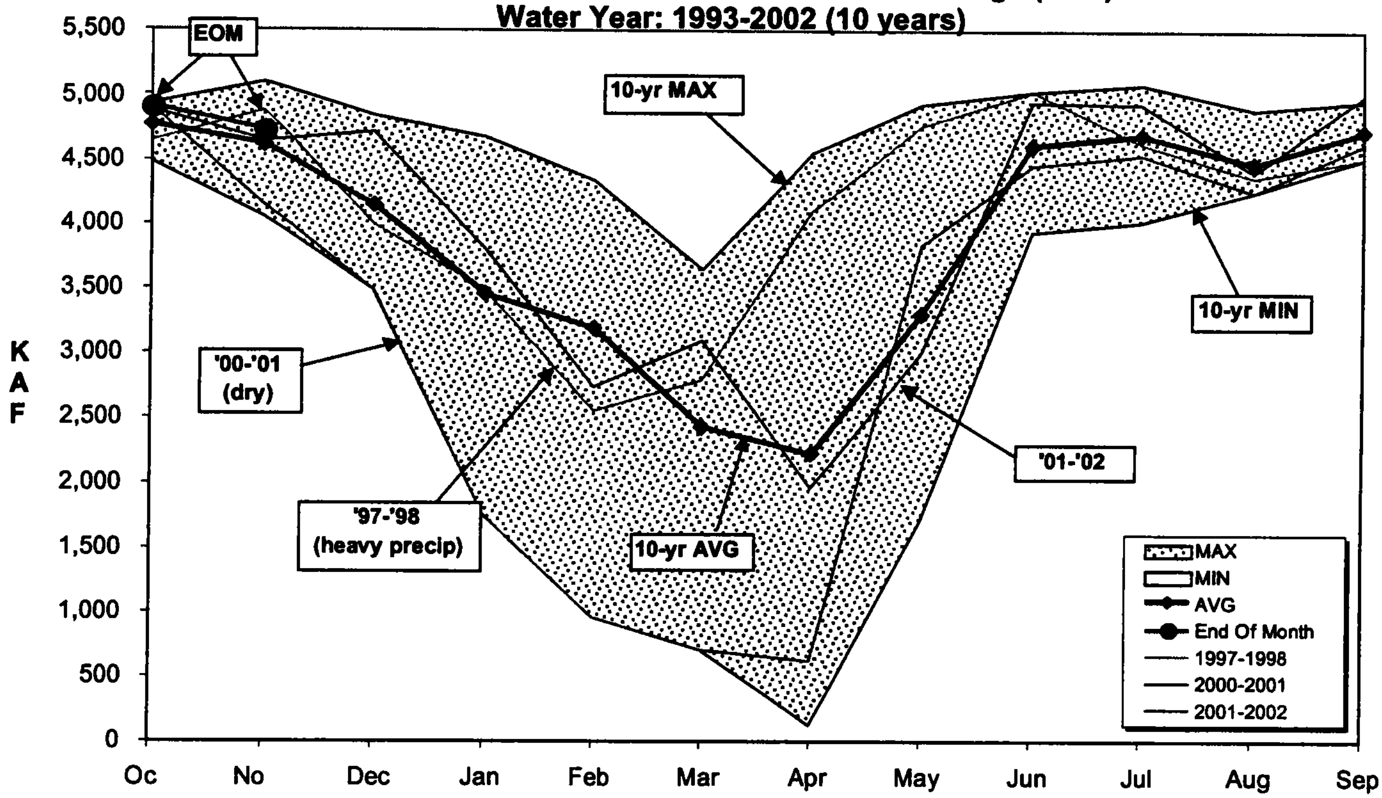
Exhibit B-3
Hydro Analysis



base case position. The final stage, which the Company is just now completing, involves taking the base case forecast and running 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.

Hydro reservoir storage provides 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 factors, in addition to plant outages, weather reports, and spot fuel prices enable PSE to understand what energy comes into the market, and the relative changes by day and through the current month of energy costs. Exhibit B-4 illustrates historical reservoir levels.

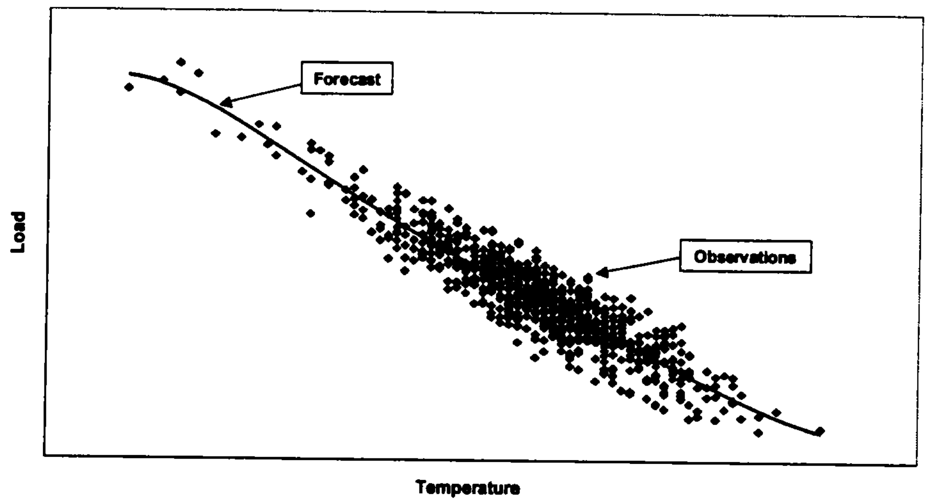
Exhibit B-4
End-Of-Month Grand Coulee Reservoir Storage (KAF)
Water Year: 1993-2002 (10 years)



Source: USBR

Load, driven by customer count, temperature and economic conditions, represents the next largest source of variability in PSE's Power portfolio. The Energy Risk Management group models expected average load, and then develops a forecast range for necessary minimum and maximum loads to model variability for exposure testing. PSE's challenge focuses on having 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.

Exhibit B-5
Load Versus Temperature Relationship



PSE's load has an 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 double peak of PSE's load profile further complicates hourly management of its load profile.

Exhibit B-6
Peak Load Analysis and Planning

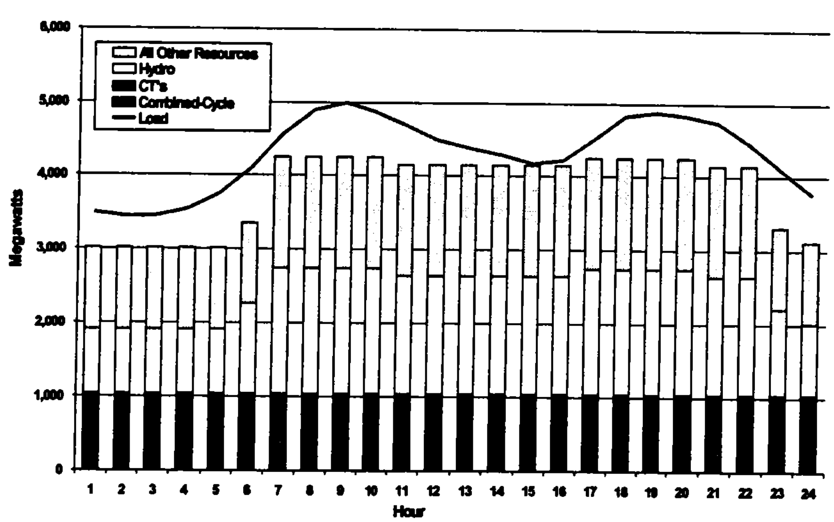
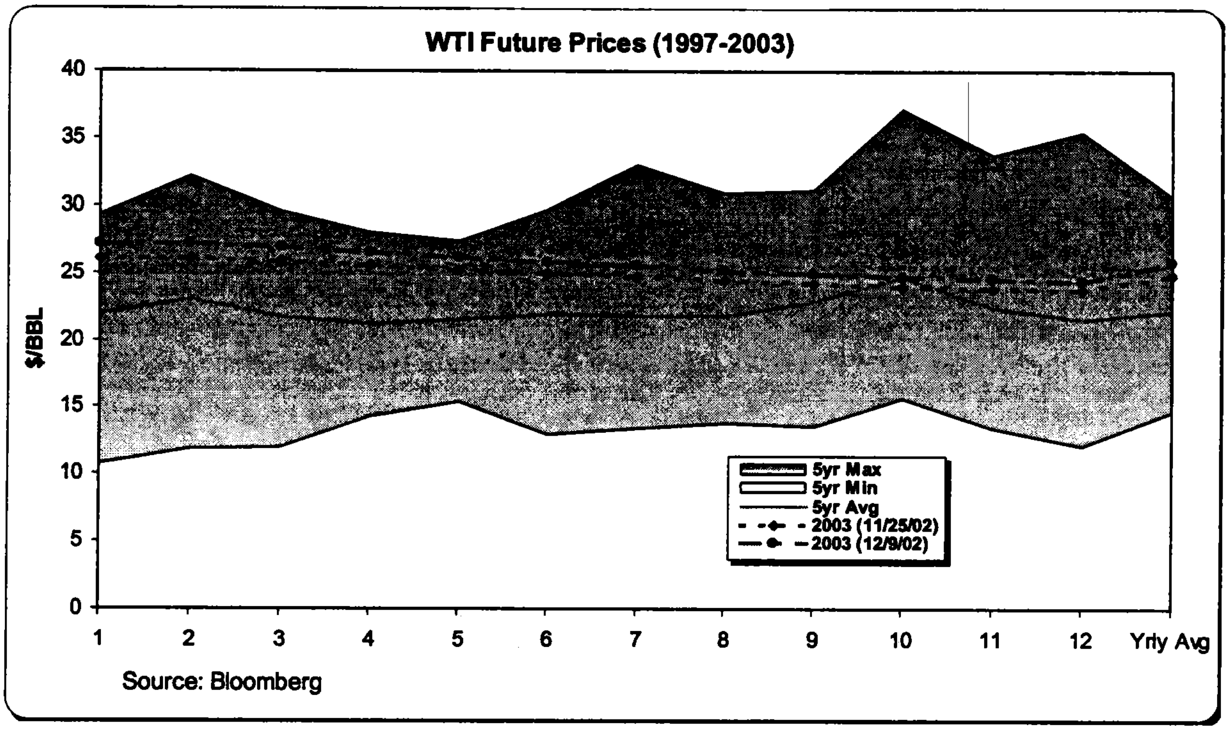


Exhibit B-6 illustrates a typical load picture over a 24-hour period. PSE's hydro storage provides a critical resource for balancing the resource and loads on a short-term basis. The Company has storage both at its Baker facilities and through its Mid-Columbia contracts.

Natural Gas Market Drivers

Natural gas represents a growing part of the generation mix in the Pacific Northwest, with similar market drivers as the power market. 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.

Exhibit B-7



As Exhibit B-7 illustrates, oil prices are strongly linked to natural gas prices. This occurs for a couple of reasons. 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 and 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', with an 8- to 18-month lag time between drilling and gas coming to market. PSE tracks rig counts to monitor the longer term increasing or decreasing supply trends.

Storage inventories provide an important gauge to natural gas supply/demand imbalances. The natural gas industry uses salt caverns and depleted oil wells as underground storage facilities. The relative level of inventory acts 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 also serve as important determinants in price volatility. PSE's gas load is predominantly heating load-based, with extreme sensitivity to variations in load on account of changing weather patterns. PSE monitors weather patterns from several sources including local weather stations, the national weather service and through a weather subscription with Weatherbank.

Credit Risk Management

PSE faces significant constraints executing wholesale transactions in short-term and medium-term power and gas markets, due to several factors. One, the markets have become less liquid with fewer parties transacting, and the forward time frame shrinking to shorter-term delivery periods. Two, default risk has become a concern, 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. This 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, scaled back for strategic purposes, stopped trading altogether in North America (Aquila, Dynegy), or simply cannot transact because of their weak credit rating. This liquidity situation has several implications. Forward hedging becomes much more difficult, with PSE being 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. PSE faces challenges in displacing and dispatching its generation units to respond to all price opportunities due to the market liquidity problem.

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, now have concerns over PSE's credit rating. By example, a surprising number of natural gas producers are reluctant to sell at a fixed price to PSE due to concerns over 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. Exhibit B-8 provides the KWI explanation for the Risk Analysis module.

Exhibit B-8

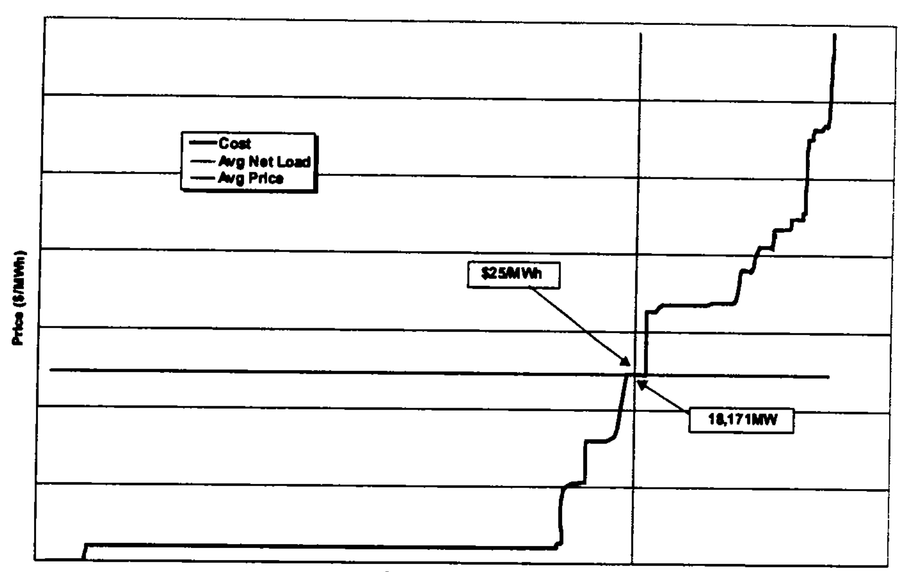
Risk Analysis Model

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. These 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.

Exhibit B-9
Fundamental Analysis Example:
Forecasting Regional Supply and Demand



The intersection of projected load and the resource stack produces the theoretical market-clearing price. PSE does not use the model as 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 includes assumptions about estimated load, transportation requirements, storage requirements and an estimated market value for unused capacity.

PSE Approach To Managing Price Risk

Risk management is the process of using financial tools to manage price volatility, and volumetric risks in power and natural gas profiles. Risk management tools can also be used to bring certainty to a given outcome, or "hedge." PSE bases the decision to hedge, and evaluation of a hedge, on the information known at the time that the hedge was put on, not on the market conditions that might exist when the hedge was recognized. In fact, existing market conditions when the hedge was recognized prove to be irrelevant because the desired outcome was achieved, with some other party bearing the market risk. When combined with its least cost planning process, PSE's risk management efforts stabilize the average cost of gas to its firm customers, but there is a cost incurred in managing the risk.

PSE uses risk management to enhance the value of the physical, portfolio optimization transactions, and those transactions used to supply its firm customers, within a defined risk framework, however, it does not maintain any speculative positions. All of the financial risk management transactions correspond to underlying physical transactions. The risk management transactions require PSE to buy and sell power and natural gas and basis positions on various exchanges or in over-the-counter (OTC) markets. For example, fixed and forward prices are used to lock in the value of storage injections or future gas purchases. PSE primarily uses fixed/floating swaps to manage the value of index-based gas sales or purchases.

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

- Providing price certainty and locking down risks
- Keeping prices stable and minimizing costs

PSE has internal risk management processes to help bring focus and order to the energy risk management function. For power, Energy Risk Management staff develop 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, with 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.

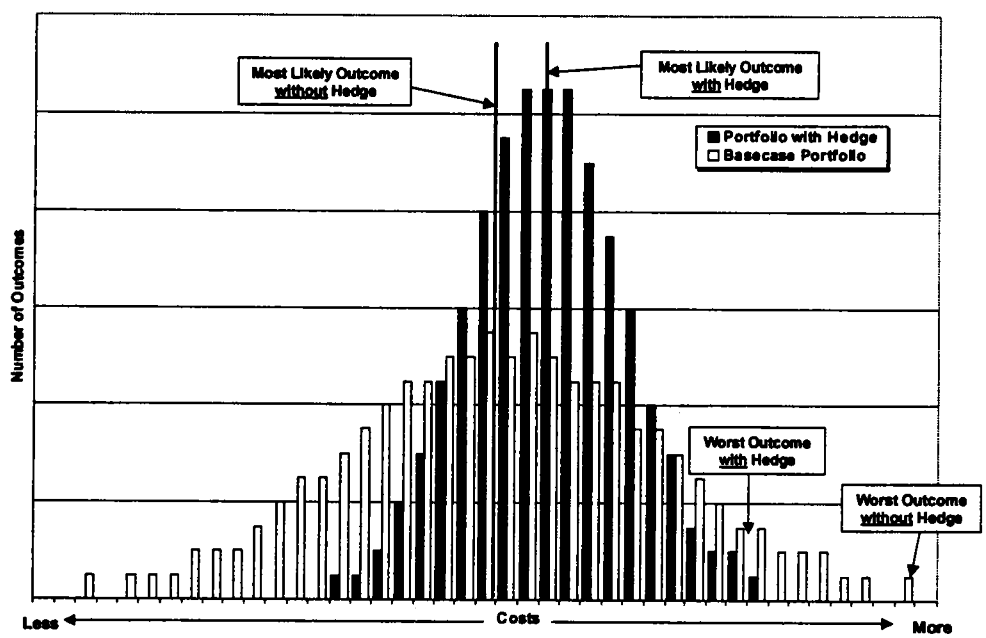
This information results in a position report that illustrates the net open position for every month for power and natural gas. The positions are generated for 12-24 months out in time. Next, the energy risk management staff evaluate the forward positions, and explore which of them have significant forward 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 through evaluating a wide range of deal structures. 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 include 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.). PSE seeks to identify a strategy not only for the base case, but also for other scenarios. Sometimes the "winning" strategy proves not to be 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. Exhibit B-10 shows a histogram of what a hedge strategy ideally does in terms of reducing outlier risks and not moving expected outcome (the mean) too much as a result of the hedged cost.

Exhibit B-10
Portfolio Risk Analysis
Measuring cost of Hedging versus Risk Reduction



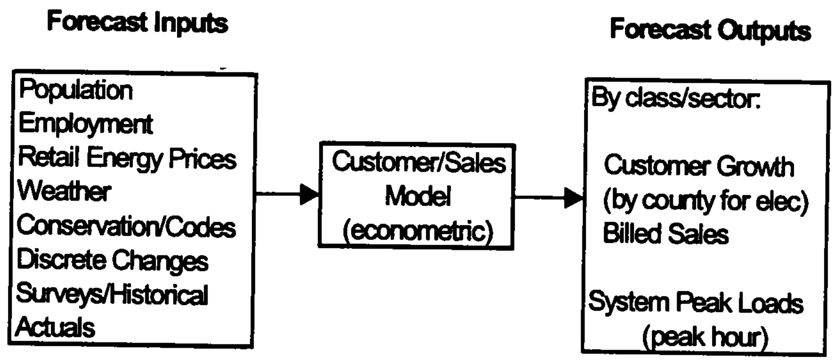
PSE monitors how the hedge costs affect the bottom line costs. PSE sets a budget for power costs at the beginning of the year. This includes hedging costs, as well as operating costs. Hedge costs need to be taken into consideration so the hedge costs do not move the expected value or outcome too much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

C

APPENDIX C
LOAD FORECASTING METHODOLOGY

Billed Sales and Customer Count Forecast Methodology

Exhibit C-1
PSE Econometric Forecasting 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 for electric, base 65 for gas) and CDDs (base 75 for electric); cycle adjusted HDDs/CDDs are created to fit consumption period implied by the billing cycles

  Prices - $/kwh for electric or $/therm for gas (constant 2000$, or the relative gas to electric price)

  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)

- **Billed Sales** = Use per customer, multiplied by customer counts

Different functional forms were used depending on the customer class. For the electric residential use per customer equation, a semi-log form was 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 was used for the other sectors, again with explanatory variables entering in a lagged form. Use of lagged explanatory variables in the equations account for changes in prices or economic variables that have both short-term and long-term effects on energy consumption. For gas, most of the use per customer equations have a linear form with prices or economic variables entering in polynomial distribution lagged form again.

The equations were estimated using historical data from January 1993 to March 2002, depending on the sector and fuel type. Electric billed sales from the data centers in the commercial sector were not included in the commercial equations. The forecast of electric billed sales from the data center was based on discussions with the customers and their planned capacity additions in the next few years. The electric industrial equations were estimated using data from January 1996 to March 2002. Note that the industrial use per customer and customer count 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 electric billed sales of these customers from the total industrial billed sales. However, a separate equation was 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 electric resale also accounted for the Seatac airport leaving the system.

Exhibit C-2, based on the estimated coefficients for the retail prices in the use per customer equations, provides the computed long-term price elasticities for the major customer classes for electric and gas.

Exhibit C-2
Long-Term Price Elasticity For Major Customer Classes

	Electric	Gas
Residential	-0.19	-0.14
Commercial	-0.21	-0.21
Industrial	-0.17	-0.24

All of the estimated price coefficients are also statistically significant.

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

The billed sales forecast was further adjusted for discrete additions and deletions 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 were obtained after accounting for own use and losses from transmission and distribution.

Electric Peak Hour Forecast

PSE obtains normal and extreme peak load forecasts through the use of 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. Since the historical data includes periods when large industrial customers left the system, the equation also accounts for this change in historical series. Finally, PSE allows the impact of peak temperature on peak loads to vary by season. This specification allows for different effects of residential and non-residential loads on peak demand by season, with and without conservation. 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.

PSE estimated the equation using monthly data from 1991 to 2001 resulting in coefficients which are statistically significant from zero and an R-Squared of 0.96. The standard error is about 2.9 percent of the forecast. To obtain the normal and extreme peak load forecasts, PSE factors the appropriate design temperatures into the equation for either condition. For PSE, these design temperatures are 23 degrees for normal peak and 13 degrees for extreme peak, both occurring in January.

Gas Peak Day Forecast

PSE uses the following equation to represent peak day firm requirements:

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

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

The design peak day requirements for this forecast are based on the company's historically coldest day in the last 20 years as measured at SeaTac Airport, containing 51 degree days (14°F average temperature, 24 hour, which occurred on February 2-3, 1989).

PSE determined the peak day requirements for the year by applying the above equation to the design, peak day degree days in January. The heating load per customer per degree day was derived from regression analysis of the actual billed sales per customer per degree day by customer class for the five winter months (November—March) over the last five years versus the respective monthly heating degree days. This resulted in regression equation coefficients that describe the relationship of use to monthly heating degree days for each of the major firm class customers. The estimated coefficients were statistically significant while the R-squared were greater than 0.95. The estimated standard error is about 3.2 percent of the forecast in January for all firm classes. Previous non-base load methodologies focused on a single HDD series. This provided an annual average temperature response, likely over-estimating shoulder periods and under-estimating peak periods. This method was not consistent with declining annual per customer consumption. The newer approach focuses on isolating responses attributable to each month. Hence, 12 HDD series have been implemented, one for each month. In this approach, January has the largest temperature coefficient, the greatest temperature sensitivity and therefore more likely to experience the design day. This also allows PSE to evaluate if there appears to be any changing temperature sensitivity over time due to conservation or other factors, observed in the peak month. There does appear to be a declining trend in heat sensitive loads for residential customers, but not other customer groups at this time.

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

Large volume customer daily contract demand was estimated from January, rather than from August. These data tend to have a seasonal shape, with interruptible customers taking more in January. The per customer January 2002 value is simply held constant over the forecast horizon, and multiplied by customers to form large volume peak demand. These data are added with their respective category, either commercial core or industrial core.

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 for forecasting Billed Sales. 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 exhibit trends over time (customer growth) the data have 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 favor 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

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

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 Exhibit C-3.

Exhibit C-3
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 degrees at SeaTac Airport. Based on historical temperature data at SeaTac, there is a 50 percent probability of the minimum hourly temperature during the winter months being 23 degrees 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 in Exhibit C-4. 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 percent per year) is slightly higher than the growth in energy (about 1.4 percent per year) since residential energy load is growing faster than non-residential energy loads and the residential sector has a larger contribution to peak.

Exhibit C-4
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

D

APPENDIX D
CONSERVATION AND EFFICIENCY

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 invested heavily in conservation programs, encouraging efficiency use by customers. Utility new construction programs of the 1980's largely resulted 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 strong working partnership with the Community Action Agencies in the communities it serves.

Recent History

During the mid-1990s, utilities invested less in demand-side resources due to uncertainty over future deregulation in the electricity industry. Electric and gas avoided costs were significantly lower than they had been up until that time, with many anticipating restructured electricity markets to produce lower prices. 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 beginning to actively target 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 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 beginning, 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. Business interests – particularly of large consumers who viewed deregulation as a way to lower energy costs for their "bulk" purchases – were influential. The Review committee addressed "public purpose" issues, including conservation, low-income assistance and renewable resources. From this committee's recommendations, the idea of "market transformation"(MT) emerged as another potential cost-effective method to get customers to invest in efficiency on their own. The philosophy driving market transformation held that through 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. Regional utilities created the Northwest Energy Efficiency Alliance ("Alliance"), with PSE as a major funding provider. The Alliance has pursued notable recent efforts such as accelerating consumer adoption of compact fluorescent lamps and horizontal-axis washing machines.

The PSPL merger with WNG in 1997 provided PSE the opportunity to offer "fuel-blind" conservation/energy efficiency programs. Instead of being sent to the "other" company, customers now benefit from a one-stop, comprehensive conservation service. PSE is indifferent to whether a customer upgrades efficiency of an electric heating system or converts to natural gas.

Initially, Puget's cost-recovery of cost-effective conservation resources were added to rate base, and amortized over 10 years. Rates allowed for a premium of plus two percent on the allowed rate of return for all unamortized conservation balances. To an industry facing deregulation, this financing method, which often created outstanding debt, could be an obstacle. 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. Two years later, PSE offered a second bond offering of $35 Million. WNG, by comparison, relied on a "tracker" mechanism; whereby costs spent on conservation were collected as an expense in the year following the year of expenditure. 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 deregulated California market, complete with rolling blackouts. The Pacific Northwest had close electricity interties with California, making a regional energy crisis 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, a societal need existed to heavily encourage conservation as a means to 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, an additional 20,000 business customers were added to the pilot. While the program set out to reward customers who used energy efficiently, the Company determined in fall 2002 that further analysis and restructuring of the program was needed to enhance customer value. The WUTC recently approved PSE's request to terminate the program.

Exhibit D-1 provides a detailed look at PSE's existing electric conservation programs and Exhibit D-2 provides a list of gas conservation programs.

Exhibit D-1
Current Electric Conservation Programs

PROGRAM NAME	DESCRIPTION Sept. 2002 – Dec. 2003 Conservation Programs	EXPECTED ANNUAL ENERGY SAVINGS
Energy Efficiency Information Services – Personal / Business Energy Profile	• Free energy audit survey, analysis, and report providing customers with specific and customized energy efficiency recommendations. • Identifies current energy costs and consumption by end-use, and provides a list of specific recommendations for energy efficiency opportunities with savings estimates. • Home version is available as a mail-in booklet. Home and business versions are available online at pse.com.	• While surveys indicate customers take actions as a result of these programs, no energy savings are currently credited to information programs. • Information programs cannot exceed 10% of the total conservation program budget.
Energy Efficiency Information Services – 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. • Discuss the potential benefits of various conservation programs and related products and services including contractor referrals. • Answer 3,000 customer inquires per month, including 150 e-mail messages.	• While surveys indicate customers take actions as a result of these programs, no energy savings are currently credited to information programs. • Information programs cannot exceed 10% of the total conservation program budget.
Energy Efficiency Information Services – Energy Efficiency Brochures	• Brochures on program participation guidelines and how-to guides on energy efficiency opportunities, including behavioral and low-cost measures, weatherization measures, appliance and equipment upgrades. • Includes investment and savings estimates as appropriate. • Available hard-copy through mail, at trade show and publicity events; available for download at www.pse.com.	• While surveys indicate customers take actions as a result of these programs, no energy savings are currently credited to information programs. • Information programs cannot exceed 10% of the total conservation program budget.
Energy Efficiency Information Services – On Line Services	• Sections of PSE's web site are dedicated to energy efficiency and energy management information, program details and application instructions. • Online Personal and Business Energy Profile energy audits, calculator "tools", and energy libraries are available for registered PSE customers.	• While surveys indicate customers take actions as a result of these programs, no energy savings are currently credited to information programs. • Information programs cannot

Exhibit D-1
Current Electric Conservation Programs

PROGRAM NAME	DESCRIPTION Sept. 2002 – Dec. 2003 Conservation Programs	EXPECTED ANNUAL ENERGY SAVINGS
	• Free, periodic PSE energy efficiency e-newsletters for residential and business subscribers. • An Energy Efficiency e-mail box is available for customer questions, featuring maximum 24-hour turn around.	exceed 10% of the total conservation program budget.
Residential Energy Efficient Lighting Program (includes a portion of C&RD funding)	• *Retail Incentive Program* – Participating retailers and lighting showrooms (approximately 350 retail stores) deduct $3 from the cost of Energy Star CFL bulbs or $10 from a qualifying Energy Star fixture at the time of purchase, when presented with a PSE coupon. Customers receive coupons with their bill and may request additional coupons through the energy Hotline. Coop promotion with Home Depot, Costco, Bartells and others. • *New Construction/Remodelers* – Builders receive rebates on qualifying Energy Star CF fixtures installed in new single-family and multi-family residences, indoor and outdoor fixtures. • *Cross Promotional/WEB Incentive* –Rebates (e.g. CFL bulb) to encourage participation in programs such as online energy-use analysis tools.	• 36,901 MWh (4.2 aMW) • 7-year resource
LED Traffic Signals	• Rebates to traffic jurisdictions installing energy efficient red, green and walk/crossing LED traffic signals. • Unmetered traffic-signal accounts must document all connected load at the intersection to request a bill adjustment. • Partner with Association of Washington Cities.	• 2,027 MWh (0.2 aMW) • 6-year resource
Small Business Energy Efficiency Programs	• Rebates for energy-efficient fluorescent lighting upgrades and conversions, lighting controls, programmable thermostats, and vending machine controllers. • Streamlined incentives for small usage commercial businesses receiving electricity under Rate Schedule 24 (<50kW demand).	• 3,333 MWh (0.4 aMW) • 10-year resource
Commercial & Industrial Retrofit Program	• Incentives in the form of grants to commercial and industrial customers are available for cost-effective energy-efficient upgrades including HVAC, water heating and refrigeration equipment, controls, process efficiency improvements, lighting upgrades, and building thermal improvements. • PSE engineers work with customers to assess energy savings	• 73,063 MWh (8.3 aMW) • 12-year resource

Exhibit D-1
Current Electric Conservation Programs

PROGRAM NAME	DESCRIPTION Sept. 2002 – Dec. 2003 Conservation Programs	EXPECTED ANNUAL ENERGY SAVINGS
	opportunities, approve project proposals, recommend bid specifications, review contractor bids and verify installations prior to grant payment. • Includes an HVAC Premium Service project, using specially trained maintenance contractors to optimize efficiency of packaged roof-top HVAC equipment. • Also for electric customers, provide grants for farm motors and processes, with funding support from CR&D.	
Commercial & Industrial New Construction Efficiency	• Incentives in the form of grants to commercial and industrial customers are available for cost-effective energy-efficient building components or systems, including HVAC, lighting, water heating, process and refrigeration equipment, controls, building design and thermal improvements, which exceed requirements of the Washington State Energy Code (NREC) by 10% or more. • Also provides funding toward cost of building commissioning beyond code requirements. • PSE Energy Management Engineers work with designers, developers, commissioning agents, owners and tenants (when available)of new C/I facilities, or major remodels, to propose cost-effective energy efficiency measures. • Funding may be provided using a prescriptive measure approach or a whole building approach.	• 1,333 MWh (0.2 aMW) • 20-year resource
Large Power User Self-Directed Program	• Incentives up to 87% of the Sch. 120 Conservation Rider revenues contributed to PSE's Conservation Program, for eligible 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, with PSE engineering staff evaluating proposals for cost-effectiveness.	• 20,000 MWh (2.3 aMW) • 12-year resource
Resource Conservation Manager (RCM) Program	• PSE supports customers who employ a RCM to implement low-cost/no cost energy saving activities with building occupants and facility maintenance staff. • Responsibilities include detailed accounting of resource consumption	• 26,667 MWh (3 aMW) • 3-year resource

Exhibit D-1
Current Electric Conservation Programs

PROGRAM NAME	DESCRIPTION Sept. 2002 – Dec. 2003 Conservation Programs	EXPECTED ANNUAL ENERGY SAVINGS
	(electricity, gas, water, sewer, recycling, etc.), costs and savings estimates. • PSE provides training, accounting tools, network meetings, review of reports and electronic data downloads.	
PILOT Programs – Fuel Switching Pilot	• Incentives toward the cost of converting electric space and/or water heating equipment to equipment fueled by natural gas. • PSE determines residential customers eligibility by targeting geographic areas where the cost of adding electric infrastructure would exceed making natural gas available to the residence.	• 4,600 MWh (.5 aMW) • 20-year resource
PILOT Programs – Residential Duct Systems Pilot	• Participating customers receive the duct diagnostic measurement services and sealing services from the certified contractor at no cost. Targets residences with central forced air electric or gas heating systems. • As this technique is new to the industry, this program provides technical support, contractor training and marketing assistance to contractors.	• 353 MWh (<0.1aMW) • 10-year resource
Market Transformation Programs – NW Energy Efficiency Alliance	• PSE is a major financial supporter of the Northwest Energy Efficiency Alliance, and serves 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.	• 20,000 MWh (2.3 aMW) • 10-year resource life • Electrical energy savings acquired at the Regional level, allocated to individual utility service territories. Most activities expected to transform market behavior, providing significantly longer efficiency impacts.
Market Transformation Programs – Local Infrastructure & Market Transformation & Research	• PSE funds specific energy efficiency initiatives and/or organizations committed to accelerating the adoption of energy efficiency in the marketplace, including research activities for which PSE may not have a related program in place.	• No savings are credited for these efforts.
Public Purpose Programs – Energy Education 6-9th Grade Environmental Education, "Powerful Choices"	• Conservation school-age education program funded by PSE, along with 26 other utilities, cities, and agencies responsible for energy, water, and environmental programs in the Puget Sound area. • Currently, in 70 schools with a reach of over 12,000 students 6th-9th	• 1,773 MWh • 0.2 aMW

Exhibit D-1
Current Electric Conservation Programs

PROGRAM NAME	DESCRIPTION Sept. 2002 – Dec. 2003 Conservation Programs	EXPECTED ANNUAL ENERGY SAVINGS
	grade students. • Provides comprehensive energy and environmental curriculum, teaching students how to apply principles and make informed choices on energy, air quality, water and solid waste.	
Public Purpose Programs – Residential Low-Income Retrofit	• Funding (up to 100% where cost-effective) for installation of home weatherization measures for low-income gas and electric heat customers. • Customers in single family, multifamily, and mobile home residences are qualified by local community action agencies, using federal income guidelines. • Also includes structure audits and energy use education.	• 2,608 MWh • 0.3 aMW
C&RD Programs – Green Power	• All customers can purchase green power directly on their monthly energy bill at $2 per 100 kWh block, with a two-block minimum purchase. • Recommended purchase is 10% of energy bill, representing $6 per month, or 3 blocks for typical residential user. Business customers can use purchases to help offset other environmental impacts.	• 34,585 "Green Tags" through Dec. 2003, to fund 0.4 aMW renewable resources sited in the Pacific Northwest
C&RD Programs – Residential New Construction Lighting Fixtures	• Rebates for qualifying Energy Star light fixtures are under development, and will be available for both retrofit and new construction electric customers through participating retailers.	• 2,832 MWh (0.3 aMW) • 15-year resource
C&RD Programs – Residential Energy Star Appliance	• Rebates for Energy Star clothes washers ($35) and Energy Star dishwashers ($20) for customers who purchase electricity from PSE; customers may also purchase natural gas. • Additional rebates may be available from customer's water utility. • Rebates offered at 140 participating retailers.	• 2,092 MWh (.2 aMW) • 12-year resource
Energy Efficient Manufactured Housing	• $300 rebate to the buyers of qualifying Super Good Cents/Energy Star labeled manufactured homes with electric heat, sited in PSE electric service territory. • Parallel with regional programs (NEEA), Washington Manufactured Housing Association.	• 1,456 MWH (0.2 aMW) • 30-year resource

Exhibit D-2
Current Gas Conservation Programs

PROGRAM NAME	DESCRIPTION Sept. 2002 – Dec. 2003 Conservation Programs	EXPECTED ANNUAL ENERGY SAVINGS
Energy Efficiency Information Services – Personal / Business Energy Profile	• Free energy audit survey, analysis, and report providing customers with specific and customized energy efficiency recommendations. • Identifies current energy costs and consumption by end-use, and provides a list of specific recommendations for energy efficiency opportunities with savings estimates. • Home version is available as a mail-in booklet. Home and business versions are available online at pse.com.	• While surveys indicate customers take actions as a result of these programs, no energy savings are currently credited to information programs. Information programs cannot exceed 10% of the total conservation program budget.
Energy Efficiency Information Services – 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. • Discuss the potential benefits of various conservation programs and related products and services including contractor referrals. • Answer 3,000 customer inquires per month, including 150 e-mail messages.	• While surveys indicate customers take actions as a result of these programs, no energy savings are currently credited to information programs. Information programs cannot exceed 10% of the total conservation program budget.
Energy Efficiency Information Services – Energy Efficiency Brochures	• Brochures on program participation guidelines and how-to guides on energy efficiency opportunities, including behavioral and low-cost measures, weatherization measures, appliance and equipment upgrades. Includes investment and savings estimates as appropriate. • Available hard-copy through mail, at trade show and publicity events; available for download at www.pse.com.	• While surveys indicate customers take actions as a result of these programs, no energy savings are currently credited to information programs. Information programs cannot exceed 10% of the total conservation program budget.
Energy Efficiency Information Services – On Line Services	• Sections of PSE's web site are dedicated to energy efficiency and energy management information, program details and application instructions. • Online Personal and Business Energy Profile energy audits, calculator "tools", energy libraries are available for registered PSE	• While surveys indicate customers take actions as a result of these programs, no energy savings are currently credited to information programs. Information

Exhibit D-2
Current Gas Conservation Programs

PROGRAM NAME	DESCRIPTION Sept. 2002 – Dec. 2003 Conservation Programs	EXPECTED ANNUAL ENERGY SAVINGS
	customers. • Free, periodic PSE energy efficiency e-newsletters for residential and business subscribers. • An Energy Efficiency e-mail box is available for customer questions, featuring maximum 24-hour turn around.	programs cannot exceed 10% of the total conservation program budget.
Efficient Natural Gas Water Heater	• $25 rebate towards purchase of an energy-efficient gas water heater (EF>=.6), served with PSE natural gas.	• 170,667 therms • 7-year resource
High-Efficiency Gas Furnace	• $150 rebate towards the purchase of a high-efficiency gas furnace (AFUE>=.9),offered to PSE residential customers, for existing homes and new construction. • Rebates not available for conversion from electricity unless installing the high-efficiency furnace.	• 224,667 therms • 15-year resource
Energy Efficient Manufactured Housing	• $150 rebate to the buyers of qualifying Natural Choice/ Energy Star labeled manufactured homes with natural gas heat, sited in PSE natural gas service territory. • Parallel with regional programs.	• 12,720 therms • 20-year resource
Small Business Energy Efficiency Programs	• Rebates for energy-efficient fluorescent lighting upgrades and conversions, lighting controls, programmable thermostats, and vending machine controllers. • Streamlined incentives for small usage commercial businesses receiving electricity under Rate Schedule 24 (<50kW demand) and Schedule 8,(or natural gas under Rate Schedule 31.	• 93,308 therms • 10-year resource
Commercial & Industrial Retrofit Program	• Incentives in the form of grants to commercial and industrial customers, are available for cost-effective energy-efficient upgrades including HVAC, water heating and refrigeration equipment, controls, process efficiency improvements, lighting upgrades, and building thermal improvements. • PSE engineers work with customers to assess energy savings opportunities, approve project proposals, recommend bid specifications, review contractor bids and verify installations prior to grant payment. • Includes an HVAC Premium Service project, using specially trained maintenance contractors to optimize efficiency of packaged roof-top	• 1,406,033 therms • 15-year resource

Exhibit D-2
Current Gas Conservation Programs

PROGRAM NAME	DESCRIPTION Sept. 2002 – Dec. 2003 Conservation Programs	EXPECTED ANNUAL ENERGY SAVINGS
	HVAC equipment.	
Commercial & Industrial New Construction Efficiency	• Incentives in the form of grants to commercial and industrial customers, are available for cost-effective energy-efficient building components or systems, including HVAC, lighting, water heating, process and refrigeration equipment, controls, building design and thermal improvements, which exceed requirements of the Washington State Energy Code (NREC) by 10% or more. Also funding towards cost of building commissioning beyond code requirements. • PSE Energy Management Engineers work with designers, developers, commissioning agents, owners and tenants (when available)of new C/I facilities, or major remodels, to propose cost-effective energy efficiency measures. • Funding may be provided using a prescriptive measure approach or a whole building approach.	• 100,000 therms • 20-year resource
Resource Conservation Manager (RCM) Program	• PSE supports customers who employ a RCM to implement low-cost/no cost energy saving activities with building occupants and facility maintenance staff. • Responsibilities include detailed accounting of resource consumption (electricity, gas, water, sewer, recycling, etc.), costs and savings estimates. • PSE provides training, accounting tools, network meetings, review of reports and electronic data downloads.	• 266,667 therms • 3-year resource
PILOT Programs – Residential Duct Systems Pilot	• Participating customers receive the duct diagnostic measurement services and sealing services from the certified contractor at no cost. Targets residences with central forced air electric or gas heating systems. • Because this is a new technique in the industry, this program provides technical support, contractor training and marketing assistance to contractors.	• 10,667 therms • 10-year resource
PILOT Programs – Commercial & Industrial Boiler Tune-up Pilot	• Pilot provides incentives of 50% of the cost of the tune-up, up to $300 per boiler, for customers to have older boilers tuned up for the first time.	• 377,000 therms • One-year resource
Public Purpose Programs – Energy	• Conservation education program funded by PSE, along with 26 other	• 80,756 therms

Exhibit D-2
Current Gas Conservation Programs

PROGRAM NAME	DESCRIPTION Sept. 2002 – Dec. 2003 Conservation Programs	EXPECTED ANNUAL ENERGY SAVINGS
Education 6-9th Grade Environmental	utilities, cities, and agencies responsible for energy, water, and environmental programs in the Puget Sound area, for over 70 schools with a reach of over 12,000 students. • Provides comprehensive energy and environmental curriculum, teaching students how to apply principles and make informed choices related to energy use, air quality, water conservation, and solid waste.	• 10-year resource life
Public Purpose Programs – Residential Low-Income Retrofit	• Funding for installation of home weatherization measures for low-income gas and electric heat customers. • Customers in single family, multifamily, and mobile home residences are qualified by local community action agencies, using federal income guidelines. • Also includes structure audits and energy use education.	• 120,800 therms • 20-year resource life

E

APPENDIX E
OPERATIONAL CONSIDERATIONS FOR EXISTING SINGLE-CYCLE CTs

Some stakeholders have questioned whether PSE should consider operating its simple-cycle Combustion Turbines (SCGTs) to satisfy baseload energy requirements as a substitute for acquiring new baseload resources. A number of factors must be carefully weighed prior to committing to such a strategy – CT plant design, staffing and spare parts inventories, heat rate and economics, emissions and environmental factors, transmission constraints, and alternative peaking needs.

This appendix provides a preliminary discussion of those factors and offers general information and insight into the implications of changing the duty cycle of PSE's SCGTs. If requested, additional detail can be provided.

General Information

Puget Sound Energy (PSE) operates four dual-fuel combustion turbine plants at sites located in Whatcom, Skagit and Pierce counties. One of the combustion turbine plants is in combined-cycle operation, with the others configured as simple-cycle plants. Exhibit E-1 provides basic plant information.

Exhibit E-1
CT Performance By Plant

PLANT NAME	LOCATION	CAPACITY (MW)	HEAT RATE (BTU/KWH)	CYCLE
Encogen	Whatcom County	170	8,700	Combined
Frederickson	Pierce County	150	12,500	Simple
Fredonia 1&2	Skagit County	210	12,500	Simple
Fredonia 3&4	Skagit County	108	10,500	Simple
Whitehorn	Whatcom County	150	12,500	Simple

Encogen Combustion Turbine

Lone Star Energy installed the Encogen NW combined cycle plant in 1993, operating it as a qualifying cogeneration facility until the assets of Encogen NW, LLP were purchased by PSE in

November, 1999. Encogen consists of three General Electric heavy frame CTs of 42 MW each and one General Electric steam turbine rated at 44 MW. The on-site management, administrative, technical, and operating staff numbers 24.

The CTs may be fueled with natural gas or distillate oil, and the fuel source may be alternated during operation. Operating hours on distillate fuel are restricted in the air operating permit limited tests periods or times when the natural gas fuel supply has been curtailed. As a result, the plant has operated almost entirely on natural gas fuel since installation.

Encogen consumes approximately 35,000 million Btus of natural gas per day and supplies an average net output of 165 MW of electrical energy to PSE, and 55,000 pounds of steam and 150,000 gallons of warm water per hour to the Georgia-Pacific mill in Bellingham.

Encogen employs various techniques to control pollutants generated by the turbines during the combustion process. Nitrogen Oxides (NO_x) are controlled by injection of steam into turbine combustors and the use of a Selective Catalytic Reduction (SCR) system. Steam injection limits peak combustion temperatures thereby limiting the formation of additional NO_x and the SCR reacts the remaining NO_x with ammonia to form elemental nitrogen and water. PSE controls ammonia emissions by carefully regulating the amount of ammonia added to the SCR system. Sulfur Dioxide (SO_2) emissions are controlled by use of natural gas the primary fuel and "road-spec" distillate fuel for the rare occasions of liquid fuel operation.

In addition to the CTs, three above-ground storage tanks of 11,000 barrels (465,000 gallons) capacity were installed. The tanks have a conventional cone roof design and store only distillate oil. This plant already operates in baseload operation and no duty cycle change is anticipated. This general information is included only for reference.

Frederickson Combustion Turbine

Frederickson 1&2 were installed in 1981, each consisting of a General Electric heavy frame CT of 75 Mw capacity each. The CT may be fueled with natural gas or distillate fuel. The fuel may be changed while the turbine is in operation. The Frederickson 1&2 turbines may be ramped from start to full load in 20 minutes. Recent operations have been made almost entirely on natural gas. Onsite staffing includes one technician and two servicemen.

In addition to the CTs, one above-ground storage tank of 100,000 barrels (4,300,000 gallons) capacity was installed. The tank has a conventional cone roof design and stores only distillate fuel. To control the formation of harmful NO_X during combustion, PSE injects demineralized water directly into the turbine combustor with the fuel supply. The water demineralizer system at Frederickson can produce 75 gallons per minute of pure water for use in the turbine, or storage in the adjacent 300,000-gallon water storage tank.

Fredonia 1&2 Combustion Turbine

Fredonia 1&2 were installed in 1984, each consisting of a Westinghouse heavy frame CT of 105 MW capacity. The CT may be fueled with natural gas or distillate fuel and the fuel may be changed while the turbine is in operation. The Fredonia 1&2 turbines may be ramped from start to full load in 50 minutes. Recent operations have been made almost entirely on natural gas. Onsite staffing includes the CT service manager (for all simple-cycle CT plants), administrative assistant, one technician and four servicemen.

In addition to the CTs, one above-ground storage tank of 100,000 barrels (4,300,000 gallons) capacity was installed. The tank has a conventional cone roof design and stores only distillate fuel. To control the formation of harmful NO_X during combustion, PSE injects demineralized water directly into the turbine combustor with the fuel supply. The water demineralizer system at Fredonia can produce 150 gallons per minute of pure water for use in the turbine, or storage in the adjacent 500,000-gallon water storage tank.

Fredonia 3&4 Combustion Turbine

Fredonia 3&4 were installed in 2001, each consisting of a Pratt & Whitney aeroderivative CT of 54 MW capacity each. The CTs may be fueled with natural gas and distillate fuel. The Fredonia 3&4 turbines may be ramped from start to full load in under 10 minutes. Recent operations have been largely on natural gas.

To control the formation of harmful NO_X during combustion, PSE injects demineralized water directly into the turbine combustor with the fuel supply. In addition, NO_x emissions are further controlled by use of a Selective Catalytic Reduction (SCR) system. CO emissions are controlled with an oxidation catalyst.

Whitehorn 2&3 Combustion Turbines

Whitehorn 2&3 were installed in 1980, each consisting of a General Electric heavy frame CT of 75 MW capacity each. The CT may be fueled with natural gas and distillate fuel. The Whitehorn 2&3 turbines may be ramped from start to full load in 20 minutes. Recent operations have been made almost entirely on natural gas. Onsite staffing includes one technician and two servicemen.

In addition to the CTs, one above-ground storage tank of 100,000 barrels (4,300,000 gallons) capacity was installed. The tank has a conventional cone roof design and stores only distillate fuel. To control the formation of harmful nitrous oxides during combustion, PSE injects demineralized water directly into the turbine combustor with the fuel supply. The water demineralizer system at Whitehorn can produce 100 gallons per minute of pure water for use in the turbine, or storage in the adjacent 500,000-gallon water storage tank.

Duty Cycle

The duty classification of a combustion turbine plant has important implications since it indicates the mission anticipated for the plant as part of PSE's energy supplies, and the associated capital and maintenance expenditures planned over its lifetime. Duty cycle also represents an important element in the original design and installation of the facility. The anticipated duty cycle impacts the basic plant layout, connection to external infrastructure, permitting, operation and maintenance strategy, and economics.

The mission, or duty classification, of a combustion turbine depends on the number of service hours and is defined by EPRI as follows:

- ***Standby Duty*** – less than 1 percent capacity factor
- ***Peaking Duty*** – between 1 percent and 10 percent capacity factor
- ***Cycling Duty*** – between 10 percent and 50 percent capacity factor
- ***Baseload Duty*** – between 50 percent and 90 percent capacity factor
- **Continuous Duty** – greater than 90 percent capacity factor

Cost Implications

PSE's heavy-frame combustion turbine plants were designed and installed in the 1980s to be used as peaking resources with relatively limited operation. The Powerplant and Industrial Fuel Use Act of 1978 governed the original permitting of these plants. PSE applied for and received an emergency peaking exemption to the Act which allowed powerplant operations up to 1,500 hours per year. As a result, the balance-of-plant equipment, staffing, anticipated spare parts and service, and emissions permits were all planned based on this operational limitation. At no time was operation as a baseload facility contemplated during the design and installation of these plants.

Economics

While the thermodynamics of energy conversion can be extremely complex, the economics of energy conversion are simple and driven by the efficiency of the thermodynamics. The thermal efficiency of a state-of-the-art combined cycle powerplant can be over 55 percent. This means that 55 percent of the energy available in the fuel source is converted to electrical energy. Compared with <30 percent thermal efficiency typical of PSE's simple-cycle plants, the modern combined-cycle plant is much less expensive to operate since it uses less fuel for a given electrical output. This high thermal efficiency is an important consideration for conserving our limited natural resources and in reducing the production of greenhouse gases.

In addition to the obvious economic issues of operating electrical generating plants at a loss, the following issues should be considered before changing the duty cycle of PSE's simple-cycle CT plants:

- ***Staffing.*** The O&M staff performs all preventive maintenance tasks for the turbines, generators and balance-of-plant equipment located at the plant site. In addition, during operation of the facility, the staff takes data readings, monitors the proper operation of the equipment, troubleshoots malfunctions, documents fuel and water consumption, operates the water treatment system, and performs fire-watch and safety checks during startup and shutdown of the equipment.

  The simple-cycle CT plants have historically been staffed to support a peaking duty cycle of 0 to 1,500 hours per year. In the years since these facilities were originally installed, operations have typically been limited to periodic exercise and testing, or responding to occasional summer or winter load peaks.

Extending the duty cycle to a baseload operation would require hiring additional staff sufficient to support round-the-clock operations, to provide for safety pairing, and to allow for normal sick days and vacations.

- ***Spares.*** The simple-cycle CT plants all inventory spare parts and consumables appropriate to the peaking duty cycle. Spares include hot gas path parts, thermocouples, fuel nozzles, control cards, batteries, indicator lamps, bearings, pumps, and other equipment typically needed for anticipated operations. Parts currently inventoried are those which experience has shown to be needed frequently or those with very long production or repair lead times. Peaking operations entail relatively short periods of operating activities and long idle periods when maintenance can be performed without staff overtime or material expediting costs. To support baseload operations, additional spares would be required to support limited maintenance time lines, higher criticality of forced outage spares and the additional importance of plant reliability for baseload energy.

- ***Balance of Plant.*** In addition to the turbine-generators, other plant systems, collectively known as the "Balance of Plant," work to supply needed electrical power and control, supply demineralized water for emission control, provide instrument air service, handle process waste products and disposal, etc. These systems, too, have been designed, sized and installed to support an anticipated peaking duty cycle. For example, water treatment systems were sized to provide demineralized water service for turbine NO_x emission controls, provided that the turbines had frequent downtime between runs. The water tank capacity, treatment system throughput capacity, and process automation levels are insufficient to support continuous duty operations. Concurrent with the water system, waste handling and disposal would also require substantial revision. In some cases it would be necessary to purchase additional public water or sanitary sewer capacity to support increased operation. No attempt has been made to quantify these costs, but they are expected to be substantial.

Emissions Issues

Various emissions limits apply to PSE's simple-cycle combustion turbine plants which restrict total annual operating hours. Operating hours would be further restricted if the turbines were to be fired on distillate fuel. PSE must keep detailed records of fuel usage and operating hours to monitor emissions and to verify compliance with all permit limits.

NO_x

To reduce NO_x emissions from PSE's simple-cycle combustion turbines, PSE injects deminerialized water into the combustion flame to reduce its peak temperature. Water injection effectively lowers NO_x emissions, but at the expense of gas turbine efficiency, more costly maintenance and higher CO emissions. It is not the preferred NO_x emission control strategy for continuous duty operations.

Operating Restrictions

Several combustion turbine units have limits on the total quantity of certain pollutants that can be emitted over a 12-month period – a rolling year mass limit. These mass limits would prevent continuous duty operations of Fredonia unit #1 and restrict operations of both Frederickson units to less than 80 percent.

In addition, the Whitehorn units may be restricted from continuous duty operations by the equipment lease agreement. The lease agreement for Fredonia 3&4 should be reviewed for potential restrictions on operation.

Greenhouse Gases

The quantity of fuel burned and the carbon content of the fuel directly impacts the production of greenhouse gases. PSE has restated its commitment to energy conservation programs in both the residential and commercial sectors to reduce the pressure on developing new resources. When new resources are needed, every effort should be made to develop renewable resources and/or resources with high thermal efficiency. Serious efforts to reduce greenhouse gas emissions and to preserve limited natural resources should not include the operation of simple-cycle combustion turbines for baseload energy needs.

Transmission Constraints

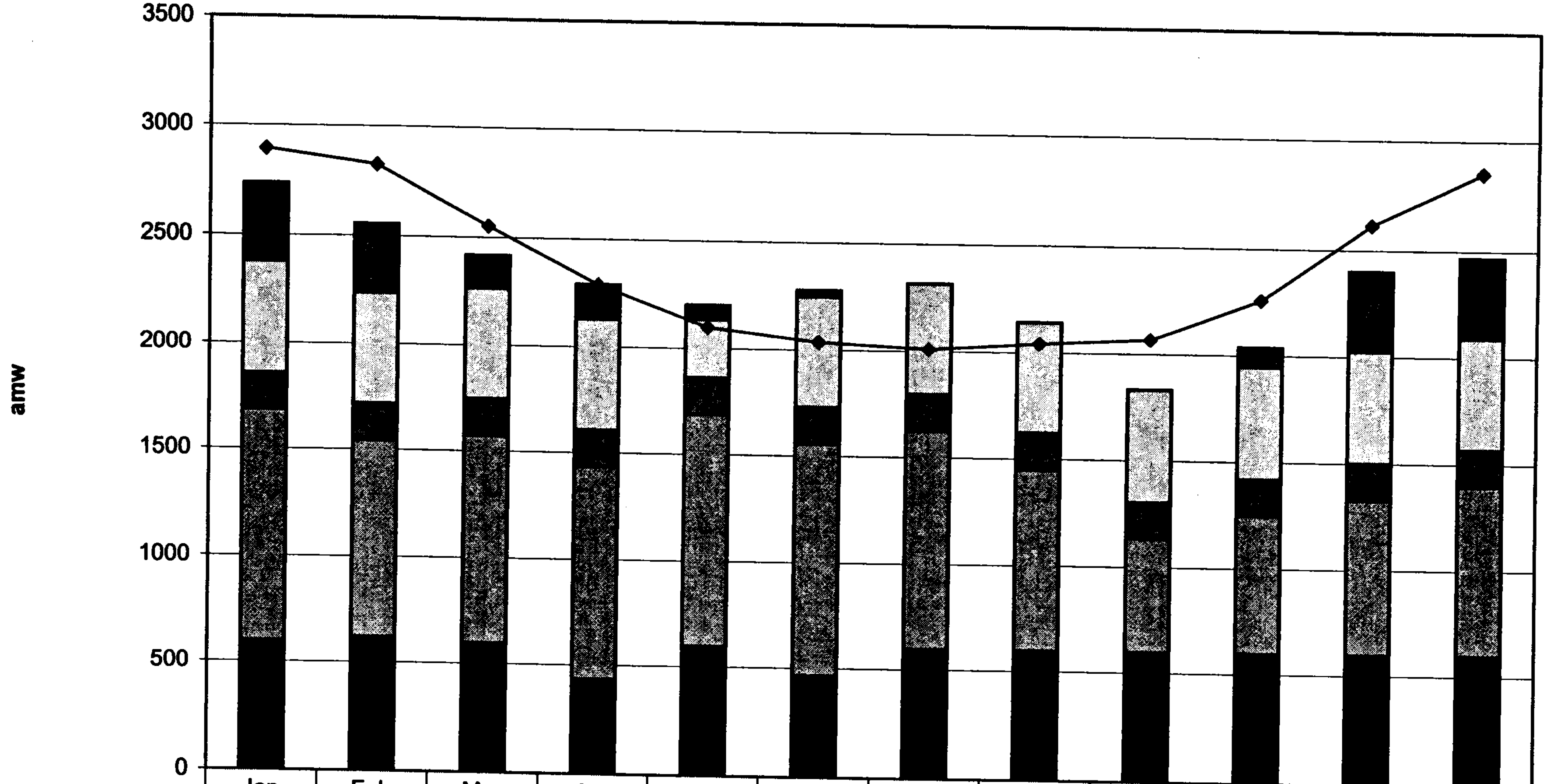
The PSE transmission system has several congestion points in its electrical transmission system. This issue would require considerable study before committing to continuous duty operations of the simple-cycle CTs and may add substantial expense for system upgrades and improvements.

Peak Load Requirement

PSE's peak load requirements have been well-served over the years by the simple-cycle combustion turbines. If these turbines were converted to continuous duty operations, in spite of the disadvantages to doing so, other peaking resources would have to be acquired to serve the peaking mission. In that event, PSE would have investments in both sub-optimal continuous duty resources and new peaking resources. Neither would be as efficient, clean, or as cost-effective as procuring high-efficiency continuous duty equipment and using the older equipment in a peaking role with limited operations.

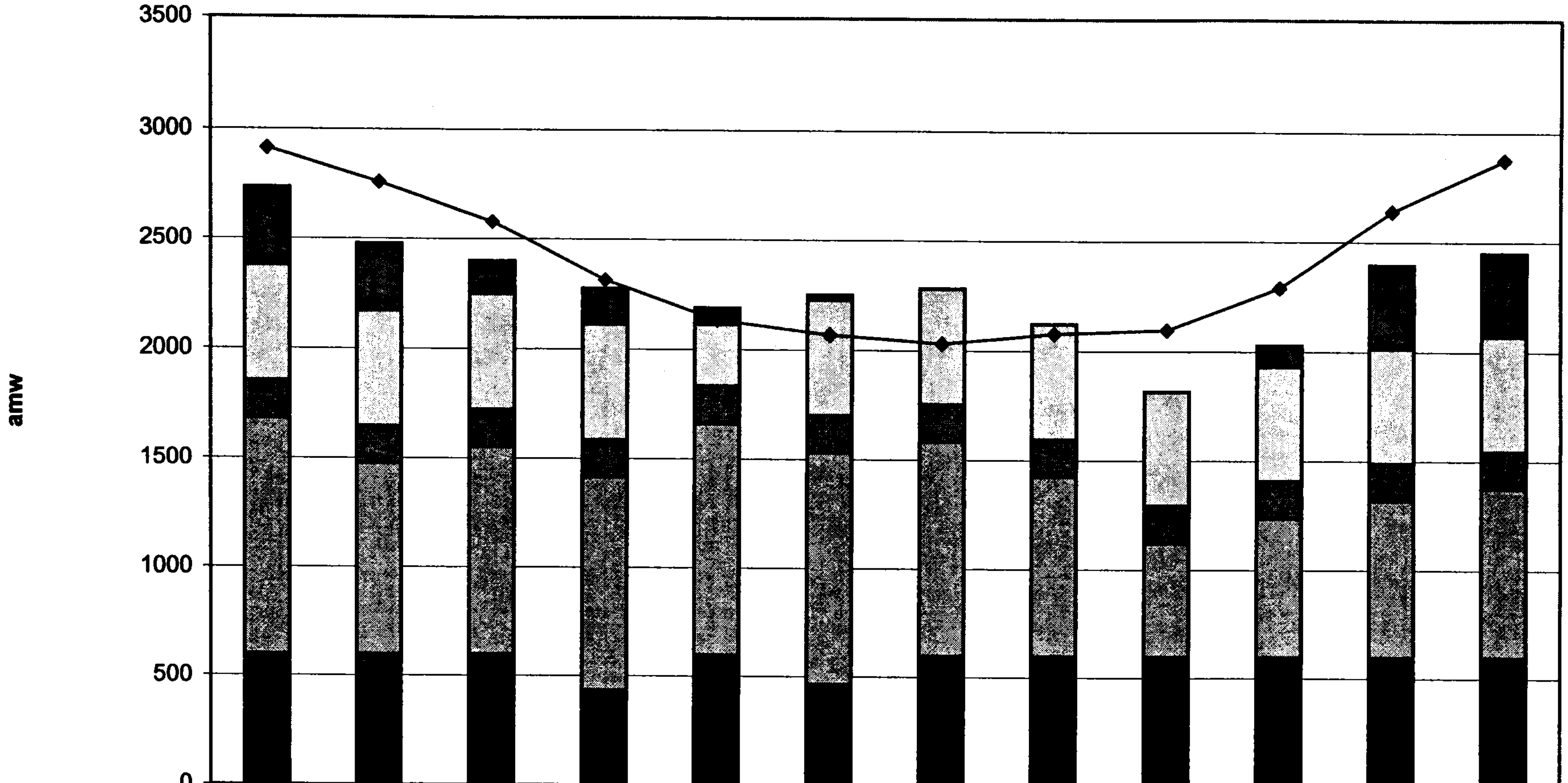
F

Exhibit F-1
2004 Monthly Energy Load-Resource Outlook



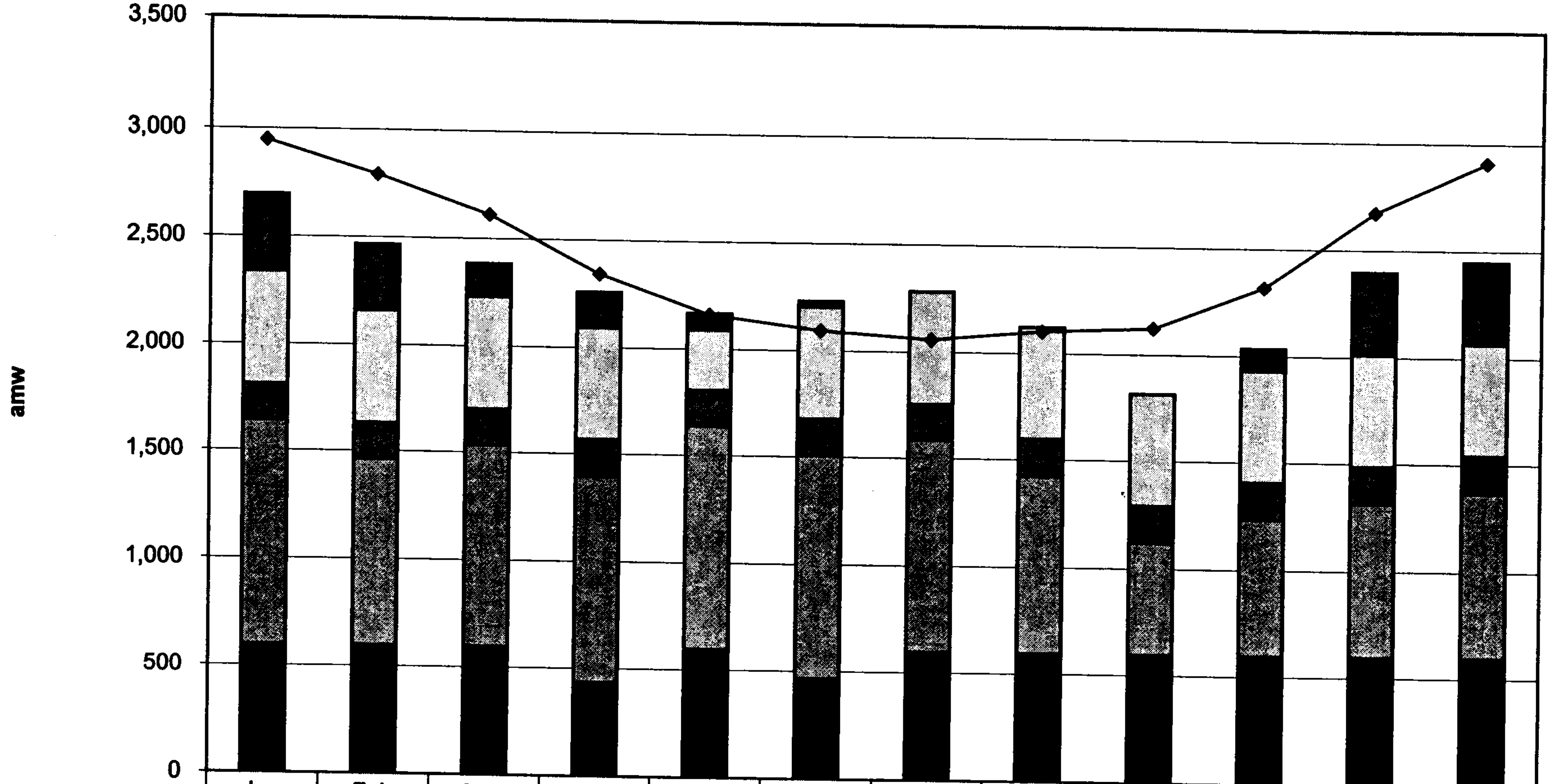
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Contracts	358	316	151	162	68	29	(79)	(75)	(85)	95	377	376
NUGs	526	526	526	526	281	526	526	526	526	526	526	526
Encogen	170	170	170	170	170	170	170	170	170	170	170	170
Hydro	1,085	924	974	1,002	1,090	1,092	1,026	852	536	652	732	800
Colstrip	598	619	598	433	598	464	598	598	598	598	598	598
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

Exhibit F-2
2005 Monthly Energy Load-Resource Outlook



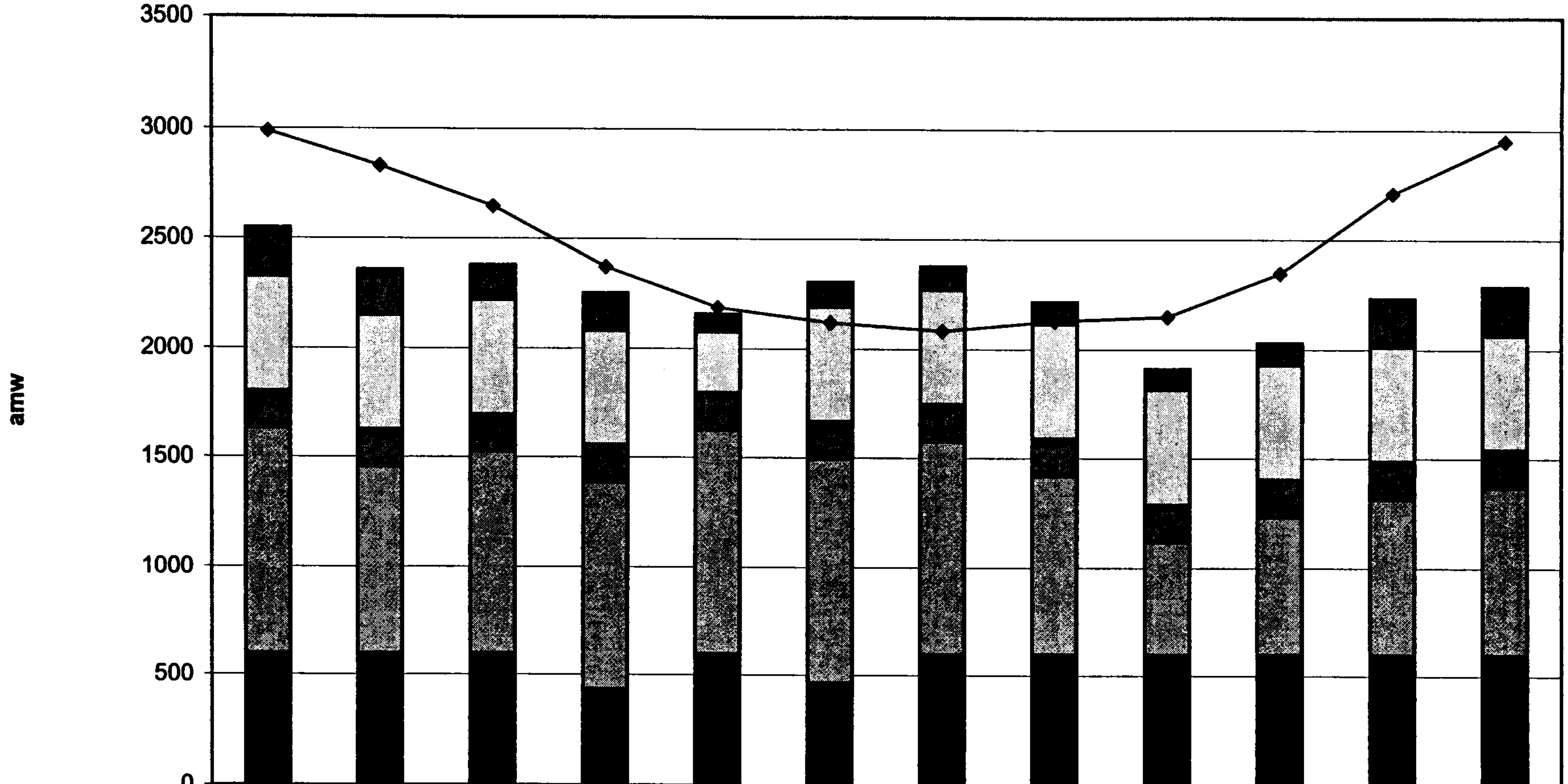
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Contracts	358	306	151	163	75	23	(78)	(74)	(83)	96	381	379
NUGs	526	526	526	526	281	526	526	526	526	526	526	526
Encogen	170	170	170	170	170	170	170	170	170	170	170	170
Hydro	1,085	878	955	982	1,065	1,068	987	828	524	638	721	777
Colstrip	598	598	598	433	598	464	598	598	598	598	598	598
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

Exhibit F-3
2006 Monthly Energy Load-Resource Outlook



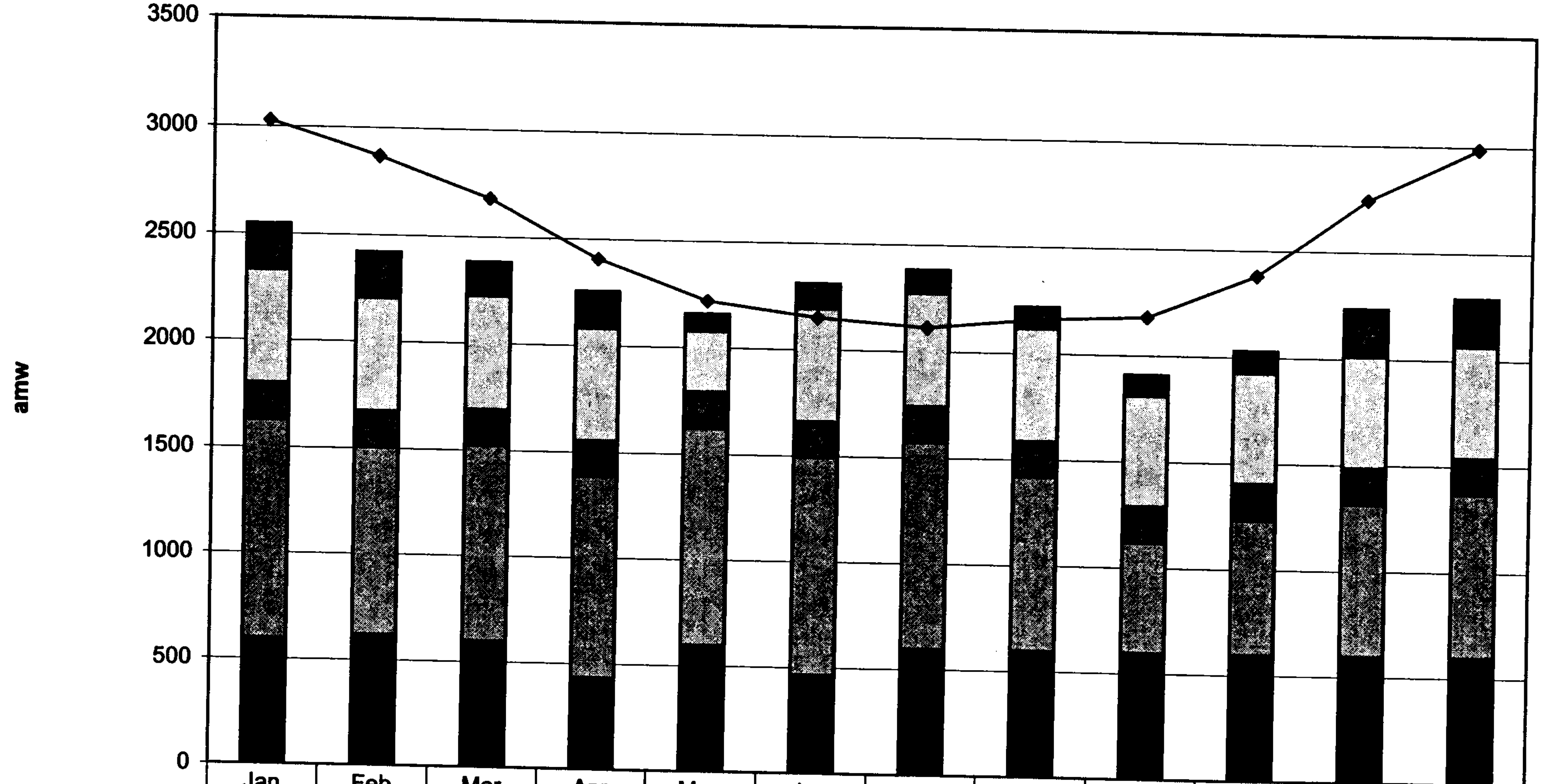
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Contracts	362	309	155	167	78	26	(75)	(71)	(77)	102	385	383
NUGs	526	526	526	526	281	526	526	526	526	526	526	526
Encogen	170	170	170	170	170	170	170	170	170	170	170	170
Hydro	1,044	864	936	962	1,040	1,043	987	828	524	638	718	771
Colstrip	598	598	598	433	598	464	598	598	598	598	598	598
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

Exhibit F-4
2007 Monthly Energy Load-Resource Outlook



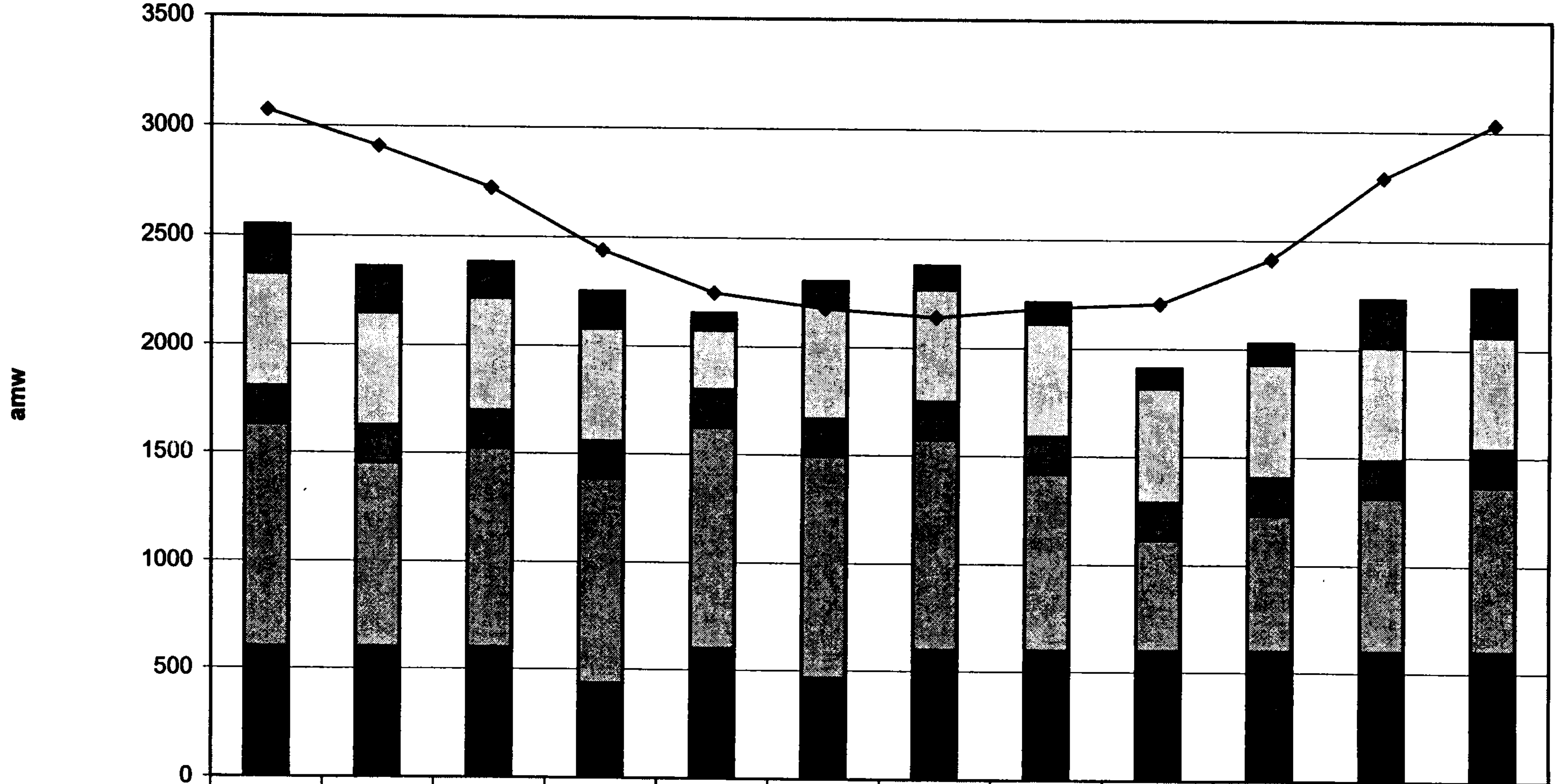
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Contracts	220	209	161	171	81	115	108	101	96	101	222	221
NUGs	526	526	526	526	281	526	526	526	526	526	526	526
Encogen	170	170	170	170	170	170	170	170	170	170	170	170
Hydro	1,033	857	926	952	1,027	1,031	977	822	521	635	718	771
Colstrip	598	598	598	433	598	464	598	598	598	598	598	598
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

Exhibit F-5
2008 Monthly Energy Load-Resource Outlook



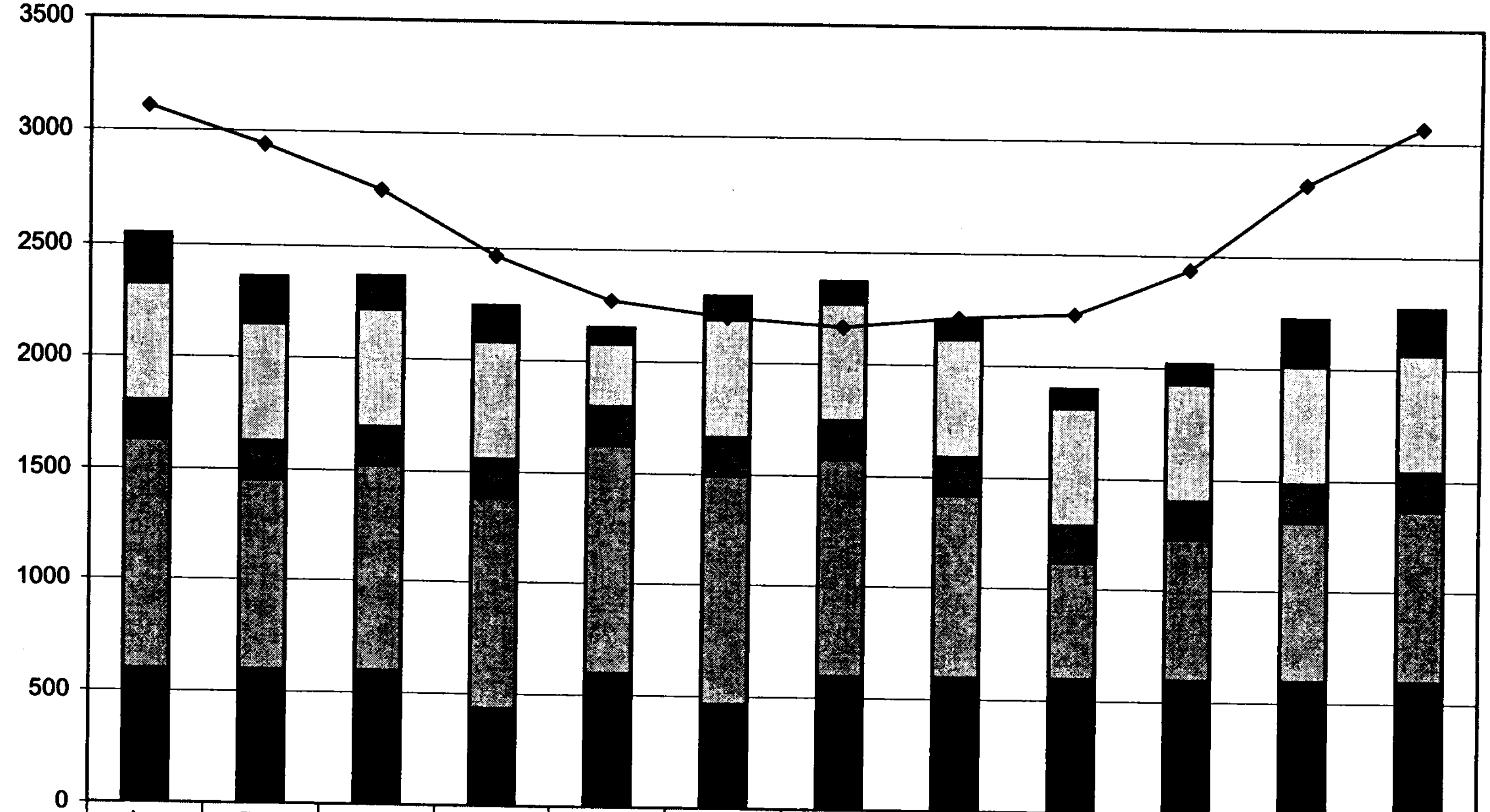
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Contracts	221	217	161	171	81	116	109	101	96	101	222	222
NUGs	526	526	526	526	281	526	526	526	526	526	526	526
Encogen	170	170	170	170	170	170	170	170	170	170	170	170
Hydro	1,033	887	926	952	1,027	1,031	977	822	521	635	718	771
Colstrip	598	619	598	433	598	464	598	598	598	598	598	598
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

Exhibit F-6
2009 Monthly Energy Load-Resource Outlook



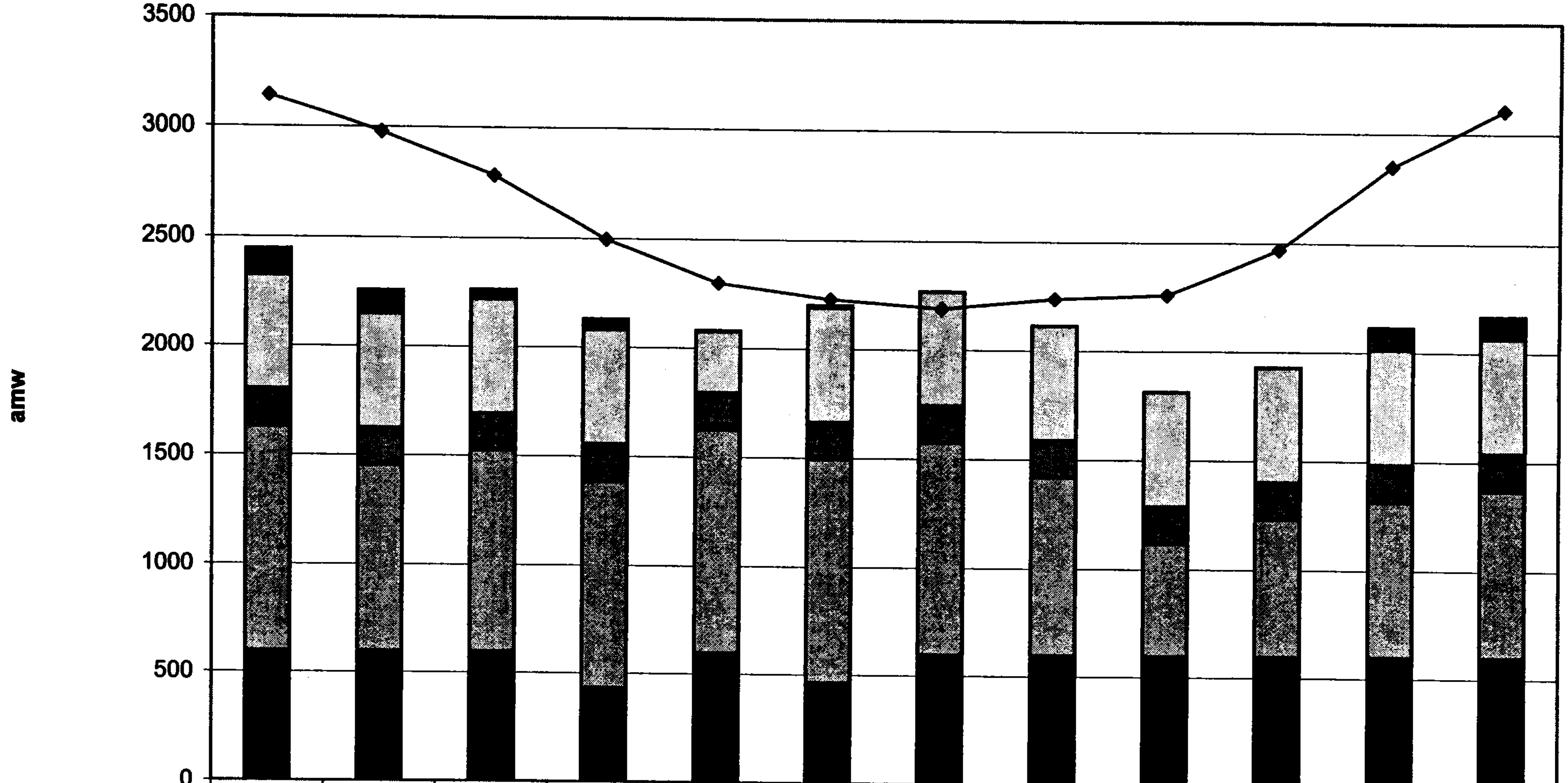
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Contracts	221	210	161	170	80	114	107	99	94	99	222	222
NUGs	526	526	526	526	281	526	526	526	526	526	526	526
Encogen	170	170	170	170	170	170	170	170	170	170	170	170
Hydro	1,033	857	926	952	1,027	1,031	977	822	521	635	718	771
Colstrip	598	598	598	433	598	464	598	598	598	598	598	598
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 Monthly Energy Load-Resource Outlook



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Contracts	222	210	150	162	74	109	100	89	86	91	211	207
NUGs	526	526	526	526	281	526	526	526	526	526	526	526
Encogen	170	170	170	170	170	170	170	170	170	170	170	170
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
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

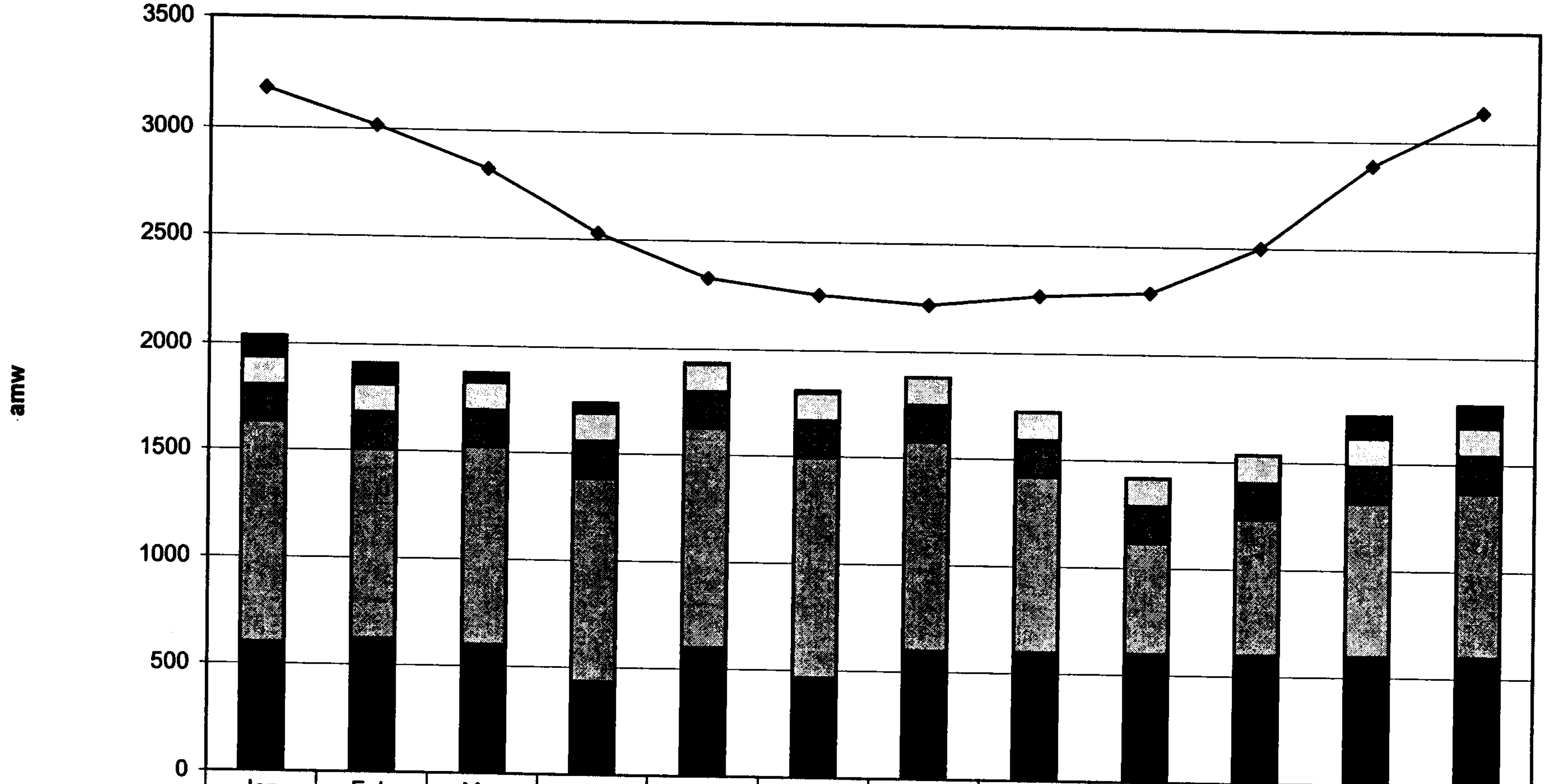
Exhibit F-8
2011 Monthly Energy Load-Resource Outlook



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Contracts	118	108	45	49	5	10	(5)	(17)	(18)	(15)	104	104
NUGs	526	526	526	526	281	526	526	526	526	526	526	526
Encogen	170	170	170	170	170	170	170	170	170	170	170	170
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
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

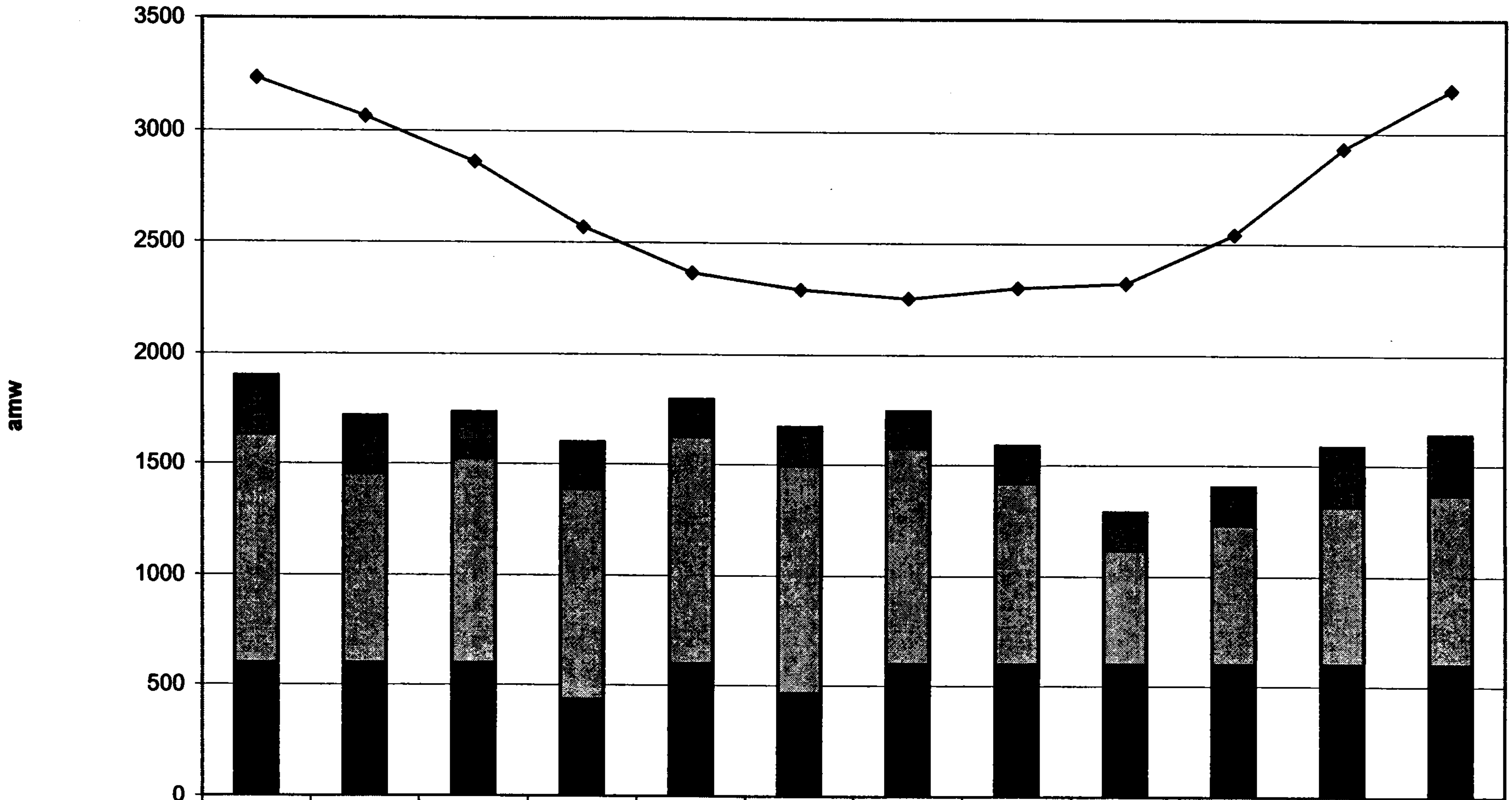
Exhibit F-9

2012 Monthly Energy Load-Resource Outlook



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Contracts	102	101	45	49	5	10	(5)	(17)	(18)	(15)	105	104
NUGs	133	133	133	133	133	133	133	133	133	133	133	133
Encogen	170	170	170	170	170	170	170	170	170	170	170	170
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
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

Exhibit F-10
2013 Monthly Energy Load-Resource Outlook



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Contracts	98	93	40	44	0	5	(10)	(19)	(26)	(20)	100	102
Encogen	170	170	170	170	170	170	170	170	170	170	170	170
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
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

G

APPENDIX G
DETAILED RESOURCE TYPE DESCRIPTIONS

OVERVIEW OF GEOTHERMAL TECHNOLOGIES

Introduction

Geothermal energy, the natural heat within the earth, arises from the ancient heat remaining in the Earth's core, from friction where continental plates slide beneath each other, and from the decay of radioactive elements that occur naturally in small amounts in all rocks.

For thousands of years, people have benefited from hot springs and steam vents, using them for bathing, cooking, and heating. During this century, technological advances have made it possible and economic to locate and drill into hydrothermal reservoirs, pipe the steam or hot water to the surface, and use the heat directly (for space heating, aquaculture, and industrial processes) or to convert the heat into electricity.

The amount of geothermal energy is enormous. Scientists estimate that just 1 percent of the heat contained in just the uppermost 10 kilometers of the earth's crust is equivalent to 500 times the energy contained in all of the earth's oil and gas resources [1].

Hydrothermal and Hot Dry Rock

This document characterizes electric power generation technology for two distinct categories of geothermal resources.

Hydrothermal resources are the "here-and-now" resources for commercial geothermal electricity production. They are relatively shallow (from a few hundred to about 3,000 meters). They contain hot water, steam, or a combination of the two. They are inherently permeable, which means that fluids can flow from one part of the reservoir to other parts of the reservoir, and into and from wells that penetrate the reservoir. In hydrothermal reservoirs, water descends to considerable depth in the crust, becomes heated and then rises buoyantly until it either becomes trapped beneath impermeable strata, forming a bounded reservoir, or reaches the surface as hot springs or steam vents. The water convects substantial amounts of heat from depths to relatively near the surface.

Hot Dry Rock (HDR) resources, on the other hand, are relatively deep masses of rock that contain little or no steam or water, and are not very permeable. They exist where geothermal gradients (the vertical profile of changing temperature) are well above average (>50°C/km). The rock temperature reaches commercial usefulness at depths of about 4,000 meters or more. To exploit hot dry rock, a permeable reservoir must be created by hydraulic fracturing, and water from the surface must be pumped through the fractures to extract heat from the rock.

There are both strong similarities and large differences between hydrothermal and HDR geothermal resources and exploitation systems. Most of the component technologies, i.e., the power plant and well drilling methods, are very similar for both systems. The most important differences are that: (a) Hydrothermal systems are commercial today, while HDR systems are not, whereas (b) HDR resources are enormously larger (between 3,170,000 EJ and 17,940,000 EJ of accessible energy in the U.S.) than hydrothermal resources (on the order of 1,060 EJ to 5,300 EJ of accessible energy) [2]. By way of comparison, in 1995 the U.S. used about 95 EJ of primary energy. U.S. hydrothermal sources could supply that amount for 10 to 50 years. But U.S. Hot Dry Rock resources could supply that amount for somewhere between 30,000 and 500,000 years.

Because of these differences, the general strategic approach of national geothermal R&D programs (including that of the U.S.) has been to try to lower costs in the hydrothermal commercial arena today and, by so doing, to improve generic "geothermal" technology enough to make HDR exploitation economically feasible in the not-too-distant future.

Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy

OVERVIEW OF GEOTHERMAL TECHNOLOGIES

Hydrothermal Features

Hydrothermal resources are categorized as dry steam (vapor dominated) or hot water resources, depending on the predominant phase of the fluid in the reservoir. Although the technology is similar for both, dry steam technology is not included in this Technology Characterization because dry steam resources are relatively rare. Hot water resources are further categorized as being high temperature (>200°C/392°F), moderate temperature (between 100°C/212°F and 200°C/392°F), and low temperature (<100°C/212°F). Only the high and moderate temperature resources are adequate for commercial power generation.

Two separate power generation technologies, flash and binary, are characterized. The boiling temperature of water depends on its pressure, so as the pressure of the high temperature geothermal fluid is lowered in the plant, a portion (about 10 to 20% of it, depending on temperature and pressure) "flashes" to steam, which is used to drive a turbine to produce electricity. For moderate temperature resources, binary technology is more efficient. It is termed "binary" because the heat is transferred from the geothermal fluid to a secondary working fluid with a lower boiling temperature than water. The secondary fluid, vaporized by the heat, drives the turbine.

Beginning commercially in the 1950s, hydrothermal electric power generation has grown into an active and healthy, albeit not large, industry. About 7,000 MW of electric generation capacity have been developed worldwide, including about 2,800 MW in the U.S. [3]. Supply and demand forces and anticipated restructuring in the U.S. electric markets have resulted in very low demand for new geothermal capacity since 1990. However, geothermal energy is competing very well in markets outside the U.S., especially in Indonesia and the Philippines, where demand is high, geothermal resources are plentiful, and government policy is favorable. Approximately 2,000 additional MW will likely be developed worldwide in 1996 through 2000, with the majority of this being in Asia.

Hot Dry Rock Features

Flash or binary technology could be used with HDR resources depending on the temperature. However, because of the constraints imposed by high well costs, a larger portion of the accessible HDR resource will produce well-head fluids in the moderate temperature range. Therefore, binary technology is characterized for HDR resources.

To date, HDR resources have not been developed commercially for two reasons. Well costs increase exponentially with depth, and since HDR resources are much deeper than hydrothermal resources, they are much more expensive to develop. Also, although the technical feasibility of creating HDR reservoirs has been demonstrated at experimental sites in the U.S., Europe, and Japan, operational uncertainties regarding impedance (resistance of the reservoir to flow), thermal drawdown over time, and water loss make commercial development too risky.

Resource Details

In the U.S., the higher quality geothermal resources (both hydrothermal and HDR) are predominately located in the western states, including Alaska and Hawaii, as shown in the map below. Development of hydrothermal resources for electric power generation has been limited to California, Nevada, Utah, and Hawaii. Most of the western U.S. contains HDR resources, with the highest grade resources probably located in California and Nevada.

Scientists have made various estimates of the geothermal resource in the U.S. The U.S. Geologic Survey (USGS) completed the nation's most comprehensive assessment of geothermal resources, documented in USGS Circular 790, published in 1978 [2]. Circular 790 estimated the known, accessible hydrothermal resource to be about 23,000 MW

Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy

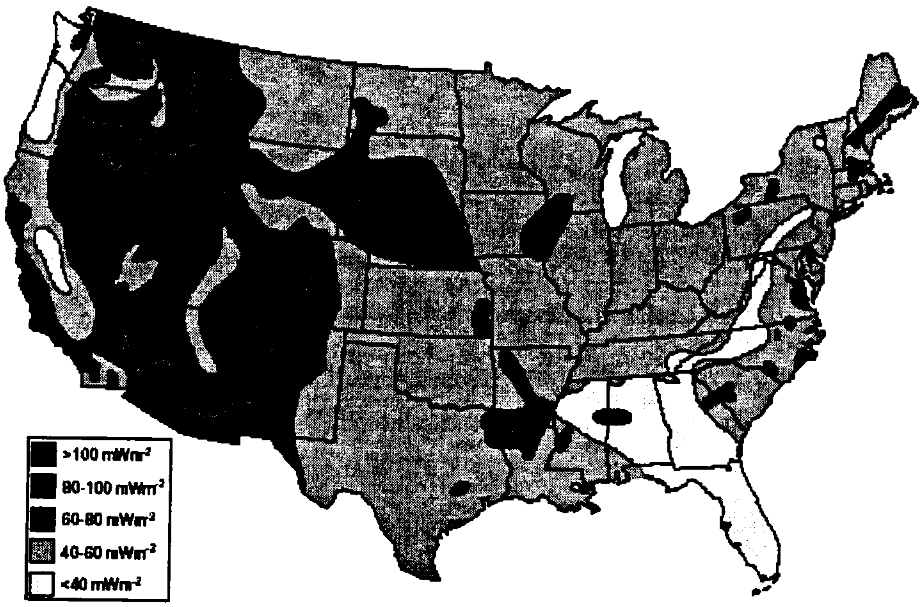


Figure 1. Geothermal resource quality in the United States.

of electric capacity for 30 years, and the as yet undiscovered accessible hydrothermal resource to be 95,000 to 150,000 MW of electric capacity for 30 years. It should be noted that the accessible resource is that which is accessible with current technology, but not necessarily economic. Considerable geothermal exploration and development in the U.S. since the mid 1950s has identified and characterized (moderately well) about 3,000 to 5,000 MW of hot water hydrothermal resources. Exploration work in the Cascade Mountains of Oregon in the 1990s seems to preclude the existence of the significant hydrothermal resource once estimated for that area.

An unpublished study by the University of Utah Research Institute in 1991 estimated about 5,000 MW of electric capacity for 30 years would be available at a cost of 5.5¢/kWh [4]. Recent preliminary analyses by the authors of the geothermal TCs suggest that for Hydrothermal electricity in 1997, no capacity would be available at ≤2¢/kWh, about 5,000 MW would be available at ≤3¢/kWh, and about 10,000 MW available at ≤5¢/kWh. If the predicted technology improvements for 2020 hold true, then 6,000 MW would be available at ≤2¢/kWh, about 10,000 MW available at ≤3¢/kWh, and about 19,000 MW available at ≤5¢/kWh. (These prices are levelized in constant dollars, using the "GenCo" financing assumptions described in Chapter 7.) Also note that the lowest prices given here are lower than the price calculated for the characterized geothermal flash power plant because the characterized plant is for a "typical" rather than "least expensive" geothermal high-temperature reservoir.

Although the potential of the nation's HDR resource has been studied less and is less well understood, it is believed to be very much larger than that of the hydrothermal resource. Tester and Herzog estimated the U.S. high grade HDR resource to have the potential of generating 2,800,000 MW at a cost ≤8.7¢/kWh (1996$) using 1990 technology [5]. For the year 2020 technology projected in the Hot Dry Rock TC, the current authors estimate that about 2,000,000 MW would be available from very high quality resource regions at ≤5¢/kWh, and that as much as 17,000,000 MW (about

Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy

24 times the current installed electric capacity in the U.S.) of HDR would be available at ≤6¢/kWh. (The economic assumptions here are the same as stated in the paragraph above.)

Aspects of Cost Estimates

The current state of many aspects of geothermal technology is fairly well documented. Indeed, the timing of this characterization of geothermal technologies is opportune in that it follows the first major engineering analysis of the cost and performance of geothermal power plants in 15 years. The "Next Generation Geothermal Power Plants" study (NGGPP), published in 1996, characterizes current flash and binary technology and evaluates new technologies proposed for the next generation of geothermal power plants [6]. Prior to this study, it has been difficult to obtain current cost and performance data for geothermal power plants because of the proprietary nature of this information.

The Hydrothermal and Hot Dry Rock TCs incorporate much data from the NGGPP. However, the characterization of Hydrothermal Flash reflects decreased flash plant capital costs (approximately 40% less than those documented in the NGGPP) due to intense competition. As of mid-1997, capital costs for binary plants appear to have been unaffected by these factors.

The HDR technology characterization depends on the NGGPP for binary power plant cost and performance data. The NGGPP includes an analysis of HDR technology that some believe is too conservative. The current HDR characterization is based on a higher grade HDR resource than that in the NGGPP. The NGGPP HDR well cost (including fracturing) estimates were about 30% higher than the TC HDR well costs, which were estimated by an experienced geothermal drilling engineer based on the costs of deep geothermal wells drilled recently in Nevada. The costs of creating the HDR reservoir, as well as its performance, are based on estimates of HDR scientists at Los Alamos National Laboratory, where HDR has been studied for the last 20 years.

Projections of Technology Improvements

For geothermal, as for other renewable energy electric supply technologies, the "accuracy" of projections of improvements in cost effectiveness are very important because in many instances, use of the technologies at specific locations will not be cost effective until the technologies are improved somewhat. The projections for improvements in the cost and performance of hydrothermal and HDR technologies are a synthesis of what various experts believe is possible.

The projections for improvements in hydrothermal technology are based on trends in performance and cost since about 1985 when U.S. firms first started constructing many hydrothermal power systems. It has been apparent that for both wells and power plants, the earliest forms of the technologies -- borrowed more or less wholly from other industries and uses -- have been constantly analyzed, rethought, and improved. The past five years especially have seen much new attention focused on how to improve the cost effectiveness of power plants, through changes in the underlying process cycles and conditions used to convert heat to electricity.

The single major exception to this ten-year (1985-1995) trend of apparent improvements has been in the area of industry's ability to locate and target, in many reservoirs, high-permeability zones for fluid collection and delivery. But here too, constant theoretical progress is being made, that is soon likely to engender practical progress.

The estimates for current and projected HDR cost and performance are more speculative than those for hydrothermal technology since HDR technology is much less mature and has not been applied commercially. Therefore, there is greater uncertainty in the HDR technology estimates. With HDR technology, the stated estimates are for the best cost

Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy

and performance that is reasonably possible; the estimated uncertainty values reflect the possibility of lower performance and less improvement in the technology.

The projections are predicated on various assumptions about factors that will affect the timing and extent of improvements in the technologies. These include the levels of funding for hydrothermal and HDR R&D in several countries, as well as fossil fuel drilling and well completion R&D, supply and demand in electricity markets, supply and demand in petroleum markets (this greatly influences drilling costs and private funding of drilling research), public policy (especially regarding energy and the environment) in several countries, currency fluctuations, and technological progress in other electric supply technologies.

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Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy

OVERVIEW OF PHOTOVOLTAIC TECHNOLOGIES

Introduction

Solar photovoltaic modules, called "photovoltaics" or "PV", are solid-state semiconductor devices with no moving parts that convert sunlight into direct-current electricity. Although based on science that began with Alexandre Edmond Becquerel's discovery of light-induced voltage in electrolytic cells over 150 years ago, significant development really began following Bell Labs' invention of the silicon solar cell in 1954. PV's first major application was to power man-made earth satellites in the late 1950s, an application where simplicity and reliability were paramount and cost was nearly ignored. Enormous progress in PV performance and cost reduction, driven at first by the U.S. space program's needs, has been made over the last 40-plus years. Since the early 1970s, private/public sector collaborative efforts in the U.S., Europe, and Japan have been the primary technology drivers. Today, annual global module production is over 100 MW, which roughly translates into a $1billion/year business. In addition to PV's ongoing use in space, its present-day cost and performance also make it suitable for many grid-isolated applications in both developed and developing parts of the world, and the technology stands on the threshold of major energy-significant applications worldwide.

PV enjoys so many advantages that, as its comparatively high initial cost is brought down another order of magnitude, it is very easy to imagine its becoming nearly ubiquitous late in the 21st century. PV would then likely be employed on many scales in vastly differing environments, from microscopic cells integrated into and powering diamond-based optoelectronic devices in kilometers-deep wells to 100-MW or larger 'central station' generating plants covering square kilometers on the earth's surface and in space. The technical and economic driving forces favoring PV's use in these widely diverse applications will be equally diverse. However, common among them will be PV's durability, high efficiency, low cost, and lack of moving parts, which combine to give an economic power source with minimum maintenance and unmatched reliability. In short, PV's simplicity, versatility, reliability, low environmental impact, and—ultimately—low cost, should help it to become an important source of economical premium-quality power within the next 50 years.

It is easy to foresee PV's 21st-century preeminence, but the task of this chapter is a difficult one of accurately predicting PV's development trajectory toward that time. The three applications described here (Residential PV; Utility-Scale, Flat-Plate Thin Film PV; and Concentrating PV) illustrate highly feasible elements of that trajectory. These applications likely will blossom at different rates and may not all develop as forecasted. Furthermore, they are not the only major applications likely to emerge. Nevertheless, the three scenarios presented serve to give a sense of the time scale in which PV is likely to evolve from its present-day state, to the pervasive low-priced appliance of the latter half of the next century. During the time period covered by these characterizations, PV will evolve from a technology serving niche markets, to one entering and then playing an important and growing role in the world's energy markets. Up to 10% of U.S. capacity could be PV by 2030, and significant PV will be used worldwide as global demand for electricity grows.

Economic Evolution

Empirical progress in manufacturing processes is frequently displayed by means of a "learning" or "experience" curve. Conventionally, such curves are plotted using logarithmic axes, to show per-unit cost versus cumulative production volume. Most often, such a plot will produce a straight line over a very large range of actual production volumes and unit costs. The slope of that line, expressed as the percent of cost remaining after each doubling in volume, is called the "progress ratio." (Since a progress ratio of 100% would represent no learning —i.e., zero cost reduction—it would perhaps be better called a "lack-of-progress ratio.") Most manufactured goods are found to yield progress ratios between 70% and 90%, but there appears to be no generally applicable rule for assigning *a priori* expectations of progress ratios for a given process.

Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy

OVERVIEW OF PHOTOVOLTAIC TECHNOLOGIES

Figure 1 shows the experience curve over the past 20-some years for PV module prices versus total sales. Price and total sales are used as proxies for cost and manufactured volume because the actual cost and production information for the entire industry is not available. Note that, although the plotted data comprise a number of technologies, the dominant technology—crystalline silicon—has set the pace for the price-volume relation. Therefore, this figure most closely represents an experience curve for crystalline silicon PV, and this curve was used within the Technology Characterization for Residential PV systems. The 82% value falls within the range typical for manufactured goods, and the projections of crystalline-silicon module sales and prices provided within that TC are further supported by a "bottom up" analysis of the industry.

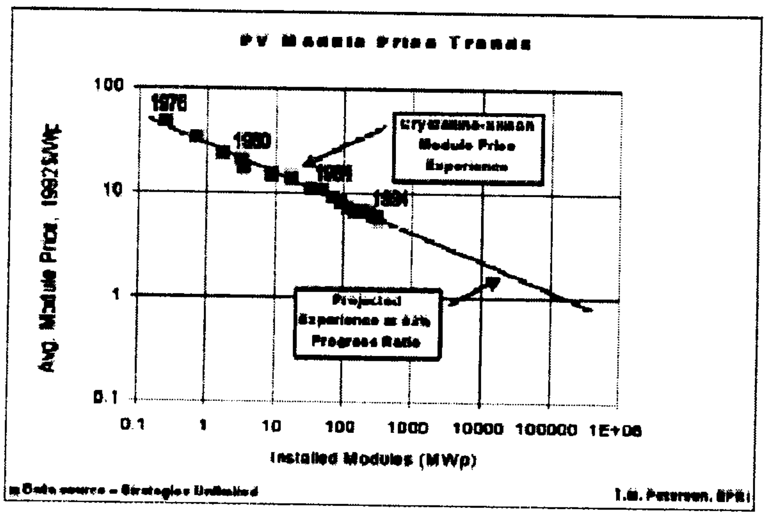


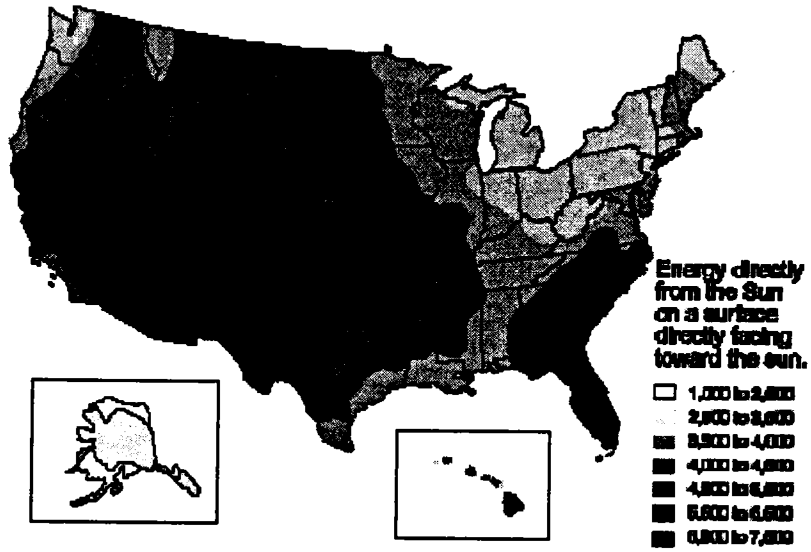
Figure 1. Learning curve for crystalline-silicon PV.

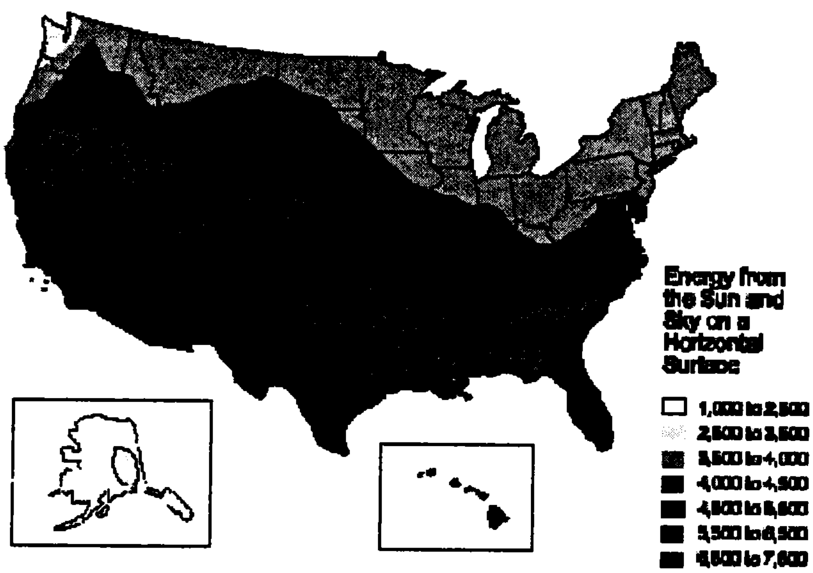
A major departure from the historical trend could be caused by emergence of a fundamentally new technology where the learning process would need to begin anew. Both thin-film and concentrator PV are likely candidates for just such a fundamental technology shift. Because historical data are not available, a great deal of uncertainty exists regarding the future costs of thin-film and concentrator PV systems which are so dependent on R&D funding and for which much industry data is proprietary.

Technology Comparison

Solar Resource: One significant difference between concentrating and other PV systems pertains to the solar resource used. Concentrating PV systems use sunlight which is incident perpendicular to the active materials (direct normal insolation). Other PV systems utilize both direct and indirect (diffuse) solar radiation. Provided in Figure 2, below, are two maps; the first is a map of direct normal insolation, the second is a map depicting global insolation for the U.S.

Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy





Reproduced from data provided by
NREL Renewable Energy Resource Information & Analysis Center
in support of the
DOE Resource Assessment Program
Solar Radiation Resource Assessment Project

Figure 2. Direct normal insolation resource for concentrator PV (above) and global insolation resource for crystalline-silicon and thin film PV systems (below).

Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy

The main consequence of this difference is that concentrator systems should be deployed in regions that are predominantly cloud free. While other PV systems do not have this requirement, total solar resource quality does of course influence system performance. The PV Technology Characterizations take resource quality into consideration by providing performance estimates based on average and high solar resource assumptions.

Deployment: The deployment needs of the two utility scale applications described in this report are similar. Medium and large-scale deployments have significant land requirements. However, it is important to note that concentrator systems are less appropriate for very small-scale deployments (less than a few tens of kilowatts) due to their costs and complexity. Customer (building) sited PV have no land requirements, however several structural requirements are important (i.e. roof integrity and orientation, shading, pitch, etc.).

Application: The PV systems characterized here all provide distributed benefits. Residential PV systems either feed power into the grid and/or reduce customer demand for grid power. Medium and larger scale systems add capacity incrementally, and to the extent that they match load patterns, may reduce the need for major capital investments in central generation.

Modularity: PV generating systems are easily scaled to meet demand. PV systems can be constructed using one or more modules, producing from a few tens of watts to megawatts. For example, the residential PV systems characterized in this report are a few kW in size, while the concentrating and utility scale thin film PV systems are multi-megawatt applications.

Low-cost operation and maintenance: PV systems have few moving parts. Flat-plate types without tracking have no moving parts, and even two-axis tracking requires only a relatively small number of low-speed moving parts. This tends to keep operation and maintenance costs down. Indeed, some early kilowatt-scale first-of-a-kind plants demonstrated O&M costs around $0.005/kWh.

Summary

The PV applications described here are both competitive and mutually supportive at the same time. They are competitive because successful pursuit of one application will divert enthusiasm and resources from the others to some degree; but supportive, because technology and marketing advances fueled by any one of them will also somewhat aid the rest. They do compete to some extent for common markets, but they each serve sufficiently distinct needs to expect their respective niches to persist indefinitely, despite the likelihood that a single one of them may dominate the overall market.

Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy

OVERVIEW OF BIOMASS TECHNOLOGIES

Situation Analysis

Biopower (biomass-to-electricity power generation) is a proven electricity-generating option in the United States. With about 10 GW of installed capacity, biopower is the single largest source of non-hydro renewable electricity. This installed capacity consists of about 7 GW derived from forest-product-industry and agricultural-industry residues, about 2.5 GW of municipal solid waste (MSW) generating capacity, and 0.5 GW of other capacity such as landfill gas-based production. The electricity production from biomass is being used, and is expected to continue to be used, as base load power in the existing electric-power system.

In the U.S., biopower experienced dramatic growth after the Public Utilities Regulatory Policy Act (PURPA) of 1978 guaranteed small electricity producers (less than 80 MW) that utilities would purchase their surplus electricity at a price equal to the utilities' avoided-cost of producing electricity. From less than 200 MW in 1979, biopower capacity grew to 6 GW in 1989 and to today's capacity of 7 GW. In 1989 alone, 1.84 GW of capacity was added. The present low buyback rates from utilities, combined with uncertainties about industry restructuring, have slowed industry growth and led to the closure of a number of facilities in recent years.

The 7 GW of traditional biomass capacity represents about 1% of total electricity generating capacity and about 8% of all non-utility generating capacity. More than 500 facilities around the country are currently using wood or wood waste to generate electricity. Fewer than 20 facilities are owned and operated by investor-owned or publicly-owned electric utilities. The majority of the capacity is produced in Combined Heat and Power (CHP) facilities in the industrial sector, primarily in pulp and paper mills and paperboard manufacturers. Some of these CHP facilities have buyback agreements with local utilities to purchase net excess generation. Additionally, a moderate percentage of biomass power facilities are owned and operated by non-utility generators, such as independent power producers, that have power purchase agreements with local utilities. The number of such facilities is decreasing somewhat as utilities buy back existing contracts. To generate electricity, the stand-alone power production facilities largely use non-captive residues, including wood waste purchased from forest products industries and urban wood waste streams, used wood pallets, some waste wood from construction and demolition, and some agricultural residues from pruning, harvesting, and processing. In most instances, the generation of biomass power by these facilities also reduces local and regional waste streams.

All of today's capacity is based on mature, direct-combustion boiler/steam turbine technology. The average size of existing biopower plants is 20 MW (the largest approaches 75 MW) and the average biomass-to-electricity efficiency of the industry is 20%. These small plant sizes lead to higher capital cost per kilowatt of installed capacity and to high operating costs as fewer kilowatt-hours are produced per employee. These factors, combined with low efficiencies which increase sensitivity to fluctuations in feedstock price, have led to electricity costs in the 8-12¢/kWh range.

The next generation of stand-alone biopower production will substantially reduce the high costs and efficiency disadvantages of today's industry. The industry is expected to dramatically improve process efficiency through the use of co-firing of biomass in existing coal-fired power stations, through the introduction of high-efficiency gasification-combined-cycle systems, and through efficiency improvements in direct-combustion systems made possible by the addition of fuel drying and higher performance steam cycles at larger scales of operation. Technologies presently at the research and development stage, such as Whole Tree Energy™ integrated gasification fuel cell systems, and modular systems, are expected to be competitive in the future.

Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy

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Technology Alternatives

The nearest term low-cost option for the use of biomass is co-firing with coal in existing boilers. Co-firing refers to the practice of introducing biomass as a supplementary energy source in high efficiency boilers. Co-firing has been practiced, tested, or evaluated for a variety of boiler technologies, including pulverized coal boilers of both wall-fired and tangentially-fired designs, coal-fired cyclone boilers, fluidized-bed boilers, and spreader stokers. The current coal-fired power generating system presents an opportunity for carbon mitigation by substituting biomass-based renewable carbon for fossil carbon. Extensive demonstrations and trials have shown that effective substitutions of biomass energy can be made in the range of 10-15% of the total energy input with little more than burner and feed intake system modifications to existing stations. One preliminary test reached 40% of the energy from biomass. Within the current 310 GW of installed coal capacity, plant sizes range from 100 MW to 1.3 GW. Therefore, the biomass potential in a single boiler ranges from 15 MW to 130 MW. Preparation of biomass for co-firing involves well known and commercial technologies. After "tuning" the boiler's combustion output, there is very little loss in total efficiency. Since biomass in general has much less sulfur than coal, there is an SO_2 benefit, and early test results suggest that there is also a NO_x reduction potential of up to 30% with woody biomass co-fired in the 10-15% range. Investment levels are very site-specific and are affected by the available space for yarding and storing biomass, installation of size reduction and drying facilities, and the nature of the boiler burner modifications. Investments are expected to be $100-700/kW of biomass capacity, with a median in the $180-200/kW range. Note that these values are per kW of biomass, so, at 10% co-fire, $100/kW adds $10/kW to the total, coal plus biomass, capacity costs.

Another potentially attractive biopower option is gasification. Gasification for power production involves the devolatilization and conversion of biomass in an atmosphere of steam or air to produce a medium-or low-calorific gas. This "biogas" is then used as fuel in a combined cycle power generation plant that includes a gas turbine topping cycle and a steam turbine bottoming cycle. A large number of variables influence gasifier design, including gasification medium (oxygen or no oxygen), gasifier operating pressure, and gasifier type. Advanced biomass power systems based on gasification benefit from the substantial investments made in coal-based gasification combined cycle (GCC) systems in the areas of hot gas particulate removal and synthesis gas combustion. They also leverage investments made in the Clean Coal Technology Program (commercial demonstration cleanup and utilization technologies) and in those made as part of DOE's Advanced Turbine Systems (ATS) Program. Biomass gasification systems will also be appropriate to provide fuel to fuel cell and hybrid fuel-cell/gas-turbine systems, particularly in developing or rural areas without cheap fossil fuels or having a problematic transmission infrastructure. The first generation of biomass GCC systems would have efficiencies nearly double that of direct-combustion systems (e.g., 37% vs. 20%). In cogeneration applications, total plant efficiencies could exceed 80%. This technology is very near to commercial availability with one small (9MW equivalent) plant operating in Sweden. Costs of a first-of-a-kind biomass GCC plant are estimated to be in the $1,800-2,000/kW range, with the cost dropping rapidly to the $1,400/kW range for a mature plant in the 2010 time frame.

Direct-fired combustion technologies are another option, especially with retrofits of existing facilities to improve process efficiency. Direct combustion involves the oxidation of biomass with excess air, producing hot flue gases which produce steam in the heat exchange sections of boilers. The steam is used to produce electricity in a Rankine cycle. In an electricity-only process, all of the steam is condensed in the turbine cycle while, in CHP operation, a portion of the steam is extracted to provide process heat. Today's biomass-fired steam cycle plants typically use single pass steam turbines. In the past decade, however, efficiency and design features found previously in large-scale steam turbine generators have been transferred to smaller capacity units. These designs include multi-pressure, reheat and regenerative steam turbine cycles, as well as supercritical steam turbines. The two common boiler designs used for steam generation with biomass are stationary and traveling-grate combustors (stokers) and atmospheric fluid-bed combustors. The addition of drying processes and incorporation of higher performance steam cycles is expected to raise the efficiency of direct-combustion systems by about 10% over today's best direct-combustion systems, and to lower the capital investment from the present $2,000/kW to about $1,300/kW or below.

Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy

OVERVIEW OF BIOMASS TECHNOLOGIES

The three technologies discussed in the detailed technology characterizations are all at either the commercial or commercial-prototype stage. There are additional technologies that are at the conceptual or research and development stage and thus do not warrant development of a comparable technology characterization at this time. However, these options are potentially attractive from a performance and cost perspective and therefore do merit discussion. These technologies include the Whole Tree Energy™ process, biomass gasification fuel cell processes, and small modular systems such as biomass gasification Stirling engines.

The Whole Tree Energy™ process is under development by Energy Performance Systems, with the support of EPRI and DOE, for application to large-scale energy crop production and power generation facilities, with generating capacities above 100 MW. To improve thermal efficiency, a 16.64 MPa/538
Whole trees are to be harvested by cutting the trees at the base, then transported by truck to the power plant, stacked in a drying building for about 30 days, dried by air heated in the second stage of the air heater downstream of the boiler, and burned under starved-air conditions in a deep-bed combustor at the bottom of the furnace. A portion of the moisture in the flue gas will be condensed in the second stage of the air heater and collected along with the fly ash in a wet particulate scrubber. The remainder of the plant is similar to a stoker plant. Elements of the process have been tested, but the system has not been tested on an integrated basis.

Gasification fuel cell systems hold the promise of high efficiency and low cost at a variety of scales. The benefits may be particularly pronounced at scales previously associated with high cost and low efficiency (i.e., from < 1MW to 20 MW). Fuel cell-based power systems are likely to be particularly suitable as part of distributed power generation strategies in the U.S. and abroad. Extensive development of molten carbonate fuel cell (MCFC) technology has been conducted under DOE and EPRI's sponsorship, largely with natural gas as a test fuel. Several demonstration projects are underway in the U.S. for long-term testing of these cells. A limited amount of testing was also done with MCFC technology on synthesis gas from a coal gasifier at Dow Energy Systems' (DESTEC) facility in Plaquamine, LA. The results from this test were quite promising.

No fuel cell testing has been done to-date with biomass-derived gases despite the several advantages that biomass has over coal in this application. Biomass' primary advantage is its very low sulfur content. Sulfur-containing species are a major concern in fossil fuel-based fuel cell systems since fuel cells are very sensitive to this contaminant. An additional biomass advantage is its high reactivity. This allows biomass gasifiers to operate at lower temperatures and pressures while maintaining throughput levels comparable to their fossil-fueled counterparts. These relatively mild operating conditions and a high throughput should permit economic construction of gasifiers of a relatively small scale that are compatible with planned fuel cell system sizes. Additionally, the operating temperature and pressure of MCFC units may allow a high degree of thermal integration over the entire gasifier/fuel cell system. Despite these obvious system advantages, it is still necessary for actual test data to be obtained and market assessments performed to stimulate commercial development and deployment of fuel cell systems.

The Stirling engine is designed to use any heat source, and any convenient working gas, to generate energy, in this case electricity. The basic components of the Stirling engine include a compression space and an expansion space, with a heater, regenerator, and cooler in between. Heat is supplied to the working gas at a higher temperature by the heater and is rejected at a lower temperature in the cooler. The regenerator provides a means for storing heat deposited by the hot gas in one stage of the cycle, and releasing it to heat the cool gas in a subsequent stage. Stirling engine systems using biomass are ideal for remote applications, stand-alone or cogeneration applications, or as backup power systems. Since the Stirling engine is an external combustion system, it requires less fuel-gas cleanup than gas turbines. A feasibility test of biomass gasification Stirling engine generation has been performed by Stirling Thermal Motors using a 25 kW engine connected to a small Chiptec updraft gasifier. While the results were encouraging, further demonstration of the concept is required.

Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy

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Markets

Biopower systems encompass the entire cycle – growing and harvesting the resource, converting and delivering electricity, and recycling carbon dioxide during growth of additional biomass. Biomass feedstocks can be of many types from diverse sources. This diversity creates technical and economic challenges for biopower plant operators because each feedstock has different physical and thermochemical characteristics and delivered costs. Increased feedstock flexibility and smaller scales relative to fossil-fuel power plants present opportunities for biopower market penetration. Feedstock type and availability, proximity to users or transmission stations, and markets for potential byproducts will influence which biomass conversion technology is selected and its scale of operation. A number of competing biopower technologies, such as those discussed previously, will likely be available. These will provide a variety of advantages for the U. S. economy, from creating jobs in rural areas to increasing manufacturing jobs.

The near-term domestic opportunity for GCC technology is in the forest products industry. A majority of its power boilers will reach the end of their useful life in the next 10-15 years. This industry is already familiar with use of its low-cost residues ("hog" fuel and even a waste product called "black liquor") for generation of electricity and heat for its processing needs. The higher efficiency of gasification-based systems would bolster this self-generation (offsetting the need for increased electricity purchases from the grid) and perhaps allow sales of electricity to the grid. The industry is also investigating the use of black liquor gasification in combined cycles to replace the aging fleet of kraft recovery boilers.

An even more near-term and low-cost option for the use of biomass is co-firing with coal in existing boilers. Co-firing biomass with coal has the potential to produce 10 to 20 GW in the next twenty years. Though the current substitution rate is negligible, a rapid expansion is possible using wood residues (urban wood, pallets, secondary manufacturing products) and dedicated feedstock supply systems such as willow, poplar and switchgrass.

Resource Issues

Nationally, there appears to be a generous fuel supply. However, the lack of an infrastructure to obtain fuels and the current lack of demonstrated technology to combust or gasify new fuels currently prevents utilization of much of this supply. According to researchers at Princeton University, of the total U.S. biomass residues available, half could be economically used as fuel. They estimate that of the 5 exajoules (4.75 quads) of recoverable residues per year, one third are made up of agricultural wastes and two thirds composed of forestry products industry residues (60% of which are mill residues). Urban wood and paper waste, recoverable in the amount of 0.56 EJ per year, will also be an important source. Pre-consumer biomass waste is also of increasing interest to urban utilities seeking fuels for co-firing, and such use also provides a useful service to the waste producer.

In the Southeast, biomass resources are plentiful, with 91.8 Tg of biomass fuel produced annually according to a study done in the mid-1980s by the Southeast Regional Biomass Energy Program. This translates to an estimated potential of 2.3 EJ of annual energy. North Carolina and Virginia are the biggest wood fuel producers (10.4 and 10.1 Tg, respectively). These residues come primarily from logging applications, culls and surplus growth, and are in the form of whole tree chips. In the western U.S., California is another major user of biomass energy. The California biomass market grew from about 0.45 Tg in 1980 to about 5 Tg in the early 1990s. Feedstocks include mill residues, in-forest residues, agricultural wastes and urban wood waste.

Worldwide, biomass ranks fourth as an energy resource, providing approximately 14% of the world's energy needs. In developing countries, biomass accounts for approximately 35% of the energy used, and in the rural areas of these nations, biomass is often the only accessible and affordable source of energy [12]. There is much optimism that biomass will continue to play a significant, and probably increasing, role in the world's future energy mix. The basis

Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy

for this optimism stems from: (1) the photosynthetic productivity of biomass (conservatively an order of magnitude greater than the world's total energy consumption); (2) the fact that bioenergy can be produced and used in a clean and sustainable manner; and (3) continuing advancements in biomass conversion technologies along several fronts. Increased bioenergy use, especially in industrialized countries, will depend on greater exploitation of existing biomass stocks (particularly residues) and the development of dedicated feedstock supply systems.

Because the future supply of biomass fuels and their prices can be volatile, many believe that the best way to ensure future fuel supply is through the development of dedicated feedstocks. Large-scale dedicated feedstock supply systems designed solely for use in biomass power plants do not exist in the U.S. today on a commercial basis. The DOE Biomass Power Program (BPP) recognizes this fact, and a major part of the commercial demonstration program directly addresses dedicated feedstock supply issues. The 'Biomass Power for Rural Development' projects in New York (willow), Iowa (switchgrass), and Minnesota (alfalfa) are developing the commercial feedstock infrastructure for dedicated feedstocks. The Minnesota Valley alfalfa producers project will involve the production of 700,000 tons/yr of alfalfa on 101,000 hectares (250,000 acres) of land. Unused agricultural lands in the U.S. (31.6 million ha in 1988) are primary candidates for tree plantations or herbaceous energy crops. About 4% of the land within an 80 km radius could supply a 100 MW plant operating at 70% capacity. Although, there are requirements for water, soil type and climate that will restrict certain species to certain areas, an assured regional fuel supply can reduce variability in prices.

Oak Ridge National Laboratory also has an extensive feedstock development and resource assessment program that is closely integrated with the DOE BPP. ORNL is responsible for development and testing of the switchgrass and hybrid poplar species that are receiving intense interest by not only the commercial power project developers, but also the forest products industry.

Although not directly applicable, there are numerous examples in the agriculture and pulp and paper industries that serve to illustrate the feasible size of sustainable commercial biomass operations. There are over fifty pulp and paper mills in the U.S. that produce more than 500,000 tons/yr of product [3]. The feed into such plants is at least one third higher than the product output, with the additional increment being used for internal power and heat generation. The sugarcane industry also routinely harvests, transports, and processes large quantities of biomass. In the U.S. alone, more than a dozen sugar mills each process more than 1.3 million tons of cane per year, including four plants in Florida that process more than 2.25 million tons/yr [4]. Sweden and the other Scandinavian countries have long been leaders in the biomass energy arena. Currently, Sweden has over 16,500 hectares of farmland planted in willow for energy use. The market for woody biomass for energy in Sweden has experienced strong growth, with a steady increase equivalent to 3-4 TWh extra each year for the last five years. This equals one nuclear power station in aggregate every two years. Additionally, Denmark annually produces roughly 7 million tons of wheat straw that cannot, by law, be burned in-field. This straw is increasingly being used for energy production. Thus, there is ample evidence that agricultural, harvest, transport, and management technologies exist to support power plants of the size contemplated.

Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy

OVERVIEW OF BIOMASS TECHNOLOGIES

Environmental Issues

Two primary issues that could create a tremendous opportunity for biomass are: (1) global climate change and (2) the implementation of Phase II of Title IV of the Clean Air Act Amendments of 1990 (CAAA). Biomass offers the benefit of reducing NO_x, SO_2, and CO_2 emissions. The environmental benefits of biomass technologies are among its greatest assets. The first issue, global climate change, is gaining greater salience in the scientific community. There now appears to be a consensus among the world's leading environmental scientists and informed individuals in the energy and environmental communities that there is a discernable human influence on the climate, and that there is a link between the concentration of carbon dioxide (i.e., greenhouse gases) and the increase in global temperatures. The recognition of this link is what led to the signing of the Global Climate Change treaty. Co-firing biomass with fossil fuels and the use of integrated biomass-gasification combined cycle systems can be an effective strategy for electric utilities to reduce their emissions of greenhouse gases.

The second issue, the arrival of Phase II emission requirements, could also create a number of new opportunities for biomass to be used more widely in industrial facilities and electric power generating units. The key determinant will be whether biomass fuels offer the least expensive option for a company when compared to the installation of pollution control equipment or switching to a "cleaner" fossil fuel.

The second, and more restrictive, phase of the CAAA goes into effect in 2000. CAAA is designed to reduce emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x), that make up acid rain, and are primarily emitted by fossil-fuel powered generating stations. The first phase of CAAA affects the largest emitters of SO_2 and NO_x, while the second phase will place tighter restrictions on emissions not only from these facilities, but also from almost all fossil-fuel powered electric generators of 25 MW or greater, utilities and non-utilities alike. The impact of Phase II will be tempered by the fact that most of the utilities that had to comply with Phase I chose to over comply, thereby creating a surplus of allowances for Phase II use. The planned strategies for compliance by utilities suggest that fuel switching will be the compliance of choice. Fuel switching will be primarily to low sulfur coal. Other strategies include co-firing with natural gas, purchasing of allowances, installing scrubbers, repowering of existing capacity, and retirement of existing capacity. An opportunity exists for biomass, especially if credit is given for simultaneous reduction in greenhouse gases.

Use of biomass crops also has the potential to mitigate water pollution. Since many dedicated crops under consideration are perennial, soil disturbance, and thus erosion can be substantially reduced. The need for agricultural chemicals is often lower for dedicated energy crops as well leading to lower stream and river pollution by agri-chemical runoff.

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Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy

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

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.

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 400 megawatt 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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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 components include a switchyard for electrical interconnection, cooling towers for

[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.

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 CO_2 per kilowatt-hour output, whereas a new coal-fired power plant would produce about 2 lb CO_2 per kilowatt-hour. To the extent that new combined-cycle plants substitute for existing coal capacity, they can substantially reduce average per-kilowatt-hour CO_2 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.

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

Natural Gas Simple-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 simple-cycle gas turbine power plants. The intent is to characterize a typical facility, recognizing that actual facilities will likely differ from these assumptions in the particulars. 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 simple-cycle power plants is needed. The Council's technology characterizations are available to others for their own purposes.

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.

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H

APPENDIX H

PUGET SOUND ENERGY

FINAL REPORT

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

Prepared by Tenaska, Inc.
Omaha, Nebraska

March 2003

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

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Disclaimer

This report is based on information obtained from various sources and Tenaska's best judgment and experience as of December 2002. This report also contains some forward-looking opinions. Certain unanticipated factors could cause actual results to differ. While we believe the information to be correct, Tenaska makes no assurances or warranties as to accuracy or completeness, and assumes no responsibility for the results of any actions taken by Puget on the basis of this report.

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 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.

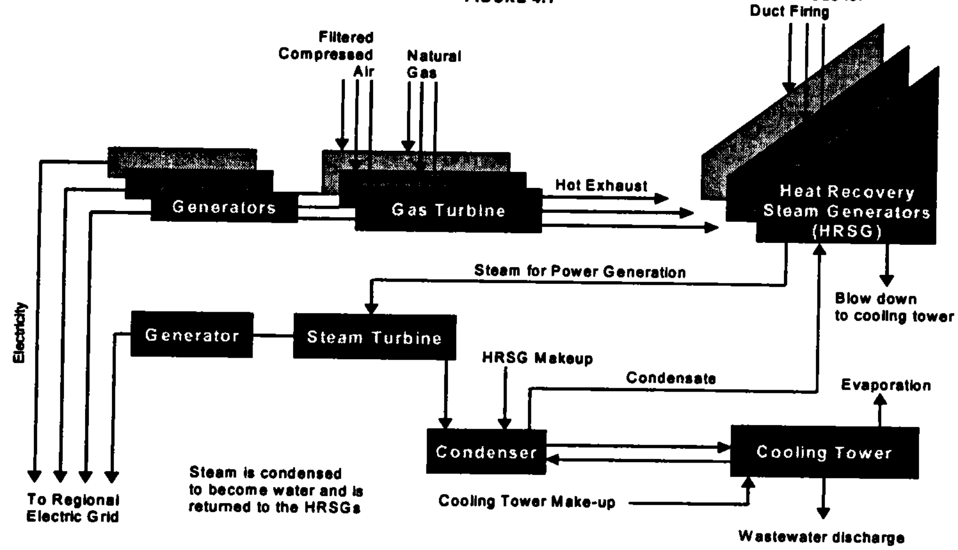
Section 3 – Basic Project Configurations

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 60 percent of the mechanical energy produced by the power turbine is consumed to drive the air compressor. The balance 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 cost 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 costs shown on Table 3.1 represent the price of electricity needed per MWh, assuming 7884 annual operating hours , 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 3.1

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 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 (using common financial assumptions and fuel cost). FA-

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

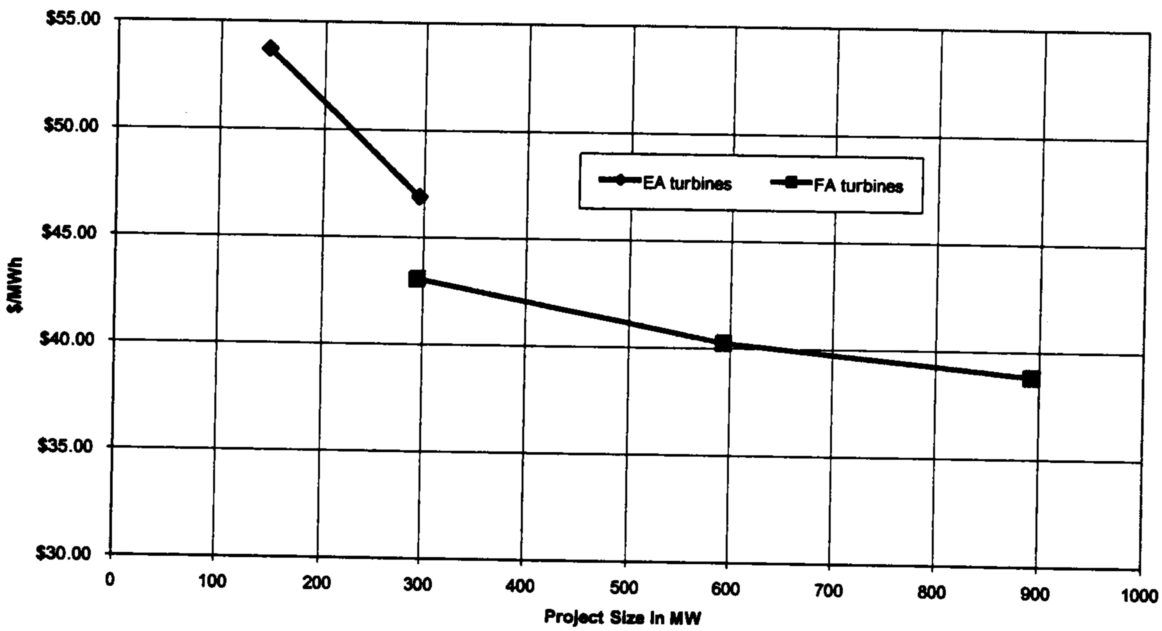
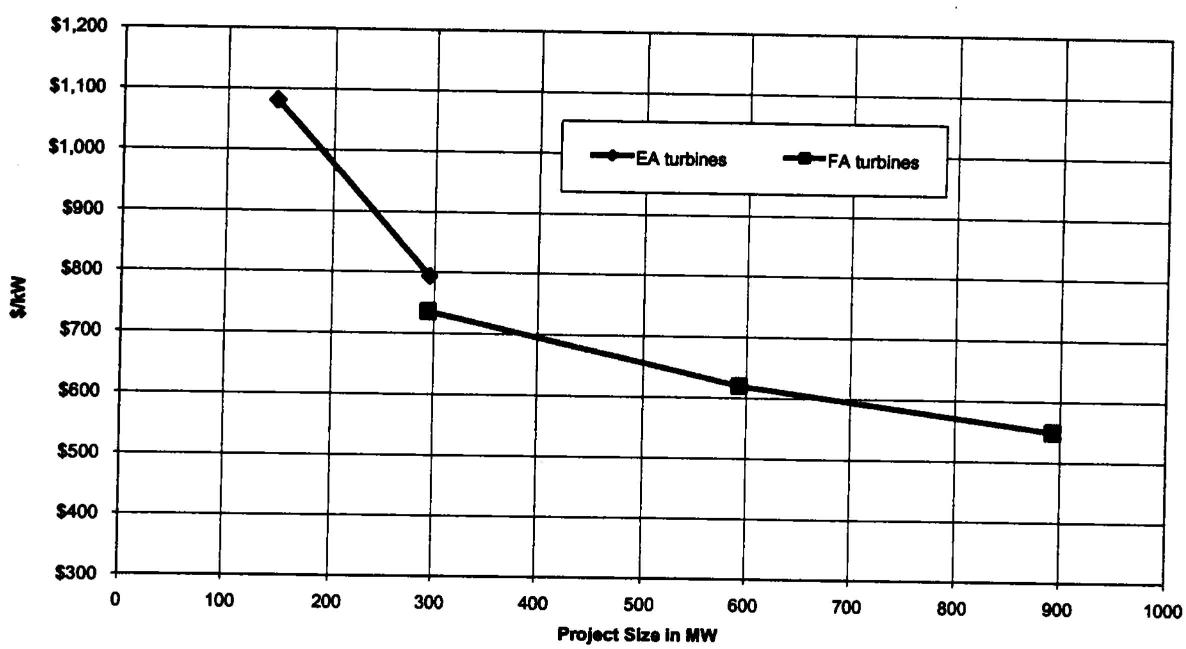


FIGURE 4.3
Generic Combined Cycle Plants - Capital Cost
June 2002 Results



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 recirculated 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 3.1 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 7FA 1 X 1 on Table 3.1, 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 observed 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 $70MM (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 perfect in every aspect. 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 with 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 6.1, based on the technical characteristics of the generic combined cycle plants detailed on Table 3.1 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 6.1

	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 (GT, ST & HRSG's)	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 per kW 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 8.1 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 $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 8.1

Example of Total Installed Project Costs ($2002)		
	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%

Example of Total Installed Project Costs ($2002)		
	000 $	Percent of Total
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 and may be dependent upon lender requirements.

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.

Table 8.2

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 9.1

Activity	Operating Hours Between Each Activity	Starts Between Each Activity
Combustion Inspection	8,000	400
Hot Gas Path Inspection	24,000	800
Major Overhaul	48,000	2,400

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 with an annual fixed minimum fee ($450 to $500/fired hour for a 1 X 1, for example). In this fashion, the manufacturer assumes most of the risks associated with parts availability, premature wear, etc. and some equipment performance issues.

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 10.1 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:

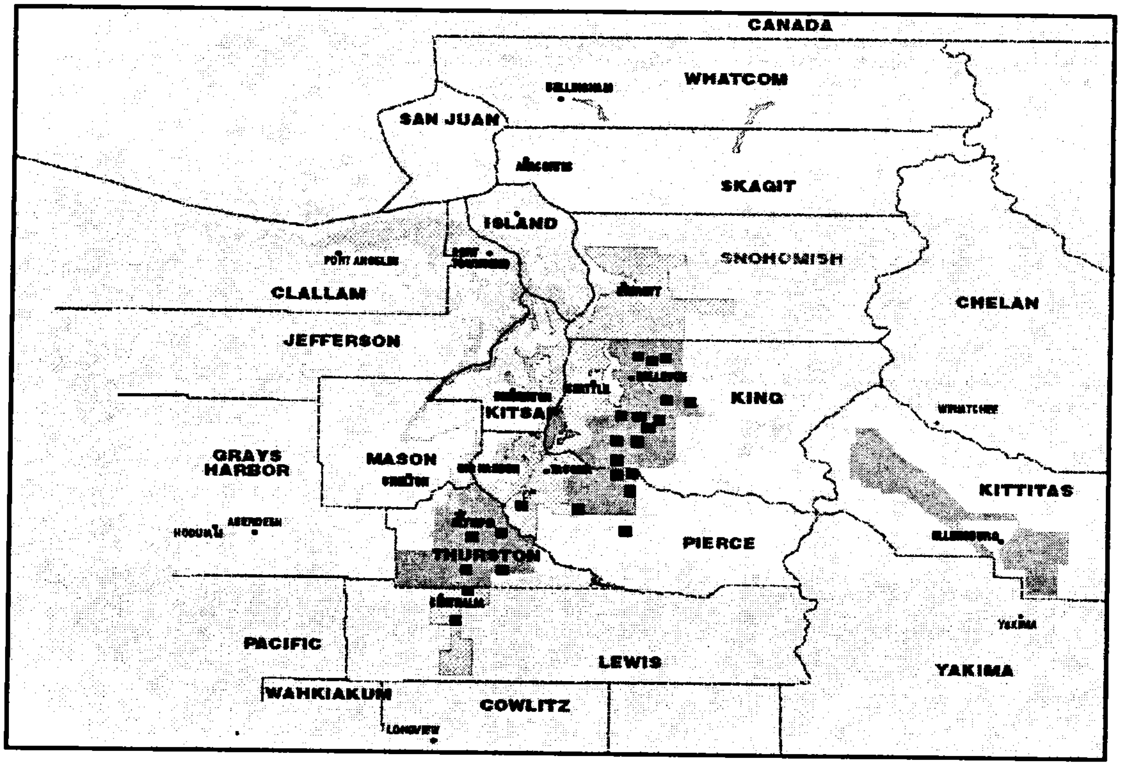
Table 10.1

	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			
Capacity Factor	60%	52.33	49.34	51.01
	70%	49.17	46.29	47.77
	80%	46.54	43.98	45.32
	90%	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 $3.63/mmbtu fuel, and other financial assumptions, range from about $42/MWh for a Frederickson 2 X 1 with a capacity factor of 90% to about $52.33/MWh for a Frederickson 1 X 1 with a capacity factor of 60%. 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



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