VIII. ELECTRIC PLANNING ENVIRONMENT

This chapter explores the major industry, regional, and Company issues and trends that form the backdrop for PSE's Least Cost Planning process. Current uncertainties in the planning environment create cost risks and can even determine whether a particular resource strategy is executable.

Many of the planning environment issues described below were identified and clarified through PSE's exploration of the long-term energy resource market following its April 2003 Least Cost Plan. In 2004, PSE issued a Request for Proposals (RFP) and from the responses, PSE has identified certain challenges and risks that can cause an otherwise cost-effective resource to be unattainable. Overriding considerations are whether the resource can be permitted and built, and whether the energy can be transmitted to PSE's system.

This chapter discusses seven key issues that can adversely impact resource opportunities. The first issue of importance is transmission, which is heavily constrained throughout the northwest and the topic of much regional debate. The second key issue is environmental initiatives, which can come from all levels of government and a variety of stakeholders. The third issue is the evolving nature of resource development and the current status of the industry. The fourth issue covers the regional load-resource balance, which is important to PSE as an active market participant. The fifth issue concerns the availability and cost of demand-side resources: energy efficiency, fuel conversion, and demand response. The last two key issues are summaries of financial issues and gas-for-power issues that are covered in greater detail elsewhere in the document.

To a large degree, this set of key issues is also the main determinant of PSE's analytic approach. The analytics are designed to explore the range of these issues and how alternate futures impact resource strategy.

A. Regional Transmission

Currently, PSE's ability to acquire generation outside its service territory is severely constrained due to limitations of the regional transmission system. Factors that are of particular concern to PSE include:

- Lack of existing capacity,

- Uncertainty about the planning process for needed expansions,
- Uncertainty about costs and rate structure for new regional transmission,
- Multi-jurisdictional siting and permitting issues,
- Mismatch of transmission and resource development processes,
- Ultimate form of Federal Energy Regulatory Commission (FERC) regulation and the future of a potential regional transmission organization, and
- Uncertainty about who will finance, build and pay for needed transmission.

If these political and institutional factors are not addressed in a timely manner, PSE will be limited in its ability to acquire certain resources such as wind from the Columbia Gorge, coal plants from Montana, Wyoming, Idaho or Nevada, geothermal power from Oregon and hydroelectric power from British Columbia.

Beginning with an overview of PSE's transmission system, this section looks at the constraints affecting use of the regional transmission grid.

A.1. Current Situation

PSE's Transmission System

PSE operates and maintains an extensive electric system consisting of generating plants, transmission lines, substations, and distribution equipment. For the most part, PSE's transmission system of 115 kV and 230 kV facilities has developed to move power to customers. PSE does not have significant excess transmission capacity either across its service area or outside its service area. To integrate resources outside its service area, PSE has typically contracted for transmission from the Bonneville Power Administration (BPA).

PSE's transmission system interconnects with several utilities including BPA, Seattle City Light, Snohomish PUD, Tacoma Power, British Columbia Transmission Corporation, Chelan County PUD, Douglas County PUD, Grant County PUD and with purchasers of the Centralia project. Most of the interconnections are west of the Cascades.

Regional Transmission System

Numerous developments have created pervasive congestion on the grid.

- Current load patterns are significantly different than those used to design the grid.

- Resource operations patterns have changed with the entrance of market participants other than utilities and the construction of new gas-fired generating sources, whose actual operation is highly variable.
- The transmission industry is in the middle of considerable change and it is unclear what the final Northwest transmission structure will look like.

Recent development of gas-fired generation and other intermittent resources has made operation of the transmission system more difficult. The number of market transactions has grown significantly, increasing the complexity of system operations. Consequently, the grid is now being utilized at near-full capability and any forced outage or critical maintenance often places the grid in a “de-rated” condition.

New generation opportunities in PSE’s service area may be limited to natural gas projects and small-scale renewables. In order to diversify with coal or wind resources, PSE must look to the east. However, bringing this new generation to PSE loads will require transmission that, at present, may not be available. Exhibit VIII-1 shows the numerous constrained paths on BPA’s system between the new potential supply and PSE loads while Exhibit VIII-2 summarizes the path constraints that are directly affecting PSE’s ability to import new generation.

Exhibit VIII-1[1]

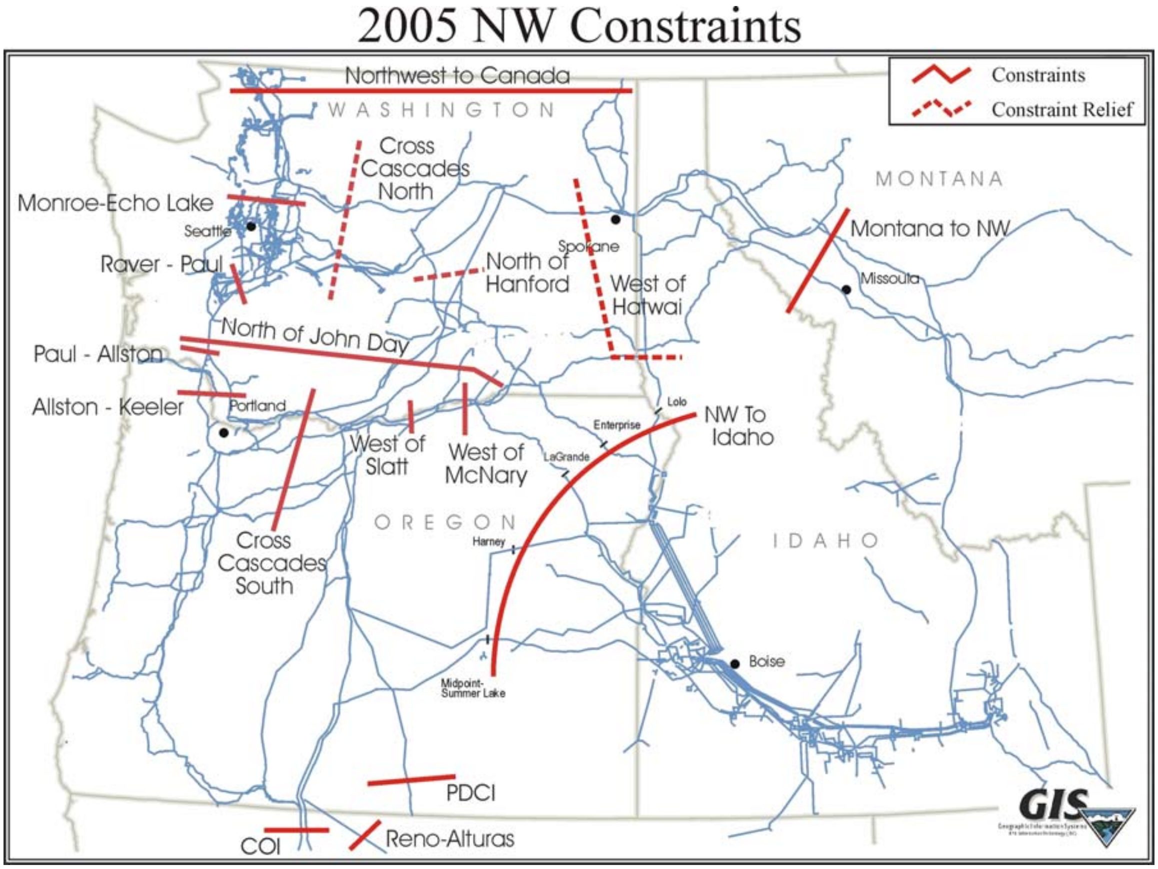


Exhibit VIII-2
Transmission Path Constraints Affecting PSE's Ability to Import New Generation

Transmission Path	Where Constrained
Across the Cascades	• Washington[2] • Oregon
From Montana to the NW	• In Montana west of Garrison • In Washington west of Spokane[3]
Along I-5 corridor	• South of Monroe
West through the Columbia River Gorge	• McNary • Slatt

[1] Reprinted with permission from the BPA
[2] Completion of the Schultz series capacitors increases across-the-Cascades capacity in Washington by 300 MW.
[3] The completion of the new Bell-Coulee 500 kV line should reduce congestion in Washington, west of Spokane.

BPA's current transmission system improvements are designed primarily to meet and maintain its current obligations, including an obligation to support load growth where contractually committed. At present, generation planning and transmission planning are not performed in an integrated manner. Thus, new upgrades are not contemplated without a specific request for service from the generation developer. BPA's studies indicate that the agency has little room to grant new firm transmission requests, which means PSE must find a transmission solution for each new generation project. Because of this, the availability and cost of transmission have become key aspects of PSE's decision-making process for acquiring new resources.

A.2. Process for Acquiring Long-Term Firm Transmission

The Northwest does not currently have a single regional body to coordinate transmission requests. Under current FERC rules, transmission providers sell long-term firm transmission through their Open Access Same-time Information System (OASIS). Resource developers, therefore, must identify and apply to individual transmission providers.

Requesting transmission is a cumbersome process, involving multiple steps and the possibility of one or more studies. Completion of this process can take anywhere from a few months to several years.

If the new transmission requires service from multiple providers, the customer must make requests with each provider. Since the review processes may not match (e.g. one provider can offer immediate service while the other requires facility upgrades), the transmission customer may face the decision to sign up for one section of the transmission before securing rights for the entire route.

In order to site a new resource, the developer needs to know the cost and availability of transmission. As a result, the request queues for key transmission routes become overloaded with applications of varying certainty. After the developer has worked through the process and is offered a service agreement, it will need to either execute the agreement regardless of the project status, or risk losing its place in the queue. Transmission providers often require customers to front the costs of network upgrades prior to undertaking the work.

Once upgrades have been built, the transmission provider must recover the cost. One rate model has the customer prepaying for wheeling and then receiving credits under the provider's tariffed rate until the total amount credited equals the money prepaid by the customer. Under this model, PSE, the customer, would pay for transmission facilities without receiving the asset benefits of ownership. This model also makes transmission upgrades essentially participant-funded without regard to the regional value provided.

A.3. Long-Term Regional Transmission Structure

The Northwest continues to function without a regional transmission organization, and without workable processes to align generation and transmission development and investment. Since the advent of open access transmission rules in 1996, regional entities have made a number of attempts to form regional transmission organizations such as IndeGO and RTO West. These previous attempts proved unsuccessful.

However, in light of the genuine need to resolve the region's transmission problems, a variety of interested regional parties came together to form two new organizations, Grid West and the Transmission Issues Group. The intention of these groups was to address critical transmission-related issues and search for solutions.

Grid West

In late 2004, a group of regional transmission stakeholders wrote and agreed upon bylaws for a new organization called Grid West. Grid West follows earlier work of IndeGO and RTO West in attempting to create an organization meeting FERC's minimum characteristics and functions as laid out in Order 2000. This was the first step in the development of a voluntary organization with regional accountability. Grid West builds upon previous efforts, such as RTO West, to define and solve the region's transmission problems. The organization has identified the following difficulties with regard to regional transmission services today:

- Current rules and practices prevent full utilization of transmission infrastructure.
- Current structure impedes efficient, region-wide transactions.
- Congestion is managed through curtailment.
- Planning and constructing needed transmission infrastructure is not being effectively performed.
- Independent market monitoring is lacking.

The Grid West proposal has the potential to improve transmission service and infrastructure development in the following ways.

- *Improve system planning and expansion procedures to ensure timely replacement and expansion of aging transmission infrastructure*—If the Grid West organization reaches the operational stage, it will be authorized to act as a "backstop" for making sure that transmission infrastructure critical to reliable operations is built when needed.
- *Facilitate multi-party agreements for cost and benefit allocation.*
- *More efficiently manage the operating conditions that affect system reliability.*

Transmission Issues Group

In a parallel effort, several regional utilities and agencies that support near-term improvements have come together to form the Transmission Issues Group (TIG). One goal of the TIG is to resolve transmission issues through contractual arrangements among existing entities without the creation of a new organization. Together, they have developed a set of suggested changes that the region could implement in the next two to three years. These changes are based upon the premise that an evolutionary and adaptive approach is the best way to solve regional transmission problems.

Position of Regional Parties

All efforts to adopt a regional transmission organization have failed due to disagreements regarding cost and control. Generally, entities without significant future transmission needs believe an RTO would inequitably shift costs from entities with transmission needs to the entire region. Some parties also argue that the costs to establish and operate an RTO are higher than the regional market benefits.

In addition to economic considerations, an RTO changes the level of control exercised by the individual transmission owners. Current transmission owners are concerned about retaining full economic and operational value for their lines after they are turned over to RTO control.

Some parties may also fear losing the local market advantage brought about by a constrained transmission system. For example, gas-fired generation may benefit from grid congestion, because coal, integrated into an unconstrained grid, would likely push market prices lower than would gas-fired generation coupled with grid congestion.

Some local governments in the Pacific Northwest are fighting FERC's transmission initiatives primarily because they oppose the idea that the federal government should usurp their control over local transmission.

Ultimately, in spite of all of the effort that has gone into the development of a regional transmission structure, the future of GridWest and other regional efforts is unknown. Parties generally agree on the problem but not the solution. In short, there are no transmission solutions visible on the horizon.

A.4. Long-Term Regional Transmission Planning and Expansion

Absent a central planning body, regional parties have formed a number of organizations to study transmission expansions and related transmission issues.

Northwest Transmission Assessment Committee (NTAC)

With the establishment of the Northwest Transmission Assessment Committee (NTAC) in 2003, the region gained an organized body that approaches transmission issues from a perspective influenced by both commercial and reliability needs. NTAC functions as an open forum to address forward-looking planning and development for the Northwest Power Pool (NWPP) area transmission system.

Specifically, NTAC has formed subcommittees to study congested paths that are of interest to participants. So far, there are subcommittees studying the Puget Sound area, the Montana to Northwest path, the Canada to California path, and the SE Washington/NE Oregon area.

The first study completed by an NTAC subcommittee was the "Puget Sound Area Upgrade Study Report," which was published in November 2004. The goal of this study was

> "to explore options that would make the transmission system in the Puget Sound area more robust when system components are out of service in meeting its current needs and to explore how these improvements may impact future load

service capability, integration of resources, reduction in Remedial Action Schemes (RAS) and higher import capability."

The study identifies problems and describes three portfolios of transmission system upgrades and expansions to fix those problems. However, it "does not make any determination or recommendation regarding the development or requirement for any project. Parties may choose to pursue further planning studies for investment decisions as necessary." In other words, NTAC does not take a role in ensuring that transmission is built.

The Rocky Mountain Area Transmission Study (RMATS)

RMATS is another planning effort that could influence PSE's ability to import energy. In RMATS, stakeholders examined the value of potential transmission expansion under different generating scenarios. Feasible transmission additions were identified and selected to proceed to a second phase (Phase II). During Phase II, technical studies will be conducted to address various issues concerning siting, cost assignment and recovery, as well as project sponsors and financing.

The process thus far has identified projects for both short- and long-term improvements. There are two recommendations for long-term improvement. The first involves expansion projects within the Rocky Mountain footprint, while the second involves export projects beyond that footprint, such as a path from Montana to the Northwest.

As a major part of its Phase II initiatives, RMATS recommends that governors of involved states convene with the CEOs of benefiting entities to help foster the development of these projects. A variety of important issues and necessary steps are clearly suggested in the Phase I final report. While the RMATS group is encouraging the construction of transmission, like NTAC, it does not have the authority to make this happen.

Involvement of Western State Governors

Western governors, partially in response to FERC's initiatives, launched a new era in transmission planning with the release of the report "Conceptual Plans for Electricity Transmission in the West" and the development of an Energy Policy Roadmap. They also explored related financing issues in a separate report entitled, "Financing Electricity Transmission Expansion in the West."

In the most recent version of the Energy Policy Roadmap, these governors urged the industry, states and provinces to implement a pro-active western interconnection transmission planning process. As a result, a collaborative process has been initiated by the Seam Steering Group-Western Interconnection. In addition, four sub-regional planning efforts are underway:

- Rocky Mountain Area Transmission Planning Study (RMATS)
- Southwest Transmission Expansion Plan
- Northwest Transmission Assessment Committee (NTAC)
- Southwest Area Transmission study

Individual states are also responding. For example, in Wyoming, the governor signed an executive order in 2003 encouraging state agencies to work closely with other states toward the development of electric transmission lines. The order also directed agencies to create efficient processes for environmental review, as well as for siting and permitting transmission lines. The Wyoming Legislature then passed a law in 2004 creating the Wyoming Infrastructure Authority. It has $1 billion in bonding authority and will participate in planning, financing, constructing, developing, acquiring, maintaining and operating electric transmission facilities.

The 2005 Washington state Legislature is also considering a bill to facilitate transmission development. Washington's bill would allow developers of transmission projects to seek permits through the state's Energy Facility Site Evaluation Council.

Role and Limitations of BPA

BPA is the only entity in the Northwest with a geographic scope and siting authority that approaches what is needed to build regional transmission. However, BPA does not currently have the borrowing authority to undertake major regional transmission expansion. BPA's scope is also limited by law and policy. Without BPA involvement, a Colstrip like solution will be difficult to organize.

In its *2004 Programs in Review* workshops, BPA discussed its financial situation. The agency has a total of $4.45 billion in borrowing authority for all BPA projects, both power and transmission. By the end of 2002, BPA had $2.77 billion in bonds outstanding, leaving less than $2 billion available. Over the last four years, BPA has invested over $1 billion in transmission infrastructure, including two major transmission line projects. A third will be completed in December. Current projections show BPA's borrowing authority expiring as early as 2007-08. BPA's existing capital plan includes some transmission construction targeted at reducing congestion or aiding economic power transactions.

As an alternative funding arrangement, BPA is attempting participant funding on the McNary–John Day upgrade. The next major step in this process is for BPA to receive signed commitments to participate from interested parties. These signed commitments are due to BPA by June 30, 2005.

BPA is also a key participant in study groups examining the transmission needs of the region. In fact, the agency provides a tremendous amount of study capability for the region. However, study alone is not enough to solve the problem. Without a clear mechanism to ensure that needed transmission is built, the development of new generation will be impeded.

A.5. Transmission Siting and Development

Transmission siting issues and development risks are commensurate with those for resource development. Developers of new energy resources must be able to bring their generation to load. Without certainty of this, lenders will not finance these efforts. To obtain that certainty, there must be adequate transmission capacity at a reasonable price, or a clear and predictable process for developing and pricing new transmission.

Most PSE construction on its own system of 115 kV and 230 kV lines involves upgrades to existing lines. Only rarely does PSE undertake development of a new line because of the difficulty in siting and permitting. PSE has similar expectations regarding broader regional transmission expansion—that most upgrades and expansions will involve existing lines and rights of way.

In order to construct new transmission, developers must be prepared for the following: working with multiple jurisdictions; observing differing processes for each jurisdiction, at each level of government (local, state and federal); anticipating local issues; working around a lack of central siting or permitting authorities.

The physical reality of electricity flow over long distance transmission lines is that as generation flows to load, the energy will cross several cut-planes and multiple states. Because facility siting lies with each state, transmission lines crossing more than one state (coal and wind, for example) will involve multiple independent, and often disjointed, state processes. These processes are distinct from those of the transmission provider(s). In order to qualify for a new transmission contract, each of the affected paths must have sufficient available transmission capacity (ATC). If the ATC is insufficient, new transmission must be built.

Early assessment of environmental conditions will determine the level of permitting necessary to gain regulatory approval. Common regulatory permits at the federal and state levels include SEPA/NEPA, Endangered Species (biological assessments), Army Corps of Engineers section 404 and 10 permits, Department of Fish/Wildlife HPA and the Department of Ecology (NPDES). At the city or county level, common permitting needs are conditional use permits for shorelines, clearing and grading, critical area review, and right-of-way use.

In addition to these permits, consideration must be made as to whether tribal lands will be affected by proposed transmission line siting, necessitating the need to enter land-use negotiations. Additionally, the company could be required to enter into long-term franchise agreements with local municipalities that are granting operating rights for facilities located in their rights-of-way.

Public involvement should be incorporated throughout the planning and development phases of transmission projects. This involves informing, consulting and involving affected and concerned stakeholders in many of the Company's decisions. Although with transmission, projects usually offer system improvements and limited direct local benefits.

Adding to the complications, there is no central permitting or siting authority, which would move transmission development more quickly through the many processes. Some states may provide a central authority, while others may not. Because the transmission line moves from one state to the next, the benefits of having sporadic central authority are lost.

In many cases, routing of transmission lines can require the use of corridors other than those available via municipal, county or state rights-of-way. In these instances, easements from individual property owners are required. Because negotiation of these rights can become contentious and ultimately result in condemnation, careful consideration is critical. The use of condemnation can prove costly from both a cost/schedule perspective, and a community perception perspective.

A.6. Transmission Needs for New Resources

For the purpose of modeling in the Least Cost Plan, PSE has created two transmission cost and availability scenarios. One scenario assumes that a regional transmission organization is established and transmission expansions are reflected in system-wide wheeling rates. The other scenario assumes that PSE funds the transmission needed for its resource additions. The first scenario assumes that regional cooperation and a central organization promotes better processes, and that transmission is in place by 2013. The second scenario has new transmission in place by 2016.

Both scenarios use the same basic cost estimates. Based upon Northwest Transmission Assessment Committee information, PSE estimated that transmission for a coal project in Montana to PSE's system would cost about $1 billion dollars to construct. This is primarily a 500 kV solution. To integrate a wind plant from SE Washington, PSE has estimated the cost of a new 230 kV line to be about $250 million.

A.7. Findings

In order for PSE to continue to provide low-cost, reliable power, it must take several steps to ensure that new energy supply can reach the Company's loads.

Short Term

In the near term, PSE must focus on resources that have existing transmission rights to the PSE system. This includes resources located west of the Cascades, resources with transmission rights, and resources obtained through utilities that are directly connected to the PSE system. Other actions that PSE should consider include:

- Retaining existing contract transmission rights
- Investing to upgrade PSE-owned transmission paths

Long Term

In order to meet its long-term resource needs, PSE must continue to participate in regional efforts to create a stable, long-lasting transmission structure. Absent a regional solution, PSE must explore acquiring transmission on its own by contracting with a transmission provider, merchant transmission entity, or by building its own transmission.

PSE's current level of participation in the Grid West effort provides on opportunity to analyze transmission options and to determine the cost and benefit of formal participation in Grid West. However, PSE must also consider working with others to jointly build and own transmission and generation.

B. Environmental Initiatives

PSE faces an uncertain future with respect to renewable energy mandates, potential greenhouse gas (GHG) regulation, and new limits on emissions including NOx, SO2 and mercury (Hg). A number of proposals and studies exist that espouse a range of emission control models with different cost levels and starting years. Washington state has already adapted laws regulating GHG emissions from certain new generating facilities. Mandatory federal regulation or caps on GHG emissions appear to be an increasingly likely part of the future regulatory landscape. Absent federal policy on greenhouse gasses, some states, like Washington, are moving forward with their own regulatory programs, raising the risk that US companies will encounter a patchwork of different restrictions. In its Least Cost Plan analysis, PSE has examined resource portfolio costs over a combination of greenhouse gas cost and renewable portfolio assumptions to determine the long-run cost impact under different futures.

B.1. Emissions

Emission Policies at the Federal Level

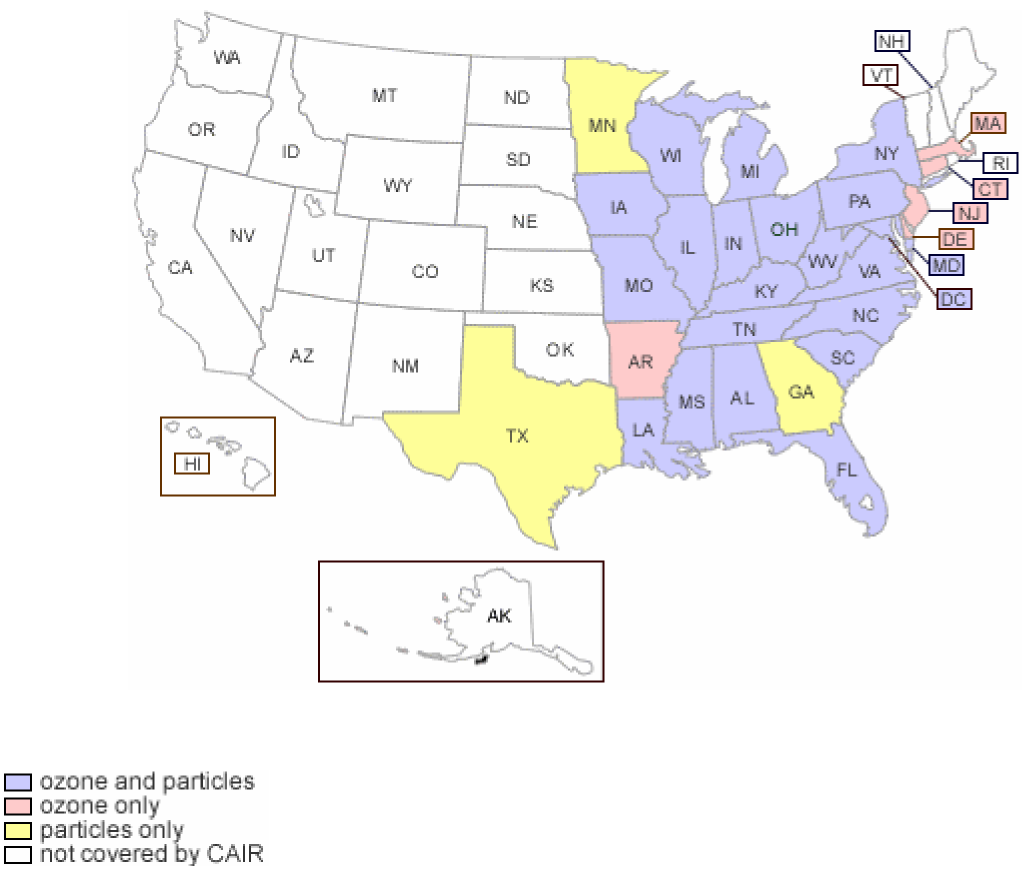
Various legislative bills continue to be introduced at the federal level to reduce GHG emissions from multiple sectors of the economy, including the power sector. Summaries of these rulemaking efforts are given below.

Two New Rules Finalized by EPA in March 2005

The EPA finalized the Clean Air Interstate Rule (CAIR) on March 10, 2005. CAIR calls for reductions in SO2 and NOx emissions from power plants in 28 eastern states and the District of

Columbia. The rule calls for reductions in SO2 emissions from power plants in the affected states from 9.4 million tons annually to 3.6 million tons in 2010 and 2.5 million tons in 2015. At full implementation, the rule will result in a 73 percent reduction in SO2 emissions. The rule will reduce NOx emissions in these states from 3.2 million tons annually to 1.5 million tons by 2009, and to 1.3 million tons in 2015. This is a 61 percent reduction. Because PSE does not operate in the CAIR affected states, it is not subject to the required SO2 and NOx reductions called for in the rule.

Exhibit VIII-3
States Affected by CAIR



On March 15, 2005, the EPA finalized the Clean Air Mercury Rule (CAMR), the intent being that CAMR would be implemented in tandem with CAIR. The CAMR applies to all power plants across the country that emit mercury. Since mercury emissions only occur with coal-fired plants, Colstrip will be the only PSE facility required to meet the mercury reduction requirements proposed in that rule. Reductions will be implemented in two phases with the first phase cap set at 38 tons. Emissions will be reduced by taking advantage of “co-benefit” reductions, that is, mercury reductions achieved by reducing SO_2 and NO_x emissions under CAIR. In the second phase, due in 2018, plants will be subject to a second cap, which will reduce emissions to 15 tons nationwide.

Both CAIR and CAMR will use cap-and-trade programs to achieve the required emissions reduction requirements. EPA will assign each state an emissions “budget”, and each state will be required to submit a State Plan revision detailing how it will meet its budget. Cap-and-trade programs provide strong incentives for utilities to make reductions at the units where controls are the most cost-effective. They also provide the flexibility necessary to mitigate risk associated with trying innovative control technologies. Experience with the Acid Rain SO_2 allowance program has shown that an efficient cap-and-trade program can effectively deliver emissions reductions at a low cost to utilities and their customers, and if a cap-and-trade program is implemented for CAIR and CAMR, it should provide the same benefits.

Because the CAIR rule is layered on top of existing SO_2 and NO_x requirements and does not provide the regulatory certainty of new legislation, it is susceptible to being overturned judicially. In fact, many in the utility industry expect lawsuits within 60 days of it being published in the Federal Register. Likewise, a report released on March 7, 2005 by the EPA’s inspector general and the nonpartisan Government Accountability Office (GAO), identified four major shortcomings in the economic analysis underlying the CAMR’s proposed control options that said the agency ignored scientific evidence. Lawsuits are also expected within 60 days of the publication of the CAMR rule.

Federal Legislative Proposals

The Clean Power Act (S. 150, 1/25/05), sponsored by Senator Jeffords (I-Vt.) and reintroduced on January 25, 2005, would regulate SO_2, NO_x, mercury, and CO_2. The Clean Air Planning Act (S.843) sponsored by Senator Carper (D-Del.), which is to be reintroduced in early 2005, would amend the Clean Air Act to reduce SO_2, NO_x, and mercury emissions, and would also regulate CO_2 emissions. This Carper bill is offered as an alternative to the Bush Administration's Clear Skies Initiative. Both bills are currently subject to hearings by the Senate Environment and Public Works Committee.

On February 10, 2005 Senator McCain (R-Ariz.) and Senator Lieberman (D-Conn.) reintroduced the Climate Stewardship Act (S. 342), legislation that would establish a US GHG emissions cap with an emissions trading system (In the House, Representatives Gilchrest (R-MD) and Olver (D-Mass.) introduced a companion bill the same day.). The Climate Stewardship Act is modeled on the acid rain trading program (outlined in the 1990 amendments to the Clean Air Act). It would require a reduction in CO2 emissions to 2000 levels by 2010 by capping the overall greenhouse gas emissions from the power, transportation, industrial, and commercial sectors, and by creating a market for individual companies to trade pollution credits.

The Clear Skies Initiative (S. 131, 1/24/05) calls for reducing power plant emissions of NOx, SO2, and mercury by roughly 70 percent by 2018. The initiative would achieve reductions through market-based emissions trading, but is currently in a deadlock in the Environment and Public works committee. Many would like to see a GHG or CO2 component included in the bill. To address concerns that GHG provisions are not in the bill, a "mark-up" proposal was drafted in mid-February as an attempt to get the bill out of deadlock. The mark-up offers to include a provision on climate change research, including incentives for GHG reduction technology.

State and Regional Activities

To date, only Washington, Maine, Massachusetts, New Hampshire, Oregon and California have enacted laws to regulate GHG emissions. The Washington rule targets only new sources of electric generation and taxes those sources based on expected future CO2 output. No other sector or source is regulated in Washington at this time; however, Washington has been involved in many regional initiatives.

West Coast Initiative

In September 2003, the Governors of Washington, Oregon and California committed to a GHG reduction initiative for the West Coast region (West Coast Initiative / WCI). The Governors directed their staffs to work together and develop joint policy measures and recommendations to reduce global warming pollution. The staffs were directed to focus on activities that require regional cooperation and action. In November 2004, the Governors approved a series of detailed recommendations that the three states developed over that year.

WCI Recommendations for Longer-term or More Broadly Focused Actions:

- Set goals and implement strategies and incentives to increase retail energy sales from renewable resources by 1 percent or more annually in each state through 2015.

- Establish energy efficiency incentive standards in Washington that are comparable to Oregon and California.
- Influence the Western Interconnection to place grid expansion investment priority where it supports development of renewable resources.
- Encourage and assist the states' congressional delegations to adopt a national renewable or emissions and efficiency portfolio standard.
- Develop and promote net-zero or premium efficiency homes with integrated renewable resources.

Specific Near-Term Recommended Actions:

- Establish goals and strategies for state and local government purchases of renewable energy.
- Assist the states' congressional delegations to extend the Federal Wind Production Tax Credit for no less than ten years, and expand it to include biomass, biofuels, geothermal, solar, ocean energy, new hydro, and other renewable resources.
- Encourage public utility commissions and local suppliers to adopt Western Renewable Energy Generation Information System reporting requirements for renewable resources.
- Improve renewable resource access on public lands.

The WCI Governors are already moving rapidly into action, and are advancing policies and measures across many key areas. In 2005, many strategies have been introduced as legislation across all three states. This includes GHG vehicle emissions standards in California and Washington and renewable electricity generation in Washington. Others, such as a utility carbon policy (e.g., cap and trade), are only beginning to undergo consideration, despite being actively pursued in other parts of the country such as in the East Coast's Regional Green House Gas Initiative (RGGI).

The Puget Sound Climate Protection Advisory Committee (CPAC)

In December 2003, then-Governor Locke requested the Puget Sound Clean Air Agency (PSCAA) to engage in a collaborative effort to formulate additional long-term measures and new initiatives to compliment the West Coast Initiative. As a result, PSCAA created the Puget Sound Climate Protection Advisory Committee. The CPAC included technical working groups, advisory panels and stakeholder interests, and was facilitated by PSCAA. The final CPAC report (issued January 2005) identifies strategies and actions that Puget Sound and Washington state governments, communities, businesses, and private citizens should undertake to reduce GHG emissions.

Key CPAC Energy Sector recommendations:

- Establish an energy portfolio bill that will include both renewable and energy-efficiency portfolio requirements for utilities.
- Establish a GHG emissions cap-and-trade and registry market.
- Establish state energy efficiency standards.

PSE Initiatives

PSE began accounting for greenhouse gas (GHG) emissions in 2003. To date, PSE has inventoried GHG emissions for the 2002 and 2003 calendar years. These GHG inventories are based on data generated by PSE, established GHG accounting guidelines, and available Department of Energy and Environmental Protection Agency (EPA) documents. Each inventory accounts for:

- PSE's direct emissions from electrical generation, vehicle fleet, storage and distribution of natural gas, and use of sulfur hexafluoride as an insulating gas;
- PSE's indirect emissions associated with firm contract and non-firm (wholesale market) purchases of electricity; and
- Avoided GHG emissions due to PSE's conservation efforts and other conservation programs.

The inventories are intended to provide PSE with the information to achieve five major goals.

- Maintaining an accurate, transparent estimate of GHG emissions
- Understanding PSE's emissions sources for relative size and importance
- Tracking PSE's GHG emissions over time
- Evaluating PSE's GHG emissions from electric production and purchase relative to other electric generators and electric utilities
- Estimating the emissions avoided through PSE's conservation programs

Conservation Programs and Emissions Avoided

PSE runs a variety of electric and natural gas conservation programs, resulting in significant reductions in demand on electric and natural gas resources. These programs led to savings of 131,867,000 kWh of electricity and 2,175,375 therms of natural gas in 2003, amounting to avoided emissions of over 72,000 tons of CO_2. PSE's natural gas conservation measures amounted to avoidance of emissions of approximately 15 tons of methane. In addition to these conservation measures, PSE owns and operates a fleet of natural gas-fueled vehicles. Assuming that these vehicles would have operated on gasoline instead of natural gas, it is estimated that approximately 500 tons of CO_2 emissions were avoided by using natural gas vehicles.

Emissions Policy Conclusions

Absent a clear policy direction, PSE is exploring a range of greenhouse gas costs in developing its resource strategy. PSE will continue to participate in regional initiatives like the Puget Sound Climate Protection Advisory Committee, and PSE is developing a corporate greenhouse gas policy.

With respect to GHG regulation, PSE generally favors:

- A comprehensive plan that looks at all sources, rather than just electric generation
- Flexibility in meeting targets
- A portfolio approach that considers conservation and renewables
- An approach that balances rate impacts

See Appendix F for greater detail on PSE's emission levels today and possible future emission levels.

B.2. Renewable Portfolio Standards

Regulatory Environment

Generally, a renewable portfolio standard (RPS) is a regulation to encourage electric utilities to meet a percentage of their demand with renewable generating resources. To date, these standards have been promulgated at the state level and currently 19 states have enacted renewable portfolio standards. This includes the southwestern states of the WECC.

Since renewable portfolio standards have been enacted on a state-by-state basis, the details of each one can vary. Typically each RPS sets out the following criteria:

- A target percentage of load to be met with renewable generation
- A target date or ramping schedule
- A definition of renewable generation
- Performance incentives or penalties

Some states also specify how much of the portfolio needs to be met with specific resource types (e.g, Colorado specifies solar generation targets). At least one state allows existing renewable resources to be counted but most standards set a date after which new renewable resources count toward the goal.

In Washington, the state legislature has been discussing both renewable portfolio standards and renewable incentives legislation. PSE has been actively participating in the legislative process regarding renewable generation and, while the future of any specific bill is unknown, PSE believes that some form of renewable portfolio standard could be enacted within the next few years.

Existing Renewable Resources

It is likely that PSE and other state utilities will not receive credit for existing hydroelectric resources in a renewable portfolio standard. Nevertheless, PSE is well-positioned should a standard be adopted. If the Hopkins Ridge and Wild Horse wind projects are developed and produce as planned, PSE will have achieved its target of approximately 5 percent of its load from new renewables by 2007.

PSE is also maintaining the 10 percent by 2013 renewable resource target that was established in its 2003 Least Cost Plan. The 10 percent level was established by policy to promote the development of renewable generating resources to diversify fuel sources, enhance fuel price stability, provide location-related benefits on the electric grid, reduce incremental air emissions, provide economic solutions to the disposal of various waste streams and stimulate local economic development.

RPS Conclusions

PSE continues to actively participate in the development of state RPS legislation. To some extent RPS legislation may have less impact on PSE than other state utilities. PSE has been conducting least cost planning since the late 1980s and has already begun the process of acquiring renewable generation as part of its overall resource strategy.

However, PSE is concerned that a poorly designed RPS could cause rate impacts and not efficiently accomplish the overall goal. In RPS legislation, PSE favors:

- A broad definition of renewable resources.
- A consistent definition of renewable resources throughout the WECC to facilitate trading of renewable credits.
- Flexibility to respond to a dynamic energy market. The RPS should consider cost-effectiveness.
- An RPS that applies to resource need. If a utility doesn't need new resources, then they shouldn't have to buy renewables solely to meet RPS.
- Greater certainty in the renewable resource development process. RPS goals need to be consistent with resource and transmission development processes.

Without legislative mandates PSE will continue with its goal of using cost-effective renewable energy to meet 10 percent of its load by 2013. PSE will already have met about 5 percent of this goal with its two new wind farm developments.

C. Resource Development and the IPP Industry

C.1. Introduction

Resource development is a complex undertaking. There are inconsistencies in the siting and permitting process that make it extremely difficult to develop projects with any sense of certainty around timing or outcome. The developer's challenge is to bring a number of disparate elements together at approximately the same time. The developer must find and obtain a permittable site. The developer must also arrange for interconnection and transmission (or sell to a utility that can arrange transmission) and strive to have these arrangements come together with the other pieces of the deal. Because development is time consuming, expensive and risky, the developer must find a financially able purchaser for either the power or the project. All of these things must happen in an ever-changing energy and regulatory market—a market that may not value the project at completion. This is the environment in which today's projects must be undertaken.

This section discusses the changing business model for energy development. The discussion includes the evolution of the IPP (Independent Power Producer) industry as a result of the 2000-2001 West Coast energy crisis. Because of credit and accounting requirements utilities are moving away from power purchase agreements (PPAs) and towards ownership, taking on more development responsibility in the process. This section also discusses the development challenges of the major resource types—gas-fired, wind, and coal. Finally there are discussions of resource acquisition challenges, including the difficulty of designing a resource solicitation process that accommodates long lead time resources, like coal, as well as various forms of PPAs, natural gas combined-cycle combustion turbine projects and small-scale renewable energy projects. The intent of this chapter is to put the environment in which PSE must operate and strive to acquire generating resources into perspective.

C.2. IPP Industry Status

The business model for energy development is changing yet again. Utilities are playing an increasing role in bringing resources to market. Independent developers are struggling to refine their function and build a business model that provides adequate, consistent financial returns. Utilities are moving away from relying upon the market or upon PPAs and toward ownership. For developers, this may mean a “development for hire” model that results in a development fee and certain contingent payments over the life of the project.

2003 Least Cost Plan

Prior to the 2000-2001 western energy crisis[4], IPPs typically developed merchant plants. Under this model, the developer would sell the energy from the facility—typically to an energy marketer. The marketer would then sell the power, under various terms, into the wholesale energy market. The developer relied upon financing to fund the project and used extensive market analysis to demonstrate a revenue stream adequate to maintain acceptable debt coverage to satisfy project lenders.

[4] See Chapter III of the April 2003 Least Cost Plan for an extensive discussion of this crisis.

The western energy crisis resulted in bankruptcies of major utilities, IPPs, and independent energy developers and, left in its wake, an overbuild of merchant power plants, partially-constructed plants, and a large number of development projects placed on hold.

PSE's 2003 Least Cost Plan was prepared in the aftermath of this crisis, with the expectation that the Company could capitalize on the glut of available projects. In fact, PSE did exactly this when it purchased a 49.85 percent interest in the Frederickson 1 natural gas combined-cycle combustion turbine project. Today, however, wind, other renewable resources, and coal are competitive with gas, due to dramatically increasing long-term gas price forecasts.

IPP Industry Evolution:

Following the energy crisis, the major industry participants, to a large extent, have inconsistent objectives. Developers want to continue doing want they know how to do: develop projects and create an asset that will provide value to their investors, preferably an income stream over time. Lenders are requiring more equity in projects and want long-term PPAs with financially viable parties before they are willing to finance projects. Furthermore, lenders are adding a risk premium, in the form of higher interest rates and financing fees, that have the effect of raising the developer's cost of capital to a rate that is appreciably higher than a regulated utility. Independent developers, who must satisfy the requirements of lenders if their projects are to proceed, are attempting to sell utilities on long-term PPAs.

Utilities, on the other hand, are moving away from relying upon PPAs. The credit rating agencies discourage utilities from entering into PPAs by looking at long-term power contracts as debt, judging the utility to have a greater credit risk for bondholders and other creditors. Likewise, accounting regulations discourage PPAs by requiring utilities to consolidate counterparty debt on their balance sheets.[5] These new rules and policies have a tendency to make long-term power purchase contracts uneconomical as compared to utility ownership.

Going forward, a "development for hire" business model may emerge as a response to utility ownership of generation assets. Under this model, projects are proposed in conceptual form but require commitments from buyers to be fully developed and built. The "development for hire" model means additional cost and risk is assumed by the utility in acquiring new generation assets. Developers will strive to recover all of their costs while minimizing their development risks. As a result, PSE would encounter additional risks by committing to a developing project that does not have the necessary permits and agreements for construction and operation, such as transmission rights, an interconnection agreement, real estate rights, supplier agreements, etc.

A "development for hire" model may also have the effect of limiting PSE's choices. In the 2004 RFPs, numerous gas projects were proposed because of the surplus of projects developed for the merchant plant era. Going forward, if "development for hire" is the primary viable model, the large development companies of a few years ago will disappear and be replaced by fewer small, private partnerships that are undercapitalized.

C.3. Lessons from the RFP and Resource Acquisitions Process

PSE, like many other regulated utilities, has responded to the changing energy marketplace by becoming a more vertically-integrated utility that is seeking to fulfill its growing energy need and avoid market risks by securing its own generation resources. Following its 2003 Least Cost Plan, PSE conducted two resource solicitations—a request for proposals (RFP) for wind resources and for all generation resources. After receiving nearly 50 proposals, with many different pricing/purchase options from almost 40 owners/developers, PSE has an even better understanding of the resource development landscape and the process for acquiring generation resources.

PSE expects that, in the short term, offerings in the marketplace for new generation resources will be similar to what was offered in the 2004 RFPs—parties offering PPAs, distressed natural gas-fired projects (although fewer in number), early stage wind projects, and conceptual projects for other technologies, including coal.

PPA financial impacts need to be considered

In the 2004 RFPs, many bidders proposed PPAs. As indicated previously, credit rating agencies and accounting regulations discourage these transactions. Going forward, PSE expects to receive many more PPA proposals but will continue to systematically evaluate the credit, financial, and economic impacts.

[5] See Chapter IV of this Least Cost Plan for a further discussion of credit and accounting issues related to PPAs.

Gas Projects are Losing Favor

In the 2004 RFP, the majority of proposals were either for natural gas-fired projects or wind projects. About half the natural gas-fired proposals were for existing facilities or partially constructed plants; the others were for new development projects. On the other hand, all of the wind proposals were for new development projects. This sheds light on the resource marketplace available to the vertically integrated utility.

As seen in the RFP responses, there were many natural gas-fired projects that were suspended after the energy crisis and the demise of the merchant plant model. Typically, natural gas-fired projects are easier to site and permit in western Washington than other fossil-fueled plants, and due to the proximity to natural gas pipelines and transmission to the major load centers, natural gas projects had been the default choice in new generation. Today, with high natural gas prices, these projects are becoming less economical to own. They typically operate on the margin, and require sophisticated and expensive hedging strategies to manage fuel price risk and related volatility.[6] However, they may still be a resource that is acquired and built due to the challenges associated with other resource types, as discussed below.

Wind is an Emerging Resource

Wind projects are becoming much more attractive due to the maturity of wind turbine technology, the adequacy of wind resources in the Northwest, trends toward portfolio renewable standards, and current tax incentives. PSE's experience from the RFP responses was that wind projects are typically immature or early in the development phase and the majority are located outside PSE's service territory. Transmission system constraints that hinder the ability of projects to serve major load centers in the Puget Sound area, as discussed below, make projects outside PSE's service territory less attractive.

Although wind developers are eager to begin the process of siting and performing preliminary studies for their projects, in PSE's experience, they will not fully develop these projects without the security of a buyer. Furthermore, PSE has found that even after committing to a proposed wind project, the Company has had to take on some of the development tasks in order to facilitate the successful development and permitting of the project.

[6] Fuel price and volatility risk is more fully discussed in Chapter V of this Least Cost Plan.

Coal Generation has Challenges

Coal-fueled resources are increasingly competitive in this era of high natural gas prices. However, given their long lead-time and high capital costs, few developers, if any, have the financial strength to support a coal project. The development cycle can take seven to ten years beginning with site selection and including permitting, engineering design, procurement, construction, start up, and testing. Permitting a coal mine and related transmission facilities can be a highly complex and lengthy process, subject to unaligned federal, state, and local requirements. Because of these challenges, developers are typically seeking utility partners for an ownership stake or as power purchasers under long-term contracts before they are willing to put much development money at risk.

Furthermore, because of environmental and political pressures, it is unlikely that a coal project will be permitted and built in the State of Washington, especially in western Washington, where transmission constraints to PSE's load centers are less of an issue. Because any new coal project would likely be outside the state, building the associated transmission from the project to PSE's service territory would be a large hurdle to overcome.

Coal Does Not Work in the Traditional RFP Process

The state-mandated resource solicitation process is not conducive to the acquisition of long-lead time and capital-intensive projects such as coal resources. In the RFP process one looks to evaluate a fully-developed proposal with tangible costs and a date-certain schedule. Coal proposals are more likely to be submitted in a conceptual form and thus do not evaluate well. This was illustrated by PSE's 2004 RFP process where four coal-fired proposals were offered: two ownership options for new coal development and two power purchase offerings from existing coal plants. Although the power purchase proposals appeared to have low initial costs, credit and accounting issues impacted their viability. One of the ownership options was rejected due to the inability to get transmission from the east to PSE's service territory. The other ownership option was quite immature in its development and deemed to have fatal flaws. In summary, without significant utility involvement, it is unlikely that new coal projects will be built in the current marketplace, and the current RFP process is not the appropriate vehicle to receive and evaluate coal project proposals.

Unaligned Permitting Processes Add Challenges

Resource development, which is never an easy task, is made more difficult by unaligned permitting processes. This is probably best illustrated by the following examples. A new transmission line, which might be needed to deliver power from a remotely located generation facility to the load center, provides benefits to those living in the load center but impacts those along its route. Furthermore, permitting requires approval by each county along the way so any one county can derail the project. Generally speaking, county decision-makers make permitting decisions based on local impacts and consistency with surrounding land uses, giving little credence to regional benefits.

A second example of unaligned permitting processes is becoming increasing evident in the development of wind projects. For wind, the county must approve the conditional use permit for the project, but, as in the transmission line example, the county will likely give less weight to the benefits received by citizens of distant counties than they will to impacts incurred locally. In general, because of concerns expressed by local residents to proposed wind projects, the permitting environment for wind seems to be evolving in such a way that permittable sites are located in remote locations. Unfortunately, transmission capacity in these remote locations tends to be unavailable to deliver the power to PSE's load center.

Transmission Constraints Limit PSE's Options

As previously described in detail in section A of the Chapter, PSE faces severe limitations to its ability to purchase generation outside of its service territory. Many of the responses to PSE's RFP were for remotely-located projects. These projects were proposed without mature transmission arrangements, leaving PSE to evaluate the likelihood and cost of transmission.

D. Regional Supply Situation

The regional and WECC load-resource situation can indicate the depth of the energy market. PSE plans to meet its long-term energy load obligation with long-term resources. In addition, the Company will also use medium-term bridging contracts and continue to operate in the energy market, to optimize its portfolio and to take advantage of opportunities. An examination of the overall market situation can indicate the price and availability of surplus energy.

Regional Energy Supply

The Northwest Power and Conservation Council's (NPCC's) 5th Power Plan (January, 2005) states that, "On the basis of generation installed in the region, the Pacific Northwest currently has more than enough electricity resources to meet demand." At a "medium" regional load growth rate of 0.95 percent for 2000-2025 the NPCC estimates that the region will be in balance through 2014 under critical water conditions (critical water condition is approximately 4,000 aMW less than average generation). If the load growth rate is 1.5 percent, there are adequate resources through 2008 under critical water conditions, and adequate resources beyond 2015 under average conditions. The current supply surplus is further supported by the Fifth Power Plan's number one recommendation: increase investment in conservation which will offset 2,500 average megawatts over the 20-year planning period.

According to the Fifth Power Plan, two key factors contribute to current and continuing surplus: the closure of aluminum smelters and the development of new gas-fueled resources by independent power producers (IPPs). The aluminum industry situation is reflected in the load forecast, which is 3,000 megawatts lower in 2015 than in the previous plan. The independent power producers have a resource supply of about 3,600 megawatts. If the IPPs sign long-term contracts outside the region, then the Northwest may not be able to depend on their supply. Furthermore, the region's limited transmission supply will be consumed by power flowing away from the northwest.

Regional Capacity

In the near-term, PSE relies on its simple-cycle combustion turbines and regional peaking capacity to plan for its potential peak loads. According to the NPCC Fifth Power Plan, "The regional generating capacity, the combined peak generation capability, is over 50,000 megawatts; much larger than current winter peak loads." The region's peak requirement is under 40,000 megawatts including reserves and exports, according to figures from the Pacific Northwest Utilities Conference Committee.

Regional load diversity (from the NPCC)

With the growth in population, the resource mix has changed in the northwest. In 1960 most of the region's power came from hydro generation. By 1980 about 15 percent of the region's supply came from coal-fired generation. Recently, most supply additions have been gas-fueled turbines, such that the 2003 supply mix was 52 percent hydro, 21 percent natural gas, 20 percent coal, with other sources accounting for the remaining 7 percent. Wind makes up about 1 percent of the regional supply and there is much interest in seeing that percentage grow.

Implications for PSE

PSE will depend, to a certain extent, on the regional market for both energy and peak capacity while it implements its long-term resource acquisition strategy. The fact that the region is surplus, both energy and capacity, provides PSE some flexibility in pursuing its resource strategy, which may include developing new resources, and buying or contracting for existing resources.

However, because the regional surplus is limited in volume and duration, PSE cannot assume that it will be able depend on the regional market to address large, long-term energy needs. Such a strategy could expose the Company and customers to price risk and potential reliability impacts.

E. Demand-Resources Implementation Issues

Demand resources continue to play a critical role in PSE's portfolio. In this Least Cost Plan, PSE is expanding its consideration of demand-side resources. While the energy efficiency programs are well-proven with accepted measurement, implementation, and regulatory treatment, fuel conversion and demand response are not as well established. This section discusses analytical and implementation issues for demand-side resources

E.1. Energy Efficiency

PSE has provided conservation services for its electricity customers since 1979 and for its natural gas customers since 1993. PSE offers programs designed to serve all customers – including residential, low-income, commercial and industrial. Savings targets and programs are determined through a collaborative effort between PSE and key external stakeholders represented in the Conservation Resource Advisory Group (CRAG). While energy efficiency is an established resource, the Least Cost Plan identifies the following current issues:

Cost Effectiveness

For least cost planning, PSE evaluates energy efficiency resources as a part of new resource portfolios.   The results of the portfolio evaluation process identify the levels of energy efficiency to include in the integrated least cost resource strategy.

Outside the Least Cost Plan, PSE evaluates the cost-effectiveness of energy efficiency programs based on the Total Resource Cost (TRC) test. Total costs, which include the utility's costs and any other costs paid by the customer or others (e.g., water rebates from a water utility), must be less than the value of the total benefits. "Total benefits" include energy-savings benefits together with the value of all other benefits (e.g., reduced water use). This definition of cost-effectiveness is different than that used to determine the level of energy efficiency in the Least Cost Plan.

A key element to assessing the cost-effectiveness of demand-side resources is the value of the saved energy, which would otherwise have to be supplied. The Least Cost Plan calculates demand-side resource value using resource portfolios. For evaluating the cost-effectiveness of specific demand-side programs outside the LCP process, PSE's approved regulatory methodology uses the AURORA forecast of power costs to calculate avoided cost for its energy efficiency cost-effectiveness analysis (PSE 2001 General Rate Case, Docket Nos. UE-11570 and UG-11571). Since the cost of the LCP supply portfolio is higher than the AURORA price projection, program cost-effectiveness based on AURORA prices will not match the Least Cost Plan. Consequently, PSE may not be able to cost-effectively obtain all the demand-side savings indicated by the Least Cost Plan. However, this should not diminish the Least Cost Plan's usefulness in providing directional guidance.

Non-Energy Benefits

Traditionally energy efficiency measures are granted a credit for non-energy benefits when compared to generation resources. Non-energy benefits may include water savings, reduced carbon emissions, restored structural integrity associated with weatherization improvements, or improved aesthetics or comfort.

The modeling performed for the Least Cost Plan accounts for the non-energy benefits of energy efficiency by assigning the 10 percent cost credit identified in the Northwest Regional Power Act. This credit is used by PSE and other NW utilities in cost-effectiveness analyses of energy efficiency resources. Additional non-energy benefits and costs may be included during individual program development subsequent to the Least Cost Plan.

Financial Impact

Existing and future energy efficiency programs cause lost revenue financial impacts. Existing regulatory policies do not allow PSE to implement appropriate lost revenue recovery mechanisms. As the energy efficiency programs have ramped up, lost revenue recovery has risen in importance.

E.2. Fuel Conversion

As detailed in Chapter VII, PSE developed estimated resource potential for fuel conversion. Fuel conversion involves replacing electrical end-uses with equivalent natural gas equipment. From a macro perspective, there are applications where it is more energy efficient to use natural gas directly than to generate electricity from natural gas and then use the electricity in the end-use application.

A large scale fuel conversion program would be a new undertaking for PSE although two small-scale pilots are underway. As such, there are a number of issues that could impact the scale or the value of such a program. This section discusses many of the potential fuel conversion issues. Resolution of many of the issues will likely require a collaborative effort with regulators and key stakeholders.

Status of Current Pilots

A single family fuel conversion pilot is under way. Seventy homes now have natural gas equipment installed. At the end of the current (2004-2005) heating season, PSE will be undertaking an evaluation to determine the energy-savings impacts, review costs in comparison to distribution alternatives, and overall assess program performance. A final report of pilot findings will be available by late summer 2005.

PSE is also conducting studies to determine the feasibility of installing natural gas in multi-family units. This research will provide a better understanding of the multi-family market, including the economics of and barriers to natural gas use in these facilities, enabling the Company to determine the design of any pilot installations. These feasibility studies and a decision to move forward with a multi-family pilot installation program will be complete by mid-2005.

Value to Customers

Customer savings are defined as the difference between their utility bills before and after the conversion. The conversion makes economic sense if the savings to the customer over time covers the up-front cost to the customer for the conversion.

With the recent run-up in natural gas prices, the value (savings) to customers has decreased. Electric retail rates are a melded value based upon the fuel mix of the portfolio while natural gas prices are directly reflected in rates. With high gas prices, the net bill savings is lower and the customer value is decreased.

PSE also runs a risk of increasing the volatility of the conversion customers' bills. Following conversion a greater percentage of the customer's total energy bill would be for natural gas and that portion is subject to direct reflection of changing natural gas prices.

Customer costs include not only the cost of the new gas appliances but also costs for new service connections, gas main extensions, or other distribution system upgrade costs set forth in applicable tariffs.

Market Conversions

PSE currently experiences 8,000 to 10,000 conversions per year. Presumably, many customers that were planning conversions would take advantage of any utility incentive offered through a new conversion program. These customers, who would have taken action even with the program, are categorized as "free riders" as they would receive an incentive payment for something they were going to do on their own. With respect to fuel conversion, PSE has no track record that would help the Company determine how best to increase the rate of fuel conversions while avoiding free riders. Given that the incentive payment level per customer may be very high for fuel conversions, the risk of subsidizing fuel conversions that would have occurred anyway is substantial.

Regulatory Mechanism and Financial Impact

PSE has well-established mechanisms for collecting and distributing funds for energy efficiency programs. No such mechanism has been established for fuel conversion. Such a program could also potentially raise rate design issues and cross-subsidy questions between gas and electric customers. For example, new incremental gas delivery resources are higher cost than

PSE's existing gas delivery resources. To the extent that a fuel conversion program creates a greater need for new resources, existing gas customers could experience higher rates because of the electric fuel conversion program.

PSE will also need to consider the financial impact of such a program. A large scale program without an appropriate cost recovery mechanism and lost revenue recovery mechanism could adversely impact PSE's financial performance.

Gas System Capacity

PSE plans its gas and electric system to meet expected demand. Fuel conversion program design must consider the potential system delivery issues and additional system costs. To some extent, increased gas system costs may be offset by electric system savings. However, these costs can vary widely from location to location and are therefore difficult to quantify for general planning analyses.

Customer Acceptance

Actual fuel conversion program participation will be affected by timing of appliance replacement, first costs (new appliances plus service hook-up), perceived bill savings, and personal preferences that are unique to each customer and are difficult to model as broad planning assumptions. Customers may balance these factors very differently when making their purchase decision. The utility attempts to influence these decisions through its programs, but the consumer is the ultimate decision-maker regarding the purchase of demand-side resources.

Estimates of program participation rates are more uncertain for fuel conversion than for energy efficiency because of the lack of a program track record with fuel conversion and because fuel conversion requires a higher up-front customer contribution. Any utility program should also ensure that fuel conversion is in the individual customer's best interest. In some cases, an electric technology, such as a heat pump, may be a better alternative. It is impossible to model such tradeoffs for individual customers in the Least Cost Plan.

Cost-Effectiveness Methodology

Again, PSE has a well-established cost-effectiveness methodology for energy efficiency but not for fuel conversion. PSE and stakeholders will need to establish the following: the value of the electric savings, cost of gas increase, typical customer costs for different conversion scenarios, electric and gas system impacts, and the consideration of non-quantified environmental savings. Fuel conversion programs should only be pursued after a more thorough assessment of cost-effectiveness.

Program Implementation

Program implementation depends on utility staff with the appropriate skills and tools to perform all phases of program design and operation. This program implementation capability is generally well developed for energy efficiency resources, but must be built up for implementing fuel conversion programs. External infrastructure considerations must also be addressed, such as product availability to utility customers, and an adequate network of contractors, retailers, and other trade allies to support a program.

As new measures or expanded programs are developed and added to the current program mix, internal and external resources and capabilities need to grow accordingly, and progress through a “learning curve". In many cases, small pilot programs precede full-scale programs to test the performance of demand-side technologies and customer acceptance of a particular market delivery mechanism. In fact, PSE has a small-scale pilot currently underway.

In short, a utility cannot immediately launch into full-scale deployment of all demand-side measures identified by their Least Cost Plan, nor should such results be expected.

The estimate of fuel conversion resource potentials in this plan does not account for any “ramp-up” that will be required to reach the savings levels achievable from fully mature programs.

E.3. Demand Response

Introduction

As detailed in Chapter VII, PSE developed estimated maximum potential peak demand reductions from demand response. Evaluated demand response tactics include direct load control, time-of-use, critical peak pricing, voluntary curtailment, and demand buyback. Demand response can provide value to the utility by reducing capacity usage on the distribution and transmission system as well as lowering exposure to high cost market prices or generation peaking resources for capacity in critical peak high-cost hours. These products also provide benefits to the wholesale transmission system as well as other regional distribution utilities that share the transmission system.

The demand-response resource potential analysis in Chapter VII represents significant advancement over the analysis in the 2003 LCP. The primary refinement was the evaluation of "achievable" demand-response potential, whereas the 2003 assessment focused solely on "technical" potential. Because "achievable" potential incorporates expected rates of program participation, it is a much more realistic projection of the savings potentially available from demand-response programs. The 2005 demand-response assessment also incorporates new data available since the 2003 analysis on program impacts, program costs, customer participation rates, and customer characteristics. This data comes from PSE, Northwest utilities (such as Portland General Electric), national utilities, and regional transmission organizations (RTOs) that have offered such programs.

While PSE has increased its understanding of the appropriate demand response programs for customers and its understanding of estimated program costs, there are still issues which must be resolved before implementation. This section discusses demand response implications for resource planning, strategy development, and implementation. PSE anticipates discussing many of these issues further in collaboration with regulators and stakeholders.

Value to Customer - Acceptance

While PSE has experience with one type of mass-market demand-response product (time-of-use), it does not have extensive experience with all types of demand-response products. Limited information exists on customer participation rates and load reductions for winter-oriented demand response programs under normal market conditions. The value to customers includes lower costs and any utility incentive payments. The cost to customers varies depending upon the demand response program design and the types of actions undertaken by customers to reduce demand. One major issue, beyond the value that customers may place on retail demand-response products, is the value of these programs to the region, including neighboring utilities, regional utilities and regional transmission providers.

Regulatory Mechanisms

Unlike energy efficiency programs, there are no regulatory cost recovery mechanisms in place to recover program costs for demand-response programs. There are also no regulatory mechanisms in place to recover lost revenues that result from any demand-side management programs, including energy efficiency programs and fuel conversion programs, as well as demand-response programs. There are currently no regulatory mechanisms that allow PSE and its customers to capture the financial benefits that these types of programs would give to other distribution and transmission utilities in the region.

Cost-Effectiveness Method

Unlike energy efficiency programs, there are no WUTC-approved cost-effectiveness methodologies in place for demand-response programs. A methodology needs to be established that considers cost-effectiveness issues such as the value to the utility portfolio (energy and peak), customer direct costs, implementation costs, life and sustainability of programs, environmental considerations, electric transmission and distribution savings, customer costs, and other customer impacts.

Resource Modeling

As with cost-effectiveness, there is no standard method to model demand response for resource planning (for example, the variability in certain demand response programs will impact capacity value or reserve requirements). PSE will need to work with stakeholders to develop an acceptable approach.

Program Design - Assessment

To move forward with demand response PSE will need to design some pilot programs and establish assessment criteria. Understanding the recent experience of other utilities and their customers may provide insight and direction for this process.

F. Financial Considerations

In support of PSE's overall mission to provide customers with reliable energy at reasonable, stable prices, PSE strives for improved risk management and lower credit costs. PSE's financial strategy requires the availability of credit and access to the capital markets on reasonable terms, which in turn require improved financial strength.

PSE is keenly aware of its financial challenges and will be considering the financial impact of resource decisions both in this Least Cost Plan and in any subsequent resource acquisition. To some extent, PSE and other electric utilities are still experiencing some repercussions from the western energy crisis of 2000-2001. The very high and volatile pricing resulted in several large and established companies defaulting on obligations. In the aftermath, energy market participants and the financial markets have become much more aware of risk and mindful of energy supply impacts on financial performance.

In addition to considering the direct cost of the various resource types, PSE will also be evaluating its resource strategy with respect to:

- *Financial strength* – the timing of resource capital expenditures combined with other corporate needs like infrastructure growth and replacement; PSE's cost and ability to finance given financial ratings

- *Credit* – credit requirements, impacts to open credit, and impacts of credit requirements on overall financial strength

- *Risk Management* – energy price risk management costs; overall risk profile for resource strategy

- *Imputed Debt* – added imputed debt for new purchase agreements and renewal of existing contracts; impact of imputed debt on overall financial strength

More in-depth discussion of the importance and significance of financial issues to PSE's least cost strategy can be found in Chapter IV.

G. Natural Gas for Power Generation

Over the last decade natural gas was the fuel of choice for new power plants. Gas prices were reasonable and gas projects were easier to site and permit. However, over the past few years, the natural gas market has experienced a fundamental upward price shift. Higher domestic demand and rapidly expanding international markets for energy continue to put upward pressure on natural gas prices.

At the same time, North American supplies have stayed flat. The prospects for future gas price moderation depend upon potential supply increases from expanded liquefied natural gas import facilities and the construction of new pipelines to access McKenzie Delta and Alaska supply basins. Both of these solutions face significant political and environmental challenges.

Tighter supplies have also led to increased price volatility and the need for expanded price risk management. Higher prices place greater financial burdens and credit requirements on market participants.

Implications for PSE

The net result is a number of outcomes that impede PSE's least cost resource strategy.

- Higher natural gas costs
- Increased price volatility and need for expanded risk management
- Increased credit requirements
- Decreased market liquidity for gas supply
- Increased need for financial strength to meet counterparty credit demands and to lengthen and expand the Company's hedging program for gas-for-power

Power generation has both price and volume risk. For LCP modeling PSE considered gas pricing uncertainty by using a range of CERA price forecasts. (See Chapter V for a discussion of the gas price forecasts.) CERA forecasts represent a compilation of all known market information. Additionally, PSE uses Monte Carlo analysis to determine the impact of price volatility.