XVI. DELIVERY SYSTEM PLANNING

This chapter addresses delivery system planning, a key component of the Least Cost Plan process. Delivery system planning employs processes that ensure the gas and electric energy delivery systems are integrated to provide safe and reliable service at the lowest cost. Within this integrated view, delivery system planning establishes the guidelines for installation, maintenance and operation of the Company's physical plant while balancing cost, safety, and operational requirements. The delivery system planning process also considers environmental management, regulatory requirements and changing customer demands as it reviews cost-effective alternatives and develops contingency plans. The chapter concludes with a discussion of PSE's involvement in the Bonneville Power Administration's (BPA's) Non-Wires Solutions Round Table.

This chapter specifically discusses the following:

- How the gas and electric energy delivery systems work,
- Industry challenges,
- System performance criteria,
- Planning process including methods for evaluating system alterations, planning tools and modeling techniques,
- Decision process for optimizing the improvement plan based on estimated benefits and constraints,
- Types of adjustments that can be made within the energy system to lessen the need for additional facilities, and
- Overview of distributed resource technologies that could impact the landscape of the electric delivery system.

A. Delivery System Mechanics

Gas Delivery System

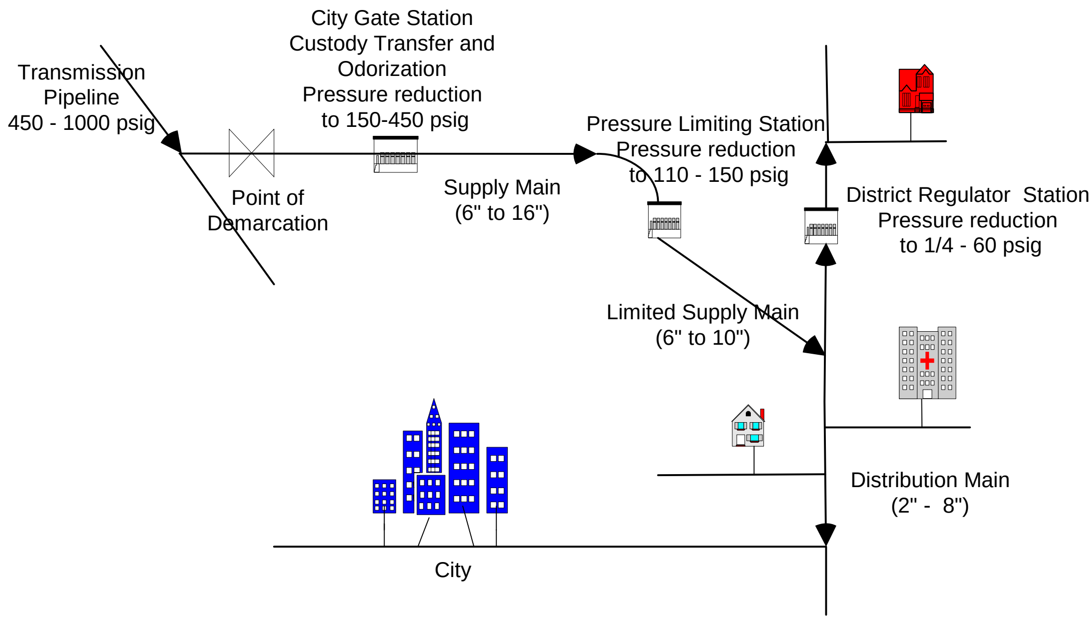
A properly sized and designed pipe system will have the capacity and reliability to deliver gas at sufficient pressure to all customers at all times. System sizing and design are driven by gas system mechanics. When gas is compressed, energy is stored in it. As gas flows through the delivery infrastructure, its pressure decreases due to friction, and the energy is converted to heat. If the delivery system is too small, high velocities and turbulent flow behavior result in an excessive pressure drop. The consequence is pressures that are too low to supply customers with the energy necessary to operate their appliances. Pipe diameter, material, roughness, efficiency, length and the fitting type, along with flow characteristics, all influence the system's pressure.

The delivery system infrastructure is comprised primarily of pipes, valves, regulation equipment (pressure reduction), and measurement equipment (meters). Transmission pipelines typically operate at pressures between 450 and 1,000 pounds per square inch gauge (psig). Pressure regulating stations reduce the operating pressure for local distribution. Distribution pipelines within residential neighborhoods typically operate at pressures between 45 and 60 psig. Pressure regulation at the customer's meter reduces the pressure for appliance operation. The pressure for a stove or space heater to operate effectively is typically ¼ psig. Exhibit XVI-1 provides a schematic view of the gas delivery system.

PSE operates and maintains an extensive gas system consisting of 46 city gate stations, 10,990 miles of high, intermediate, and low pressure gas distribution pipelines, and 980 district regulator stations. This infrastructure serves approximately 669,190 natural gas customers in six counties that lie within approximately 2,800 square miles of service territory. Approximately 326,320 customers receive both gas and electric service from PSE. In areas where PSE provides both electric and gas service, additional efficiencies and lower costs can be realized by coordinating plans for energy need, and considering alternatives such as fuel switching and distributed generation.

Exhibit XVI-1

Gas Delivery System

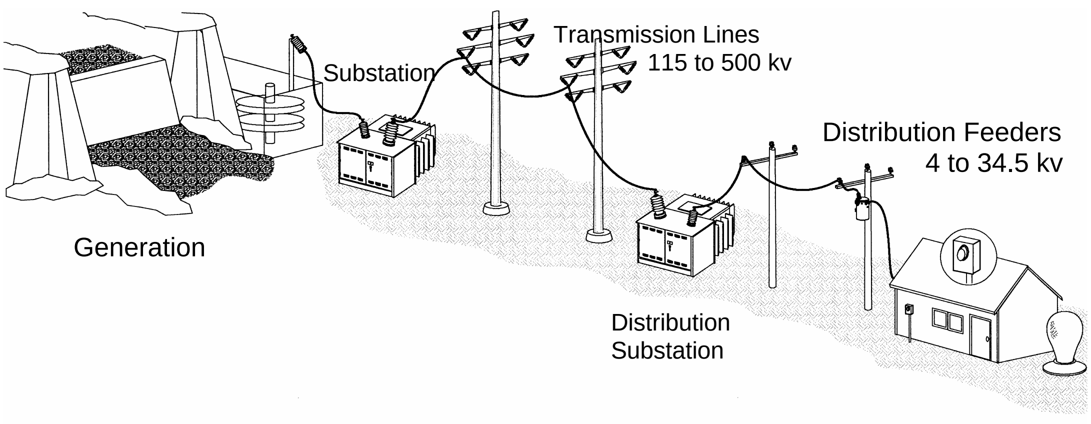


Electric Delivery System

Delivering electricity to customers requires an intricate system of generation, transmission, and distribution infrastructure. A unique product, energy moves from electric generators to the consumers over wires and cables, using a wide range of voltages and capacities. Unlike other forms of energy, electrical energy cannot be stored in quantities sufficient for widespread use. It must be continuously generated using other forms of energy, such as falling water and steam. The electrical generators and electrical network are designed to automatically regulate the flow of electricity through the system to quickly accommodate instantaneous changes in consumer demand.

The delivery system infrastructure is composed primarily of wires, circuit breakers, transformers, and measurement equipment (meters). The voltage at the generation site must be stepped up to a high voltage for efficient transmission over long distances. Generally, transmission lines operate at voltages between 115 and 500 kilovolts (kV). Substations reduce the voltage for local distribution. Distribution lines typically operate at voltages between 4 and 34.5 kV. Finally, transformers at the customer site reduce the voltage to under 600 volts (V) for effective operation of appliances. Exhibit XVI-2 provides a schematic view of the electric delivery system.

Exhibit XVI-2
Electric Delivery System



PSE operates and maintains an extensive electric system consisting of 303 substations, 2,671 miles of transmission line, 10,512 miles of overhead distribution line, and 8,418 miles of underground distribution line. This infrastructure serves approximately 999,375 electric customers in nine counties within approximately 4,500 square miles of service territory.

PSE's complex electric and gas networks must be flexible enough to meet changing operating conditions as well as future service needs. Significant investment in this infrastructure means that it is important that PSE make additions and improvements as cost-effectively as possible.

B. Challenges

Planning these infrastructure networks is an evolving and complicated process due to changes in the industry. For example, planning processes and investments are subject to increasing scrutiny in the wake of recent events and drivers including the Northeast and upper Midwest blackout in 2003, pipeline safety regulation implementation, aging infrastructure, and continued customer sensitivity to electric reliability. For several years, the industry has been on a path towards deregulation. This caused utilities to defer investments because future ownership and operation have been unknown. More recently, electric transmission investments have been on the rise, due to the cascading event experienced in the northeast in August, 2003 and the resulting loss of power to 50 million customers. Regulations mandating the reliable operation of that particular system are being finalized. PSE will continue to emphasize the development of plans to ensure its transmission infrastructure meets these regulations.

As a result of the Olympic pipeline rupture in 2003, the Pipeline Safety Law has been enacted and the industry is actively working to comply with the law's greater pipeline integrity requirements. PSE is on track to implement its own program resulting from the safety law. As a result, there will be more focus on transmission pipelines to ensure continued system integrity.

On an ongoing basis, PSE reviews the reliability of its gas and electric infrastructure. PSE's gas system has been operating since 1890, and its electric system since 1917. The Company continually reviews the performance of these systems and the impact their condition has on reliability. Programs to replace aging cast iron mains, bare steel mains, power poles, and underground cables are in place to minimize leaks and outages, and to ensure continued safe operation.

In the future, active coordination and collaboration with other utilities and municipalities will be increasingly important to minimize conflicting objectives, issues, concerns, and the costs of operating within rights-of-way. Because customer concerns and environmental regulations are making installation in new rights-of-way increasingly difficult and lengthy, proper planning is essential.

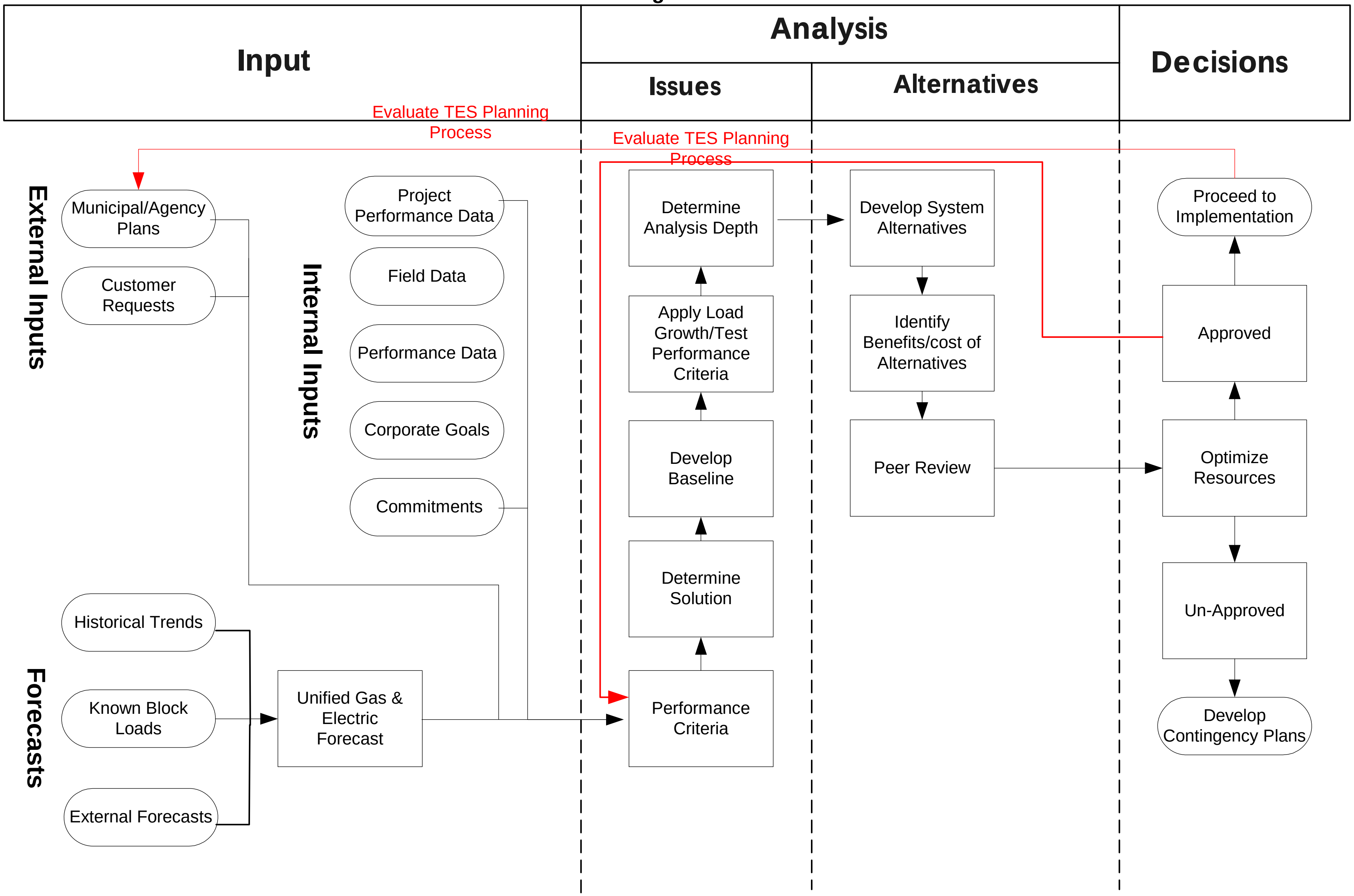
Higher performance standards pose additional challenges that need to be reflected in an evolving delivery system plan. For example, computers and other highly sophisticated voltage-sensitive equipment drive the need for more stringent power quality than was previously required.

If PSE is to remain prepared to address these ever-changing challenges, the Company must actively review and participate in emerging electric and gas technology. A key example is distributed resources (DR) technology, which will eventually alter the historic demand on both the gas and electric systems, and change electricity usage as power is generated at the customer's site (i.e., fuel cell, micro-turbine, photovoltaics, wind generation, etc.). Each of these generation technologies has a variety of operating characteristics that create complexity when they are integrated into the delivery system. Furthermore, despite a customer's ability to self-produce generation, PSE will still need to maintain a system equipped to meet the customer's use and capacity requirements in the event the distributed resource fails. These advances mean that in the future, customers will rely more heavily on the gas delivery system to supply some of their electricity needs.

C. Planning Process

The goal of the planning process is to find cost-effective ways to meet customer needs. The delivery system planning process begins with an analysis of the current situation and an understanding of the existing operational and reliability challenges. Planning considerations (inputs) include both internal and external factors, load forecasting, and customer expectations. The planning process also incorporates the impact of one energy type on the other, and optimizes the whole energy delivery system. Having incorporated all of these inputs, planners then determine the magnitude of the issues based on the performance definitions previously mentioned. Alternatives for improving the infrastructure are developed, and the benefits for each are determined. Cost estimates are prepared for each alternative that meets the performance criteria. Lastly, planners select and plan for the alternative that best balances customer needs, company economic parameters, and local and regional plan integration. Exhibit XVI-3 provides a view of this process.

Exhibit XVI-3
Planning Process



Inputs

Internal planning considerations, or inputs, include system performance, company goals and commitments, and load forecasts. External inputs include regulations, municipal and utility improvement plans and customer expectations. System performance information is gathered from field charts, remote telemetry units, supervisory control and data acquisition equipment (SCADA), field employees, and customer feedback. Some information is analyzed over multiple years rather than during a single year's performance. For example, outage information is analyzed over 3 to 5 years, which provides a clearer indication of issues in light of such variables as weather (which can have a significant impact from year to year). Upon project completion, system performance reviews are again analyzed over several years in order to lessen the impact of a single event affecting system performance.

Load forecasting for delivery system planning may be performed at the local city, circuit, or neighborhood level. For these local forecasts, PSE uses a trend of actual system peak-load readings and customer growth within the area. This forecast is augmented with known permitted construction activity that is projected over the next two years. Longer-term forecasting comes from PSE's corporate econometric forecasting method that includes population growth and employment data by county (see Chapter VI). PSE also continues to use its automated meter reading (AMR) technology to facilitate load analysis.

In order to minimize costs, PSE regularly gathers and reviews municipal and utility improvement plans. These plans provide an opportunity to upgrade existing infrastructure or install new infrastructure when system relocation is required or savings can be gained through coordination between utilities. PSE works with outside entities to find mutually beneficial schedules or coordinate installation.

The Company relies on several methods to collect customer feedback. PSE continually investigates customer complaints, and tracks ongoing service issues. Customers receive follow-up correspondence to discuss the concern, and any plans for resolution. These complaints may provide information where field data isn't available or modeling doesn't indicate an area of concern. PSE also relies on customer surveys to provide general information regarding customer expectations and possible specific concerns. For example, in January 2004, PSE surveyed electric customers that were impacted by two large storms. The feedback provided tremendous information and helped validate customer expectations and polish plans.

Performance Criteria

PSE primarily categorizes system needs as “capacity” and “reliability”. System performance is reviewed with these needs in mind, which forms the basis for planning. For PSE’s gas delivery system, performance criteria are defined by:

- Safety and compliance,
- The temperature at which the system is expected to perform,
- The nature of service (“firm supply”) each type of customer is contracted for (interruptible vs. firm),
- The minimum pressure that must be maintained in the system,
- The maximum pressure acceptable in the system, and
- The cost customers are willing to pay for target levels of performance.

For PSE’s electric system, performance criteria are defined by:

- Safety and compliance,
- The temperature at which the system is expected to perform,
- The level of reliability (“firm supply”) each type of customer is contracted for,
- The minimum voltage that must be maintained in the system,
- The maximum voltage acceptable in the system,
- The interconnectivity with other utility systems and resulting requirements, and
- The cost customers are willing to pay for target levels of performance.

These performance criteria, in addition to state and federal requirements, provide the foundation for planning infrastructure improvements. Adhering to these criteria ensures full use of existing facilities before adding new ones. However, this can occasionally be offset by the cost advantages associated with early installation. Each year, PSE identifies new areas experiencing diminishing capacity resulting from load growth, diminished reliability, or simply where customer expectations are on the rise. On smaller distribution systems, annual performance issues are generally resolved within a year or two, while large distribution or transmission performance issues generally take more than two years. In fact, securing substations and transmission facilities can take more than a decade. This makes it all the more important that strong processes are in place for predicting and modeling future issues.

As mentioned earlier, proper planning requires evaluation criteria for capacity and reliability issues. Exhibit XVI-4 shows a typical annual expenditure level for these types of issues.

Exhibit XVI-4

Capital Planning Initiatives (millions)					
	2005	2006	2007	2008	2009
Capacity	$ 73	$ 87	$ 59	$ 68	$ 66
Reliability	$ 83	$ 79	$ 79	$ 71	$ 66

Planning Tools

PSE relies on many different tools during the planning process. With the identified planning considerations (inputs), a variety of results (outputs) are derived to help identify and weigh the benefits of each alternative action. Exhibit XVI-5 shows the tools that will be described in more detail in the Least Cost Plan.

Exhibit XVI-5

Planning Tools			
Tool	**Use**	**Inputs**	**Outputs**
Advantica Synergee	Network Modeling	Gas and Electric distribution infrastructure and load characteristics	Predicted system performance
MUST Power Flow	Network Modeling	Electric transmission infrastructure and load/generation characteristics	Predicted system performance
Area Investment Model	Economic Analysis	Cost schedule, growth scenarios	Net present value, revenue requirement
Simplified Probabilistic Spreadsheet	Probabilistic Analysis	Outage history, equipment failure probabilities	Outage savings based on probability of occurrence
Estimated Unserved Energy	Unserved Energy	Growth/load at specific conditions, annual load profile	Annual unserved energy, O&M costs as a result, value of service in cost terms
BudAPP	Project Data Storage	Scope, budget, justification, alternatives and benefits	Predicted benefit score, project scope/start document
Expert Choice	Optimization	Projects, benefits, resources/financial constraints	Set of optimal projects for given constraints

Modeling Tools

To facilitate system performance evaluation, PSE uses system models for both its gas and electric delivery systems. The use of sophisticated modeling software and field data, including real-time information, ensures optimal system planning. PSE has a mature gas system model using an Advantica SynerGEE software application. This model is continually updated to reflect new customer loads and system and operational changes. Planners validate the accuracy of the model by comparing its results against actual system performance data. The model helps to predict capacity constraints and subsequent system performance on a variety of degree days and under a variety of load growth scenarios. Where issues surface, the model can then be used to evaluate alternatives and their effectiveness in resolving the issues. Augmenting these alternatives with cost estimates and feasibility analysis helps to ensure the least cost solution to serve both current and future loads. PSE's model is one of the largest integrated system models in the United States.

For the electric distribution system, PSE also uses the Advantica SynerGEE software application. Due to the complexity of the mathematical analysis, the feeder system is modeled regionally rather than as one single large model. Planners use these models to implement accuracy assessments and evaluations similar to those performed on the gas side. As software capability improves, PSE hopes to unify its gas and electric models. This will enhance the Company's ability to meet customer energy needs and take advantage of possible fuel switching opportunities at the lowest possible cost.

For both PSE's gas and electric system modeling, the process begins with the digital creation of the infrastructure and its operational characteristics. For gas infrastructure, these characteristics include the diameter, roughness and length of the pipe, connecting equipment, regulating station equipment and operating pressure. For electric infrastructure, these characteristics include conductor cross-sectional area, resistance, length, construction type, connecting equipment, transformer equipment and voltage settings. PSE then identifies customer loads in the model, either specifically (for large customers) or as block loads through address ranges. Existing customer loads are acquired using PSE's customer information system (CLX) or from actual circuit load readings. From this set up, the planner can then vary temperature conditions, types of customers served (interruptible vs. firm), time of day (at peak daily usage) or with various components out of service (valves closed or switches open). Thereafter, various scenarios of infrastructure or operational adjustments can be modeled in search of the least cost solution to a given issue.

To simulate the performance of the electric transmission system, PSE uses a Power Technologies Inc. (PTI) product called PSS/E, and a General Electric product called PSLF. In addition, PSE uses Managing and Utilizing System Transmission (MUST), another PTI product to study the capability of the power system to move power from one area to another under various conditions. These simulation programs utilize a model of the transmission system that spans 11 western states, 2 provinces in Western Canada and parts of northern Mexico. The power flow and stability data for these models is collected, coordinated, and distributed through regional organizations including Northwest Power Pool (NWPP) and Western Electric Coordinating Council (WECC). WECC is one of 10 regional reliability organizations under the North American Electric Reliability Council (NERC). These power system study programs support PSE's planning process and facilitate demonstration of compliance with reliability performance standards as outlined by WECC and NERC.

System Alternatives

PSE has a variety of alternative approaches to solving delivery issues. Gas and electric facility alternatives include:

<u>Electric</u>

· Add energy source
    - Substation
· Strengthen feed to local area
    - New conductor
    - Replace conductor
· Improve existing facility
    - Substation modification
    - Expanded right-of-way
    - Uprate system
    - Rebalance load
    - Modify automatic switching scheme
· Off load system
    - Distributed Generation
    - Fuel Switching
    - Conservation
    - Load control equipment
    - Possible new tarriffs
· Do nothing

<u>Gas</u>

· Add energy source
    - City-gate station
    - District regulator
· Strengthen feed to local area
    - New high pressure main
    - New intermediate pressure main
    - Replace main
· Improve existing facility
    - Regulation equipment modification
    - Uprate system
· Off load system
    - Fuel Switching
    - Conservation
    - Load Control Equipment
    - Possible new tarriffs
· Do nothing

Energy flow can be managed temporarily with some of these same alternatives. This is useful when the issues are short in duration either due to the peaking nature of the issues, or when project completion timing is the problem. Some examples of this include:

- Temporary adjustment of regulator station operating pressure, as executed through PSE's Cold Weather Action Plan.
- Temporary adjustment of substation transformer operating voltage, as done using load tap changes to alter turn ratios.
- Temporary siting of mobile equipment such as compressed natural gas (CNG) injection vehicles, liquid natural gas (LNG) injection vehicles, mobile substations, and portable generation.

In every decision-making process, one of the alternatives is to "do nothing". Understanding and managing risk becomes important with this alternative.

Examples of Project Analysis and Development

PSE has many examples of this successful planning process: the reinforcement of the Gig Harbor gas system, the reinforcement of the Hansville Peninsula electric distribution system, and the reinforcement of the West Kitsap transmission system are described below. For each project, all the alternatives are reviewed and optimized, and prioritized to determine the most cost-effective solution.

1. Gig Harbor gas distribution system:

   PSE began serving Gig Harbor in 1969 via 6" and 8" high-pressure pipelines installed from Zenith, in the Des Moines area, across Puget Sound to Vashon Island, and then across Colvos passage to the Gig Harbor Peninsula. Annually, PSE has seen a 5 percent to 8 percent increase in customer additions since 1995. PSE began planning in 1995 to resolve the capacity problem expected in 1999. Planning began using SynerGEE to model the growth and to predict when available pipe capacity would begin to adversely impact performance.

   As a solution, PSE chose to install a liquid natural gas (LNG) satellite plant to supply the needed gas on colder days. This plant is loaded with LNG and only operates 20 to 30 days a year. This solution implemented technology never before considered by PSE. A cost analysis of this solution vs. a pipeline water crossing proved the LNG satellite plant was the least cost solution to serve existing and future growth for 20 to 25 years. The construction of the plant was completed in 2004. The peak loads that occurred between 1999 and 2004 were maintained using a mobile LNG vehicle. The cost of the LNG satellite alternative was approximately 40 percent less than a new pipeline. Other system alternatives which were considered and studied to resolve this capacity issue included the following:

a) Tacoma Narrows passage crossing project. This alternative was to install a high-pressure pipeline under the Tacoma Narrows passage from Point Defiance to the south end of the peninsula. This alternative met the needs, but the estimated cost was approximately $33 million.
b) Tacoma Narrows Bridge project. This alternative was to install a high-pressure pipeline on the existing Tacoma Narrows Bridge or on a new proposed bridge. This alternative met the needs, but the state and local permitting agencies would not allow PSE to install this facility due to safety concerns. The estimated cost was approximately $16 million.
c) Firm Supply from neighboring utility. This alternative was to purchase firm supply from PSE's neighboring utility. The estimated cost was approximately $22 million for the connecting pipeline and future gas cost.
d) Home Comfort Control project. This alternative, which did not meet the system need, was to implement the use of a two-way CellNet radio to control the settings on customers' home electronic thermostats. During peak periods, PSE would remotely reduce the thermostat setting a degree or two to limit the system demand. The expected system demand reduction was 6 percent. Unfortunately, a minimum of 14 percent reduction was necessary to maintain reliable service. The estimated cost to execute this program was approximately $6 million.
e) Replace the existing supply pipeline project. This alternative was to replace the existing pipeline that crossed Vashon Island in multiple phases. The estimated cost was approximately $30 million. Additionally, from a reliability and system flexibility standpoint, a new second supply pipeline, as described in alternatives a and b, was more preferable than replacement of the existing supply.

PSE performed an economic comparison several times throughout the development of the scope. Each time, the LNG satellite plant was the best alternative. The result is shown in Exhibit XVI-6.

Exhibit XVI-6

Alternatives	Capital	NPV 30 Yr	Comments
Tacoma Narrow Water Crossing	$33M	($18.6M)	Potential impacts of ESA.
Tacoma Narrow Bridge Crossing	$16M	($15.4M)	Permitting agencies did not approve.
Replace Vashon Crossing	$ 30M	NA	Not evaluated by AIM.
LNG Satellite Facility	$13M	($13.2M)	Siting and permitting would be concern.
Firm Supply from Neighbor Utility	$22M	($13.1M)	Only interruptible service available. Did not meet project objective.
Home Thermostat Control Program.	$ 6M	($8.5M)	Deferred larger project only 1-2 years. Did not meet project objective.

2. Hansville Peninsula electric distribution system:

   The North Kitsap electric system has experienced concerns similar to those of the Gig Harbor area due to its isolation and slow solid growth. PSE began serving the Hansville Peninsula in 1980 via a cable sitting on the floor of the Port Gamble Bay water passage between the town of Port Gamble and the Little Boston Community. Annually, PSE has seen a 0.5 percent increase in customer additions in the Hansville area. PSE began planning in 2003 to resolve the predicted capacity problem expected in 2005. Planning began by using SynerGEE to model growth and to predict when available system capacity would begin to adversely impact performance.

   As a result, PSE began looking for additional options including the installation of a new underwater cable. However, due to the length of time needed for study, design and permitting of new facilities, PSE began planning for generation to temporarily support this area in order to prevent the cable from becoming over-utilized and failing. A failure at peak load times would mean that approximately 2,000 customers would be out of service. PSE has installed a temporary generator at Hansville that is operated during colder days, similar to the LNG satellite plant in Gig Harbor. The temporary use of a generator on cold days does not meet the long-term needs of this area and is seen as a bridging solution until permanent facilities are installed. The cost analysis currently underway may demonstrate that a new additional cable is the least cost solution to serve existing and future growth for the next 10 to 20 years.

The other system alternatives considered and studied to resolve this capacity issue include the following:

a) Second distribution submarine cable. This alternative involves laying 6000 feet of 15kV cable across Port Gamble Bay. It meets the near and long term demand for the Hansville community. However, it does not contribute to a project need for additional capacity to serve the Kingston area. The cost of a cable project is estimated at about $4 million.
b) The Kingston Substation. This alternative involves construction of a new distribution substation. The cost of the new substation and related transmission line is about $5 to $7 million. In addition to providing capacity to the peninsula, the new substation would provide future capacity to the town of Kingston.
c) Underwater transmission cable with a substation on the Hansville peninsula. This alternative was ruled out due to an estimated costs ranging from $15 to $20 million.

Exhibit XVI-7

Alternatives	Capital	NPV 30 Yr	Comments
Second Distribution underwater cable	$4 M	($6.5M)	Under study
Kingston Substation	$5-$7 M	($4.7M)	Under study
Transmission Underwater cable	$15-$20 M	N.A.	Is not now considered a viable alternative

3. West Kitsap transmission system:

PSE serves North Kitsap County via two transmission lines from Bremerton/Valley Junction to Foss Corner. Annually, PSE has seen a 1 to 1.5 percent increase in customer additions. PSE began planning in the early 1990s to resolve the predicted reliability problem expected in 2005. The continuing load growth is limiting the capability of the Bremerton Foss and Valley Junction—Foss 115 KV lines to serve all customers under conditions where one line is out of service. This is called an N-1 condition.

The alternative chosen to resolve the problem was a third transmission line, the Foss—Bangor 115/230 kV transmission line. This alternative meets the need to increase transmission capacity and improve reliability to North Kitsap and Bainbridge Island. The estimated cost is approximately $5 million.

The other system alternatives considered and studied to resolve this reliability issue include the following:

a) Silverdale—Foss Corner 115/230kV transmission line project. This alternative does not provide the full backup required. However, it would have provided an interim solution to the loading and reliability problems until it is extended further into South Bremerton. The estimated cost was approximately $6 to $7 million.
b) Hood Canal submarine cable intertie between Jefferson and Kitsap Counties. This alternative was less robust than the Foss - Bangor transmission line at solving the N-1 issue. The estimated cost was approximately $24 to $30 million.
c) Generation resource. This alternative was considered and ruled out due to siting uncertainties in North Kitsap County. A benefit of this alternative was that it would reduce system losses by approximately 5 percent, or 2 MW. The estimated cost was approximately $20 to $30 million.
d) Westsound transmission line. This alternative, which involves installing a new transmission line between the Bremerton and Winslow substations on Bainbridge Island, meets the requirements of the need statement. However, the estimated cost was approximately $20 to $25 million.

Exhibit XVI-8 shows the economic comparison of the alternatives. The third transmission line, Foss—Bangor, proved to be the least cost alternative.

Exhibit XVI-8

Alternatives	Capital	NPV 30 Yr	Comments
Foss—Bangor Transmission Line	$5M	($3.9M)	Preferred alternative
Foss—Silverdale Transmission Line	$6.3M	($4.9M)	Does not meet full need
Hood Canal Cable	$24M	($18.9M)	Doesn’t solve N-1 entirely
Generation	$21M	($15.8M)	Permitting uncertain
West Sound Transmission Line	$22M	($17.3M)	Meets need, but costly

4. Everett—Delta gas distribution system:

   PSE serves North Seattle and Everett via 12” and 8” high-pressure pipelines installed from Northwest Pipeline’s (NWP) North Seattle Lateral which terminates in the Lynnwood area. This system provides service to approximately 92,000 residential and commercial customers and some of PSE’s largest industrial customers. Annually, PSE has seen a 3 percent increase in customer additions in the Everett and Lake Stevens areas and 10 percent in the Marysville and Granite Falls areas. PSE began planning in 1994 to resolve the capacity project expected in 2004.

   The alternative chosen to resolve the problem was the installation of a 16” high-pressure pipeline from the Lake Stevens area across multiple rivers and waterways and across I-5 to the north end of Everett. This solution provides a second source to the North Seattle/Everett system and therefore increases the reliability of service, supports growth for 25 to 30 years and shifts demand off of the North Seattle Lateral so that it can better support growth south. The initial project proposal was to be built by PSE in conjunction with service to a proposed power plant at the north end of Everett. Over time, various proposals for this developed and eventually NWP proposed to construct this line in support of one of the power plant proposals. PSE was able to contract with NWP for inclusion in their proposed project, which was subsequently approved by FERC.

   In 2002, the power plant project backed out of the arrangement with NWP. Even though the FERC approved project was in jeopardy, PSE continued to see this line as the most effective means of meeting the capacity needs. After analysis, PSE entered into negotiations with NWP to continue to construct this line solely for PSE’s need. PSE and NWP ultimately established a novel arrangement whereby PSE would fund and own the lateral, and lease it to NWP—who would operate it—for 5 years. After 5 years, subject to FERC approval, the lateral would revert to PSE’s operation. NWP successfully completed the installation of the 9.16 mile 16” HP main line in December 2004, in time to meet the growth in the area.

   Other system alternatives that were considered and studied to resolve this capacity issue included the following:

a) Everett Delta Ownership options. Several options were reviewed to determine the most economic arrangement for ownership.

i. The first ownership option was for PSE to construct the pipeline. The estimated cost is approximately $25 million. Project risks could drive project costs to $42 million. However, this option would put PSE on track for completion in 2008. Due to this timing and the previous work already completed by NWP on the project, this was unreasonable. This option would have required PSE to construct “short-term solution” projects, estimated at $7 million, and utilize liquefied natural gas (LNG) and other cold weather actions, estimated to cost $1.4 million annually, to ensure reliable service until the project was completed.

ii. The second ownership option was for NWP to construct the pipeline (with PSE funding because NWP did not have sufficient capital). PSE would own the line after completion, but NWP would continue to operate the line and provide service to PSE. The estimated project cost was approximately $32 million. Under FERC approved rate principles, this option would require PSE to pay approximately $1 million annually for operation and maintenance to NWP.

iii. The third ownership option was for NWP to construct the pipeline (with PSE funding). PSE would own the line after completion, PSE would then lease it to NWP. NWP would operate the lateral as part of its system and provide service through the lateral to PSE. After the 5 year lease term, subject to FERC approval of abandonment of service by NWP, PSE would take over the operation of the line as part of its distribution system. The estimated cost was approximately $32 million due to design and construction to meet the higher standards required by Washington regulation. Through this arrangement, PSE was able to avoid the large annual maintenance charge, and assume actual operations after the 5-year term.

b) Granite Falls project. This alternative was to install a high-pressure pipeline from the Granite Falls high-pressure termination through Marysville to Everett. Detailed analysis showed that this option would not be sufficient without upgrading the Granite Falls high-pressure system as well. The cost of this project became prohibitive relative to its benefit life span due to the immediate need to begin adding additional high-pressure main and gate station capacity. In the initial project development phase this project was determined to be significantly higher in cost than other alternatives and therefore was never revisited in later analysis and cost refinement.

c) North Seattle Lateral upgrade project. This alternative was to have NWP upgrade/expand the North Seattle laterals. This option was significantly more expensive than the Everett—Delta proposal. In addition, it did not increase reliability to this large area, maintaining reliance on only one pipeline feed. The estimated cost was approximately $58 million.

d) Anderson Canyon project. This alternative was an alteration to the route between Lake Stevens and Everett. This pipeline was to be installed from the south end of Lake Stevens to Everett. It traveled along PSE's electric transmission right of way. The substantial length, along with the environmental issues associated with this route made it risky and ultimately infeasible. The estimated cost was approximately $21 million. Project risks could have driven project costs to $38 million.

e) BPA Snohomish project. This alternative was an alteration to the route between Lake Stevens and Everett. This pipeline traveled along BPA's electric transmission right of way. The substantial length, along with the environmental issues associated with this route made it risky and ultimately infeasible. The estimated cost was approximately $22 million. Project risks could have driven project costs to $38 + million.

PSE performed an economic comparison several times throughout the development of this project. Each time, the Everett Delta project (a.iii) was the best alternative. The result is shown in Exhibit XVI-9.

Exhibit XVI-9

Alternatives	Capital	NPV 30 Yr	Comments
Everett-Delta – i	$24M	($24.6M)	Risks associated with re-start of project. Immediate temporary measures.
Everett-Delta – ii	$32M	($29.8M)	Large O&M annual outlay.
Everett-Delta – iii	$32M	($17.5M)	Passive ownership (via 5-yr. leasing arrangement)
North Seattle Lateral upgrade	$58M	($17.5M)	Does not increase system reliability. Large revenue requirement due to capital outlay.
Anderson Canyon	$21M	($21.3M)	Environmental and property owner impacts, and construction cost risks.
BPA Snohomish	$22M	($22.3M)	Environmental and property owner impacts, and construction cost risks.

Decision Making

To make prudent investment decisions for hundreds of gas and electric projects, an objective way to synthesize, analyze, and optimize projects based on resource constraints is required. These decisions are too complex to be made based solely on instinct or simple analysis. To be successful at this task, PSE initiated the use of value-based budget prioritization. PSE currently uses a technique known as the Analytical Hierarchy Process (AHP) for the allocation of its resources. In order to allocate resources wisely, planners must know both the cost and benefits associated with each project. Planners must also account for how resource constraints affect the optional mix of projects. This helps to determine a project's value for consideration.

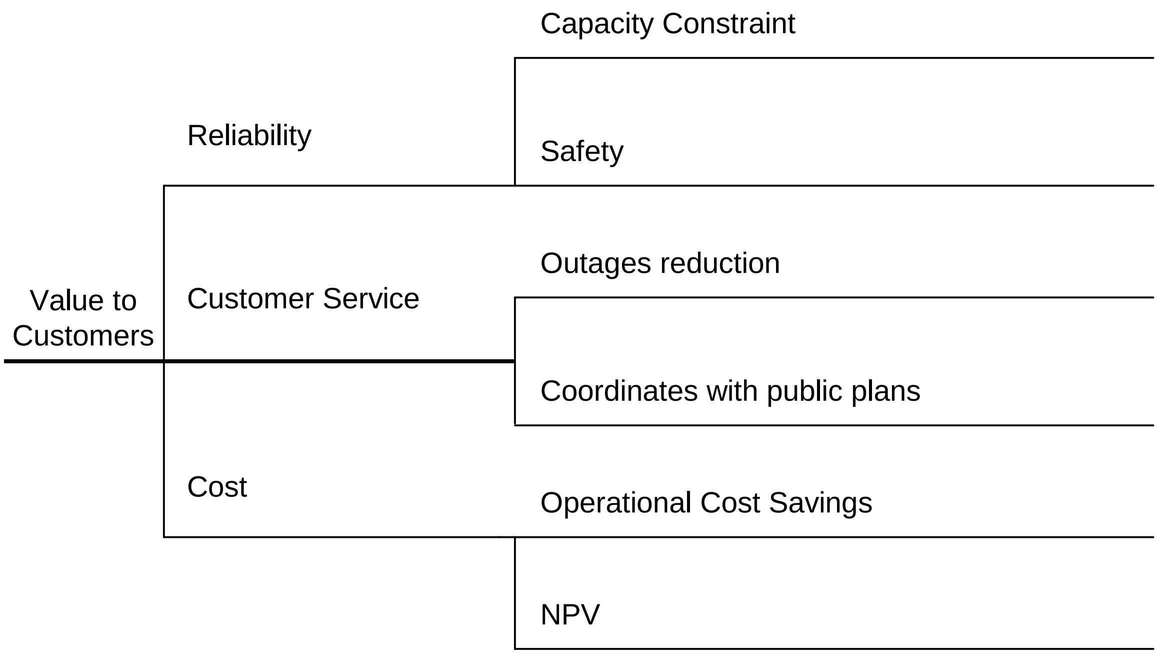
Planners determine the cost of projects using a variety of tools, including historical cost analysis and unit pricing models based on service provider contracts. As projects move through detailed scoping, cost estimates are refined. Planners use a software program called Area Investment Model (AIM) to calculate a wide range of financial performance indicators for each project. This analysis includes the traditional Net Present Value and Rate of Return analysis, but also identifies the future revenue potential as a result of the added capacity gained by a particular solution. This does not drive the need for the project, but allows further comparison for infrastructure that will be in service for 30 to 50 years.

A more difficult task has been to quantify the benefits of a particular project. A single project may have a wide range of benefits. The benefits of the best alternative are assessed, which include both quantitative and qualitative benefits. Some of these benefits include how much energy will not be served in the future, the outages avoided based on the history and probability of equipment failure, the impact that a project or the resolution of an issue may have on public relationships, the reduction in cost due to coordination with municipal projects, and the value of service as determined by customers.

Dr. Thomas Saaty developed the analytical hierarchy process (AHP) circa 1970. He was a professor at the Wharton School of Business. AHP continues to be one of the most highly regarded and widely used decision making theories. It is especially suitable for complex decisions that involve the comparison of decision elements that are difficult to quantify. It involves building a hierarchy ranking of decision elements, then making comparisons between each possible pair in each cluster of common objectives. It captures both subjective and objective evaluation measures, providing a useful mechanism for checking the consistency of the evaluation measures and alternatives suggested by the team, thus reducing bias in decision making. As a result of this benefit analysis, projects receive a score. This score is then synthesized through an AHP application tool, Expert Choice, which optimizes scores and cost given designated financial constraints. The application of AHP for resource allocation decisions proves to be straightforward, with growing use by other organizations such as Xerox, IBM and Lucent. Exhibit XVI-10 represents an example of the hierarchy developed for making project comparisons.

Exhibit XVI-10

Benefit Heirarchy



D. System Plans

The planning processes and decision-making methodology described above help to develop the Least Cost Plan. This analysis helps to build short- and long-range plans. For 2005, over 700 projects have been identified for engineering or completion to meet capacity and reliability needs. An example of the proposed 5-year infrastructure plans for predicted system capacity needs is provided. As the plan year gets closer, further analysis is performed to flush out additional alternatives based on more information. As a result, these types of plans may change in an effort to incorporate new information and implement the least cost solution. Exhibit XVI-11 shows gas infrastructure plans and Exhibit XVI-12 shows electric distribution infrastructure plans.

Exhibit XVI-11

5-Year HP Supply Construction Plan 2005 - 2009

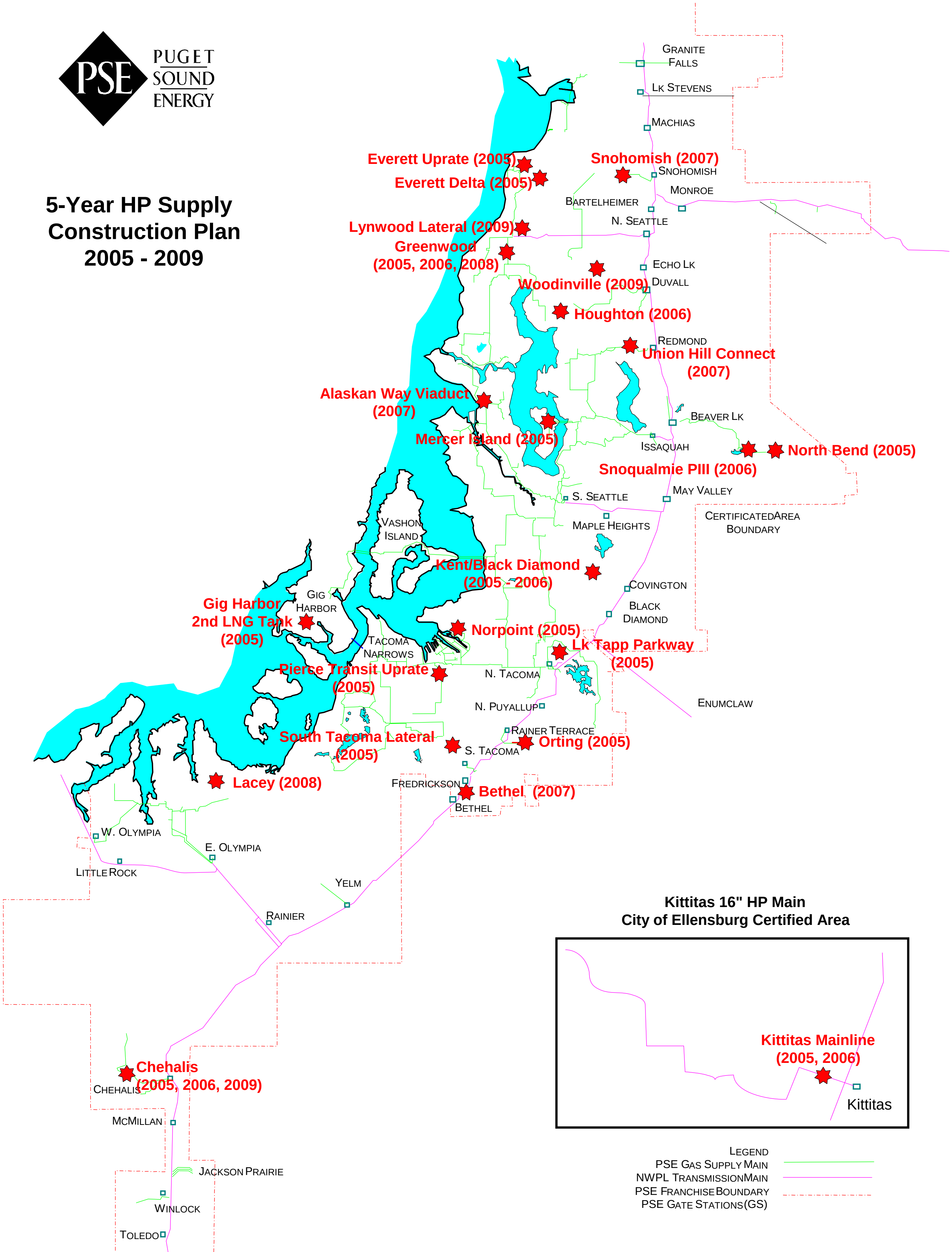


Exhibit XVI-12

5-Year Substation Construction Plan

2005 - 2009

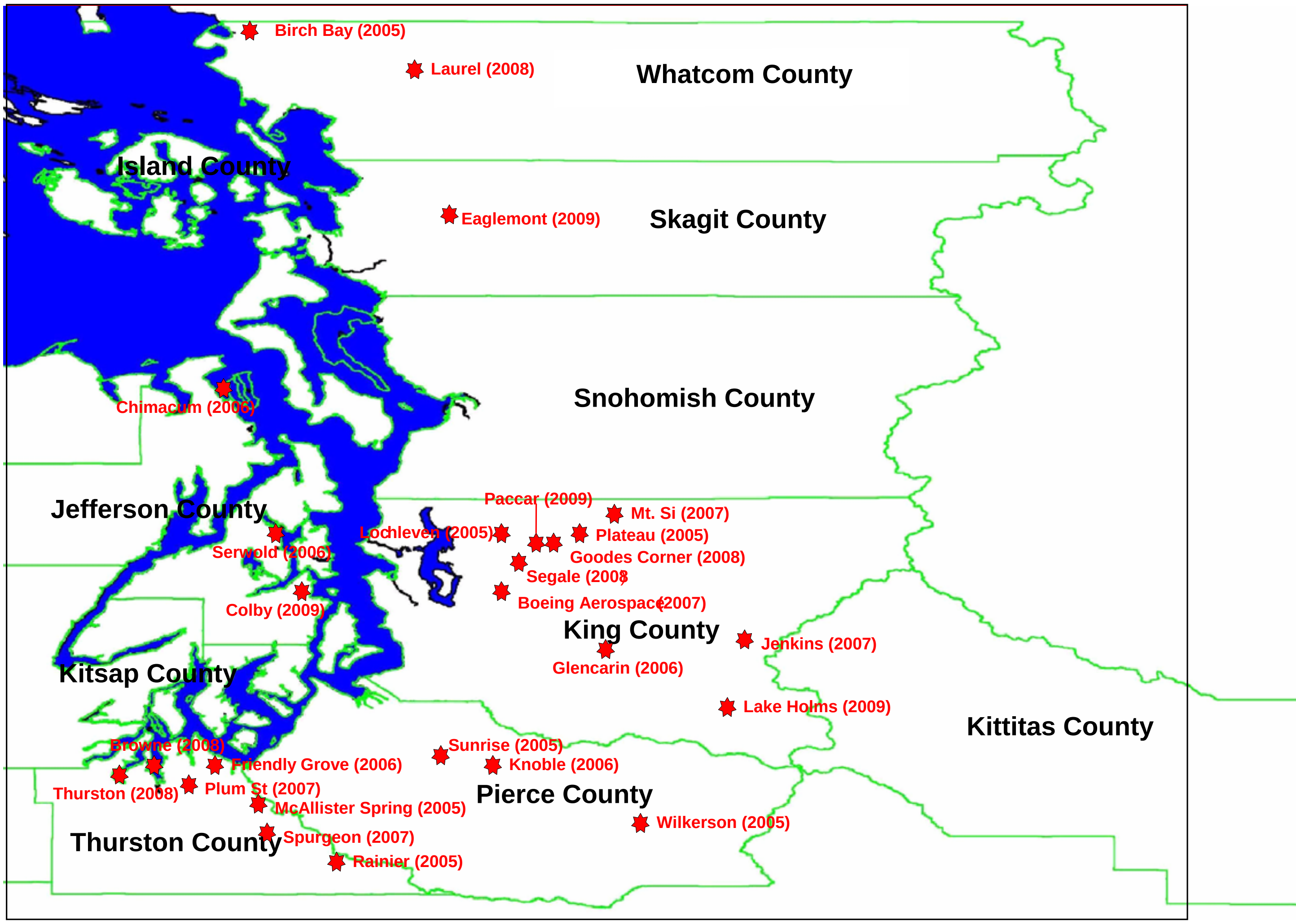


Exhibit XVI-13
5-Year Construction Plan—Gas-HP Supply

Year	Name of Project	City	Job Description
2005	Everett Uprate	Everett	Increase MAOP of system by completing an HP Uprate
2005	Everett Delta	Everett	Incidental carry-over costs from previous Everett Delta HP job
2005	Greenwood	Seattle	Greenwood IIA – install 16” HP out of the North Seattle Town Border Station (south)
2005	Mercer Island	Mercer Island	Increase MAOP of system by completing an HP Uprate
2005	North Bend	North Bend	Install approximately 16,000’ of 8” HP main along Snoqualmie Parkway to SR202
2005	Kent/Black Diamond	Kent	Complete paving for Phase 1A and begin engineering for Phase 1B
2005	Gig Harbor 2nd LNG Tank	Gig Harbor	Purchase and install 2nd LNG tank for existing Gig Harbor LNG plant
2005	Norpoint	Tacoma	Replace 6" HP with 8" HP, ~10,200 feet
2005	Lake Tapp Parkway	Bonney Lake	8" Steel wrapped HP road opportunity
2005	Pierce Transit Uprate	Tacoma	Increase MAOP of system by completing an HP Uprate
2005	South Tacoma Lateral	Tacoma	Increase MAOP of system by completing an HP Uprate
2005	Orting	Orting	Install 8" HP along 144 ST E; tie to the existing 8" to the 8"HP
2005	Chehalis	Chehalis	Preliminary Engineering for the Installation of 5,000’ 8” HP Main
2005	Kittitas Mainline	Kittitas	Install 108,000 feet of 12" Steel wrapped high pressure main along the Prairie route
2006	Greenwood	Seattle	Greenwood IIIA – install 16” HP out of the North Seattle Town Border Station (North)
2006	Houghton	Kirkland	Replace 2500' of 4" with 8" HP Main to DR 2485
2006	Snoqualmie PIII	Snoqualmie	Replace 4" HP bottleneck with 12", ~11,600'
2006	Kent/Black Diamond	Kent	Install 16”HP from 132 Ave SE & 288 ST to Auburn Way N & tie-in to the HP (Ph. 1b)
2006	Chehalis	Chehalis	Engr., Constr. & Install 5,000’ of 8” HP Main
2006	Kittitas Mainline	Kittitas	Install 12" HP out of Thorp TBS to Suncadia Development, ~4.8 miles
2007	Snohomish	Snohomish	8" HP, Upgrade 4" HP out of Snoh, GS to 8:"; retire DR1780 and install new DR
2007	Union Hill Connect	Redmond	Connect Union Hill Phases; raise set pressure at gate station, ~6000'
2007	Alaskan Way Viaduct	Seattle	Replace ~ 4000' of 152" HP with 16" HP to accommodate Alaskan Way Viaduct PI work
2007	Bethel	Bethel	Extend 12" HP from existing 8" HP to serve Cascadia
2008	Greenwood	Seattle	Install 16" HP from Phase IIIA to W. Greenwood Lateral
2008	Lacey	Lacey	Extend 8" HP from existing 12" HP to serve Lacey
2009	Lynnwood Lateral	Lynnwood	Install 16" to bisect Greenlake Loop; connect with LS North of Ship Canal crossing
2009	Woodinville	Woodinville	Completed Woodinville Phase III; install 16" on TW ROW
2009	Chehalis	Chehalis	Install 8" HP from GS to TBS

Exhibit XVI-14
5-Year Construction Plan—Substation

Year	Name of Substation	County	Job Description
2005	Birch Bay	Whatcom	Change to 15 MVA Transformer, 115 KV Substation
2005	Lochleven	King	Install 25 MVA Transformer, 115 KV Substation (2nd Bank)
2005	Wilkerson	Pierce	Change to 15 MVA Transformer, 115 KV Substation
2005	Plateau	King	New, 25 MVA Transformer, 115 KV Substation
2005	Rainier	Thurston	New, 25 MVA Transformer, 115 KV Substation
2005	Sunrise	Pierce	New, 25 MVA Transformer, 115 KV Substation
2005	McAllister Spring	Thurston	Change to 15 MVA Transformer, 115 KV Substation
2006	Chimacum	Jefferson	New, 25 MVA Transformer, 115 KV Substation
2006	Glencarin	King	New, 25 MVA Transformer, 115 KV Substation
2006	Friendly Grove	Thurston	Uprate 55 Kv to 115 KV, change to 5 MVA Transformer, 115 KV Substation
2006	Knoble	Pierce	New, 25 MVA Transformer, 115 KV Substation
2006	Serwold	Jefferson	New, 25 MVA Transformer, 115 KV Substation
2007	Jenkins	King	New, 25 MVA Transformer, 115 KV Substation
2007	Spurgeon	Thurston	New, 25 MVA Transformer, 115 KV Substation
2007	Plum Street	Thurston	Uprate 55KV to 115KV, change to 20 MVA Transformer, 115 KV Substation
2007	Boeing Aerospace	King	25 MVA Transformer, 115 KV Substation (customer owned to PSE owned)
2007	Mt. Si	King	New, 25 MVA Transformer, 115 KV Substation
2008	Laurel	Whatcom	New, 25 MVA Transformer, 115 KV Substation
2008	Browne	Thurston	New, 25 MVA Transformer, 115 KV Substation
2008	Thurston	Thurston	Uprate 55KV to 115KV, change to 10 MVA Transformer, 115 KV Substation
2008	Segale	King	New, 25 MVA Transformer, 115 KV Substation
2008	Goodes Corner	King	Install 25 MVA Transformer, 115 KV Substation (2nd Bank)
2009	Eaglemont	Skagit	New, 25 MVA Transformer, 115 KV Substation
2009	Lake Holms	King	New, 25 MVA Transformer, 115 KV Substation
2009	Colby	Jefferson	New, 25 MVA Transformer, 115 KV Substation
2009	Paccar #2	King	25 MVA Transformer, 115 KV Substation (2nd Bank)

E. Distributed Resource Opportunities

Distributed Resources (DR) are commonly defined as small-scale generation facilities connected to the distribution level of the transmission and distribution grid located near the source of the load being served. DR is not a new concept, dating back to the earliest days of the electric industry. For much of the 20th century, small-scale customer based generation could not compete economically with utility-owned centralized plants. These economics began to change in the mid-1980s when centralized fossil plant technology reached maturity and research and development then focused on micro-turbines and fuel cell technologies.

In addition, customers' electricity and energy requirements began to change. For example, some industrial customers now focus on meeting combined electric and thermal needs through one system, hospitals and computer-based internet service firms now require higher levels of power quality and reliability due to the substantial impact of not having service, and other customers want renewable or green power. In response to these factors and to changing federal laws, small-scale generation has become more common among PSE's large industrial customers. While DR continues to emerge, it is slower than previously expected because the economics remain unattractive.

Background

Although DR offers some potential benefits as part of PSE’s distribution system facilities planning process, a host of regulatory, business practice, technical, and market barriers continue to challenge the full-scale implementation of this technology. In May 2000, the National Renewables Energy Laboratories (NREL) issued a report identifying some of these challenges.

Since then federal and state agencies have taken some steps to address the barriers identified by NREL. The United States Department of Energy’s Distributed Energy Resource (DER) program implements a Distributed Energy Resource Strategic Plan. This national effort promotes the “next generation” of clean, efficient, reliable and affordable distributed energy technologies. As a follow-up to FERC’s October 2001 Advance Notice of Proposed Rulemaking (ANOPR), and the National Association of Regulatory Utility Commission’s (NARUC) June 2002 release of the draft Interconnection Agreement and draft Interconnection Procedures, FERC initiated a Notice of Proposed Rulemaking (NOPR) in July 2003. It was designed to finalize the standardization of small generator interconnection agreements and procedures. In October

2003, NARUC published the model agreement for Interconnection and Parallel Operation of Small Distributed Generation Resources as an information tool and to serve as a catalyst for DR interconnection proceedings.

Industry groups have also taken steps to address technology barriers to DR implementation. The Institute of Electric and Electronic Engineers (IEEE) is developing specific and voluntary DR standards. In June 2003, IEEE Standard 1547-2003, Standards for Distributed Resource Interconnection with the Electric Power Systems, was established and approved by the IEEE board. The IEEE Standards Coordinating Committee is currently drafting and establishing technical guidelines for the interconnection of electric power sources greater than 10 MVA to the power transmission grid. A draft paper on the impact of DR to utilities was written by the IEEE Distributed Resources Integration working group. As many of these standards and guidelines become finalized and approved, DR will become easier for small customers to implement.

PSE's Use of Distributed Resources

Despite remaining barriers to full-scale DR implementation, PSE strives to incorporate DR elements into its planning process. PSE has developed DR guidelines that identify those projects with the highest probability of serving the least cost capacity deferral alternative. For example, the Hansville Peninsula project mentioned previously is utilizing this technology in order to have time to implement the long-term least cost solution. When the submarine cable supplying electricity approaches its design capacity, the temporary generator is operated to pick up the excess load and protect the cable from prematurely failing prior to completion of a new cable or substation. In addition, PSE currently has over 24 photovoltaics and micro-hydro customer generators connected to the grid company-wide.

PSE implemented a distributed resource peak shaving strategy at Crystal Mountain. Crystal Mountain is an area that could reach peak load capacity capabilities within a few years. The load was projected to climb from 5.9 MVA to 11.2 MVA by 2006-2007. The estimated capital cost for a traditional wire solution was about $2.5 million. PSE decided to refurbish and test a 2.4 MVA diesel standby generator located near the load. PSE ran a test to prove the concept and its feasibility, which provided sufficient justification to defer the $2.5 million traditional system upgrade for three to seven years.

PSE views the DR technology as an alternative for delivering reliable energy at low cost. Currently, PSE monitors and evaluates DR developments at the federal, state and utility levels. From 2000 to 2004, PSE participated in the Universal Interconnect Detail Design project with the Department of Energy (DOE), National Renewable Energy Laboratory (NREL), and General Electric (GE). The final report on this project was issued in December 2004, and emphasized that standard compliance is key for entry into the distributed generation market. It also addressed microgrid application issues, and summarized the detailed study and development of new GE anti-islanding controls. PSE continues to search for opportunities to implement DR and adopt effective and workable solutions already developed by the industry.

F. Non-Wires Solution (NWS)

Background [1]

Over the last 20 years, transmission systems throughout North America have experienced significantly increased end-use *consumption* and grid utilization despite comparatively little investment in new transmission infrastructure. The result of this imbalance is a grid under stress and a growing awareness of the need to reinforce transmission systems across North America including in the Pacific Northwest.

BPA owns and operates approximately three-quarters of the electrical transmission system in the Pacific Northwest. According to "Transmission Planning through a Wide-Angle Lens," a report published by the BPA in September 2004, "BPA did not undertake any substantial transmission construction between 1987 and 2003." The report goes on to say that, "Since 1999, the system has operated at or near capacity to meet demand." The Olympic Peninsula, where PSE serves approximately 45 percent of the load, is one of these congested areas.

In 2001, BPA's Transmission Business Line (TBL) developed a program aimed at strengthening the existing grid. As part of this process, BPA broadened its strategy to include non-wires solutions such as demand response, distributed generation and conservation measures that reduce peak demand as a means of deferring transmission projects when possible. The goal was to identify and consider potential non-wires solutions that would also be cost-effective.

[1] Some information in this section, regarding BPA's Transmission Business Line, has been paraphrased from BPA's "Transmission Planning through a Wide-Angle Lens: A Two-Year Report on BPA's Non-Wires Solutions Initiative," published in September 2004.

The Non-Wires Solutions Roundtable [2]

In 2003 BPA held its first Non-Wires Solutions (NWS) Roundtable. Comprised of 17 member organizations, including utilities, regulators, renewable resource advocates, environmental interest groups, industrial energy users, an organization of Indian tribes, and independent power generators, the group employs a broad, regional approach to considering non-wires solutions. PSE is a member of the Roundtable via Sue McLain, the Company's Sr. Vice President of Operations.

In the past 18 months the Roundtable focused on the following activities:

- Identifying transmission planning screening criteria—to evaluate whether a non-wires solution might defer a transmission project,
- Reviewing detailed studies for existing problem areas on BPA's transmission system—again to determine when a non-wires solution might defer transmission,
- Reviewing non-wires technologies,
- Defining institutional barriers, which create obstacles for non-wires solutions, and
- Piloting non-wires solutions.

PSE Activities in the area of NWS

1. The Conservation Voltage Reduction (CVR) pilot, which is currently in-progress in PSE's System Planning & Operations Group, can be viewed as an NWS application. PSE is working with NEEA in a pilot project to research potential savings by applying CVR technologies. This study involves lowering substation and feeder voltage without adversely affecting power quality to PSE customers. It remains to be seen whether the effort will result in meaningful load reduction at the substation to influence investment decisions.
2. PSE submitted two demand response pricing programs in response to BPA's RFP process for NWS pilots in 2004. The proposed pilot programs were a Community Incentive Peak-Reduction program and a Voluntary Extreme Day Pricing program. The pilots were designed to test winter peak-day demand response potential in a small targeted area of PSE's electric service territory. The technology to test these pilots (PAR3, PEM and AMR) is currently available. PSE may consider the possibility of

[2] Some information in this section, regarding BPA's Non-Wires Solutions Roundtable, has been paraphrased from BPA's "Transmission Planning through a Wide-Angle Lens: A Two-Year Report on BPA's Non-Wires Solutions Initiative," published in September 2004.

evaluating future pilot programs such as these, outside the BPA Non-Wires Request for Proposals process.

In addition to more traditional “wires” solutions, PSE recognizes that there are economic and other factors which make it necessary and appropriate to consider NWS where possible. In conjunction with this, PSE maintains a staunch commitment to the position that such solutions must be as reliable as a transmission or distribution project to ensure that customer reliability is not impacted. The above examples illustrate PSE efforts toward that goal.