Delivery System Planning

PSE manages two types of delivery systems. One is company-owned and delivers electricity and natural gas *within* our local service area to more than 1.7 million customers. The other is "merchant-based" and involves arrangements made with outside companies and organizations to transport power and natural gas *to* our service area. The two are governed by different rules and planned under separate processes and toolkits. This chapter addresses planning for the PSE-owned delivery system within our service area, while merchant-based delivery systems are discussed in Chapter 5, Electric Resources. This chapter is organized in five parts:

Our delivery system planning process is designed to balance safety, cost, and operational requirements while considering environmental management, regulatory requirements, and changing customer demands. The purpose is to identify the most cost-effective solutions to the needs that we face. Safety, capacity, and reliability are our most important performance criteria. Simply put: How will PSE safely and continuously deliver enough energy through the pipes or wires to meet demand on the other end?

- We must operate the system as safely and efficiently as possible on a year-by-year, day-by-day and even hour-by-hour basis.
- We must accomplish needed maintenance and improvements as cost effectively as possible.
- We must anticipate future needs so that infrastructure will be in place to meet that need when it arrives.

Our goal is to fulfill these responsibilities at the lowest reasonable cost.

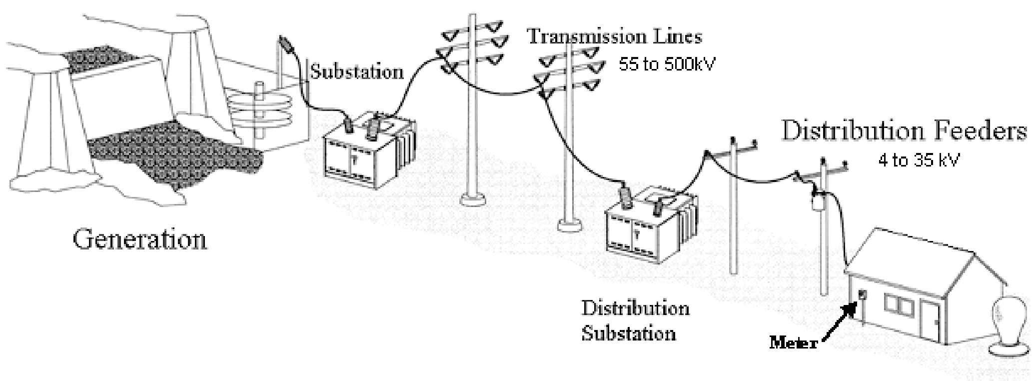
I. System Mechanics and 5-year Infrastructure Plan

Familiarity with the mechanics of the gas and electric systems is helpful to understanding PSE's delivery system planning process.

A. Electric Delivery Systems

Electricity is transported from power generators to consumers over wires and cables, using a wide range of voltages and capacities. The voltage at the generation site must be stepped up to high levels for efficient transmission over long distances (generally 55 to 500 kilovolts). Substations receive this power and reduce the voltage in stages to levels appropriate for travel over local distribution lines (between 4 and 34.5 kV). Finally, transformers at the customer's site reduce the voltage to levels suitable for the operation of lights and appliances (under 600 volts). Wires and cables in the system carry electricity from one place to another. Substations and transformers change its voltage to the appropriate level. Circuit breakers prevent overloads and meters measure how much power is used.

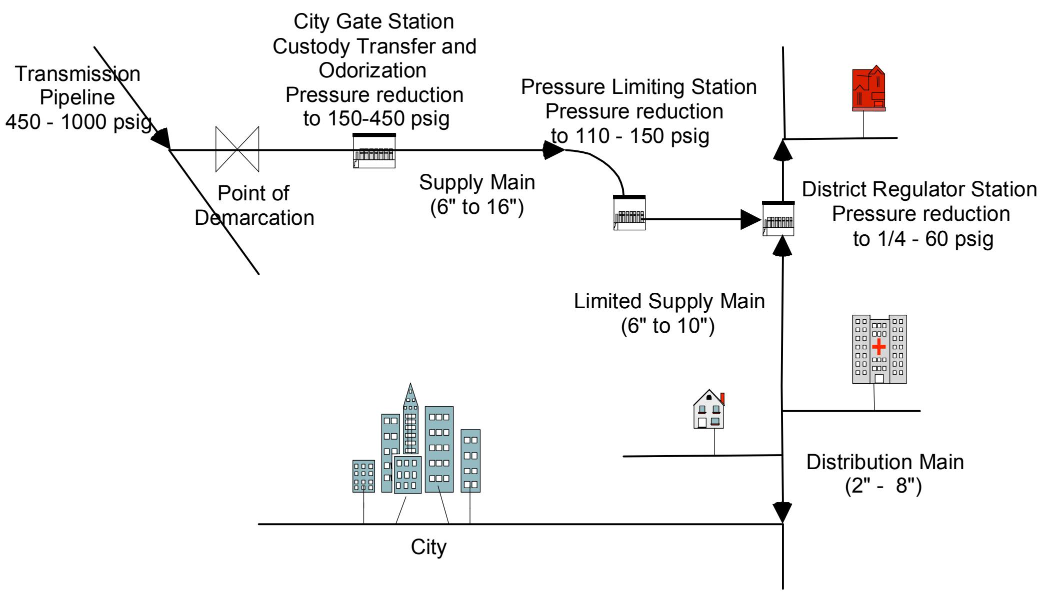
Figure 7-1
Electric Delivery System



B. Natural Gas Delivery Systems

Natural gas is transported at a variety of pressures through pipes of various sizes. Large transmission pipelines deliver gas to city gate stations at high pressures, generally 450 to 1,000 pounds per square inch gauge (psig). There, pressure is reduced to 150 to 450 psig for travel through supply main pipelines to district regulator stations which further reduce the pressure to less than 60 psig. From this point the gas flows through a network of piping (mains and services) to a meter set assembly at the customer's site. There the pressure is reduced to what is appropriate for the operation of the customer's equipment (0.25 psig for a stove or furnace) and the gas is metered to determine how much is used. As gas flows through the distribution system, the system pressure will drop due to friction. This friction and resulting pressure drop depends on the diameter, material, roughness and length of the pipe that is used; it is also impacted by the type and number of fittings that are included in the system. As a result, each of these items is carefully considered when designing the system.

Figure 7-2
Gas Delivery System



C. PSE's Existing Delivery System

The table below summarizes the transmission and distribution infrastructure owned and operated by PSE as of December 31, 2008.

Figure 7-3
PSE-owned Transmission and Distribution System

Electric	Gas
Customers: 1,078,629	Customers: 750,164
Service territory: 4,500 square miles	Service territory: 2,800 square miles
Substations: 349	City gate stations: 40
Miles of transmission line: 2,614	Pressure regulating stations: 652
Miles of overhead distribution line: 10,392	Miles of pipeline: 11,930
Miles of underground distribution line: 9,794	Transmission pipeline pressure: 450-1,000 psig
Transmission line voltage: 55-500 kV	Supply Main pressure: 150–450 psig
Distribution line voltage: 4-34.5 kV	Distribution pipeline pressure: 45-60 psig
Customer site voltage: less than 600 V	Customer meter pressure: 0.25 psig

D. 5-year Infrastructure Plan

The maps and lists that follow show PSE's proposed 5-year infrastructure plan for meeting predicted capacity and reliability needs. The plan is reviewed annually and remains dynamic. As the plan year gets closer, we refine plan projections based on new developments or information, and perform additional analyses to reveal and evaluate additional alternatives. The plan may change as a result of these investigations.

Figure 7-4
Map of Electric Substation Construction Plans, 2009–2013

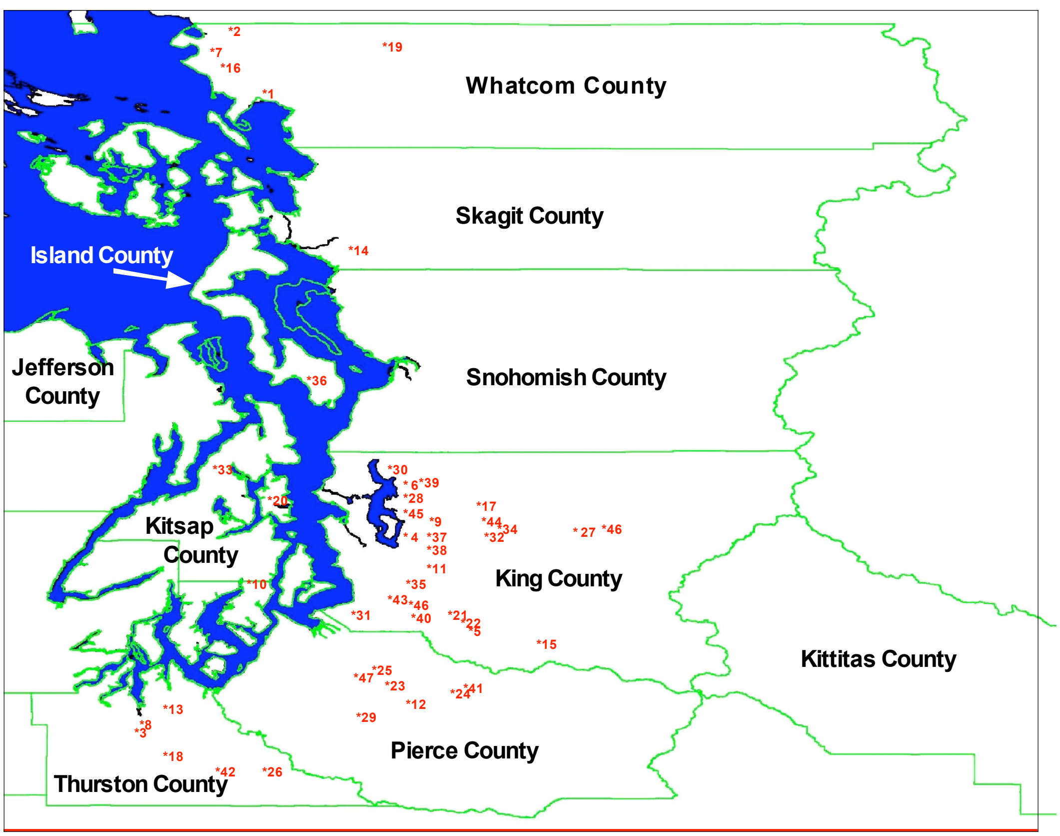


Figure 7-5
List of Electric Substation Construction Plans, 2009-2013

No.	Year	Substation	County	Description
1	2009	Bellis	Whatcom	Replace existing transformer with 115 kV, 25 MVA transformer
2	2009	Berthusen	Whatcom	Construct new 115 kV substation with 25 MVA transformer
3	2009	Capital	Thurston	Rebuild existing 55 kV substation to 115 kV. Replace existing transformer with 115kV, 25 MVA transformer
4	2009	Factoria Bank #2	King	Rebuild existing 115 kV substation. Install second 115 kV, 25 MVA transformer
5	2009	Four Corners	King	Construct new 115 kV substation with 25 MVA transformer
6	2009	Juanita Sub #2	King	Install second 115 kV, 25 MVA transformer
7	2009	Semiahmoo	Whatcom	Construct new 115 kV substation with 25 MVA transformer
8	2009	Thurston	Thurston	Rebuild existing 55 kV substation to 115 kV. Replace existing 2 transformers with 115kV, 25 MVA transformers.
9	2010	Ardmore	King	Construct new 115 kV substation with 25 MVA transformer
10	2010	Bethel	Kitsap	Construct new 115 kV substation with 25 MVA transformer
11	2010	Boeing Aerospace	King	Purchase and rebuild existing 115kV substation. Install new 115 kV, 25 MVA transformer
12	2010	Buckley	Pierce	Construct new 115kV substation, retire old substation, 25 MVA transformer
13	2010	Carpenter	Thurston	Construct new 115 kV substation with 25 MVA transformer
14	2010	Eaglemont	Skagit	Construct new 115 kV substation with 25 MVA transformer
15	2010	Greenwater	Pierce	Replace existing transformer with 115 kV, 25 MVA transformer
16	2010	State St	Whatcom	Replace existing transformer with 115 kV, 25 MVA transformer
17	2010	Sterling Bk#1 and #2	King	Construct new 115 kV substation with 2 - 25 MVA transformers
18	2010	Spurgeon	Thurston	Construct new 115 kV substation with 25 MVA transformer
19	2011	Kendall	Whatcom	Construct new 115 kV substation with 25 MVA transformer
20	2011	Bainbridge	Kitsap	Construct new 115 kV substation with 25 MVA transformer
21	2011	Briscoe Park	King	Construct new 115 kV substation with 25 MVA transformer
22	2011	Jenkins	King	Construct new 115 kV substation with 25 MVA transformer

No.	Year	Substation	County	Description
23	2011	Kelly/Dingo	Pierce	Construct new 115 kV substation with 25 MVA transformer
24	2011	Krain Corner	Pierce	Install 115 kV, 25 MVA transformer at existing 115 kV Switching Station
25	2011	Lakeland	Pierce	Construct new 115 kV substation with 25 MVA transformer
26	2011	Longmire Bank #2	Thurston	Rebuild existing 115 kV substation. Install second 115 kV, 25 MVA transformer
27	2011	Mt. Si	King	Construct new 115 kV substation with 25 MVA transformer
28	2011	North Bellevue #3	King	Install third 115 kV, 25 MVA transformer
29	2011	Thrift	Pierce	Construct new 115 kV substation with 25 MVA transformer
30	2012	Duvall Bk #2	King	Install second 115 kV, 25 MVA transformer
31	2012	Enchanted Sub	King	Construct new 115 kV substation with 25 MVA transformer
32	2012	Goodes Corner Bank #2	King	Install second 115 kV, 25 MVA transformer
33	2012	Holly	Kitsap	Construct new 115 kV substation with 25 MVA transformer
34	2012	Issaquah Highlands	King	Construct new 230 kV substation with 25 MVA transformer
35	2012	Kent Bank #3	King	Install third 115 kV, 25 MVA transformer
36	2012	Maxwelton	Island	Construct new 115 kV substation with 25 MVA transformer
37	2012	Northrup Bank #2	King	Install second 115 kV, 25 MVA transformer
38	2012	Renton Junction Bank #3	King	Install third 115 kV, 25 MVA transformer
39	2012	Totem Lake Bk #2	King	Install second 115 kV, 25 MVA transformer
40	2013	Alpac	King	Replace existing transformers with 115 kV, 2 - 25 MVA transformer
41	2013	Cumberland	Pierce	Replace existing transformer with 115 kV, 25 MVA transformer
42	2013	Hobby Acres Sub	Thurston	Construct new 115 kV substation with 25 MVA transformer
43	2013	Lake Holm	King	Construct new 115 kV substation with 25 MVA transformer
44	2013	Lakemont	King	Construct new 115 kV substation with 25 MVA transformer
45	2013	Norkirk Bk #2	King	Install second 115 kV, 25 MVA transformer
46	2013	North Bend Bk #2	King	Install second 115 kV, 25 MVA transformer
47	2013	Pioneer Sub	Pierce	Construct new 115 kV substation with 25 MVA transformer

Figure 7-6
Map of Gas System Infrastructure Plans 2009-2013

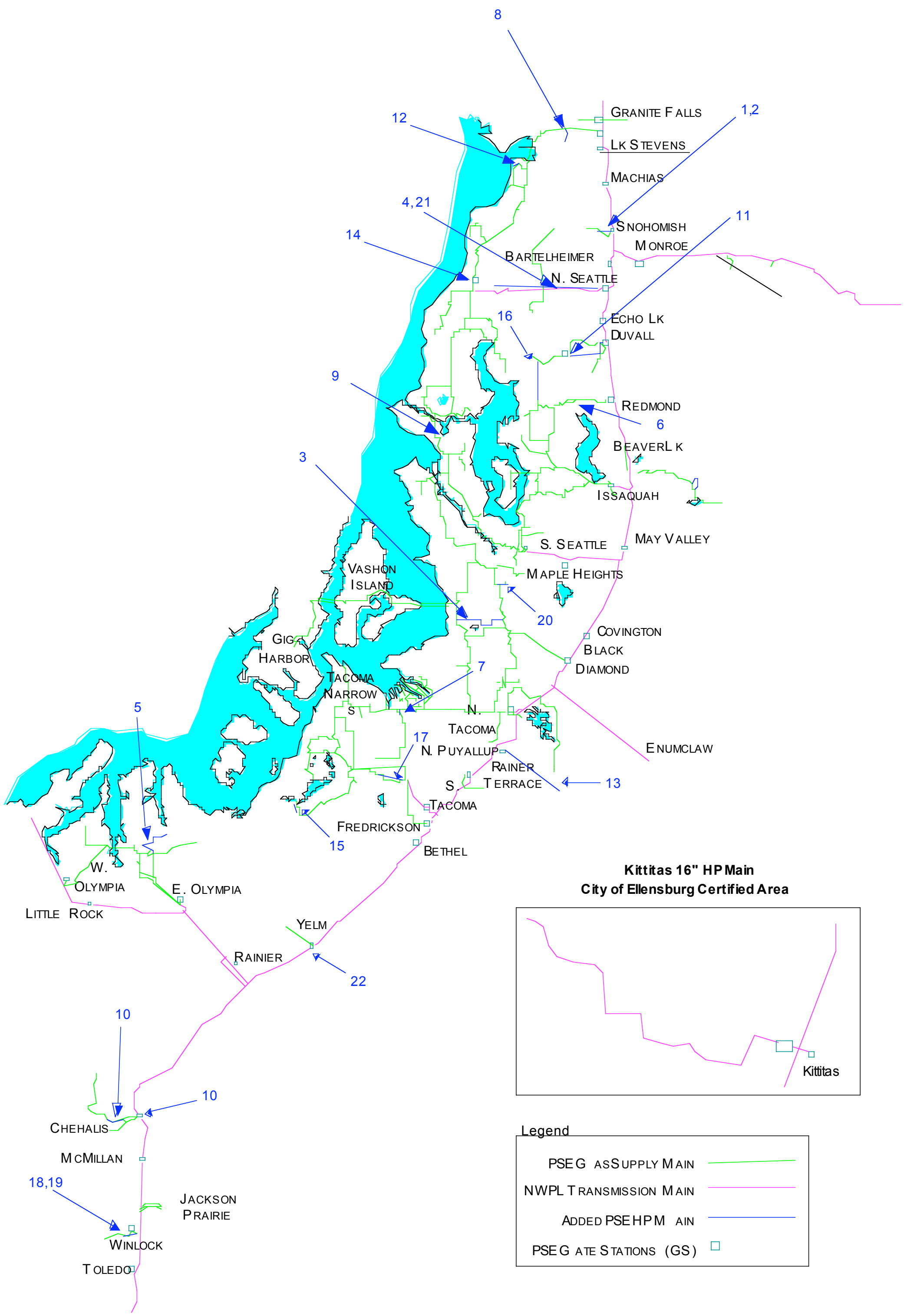


Figure 7-7
List of Gas System Infrastructure Plans 2009-2013

No.	Year	Name of Project	City	Description
1	2009	Snohomish 8" HP	Snohomish	Install ~11,000 feet of 8" HP to replace 4" HP out of Snohomish GS.
2	2009	Snohomish Gate Station Rebuild	Snohomish	Rebuild a portion of the Snohomish GS improve capacity.
3	2009	Kent Black Diamond Ph. II & GS Rebuild	Kent	Install ~ 27,000 feet of 16" HP from the end of Ph 1b to the Vashon Lateral. Include a small GS Modification by Williams to match mainline capacity.
4	2009	N. Seattle Lateral Pressure Increase	Seattle/Lynnwood	Increase Williams lateral pressure from 500 psig to 525 psig. Install heater at N Seattle TBS prior to increase.
5	2009	N. Lacey Supply Extension	North Lacey	Install ~25,000 feet of 8" and 12" HP to serve N. Lacey.
6	2009	Evans Creek Bridge Replacement	Redmond	Install 16" HP pipe on new bridge.
7	2009	I-5 Tacoma HOV Relocate	Tacoma	Install new 12" HP due to bridge demolition across I-5.
8	2009	Soper Hill Rd. 8 Inch IP Reinforcement	Lake Stevens	Install 6000 feet of 8" IP from Soper Hill DR to Lake Stevens.
9	2009	SDOT Mercer Corridor Relocates	Seattle	Install new 12" HP and 8" IP due to Mercer construction activities.
10	2010	Chehalis GS1360 Rebuild	Chehalis/Centralia	Rebuild Chehalis GS for new HP project capacity.
10	2010	Chehalis HP Supply Ph 2	Chehalis/Centralia	Install ~18,000 feet of 12" HP to replace 4" HP out of Chehalis GS
11	2010	Tolt Corridor HP Install & Gate Station	Woodinville/Duval	Install ~34,000 feet of 16" HP from Duval to Woodinville. Modify/construct gate station as required.
12	2010	Everett Supply Loop	Everett	Complete the HP loop with 16" HP near the Everett Delta LS.
13	2011	Bonney Lake/Cascadia HP Supply	Bonney Lake/Cascadia	Install 36,000 feet of 16" HP to the Cascadia area and associated pressure regulation facilities.

No.	Year	Name of Project	City	Description
14	2011	N Seattle Lateral to Everett Delta Control Valve	North Seattle/Lynnwood	Install control valve to limit flow to Everett area during heavy loads.
15	2011	Dupont HP Lateral Uprate to 250 psig	Dupont	Remove LS and uprate to 250 psig MAOP.
16	2011	Woodinville/Tolt to Kirkland 12" HP Connector	Woodinville/Redmond/Kirkland	Install 25,000 feet of 12" HP from Woodinville south to Kirkland area.
17	2011	Frederickson/S Tacoma 16" HP Lateral Expansion Ph I	Tacoma/Frederickson	Install 12,000 feet of 16" HP.
18	2012	Winlock GS1362 Rebuild	Winlock	Williams to rebuild Winlock GS for additional capacity.
19	2012	Winlock Lateral HP Uprate	Winlock	Complete an uprate from 150 to 250 psig.
20	2012	LS1996 HP Uprate from 100 to 150 or 250 psig	Renton	Uprate from 100 psig to 150 or 250 psig
21	2013	N. Seattle Lateral 8" HP Replcmt w/16' HP	Seattle/Lynnwood /Everett	Williams to replace 5 miles of the N Seattle lateral with 16" or 20" HP.
22	2013	Yelm GS1354 Rebuild	Yelm	Rebuild GS to maintain capacity and pressure.

II. Changes and Challenges

Aging infrastructure, changes in the industry, and increasing sensitivity to energy costs, electric system reliability, and environmental impact all make planning delivery systems an evolving and complicated process. The electric planning process itself is subject to increasing regulation under North American Electric Reliability Corporation (NERC) which enforces regulations for the reliability of the bulk power system in North America. Gas pipeline safety regulations are changing. Throughout the industry, infrastructure investments are rising as infrastructure nears the end of its usable life, and in response to the industry's limited spending during the push for utility deregulation (when facility ownership and cost recovery were uncertain). These changes, combined with the region's strong growth rate and our commitment to keeping gas and electric networks flexible enough to meet changing operating conditions and future needs, are resulting in significant delivery system investments by PSE.

A. General Infrastructure Needs

Electrical and gas equipment installed many years ago are aging PSE's infrastructure. Some components of our gas delivery system have been operating since 1899, and some electric-related equipment since 1923. We review the performance and reliability of these systems continually to ensure safe and reliable operation and to reduce leaks and outages. We have developed programs and processes to maintain existing facilities and add new components as necessary. In addition, aging bare steel mains, power poles, underground cables, substation transformers and circuit breakers are being systematically replaced under multiyear replacement programs. Finally, we make investments to respond to changing conditions and needs. Annual performance issues for smaller distribution systems can often be resolved within a year or two, but large distribution or transmission issues take much longer to resolve. For example, securing substations and transmission facilities can take more than a decade.

B. Changing Regulations

The blackouts that affected the Northeast and Midwest in 2003 continue to generate changes for electric utilities. New regulations, mandated by The Energy Policy Act of 2005 and developed by NERC, became effective in 2007. Triggered by concern about the electrical grid's reliability, they move the industry into an era in which system planning, performance and operating requirements are mandated and take place under increasing scrutiny. The Federal Energy Regulatory Commission (FERC) selected NERC as the nation's Electric Reliability Organization (ERO). Per the Act, the ERO is responsible for enforcing the new standards. NERC has delegated enforcement of the western region to Western Electricity Coordinating Council (WECC).

In 2007, PSE formalized the NERC Reliability Standards Compliance program in alignment with the guidelines set forth by FERC. The NERC Program outlines methods and procedures through which PSE monitors, assesses, and ensures compliance with NERC's Reliability Standards

PSE complies with more than 85 NERC Reliability Standards and Regional Standards. While the majority of these standards were voluntary prior to June 2007, many if not all are undergoing revision over the next 3 to 5 years and new ones are being developed. This necessitates a continual review of process and practice to ensure compliance with the changes. For example, with the Critical Infrastructure Protection Standards, PSE formalized many new and changed processes and implemented technologies to secure the critical cyber assets that ensure reliable operation of the Bulk Electric System. Documentation of compliance with these and all the standards is now a significant on-going effort, and is an important component of the regional enforcement agency, or WECC's audits.

The Pipeline Safety Improvement Act (PSIA) of 2002 enacted stricter pipeline integrity requirements for the natural gas industry. In response, we implemented out own transmission integrity management program in 2005 in order to comply with the act and to place additional focus on the transmission pipelines.

In December 2006, the Pipeline Inspection, Protection, Enforcement and Safety Act was signed into law. The Act reauthorizes and amends the Department of Transportation's pipeline safety programs, and directs the Pipeline and Hazardous Materials Safety Administration to implement a distribution integrity management program (DIMP). Under the rule, concepts from the PSIA of 2002 will be applied to place additional focus on natural gas distribution systems. We anticipate the need to develop and implement our own DIMP by the end of 2010.

C. Right-of-way Issues

PSE expects right-of-way issues to become more challenging in the future. The cost and effort to acquire these new rights-of-way is rising, and communities are increasingly concerned about their impacts. For these reasons, PSE strives to maximize our use of existing company-owned and public rights-of-way before considering creation of new ones. When we must seek new acquisitions, we believe it is crucial to seek input from the communities and jurisdictions they will affect before finalizing line routing and design. Maintenance of rights-of-way is an ongoing responsibility, and PSE has implemented more stringent vegetation standards for certain right-of-way corridors in accordance with NERC requirements and in response to the record-breaking windstorm of Dec. 2006.

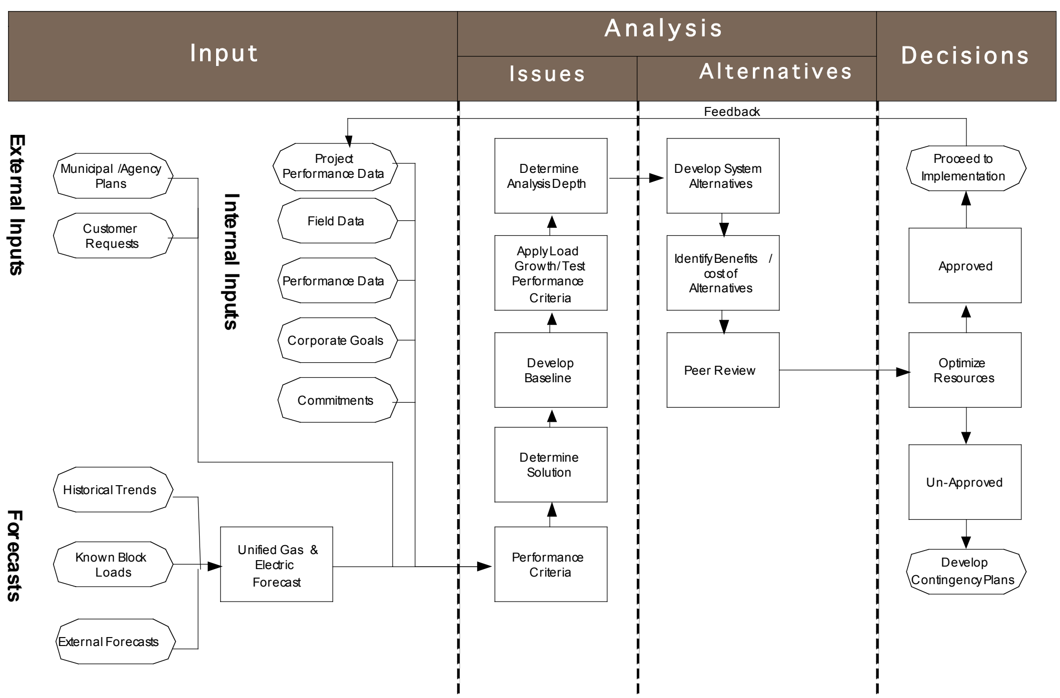
D. Emerging Alternatives

PSE is closely watching the development of Smart Grid and new technologies that offer possible “non-wires” solutions to transmission and distribution challenges. Distributed energy resources technology has the potential to increase capacity on the system by incorporating power that is generated closer to, or at, the customer’s location. It has promise, despite a variety of operating characteristics and complexities that must be addressed before it can be reliably integrated into the larger delivery system. Also, regardless of a customer’s ability to self-produce generation, PSE must maintain a system equipped to meet use and capacity requirements if the distributed resource is unable to meet the customer’s needs. See Section 5 of this chapter for a more detailed discussion of emerging alternatives.

III. Planning Process

The goal of the delivery system planning process is to find cost-effective ways to meet constituent needs. The 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 forecasts, customer expectations, and the impact of one energy type on the other. An analysis is conducted to identify alternatives that will address the challenge. Benefits and costs are then forecasted 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. Figure 7-8 diagrams the planning process.

Figure 7-8
Diagram of Delivery System Planning Process



A. Inputs

Internal planning considerations, or inputs, include system performance, company goals and commitments, and load forecasts.

PSE gathers system performance information from field charts, remote telemetry units, supervisory control and data acquisition equipment (SCADA), employees, and customers. Some information is analyzed over multiple years rather than a single year to normalize the effect of variables that can change significantly from year to year, such as weather. For near-term load forecasting at the local city, circuit, or neighborhood level, we use system peak-load and customer growth trends augmented by permitted construction activity for the next two years. For longer-term forecasting we use a corporate econometric forecasting method, which includes population growth and employment data by county (see Chapter 3).

External inputs include regulations, municipal and utility improvement plans, and customer feedback.

Reviewing municipal and utility improvement plans regularly enables us to minimize costs by scheduling upgrades or installation of new infrastructure when the ground is already being impacted by other construction work. We coordinate with other utilities whenever possible, and we work with other outside entities as well to find mutually beneficial schedules. Although our intent is to fully use existing assets before adding new ones, sometimes cost advantages can be gained from early installation for future needs.

PSE collects customer feedback in many ways. We continually investigate customer complaints and track ongoing service issues as they are communicated to us. Customers receive follow-up correspondence to discuss their concern, as well as plans for resolution. This communication provides valuable information that field data or statistical modeling may not have revealed.

In July 2007, PSE completed an extensive performance review prior to, during and following the record-breaking windstorm that hit the Pacific Northwest in mid-December 2006. In addition to seeking customer and employee feedback through focus groups, telephone and Web surveys, and internal debriefings, we hired KEMA, an 80-year-old energy consulting firm, to provide an independent, third-party, five-month analysis of the utility's pre-storm readiness and post-storm response. The KEMA analysis concluded that "PSE, its employees, and service providers performed well restoring power after this record-breaking storm." It also recommended actions PSE could take immediately to provide improved customer communications and improved outage response during future storms and other natural disasters. We accepted and implemented most of the KEMA recommendations and continue to refine and improve our processes in response to storms through post event reviews.

We have identified a number of system enhancements that may improve the electric system's resilience to minor or major storm events. To analyze the benefits of these strategies, PSE engaged a consultant to review these tactics and relative costs and to identify additional techniques with cost information that should be considered in the system planning process. The consultant completed his study in August 2008 and provided a roadmap for targeting reliability improvements. PSE will be incorporating consideration of these projects in our budgeting process.

B. Performance Criteria

PSE primarily categorizes system needs as "capacity" and "reliability." These performance criteria lie at the heart of our planning process, and along with state and federal requirements provide the foundation for planning our infrastructure improvements.

Figure 7-9
Performance Criteria for Electric and Gas Delivery Systems

Electric delivery system performance criteria are defined by:	Gas delivery system performance criteria are defined by:
Safety and compliance	Safety and compliance
The temperature at which the system is expected to perform	The temperature at which the system is expected to perform
The nature of service and level of reliability that each type of customer is contracted for	The nature of service each type of customer is contracted for (interruptible vs. firm)
The minimum voltage that must be maintained in the system	The minimum pressure that must be maintained in the system
The maximum voltage acceptable in the system	The maximum pressure acceptable in the system
The cost customers are willing to pay for target levels of performance	The cost customers are willing to pay for target levels of performance
The interconnectivity with other utility systems and resulting requirements; including compliance with NERC Planning Standards	

All PSE facilities that are part of the Bulk Electric System (BES) and the interconnected western system are planned and designed in accordance with the latest approved version of the NERC Reliability Standards, and the WECC standards and reliability criteria. These standards outline the performance expectations that affect how the PSE transmission system – 100 kV and above – is planned, operated and maintained.
The criteria by which the transmission system is measured are:

1. Its ability to maintain load service during normal operations (no outages, N-0) and,
2. Its ability under certain common contingencies where one element of the system is not in service (N-1).

For other less common contingencies --where two elements or more of the system are not in service-- the minimum reliability performance targets allow for planned, controlled load interruptions. There are several detailed contingency events specified in the NERC and WECC standards and reliability criteria that influence the planning of PSE's transmission system.

Modeling Tools

PSE relies on many different tools during the planning process to help identify and weigh the benefits of alternative actions. To evaluate both our gas and electric system performance, we use sophisticated modeling software that incorporates field data, including real-time information. Figure 7-10 provides a brief list of these tools, the planning considerations (inputs) that go into each, and the results (outputs) that they produce.

Figure 7-10
Summary of Delivery System Planning Tools

Tool	Use	Inputs	Outputs
Advantica SynerGEE	Network Modeling	Gas and Electric distribution infrastructure and load characteristics	Predicted system performance
Power World Simulator - Power Flow	Network Modeling	Electric transmission infrastructure and load/generation characteristics	Predicted system performance
PSS/E Power Flow & Stability	Network Modeling	Electric transmission infrastructure and load/generation characteristics	Predicted system performance
PSLF Power Flow & Stability	Network Modeling	Electric transmission infrastructure and load/generation characteristics	Predicted system performance
Probabilistic Spreadsheet	Probabilistic Analysis	Outage history, equipment failure probabilities	Outage savings based on probability of occurrence
Estimated Unserved Energy (EUE)	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
Investment Decision Optimization Tool (iDOT)	Project Data Storage & Portfolio Optimization	Project scope, budget, justification, alternatives and benefits; Resources/financial constraints	Optimized project portfolio, benefit cost ratio for each project, project scoping document
Area Investment Model (AIM)	Financial Analysis	Project costs, 8760 load data; and load growth scenarios	NPV; Income statement; Load Growth vs Capacity comparisons; EUE

PSE's gas system model is one of the largest integrated system models in the United States. It uses an Advantica SynerGEE software application that is continually updated to reflect new customer loads and system and operational changes. The accuracy of its results is validated by comparing them to actual system performance data. This model helps 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 be used to evaluate alternatives and their effectiveness in resolving the issues. We augment these alternatives with cost estimates and feasibility analysis to identify the lowest reasonable cost solution for both current and future loads.

For our electric distribution system, PSE also uses Advantica SynerGEE software. Here, the feeder system is modeled regionally rather than as a single large model. This is due to the limited connectivity between regions and the complexities with the management of a single large system model. Again, we use the model to evaluate system performance and predict capacity constraints on a variety of degree days and under a variety of load growth scenarios.

Modeling begins with building a digital map of the infrastructure and its operational characteristics. For gas, these include the diameter, roughness and length of the pipe, connecting equipment, regulating station equipment and operating pressure. For electric infrastructure, these include conductor cross-sectional area, resistance, length, construction type, connecting equipment, transformer equipment and voltage settings. Next, we identify customer loads, either specifically (for large customers) or as block loads for address ranges. Existing customer loads come from PSE's customer information system (CLX) or actual circuit readings. Finally, we vary temperature conditions, types of customers (interruptible vs. firm), time of peak daily usage, and the status of components (valves or switches closed or open) to model scenarios of infrastructure or operational adjustments to find the optimal solution to a given issue.

To simulate the performance of the electric transmission system, PSE uses three different programs: Power World Simulator, PSS/E (from Power Technologies Inc.), and PSLF (from General Electric). These simulation programs use a transmission system model 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 WECC, one of 8 regional reliability organizations under NERC. These power system study programs support PSE's planning process and facilitate demonstration of compliance with WECC and NERC reliability performance standards.

C. System Alternatives

A variety of approaches are available to address delivery system capacity and reliability issues. Each alternative has its own costs, benefits, challenges, and risks. These alternatives include the following.

Figure 7-11
Alternatives for Addressing Delivery System Capacity and Reliability Issues

Electric
- 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
- Load Reduction
  - Distributed Energy Resource
  - Fuel Switching
  - Conservation
  - Load control equipment
  - Possible new tarriffs
- Do nothing

Gas
- 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
- Load Reduction
  - Fuel Switching
  - Conservation
  - Load Control Equipment
  - Possible new tarriffs
- Do nothing

When issues are short term, like peaking events or meeting needs until a construction project is finished, energy flow can be managed temporarily with some of the same alternatives. Examples 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 changers to alter turn ratios.
- Automatic capacitor bank switching to optimize VAR consumption and maintain adequate voltage.
- Temporary siting of mobile equipment such as compressed natural gas injection vehicles, liquid natural gas injection vehicles, mobile substations, and portable generation.

D. Optimizing Value

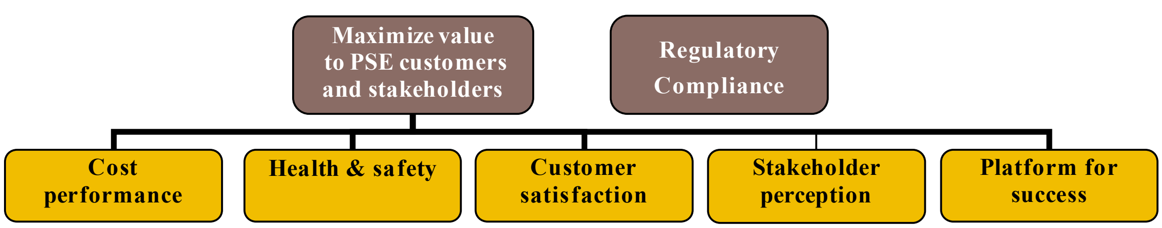
Making prudent investment decisions for hundreds of our gas and electric projects requires an objective way to synthesize, analyze, and optimize projects to maximize value to the company, customers, and the community. For this purpose, we use value-based budget prioritization.

In 2005, we updated the T&D Asset Investment Optimization System to better reflect our objectives, strategy and goals in light of the changing business environment, and to more efficiently and accurately quantify the value of projects, justify funding needs, prioritize projects, and account for risk and uncertainty. Formal "value modeling" refines and integrates existing tools to prioritize projects based on a measure of project value. Project value is estimated by simulating project impacts over the asset life or duration of maintenance funding and applying multi-attribute utility theory. The model we use, Investment Decision Optimization Tool (iDOT), identifies—from any portfolio of possible delivery system capital and maintenance projects, and any constraints on budget-year costs—the set of projects that will create maximum value.

Project costs are calculated 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 Area Investment Model (AIM) software to calculate a wide range of financial performance indicators for each project—including net present value and rate of return—as well as future revenue potential from capacity gained by a particular solution. This allows further comparisons for infrastructure that will be in service for 30 to 50 years.

The diagram below shows PSE's benefit structure to evaluate delivery system projects.

Figure 7-12
Benefit Structure to Evaluate Delivery System Projects



The results of the process are a portfolio of projects. This portfolio is ultimately reviewed and may be refined to ensure our ability to execute the projects (are there adequate resources to execute; is the work dispersed geographically to maintain crew presence for rapid response to outages and emergencies) and may be limited by budget.

IV. Case Studies

To illustrate the planning process through example, below we describe three situations and show how PSE addressed them.

A. Lake Stevens/Marysville Intermediate Pressure (IP) Distribution System

PSE currently serves the Lake Stevens area and southern Marysville areas with two existing gate stations (Lake Stevens and Machias) and a large district regulator known as the Soper Hill DR. The two gate stations are fed by the Williams lateral, while the Soper Hill DR is fed by the Everett Delta lateral. This means there are currently three separate feeds into these areas. The growth in these areas has ranged from 4% to 5.5% (and greater) in the most recent years. Due to this past growth and anticipated future growth, the existing two gate stations are approaching their capacities and this area will require additional supply capacity to maintain service to the existing and future customers.

During this investigation, multiple solutions were proposed and studied to determine the least-cost option to solve this capacity issue.

PSE explored three options as follows:

A. Add additional capacity through the Lake Stevens gate station (GS) and the Machias gate station.
B. Connect the intermediate pressure system to the existing Snohomish intermediate system to the south.
C. Install 6,000 feet of intermediate pressure pipe from the outlet of the existing Soper Hill DR towards the Lake Stevens area.

All three of these potential solutions were evaluated through our planning process to help determine the option that would provide the most value at the least cost.

Option (A) would have solved the problem for the foreseeable future. Unfortunately, the Lake Stevens gate station is currently approaching design capacity of 113,000 scfh, and will require approximately a $300,000 rebuild to extend its capacity as required by Williams. The Machias GS is also at capacity and will need a complete rebuild and PSE to take over regulation to extend its capacity. The Machias option would solve the problem, but at a very high cost of more than $2 million. Other alternatives were much less costly.

Option (B) also would have solved the problem by connecting the Lake Stevens system to the Snohomish system to the south. This project would have required approximately 10,000 feet of 6” or 8” intermediate pressure pipe (difficult route), and the replacement of a 4” IP pipe across the Pilchuck River (also difficult construction). However, difficult permitting issues posed a high risk for non-completion. These unknown risk factors and the estimated cost of at least $1 million lead us to alternative (C).

Ultimately, we selected Option (C) because of its low cost and its solution to the problem. This project entails installing 6,000 feet of 8” IP pipeline out of the existing Soper Hill DR along Soper Hill Road into the town of Lake Stevens. The existing Soper Hill DR has significant unused capacity and will require no work to supply additional capacity to the area. Because the cost for this project is estimated at $500,000 and the risks are low, PSE funded Option (C) for construction in 2009.

After completing this project and as opportunities and needs arise, PSE will continue to build out the IP system to the south towards the Machias GS and towards the town of Snohomish. We also anticipate many opportunities ahead to partner with public improvement and new customer construction, which should decrease the installation costs for some future projects.

Figure 7-13
Lake Stevens/Marysville Intermediate Pressure (IP) Distribution System Alternatives

Alternatives	Capital	Comments
Replace/Rebuild 2 Gate Stations	$2.3M	Not cost competitive with other options.
Connect IP system to Snohomish System to the South	$1M	Project option abandoned due to reliance on 2 other separate projects with high risk of completion. Cost also greater than option below and adds less capacity.
Install 6000 feet of IP System to Lake Stevens	$500,000	Least cost alternative that provided low risk solution

B. Novelty Hill 230-115 kV Transformer

In a 1994 planning study, PSE forecast the need for additional transformation in North King County by the year 2000. Subsequent planning studies have updated growth rates, timing of the project, and alternatives to be studied.

Sammamish Substation, with two 230-115kV transformers, is fed by three transmission lines originating at the Seattle Bothell, BPA Monroe and BPA Maple Valley Substations. There are no other 230-115 kV transformers in North King County. The next closest PSE 230-115 kV transformers are located at Talbot Hill Substation in Renton.

Under high winter loads, loss of one transformer at Sammamish Substation would lead to overload of the other Sammamish transformer. This is a violation of the Category B outage requirements under NERC's TPL standards.

We considered five alternatives for the North King Transformation:

A. Triple Banking at Sammamish Substation
B. 115 kV Ties at BPA Sno King Substation 115 kV Bus
C. Novelty Hill Substation 230-115 kV Development
D. Sammamish-Lakeside 230 kV Development
E. Lake Tradition Substation 230-115 kV Development

Option (A) was not desirable because bus section breaker failure scenarios (that were not studied in 1994) would still cause overloads, and because the 115 kV system would not be adequate to load the three transformers. We rejected Option (B) because it would require new agreements with BPA and Snohomish PUD, would increase the load on BPA's transformers, would require easements from Seattle City Light, and was more expensive than the Novelty Hill project. We also rejected Option (D), since it would require upgrading of the Sammamish-Lakeside 115 kV line to 230 kV, where permitting and construction may not be feasible, and it was significantly more expensive than Option (C). Option (E) was not selected because the Novelty Hill project would defer the need for the Lake Tradition project for an estimated seven years, while the Lake Tradition project would defer the Novelty Hill project for only an estimated five years; it is possible that by the seven-year time frame the 230 kV line from Wind Ridge will be constructed, connecting at Lake Tradition.

Option (C) proved optimal from cost/performance measures. The Novelty Hill 230-115 kV transformer addition increases capacity in North King County, while meeting NERC's reliability requirements. The project was completed and energized in late 2008.

C. Frederickson High Pressure (HP) Gas Distribution System

At present, the greater Tacoma, Puyallup, Lakewood, Dupont, Steilacoom and McChord Air Force Base are served essentially by the N Tacoma GS lateral and the South Tacoma GS and lateral. These 250 psig MAOP systems are separated by a 150 psig MAOP system (that both also feed). The southern half of this system being fed by the South Tacoma GS lateral has exceeded its capacity and cold weather actions and curtailments are required to ensure system stability during cold weather. Because potential gas outages could be so large, and growth is widespread, a solution providing a significant source of supply gas is necessary to reinforce this system for the current and future requirements.

During this investigation, multiple solutions were proposed and studied to determine the least cost option to solve this capacity issue.

Three options were explored and are as follows:

A. Install 24,000 feet of 16” HP supply pipe from 128th St East and 98th Ave E to 128th St East and Waller Road. Install a new GS in the vicinity of 128 St E and 98th Ave E.

B. Uprate the existing S Tacoma lateral to 620 psig MAOP and provide a one mile long HP lateral to allow this uprate to be accomplished. One mile long lateral required to allow shutdown of S Tacoma lateral for hydro-test (to enable 620 psig MAOP). Replace the existing S Tacoma Gate Station. The existing S Tacoma lateral is a Williams-owned facility.

C. Install 29,000 feet of 16” HP supply pipe from the existing Frederickson GS to the intersection of 128th St East and Waller Road. The Frederickson GS has existing capacity available for this project.

PSE studied Option (A) in detail, and determined that installing 24,000 feet of HP lateral would be very difficult and risky. In addition, the project team was unable to secure a suitable parcel of land or easement for a new gate station that was necessary to complete the project. Ultimately, PSE abandoned this option because of the routing difficulties and the inability to obtain a practical site for the new gate station.

Option (B) required Williams Pipeline to uprate its existing 8” HP lateral to 620 psig and replace its existing S Tacoma GS. In order to complete the uprate, the lateral necessitated a temporary shut-down, which would have required PSE to build a one mile HP pipeline to backfeed the system during a short period in the summer. Even with this “temporary” lateral, it would have been difficult to “hold” the system for the hydro-test. After the test, this temporary lateral would have been “shut-in,” as it provides no benefits to the area of concern. The capacity gained from this option was not satisfactory even for the near term. This project did not solve the capacity issues in this area and was therefore abandoned.

Option (C) was selected because its ability to solve the problem for the long term, add a separate third supply feed into the area, and utilize the existing capacity of the Frederickson GS. All other options entertained were not feasible or did not solve the problem. PSE reviewed many different routes for connecting the existing Frederickson GS and 128th St. East/Waller Road intersection, and selected the most feasible and cost-efficient option. When completed, this project will have significant future capacity to serve the greater Tacoma, Puyallup, Lakewood, Dupont, Steilacoom and McChord Air Force Base areas.

After completing this project, the downstream HP system will eventually be built-out to take full advantage of this future capacity as the Tacoma area continues to grow.

Figure 7-14
Frederickson High Pressure (HP) Gas Distribution System Alternatives

Alternatives	Capital	Comments
Install 24,000 feet of 16" HP and new Gate Station	N.A.	Project option abandoned - infeasible
Uprate the existing lateral to 620 psig, install 1 mile of HP pipe and replace GS	$5M	Project option abandoned due to lack of benefit and feasibility of hydro-test
Install 29,000 feet of 16" HP and utilize existing GS capacity	$13.86M	Least cost alternative that was feasible

V. Emerging Alternatives

In the last 20 years, electricity consumption has increased by 2% to 2.5% annually in North America, though transmission infrastructure expansions have not kept pace. The resulting strain on the North American transmission system includes the Pacific Northwest, where the main grid transmission system has operated at or near capacity because of little transmission construction between 1987 and 2003.

PSE and the region's utilities have a vested interest in finding an optimal solution to this problem, and we are studying several emerging alternatives to meet today's transmission and distribution challenges. They include distributed energy, demand-response alternatives, and the development of a "smart grid."

A. Distributed Energy Resources

Distributed energy is a way of incorporating small-scale generation into the grid close to where the power is used. Many such sources exist: internal combustion engines, fuel cells, gas turbines and micro-turbines, hydro and micro-hydro applications, photovoltaics, wind energy, solar energy, and waste/biomass. The challenge for the delivery system is how to integrate this power into a system that was designed to transport power from large generating plants located far away.

For much of the 20th century, small-scale customer-based generation could not compete economically with centralized, utility-owned power plants, but those economics have begun to change. Though not yet cheaper than the conventional system in most cases, an increasing variety of customers find small-scale solutions desirable. Some industrial customers want to meet their heating and electrical needs with one system. Hospitals and computer-based internet service firms now require higher levels of power quality and would suffer significant consequences if a service interruption were to occur. Some customers want renewable or green power.

The formal name for distributed energy solutions is distributed energy resources (DER). It includes all technologies in distributed generation (DG), distributed power (DP) and demand-response applications. Unlike the conventional system through which power generally flows in one direction, DER configurations allow power to travel in both directions: Customers who generate electricity for their own use (or have back-up generators standing by) can sell power back to the grid. PSE already has more than 100 such "interconnected" customers. Demand-response applications build two-way communications into the system that enable customers and the company to calibrate actual usage much more closely.

Although a host of regulatory, business practice, technical and market barriers continue to challenge the full-scale implementation of DER technology, PSE believes that it has the potential to provide cost-effective, appropriate and meaningful solutions. We are already incorporating DER elements into our planning process, and have developed guidelines to identify projects most likely to serve as the lowest reasonable cost solution. To ensure no adverse effects on our customers, we require that such solutions be as reliable as traditional "wires-based" projects.

PSE has past experience in the implementation of some DER solutions, and we are testing others to find out if they can provide benefits that justify their costs.

B. Demand Response Alternatives

PSE began testing a conservation voltage reduction pilot program in 2006 in conjunction with the Northwest Energy Efficiency Alliance (NEEA). The homes of 10 customers in two locations were fitted with meters capable of monitoring energy usage at the residence and transmitting that information back to PSE every 15 minutes over telephone lines. On alternate days, PSE reduced substation transformer control voltage from a range of 123 volts to a range of 119 volts. This results in a feeder voltage reduction of 3%. Two-way communication helped us determine whether the reduced voltage adversely affected any customers. Results from the study were favorable, indicating a 2% energy savings at both pilot locations with no adverse effects.

PSE continues to evaluate locations where conservation voltage reduction may be practical to implement and similar energy savings may be realized.

C. Modernizing the Grid

Smart grid is a movement to integrate intelligent devices and new technologies into the electrical grid to optimize the system to a degree not possible with existing infrastructure. It is less well developed than DER technologies, but has the potential to integrate all parts of the electric power system—production, transmission, and distribution—in ways that would be extremely beneficial. The smart grid will:

- Enable active participation by consumers
- Accommodate all generation and storage options
- Enable new products, services and markets
- Provide power quality for the digital economy
- Optimize asset utilization and operate efficiently
- Anticipate and respond to system disturbances (self-heal)
- Operate resiliently against attack and natural disaster

PSE is monitoring and researching smart grid devices, and participating with various governmental, regional, industry and utility groups in workshops and summits. When these devices become commercially available, we will integrate them into our cost-benefit analysis.