Gas Resources

PSE provides gas service to approximately 700,000 customers in Washington state. This chapter describes the future resource needs of our gas sales customers, and our existing gas resources. It presents the alternatives available to meet long-term needs, introduces the methods we used to evaluate those alternatives, and summarizes the key results and findings of that analysis. Also included is a comparison of projected gas resources needed for electric generation fuel. The chapter is presented in six sections.

I. Gas Resource Need

Peak demand usage by our gas sales customers is projected to increase at an average rate of 1.9% per year over the next 20 years due to increasing employment and population growth in our service territory. (See Chapter 4 for a detailed discussion of the demand forecast.)

PSE holds firm pipeline transportation and peaking capacity that allows the Company to transport or otherwise deliver gas, on a firm basis, from points of receipt to customers. This capacity ensures that we can provide our customers with reliable and cost-effective gas supplies during the coldest expected weather, and over a range of expected scenarios. In addition, PSE maintains upstream pipeline capacity to ensure direct access to gas production areas and the inherent reliability that this brings. PSE also maintains a mix of on-system resources that assists in meeting peak demands and contributes to the reliability of the distribution system. Figure 6-1 illustrates our natural gas capacity need over the planning horizon under the three load forecast scenarios.

Figure 6-1
Gas Sales Resource Need 2008-2027:
Existing Resources Compared to Design Peak Day Gas Demands

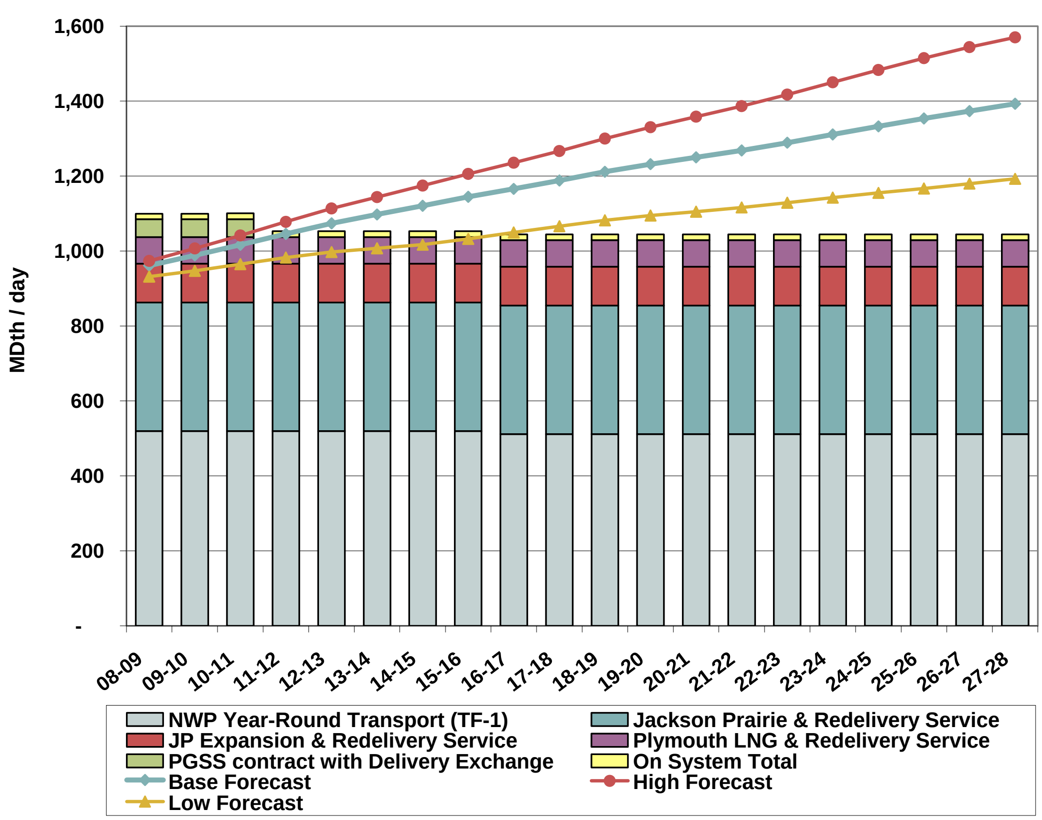


Figure 6-1 summarizes the balance between existing resources and projected peak day demand for direct sales customers. As shown, PSE has sufficient resources to meet the base (or expected) load forecast until the winter of 2012-2013. Under the high demand forecast, PSE will become deficit by the 2010-2011 heating season, and under the low demand forecast PSE will have sufficient resources to meet peak loads through the winter of 2016-2017.

We anticipated we would require additional delivery resources for the 2008-2009 heating season in the 2005 Least Cost Plan. The acquisition of 55 MDTh/day of firm pipeline capacity from Duke Energy Trading and Marketing (DETM) and the development of the Jackson Prairie expansion and redelivery service has added additional deliverability of 104 MDTh/day. This increased capacity is scheduled to come on-line in time for the 2008-2009 heating season and has extended the adequacy of PSE's peak supply resources.

II. Existing Gas Resources

A. Supply-side Resources

Supply-side gas resources include pipeline capacity, storage capacity, peaking capacity, and gas supplies.

Existing Pipeline Capacity

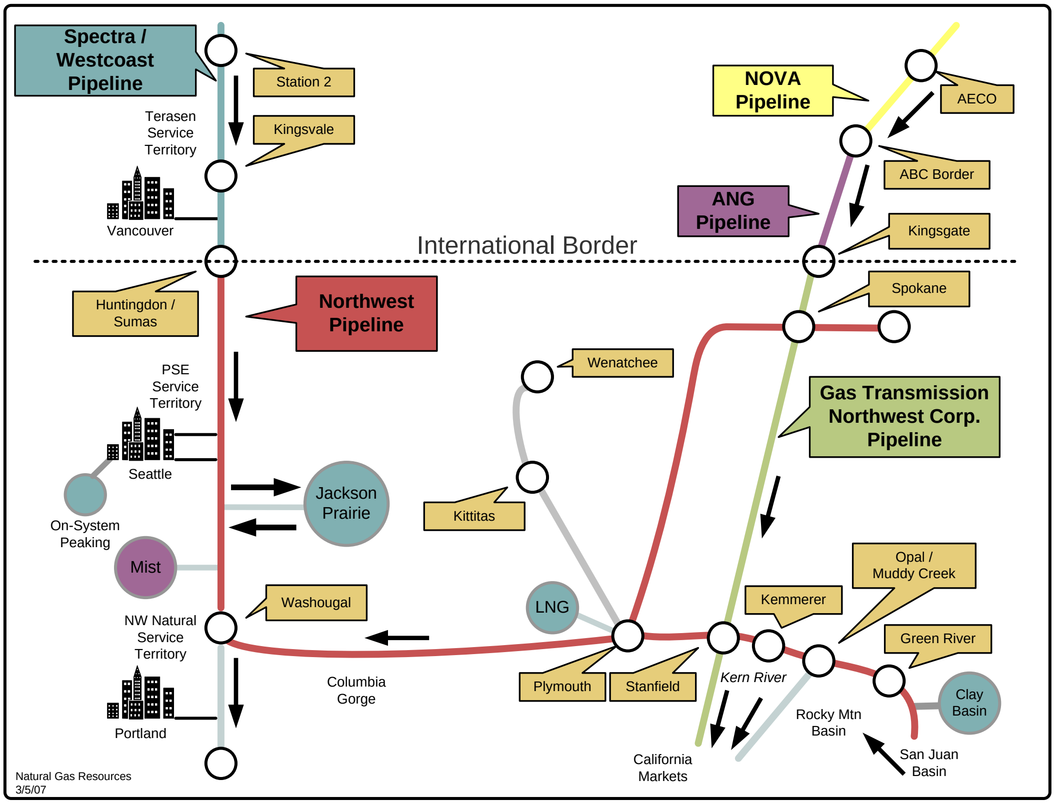
PSE holds firm pipeline transportation and peaking capacity that ensures we can provide customers with reliable and cost-effective gas supplies during the coldest expected weather and over a range of expected scenarios.

The two types of pipeline capacity are “direct connect,” which delivers supplies directly to PSE’s local distribution system from production areas, storage facilities or interconnections with other pipelines; and “upstream,” which delivers gas to the direct pipeline from remote production areas, market centers, and storage facilities. Figure 6-2 provides a general picture of the resources in the Pacific Northwest.

Direct-Connect Pipeline Capacity. All gas delivered to our gas distribution system is handled last by PSE’s only direct-connect pipeline, Northwest Pipeline (NWP). We hold 520,053 dekatherms per day (Dth/day) of NWP’s firm TF-1 transportation capacity, and 413,557 Dth/day of firm TF-2 capacity. TF-1 transportation contracts are firm contracts, available 365 days each year. TF-2 service on the other hand, is intended only for delivery of storage volumes during the winter heating season, and as such has significantly lower annual costs than the year-round service provided under TF-1.

Receipt points on the NWP contracts access supplies from four production regions: British Columbia, Alberta, the Rocky Mountain area, and the San Juan Basin. This provides valuable delivery point flexibility, including the ability to source gas from different regions on a day-to-day basis in some contracts.

Figure 6-2
PSE Gas Transportation Map



System reliability and supply dependability are ongoing concerns, and NWP has consistently met these challenges. For example, in 2003 NWP experienced two pipeline failures on its 26-inch Washington mainline. Following the second failure, NWP notified customers that it was idling a 268-mile segment of the pipeline between Sumas and Washougal, which temporarily reduced capacity by about 360,000 Dth/day. However, no customers were affected by this reduction, nor was there any decrease in transportation volumes. Even during cold snaps in January 2004 and 2005, NWP met its customers' firm service requirements.

NWP worked with the Office of Pipeline Safety (OPS) to restore 131,000 Dth/day of capacity by the end of June 2004. In addition, NWP filed an application with the Federal Energy Regulatory Commission (FERC) to replace the contractual capacity of the 26-inch pipeline with a new, larger-diameter pipe and additional compression by November 2006.

PSE reviewed the NWP Capacity Replacement Project proposal, compared it to other proposals, and concluded it was the most cost-effective solution to retain the region's access to gas supplies. Completed on-budget ($333 million) in December 2006, the project restored and replaced the capacity, flexibility, and reliability of the original facilities.

Upstream Pipeline Capacity. To transport gas supply from production basins or trading hubs to the NWP system, PSE holds capacity on several upstream pipelines. Figure 6-3 summarizes our direct-connect and upstream pipeline capacity position.

Figure 6-3
Existing Pipeline Capacity Position (Dth/Day)

Pipeline/Receipt Point	Note	Total	Year of Expiration			
			2008	2009	2010	Other
Direct Connect						
NWP/Westcoast Interconnect (Sumas)	1	259,761	58,000	128,705		18,056 (2016) 55,000 (2018)
NWP/GTN Interconnect (Spokane)	1	75,936	-	75,936	-	
NWP/various Rockies	1	184,356	43,848	139,892		8,056 (2016)
Total TF-1		520,053	101,848	344,533	26,112	55,000
NWP/Jackson Prairie	1,2	-	343,057	-	-	
NWP/Plymouth LNG	1,2	-	70,500	-	-	
Total TF-2		413,557	413,557	-	-	
Total Capacity to City Gate		**933,610**	**515,405**	**344,533**	**26,112**	**55,000**
Upstream Capacity						
TCPL-Alberta/from AECO to TCPL-BC Interconnect (A-BC Border)	3	80,000				
TCPL-BC/from TCPL-Alberta to TCPL-GTN Interconnect (Kingsgate)	4	80,000				
TCPL-GTN/from TCPL-BC Interconnect to NWP Interconnect (Spokane)	5	65,392	-	-	-	65,392 (2023)
TCPL-GTN/from TCPL-BC Interconnect to NWP Interconnect (Stanfield)	5,6	25,000	-	-	-	25,000 (2023)
Westcoast/from Station 2 to NWP Interconnect (Sumas)	4,7	95,000	-	-	-	25,000 (2014) 55,000 (2018) 15,000 (2019)
Total Upstream Capacity	**8**	**345,392**				

Notes:

1) *NWP contracts have automatic annual renewal provisions, but can be canceled by PSE upon one year's notice.*
2) *TF-2 service is intended only for redelivery of storage volumes during the winter heating season, and as such has significantly lower annual costs than the year-round service provided under TF-1.*
3) *Converted to approximate Dth per day from contract stated in gigajoules per day.*
4) *Converted to approximate Dth per day from contract stated in cubic meters per day.*
5) *TCPL-GTN contracts have automatic renewal provisions, but can be canceled by PSE upon one year's notice.*
6) *Capacity can alternatively be used to deliver additional volumes to Spokane.*
7) *The Westcoast contracts contain a right of first refusal upon expiration.*
8) *Upstream capacity is not necessary for supplies acquired at interconnects in the Rockies and for some of the supplies available at Sumas.*

Firm and Interruptible Capacity. Firm pipeline transportation capacity carries the right, but not the obligation, to transport up to a maximum daily quantity (MDQ) of gas from one or more receipt points to one or more delivery points in accordance with the pipeline's published tariff (which is approved by FERC or the Canadian National Energy Board). The tariff defines the scope of service, which includes the number of days that the transportation service is available, along with the rates, rate adjustment procedures, and other operating terms and conditions. Firm transportation capacity requires a fixed payment, whether or not that capacity is used.

Firm capacity on NWP and GTN may be "released" and remarketed to third parties under the FERC-approved pipeline tariffs. Firm capacity on Westcoast can also be remarketed under recently instituted "streamlined capacity assignment" provisions. PSE aggressively releases capacity when we have a surplus and when market conditions make such transactions favorable for our customers. We also use the capacity release market to access additional firm capacity when it is available.

Interruptible service is subordinate to the rights of shippers who hold and use firm transportation capacity; when firm shippers do not use their pipeline capacity, they may release it for limited periods of time. Interruptible service is available to PSE from NWP under TI-1 rate schedules, but has a limited role in PSE's resource portfolio because it cannot be relied on to meet peak demand. The rate for interruptible capacity is negotiable, and is typically billed as a variable charge.

Existing Storage Resources

PSE's natural gas storage capacity is a significant component of our gas resource portfolio. It confers advantages that not only improve system flexibility, but create significant cost savings for both the system and customers.

- Ready access to an immediate and controllable source of firm gas supply enables us to handle many imbalances created at the interstate pipeline level without incurring balancing or scheduling penalties.
- Access to a pooling point makes it possible for us to store gas that was purchased but not consumed during off-peak seasons, and to buy additional gas during the lower-demand summer season at significant cost savings.
- Combining storage capacity with seasonal TF-2 transportation allows us to eliminate the need to contract for year-round pipeline capacity to meet winter-only demand.

PSE also uses storage to balance city-gate gas receipts with the actual loads of our gas transportation customers. Industrial and commercial customers who elect gas transportation service (rather than gas sales service) make nominations directly or through marketer-agents to move city-gate gas deliveries to their respective meters. When these customers or marketers have imbalances between scheduled and actual gas consumption, our storage capacity allows us to manage these imbalances on a daily basis.

We have contractual access to two underground storage projects. Each serves a different purpose. Jackson Prairie storage, in Lewis County, is an aquifer-driven storage field designed to deliver large quantities of gas over a relatively short period of time. Clay Basin in northeastern Utah provides supply-area storage and a winter gas supply. Figure 6-4 presents details about our storage capacity.

Figure 6-4
Existing Gas Storage Position

	Storage Capacity (Dth)	Injection Capacity (Dth/Day)	Withdrawal Capacity (Dth/Day)	Expiration Date
Jackson Prairie – Owned (1)	7,310,436	147,334	294,667	N/A
Jackson Prairie – NWP SGS-2F (2)	1,181,021	24,195	48,390	2006
Jackson Prairie – NWP SGS-2F (3)	140,622	3,352	6,704	2006
Clay Basin	13,419,000	55,900	111,825	2013/19
Total	**22,051,079**		**454,882**	

Notes:

1) *Storage capacity at 12/31/2006. Storage capacity will continue to grow due to current expansion of the process.*
2) *NWP contracts have automatic annual renewal provisions, but can be canceled by PSE upon one year's notice.*
3) *Obtained through capacity release market.*

Jackson Prairie Storage. PSE uses Jackson Prairie and the associated NWP TF-2 transportation capacity primarily to meet the intermediate peaking requirements of core customers—that is, to meet seasonal load requirements, balance daily load, and eliminate the need to contract for year-round pipeline capacity to meet winter-only demand. We have 343,057 Dth/day of TF-2 transportation capacity from Jackson Prairie.

PSE, NWP, and Avista Utilities each own an undivided one-third interest in the Jackson Prairie Gas Storage Project, operated under FERC authorizations. In addition to firm daily deliverability and firm seasonal capacity, we have access to deliverability and seasonal capacity through a contract for SGS-2F storage service from NWP and from a third party through the capacity release market. The NWP contract is automatically renewed each year on October 31, but we have the unilateral right to terminate the agreement with one year's notice. We have interruptible withdrawal rights of up to 58,000 Dth/day, plus interruptible transportation service.

To meet growing peaking requirements, the three owners of Jackson Prairie are currently increasing deliverability from 884,000 Dth/day to 1,196,000 Dth/day. Our share of this expansion, 104,000 Dth/day, is expected to cost $15 million and be in service by November 2008.

Clay Basin Storage. Questar Pipeline owns and operates the Clay Basin storage facility in Daggett County, Utah. This depleted gas reservoir stores gas during the summer for withdrawal in the winter. PSE has two contracts to store up to 13,419,000 Dth and withdraw up to 111,825 Dth/day under a FERC-regulated agreement.

We use Clay Basin as a pooling point for purchased gas, and as a partial supply backup in the case of well freeze-offs or other supply disruptions in the Rocky Mountains during the winter. This supply provides a reliable source throughout the winter, including on-peak days; it also provides a partial hedge to price spikes in this region. Gas from Clay Basin is delivered to PSE's system (and other markets) using firm TF-1 transportation.

Treatment of Storage Cost. Similar to firm pipeline capacity, firm storage arrangements require a fixed charge whether or not the storage service is used. Charges for Clay Basin service (and the non-PSE-owned portion of Jackson Prairie service) are billed to PSE pursuant to FERC-approved tariffs, and recovered from customers through a purchased gas adjustment (PGA), while costs associated with the PSE-owned portion of Jackson Prairie are recovered from customers through base rates. We pay a variable charge for gas injected into and withdrawn from Clay Basin.

Existing Peaking Supply and Capacity Resources

Firm access to other resources provides supplies and capacity for peaking requirements or short-term operational needs. Liquefied natural gas (LNG) storage, LNG satellite storage, vaporized propane-air (LP-Air) and a peak gas supply service (PGSS) provide firm gas supplies on short notice for relatively short periods of time. Generally a last resort due to their relatively higher variable costs, these sources typically meet extreme peak demand during the coldest hours or days. LNG, PGSS, and LP-Air do not offer the flexibility of other supply sources.

Figure 6-5
Existing Peaking Gas Resources

	Storage Capacity (Dth)	Injection Capacity (Dth/Day)	Withdrawal Capacity (Dth/Day)	Transport Tariff
Plymouth LNG	241,700	1,208	70,500	TF-2
Gig Harbor LNG (1)	5,250 10,500 (06-07) 15,750 (10-11)	1,500 3,000 (06-07)	2,000 3,000 (06-07) 4,000 (08-09) 5,250 (10-11)	On-system
Swarr LP-Air	128,440	16,680 (2)	10,000	On-system
PGSS	NA	NA	48,000	City-gate delivered, via TF-1 or commercial arrangement
Total	**375,390**	**19,388**	**131,500**	

Notes:
1) *Withdrawal capacity will grow as the load on the distribution system grows, allowing more supply to be absorbed.*
2) *Swarr holds 1.24 million gallons. At a refill rate of 111 gallons/minute, it takes 7.7 days to refill, or 16,680 Dth/day.*

Plymouth LNG. NWP owns and operates an LNG storage facility located at Plymouth, Washington, which provides a gas liquefaction, storage, and vaporization service under its LS-1 and LS-2F tariffs. PSE's long-term contract provides for seasonal storage with an annual contract quantity (ACQ) of 241,700 Dth, liquefaction with an MDQ of 1,208 Dth/day, and a withdrawal MDQ of 70,500 Dth/day. The ratio of injection and withdrawal rates means that it can take over 200 days to fill to capacity, but only 3-1/2 days to empty. Therefore we use LS-1 service to meet needle-peak demands, with LS-1 gas delivered to PSE's city gate using firm TF-2 transportation.

Gig Harbor LNG. In the Gig Harbor area, a new satellite LNG facility ensures sufficient supply during peak weather events for a remote but growing region of our distribution system. The facility receives, stores, and vaporizes LNG that has been liquefied at other LNG facilities; the LNG comes by tanker truck from third-party providers. Because the LNG source is outside our distribution system, this facility represents an incremental supply source and is therefore included in the peak day resource stack, even though the plant was justified based on distribution capacity need. Daily deliverability is limited by hourly deliverability, total storage capacity, and the ability of the distribution system to absorb the supply. Although this facility directly benefits only areas adjacent to the Gig Harbor plant, its operation indirectly benefits other areas in our service territory since it allows gas supply from pipeline interconnects or other storage to be diverted elsewhere.

A second tank, substantially completed in the fall of 2006, doubles on-site storage capacity and increases operational flexibility (one tank can be filled while the other is used). A possible third tank has space allocated but no installation date has been projected. It will cost substantially more than the second tank because of additional site preparation requirements, so any expansion decision will be based on distribution capacity need rather than supply need.

Swarr LP-Air. The Swarr LP-Air facility has a net storage capacity of 128,440 Dth equivalent, and can vaporize approximately 30,000 Dth/day—a little over four days of supply at maximum capacity. Swarr connects to PSE's distribution system, requiring no upstream pipeline capacity. We typically use it to meet extreme hourly or daily peak demand, or to supplement distribution pressures during pressure declines on NWP. We operate this facility to meet peak early morning and evening demand periods; given its operational flow characteristics, it is highly unlikely we will operate it for more than eight hours per day. Therefore, for peak-day planning purposes we consider this facility capable of supplying only 10,000 Dth/day.

Third-party Suppliers. Under our PGSS agreements, PSE can call on third-party gas supplies during peak periods for up to 12 days during the winter season. Currently, these amount to 48,000 Dth/day at a price tied to the replacement cost of distillate oil. The supply would be delivered to PSE city gates from Sumas on a firm basis through TF-1 capacity (when such capacity is not needed for other supplies) or by a commercial exchange agreement with a third party. The PGSS agreement expires after the 2011-2012 heating season, and renewal options are uncertain at this time.

Existing Gas Supplies

PSE maintains a policy of sourcing gas supplies from a variety of geographically diverse supply basins. Currently, we maintain pipeline capacity access to producing regions in the Rockies and San Juan, British Columbia, and Alberta. By avoiding concentration in one market, we increase reliability; if a supplier defaults, we can source the needed gas from another place along the pipeline. We can also mitigate price volatility somewhat; our capacity rights on NWP provide some flexibility to buy from the lowest-cost basin.

Price and delivery terms tend to be very similar across supply basins, though shorter-term prices at individual supply hubs may "separate" due to pipeline capacity shortages.

This separation cycle can last one to three years and is alleviated when additional pipeline infrastructure is constructed. We expect generally comparable pricing across regional supply basins over the 20-year planning horizon, with differentials primarily driven by differences in the cost of transportation.

We have always purchased our supply at market hubs or pooling points. In the Rockies, the transportation receipt point is Opal; but alternate points, such as gathering system interconnects with NWP, allow some purchases directly from producers as well as from gathering and processing firms. In fact, we have a number of supply arrangements with major producers in the Rockies to purchase supply at or close to the wellhead, or point of production. Adding pipeline transportation capacity on Westcoast and ANG/Nova to our portfolio has increased our ability to access supply at the wellhead in Canada as well.

Gas supply contracts tend to have a shorter duration than pipeline transportation contracts, with terms to ensure supplier performance. We meet average loads with a mix of long-term (more than two years) and short-term (two years or less) gas supply contracts. Long-term and medium-term contracts typically supply baseload needs and are delivered at a constant daily rate over the contract period. We also contract for seasonal baseload firm supply, typically for the winter months. Forward-month transactions supplement baseload transactions, particularly for November through March; we estimate average load requirements for upcoming months and enter into month-long transactions to balance load. We balance daily positions using storage (from Jackson Prairie), day-ahead purchases, and off-system sales transactions. Our markets are liquid, so long-term contracts do not offer significant advantages (other than reliability) at this time. We will continue to monitor gas markets to identify trends and opportunities to fine-tune our contract policies.

Like many local distribution companies (LDCs), PSE is somewhat at a buying disadvantage because of our very low load-factor market compared to industrial and power-generation markets, which may make access to additional supply more difficult over time. Therefore, our policy is to hold long-term contracts that cover at least 50% of our annual sales volumes.

Figure 6-6 summarizes PSE's long-term gas contracts as of March 2007. Termination dates are spread out over a number of years. We will renew, extend, or replace contracts as they expire.

Figure 6-6
Existing Long-term Gas Supply Contracts

Contract	Basin	Winter Volume (Dth/d)	Summer Volume (Dth/d)	Primary Term Start Date	Primary Term Termination Date
Contract 1	**System**	**750**	**750**	05/15/1985	
Contract 2	BC/Sumas	10,000	10,000	11/01/2004	10/31/2008
Contract 3	BC/Sumas	20,000	20,000	11/01/2004	10/31/2009
Contract 4	BC/Sumas	10,000	10,000	11/01/2004	10/31/2009
Contract 5	BC/Stn 2	10,000	10,000	11/01/2004	10/31/2009
Contract 6	BC/Sumas	0	10,000	11/01/2007	03/31/2010
Contract 7	BC/Stn 2	0	10,000	10/01/2007	04/30/2010
Subtotal	**BC**	**50,000**	**70,000**		
Contract 8	Alberta	20,000	20,000	11/01/2004	10/31/2008
Contract 9	Alberta	10,000	10,000	11/01/2004	10/31/2009
Contract 10	Alberta	0	10,000	10/01/2006	04/30/2010
Contract 11	Alberta	0	10,000	10/01/2006	04/30/2010
Contract 12	Alberta	0	10,000	02/01/2007	04/30/2010
Subtotal	**Alberta**	**30,000**	**60,000**		
Contract 13	Rockies	30,000	30,000	05/01/2006	03/31/2008
Contract 14	Rockies	10,000	10,000	04/01/2005	10/31/2009
Contract 15	Rockies	10,000	10,000	04/01/2005	10/31/2010
Contract 16	Rockies	30,000	20,000	11/01/2004	10/31/2014
Contract 17	Rockies	0	10,000	10/01/2006	04/30/2010
Contract 18	Rockies	0	10,000	10/01/2006	04/30/2010
Subtotal	**Rockies**	**80,000**	**90,000**		
TOTAL		160,750	220,750		

Gas Futures Market

PSE began hedging our core gas portfolio in September 2002. At that time, hedge instruments—such as fixed-price physical transactions and fixed-price financial swap transactions—were the most effective means.

The delivery point for the New York Mercantile Exchange futures market is the Henry Hub in Louisiana. However, there can be a significant price variance between the Henry Hub and the physical locations of our supplies (the Rockies, British Columbia, and Alberta). To make a futures hedge fully effective, we would need an Exchange for Physical (EFP) transaction with another party to execute local delivery.

While an EFP is a viable hedging mechanism, its execution is rather complex. We have been able to negotiate much more simple, fixed-price physical agreements directly with regional suppliers. In addition, a liquid market has developed in over-the-counter financial derivatives for fixed-price and basis transactions. A master agreement governs these transactions, and the parties negotiate a range of contractual items including credit, netting, and cross-collateral terms. These transactions can be combined with our physical index-based purchase contracts, so financial derivatives work well within PSE's portfolio.

We will continue to evaluate all available hedging mechanisms to determine their applicability to our portfolio, particularly to balance the advantages to our customers of market prices with fixed supplies.

B. Existing Demand-side Resources

PSE has provided demand-side resources (that is, resources generated on the customer side of the meter) since 1993. Energy efficiency measures installed through 2005 have saved a cumulative total of 1,403,922 Dth in 2005 – more than half of which has been achieved since 2002. Through 1998, these programs primarily served residential and low-income customers. In 1999 we expanded to add commercial and industrial customer facilities. We have spent more than $17 million for natural gas conservation programs since 1993. PSE's energy efficiency programs operate in accordance with requirements established as part of the stipulated settlement of our 2001 General Rate Case.

In our April 2005 Least Cost Plan Update, we presented an extensive analysis of energy efficiency savings potential and its contribution to our electric and gas resource portfolios. In collaboration with key external stakeholders represented in the Conservation Resource Advisory Group (CRAG) and Least Cost Plan Advisory Group (LCPAG), we used the results to develop a two-year energy savings stretch target of approximately 420,000 Dth by the end of 2007 through program offerings to all customer classes.

Current Gas Energy Efficiency Programs

PSE's energy efficiency savings targets and the programs to achieve those targets are established every two years. Our current gas energy efficiency programs are authorized to operate January 1, 2006 through December 31, 2007. Programs engage all customer sectors and deliver a cost-effective resource. The majority of these programs are funded with electric “rider” and gas “tracker” funds collected from all customers.

2005 marked the end of a conservation tariff period spanning 2004 and 2005 that continued ongoing programs. Figure 6-7 shows how PSE has performed in the 2004 – 2005 tariff period compared to two-year budget and savings goals. The programs saved a total of 634,268 Dth, enough for 7500 homes, and exceeded our two-year savings goal of 500,000 Dth. 2004 - 2005 savings were achieved at a cost of $7,285,121. It is also important to note that 2006 actual savings decreased slightly and costs more than doubled. Our 2004 – 2005 achievement includes about two million therms of savings from commercial spray heads which represented a unique opportunity that could not be replicated in 2006 – 2007. While we are always seeking such prospects through both internal channels and our RFP process, at the present time, we have not yet uncovered a similar opportunity of such magnitude. After considering the effect of the spray head program on savings achievement in 2004 - 2005, our 2006 - 2007 levels track in alignment with our previous accomplishments.

Figure 6-7
Annual Gas Energy Efficiency Program Summary

Tariff Programs	2004- 2005 Actuals	’04–‘05 Budget/ Goal	’04 vs. ‘04/05 % Total	2006 Actual	’06 – ’07 2- Year Budget/ Goal	’06 vs. ’06/’07 % Total
Gas Program Costs*	$7,285,121	$9,106,000	41.7%	$6,759,062	$12,802,000	52.8%
Dth Savings	634,268	501,348	57.7%	237,724	420,000	56.6%

** Does not include low-income weatherization O&M funding of $297,000 per year.*

PSE’s **Commercial/Industrial Retrofit Program** achieves energy savings through improvements to HVAC systems, boilers, and process gas modifications – such as efficiency gains in radiator steam trap systems. In 2006 these efforts netted savings totaling 888,532 therms at a cost of $2,433,674; this program was the second largest generator of energy efficiency savings.

The **Energy-efficient Gas Furnace** program generated the most energy efficiency savings on the residential side. PSE customers and builders who installed a 90%+ efficient furnace received rebates; the program saved 248,399 therms at a cost of $933,970, accounting for 10% of all gas savings in 2006

In November 2005, we issued an “all-comers” RFP for energy efficiency resources to be added in 2006-2007. The RFP process is used to seek out and fill untapped market segments or add under-utilized energy efficiency technologies to complement our ongoing efforts. The results of that RFP process did not identify any significant new opportunities for additional natural gas energy efficiency. Out of 18 proposals received, six involved natural gas energy efficiency of which two were implemented.

III. Gas Resource Alternatives

The gas resource alternatives presented in this IRP address long-term capacity challenges rather than the shorter-term optimization and portfolio management strategies we use in our daily conduct of business to minimize costs.

As PSE's existing NWP transportation contracts expire periodically over the next several years, we can consider a number of alternatives including new pipeline projects, LNG and natural gas underground storage projects, LNG import facilities, and additional demand-side energy efficiency programs. Our review and analysis focuses on natural gas alternatives for the winter of 2012-2013 and beyond, since PSE has sufficient capacity until that time.

A. Pipeline Capacity Alternatives

Direct-Connect Pipeline Capacity Alternatives

PSE's exclusive reliance on NWP to connect to upstream natural gas supplies is a matter of geography, not preference, and this situation is not likely to change in the near term. Potential sponsors have shown little interest in the construction of new pipelines because the challenges are so significant. New pipelines would have to build around or over the Cascade Range or the Columbia River Gorge to access anything but British Columbia–sourced gas, and so far new construction cannot compete financially with the inherently lower cost of expanding or rebuilding infrastructure in an existing right-of-way.

PSE retains the unilateral right to cancel NWP contracts upon one year's notice, so pending contract expirations in 2008, 2009, and 2016 create opportunities to make alternative resource decisions; however, future expansions of NWP, even though incrementally priced, will likely be our most cost-effective alternative.

In meeting customer loads, PSE strives to balance low cost and reliability with "reliability in diversity"; that is, acquiring multiple alternate routes for our supply so that when one source becomes economically less advantageous, others are available. Our current pipeline transportation capacity accesses four market hubs:

- Sumas provides 260 MDth, or 50% of our current supply. This includes 95 MDth of upstream capacity to Station 2.
- The Rockies and San Juan combine to provide 184 MDth, or 35% of current supply.
- AECO provides 76 MDth, or 15% of current supply. This includes 80 MDth of upstream capacity to AECO.

We have some concerns about relying on Sumas for half of the transportation capacity to our city gate. In recent years, producers and marketers have shown a preference to market and sell gas at the AECO hub rather than at Sumas or Station 2. The AECO hub is more liquid and the prices less volatile than Sumas because it has access to the Northwest and California, as well as Chicago and other midwestern areas.

The attractiveness of the AECO hub over Sumas is demonstrated by the recent completion of the Ellhwa pipeline (200 MDth/day), which was built to move gas from the gathering area that normally feeds Station 2 eastward to a tie-in with the TransCanada's Alberta pipeline system and thus to the AECO hub, and also the failure of Westcoast pipeline capacity holders to renew their contracts for capacity from T-South to Huntingdon (Sumas). Currently, approximately 50% of the Westcoast pipeline capacity is not under long term contract. In addition, it is likely that future supplies from the North Slope and/or the Mackenzie delta would be interconnected to AECO rather than Westcoast.

On the other hand, completion of the Kitimat or another northern B.C. LNG import facility would tend to firm up supplies at Sumas. Also, expansion of the NWP segment between Sumas and PSE's city gate is probably the lowest-cost alternative for increased access to any market hub. A decision to expand access to the Sumas hub would have to be balanced with the dangers of increased reliance on Sumas.

For economic reasons, PSE may need to rely on NWP to move incremental gas supplies from Sumas to the city gate, but at least one upstream pipeline alternative discussed in the next section—Southern Crossing + Inland Pacific Connector—would help diversify how the gas gets to Sumas.

Expansion of NWP pipeline capacity through the Columbia Gorge to Stanfield, and to the Rockies hubs, would be relatively expensive. Opportunities to acquire existing capacity are limited.

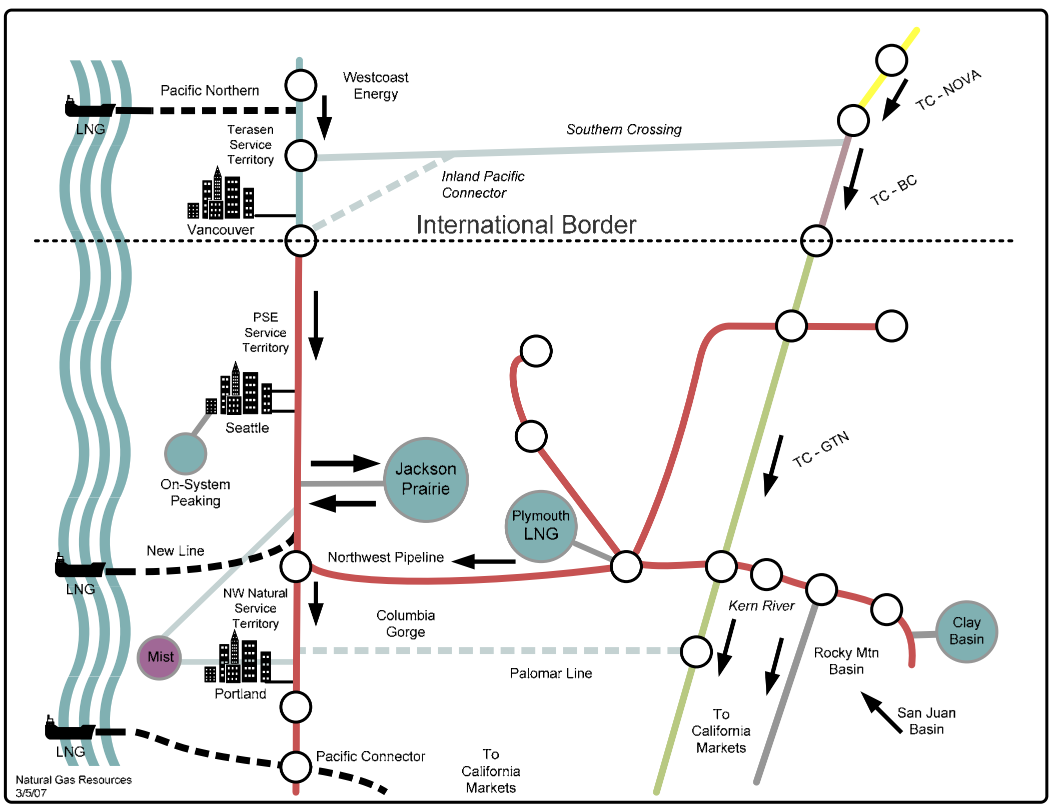
The direct-connect pipeline alternatives considered in this IRP analysis are summarized below.

Figure 6-8
Direct-Connect Pipeline Alternatives Analyzed

Name	Description
NWP - Sumas to PSE city gate	Expansions considered only in conjunction with upstream pipeline/supply expansion alternatives (Southern Crossing, additional Westcoast capacity, or access to a northern BC LNG import facility).
NWP - Washougal to PSE city gate	Expansion considered in conjunction with assumed LNG import terminal south of PSE service territory.

Figure 6-9 shows the location of these pipelines and LNG import terminals, and other pipeline and storage alternatives. Additional details are provided in Figure 6-2 (PSE Gas Transportation Map).

Figure 6-9
PSE Gas Transportation Map Showing Supply Alternatives



Upstream Pipeline Capacity Alternatives

In some cases, a tradeoff exists between buying gas at one point, and buying capacity to enable purchase at an upstream point closer to the supply basin. PSE has faced this tradeoff with our supply purchases at the Canadian import points of Sumas and Kingsgate.

We hold Gas Transmission Northwest (GTN) capacity from Kingsgate (Canadian border) south to NWP. Previous analyses led us to acquire approximately 80,000 Dth/day of upstream pipeline capacity on TransCanada's Alberta system (TCPL-Alberta) and TransCanada's British Columbia system (TCPL-BC). This enabled us to purchase gas directly from suppliers at the very liquid AECO trading hub and transport it to Kingsgate on a firm basis.

We also acquired 40,000 Dth/day of capacity on Westcoast Pipeline from Station 2 to Huntingdon, B.C. (Sumas) in 2003, and an additional 55 MDth of firm capacity in 2006. This upstream capacity accesses supplies at Station 2, adding supply diversity and hedging against Sumas price spikes.

Two potential upstream pipeline expansion alternatives that would further diversify supplies or enhance access to more liquid market hubs are modeled in the IRP analysis.

Figure 6-10
Upstream Pipeline Alternatives Analyzed

Name	Description
Station 2 to Sumas	Expansion of Westcoast considered to increase access to gas supply at Station 2 and an assumed northern BC LNG import terminal.
Southern Crossing Pipeline	Expansion of the existing Terasen gas pipeline across southern BC, a new lateral connecting to Huntingdon BC (Sumas), plus a commensurate expansion of the capacity on TCPL-Alberta and TCPL-BC as well as to NWP from Sumas to PSE's city gate.

Acquiring additional capacity on Westcoast would increase access to Station 2 supplies, but concerns about Station 2's liquidity and supply would have to be addressed.

The Southern Crossing alternative includes (1) PSE participation in the existing (or an expansion of the existing) Terasen pipeline across southern B.C., and (2) a new connector pipeline connects this pipeline to Huntingdon B.C. (Sumas). Acquisition of this capacity, as well as additional capacity on the TCPL-Alberta and TCPL-BC lines, would improve access to the AECO trading hub. While not inexpensive, such an alternative would increase geographic diversity and reduce reliance on B.C.-sourced supply.

A proposed Palomar pipeline (from NWP's Grants Pass lateral to GTN) offers an alternative route for AECO/Rockies gas that bypasses NWP through the gorge. Extending the line to a Columbia River LNG importing facility would provide access to the California market without using NWP. Although this pipeline was not part of our IRP modeling, we will monitor its progress.

B. Storage and Peaking Capacity Alternatives

As described in the existing resources section, PSE is a one-third owner and operator of the Jackson Prairie storage facility, and we also contract for capacity at the Clay Basin storage facility located in northeastern Utah through 2013 and 2020.

The current capacity expansion project at Jackson Prairie will increase PSE's peak deliverability by approximately 104 MDth/day, and increase our storage capacity portion by about 2,100 MDth. Completion isn't expected until 2012, though we anticipate increased deliverability by the fall of 2008. Previous expansions of Jackson Prairie have proven to be the least expensive way to meet our firm load growth, but no further expansions appear feasible.

The region's other underground storage project, the Mist storage project near Portland, Oregon, does not appear to be a viable alternative. It has relatively high costs and limited firm access to our city gate.

In this IRP analysis, PSE evaluated participation in a regional LNG storage facility as an alternative for meeting peak supply needs.

Figure 6-11
Peaking Storage Alternatives Analyzed

Name	Description
Regional LNG Storage Facility	To be cost effective, such a facility should be located to allow firm exchange delivery to PSE's city gate. The returns to scale of LNG storage imply that joint participation would be attractive. These analyses assume a 10-day supply at full deliverability.

C. Gas Supply Alternatives

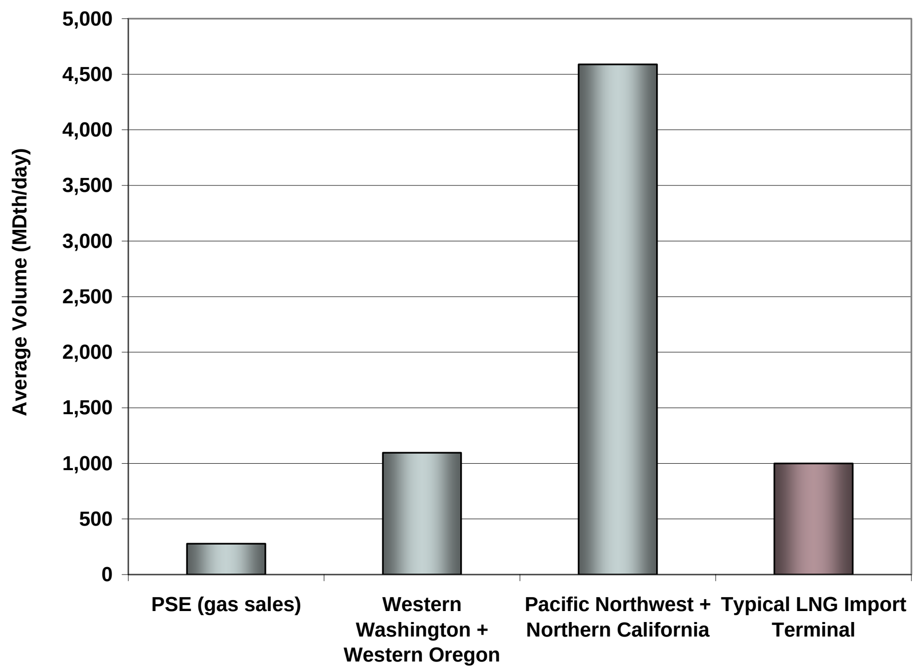
PSE's current pipeline contracts give us access to four regional supply basins that put us in a strong position to meet incremental load increases with additional reliable and economical capacity: the Rockies and the San Juan basin, British Columbia, and Alberta. It is likely that prices will remain competitive, as we see a focus on reserve development. For these reasons, one alternative modeled in this IRP assumes the current mix of term contracts and spot purchases—with Sumas and Station 2 supplies assumed to be limited and supply at AECO and the Rockies assumed to be sufficient.

Current and long-term views on natural gas availability suggest slower growth in supply and higher growth in demand going forward. Since supply scarcity can cause high and volatile pricing, PSE carefully monitors projects and resources that will ensure stable future supplies.

Two major pipelines have been proposed to transport gas from the Arctic to the North American markets, but both projects are too distant to provide short- or medium-term relief. The Alaska Natural Gas Transmission System would transport natural gas from the North Slope through Canada and to Chicago, and provide 4.5 Bcf/day between 2013 and 2015. The Mackenzie Valley Pipeline would transport natural gas from the Tablus, Parsons Lake, and Niglintgak fields to the northern border of Alberta and eventually deliver 800 Mcf/day.

While there currently are no LNG import terminals on the west coast, LNG imports could significantly increase the availability of gas in the region[1]. For example, Figure 6-12 compares the annual import volume of a typical LNG import terminal (capacity of one billion cubic feet per day {Bcf}) with the projected annual demand for 2010-2011 for PSE gas sales, for western Washington and western Oregon, and for combined demand from the Pacific Northwest (including BC) and northern California (including Pacific Gas & Electric). As shown, a typical LNG import terminal could nearly supply the full requirements of western Washington and western Oregon.

Figure 6-12
Comparison of Projected Annual Demand for 2010-11
with Capacity of Typical LNG Import Terminal



As demonstrated by Figure 6-12, an LNG import facility must be located to have access to relatively large market areas such as the Pacific Northwest plus northern California.

[1] The first LNG import project on the west coast of the North America expected to become operational is Sempra LNG's Costa Azul project on the Baja Peninsula of Mexico. Deliveries from the project are expected to begin in 2008, some of which will be transported into southern California.

At today's gas prices, LNG can be competitively transported, stored, and marketed. Major oil and gas companies recognize that LNG can both help alleviate the potential future supply scarcity, and provide an opportunity to market "stranded" reserves. To date, they have proposed more than 50 terminals, at least seven of them in Oregon, Washington, and British Columbia. Many experts believe that significant LNG imports into North America will be required to balance supply and demand in the future.

LNG production costs are well within current and anticipated market prices. LNG projects typically have low exploration and technology risks, and high capital costs. Projects generally require an experienced sponsor with a strong balance sheet, a secure source of natural gas, a large immediate market or an extensive infrastructure capable of consuming the entire output, and long-term off-take agreements to support the project's financing costs.

Siting domestic regasification terminals will be challenging. They must be large enough to capture economies of scale. Models of the North American gas market indicate that introducing incremental imported LNG at any location lowers or at least stabilizes prices throughout the market. Additionally, depending on location, imported LNG could displace some of the current supply for a given region—freeing up that supply for other markets. Whatever the location, however, import and regasification projects have the potential to relieve near-term supply scarcity and price volatility.

For this IRP, we considered two hypothetical regional LNG import terminals shown in Figure 6-13:

- South LNG Import—connected to the NWP system south of our service territory and assumed to require incremental NWP capacity construction north to PSE's service territory
- North LNG Import—connected to the Westcoast system in B.C. and requiring Westcoast T-South capacity and NWP capacity to deliver to the PSE system.

Costs and other commercial terms of purchase agreements are undetermined, but we assumed that the LNG itself would be priced at the AECO index plus a small demand charge (at the regasification plant outlet/pipeline interconnect).

Figure 6-13
Gas Supply Alternatives Analyzed

Name	Description
Northern LNG Import Interconnected with Westcoast Pipeline	Interconnects with Westcoast pipeline, flows over T-South transport to Sumas and then on existing or incremental NWP capacity to PSE.
Southern LNG Import Interconnected with NWP south of PSE service territory	Flows over NWP north to PSE on incremental transport capacity.
Conventional Gas Supply Purchase Contracts	Assume current mix of term contracts and spot purchases. Sumas and Station 2 supplies assumed limited. Supply at AECO and Rockies assumed to be sufficient.

D. Demand-side Resource Alternatives

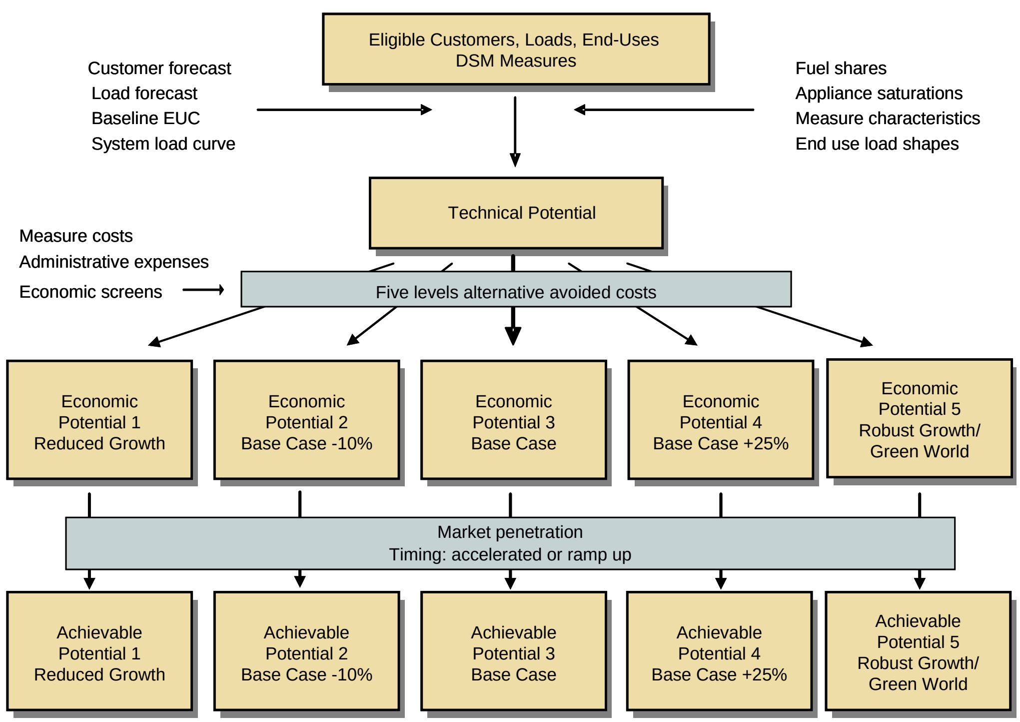
This IRP used a different evaluation than the 2005 LCP to analyze the cost-effectiveness of demand-side resources. The 2005 plan used SENDOUT® to test the cost-effectiveness of specific programs and to select programs to be included in each scenario; sets of increasingly expensive efficiency programs were added until SENDOUT rejected programs as not cost-effective.

In this IRP, the various bundles were pre-screened as discussed below, and then input into SENDOUT to confirm or “double-check” the cost effectiveness of the bundles. With only minor differences, the program bundles developed earlier were found to be cost-effective.

Gas demand-side resources were evaluated and combined into various bundles for integration with the supply-side analysis. The general approach to estimating the potentials for all demand-side categories was fundamentally the same: each individual type was screened for technical potential, economic potential, achievable implementation level, and achievable savings. The three screens are widely used in utility resource planning, consistent with the Northwest Power Planning and Conservation Council methodology, and with evaluation of energy efficiency resource potentials in general. Using them enables us to address the different technologies, load impacts, and markets that occur for each type of demand-side resource. After individual evaluation, demand-side resources were combined into bundles for further analysis.

The first screen, for technical potential, assumed that all energy efficiency resource opportunities could be captured regardless of costs or market barriers. It produced an end-use forecast assuming "frozen" end-use efficiencies, and then calibrated it to PSE's system load forecast. We then generated a second forecast that included all technically feasible demand-side measures. Technical energy efficiency resource potentials were then calculated as the difference between the forecasts.

Figure 6-14
General Methodology for Assessing Demand-side Resource Potential



The second screen, for economic potential, included only measures deemed to be cost effective based on a total resource cost test. Five levels of avoided costs were used. We started with a base case, "economic potential 3." "Economic potential 1" assumed avoided costs of base case -14%. "Economic potential 2" assumed avoided costs equal to the base case -10%. "Economic potential 4" assumed avoided costs 25% higher than the base case. Note that "economic potential 5" - Robust Growth/Green World - used the same, higher avoided cost.

This wide range enabled us to test for sensitivity of energy efficiency resource potential to different levels of avoided costs. This resulted in five bundles containing different amounts of energy efficiency resources for each level of avoided costs.

Finally, we screened out any resources not considered achievable. Establishing achievable potentials largely relied on customer response to PSE's past energy efficiency programs, the experience of other utilities offering similar programs, and review of the Northwest Power and Conservation Council's most recent electric energy efficiency potential assessment. For this IRP we assumed that economic energy-efficiency potentials of 75% and 55% in existing buildings and new construction markets, respectively, are likely to be achievable over the planning period.

IV. Gas Analytic Methodology

In order to estimate PSE's gas needs over the next 20 years, we compare peak-day demand forecasts with our current resources. We then use planning tools, optimization analyses, and scenarios, along with input assumptions, to determine the most-reasonable-cost portfolio of gas resources to meet our increasing service demands over the 20-year planning period.

Our analytical approach for analyzing and selecting the lowest cost supply portfolio for gas resources is different from the approach used for the electric portfolio analysis discussed earlier in Chapter 5. In general, analysis of the gas supply and demand system is less complex than analysis of the electrical supply system. The network of gas supply areas and market hubs, the pipeline transportation system, storage facilities, and demand areas lends itself to analysis using linear programming (LP) optimization models. In a single run, a LP model can determine the portfolio of resources that will minimize costs over the planning horizon, based on a set of assumptions regarding resource alternatives, resource costs, demand growth, and gas prices. This approach eliminates the need to develop alternative supply portfolios and to compare the resulting costs and other impacts to select the portfolio with the lowest reasonable cost.

A. Optimization Analysis Tools

PSE enhanced its ability to model gas resources for long-term planning and long-term gas resource acquisition activities for the 2005 LCP. The Company acquired SENDOUT and VectorGas™ from New Energy Associates in August of 2004. SENDOUT is a widely used model that helps identify the long-term least cost combination of resources to meet stated loads using a linear programming model. SENDOUT has the capability to integrate demand side resources alongside supply-side resources in determining the optimal resource portfolio. The linear programming approach is a helpful analytical tool to help guide decisions, but it is important to acknowledge this technique provides the model with "perfect foresight," meaning the theoretical results would not really be achievable. For example, the model knows the exact load and price for every day throughout a winter period, and can therefore minimize cost in a way that would not be possible in the real world. Real-world decisions must be made where numerous critical factors about the future will always be uncertain. Linear programming analysis provides helpful but not perfect information to guide decisions.

Because decisions must be made in the context of uncertainty about the future, PSE acquired VectorGas along with SENDOUT. VectorGas is an add-in product that facilitates the ability to model gas price and load (driven by weather) uncertainty into the future. VectorGas uses a Monte Carlo approach in combination with the linear programming approach in SENDOUT. This additional modeling capability will provide additional information to decision-makers under conditions of uncertainty. These new tools provide valuable enhancements to the robustness of the Company's long-term resource planning and acquisition activities. See the Gas Analysis Appendix for a more complete description of SENDOUT and VectorGas, as well as details of the various modeling inputs.

Monte Carlo analysis of physical supply risk indicates that a portfolio that meets our design-day peak forecast is sufficient, in an otherwise normal-temperature winter, to meet our obligations under a variety of possible conditions. Monte Carlo analysis of the optimal portfolio also indicates that the timing of certain resource additions is highly sensitive to Base Case assumptions.

B. Static Optimization Analysis

As described in Chapter 3, PSE selected four gas sales scenarios to examine the impact of different future demand and price scenarios on resource planning. The key to scenario analysis is understanding how different resources perform across a variety of conditions. Scenario analysis clarifies the robustness of a particular resource strategy. In other words, it helps determine if a particular strategy is reasonable only under a wide range of future circumstances.

PSE used SENDOUT to identify the optimal portfolio in each scenario. Supply-side resource alternatives generally were consistent across the scenarios. As discussed above, we developed energy efficiency programs for each of the three gas price scenarios. The appropriate level of energy efficiency was used in each resource planning scenario. For Robust Growth and Green World, for example, we included higher-cost efficiency programs based on the high gas price scenario. The gas planning analysis thereby necessarily focuses on where to buy gas, how to transport it to customers, and how to best utilize storage facilities to minimize the cost of meeting customer loads.

C. Monte Carlo Analysis on Base Case Portfolio

We performed two kinds of Monte Carlo analysis to test different dimensions of uncertainty. The first tested how a specific portfolio (in this case, the optimal portfolio derived from the static Base Case analysis) performs under price-induced and temperature-induced demand uncertainty. Examining the performance of a specific scenario helps determine financial and physical risk because it estimates cost variability. This can be particularly helpful when comparing two portfolios with similar expected costs but different cost risk profiles, which would not be evident in the traditional static analysis.

We used Monte Carlo analysis on 100 daily price and temperature scenarios—or draws—for the 20-year planning horizon. Each price draw started with the Reference Case (prices and weather are related in the underlying analysis that generates each scenario). For details of SENDOUT and VectorGas analyses, see Appendix J.

D. Monte Carlo Analysis Including Resource Optimization

The Monte Carlo analysis described above used optimal resources from the static Base Case analysis to examine how that portfolio would perform physically and financially. Another Monte Carlo analysis examined the robustness of that same portfolio by creating 100 scenarios of daily prices and demands for 20 years, then calculating the optimal portfolio to meet each of the 100 scenarios—again starting with Reference Case prices. This generated probability distributions for each potential resource addition. A static analysis often overemphasizes the importance of the “optimal” portfolio. Analysis showed how resource additions in the Base Case optimal portfolio are sensitive to the underlying price and demand assumptions.

V. Natural Gas Analysis: Results and Key Findings

PSE analyzed four planning scenarios for gas sales. This section compares resulting annual average gas costs and relevant differences between the resource addition alternatives that were considered, including energy efficiency programs.

A. Comparison of Resulting Average Annual Portfolio Costs

Figure 6-15 should be read with caution. It is not a projection of average purchased gas adjustment rates. The costs are based on a theoretical construct of highly incrementalized resource availability. Additionally, average portfolio costs include items that are not included in the PGA. These include rate-base costs related to Jackson Prairie storage and costs for energy efficiency programs, which are included on an average levelized basis rather than a projected cash flow basis. Also, the perfect foresight of a linear programming model creates theoretical results that cannot be achieved in the real world.

Figure 6-15
Cost Projections for Gas Scenarios

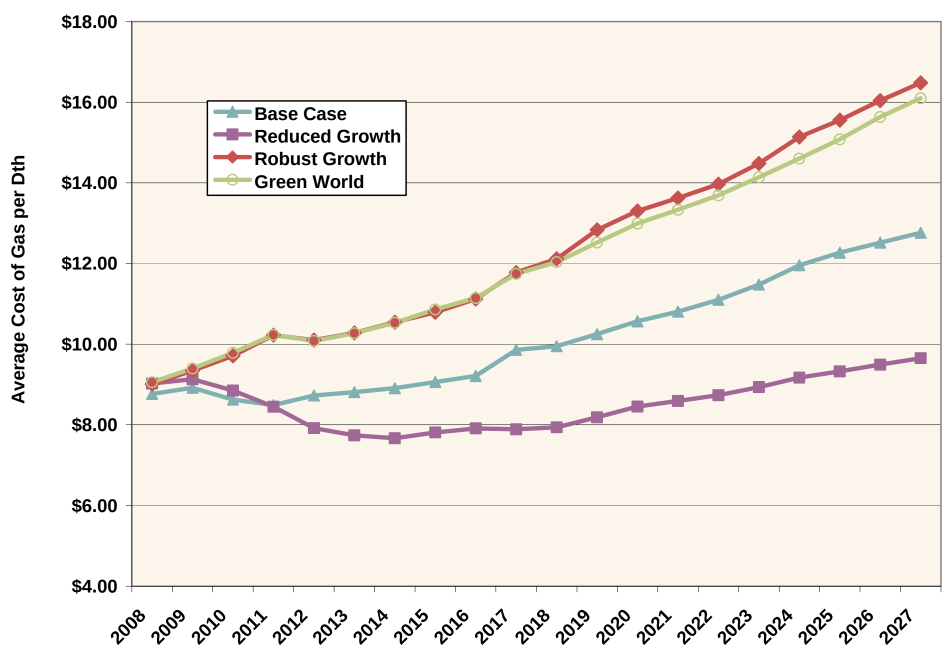


Figure 6-15 shows that average optimized portfolio costs follow expectations. Reference Case costs are about $8.76/Dth in 2008 and increase to about $12.70/Dth by 2027. Robust Growth costs are the highest of the four scenarios. Green World costs are somewhat lower, reflecting moderate load growth rather than the high load growth assumed for the Robust Growth scenario. Robust Growth costs are higher because of slightly higher average fixed costs—that is, the increase in fixed gas supply costs to meet the higher load growth is greater than the corresponding increase in volumes.

The Reduced Growth scenario has the lowest average portfolio costs, reflecting its low gas price and low load growth assumptions.

B. Comparison of Resource Additions

Differences in resource additions are generally driven by load growth. The exception is demand-side resources; they are influenced more directly by the gas price forecast than supply resources because by their nature they avoid commodity costs. However, the absolute level of efficiency programs is also affected by load growth assumptions. Optimal resource additions across scenarios are presented below by resource type.

Pipeline Capacity Additions

We considered two types of pipeline additions: upstream transportation alternatives that would interconnect with NWP (our direct-connect pipeline) at Sumas and at Washougal, and expansions of NWP capacity sufficient to deliver upstream gas to PSE’s city gates.

Three pipeline alternatives were considered:

- Expanded Westcoast Pipeline capacity for delivery of gas from Station 2 and from the North LNG import facility.
- The Pacific Connector in conjunction with gas from the proposed South LNG facility; this alternative also includes enhancements of NWP’s Grants Pass Lateral and the expansion of NWP from Washougal to PSE’s city gate.
- The Southern Crossing/Inland Pacific Connector alternative that would increase supply diversity by connecting to the AECO hub instead of Sumas or Station 2; it

incorporates corresponding expansions of the TransCanada-Alberta and TransCanada-B.C. pipelines as well as NWP from Sumas to PSE's city gate.

Figure 6-16 summarizes the pipeline resources selected across the different planning scenarios. A limited expansion of Westcoast Pipeline capacity (25 MDth/day) in 2011 was selected in all scenarios except Reduced Growth. This expansion allows Sumas supply, purchased at either Sumas or Station 2 and transported to Sumas via Westcoast Pipeline, to match the existing delivery capacity of NWP from Sumas to PSE's city gate (260MDth/day). Further expansions of Westcoast capacity were not selected until 2018 in Robust Growth, and 2023 in the other scenarios. Since none of the scenarios selected the North LNG facility, these Westcoast expansions would be used to transport gas from Station 2.

Selected expansions of the Pacific Connector matched expansion of the South LNG—it was selected in all scenarios, although in relatively small amounts in Reduced Growth.

The Southern Crossing/Inland Pacific Connector was selected relatively late (beyond 2016) in all scenarios except Robust Growth. Its relatively high cost (because of the need to acquire capacity on four pipeline segments) does not make it attractive unless there is a compelling reason to diversify supplies away from Station 2 and Sumas.

Figure 6-16
Results of Pipeline Transportation Analysis

	Reference Case	Reduced Growth	Robust Growth	Green World
Westcoast (Sation 2 Sumas)				
2011	25MDth/d	-	25MDth/d	25MDth/d
2018	25MDth/d	-	100MDth/d	25MDth/d
2023	107MDth/d	65MDth/d	200MDth/d	98MDth/d
Pacific Connector (Pacific Connector & Grants Pass Lateral)				
2013	30MDth/d	5MDth/d	55MDth/d	40MDth/d
2016	55MDth/d	6MDth/d	55MDth/d	55MDth/d
2023	55MDth/d	23MDth/d	55MDth/d	55MDth/d
Southern Crossing/Inland Pacific Connector (TCAB, TCBC, SC & NWP)				
2011	-	-	20MDth/d	-
2016	48MDth/d	4MDth/d	83MDth/d	29MDth/d
2018	48MDth/d	-	120MDth/d	29MDth/d
2022	65MDth/d	-	137MDth/d	46MDth/d
2023	65MDth/d	-	193MDth/d	46MDth/d

Storage Additions

This analysis considered a single storage resource because PSE is currently participating in a relatively large expansion (104 MDth/day delivery) of the Jackson Prairie storage project scheduled to come on line in 2008. The alternative considered is a new LNG storage project in British Columbia. This northern location would facilitate a commercial exchange agreement to facilitate low-cost gas transportation. All scenarios selected this option, assumed to provide a 10-day supply at up to 100 MDth/day, as shown in Figure 6-17.

Figure 6-17
Results of Regional LNG Storage Analysis

	Reference Case	Reduced Growth	Robust Growth	Green World
2011	46MDth/d	6MDth/d	70MDth/d	37MDth/d
2015	100MDth/d	100MDth/d	100MDth/d	100MDth/d
2022	100MDth/d	100MDth/d	100MDth/d	100MDth/d

The results indicate that PSE's strategy should include consideration an LNG storage facility. However, since the SENDOUT analysis generally limited the initial project size to approximately 50 MDth/day in 2011 (the first year it was assumed to be available), a deliverability of 50 MDth/day, with later increases, may be an appropriate assumption.

Supply Additions

PSE will continue to rely on acquiring natural gas from creditworthy and reliable suppliers at major market hubs or production areas. For our SENDOUT model, we assumed continuation of our geographically diverse, long-term supply contracts (currently about two-thirds of annual requirements) throughout the planning horizon. The optimal portfolio would contain additional gas supply from various supply basins or trading locations, along with optimal utilization of existing and new capacity. The majority of this additional supply would likely be acquired under short-term contracts (one month to two years) at market price, as is the standard in the industry.

Supply additions considered included imported LNG supply terminals built at two locations. North LNG in northern British Columbia would connect to the pipeline system near Station 2, requiring transportation via the Westcoast system to Sumas, then on NWP to PSE's city gates; all scenarios assumed a maximum PSE supply of 150 MDth/day.

A South LNG import facility located in southern Oregon would connect to the existing NWP Grants Pass lateral and the GTN pipeline at Malin, and interconnect with other pipelines via the proposed Pacific Connector Gas Pipeline. The entire project could be in service by late 2011 with a capacity of about 1,000 MDth/day. We assumed PSE availability of 55 MDth/day, based on preliminary estimates of delivery capacity available via the Grants Pass Lateral and the NWP mainline to our city gate. Commodity prices for both the North and South LNG facilities were assumed to be the AECO index.

As shown in Figure 6-18, the South LNG alternative was selected in all scenarios, although in relatively small amounts in the Reduced Growth scenario. North LNG imports were rejected across all scenarios. This is not surprising, since North LNG supplies would likely require transportation on three pipelines (resulting in rate-stacking).

Figure 6-18
Results of LNG Import Terminal Analysis

	Reference Case	Reduced Growth	Robust Growth	Green World
South LNG Alternative				
2013	30MDth/d	5MDth/d	55MDth/d	45MDth/d
2016	55MDth/d	6MDth/d	55MDth/d	55MDth/d
2022	55MDth/d	23MDth/d	55MDth/d	55MDth/d
North LNG Alternative				
2013	-	-	-	-
2016	-	-	-	-
2022	-	-	-	-

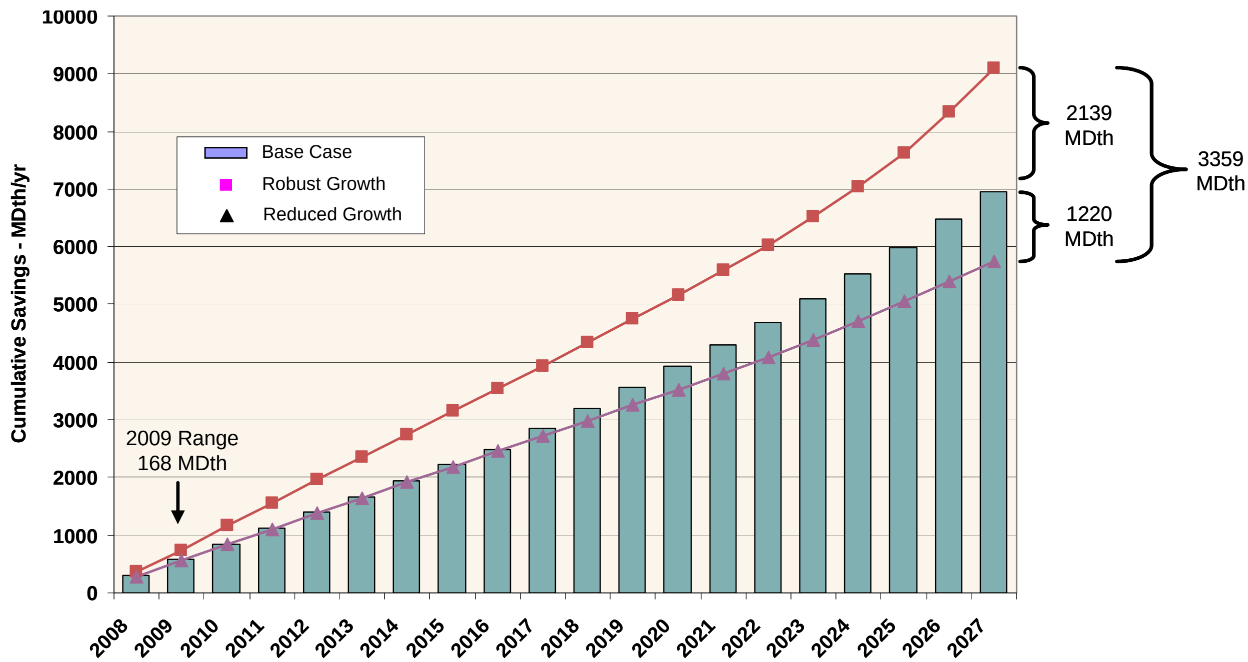
Assumptions about commodity cost pricing and supply terms will have a significant impact on the cost effectiveness of LNG imports. This analysis indicates that we should closely evaluate proposed LNG import terminals located to the south of PSE's service territory as more information becomes available, and continue to monitor development of other regional LNG import facilities.

Energy Efficiency Additions

As discussed earlier, in this IRP the various demand-side bundles were pre-screened and then input into SENDOUT to confirm or "double-check" the cost effectiveness of the bundles. With only minor differences, the program bundles developed in the screening analysis were found to be cost-effective.

Demand-side bundles demonstrated sensitivity to avoided costs, as illustrated in Figure 6-15. During the first two years the range is relatively tight, varying by 168 MDth between the Reduced Growth and the Robust Growth Bundles in 2009; by 2027, the difference increases to 3,359 MDth. In 2027, the variance between the Base Case and Robust Growth Bundles was 2,139 MDth, while the Reduced Growth Bundle differed from the Base Case Bundle by 1,220 MDth.

Figure 6-19
Gas Energy Efficiency Price Sensitivities



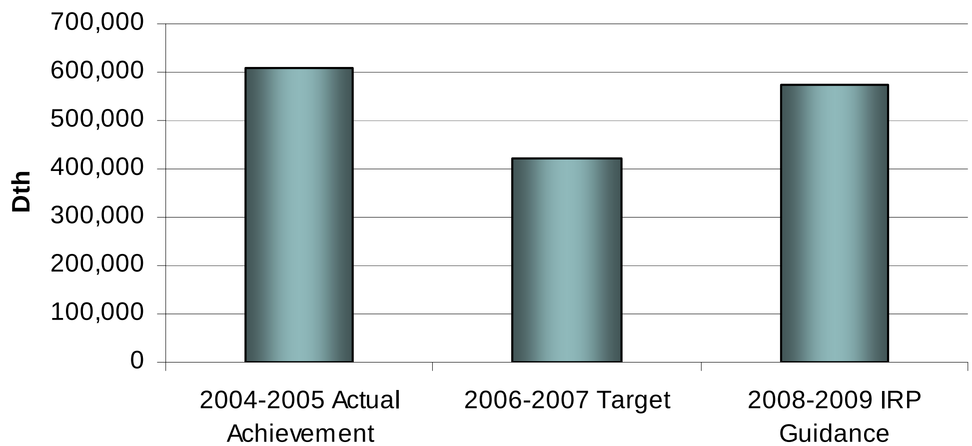
This 2007 IRP analysis revealed a seemingly counterintuitive effect in the magnitude of gas energy efficiency potentials compared to the previous plan. That is, the amount of achievable energy efficiency resources selected by the SENDOUT analysis in this plan is 1,611 MDth less than the previous plan, despite the higher gas price projections. The reduction is mainly due to the technical potential for energy efficiency being 3,114 MDth less in 2007 than 2005 (pre-SENDOUT economic potentials should not be compared due to changes in methodology). In 2007, we refined our assumptions about baseline end-use consumptions, savings, costs, and applicability of individual measures, which in turn reduced the magnitude of technical potential compared to 2005. However, the market penetration assumptions used to estimate achievable potential in 2007 are more aggressive than those used in the previous plan, which partly offset the reduction in technical potentials.

Figure 6-20
2005 - 2007 Technical and Achievable Energy Efficiency Potential Comparison

Year	Technical Potential (Dth)	SENDOUT® Results (Dth)
2005	38,223,912	8,576,600
2007	35,109,051	6,965,000

Figure 6-21 further compares our previous energy efficiency accomplishments, current target, and our new level of guidance. In the short term, this IRP guidance includes 576,000 Dth of energy efficiency savings for the 2008-2009 period. This is an increase of 37% over current 2006 – 2007 targets. It is slightly less than the savings achieved in 2004 – 2005, which included large savings from the unique, one-time commercial spray heads project.

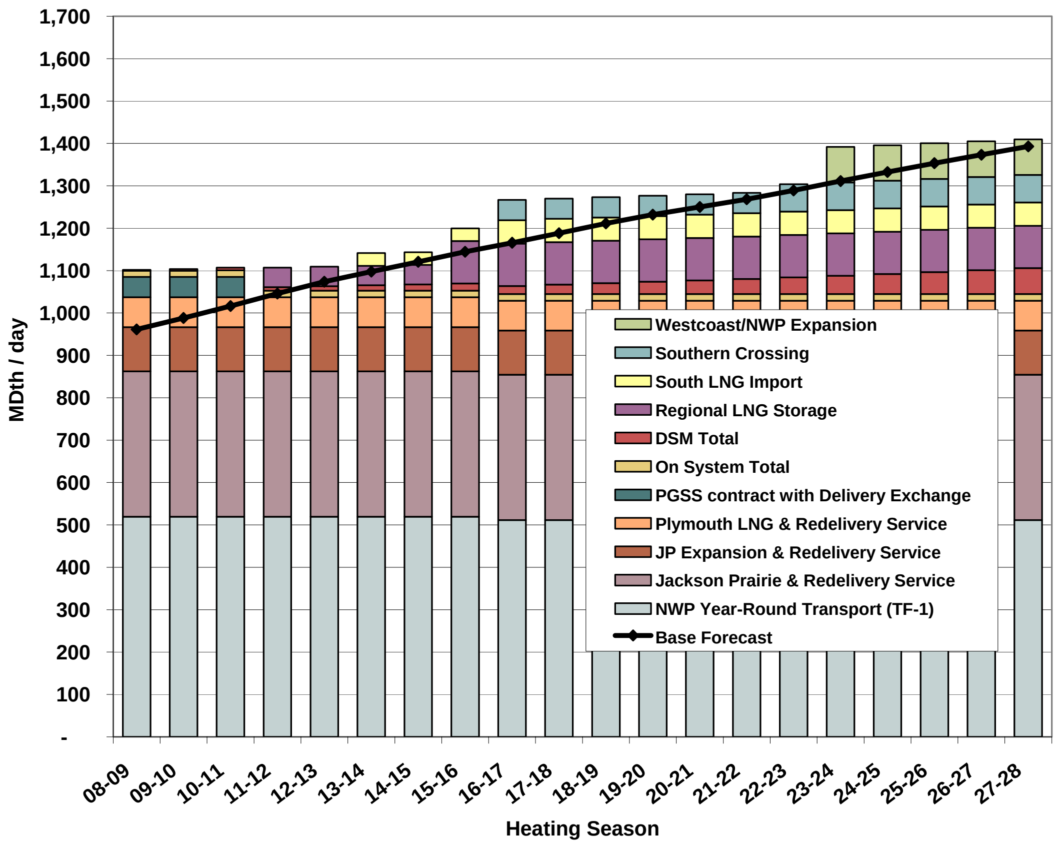
Figure 6-21
Short-term Comparison of Gas Energy Efficiency



C. Complete Picture: Base Case

A complete picture of the Base Case optimal resource portfolio is presented below in Figure 6-22. Additional Scenario results are included in the Gas Analysis Appendix.

Figure 6-22
Preferred Gas Portfolio, 2007 IRP

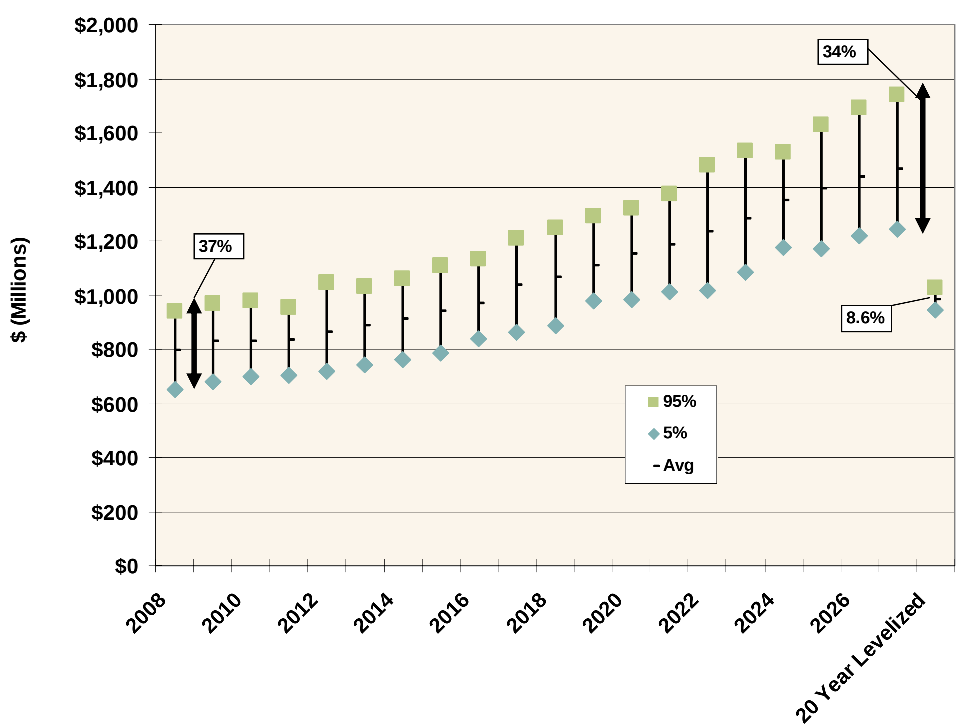


D. Results of Monte Carlo Analysis on Base Case Portfolio

As noted above, we used the Monte Carlo capabilities of Vector Gas to examine the effects of temperature-induced load uncertainty and price uncertainty on the Optimal Base Case portfolio. In this analysis, daily temperatures affect both load and daily gas prices. The Monte Carlo analysis was performed using 100 draws. Each of the 100 draws results in 20 years worth of daily prices and loads.

Figure 6-23 illustrates the nominal mean, and the 5th and 95th percentiles of total portfolio costs on an annual basis, along with the 20-year levelized results.

Figure 6-23
Annual and 20-Year Levelized Cost and Variability



As shown, the annual variability of total portfolio costs among the Monte Carlo draws is fairly consistent at over the 20 year time horizon (roughly 34% to 37%). It is important to note that the variability of the 20 year levelized costs is much lower at about 8.6%. The key take-away from a review of the Monte Carlo portfolio cost analysis is that measuring risk in the long term tends to dampen the effects of variability, thus short-term measures of risk in the context of the long-term analysis should also be considered.

Monte Carlo analysis on the Base Case optimal portfolio also provided information on the physical robustness of the optimal portfolio. This provides a reasonable test of whether the Company's planning standard of using normal weather with one design peak day per year creates a portfolio that will meet firm demands under a wide range of different temperature conditions. Results indicate that the Base Case portfolio, based on PSE's planning standard, will meet firm demands in 93% of the draws.

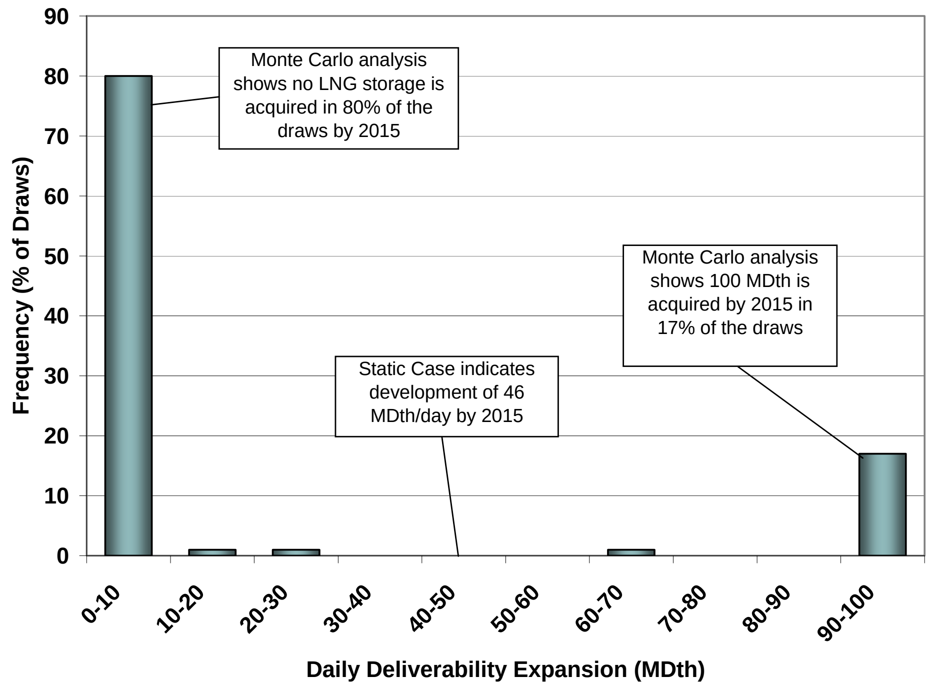
A Monte Carlo analysis was also done to test the sensitivity of resource additions in the Base Case scenario. Analyses were done on three specific resource addition decisions; the regional LNG storage alternative, the results of both the Southern and the Northern LNG import supply terminals, and the Southern Crossing/Inland Pacific connector pipeline alternative. The following tables will compare results from the static Base Case with the mean results from the resource optimization Monte Carlo analysis along with probability distributions for each of the resources.

The expansion of the Westcoast pipeline capacity by 25 MDth to allow supply of 260 MDth/day of gas at Sumas was selected in all 100 of the draws in 2011. The Northern LNG alternative at Kitimat was not selected in any of the 100 draws at any time in the analyses.

Monte Carlo Optimization Results—Regional LNG Storage

The regional LNG storage alternative included in the static analysis appears to be sensitive to the specific underlying assumptions. The frequency distribution of how the regional LNG storage alternative is selected across the 100 scenarios by the year 2015 is shown in Figure 6-24. The Monte Carlo analysis demonstrates that in 17% of the 100 draws, the full regional LNG storage deliverability of 100 MDth/day is developed by 2015, while in 80% of the draws no regional LNG storage is included.

Figure 6-24
Frequency Distribution of Regional LNG Storage Development by 2015

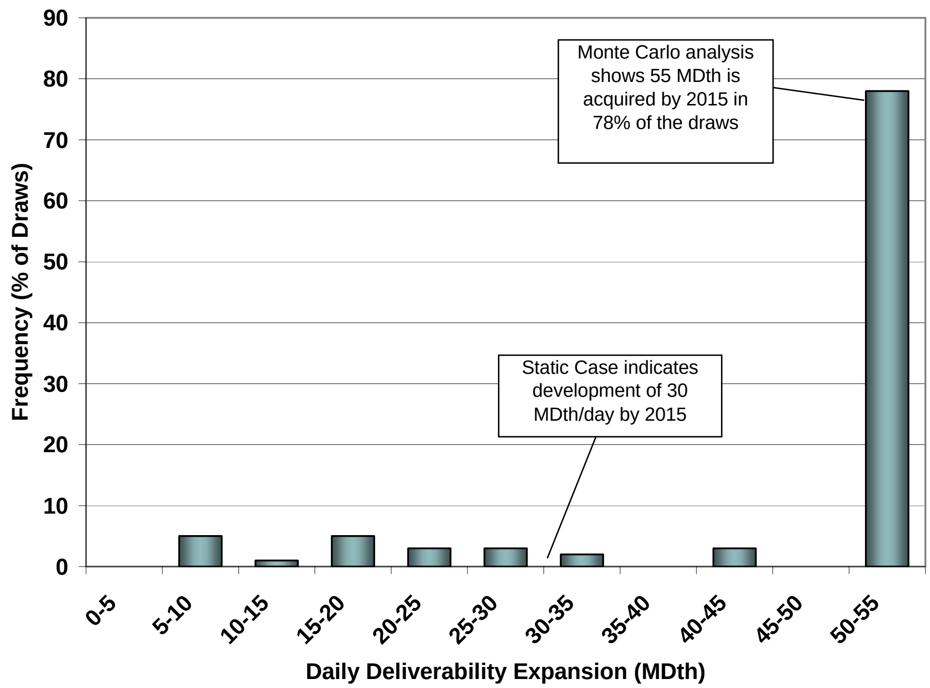


The Monte Carlo analysis indicates that the decision to acquire regional LNG storage capacity, while attractive in the static analysis, should be analyzed in greater detail as the Company proceeds to study the various capacity expansion alternatives.

Monte Carlo Optimization Results—Southern LNG Import Supply

Figure 6-25 illustrates the frequency distribution for the Southern LNG Import Supply and shows results of the static Base Case analysis. As shown, in 78% of the Monte Carlo scenarios, Import LNG was selected as part of the optimal resource portfolio. In the static analyses, the optimum quantity to be selected was about 30 MDth/day. These results support the conclusion that PSE should carefully consider the Southern LNG alternative as more information becomes available. As noted earlier, however, the specific terms and conditions of a long-term LNG import supply contract is the key determinant of the attractiveness of LNG imports.

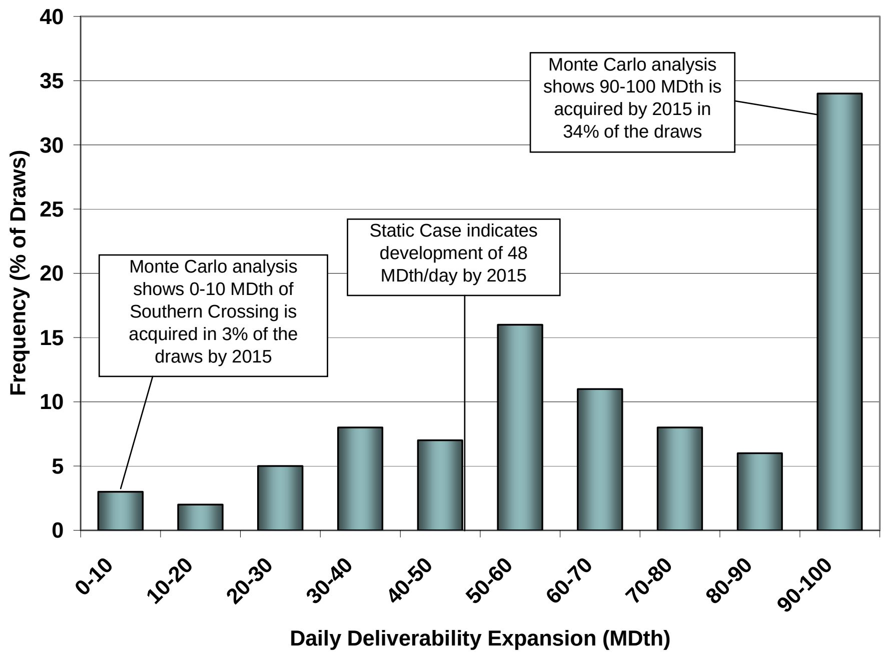
Figure 6-25
Frequency Distribution for South LNG Import Development by 2015



Monte Carlo Optimization Analysis—Southern Crossing/Inland Pacific Connector

We also found that the Southern Crossing/Inland Pacific Connector results appear to be highly sensitive to weather and gas price input assumptions. Figure 6-26 shows the frequency distribution for the Southern LNG Import Supply results as well as the results of the static Base Case analysis. In 34% of the Monte Carlo scenarios, a capacity of 90 to 100 MDth/day was selected for the Southern Crossing alternative. The static analyses indicated that the optimum level for development by 2015 was about 48 MDth.

Figure 6-26
Frequency Distribution for Southern Crossing Pipeline Development by 2015



Monte Carlo Optimization Analysis—Summary Conclusion

Monte Carlo analysis in the resource optimization approach provides information about the sensitivity of the optimality of resource additions to underlying assumptions of price and demand variability. As with the static optimization analysis, results of the Monte Carlo analysis will not provide the answer as to what kind of resources should be added to the portfolio at different times. Rather, this analysis will provide additional information to help support the Company's efforts to make informed resource acquisition decisions.

E. Key Findings

This analytical and statistical evaluation led to several key findings that will guide PSE not only as we develop our resource strategy over the 20-year planning horizon but also as we consider specific resources for the next two years.

1. PSE should investigate expanding gas energy efficiency programs.

Expanding these offerings will be challenging.

- We are doing greater amounts of gas energy efficiency compared to our previous achievements.
- We need to review gas prices frequently in order to understand what scenario is in operation.
- Long term (20 years), there is some risk that pursuing a Base Case energy efficiency strategy and ending up in a Robust or Reduced Growth Scenario future would cause PSE to under/over acquire energy efficiency, respectively. However, in the short term, the variance in the range of energy efficiency potential is only 168 MDth.

2. Investigate participation in a jointly owned LNG storage facility located to take advantage of locational displacement for low-cost withdrawal transportation to our service area.

This alternative appears to be a feasible and low-cost alternative to meet future peak load growth. Our core gas portfolio has a relatively low capacity factor (annual average volume divided by peak day loads). In general, we have sufficient pipeline capacity to deliver the total annual requirements but will need additional peak day delivery capacity starting in 2012. Acquiring firm year-around pipeline capacity is a relatively expensive alternative for meeting peak day loads.

3. Monitor the development of regional LNG import facilities.

Based on these analyses, acquisition of gas supplies from an LNG import terminal located south of PSE's service area appears to be a beneficial way to increase peak supply capacity and diversify of supply sources. It appears that it is feasible to cost-effectively develop some limited transportation capacity from the Jordan Cove site to PSE's city gate. At this time the terms for supply of gas to the LNG terminal have not been developed nor has PSE had the opportunity to discuss what form such a supply agreement might take. The final terms and conditions of the gas supply agreement will largely determine the attractiveness of this alternative.

4. Seek to develop additional long-term gas supply agreements for purchase of Sumas and Station 2 gas.

Fully 50% of PSE direct connect pipeline capacity is from Sumas to the PSE city gate. We are concerned that it is becoming more difficult to negotiate long-term gas supply agreements (up to 3 years) with gas producers and marketers at either Sumas or Station 2. Producers and marketers appear reluctant to make additional investments in new gas production facilities in northern British Columbia and they are electing to transport gas eastward to gain access to the AECO market hub. The AECO hub is more liquid than Sumas or Station 2 and has pipeline access to the Chicago and other mid-west markets. We will need to diversify our sources of supply away from Sumas and Station 2 if we have ongoing difficulties in purchasing gas at these hubs.

5. Consider increasing access to the AECO market hub in order to maintain diversity of supply.

The Southern Crossing/Inland Pacific Connector is a feasible alternative to increased dependence on gas supplies from northern BC. It also appears to be the highest cost of the four main alternatives evaluated as part of this analysis; however, the Southern Crossing alternative has the dual benefits of increasing peak day capacity as well as diversifying gas supplies by increasing access to the AECO hub.

6. The growth in the need for generation fuel will outpace the growth in need for gas sales.

The increase in both peak capacity and annual volumes of gas for generation fuel will exceed the increases in need for the gas sales portfolio. (See Section VI of this chapter.)

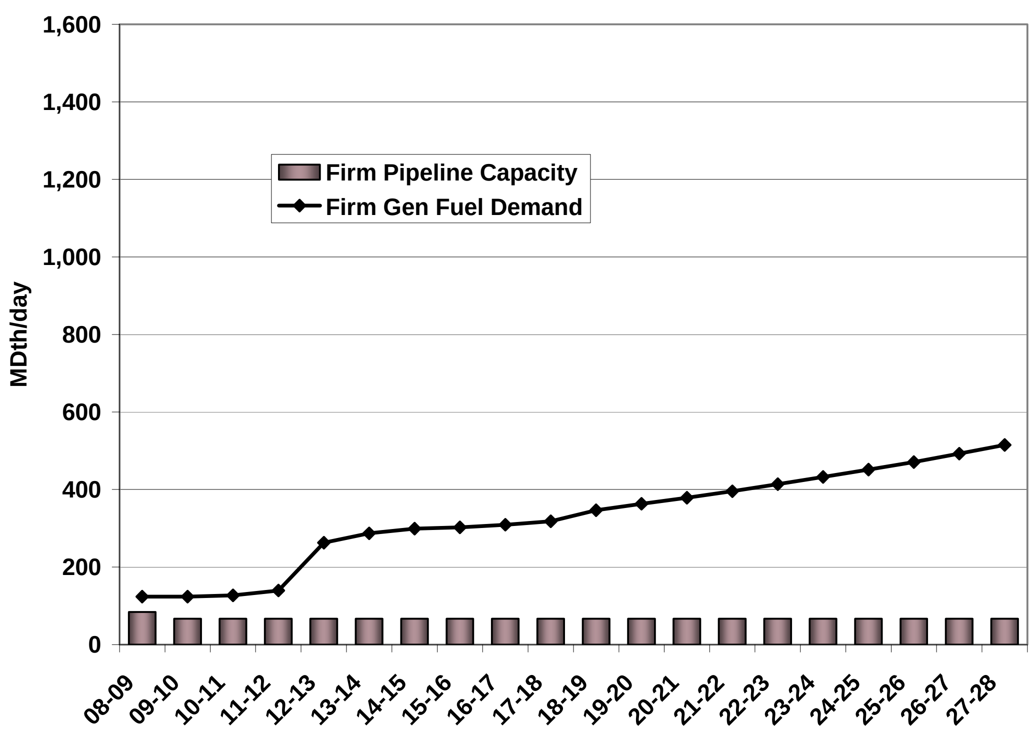
VI. Gas for Electric Generation

As discussed earlier in Chapter 5, all the electric portfolios evaluated in the electric analysis include relatively high amounts of gas fired generation. Selecting the best sources of supply, purchasing and hedging this gas, transporting and potentially storing it will be an important issue for the Company to deal with over the next several years. The following discussion uses the Aggressive Gas Portfolio 1-a, as discussed in Chapter 5, as the basis for determining gas resource needs for generation fuel.

A. Need for Gas for Electric Generation

The existing gas for electric generation firm peak supply portfolio and projected peak day need based on the gas requirements from Portfolio 1A are shown in Figure 6-27.

Figure 6-27
Gas for Generation Resource Need 2008-2027:
Existing Resources Compared to Design Peak-day Gas Demands



B. Existing Gas Resources for Power Generation

We also have firm pipeline transportation capacity for delivery of fuel to our gas-fired generation plants. Figure 6-28 summarizes that capacity.

Figure 6-28
Power Generation Gas Pipeline Capacity (Dth/Day)

Direct Connect Capacity						
Plant	**Transporter**	**Service**	**Capacity**	**Primay Path**	**Primary Term End**	**Renewal Right**
Whitehorn	Cascade Natural Gas	Firm	(1)	Westcoast/CNG Intereconnect (Sumas) to plant	12/31/2000	Yr to Yr
Tenaska	Cascade Natural Gas	Firm	(1)	Westcoast/CNG Intereconnect (Sumas) to plant	12/31/2000	Yr to Yr
Encogen	Cascade Natural Gas	Firm	(1)	NWP-Bellingham to plant	6/30/2008	Yr to Yr
Fredonia	Cascade Natural Gas	Firm	(1)	NWP-Sedro Wooley to plant	7/31/2021	Yr to Yr
Freddy1	NWP	Firm	21,747	Westcoast/NWP Interconnect (Sumas) to Plant	9/30/2018	Yr to Yr
Goldendale Generating Station	NWP	Firm	45,000	Westcoast/NWP Interconnect (Sumas) to Everett (3)	9/30/2018	Yr to Yr

Upstream Capacity						
Plant	**Transporter**	**Service**	**Capacity**	**Primay Path**	**Primary Term End**	**Renewal Right**
Various	Westcoast	Frim	22,000 (2)	Station 2 to Westcoast/NWP Interconnect (Sumas)	10/31/2014	Yes
Various	NWP	Firm (4)	16,884	Rockies to Bellingham	3/31/2008	No
Various	NWP	Firm	6,600	Westcoast/NWP Interconnect (Sumas) to Bellingham	6/30/2008	Yes

Notes:
(1) Plant Requirements
(2) Converted to approximate Dth/day from contract stated in cubic meters/day
(3) Gas is moved from Everett to Goldendale pursuant to flex provisions pursuant to NWP agreement and displacement agreement with PSE Gas Sales
(4) Capacity Held by a third party, controlled by PSE via grandfathered agreement

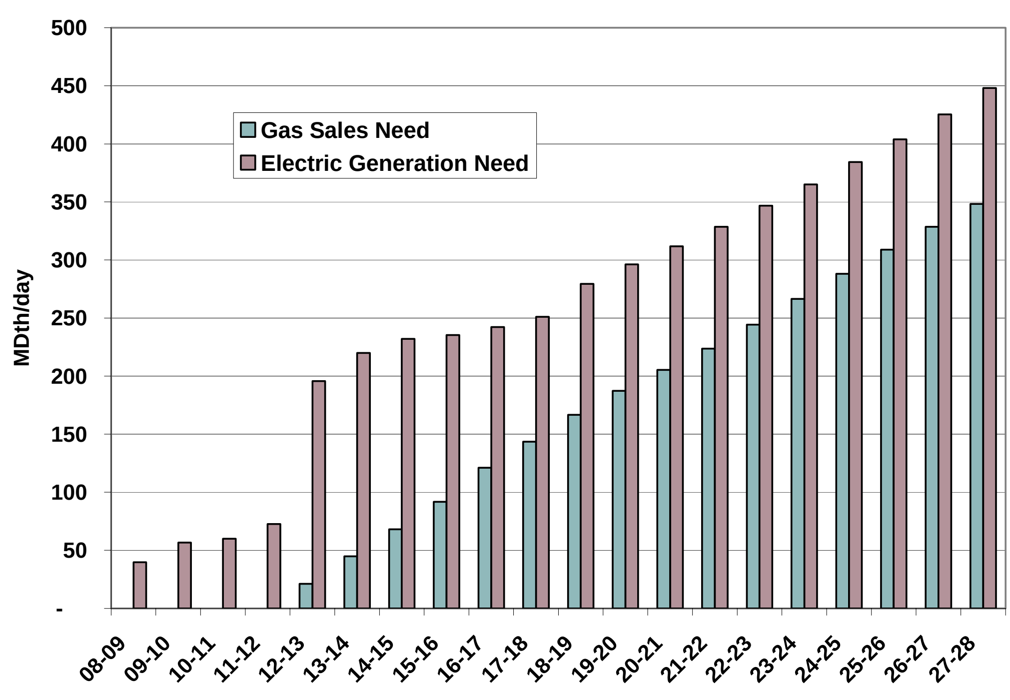
We have firm pipeline capacity to serve our combined cycle generating plants (Freddy1, Goldendale and Encogen). Several of our combustion turbine generation units (Whitehorn, Fredonia, and Frederickson) have backup fuel-oil firing capability and thus do not require firm pipeline capacity. The Tenaska generating facility also has backup fuel-oil firing capability.

C. Capacity Need for Gas Sales Compared to Electric Generation Gas Need

It is helpful to compare the projected need for peak day gas delivery capacity for electrical generation with the needs for the gas sales portfolio. (Note that the needs for the gas sales portfolio are shown in Figure 6-1.)

Figure 6-29 shows a comparison of the peak capacity needs of electric Portfolio 1A with the needs of the gas sales portfolio.

Figure 6-29
Comparison of Peak Day Need
for Gas Sales Portfolio and Electric Portfolio 1A



Note that the needs for electric generation are more immediate and increases more rapidly than the need for gas sales reflecting the addition of gas fuel generation in Portfolio 1A.

Developing long term plans to supply gas for generation is difficult since arranging for gas transportation is highly dependent on the specific location of the generating plants. For example, a location near a gas trading hub such as Sumas or with access to a gas storage facility greatly reduces the need for additional pipeline capacity.

While the gas required for electric generation is anticipated to increase faster than for the gas sales portfolio, the overall requirements are less than for gas sales and are projected to remain so over the 20-year planning horizon.

Figure 6-30 compares the annual volume of gas load forecasted for the gas sales portfolio and the gas required for electrical generation.

Figure 6-30
Projected Annual Gas Volumes Compared:
Gas Sales vs. Electric Portfolio 1A