7

2017 PSE Integrated Resource Plan

Gas Analysis

This analysis enables PSE to develop valuable foresight about how resource decisions to serve our natural gas customers may unfold over the next 20 years in conditions that depict a wide range of futures.

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1. RESOURCE NEED AND KEY ISSUE

Resource Need

More than 800,000 customers in Washington state depend on PSE for safe, reliable and affordable natural gas services.

PSE's gas sales need is driven by peak day demand, which occurs in the winter when temperatures are lowest and heating needs are highest. The current design standard ensures that supply is planned to meet firm loads on a 13-degree design peak day, which corresponds to a 52 Heating Degree Day (HDD).[1] Two primary factors influence demand, peak day demand per customer and the number of customers. The heating season and number of lowest-temperature days in the year remain fairly constant and use per customer is growing slowly, if at all, so the the biggest factor in determining load growth at this time is the increase in customer count.

The IRP analysis tested three customer demand forecasts over the 20-year planning horizon: the 2017 IRP Base Demand Forecast, the 2017 IRP High Demand Forecast and the 2017 IRP Low Demand Forecast.[2]

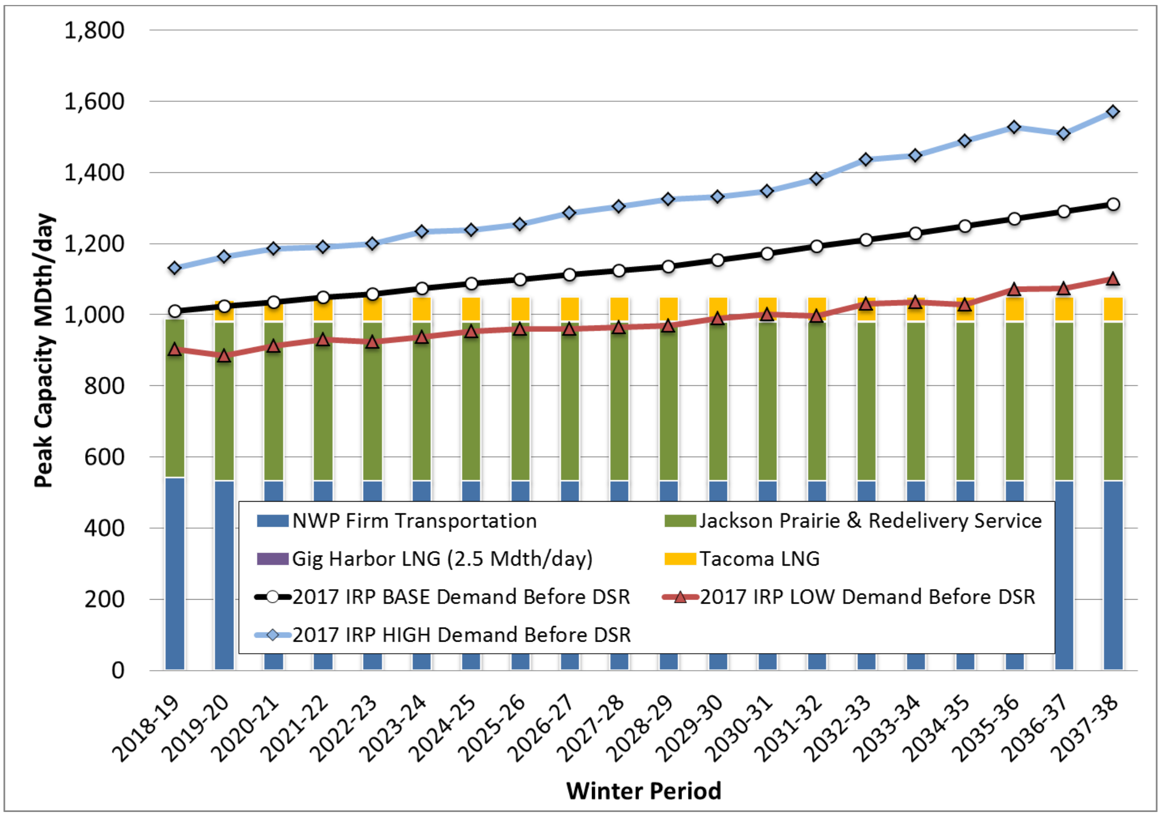
- In the Low Demand Forecast, we have sufficient firm resources to meet peak day need until the winter of 2035/36.
- In the Base Demand Forecast, the first resource need occurs in the winter of 2018/19 in the study, after that, there are sufficient firm resources to meet peak day need until the winter of 2022/23.
- In the High Demand Forecast, we do not have sufficient firm resources to meet peak day need throughout the study.

Figure 7-1 illustrates gas sales peak resource need over the 20-year planning horizon for the three demand forecasts modeled in this IRP. Figure 7-2 shows the resource need surplus/deficit for the Base Demand Forecast.

1 / HDDs are defined as the number of degrees relative to the base temperature of 65 degrees Fahrenheit. A 52 HDD day is calculated as 65° less the 13° temperature for the day.
2 / The 2017 IRP demand forecasts are discussed in detail in Chapter 5, Demand Forecast.

In Figure 7-1, the lines rising toward the right indicate peak day customer demand before demand-side resources (DSR),[3] and the bars represent existing gas supply resources to deliver gas to our customers. These resources include contracts for transporting natural gas on interstate pipelines from production fields, storage projects and on-system peaking resources.[4] The gap between demand and existing resources represents the resource need.

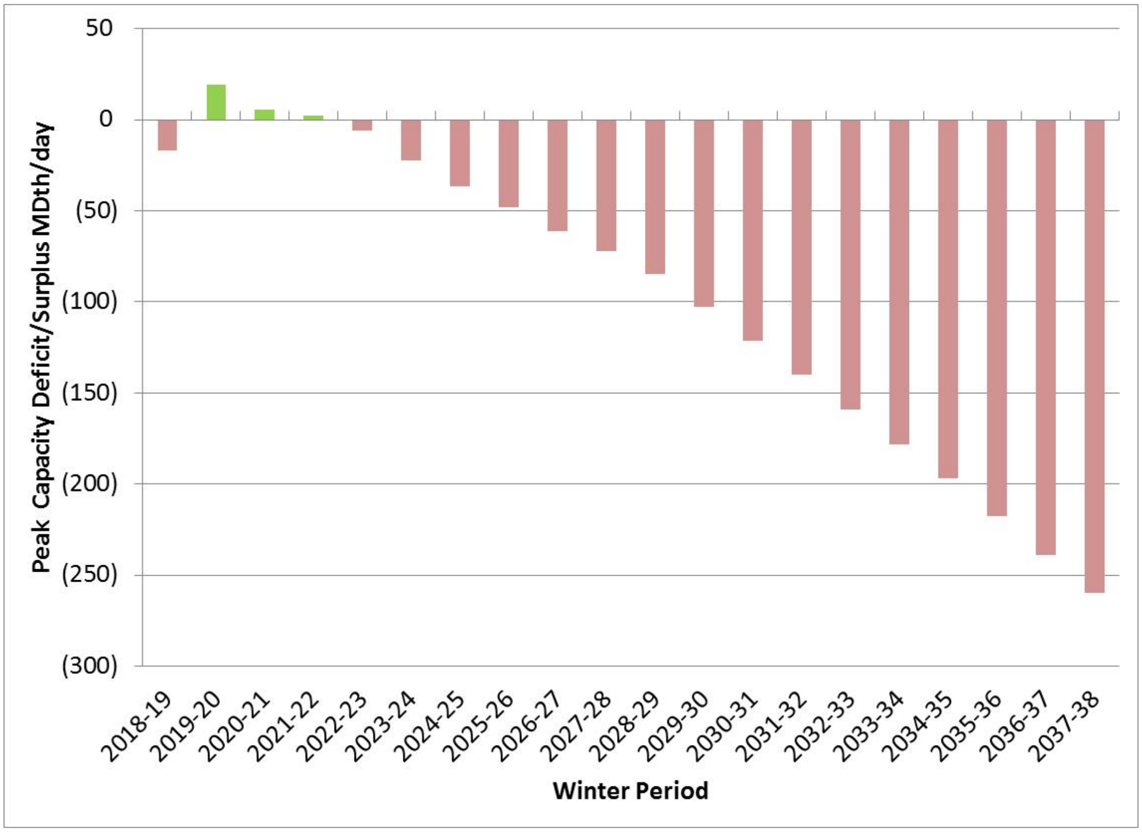
Figure 7-1: Gas Sales Peak Resource Need before DSR, Existing Resources Compared to Peak Day Demand (Meeting need on the coldest day of the year)



3 / *One of the major tasks of the IRP analysis is to identify the most cost-effective amount of conservation to include in the resource plan. To accomplish this, it is necessary to start with demand forecasts that do not already include forward projections of conservation savings. Therefore the IRP Gas Demand Forecasts include only DSR measures implemented* ***before*** *the study period begins in 2018. These charts and tables are labeled "before DSR."*

4 / *Tacoma LNG is shown as an existing resource, as the facility is currently under construction and anticipated to be in service and available by the winter of 2019.*

Figure 7-2: Gas Sales Peak Resource Need Surplus/Deficit in Base Demand Forecast before DSR



Gas Sales Key Issue

Adequacy of Sumas Market

The Sumas market (the Huntingdon, British Columbia / Sumas, Washington hub) is essentially an interconnection between the Enbridge/Westcoast Energy Pipeline (Westcoast) and Northwest Pipeline (NWP). Unlike other market hubs, there is no gas production and no convergence of several supply pipelines. PSE implemented a strategy to hold firm capacity on Westcoast for approximately 50 percent of its peak demand for gas from British Columbia (B.C.). This strategy provides a level of reliability (physical access to gas in the production basin) and an opportunity for pricing diversity, as often there is a significant pricing differential between Station 2 and Sumas that more than offsets the cost of holding the capacity.

Since its last major expansion in 2002, Westcoast has had capacity to transport adequate supplies to satisfy all firm demand relying on gas from northeast British Columbia (NE B.C.). Subsequent to the expansion, as Station 2 to Sumas price differentials decline, some shipper contracts expired and were not renewed. This left much of the Westcoast system uncontracted on a firm basis. Then, at the very time the Pacific Northwest (PNW) demand for natural gas to serve gas customer growth and electric generation fuel needs was increasing, conventional production in B.C. began to decline and prices rose, leaving PNW demand to consider the less expensive supplies in the Rockies. The region and California considered new pipeline proposals from the Rockies, and ultimately Ruby Pipeline was built.

The shale revolution changed everything. As production costs fell and supply increased, the abundant and low-cost production of NE B.C. and the Montney region, in particular, is now trapped by a shortage of pipeline capacity leaving the basin. Westcoast is now fully contracted as NE B.C. producers have sought a market outlet for their growing production. In the last two years Westcoast has run at its maximum available capacity nearly year-round (limited by maintenance restrictions). This has resulted in adequate supply at Sumas in winter months and an excess in summer months.

A recently completed Westcoast capacity offering was fully subscribed and will drive construction of an additional 105,000 Dth/d of firm capacity on Westcoast and the availability of 94,000 Dth of capacity previously held back for maintenance and reliability reasons, but this is available only on a best-efforts basis. While these new contracts of 199,000 Dth/d will bring more firm gas reliably to the Sumas hub beginning in November 2020, two new large-volume firm demands of approximately 420,000 Dth/d are expected to come online between 2020 and 2023. Because these two new loads have acquired the firm Westcoast capacity necessary to serve their demand, they will control their own supply and destiny. The firm gas supply controlled by these new industrial loads will effectively remove the supply available at Sumas for other customers on most days.

PSE is comfortable with the notion that there will be adequate supplies at Sumas at most times of the year with the increased capacity on Westcoast beginning in 2020, and that PSE would be able to compete (on price) to obtain sufficient supplies in peak periods, even with the new loads.

The table in Figure 7-3 illustrates an approximation of the supply and demand balance at Sumas, currently and in 2020 and 2023. Interruptible loads are shown in blue. The potential start-up of the first of the two new large-volume firm loads – each of which holds their own capacity on Westcoast and thus controls their own supply – may fully absorb all remaining supply at Sumas in winter peak conditions, forcing a rationing of supply among interruptible loads based on price. When the second of the new large-volume firm loads is added, the shortfall in supply (307 MDth/d) is greater than the total interruptible loads (300 MDth/d), which may result in a lack of sufficient gas supply for some firm loads. This would suggest that any additional firm load would require an expansion of Westcoast in order to maintain reliability.

Figure 7-3: Projected Supply and Demand at Sumas

Projected Supply & Demand at Sumas	Current 2017-18		Expected 2020-21		Expected 2023-24	
	Winter	Summer	Winter	Summer	Winter	Summer
	MDth/d	MDth/d	MDth/d	MDth/d	MDth/d	MDth/d
Max Westcoast capacity (pre-expansion)	1,518	1,518	1,518	1,518	1,518	1,518
Westcoast Winter Only Firm Service (WOFS)	168	-	168	-	168	-
Westcoast AOS capacity (absorbed by Expansion)	94	94	-	-	-	-
WEI Proposed Expansion (eff. 11/2020)	-	-	199	199	199	199
Max Westcoast capacity -total gas availailable at Sumas	1,780	1,612	1,885	1,717	1,885	1,717
PSE - Guaranteed Access-Firm T-South for Firm Reqmts	**219**	**219**	**219**	**219**	**219**	**219**
PSE -AOS T-South@ 50% for Firm Reqmts	**12**	**11**	**-**	**-**	**-**	**-**
Remaining Gas Supply available at Sumas	**1,550**	**1,383**	**1,666**	**1,498**	**1,666**	**1,498**
Other Demand						
PSE - Purchase at Sumas for Firm Reqmts	**247**	**123**	**259**	**123**	**259**	**123**
PSE - Purchase at Sumas -Peakers	***155***	***155***	***155***	***155***	***155***	***155***
Fortis BC Energy Firm load	525	275	525	275	525	275
Other Firm Gen. (PGE, Pac.,)	170	170	170	170	170	170
Other Firm LDC (NWN, CNGC, InterMtn, Sierra)	220	125	220	125	220	125
Other Firm Indust. Load (I-5 corridor)	80	70	80	70	80	70
Other Interruptible Gen. (Grays H)	*105*	*105*	*105*	*105*	*105*	*105*
Other Interruptible Indust. Load (I-5 corridor)	*40*	*35*	*40*	*35*	*40*	*35*
NWIW-Kalama from Sumas (eff. 11/2020)	-	-	180	180	180	180
WoodFibre LNG demand at Sumas (eff. 11/2023)	-	-	-	-	240	240
Total Demand	1,542	1,058	1,734	1,238	1,974	1,478
Uncommitted supply at Sumas	**8**	**325**	**(67)**	**261**	**(307)**	**21**
potential unserved	**-**	**-**	**3%**	**n/a**	**14%**	**n/a**
Percent of PSE Firm Requirements covered by T-South	**48.3%**	**65.2%**	**45.8%**	**64.1%**	**45.8%**	**64.1%**
Percent of PSE Total Requirements covered by T-South	**36.5%**	**45.2%**	**34.6%**	**44.0%**	**34.6%**	**44.0%**
PSE Pro-rata share of unserved volume (MDth/d)	**-**	**-**	**16**	**n/a**	**64**	**n/a**

Because there is an equilibrium of supply and firm demand in peak winter periods and a surplus in summer periods, PSE does not believe it is necessary to secure additional firm Westcoast capacity beyond the current level, which is approximately 50 percent of PSE's peak period demand. However, we do believe that there is a potential for inadequate capacity to bring sufficient supply to Sumas in peak periods beyond 2023, assuming the two new large-volume loads materialize. Therefore, in this IRP, we are continuing to assume that any new NWP capacity from Sumas that PSE would consider using to serve incremental PSE firm loads would need to be coupled with additional firm capacity on Westcoast from the supply source in NE B.C., in order to be deemed a reliable new resource. PSE will continue to monitor developments in the NE B.C. supply and capacity market and to analyze the implications on an ongoing basis.

2. ANALYTIC METHODOLOGY

In general, analysis of the gas supply portfolio begins with an estimate of resource need that is derived by comparing 20-year demand forecasts with existing long-term resources. Once need has been identified, a variety of planning tools, optimization analyses and input assumptions help PSE identify the lowest-reasonable-cost portfolio of gas resources in a variety of scenarios. Such resources would include the consideration of renewal or extension of existing resources.

Analysis Tools

PSE uses a gas portfolio model (GPM) to model gas resources for long-term planning and long-term gas resource acquisition activities. The current GPM is SENDOUT Version 14.3.0 from ABB Ventyx, a widely-used model that employs a linear programming algorithm to help identify the long-term, least-cost combination of integrated supply- and demand-side resources that will meet stated loads. While the deterministic linear programming approach used in this analysis is a helpful analytical tool, it is important to acknowledge this technique provides the model with "perfect foresight" – meaning that its theoretical results may not 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 is not possible in the real world. Numerous critical factors about the future will always be uncertain; therefore we rely on linear programming analysis to help *inform* decisions, not to *make* them. See Appendix O, Gas Analysis, for a more complete description of the SENDOUT gas portfolio model.

Deterministic Optimization Analysis

As described in Chapter 4, Key Analytical Assumptions, PSE developed 11 scenarios for this IRP gas analysis. Scenario analysis allows the company to understand how different resources perform across a variety of economic and regulatory conditions that may occur in the future. Scenario analysis also clarifies the robustness of a particular resource strategy. In other words, it helps determine if a particular strategy is reasonable under a wide range of possible circumstances.

PSE also tested four sensitivities in the gas sales analysis; these are described below. Sensitivity analysis allows us to isolate the effect a single resource has on the portfolio.

1. **DEMAND-SIDE RESOURCES.** How much does DSR reduce cost and risk? This sensitivitity compares a portfolio with all cost-effective DSR per RCW 19.285 to a portfolio with no DSR in which all future needs are met with supply-side resources.
2. **RESOURCE ADDITION TIMING OPTIMIZATION**. How does the timing of PSE-controlled resource additions affect resource builds and portfolio costs? Instead of offering PSE-controlled resources every two years, the model is allowed to offer them every year.
3. **ALTERNATE RESIDENTIAL CONSERVATION DISCOUNT RATE**. Would using a societal discount rate on conservation savings from residential energy efficiency impact cost-effective levels of conservation? This sensitivity applies an alternate discount rate that is lower than PSE's approved weighted average cost of capital (WACC) on residential savings.
4. **ADDITIONAL GAS CONSERVATION.** What happens if DSR is added beyond what is cost-effective per RCW 19.285? This sensitivity adds two additional demand-side bundles above the bundles chosen as cost effective.

Gas portfolio analysis is discussed in more detail in Appendix O, Gas Analysis.

3. EXISTING SUPPLY-SIDE RESOURCES

Existing gas sales resources consist of pipeline capacity, storage capacity, peaking capacity, gas supplies and demand-side resources.

Existing Pipeline Capacity

There are two types of pipeline capacity. “Direct-connect” pipelines deliver supplies directly to PSE’s local distribution system from production areas, storage facilities or interconnections with other pipelines. “Upstream” pipelines deliver gas to the direct pipeline from remote production areas, market centers and storage facilities.

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 nearly one million dekatherms (Dth) of firm capacity with NWP.

- 532,872 Dth per day of year-round TF-1 (firm) transportation capacity
- 447,057 Dth per day of firm storage redelivery service from Jackson Prairie

Receipt points on the NWP transportation contracts access supplies from four production regions: British Columbia, Canada (B.C.); Alberta, Canada (AECO); the Rocky Mountain Basin (Rockies) and the San Juan Basin. This provides valuable flexibility, including the ability to source gas from different regions on a day-to-day basis in some contracts.

Upstream Pipeline Capacity

To transport gas supply from production basins or trading hubs to the direct-connect NWP system, PSE holds capacity on several upstream pipelines.

A schematic of the gas pipelines for the Pacific Northwest region is provided in Figure 7-4 below. In addition, please see Figure 7-5 for details of PSE's gas sales pipeline capacity.

Figure 7-4: Pacific Northwest Regional Gas Pipeline Map

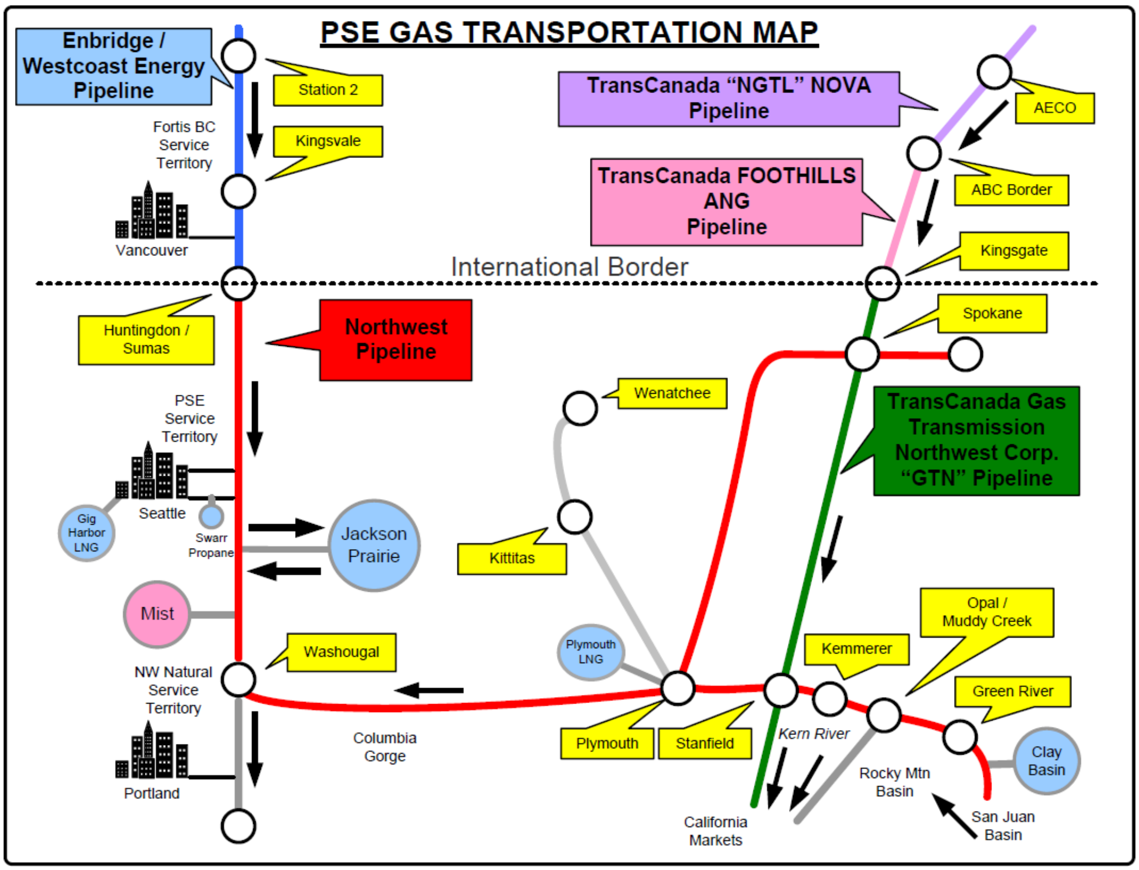


Figure 7-5: Gas Sales - Firm Pipeline Capacity (Dth/day) as of 03/31/2017

Pipeline/Receipt Point	Note	Total	Year of Expiration 2018-22	2023+
Direct Connect				
NWP/Westcoast Interconnect (Sumas)	1,2	277,237	20,416	256,821
NWP/TC-GTN Interconnect (Spokane)	1	75,936	-	75,936
NWP/various in US Rockies	1	179,699	840	178,859
Total TF-1		**532,872**	**21,256**	**511,616**
NWP/Jackson Prairie Storage Redelivery Service	1,3	447,057	-	447,057
Storage Redelivery Service		**447,057**	**0**	**447,057**
Total Capacity to City Gate		**979,929**	**21,256**	**958,673**

Pipeline/Receipt Point	Note	Total	Year of Expiration 2018-22	2023+
Upstream Capacity				
TC-Alberta/from AECO to TC-BC Interconnect (A-BC Border)	4	79,744	79,744	-
TC-BC from TC-Alberta to TC-GTN Interconnect (Kingsgate)	4	78,631	70,604	8,027
TC-GTN from TC-BC Interconnect to NWP Interconnect (Spokane)	5	65,392	-	65,392
TC-GTN from TC-BC Interconnect to NWP Interconnect (Stanfield)	5,6	11,622	-	11,622
Westcoast/from Station 2 to NWP Interconnect (Sumas)	7,8	132,401	132,401	-
Total Upstream Capacity	**9**	**367,790**	**282,749**	**85,041**

NOTES
1. NWP contracts have automatic annual renewal provisions, but can be canceled by PSE upon one year's notice.
2. After planned transfer of 10,000 Dth/day effective 11/1/2019 to Puget LNG to provide service to TOTE.
3. Storage redelivery service (TF-2 or discounted TF-1) is intended only for delivery of storage volumes during the winter heating season, November through March; these annual costs are significantly lower than year-round TF-1 service.
4. Converted to approximate Dth per day from contract stated in gigajoules per day.
5. TC-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. Converted to approximate Dth per day from contract stated in cubic meters per day.
8. The Westcoast contracts contain a right of first refusal upon expiration.
9. Upstream capacity is not necessary for a supply acquired at interconnects in the Rockies and for supplies purchased at Sumas.

Transportation Types

TF-1

TF-1 transportation contracts are “firm” contracts, available every day of the year. PSE pays a fixed demand charge for the right, but not the obligation, to transport gas every day.

Storage Redelivery Service

PSE holds TF-2 and winter-only discounted TF-1 capacity under various contracts to provide for firm delivery of Jackson Prairie storage withdrawals. These services are restricted to the winter months of November through March and provide for firm receipt only at Jackson Prairie; therefore, the rates on these contracts are substantially lower than regular TF-1 transportation contracts.

Firm versus Non-firm Transportation Capacity

Firm transportation capacity carries the right, but generally not the obligation (subject to operational flow orders from a pipeline), to transport up to a maximum daily quantity of gas on the pipeline from a specified receipt point to a specified delivery point. Firm transportation requires a fixed payment, whether or not the capacity is used, plus variable costs when physical gas is transported. The rate for interruptible capacity is negotiable, and is typically billed as a variable charge.

Primary firm capacity is highly reliable when used in the contracted path from receipt point to delivery point. Firm shippers have the right to temporarily alter the contractual receipt point, the delivery point and even the flow direction – subject to availability of capacity for that day. The reliability of this use of “alternate firm” can be reasonably predicted; it is very reliable if the contract is used to flow gas in the contractual direction to or from the primary delivery or receipt point (i.e., within the primary path).

Alternate firm is much less reliable or predictable if used to flow gas in the opposite direction or “out of path.” While this capacity has higher rights than interruptible capacity, it is not considered reliable in most circumstances. Non-firm capacity on a fully contracted pipeline results from a firm shipper not fully utilizing its firm rights on a given day. This unused (interruptible) capacity, if requested (nominated) by a shipper and confirmed by the pipeline, becomes firm capacity for that day. The rights of this type of non-firm capacity are subordinate to the rights of firm pipeline contract owners who request to transport gas on an alternate basis, outside of their contracted firm transportation path.

The flexibility to use firm transport in an alternate firm manner as “within path” or “out of path” modes, along with the ability to create “segmented release” capacity has resulted in very low interruptible volumes on the NWP system.

PSE may release capacity when it has a surplus of firm capacity and when market conditions make such transactions favorable for customers. The company also uses the capacity release market to access additional firm capacity when it is available. Interruptible service plays a limited role in PSE’s resource portfolio because of the flexibility of its firm contracts and because it cannot be relied on to meet peak demand.

Existing Storage Resources

PSE’s natural gas storage capacity is a significant component of the company’s gas sales resource portfolio. Storage capacity improves system flexibility and creates significant cost savings for both the system and customers. Benefits include the following.

- Ready access to an immediate and controllable source of firm gas supply or storage space enables PSE to handle many imbalances created at the interstate pipeline level without incurring balancing or scheduling penalties.
- Access to storage makes it possible for the company to purchase and store additional gas during the lower-demand summer season, generally at lower prices.
- Combining storage capacity with firm storage redelivery service transportation allows us to contract for less year-round pipeline capacity to meet winter-only or peak-only demand.
- PSE also uses storage to balance city gate gas receipts from gas marketers with the actual loads of our gas transportation customers.

We have contractual access to two underground storage projects. Each serves a different purpose. Jackson Prairie Gas Storage Project (Jackson Prairie) in Lewis County, Wash. is an aquifer-driven storage field, located in the market area, 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-long gas supply. Figure 7-6 presents details about storage capacity.

Figure 7-6: Gas Sales Storage Resources[1] as of 03/31/2017

	Withdrawal Capacity (Dth/Day)	Injection Capacity (Dth/Day)	Storage Capacity (Dth)	Expiration Date
Jackson Prairie – PSE Owned	398,667	156,000	8,528,000	N/A
Jackson Prairie – PSE Owned[2]	(50,000)	(50,000)	(500,000)	2019
Net JP Owned	**348,667**	**106,000**	**8,028,000**	
Jackson Prairie – NWP SGS-2F[3]	48,390	18,935	1,181,021	2023
Jackson Prairie – NWP SGS-2F[3]	6,077	2,378	178,460	2026
Jackson Prairie – NWP SGS-2F[4]	(6,077)	(2,378)	(178,460)	2020
Net Jackson Prairie	**397,057**	**124,935**	**9,209,021**	
Clay Basin[5]	107,356	53,678	12,882,750	2018/20
Clay Basin[6]	(33,333)	(16,667)	(4,000,000)	2018
Net Clay Basin	**74,023**	**37,011**	**8,882,750**	
Total	**471,080**	**161,946**	**18,091,771**	

NOTES
1. Storage, injection and withdrawal capacity quantities reflect PSE's capacity rights rather than the facility's total capacity.
2. Storage capacity made available (at market-based price) from PSE gas sales portfolio. Renewal may be possible, depending on gas sales portfolio needs. Firm withdrawal rights can be recalled to serve gas sales customers.
3. NWP contracts have automatic annual renewal provisions, but can be canceled by PSE upon one year's notice.
4. Released to Cascade Natural Gas Co. through 4/1/2020.
5. PSE expects to renew the Clay Basin storage agreements.
6. Assigned to third parties through 3/31/2018; PSE is considering renewal.

Jackson Prairie Storage

PSE, NWP and Avista Utilities each own an undivided one-third interest in the Jackson Prairie Gas Storage Project, which is operated by PSE under FERC authorization. As shown in Figure 7-5, PSE owns 398,667 Dth per day of firm storage withdrawal rights and associated storage capacity from Jackson Prairie. Some of this capacity has been made available to PSE's electric portfolio at market rates. The firm withdrawal rights – but not the storage capacity – may be recalled to serve gas sales customers under extreme conditions. In addition to the PSE-owned portion of Jackson Prairie, PSE has access to 48,390 Dth per day of firm deliverability and associated firm seasonal capacity through contracts for SGS-2F storage service from NWP. In total, PSE holds 447,057 Dth per day of firm withdrawal rights for peak day use. As shown in Figure 7-4, PSE has 447,057 Dth per day of storage redelivery service transportation capacity from Jackson Prairie. The NWP contracts renew automatically each year, but PSE has the unilateral right to terminate the agreement with one year's notice.

PSE uses Jackson Prairie and the associated NWP storage redelivery service transportation capacity primarily to meet the intermediate peaking requirements of core gas customers – that is, to meet seasonal load requirements, balance daily load and minimize the need to contract for year-round pipeline capacity to meet winter-only demand.

Clay Basin Storage

Dominion-Questar Pipeline owns and operates the Clay Basin storage facility in Daggett County, Utah. This reservoir stores gas during the summer for withdrawal in the winter. PSE has two contracts to store up to 12,882,750 Dth and withdraw up to 107,356 Dth per day under a FERC-regulated service. As shown in Figure 7-5, 4,000,000 Dth of this storage capacity has been released to third parties through March 2018. PSE is considering the extension of these arrangements.

PSE uses Clay Basin for certain levels of baseload supply, and for backup supply in the case of well freeze-offs or other supply disruptions in the Rocky Mountains during the winter. It provides a reliable source of supply throughout the winter, including peak days; it also provides a partial hedge to price spikes in this region. Gas from Clay Basin is delivered to PSE's system (or other markets) using firm NWP 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. PSE also pays a variable charge for gas injected into and withdrawn from Clay Basin. 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 the Purchased Gas Adjustment (PGA) regulatory mechanism, while costs associated with the PSE-owned portion of Jackson Prairie are recovered from customers through base distribution rates. Some Jackson Prairie costs are recovered from PSE transportation customers through a balancing charge.

Existing Peaking Supply and Capacity Resources

Firm access to other resources provides supplies and capacity for peaking requirements or short-term operational needs. The Gig Harbor liquefied natural gas (LNG) satellite storage and the Swarr vaporized propane-air (LP-Air) facility 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 resources typically help to meet extreme peak demand during the coldest hours or days. These resources do not offer the flexibility of other supply sources.

Figure 7-7: Gas Sales Peaking Resources

	Withdrawal Capacity (Dth/Day)	Injection Capacity (Dth/Day)	Storage Capacity (Dth)	Transportation Tariff	Availability
Gig Harbor LNG	2,500	2,500	10,500	On-system	current
Swarr LP-Air [1, 2]	10,000	16,680	128,440	On-system	Nov. 2019+
Tacoma LNG [3]	59,500	2,000	538,000	On-system	Nov. 2019
TOTAL	**92,000**	**21,680**	**682,190**		

NOTES
1. Swarr is currently out of service, pending upgrades to reliability, safety and compliance systems, to be considered in resource acquisition analysis for an in-service date of November 2019 or later.
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.
3. Planned in-service date of Nov. 1, 2019. Withdrawal capacity will rise in the future when the distribution system is upgraded, and again when an additional 10 MDth/day will be subscribed by a third party (assumed to be available starting Nov 2021).

Gig Harbor LNG

Located in the Gig Harbor area of Washington state, this satellite LNG facility ensures sufficient supply during peak weather events for a remote but growing region of PSE's distribution system. The Gig Harbor plant receives, stores and vaporizes LNG that has been liquefied at other LNG facilities. It represents an incremental supply source and its 2.5 MDth per day capacity is therefore included in the peak day resource stack. Although the facility directly benefits only areas adjacent to the Gig Harbor plant, its operation indirectly benefits other areas in PSE's service territory since it allows gas supply from pipeline interconnects or other storage to be diverted elsewhere.

Swarr LP-Air

The Swarr LP-Air facility has a net storage capacity of 128,440 Dth natural gas equivalents and can produce the equivalent of approximately 10,000 Dth per day. Swarr is a propane-air injection facility on PSE's gas distribution system that operates as a needle-peaking facility. Propane and air are combined in a prescribed ratio to ensure the compressed mixture injected into the distribution system maintains the same heat content as natural gas. Preliminary design and engineering work necessary to upgrade the facility's environmental safety and reliability systems and increase production capacity to 30,000 Dth per day is under way. The upgrade is evaluated as a resource alternative for this IRP (see Combination #7 – Swarr), and is assumed to be available on two years' notice as early as the 2019/20 winter season. Since Swarr connects to PSE's distribution system, it requires no upstream pipeline capacity.

Tacoma LNG

PSE expects the completion of construction and successful start-up of this LNG peak-shaving facility to serve the needs of core gas customers as well as regional LNG transportation fuel consumers. By serving new LNG fuel markets (primarily large marine consumers) the project will achieve economies of scale that reduce costs for core gas customers. This project is located at the Port of Tacoma and connects to PSE's existing distribution system. The 2017 IRP assumes the project is put into service in sufficient time to be a reliable resource for the 2019/20 heating season, providing 59.5 MDth per day of capacity. The full 85 MDth per day capacity will be available with additional upgrades to the gas distribution system, which are assumed to be available (as a new resource) beginning in the 2020/21 heating season.

Existing Gas Supplies

Advances in shale drilling have expanded the economically feasible natural gas resource base and dramatically altered long-term expectations with regard to gas supplies. Not only has development of shale beds in British Columbia directly increased the availability of supplies in the West, but the east coast no longer relies so heavily on western supplies now that shale deposits in Pennsylvania and West Virginia are in production.

Within the limits of its transportation and storage network, PSE maintains a policy of sourcing gas supplies from a variety of supply basins. Avoiding concentration in one market helps to increase reliability. We can also mitigate price volatility to a certain extent; the company's capacity rights on NWP provide some flexibility to buy from the lowest-cost basin, with certain limitations based on the primary capacity rights from each basin. While PSE is heavily dependent on supplies from northern British Columbia, it also maintains pipeline capacity access to producing regions in the Rockies, the San Juan basin and Alberta.

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 or high local demands. This separation cycle can last several years, but is usually alleviated when additional pipeline infrastructure is constructed. PSE expects generally comparable pricing across regional supply basins over the 20-year planning horizon, with differentials primarily driven by differences in the cost of transportation and forecasted demand increase.

PSE has always purchased our supply at market hubs. In the Rockies and San Juan basin, there are various transportation receipt points, including Opal and Clay Basin; but alternate points, such as gathering system and upstream pipeline interconnects with NWP, allow some purchases directly from producers as well as marketers. In fact, PSE has a number of supply arrangements with major producers in the Rockies to purchase supply near the point of production. Adding upstream pipeline transportation capacity on Westcoast, TransCanada's Nova (NGTL) pipeline, TransCanada's Foothills pipeline and TransCanada's Gas Transmission NW (GTN) pipeline to the company's portfolio has increased PSE's ability to access supply nearer producing areas in Canada as well.

Gas supply contracts tend to have a shorter duration than pipeline transportation contracts, with terms to ensure supplier performance. PSE meets average loads with a mix of long-term (more than two years) and short-term (two years or less) gas supply contracts. Long-term contracts typically supply baseload needs and are delivered at a constant daily rate over the contract period. PSE also contracts for seasonal baseload firm supply, typically for the winter months November through March. Near-term transactions supplement baseload transactions, particularly for the winter months; PSE estimates average load requirements for upcoming months and enters into month-long or multi-month transactions to balance load. PSE balances daily positions using storage from Jackson Prairie and Clay Basin, day-ahead purchases and off-system sales transactions, and balances intra-day positions using Jackson Prairie. PSE continuously monitors gas markets to identify trends and opportunities to fine-tune our contracting strategies.

PSE's customer demand is highly weather dependent and therefore seasonal in nature. PSE's general policy is to maintain longer-term firm supply commitments equal to approximately 50 percent of expected seasonal demand, including assumed storage injections in summer and net of assumed storage withdrawals in winter; that percentage grows as we move closer to the delivery month and day.

Existing Demand-side Resources

PSE has provided demand-side resources to our customers since 1993.[5] These energy efficiency programs operate in accordance with requirements established as part of the stipulated settlement of PSE's 2001 General Rate Case.[6] Through 1998, the programs primarily served residential and low-income customers; in 1999 the company expanded them to include commercial and industrial customer facilities. Figure 7-8 shows that energy efficiency measures installed through 2016 have saved a cumulative total of over 5 million Dth, which equates to approximately 300,000 metric tons of CO_2 emissions – more than half of which has been achieved since 2007.

Energy savings targets and the programs to achieve those targets are established every two years. The 2014-2015 biennial program period concluded at the end of 2015. The current program cycle is January 1, 2016 through December 31, 2017. The majority of gas energy efficiency programs are funded using gas "rider" funds collected from all customers.

PSE spent over $13.5 million for natural gas conservation programs in the most recent complete program year of 2016, compared to $3.2 million in 2005. Spending over that period increased more than 25 percent annually. In the last ten, years the savings have been in the range of 3 to 4 millions of therms per year. Savings reached a peak in 2009 at just over 5 million therms. The low cost of gas and increasing cost of materials and equipment have put pressure in the cost-effectiveness of savings measures. PSE is engaged in collaborative regional efforts to find creative ways to make delivery and marketing of gas efficiency programs more cost-effective and to find ways to reduce barriers for promising measures that have not yet gained significant market share.

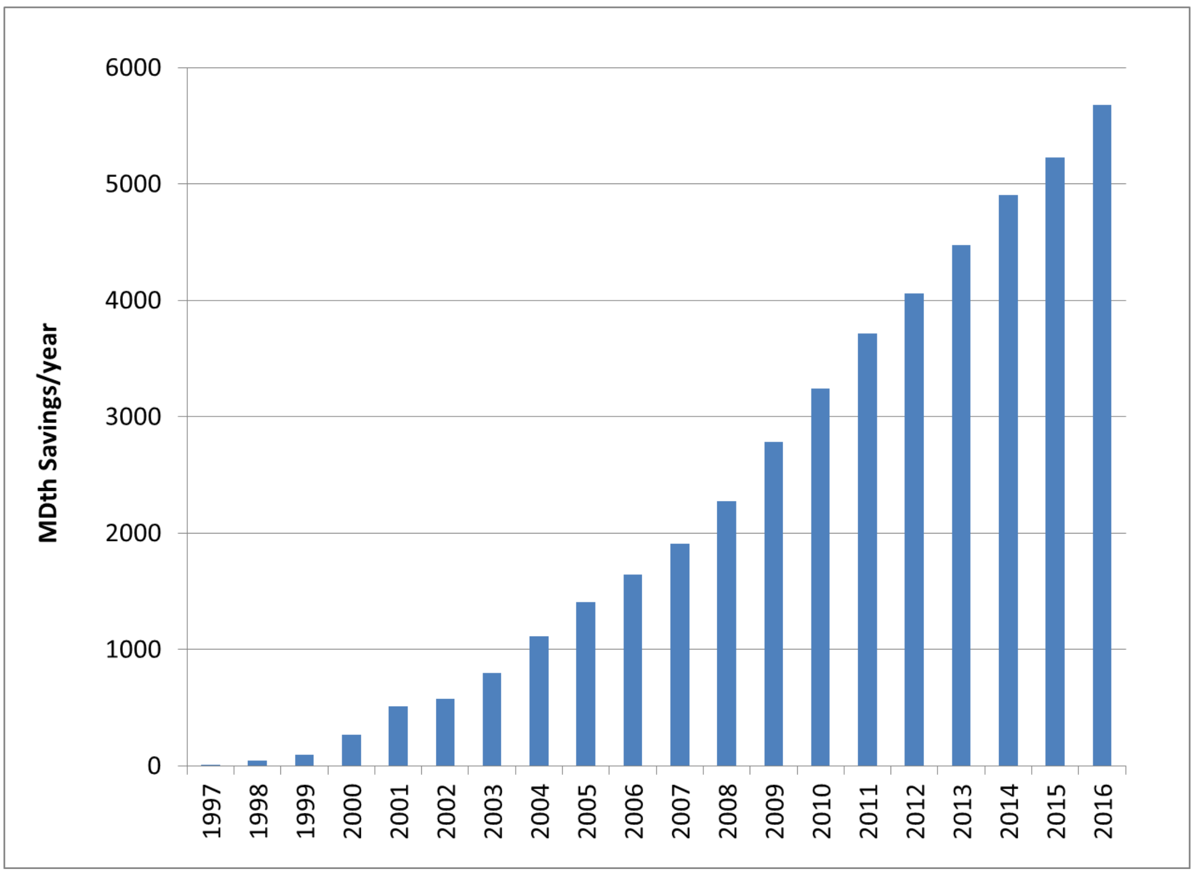
For the 2016-2017 period, PSE has a two-year target of approximately 7.4 million therms in energy savings; savings of 4,480,000 therms were achieved in 2016. This goal was based on extensive analysis of savings potentials and developed in collaboration with key external stakeholders represented by the Conservation Resource Advisory Group and Integrated Resource Plan Advisory Group. Figure 7-8 summarizes energy savings and costs for 2014 through 2016.

5 / Demand-side resources, also called conservation, are resources that are generated on the customer (demand) side of the meter.
6 / PSE's 2001 General Rate Case, WUTC Docket Nos. UG-011571 and UE-011570.

Figure 7-8: Gas Sales Energy Efficiency Program Summary, 2014 – 2016
Total Savings and Costs

Program Year	Actual Savings (Therms)	Actual Cost ($)	Target Savings (Therms)	Budget ($)
2014	4,346,000	$ 11,888,000	3,880,000	$11,927,000
2015	3,242,000	$13,094,000	3,081,000	$13,140,000
2016	4,480,000	$13,644,000	3,963,000	$14,714,000

Figure 7-9: Cumulative Gas Sales Energy Savings from DSR, 1997 – 2016



5. RESOURCE ALTERNATIVES

The gas sales resource alternatives considered in this IRP address long-term capacity challenges rather than the shorter-term optimization and portfolio management strategies PSE uses in the daily conduct of business to minimize costs.

Combinations Considered

Transporting gas from production areas or market hubs to PSE's service area generally entails assembling a number of specific pipeline segments and gas storage alternatives. Purchases from specific market hubs are joined with various upstream and direct-connect pipeline alternatives and storage options to create combinations that have different costs and benefits. Within PSE's service territory, demand-side resources are a significant resource.

In this IRP, the alternatives have been gathered into seven broad combinations for analyses. These combinations are discussed below and illustrated in Figure 7-9. Note that DSR is a separate alternative discussed later in this chapter.

The following acronyms are used in the descriptions below.

- AECO – the Alberta Energy Company trading hub
- LP-Air – liquid propane air (liquid propane is mixed with air to achieve the same heating value as natural gas)
- NWP – Northwest Pipeline
- TC-Foothills – TransCanada-Foothills Pipeline
- TC-GTN – TransCanada-Gas Transmission Northwest Pipeline
- TC-NGTL – TransCanada-NOVA Gas Transmission Pipeline
- Westcoast - Enbridge/Westcoast Energy Pipeline

Combination # 1 & 1a – NWP Additions + Westcoast

This option expands access to northern British Columbia gas at the Station 2 hub beginning Novermber 2021, with expanded transport capacity on Westcoast pipeline to Sumas and then on expanded NWP to PSE's service area. Gas supplies are also presumed available at the Sumas market hub. In order to ensure reliable access to supply and achieve diversity of pricing, PSE believes it will be necessary to acquire Westcoast capacity equivalent to 100 percent of any new NWP firm take-away capacity at Sumas.

COMBINATION #1A – NWP-TF-1. This is a short-term pipeline alternative that represents excess capacity on the existing NWP system from Sumas to PSE that could be contracted to meet PSE needs from November 2017 to October 2020 only. PSE believes that the vast majority of under-utilized firm pipeline capacity in the I-5 corridor will be absorbed by other new loads by Fall 2020. Beyond October 2020, other long-term resources would be added to serve PSE demand.

Combination # 2 – FortisBC/Westcoast (KORP)

This combination includes the Kingsvale-Oliver Reinforcement Project (KORP) pipeline proposal, which is in the development stages and sponsored by FortisBC and Westcoast. Availability is estimated beginning November 2021. Essentially, the KORP project expands and adds flexibility to the existing Southern Crossing pipeline. This option would allow delivery of Alberta (AECO hub) gas to PSE via existing or expanded capacity on the TC-NGTL and TC-Foothills pipelines, the KORP pipeline across southern British Columbia to Sumas, and then on expanded NWP capacity to PSE.

Combination # 3 – Cross Cascades - AECO

This option provides for deliveries to PSE via the prospective Cross Cascades pipeline. The increased gas supply would come from Alberta (AECO hub) via existing or new upstream pipeline capacity on the TC-NGTL, TC-Foothills and TC-GTN pipelines to Stanfield. Final delivery from Stanfield to PSE would be via the proposed Cross Cascades pipeline and a northbound upgrade to NWP. As a major greenfield project, this resource option is dependent on significant volume of additional contracting by other parties.

Combination # 4 – Cross Cascades - Malin

This option provides for deliveries to PSE via the prospective Cross Cascades pipeline. The increased gas supply would come directly from Malin or from the Rockies hub on the Ruby pipeline to Malin, with backhaul on the TC-GTN pipeline to Stanfield. Final delivery from Stanfield to PSE would be via the proposed Cross Cascades pipeline and a northbound upgrade to NWP. As a major greenfield project, this resource option is dependent on significant volume of additional contracting by other parties.

Combination # 5 – LNG-related Distribution Upgrade

This combination assumes completed construction and successful commissioning of the LNG peak-shaving facility for the 2019/20 heating season, providing 59.5 MDth per day of capacity. This option considers the timing of the contemplated upgrade to the Tacoma area distribution system, allowing an additional 16 MDth per day of vaporized LNG to reach more customers. The effect is to increase overall delivered supply to PSE customers because gas otherwise destined for the Tacoma system is displaced by vaporized LNG and delivered to other parts of the system. The incremental volume resulting from the distribution upgrade can be implemented on two years' notice starting as early as winter 2021/22.

Combination # 6 – Mist Storage and Redelivery

This option provides for PSE to lease storage capacity from NW Natural after an expansion of the Mist storage facility. Delivery of gas would require expansion of pipeline capacity from Mist to PSE's service territory for Mist storage redelivery service. The expansion of pipeline capacity from Mist to PSE will be dependent on an expansion on NWP from Sumas to Portland with significant additional volume contracting by other parties.

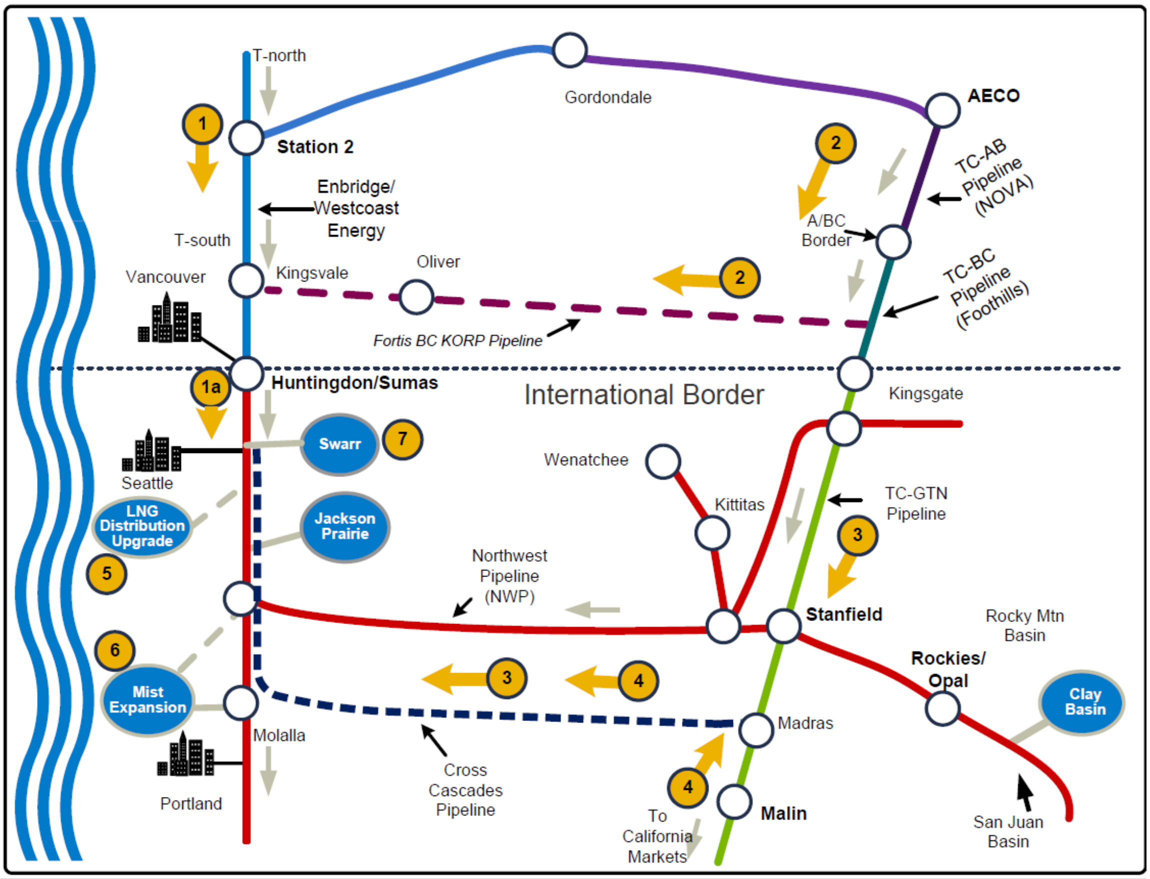
Combination # 7 – Swarr LP-Air Upgrade

This is an upgrade to the existing Swarr LP-Air facility as discussed above. This upgrade would increase the peak day planning capability from 10 MDth per day to 30 MDth per day. This plant is located within PSE's distribution network.

NOTE: Options 2, 3, 5, and 6 include new greenfield projects and would require significant participation by other customers in order to be economic.

A schematic of the gas sales resource alternatives is depicted in Figure 7-10 below.

Figure 7-10: PSE Gas Transportation Map Showing Supply Alternatives



Pipeline Capacity Alternatives

Direct-connect Pipeline Capacity Alternatives

The direct-connect pipeline alternatives considered in this IRP are summarized in Figure 7-11 below.

Figure 7-11: Direct-connect Pipeline Alternatives Analyzed

Direct-connect Pipeline Alternatives	Description
NWP - Sumas to PSE city gate *(from Combinations 1 & 2)*	Expansions considered either independently (from 2021), or in conjunction with upstream pipeline/supply expansion alternatives (KORP or additional Westcoast capacity) assumed available November 2021.
Cross Cascades – Stanfield/TC-GTN to PSE city gate *(from Combinations 3 & 4)*	Representative of costs and capacity of the proposed Cross Cascades pipeline with delivery on NWP to PSE city gate. Assumed to be available by November 2021.

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 supply purchases at the Canadian import points of Sumas and Kingsgate. For example, previous analyses led the company to acquire capacity on Westcoast (Enbridge/Westcoast Energy's B.C. pipeline), which allows PSE to purchase gas at Station 2 rather than Sumas and take advantage of greater supply availability at Station 2. Similarly, acquisition of additional upstream pipeline capacity on TransCanada's Canadian and U.S. pipelines would enable PSE to purchase gas directly from suppliers at the very liquid AECO/NIT[7] trading hub and transport it to interconnect with the proposed Cross Cascades pipeline on a firm basis. FortisBC and Westcoast have proposed the KORP, which in conjunction with additional capacity on TransCanada's Canadian pipelines, would also increase access to AECO/NIT supplies.

7 / *AECO-Nova Inventory Transfer*

Figure 7-12: Upstream Pipeline Alternatives Analyzed

Upstream Pipeline Alternatives	Description
Increase Westcoast Capacity (Station 2 to PSE) *(from Combination 1)*	Acquisition of new Westcoast capacity is considered to increase access to gas supply at Station 2 for delivery to PSE on expanded NWP capacity from Sumas.
Increase TransCanada Pipeline Capacity (AECO to Stanfield) *(from Combinations 2 & 3)*	Acquisition of new capacity on TransCanada pipelines (NGTL, Foothills and GTN), to increase deliveries of AECO/NIT gas to Stanfield for delivery to PSE city gate via the proposed Cross Cascades pipeline and a northbound upgrade of NWP.
Kingsvale-Oliver Reinforcement Project (KORP) *(from Combination 2)*	Expansion of the existing FortisBC Southern Crossing pipeline across southern B.C., enhanced delivery capacity on Westcoast from Kingsvale to Huntingdon/Sumas. This alternative would include a commensurate acquisition of new capacity on the TC-NGTL and TC-Foothills pipelines.

The KORP alternative includes PSE participation in an expansion of the existing FortisBC pipeline across southern British Columbia, which includes a cooperative arrangement with Westcoast for deliveries from Kingsvale to Huntingdon/Sumas. Acquisition of this capacity, as well as additional capacity on the TC-NGTL and TC-Foothills pipelines, would improve access to the AECO/NIT trading hub. While not inexpensive, such an alternative would increase geographic diversity and reduce reliance on British Columbia-sourced supply connected to upstream portions of Westcoast.

Storage and Peaking Capacity Alternatives

As described in the existing resources section, PSE is a one-third owner and operator of the Jackson Prairie Gas Storage Project, and PSE also contracts for capacity at the Clay Basin storage facility located in northeastern Utah. Additional pipeline capacity from Clay Basin is not available and storage expansion is not under consideration. Expanding storage capacity at Jackson Prairie is not analyzed in this IRP although it may prove feasible in the long run. For this IRP, the company considered the following storage alternatives.

LNG-related Distribution System Upgrade

This option considers the timing of the contemplated upgrade to the Tacoma area distribution system, allowing an additional 16 MDth per day of vaporized LNG to reach more customers. The effect is to increase overall delivered supply to PSE customers because gas otherwise destined for the Tacoma system is displaced by vaporized LNG and delivered to other parts of the system. The incremental volume resulting from the distribution upgrade can be implemented on two years' notice starting as early as winter 2021/22.

Mist Expansion

NW Natural Gas Company, the owner and operator of the Mist underground storage facility near Portland, Ore., would consider a potential expansion project to be completed in 2021/22. PSE is assessing the cost-effectiveness of leasing storage capacity beginning November 2021, once the Mist upgrade is built. This would also require expansion of NWP's interstate system to PSE's city gate. PSE may be able to acquire discounted winter-only capacity from Mist to PSE's city gate if NWP expands from Sumas to Portland for other shippers, making the use of Mist storage cost-effective. Since this resource is dependent on other parties willingness to contract for an expansion, this resource availability is not in PSE's control.

Swarr

The Swarr LP-Air facility is discussed above under "Existing Peaking Supply and Capacity Resources." This resource alternative is being evaluated as PSE is in the preliminary stages of upgrading Swarr's environmental safety and reliability systems and increasing production capacity to 30,000 Dth per day. The facility is assumed to be available on two years' notice for the 2019/20 heating season or beyond.

Figure 7-13: Storage Alternatives Analyzed

Storage Alternatives	Description
Distribution upgrade allowing greater utilization of Tacoma LNG *(Combination 4)*	Considers the timing of the planned upgrade to PSE's Tacoma area distribution system allowing an incremental 16 MDth/day of LNG pea-shaving beginning the 2021-22 heating season.
Expansion of Mist Storage Facility *(Combination 6)*	Considers the acquisition of expanded Mist storage capacity, based on estimated cost and operational characteristics. Assumes a 20-day supply at full deliverability of up to 100 MDth/day beginning the 2021-22 heating season.
Swarr LP-Air Facility Upgrade *(Combination 7)*	Considers the timing of the planned upgrade for reliability and increased capacity (from 10 MDth/day to 30 MDth/day) beginning the 2019-20 heating season.

Gas Supply Alternatives

As described earlier, gas supply and production are expected to continue to expand in both northern British Columbia and the Rockies production areas as shale and tight gas formations are developed using horizontal drilling and fracturing methods. With the expansion of supplies from shale gas and other unconventional sources at existing market hubs, PSE anticipates that adequate gas supplies will be available to support pipeline expansion from northern British Columbia or from the Rockies basin.

Additional cost and capacity data for all of the supply-side resource alternatives is presented in Appendix O, Gas Analysis.

Demand-side Resource Alternatives

To develop demand-side alternatives for use in the portfolio analysis, PSE first conducts a conservation potential assessment. This study reviews existing and projected building stock and end-use technology saturations to estimate the savings possible through installation of more efficient commercially available technologies. The broadest measure of savings from making these installations (or replacing old technology) is called the technical potential; this represents the total unconstrained savings that could be achieved without considering economic (cost-effectiveness) or market constraints.

The next level of savings is called *achievable* technical potential. This step reduces the unconstrained savings to levels considered achievable when accounting for market barriers. In this IRP, the achievability factors were changed from 75 percent to 85 percent to be consistent with the electric measures. Also, all gas measures were given a 10 percent conservation credit similar to the 10 percent conservation credit electric measures receive stemming from the Power Act of 1980. The measures are then organized into a conservation supply curve, from lowest to highest levelized cost.

Next, individual measures on the supply curve are grouped into cost segments called “bundles.” For example, all measures that have a levelized cost of between $2.2 per Dth and $3.0 per Dth may be grouped into a bundle and labeled “Bundle 2.” The Codes and Standards bundle has zero cost associated with it because savings from this bundle accrue due to new codes or standards that have been passed but that take effect at a future date. This bundle is always selected in the portfolio, where it effectively represents a reduction in the load forecast.

Figure 7-14 shows the twelve price bundles that were developed for this IRP. One uses the weighted average cost of capital (WACC) assigned to PSE and the other uses the alternate discount rate developed for the discount rate sensitivity analysis.

PSE currently seeks to acquire as much cost-effective gas demand-side resources as quickly as possible. The acquisition or “ramp rate” of gas sales DSR can be altered by changing the speed with which discretionary DSR measures are acquired. In these bundles, the discretionary measures are assumed to be acquired in the first 10 years; this is called a 10-year ramp rate. Acquiring these measures sooner rather than later has been tested in prior IRPs and has consistently been found to reduce portfolio costs. Ten years is chosen because it aligns with the amount of savings that can practically be acquired at the program implementation level.

Figure 7-14: DSR Cost Bundles and Savings Volumes (MDth/year)

	WACC		Alternate Discount	
	2027	2037	2027	2037
Codes & Standards	1,175	2,705	1,175	2,705
Bundle 1: <$0.22	657	961	519	710
Bundle 2: $0.22 to$0.30	721	1,125	721	1,125
Bundle 3: $0.30 to $0.45	1,183	1,879	1,202	1,902
Bundle 4: $0.45 to $0.55	1,298	2,086	1,299	2,089
Bundle 5: $0.55 to $0.70	1,513	2,458	1,514	2,462
Bundle 6: $0.70 to $0.85	1,610	2,657	2,913	5,218
Bundle 7: $0.85 to $0.95	1,697	2,750	2,918	5,233
Bundle 8: $0.95 to $1.20	2,995	5,424	4,280	7,122
Bundle 9: $1.20 to $1.50	3,733	6,536	4,625	7,604
Bundle 10: $1.50 to $2.00	4,843	7,994	5,033	8,180
Bundle 11: >$2.00	10,959	16,151	10,933	16,107

More detail on the measures, assumptions and methodology used to develop DSR potentials can be found in Appendix J, Conservation Potential Assessment.

In the final step, the gas portfolio model (GPM) was used to test the optimal level of demand-side resources in each scenario. To format the inputs for the GPM analysis, the cost bundles were further subdivided by market sector and weather/non-weather sensitive measures. Increasingly expensive bundles were added to each scenario until the GPM rejected bundles as not cost effective. The bundle that reduced the portfolio cost the most was deemed the appropriate level of demand-side resources for that scenario. Figure 7-15 illustrates the methodology described above.

Figure 7-15: General Methodology for Assessing Demand-side Resource Potential

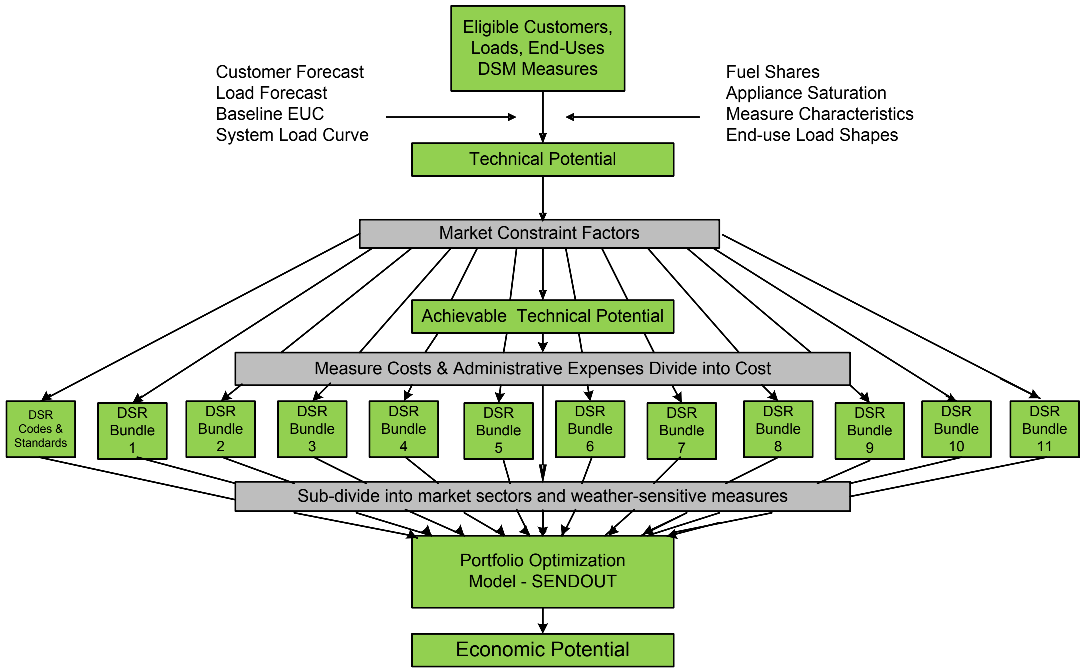


Figure 7-16 shows the range of achievable technical potential among the twelve cost bundles used in the GPM. It selects an optimal combination of each bundle in every customer class to determine the overall optimal level of demand-side gas resource for a particular scenario.

Figure 7-16: Demand-side Resources – Achievable Technical Potential Bundles

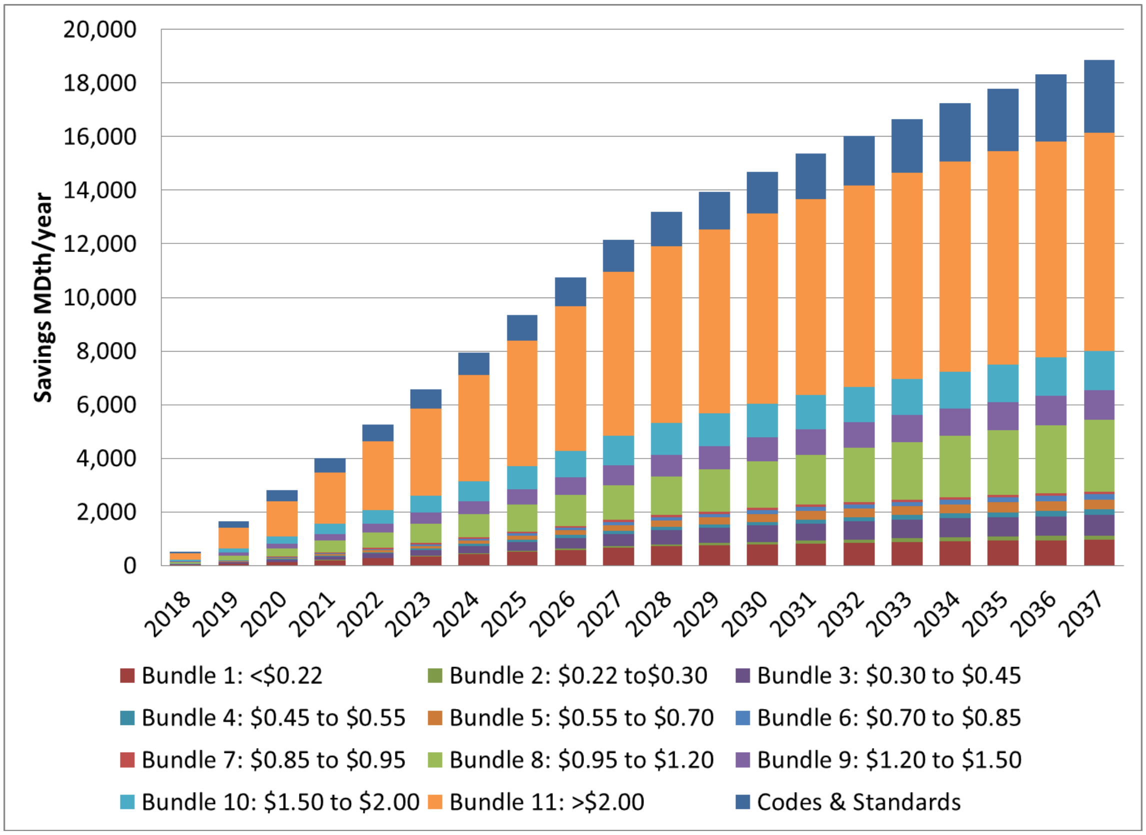
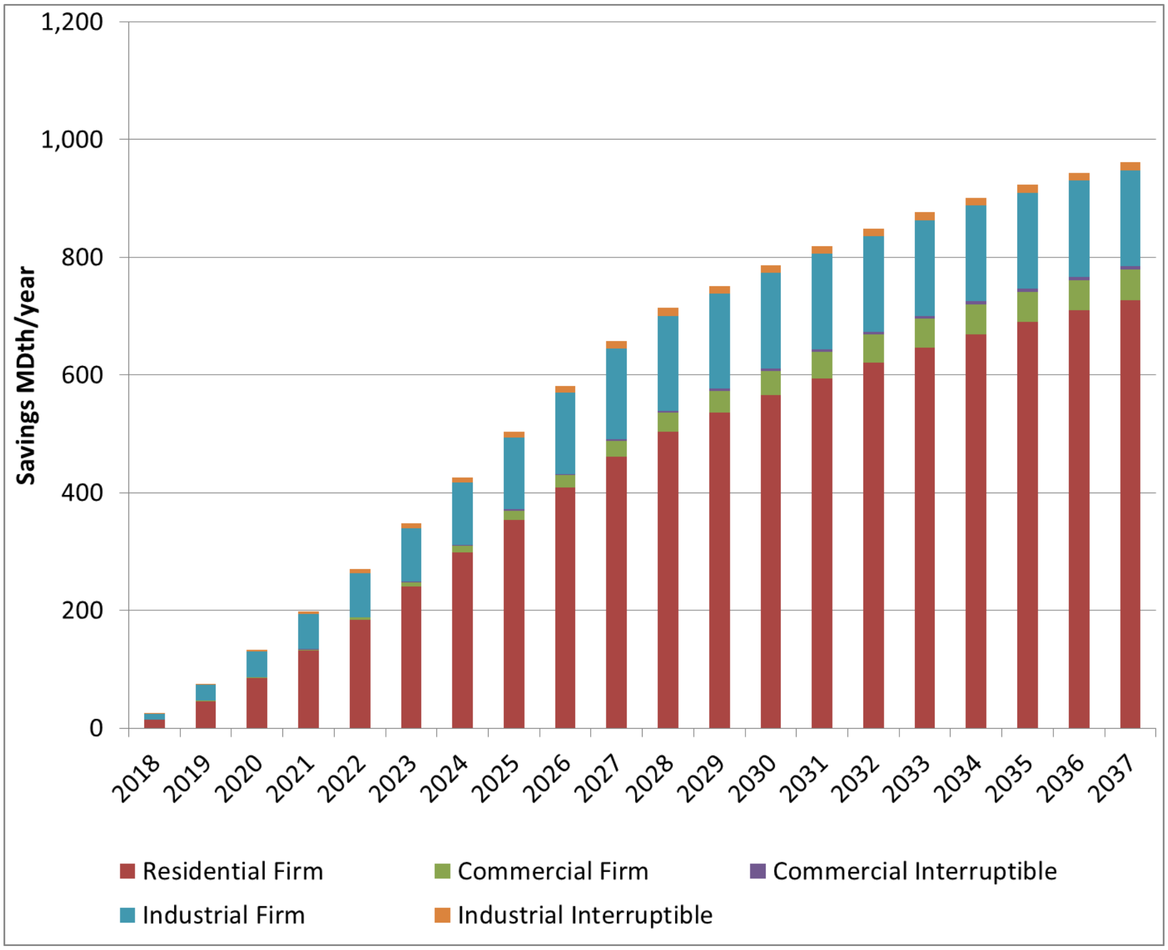


Figure 7-17 shows a sample input format subdivided by customer class for Bundle 1 (<$2.20 per Dth) used in the GPM for all the IRP scenarios.

Figure 7-17: Savings Formatted for Portfolio Model Input by Customer Class – Bundle 1 (< $2.20/Dth)



6. GAS SALES ANALYSIS RESULTS

Key Findings

The key findings from this analytical and statistical evaluation will provide guidance for development of PSE's long-term resource strategy, and also provide background information for resource development activities over the next two years.

1. **In the Base Scenario, the gas sales portfolio is short resources for the winter of 2018/19 and each year beginning the winter of 2022/23.** The High Scenario shows a current and growing resource shortfall, while in the Low Scenario the gas sales portfolio is surplus until the winter of 2035/36.
2. **Immediate short-term need will be met with combination of two resources in the Base Scenario: demand-side resources and a short-term contract for firm pipeline capacity from Sumas to PSE.** In the High Scenario the short-term pipeline contract along with immediate implementation of the Swarr LP-Air facility upgrade and the LNG related distribution upgrade will still leave PSE short until new pipeline capacity can be built for winter 2021/22.
3. **Cost-effective DSR is slightly lower in the 2017 IRP.** The cost-effective bundle is slightly lower on the supply curve compared to the 2015 IRP. The decrease is due to two more years of conservation implementation since the last IRP, a lower demand forecast and updated measure savings and costs. Offsetting these factors was the change in the achievability factor from 75 percent to 85 percent. The result is a slightly lower amount of cost-effective DSR.
4. **The Swarr LP-Air upgrade project is cost effective in all but low demand scenarios** and is expected to provide 30 MDth per day of peaking capacity effective November 2024.
5. **The Tacoma area distribution system upgrade project is cost effective in all scenarios,** allowing Tacoma LNG to reach its full peaking capacity of 85,000 Dth per day starting the winter of 2027/28.
6. **Increased Northwest Pipeline and Westcoast capacity from Station 2 is the favored pipeline alternative in most scenarios.** The GPM indicates this pipeline capacity is more cost effective as early as 2020/21 in some scenarios and by 2029/30 in most scenarios. While potentially less expensive with greater participation, this capacity does not require participation by other parties. The pipeline alternatives to purchase gas at Malin or AECO and deliver it to PSE's city gate via the TC-GTN pipeline across the proposed Cross Cascades pipeline is chosen only in high demand scenarios by winter 2023/24.

7. **Neither the Mist storage expansion or the Fortis BC KORP project are selected in any scenario.** These options required significant demand by third parties or reliance on other projects, and like the Cross Cascades pipeline project, the feasibility and timing is outside of PSE control.
8. **The carbon cost assumption was significantly higher in the 2017 IRP compared to the 2015 IRP, and this impacted resource choices.** The levelized cost of carbon was almost the same as the levelized gas price in the mid case. We can see that in the Base + No CO_2 Scenario, a lower amount of DSR was cost effective, it was the lowest of the scenarios.

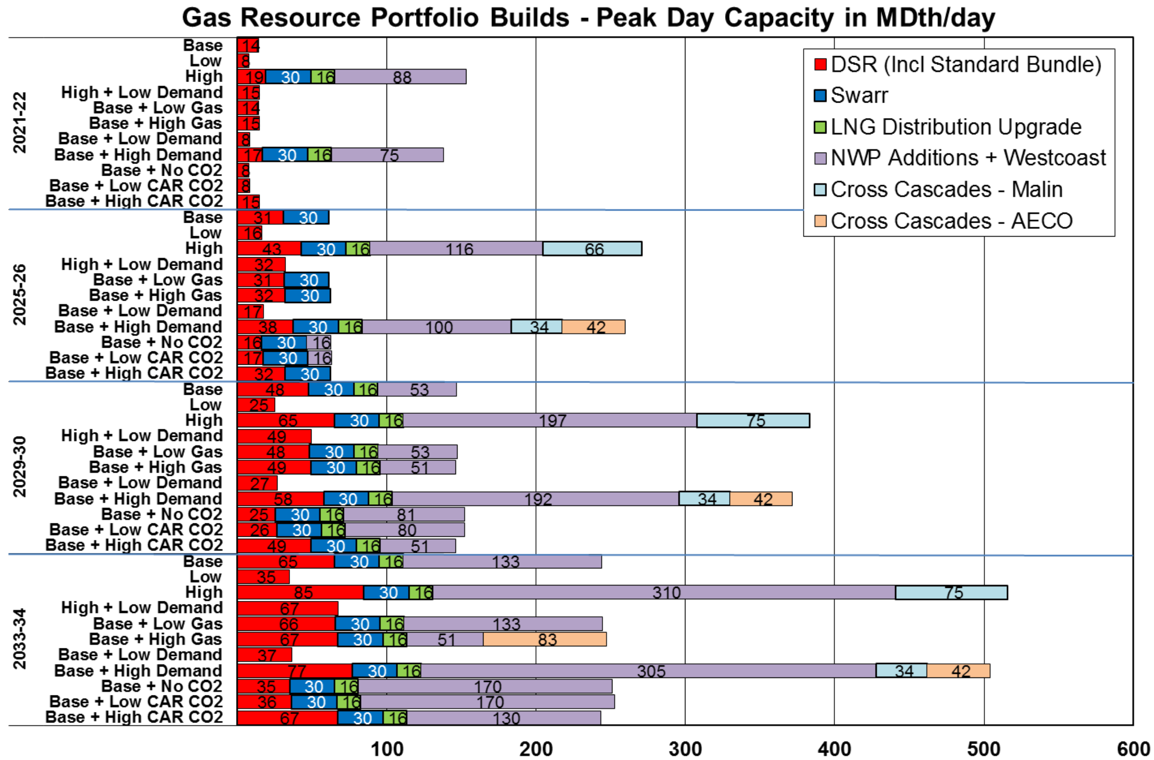
Gas Sales Portfolio Resource Additions Forecast

Differences in resource additions were driven primarily by three key variables modeled in the scenarios: load growth, gas prices and CO_2 price assumptions. Demand-side resources are influenced directly by gas and CO_2 price assumptions because they avoid commodity and emissions costs by their nature; however, the absolute level of efficiency programs is also affected by load growth assumptions. Also, the timing of pipeline additions was limited to four-year increments, because of the size that these projects require to achieve economies of scale.

The optimal portfolio resource additions in each of the eleven scenarios[8] are illustrated in Figure 7-18 for winter periods 2018/19, 2022/23 and 2030/31. Combination #3, Cross Cascades – AECO, and Combination #4, Cross Cascades – Malin, are chosen only in high demand and high gas scenarios.

8 / *Scenarios are explained in detail Chapter 4, Key Analytical Assumptions.*

Figure 7-18: Gas Resource Additions in 2021/22, 2025/26, 2029/30 and 2033/34
(Peak Capacity – MDth/day)



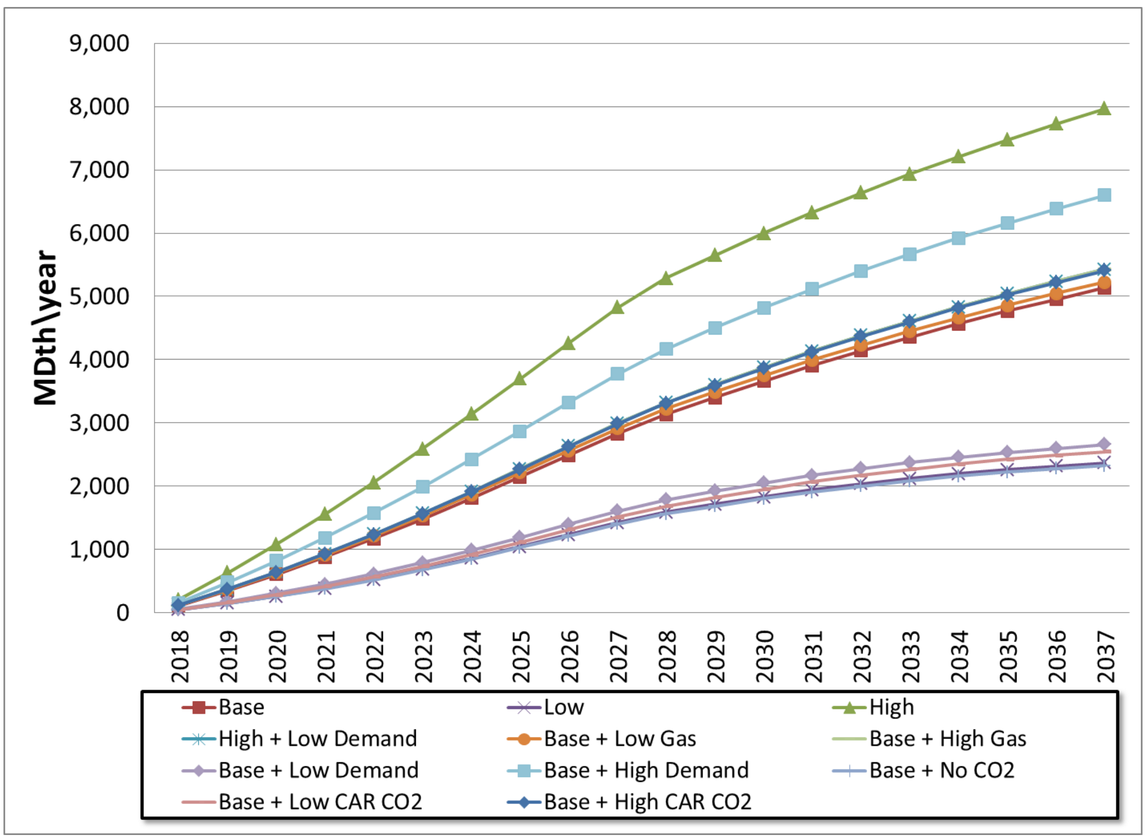
Demand-side Resource Additions

Two categories of demand-side resources are input in to the GPM: codes and standards and program measures. Codes and standards is a no-cost bundle that becomes a must-take resource; it essentially functions as a decrement to gas demand. Program measures are input as separate cost bundles along the demand-side resource supply curve. The bundles are tested from lowest to highest cost along the supply curve until the system cost is minimized. The incremental bundle that raises the portfolio cost is considered the inflexion point, and the prior cost bundle is determined to be the cost-effective level of demand-side resources.

Carbon costs do impact the amount of cost-effective DSR. Compared to the 2015 IRP, the 2017 IRP carbon costs in the Base Scenario are significantly higher relative to gas prices, which is a function of both declining gas prices and higher carbon cost assumptions. Carbon costs are almost as much as the gas prices in the mid-scenarios.

The sensitivity of DSR to carbon prices is illustrated in Figure 7-19. In the Base Scenario, which includes a CO_2 price, cost-effective DSR is 14 MDth per day by 2021/22, while in the Base + No CO_2 Scenario, the DSR level falls to 8 MDth per day. In terms of gas supply planning, 6 MDth per day is not a significant volume; however, it does highlight that including a CO_2 price in the IRP Base Scenario increases conservation. In the 2017 IRP scenarios that model high carbon price assumptions, cost-effective DSR increases by 75 percent in the 2021/22 winter period.

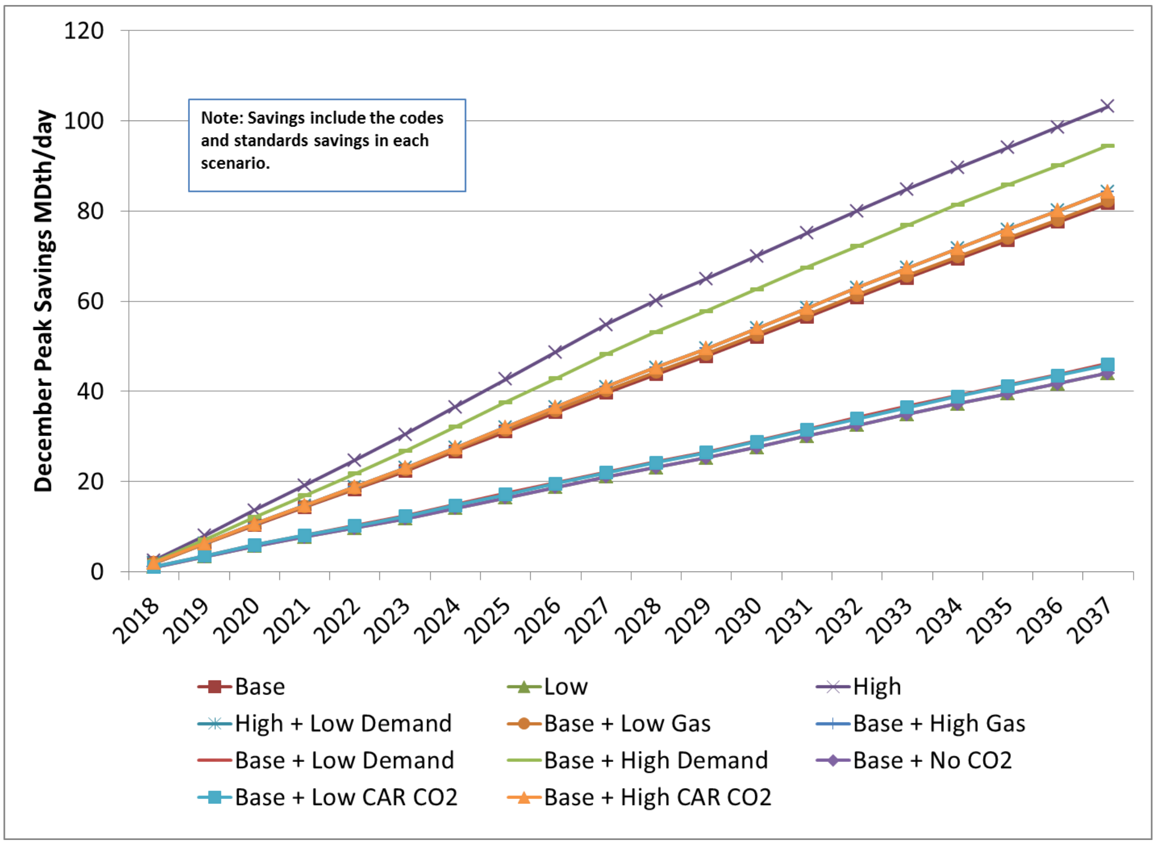
Figure 7-19: Cost-effective Gas Energy Efficiency Savings by Scenario



DSR remains relatively sensitive to avoided costs in the gas analysis. The amount of achievable energy efficiency resources selected by the portfolio analysis in this resource plan forecast ranged from roughly 3,800 MDth in 2037 for the Low Scenario to nearly 50 percent higher at 5,700 MDth in 2037 in the High Scenario.

Peak savings by scenario are shown in Figure 7-20.

Figure 7-20: Cost-Effective Gas Efficiency, Peak Day Savings by Scenario



The optimal levels of demand-side resources selected by customer class in the portfolio analysis are shown in Figures 7-21 and 7-22, below. More detail on this analysis is presented in Appendix J, Conservation Potential Assessment.

Figure 7-21: Gas Sales Cost-effective DSR Bundles by Class and Scenario

Bundles	Base	Low	High	High + Low Demand	Base + Low Gas	Base + High Gas	Base + Low Demand	Base + High Demand	Base + No CO2	Base + Low CO2	Base + High CO2
Residential Firm	5 + 8	4	10	8	8	8	5	9	4	4	8
Commercial Firm	6	5	10	8	6	8	6	10	5	6	8
Commercial Interruptible	6	5	8	8	6	8	6	6	3	5	7
Industrial Firm	3	3	3	3	3	3	3	3	3	3	3
Industrial Interruptible	3	3	3	3	3	3	3	3	3	3	3

Figure 7-22: Gas Sales Cost-effective Annual Savings by Class and Scenario

Savings (MDth/year)	Base	Low	High	High + Low Demand	Base + Low Gas	Base + High Gas	Base + Low Demand	Base + High Demand	Base + No CO2	Base + Low CO2	Base + High CO2
Residential Firm	3,346	776	5,690	3,436	3,436	3,436	867	4,343	776	1,388	3,436
Commercial Firm	1,463	1,101	1,750	1,282	1,460	1,463	1,282	1,750	1,101	1,282	1,463
Commercial Interruptible	126	108	143	108	126	143	126	126	19	108	127
Industrial Firm	353	353	353	353	353	353	353	353	353	353	353
Industrial Interruptible	29	29	29	29	29	29	29	29	29	29	29

Overall, the economic potential of DSR in this IRP is slightly lower than in the 2015 gas sales Base Scenario, and slightly lower-cost bundles are being selected by the analysis as the most cost-effective level of DSR (see Figure 7-23 below).

The downward shift in the overall savings is due to several factors.

- Past program accomplishments have lowered future achievable potentials.
- Updates to the measure costs and savings.
- Building stock data has been updated using the Commercial Building Stock Assessment.
- A lower demand forecast in the 2017 IRP.

On the other hand, inclusion of a higher CO_2 price in the Base Scenario increased conservation, because it made the overall levelized cost of gas in the 2017 IRP Base Scenario comparable to the 2015 IRP Base Scenario, even though the underlying gas commodity prices had declined. For more information on how gas sales DSR differs in the 2017 IRP vs. the 2015 IRP, see Appendix J, Conservation Potential Asessment.

Figure 7-23: Cost-effective Gas Energy Efficiency Savings, 2015 IRP vs 2017 IRP

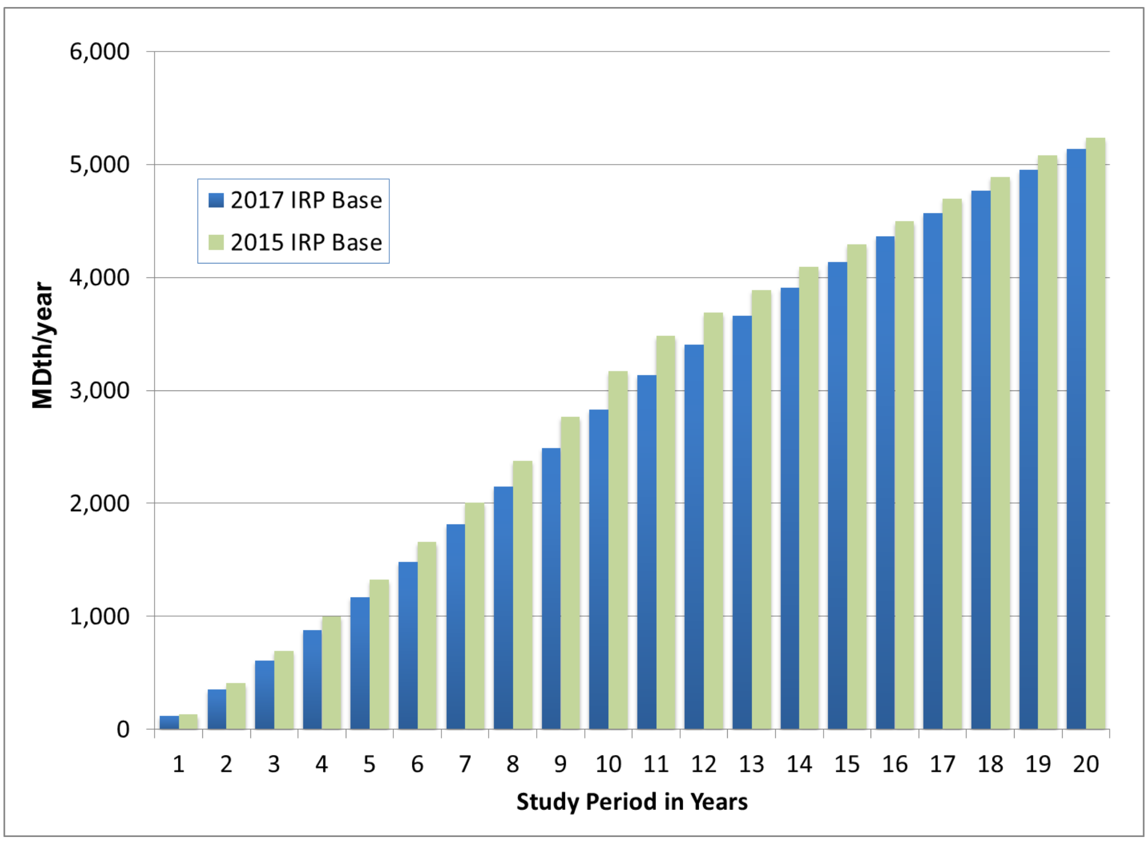


Figure 7-24 below compares PSE's energy efficiency accomplishments, current targets and the new range of gas efficiency potentials as determined by the analysis. In the short term, the 2017 IRP indicates an economic potential savings of 397 to 618 MDth for the 2016-2017 period.[9] The

9 / These savings are based on a no-intra year ramping, which are used to set conservation program targets.

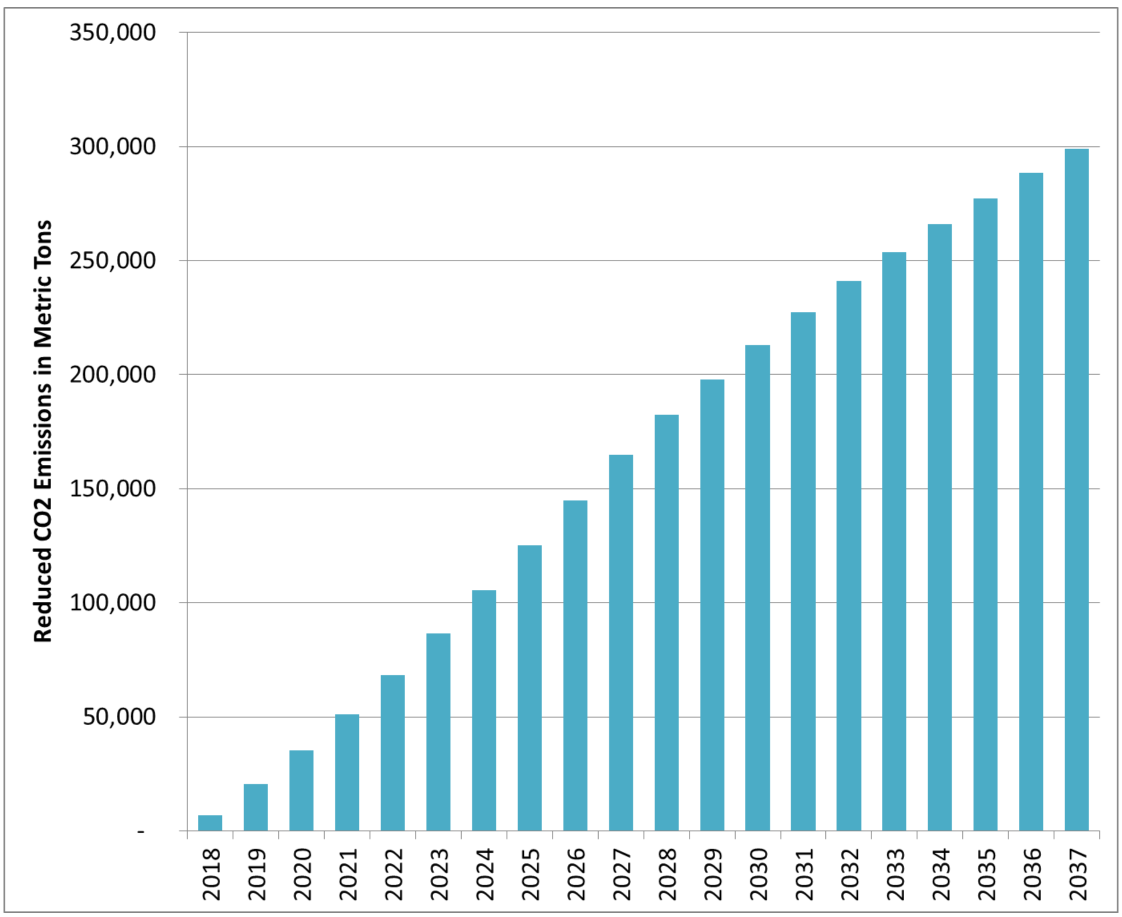
694 MDth target for the current 2016-2017 period is higher than this range. These two-year program accomplishments and projections show a downward trend for the reasons discussed above.

Figure 7-24: Short-term Comparison of Gas Energy Efficiency in MDth

Short-term Comparison of Gas Energy Efficiency	Dth over 2-year program
2014-2015 Actual Achievement	759
2016-2017 Target (updated January 2017)	801
2018-2019 Range of Economic Potential	147-633

Figure 7-25 shows the impact on CO_2 emissions from energy efficiency measures selected in the Base Scenario.

Figure 7-25: CO_2 Emissions Reduction from Energy Efficiency in Base Scenario



Peaking Resource Additions

The Swarr LP-Air upgrade project was selected as least cost (and as the first long-term resource) in all but the low demand scenarios, preceding the Tacoma LNG-related distribution upgrade by two to three years.

Distribution Upgrade Related to Tacoma LNG Project

PSE is in the construction phase of this small-scale natural gas liquefaction and LNG storage facility located within its service territory, which will serve the peaking needs of PSE's core gas customers and the growing demand for LNG as a marine and vehicle transportation fuel. The Tacoma LNG Project was found to be cost effective in every scenario of the 2015 IRP, however, with the revised load forecast, the full 85 MDth per day of LNG is not required initially. In the 2017 IRP, Tacoma LNG is modeled as an existing resource of 59.5 MDth per day beginning in 2019/20, growing to 69 MDth per day by 2021/22. PSE studied the optional resource of a planned upgrade to the distribution system that would allow the plant to deliver the full 85 MDth per day. The GPM selected the distribution upgrade to be effective in 2029/30 or earlier in all but the low demand scenarios.

Pipeline Additions

Pipeline expansion alternatives were made available as early as the 2018/19 winter season, the same time that the other non-pipeline alternatives were made available. Though this timeline is too short for any realistic pipeline expansion, it allowed PSE to ensure that the other resources were selected on their own merits as least cost. A short-term, firm pipeline contract was also included as an alternative. That contract would transport gas from Sumas to PSE as a bridge contract from November 2018 through October 2019, when Tacoma LNG will be on line.

The Sumas to PSE 2018-2019 short-term contract was selected in most scenarios. Based on lower costs, in most scenarios the GPM chose some of the NWP and Westcoast pipeline expansion to purchase gas from Station 2 as cost effective by 2029/30, after the peaking resources, increasing the capacities in subsequent years.

The Cross Cascades projects which source gas from either Malin or AECO through Stanfield across the proposed Cross Cascades pipeline were selected only in high demand scenarios as early as 2022/23. The NWP + KORP pipeline alternative was more expensive and not chosen in any scenario.

Storage Additions

The Mist storage expansion was not selected in any scenario.

Observation

All of the selected resources (listed here in general order of least cost) – DSM, Swarr LP-Air, Tacoma LNG-related distribution upgrade and Northwest + Westcoast Pipeline expansion – are within PSE's control. The timing of individual projects can be fine-tuned by PSE in response to load growth, and none of these projects rely on participation by any other contracting party to be feasibly implemented.

Complete Picture: Gas Sales Base Scenario

A complete picture of the Gas Sales Base Scenario optimal resource portfolio is presented in graphical and table format in Figures 7-26 and 7-27, respectively. Note that Combination #2, Fortis BC/Westcoast (KORP), was not chosen in any of the years. Again, additional scenario results are included in Appendix O, Gas Analysis.

Figure 7-26: Gas Sales Base Scenario Resource Portfolio

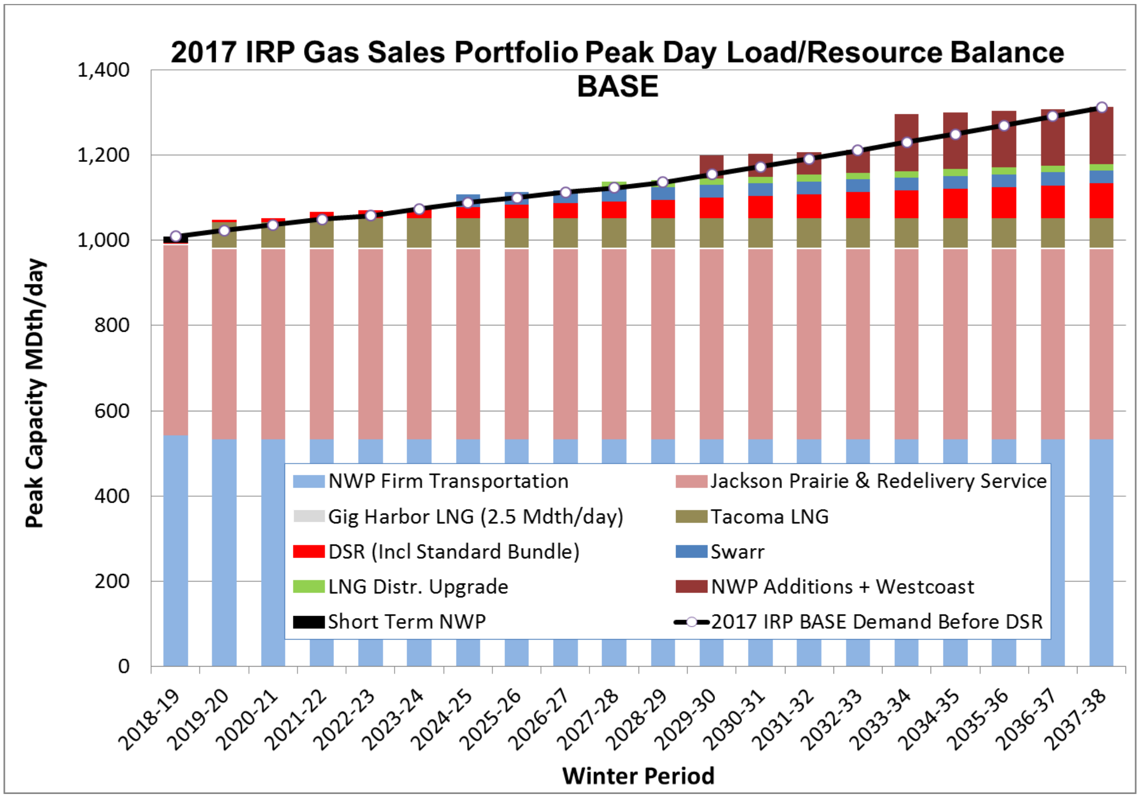


Figure 7-27: Gas Sales Base Scenario Resource Portfolio (table)

Base Scenario – MDth/day	2021-22	2025-26	2029-30	2033-34	2037-38
Demand-Side Resources	14	31	48	65	82
7- Swarr Propane-Air Upgrade	-	30	30	30	30
5- LNG Distribution Upgrade	-	-	16	16	16
1- NWP/Westcoast Expansion	-	-	53	133	133
3- Cross-Cascades from Malin Expansion	-	-	-	-	-
4- Cross-Cascades from AECO Expansion	-	-	-	-	-
6- Mist Storage/ NWP Expansion	-	-	-	-	-
2- NWP/KORP Expansion	-	-	-	-	-
Total	14	61	147	244	261

Average Annual Portfolio Cost Comparisons

Figure 7-28 should be read with the awareness that its value is comparative rather than absolute. It is not a projection of average purchased gas adjustment (PGA) rates; instead, costs are based on a theoretical construct of highly incrementalized resource availability. Also, average portfolio costs include items that are not included in the PGA. These include forecast rate-base costs related to Jackson Prairie storage, the PSE LNG Project and Swarr LP-Air, as well as costs for energy efficiency programs, which are included on an average levelized basis rather than a projected cash flow basis. Also, note that the perfect foresight of a linear programming model creates theoretical results that cannot be achieved in the real world.

Figure 7-28: Average Portfolio Cost of Gas for Gas Sales Scenarios

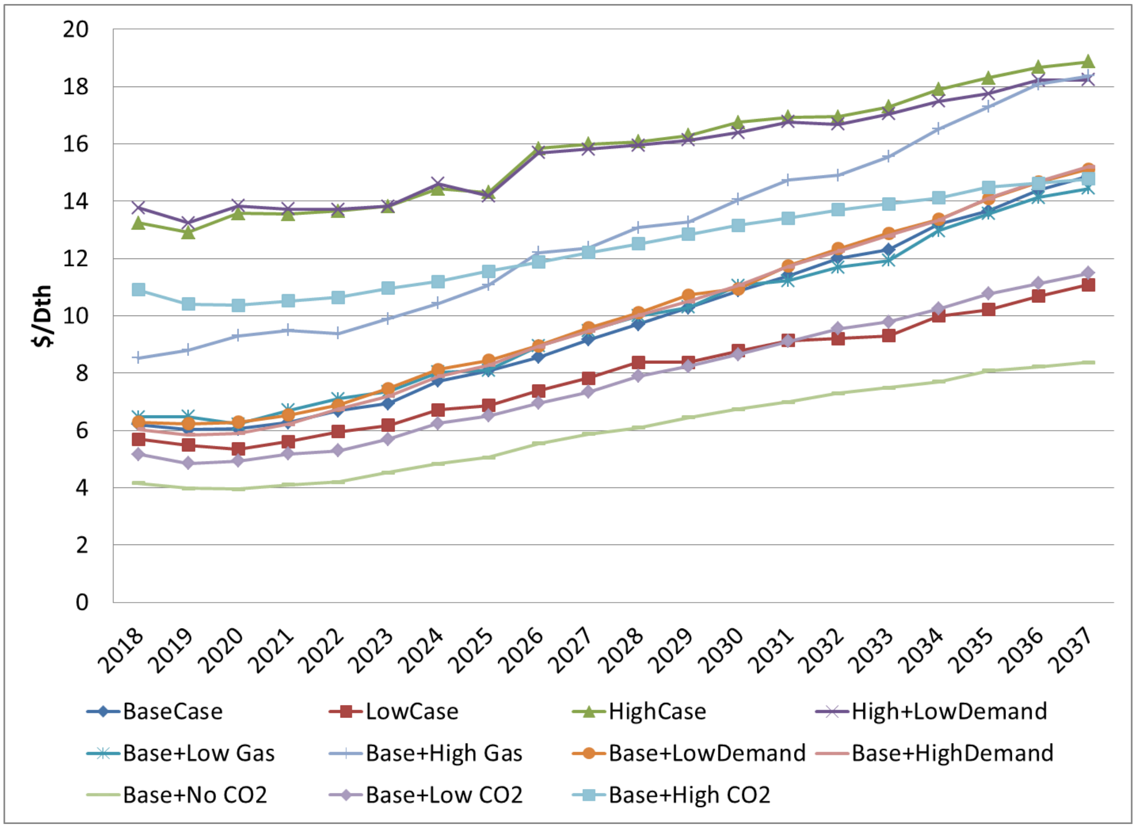


Figure 7-28 shows that average optimized portfolio costs are heavily impacted by the gas prices and CO_2 cost assumptions included in each scenario.

- Changes in customer demand cause only minimal changes in average portfolio costs as shown by the similarity of average portfolio costs in the Base, Base + Low Demand and Base + Low Gas scenarios.
- Scenario costs range from \$4.16 to \$13.23 per Dth in 2018 to \$8.37 to \$18.87 per Dth in 2037.
- The Base Scenario portfolio costs are about \$6.2 per Dth in 2018, increasing to about \$14.90 per Dth by 2037.
- The highest average system cost was in the High Scenario, which ranged from \$13.23 per Dth in 2018 to \$18.87 per Dth in 2037. The High Scenario included high CO_2 costs; this helped it track closely to the Base + Very High Gas Price Scenario which included mid CO_2 costs.
- The lowest average portfolio cost was in the Base + No CO_2 Scenario, which ranged from \$4.16 per Dth in 2018 to \$8.87 per Dth in 2037. This is because this scenario had the lowest gas plus CO_2 price assumptions. The results show that the relatively high CO_2 cost compared to the gas price has a significant impact on system costs.

Sensitivity Analyses

Four sensitivities were modeled in the gas sales analysis for this IRP. Sensitivities start with the Base Scenario portfolio and change one resource. This allows PSE to evaluate the impact of a single resource change on the portfolio.

1. DEMAND-SIDE RESOURCES
BASELINE: All cost-effective DSR per RCW 19.285 requirements.
SENSITIVITY > No DSR, all future resource needs are met in with supply-side resources.

2. ALTERNATE RESIDENTIAL CONSERVATION DISCOUNT RATE
BASELINE: All demand-side resources are evaluated using the weighted average cost of capital (WACC) assigned to PSE.
SENSITIVITY > Evaluate residential DSR using an alternate discount rate. The WACC is still applied to commercial and industrial energy efficiency measures.

3. RESOURCE ADDITION TIMING OPTIMIZATION
BASELINE: Swarr LP-Air and the LNG distribution system upgrade are built starting in 2019 and 2021 respectively, and offered every two years in the model.
SENSITIVITY > Swarr and the LNG distribution system upgrade are allowed every year starting in 2019 and 2021 respectively.

4. ADDITIONAL GAS CONSERVATION
BASELINE: All cost-effective DSR per RCW 19.285 requirements.
SENSITIVITY: Add two more demand-side bundles above the cost-effective demand-side bundles.

Demand-side Resources

In the Base Scenario the portfolio model assumes all cost-effective DSR per RCW 19.285 requirements. The portfolio model is then run a second time with demand-side resource alternatives removed as an option, and the model meets need with only supply-side resource alternatives. The results show that portfolio costs are significantly lower in the Base Scenario where demand-side resources are offered and are selected to optimize the portfolio. The net present value of the portfolio with demand-side resources is lower by about $360 million.

Alternate Residential Conservation Discount Rate Sensitivity

An alternate discount rate was applied to the demand-side resource alternative in this sensitivity analysis (one that was lower than PSE's assigned WACC) to find out if it would result in a higher level of cost-effective DSR. The alternate discount rate was modeled as 1) the 3-month average of a long-term 30-year nominal treasury rate for residential customer class,[10] and 2) the WACC discount rate for the commercial and industrial customer classes. The treasury rate used for developing the residential bundles was 2.94 percent. The impact was to shift measures to the lower cost point on the conservation supply curve.

This alternate discount rate was used to estimate the achievable DSR potential for the new DSR bundles (see Figure 7-14). These "alternate discount rate" bundles were then input into the gas portfolio model to obtain the cost-effective level of DSR.

The residential bundles chosen with the alternate discount rate were at a lower point on the supply curve for the residential class, and they remained unchanged for the commercial class of customers. The net effect was that cost-effective savings from residential customers was slightly higher. This impact was muted due to the "lumpiness" of the supply curve. The Base Scenario bundle had a significant jump in savings in Bundle 8, and when the alternate discount rate was used to redevelop the supply curve, the large savings shifted to lower point on the supply curve and moved to Bundle 6. This resulted in the model selecting Bundle 6, since it was likely able to satisfy the resource need with lower cost and a higher amount of conservation. In Bundle 6, cost-effective savings in the commercial and industrial bundles was the same as in the Base Scenario, as these bundles were not affected by the discount rate.

See Figure 7-29 for the residential customer DSR savings comparison.

There are slightly more measures – in particular in the residential bundles – since the lower discount rate shifted some of the measures on the margin to the lower cost bundles. Thus the overall cost-effective level of DSR increased slightly by the end of the twentieth year (see Figure 7-30). While the choice of the appropriate discount rate by customer class is still a topic of discussion, a lower discount rate increases the amount of cost-effective DSR, as expected. However, in a real program-level evaluation, such an increase in the level of savings will also impact acquisition costs. Higher administrative costs would need to be reflected in the assumptions, and then the bundles would need to be re-optimized.

10 / Source: https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yieldYear&year=2017

Figure 7-29: Cost-effective Level of Gas DSR for Residential Customer Class, Base vs. Alternate Discount Rate

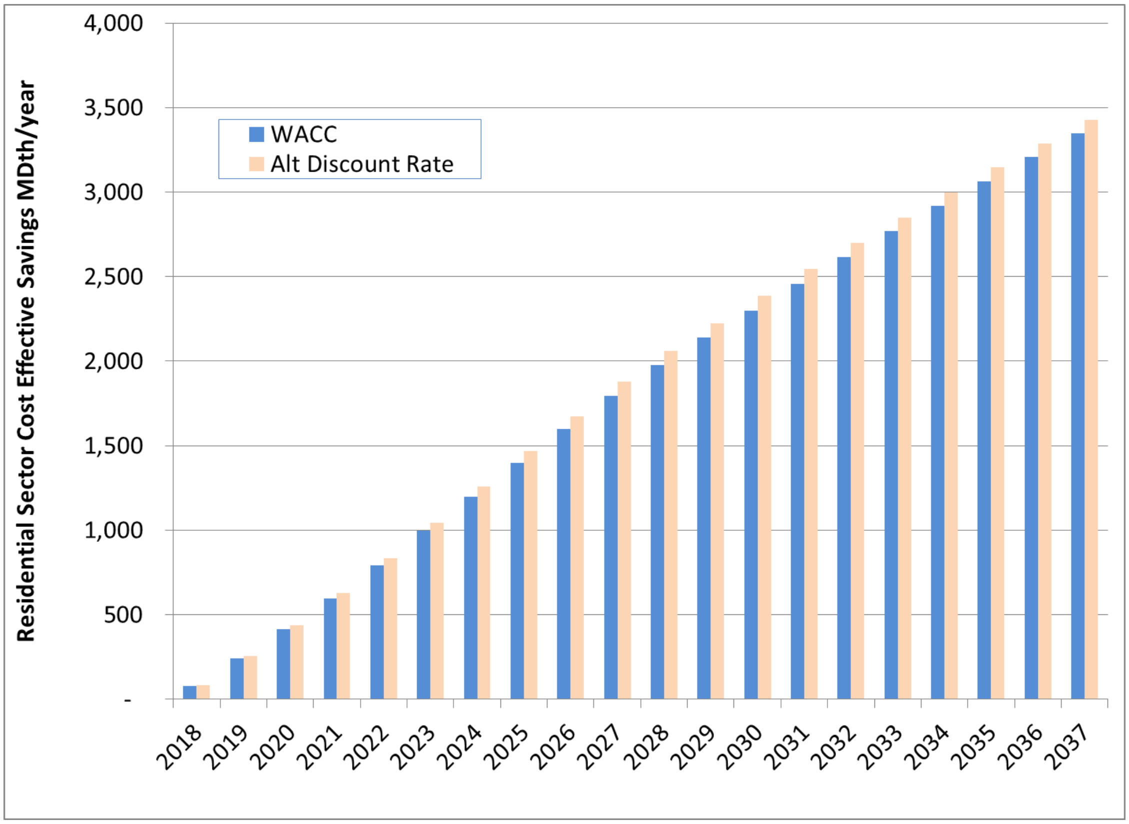
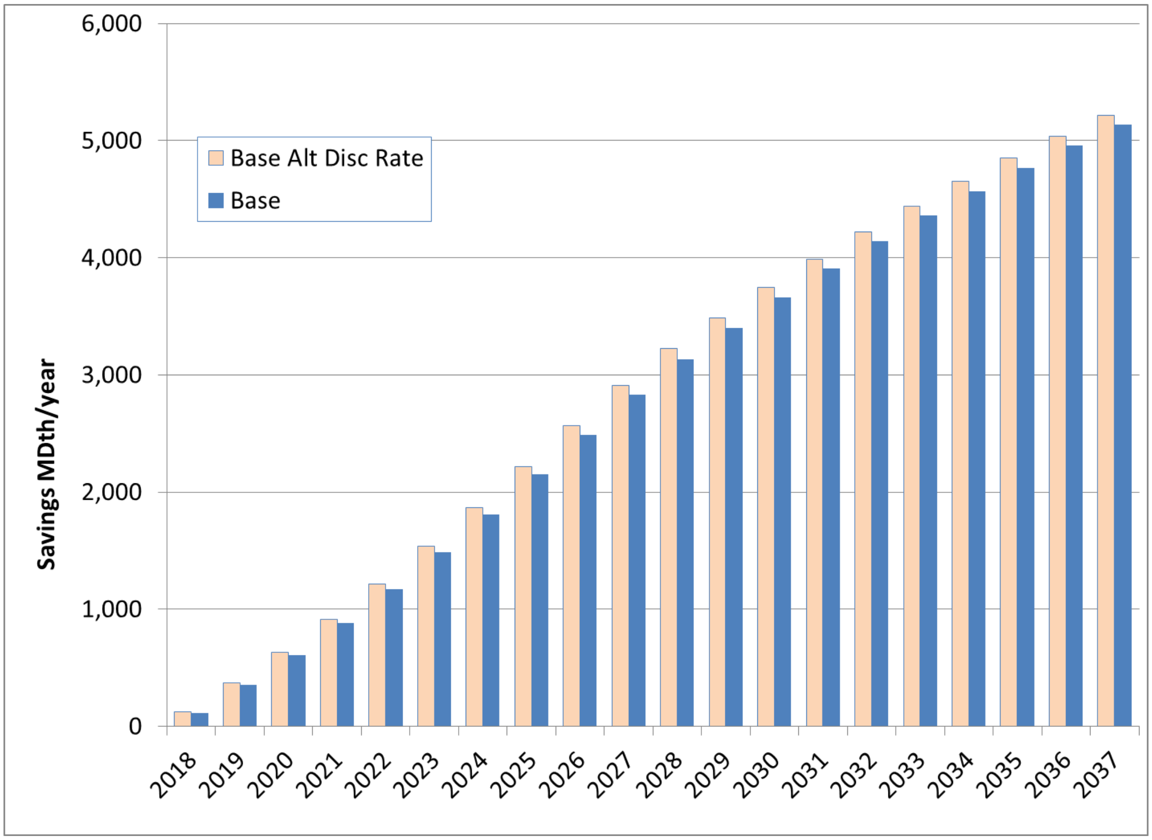


Figure 7-30: Cost-effective Level of Gas DSR,
Base vs. Alternate Residential Conservation Discount Rate



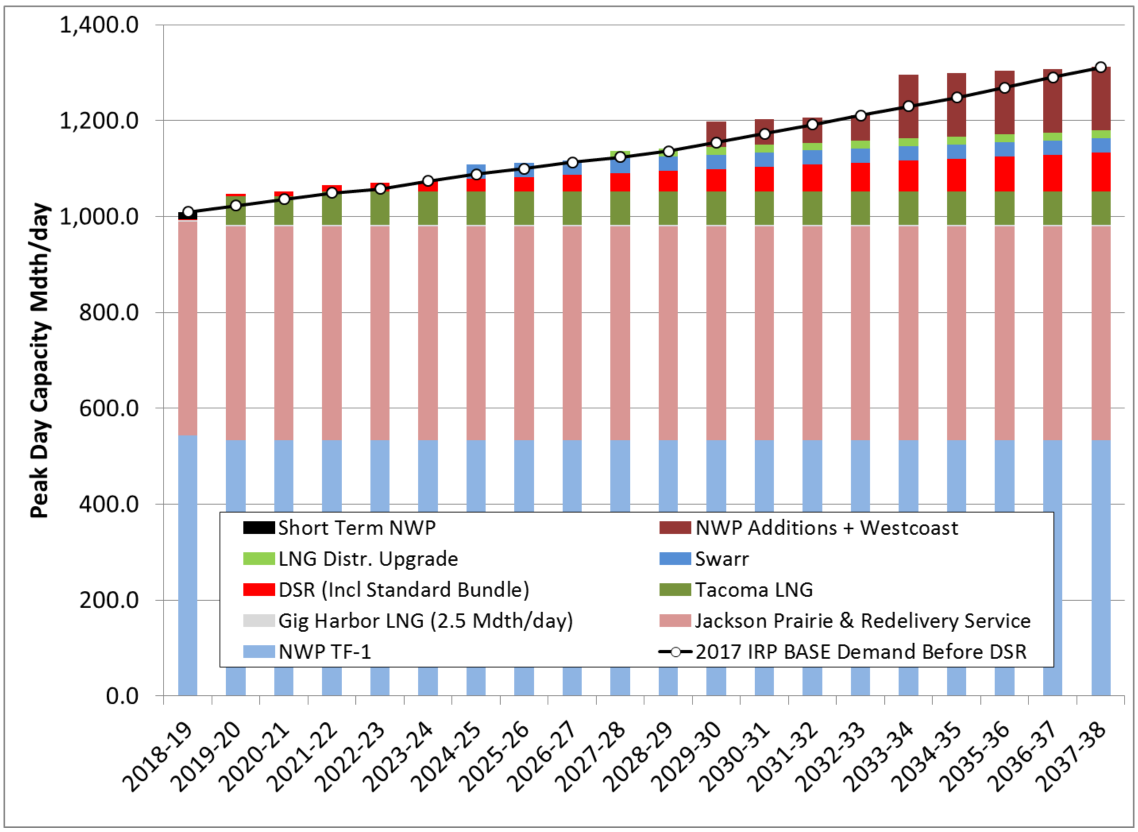
Resource Addition Timing Optimization

Two of the supply-side resources are projects that PSE would implement to increase peaking capacity: Swarr and the LNG distribution system upgrade. The timing for these resources is in PSE's control, and the lead times are short enough that these resources can be developed with a year's notice. Therefore, the Base Scenario was tested to allow these resources to be built in any given year. Swarr is available starting in November of 2019 and the LNG distribution upgrade is offered first in November 2021. Given that PSE is surplus, and the first need occurs in the winter of 2022/23, these resources are not needed in the near term in any case. However, by looking at the annual expansion option, we can determine in what year the resource is needed and we can determine if that will produce a lower portfolio cost.

KEY FINDINGS. Reflecting the flexibility PSE has in timing the Swarr and LNG distribution upgrades makes slight changes in the timing of resource builds and lowers the overall NPV portfolio cost.

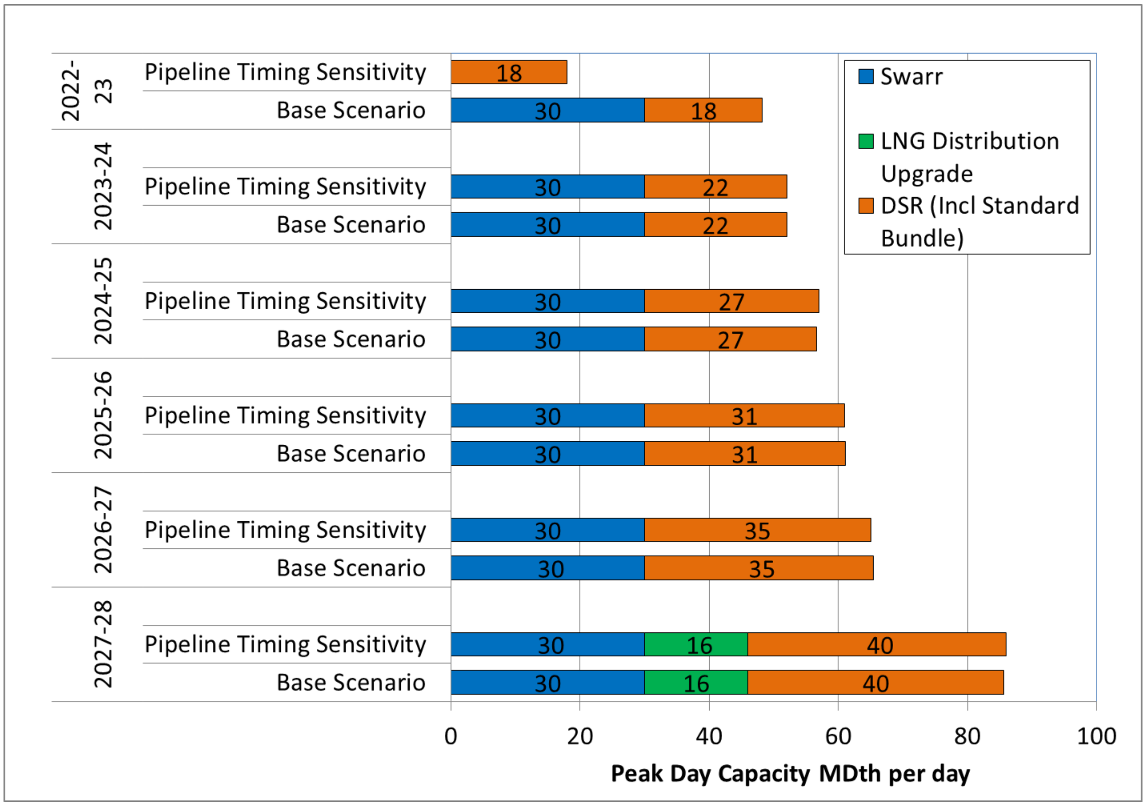
As shown in Figure 7-31, the result was a slightly smoother load/resource balance in the first ten years when Swarr and LNG distribution upgrades are selected instead of the step or "lumpy" resource additions that can be seen in in the latter half of the study when pipeline additions are offered every four years.

Figure 7-31: Timing Sensitivity Gas Resource Portfolio



The portfolio builds for the timing sensitivity are shown in comparison with the Base Scenario portfolio in Figure 7-32 below. The chart below shows that the Swarr and LNG distribution upgrade additions are the same in the Base Scenario as in the timing sensitivity, the only difference being that Swarr is delayed by one year in the timing sensitivity. All the other resource additions are unchanged.

Figure 7-32. Timing Sensitivity Impact on Other Resource Builds



PORTFOLIO COST IMPACTS. Results indicate the revised timing of resource additions from the pipeline timing sensitivity reduce portfolio costs. The 20-year NPV of cost for the Base Scenario portfolio was $8,799 million. The 20-year NPV cost for the pipeline timing sensitivty portfolio was $8,797 million – a slight reduction in portfolio cost..

Additional Gas Conservation

The cost-effective amount of conservation in the Base + No CO_2 Scenario was used as the basis for this analysis. Figure 7-33 shows the two levels of additional DSR bundles that were tested. The incremental approach estimated the cost of reducing carbon using two additional DSR bundles, and a second approach added all 10 of the DSR bundles.

Figure 7-33: Additional Conservation Bundles Tested

DSR Bundle	Base No CO2	Incremental DSR	All DSR
Residential Firm	4	6	10
Commercial Firm	5	7	10
Commercial Interruptible	3	5	10
Industrial Firm	3	5	10
Industrial Interruptible	3	5	10

NOTE: Incremental DSR is two bundles over the cost effective bundles in the Base + No CO_2 portfolio.

The additional bundles in the two cases were forced into the SENDOUT portfolio optimization model and both the total system costs and incremental carbon reduction was compared to the Base + No CO_2 portfolio. The results are shown in Figure 7-34 below.

Figure 7-34: Cost of Emission Reduction with Additional Conservation

	Base Deterministic Portfolio Cost (Levelized Millions $)	Difference from Base (Millions $)	Regional Emissions (Levelized Million Tons)	Difference from Base (Millions Tons)	Cost of Carbon Reduction ($/ton)
Base + No CO2 (Reference) GAS	$5,599		59.77		
Additional Conservation – Incremental GAS	$5,601	$2	59.69	0.08	$20.45
Additional Conservation – All GAS	$5,768	$169	58.30	1.47	$114.83

The cost of carbon reduction increases as you move up on the gas conservation supply curve. The amount of conservation is dependent on the distribution of the conservation resources on the supply curve; it is non-linear, and so the impact on emissions can vary.