EXISTING RESOURCES AND ALTERNATIVES

APPENDIX E

PSE PUGET SOUND ENERGY

Contents

1. Existing Resources

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

1.1. Existing Pipeline Capacity

There are two types of pipeline capacity. Direct-connect pipelines deliver supplies directly to Puget Sound Energy's (PSE) local distribution system from production areas, storage facilities, or interconnections with other pipelines. Upstream pipelines deliver natural gas to the direct pipeline from remote production areas, market centers, and storage facilities.

1.1.1. Direct-connect Pipeline Capacity

Natural gas delivered to PSE's distribution system is handled last by our only direct-connect pipeline, Northwest Pipeline (NWP). We hold nearly one million dekatherms (Dth) of firm capacity with NWP.

- 447,057 Dth per day of firm storage redelivery service from Jackson Prairie
- 542,872 Dth per day of year-round TF-1 (firm) transportation capacity

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 arrangement provides valuable flexibility, including sourcing natural gas from different regions daily in some contracts.

1.1.2. Upstream Pipeline Capacity

Puget Sound Energy holds capacity on several upstream pipelines to transport natural gas supply from production basins or trading hubs to the direct-connect NWP system.

Figure E.1 shows a schematic of the natural gas pipelines for the Pacific Northwest. For the details of PSE's natural gas sales pipeline capacity, see Table E.1.

Figure E.1: Pacific Northwest Regional Natural Gas Pipeline Map

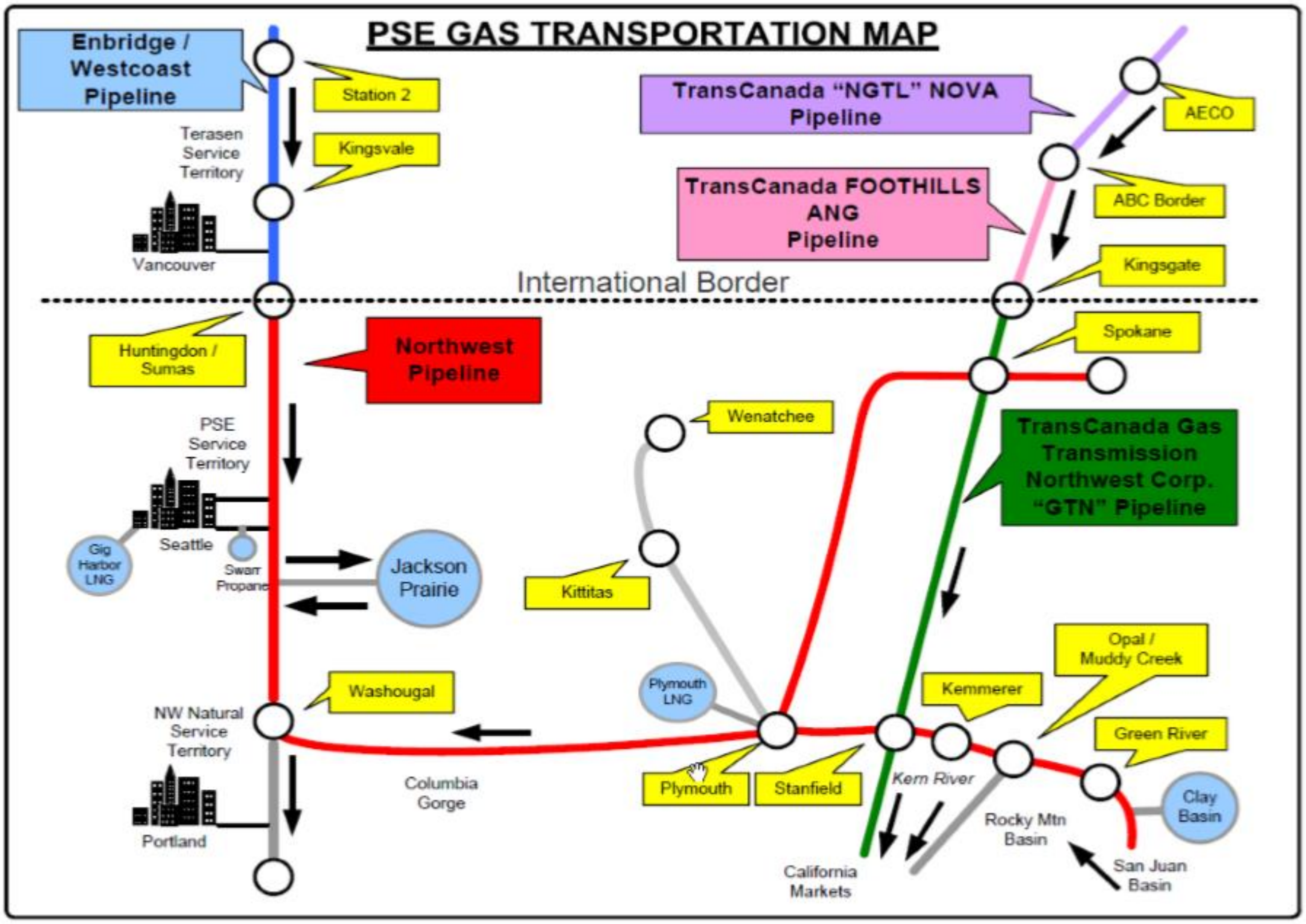


Table E.1: Natural Gas Sales — Firm Pipeline Capacity (Dth/day) as of 11/01/2020

Pipeline/Receipt Point	Total	2023–2028	2028+
Direct-connect	-	-	-
NWP/Westcoast Interconnect (Sumas)[1]	287,237	135,146	152091
NWP/TC-GTN Interconnect (Spokane)[1]	75,936	-	75,936
NWP/various in US Rockies & San Juan Basin[1]	179,699	52,423	127,276
Total TF-1	**542,872**	**187,569**	**355,303**
NWP/Jackson Prairie Storage Redelivery Service[1,2]	447,057	444,184	2,873
Storage Redelivery Service	**447,057**	**444,184**	**2,873**
Total Capacity to City Gate	**989,929**	**631,753**	**358,176**
Upstream Capacity	-	-	-
TC-NGTL: from AECO to TC-Foothills Interconnect (A/BC Border)[3]	79,744	79,744	-
TC-Foothills: from TC-NGTL to TC-GTN Interconnect (Kingsgate)[3]	78,631	78,631	-
TC-GTN: from TC-Foothills Interconnect to NWP Interconnect (Spokane)[4]	65,392	65,392	-
TC-GTN: from TC-Foothills Interconnect to NWP Interconnect (Stanfield)[4,5]	11,622	11,622	-
Westcoast: from Station 2 to NWP Interconnect (Sumas)[6,7]	135,795	135,795	-
Total Upstream Capacity[8]	**371,184**	**371,184**	-

Notes:

1. Northwest Pipeline (NWP) contracts have automatic annual renewal provisions but can be canceled by PSE with one year's notice.
2. Storage redelivery service (TF-2 or discounted TF-1) is 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.
3. Converted to approximate Dth per day from the contract stated in gigajoules per day.
4. TC-GTN contracts have automatic renewal provisions but can be canceled by PSE with one year's notice.
5. We can use capacity alternatively to deliver additional volumes to Spokane.
6. Converted to approximate Dth per day from the contract in cubic meters per day. Westcoast adjusted the heat content factor up to reflect the higher Btu gas now normal on its system. This allows customers to transport more Btu in the same contractual capacity.
7. The Westcoast contracts contain a right of first refusal upon expiration.
8. Upstream capacity is not necessary for a supply acquired at interconnects in the Rockies and for supplies purchased at Sumas.

1.2. Transportation Types

This section discusses the pipeline contracts we use to transport gas from production areas to our city gate. The city gate connects to the delivery system in the PSE service areas. This discussion does not include delivery system pipelines.

1.2.1. TF-1 Contracts

TF-1 transportation contracts are firm contracts available every day of the year. We pay a fixed demand charge for the right but are not obligated to transport natural gas daily.

1.2.2. Storage Redelivery Service

Puget Sound Energy holds TF-2 and winter-only discounted TF-1 capacity under various contracts that provide 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.

1.2.3. Primary Firm, Alternate Firm, and Interruptible Capacity

Primary 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 natural gas on the pipeline from a specified receipt point to a selected delivery point. Firm transportation requires a fixed payment, whether the capacity is used or not, plus variable costs when physical gas is transported. Primary firm capacity is highly reliable when used in the contracted path from the receipt point to the delivery point.

Alternate Firm Capacity occurs when firm shippers have the right to alter the contractual receipt point temporarily, delivery point, and flow direction — subject to the availability of capacity for that day. This alternate firm capacity can be very reliable if the contract flows natural gas within the primary path, in the contractual direction to or from the primary delivery or receipt point. The alternate firm is much less reliable or predictable if used to flow natural gas in the opposite direction or out of the path. While out-of-path alternate firm capacity has higher rights than non-firm, interruptible capacity, it is not considered reliable in most circumstances.

Interruptible Capacity on a fully contracted pipeline can become available if a firm shipper does not fully utilize 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 rate for interruptible capacity is negotiable and typically billed as a variable charge. The rights of this type of non-firm capacity are subordinate to the rights of firm pipeline contract owners who request to transport natural gas on an alternate basis outside their contracted firm transportation path.

The flexibility to use firm transport in an alternate firm manner within path or out of path, and the ability to create segmented release capacity, results in low non-firm, interruptible volumes on the NWP system.

When we do not need the capacity to serve natural gas customers on a given day, we may use our firm capacity to transport natural gas from a low-priced basin to a higher-priced location and resell the gas to third parties to recoup a portion of demand charges. When PSE has a surplus of firm capacity and market conditions make such transactions favorable for customers, we may release capacity into the capacity release market. The company may also access additional firm capacity from the capacity release market on a temporary or permanent basis when available and competitive with other alternatives.

Interruptible service plays a limited role in PSE's resource portfolio because of the flexibility of the company's firm contracts and because we cannot rely on it to meet peak demand.

2. Existing Storage Resources

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

- Access to storage allows the company to purchase and store natural gas during the lower-demand summer season, generally at lower prices, for use during the high-demand winter season.
- Combining storage capacity with firm storage redelivery service transportation allows PSE to contract for less of the more expensive year-round pipeline capacity.
- Ready access to an immediate and controllable source of firm natural gas supply or storage space enables us to handle many imbalances created at the interstate pipeline level without incurring balancing or scheduling penalties.
- We also use storage to balance city gate gas receipts from natural gas marketers with the actual loads of our natural 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, Washington, is an aquifer-driven storage field located in the market area designed to deliver large quantities of natural gas over a relatively short period. Clay Basin, in northeastern Utah, provides supply-area storage and a winter-long natural gas supply. Table E.2 presents details about storage capacity.

Table E.2: Natural Gas Sales Storage Resources[1] as of 11/1/2020

	Withdrawal Capacity (Dth/Day)	Injection Capacity (Dth/Day)	Storage Capacity (Dth)	Expiration Date
Jackson Prairie — PSE-owned	398,667	147,333	8,528,000	-
Jackson Prairie — PSE-owned [2]	(50,000)	(18,500)	(500,000)	2023
Net Jackson Prairie-owned	**348,667**	**128,833**	**8,028,000**	**-**
Jackson Prairie — NWP SGS-2F [3]	48,390	20,404	1,181,021	2023
Net Jackson Prairie	**397,057** [5]	**149,237**	**9,209,021**	**-**
Clay Basin [4]	107,356	53,678	12,882,750	2023
Net Clay Basin	**107,356**	**53,678**	**12,882,750**	**-**
Total	**504,413** [6]	**202,915**	**22,091,771**	**-**

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 to PSE's electric generation portfolio (at a market-based price) from PSE's natural gas sales portfolio. We may be able to renew, depending on gas sales portfolio needs. We can recall firm withdrawal rights serving natural gas sales customers.
3. Northwest Pipeline contracts have automatic annual renewal provisions, but PSE can cancel them with one year's notice.
4. We expect to renew the Clay Basin storage agreements.
5. Plus 50,000 Dth when Jackson Prairie is recalled from the electric portfolio for 447,057 Dth/day.
6. Plus 50,000 Dth when Jackson Prairie is recalled from the electric portfolio.

2.1. Jackson Prairie Storage

As we show in Table E.2, PSE, NWP, and Avista Utilities, each own an undivided one-third interest in the Jackson Prairie Gas Storage Project, which PSE operates as authorized by the Federal Energy Regulatory Commission (FERC). We own 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 natural gas sales customers under extreme conditions. In addition to the PSE-owned portion of Jackson Prairie, we have access to 48,390 Dth per day of firm deliverability and associated firm storage capacity through an SGS-2F storage service contract with NWP. We hold 447,057 Dth per day of firm withdrawal rights for peak day use. We have 447,057 Dth per day of storage redelivery service transportation capacity from Jackson Prairie. The NWP contracts automatically renew each year, but PSE has the unilateral right to terminate the agreement with one year's notice.

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

2.2. Clay Basin Storage

Dominion-Questar Pipeline owns and operates the Clay Basin storage facility in Daggett County, Utah. This reservoir stores natural gas during the summer for withdrawal in the winter. Puget Sound Energy 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.

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

2.3. Treatment of Storage Cost

Like firm pipeline capacity, firm storage arrangements require a fixed charge whether the storage service is used or not. We also pay a variable charge for natural 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 according to FERC-approved tariffs and recovered from customers through the Purchased Gas Adjustment (PGA) regulatory mechanism. In contrast, we recover customers' costs associated with the PSE-owned portion of Jackson Prairie through base distribution rates. We recover some Jackson Prairie costs from PSE transportation customers through a balancing charge.

2.4. 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 natural gas supplies on short notice for relatively short periods. A last resort due to their relatively higher variable costs, these resources typically help meet extreme peak demand during the coldest hours or days. These resources are not as flexible as other supply sources.

Table E.3: Natural Gas Sales Peaking Resources

Facility	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]	30,000	16,680	128,440	On-system	Nov. 2025+
Tacoma LNG	85,000	2,100	538,000	On-system	Current
TOTAL	101,800	21,280	676,940	-	-

Notes:

1. Swarr is currently out of service pending upgrades to reliability, safety, and compliance systems. We may consider it in resource acquisition analysis for an in-service date of in the latter part of the decade.
2. Swarr holds 1.24 million gallons. At a refill rate of 111 gallons per minute, it takes 7.7 days to refill, or 16,680 Dth per day.

2.4.1. Gig Harbor Liquefied Natural Gas

Located in the Kitsap Peninsula Gig Harbor area, 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 is an incremental supply source, and we included its 2.5 MDth per day capacity 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 natural gas supply from pipeline Interconnects or other storage to be diverted elsewhere.

2.4.2. Swarr Vaporized Propane-air

The Swarr LP-Air facility has a net storage capacity of 128,440 Dth natural gas equivalents and is not currently configured to inject into the PSE system. Swarr is a propane-air injection facility on PSE's natural 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 underway. We evaluated the upgrades as a resource alternative for this plan in Combination Nine — Swarr LP-Air Upgrade and assumed it would be available on three years' notice as early as the 2028–2029 winter. Since Swarr connects to PSE's distribution system, it requires no upstream pipeline capacity.

2.4.3. Tacoma Liquefied Natural Gas

The Tacoma LNG peak shaving facility came online in 2021 to serve the needs of core natural gas customers and regional LNG transportation fuel consumers. By serving new LNG fuel markets (primarily large marine consumers), the project achieved economies of scale and reduced costs for core natural gas customers. This LNG peak-shaving facility is located at the Port of Tacoma and connects to PSE's existing distribution system. The 2023 Gas Utility IRP assumes we put the project in service late in the 2021–2022 heating season, providing 85 MDth per day of capacity — 66 MDth per day of vaporization, and 19 MDth per day of recalled natural gas supply.

2.4.4. Existing Natural Gas Supplies

Advances in shale drilling have expanded the economically feasible natural gas resource base and dramatically altered long-term expectations about natural gas supplies. Shale beds in British Columbia directly increased the availability of supplies in the West, but the east coast no longer relies as heavily on western supplies now that shale deposits in Pennsylvania and West Virginia are in production.

Within its transportation and storage network limits, PSE maintains a policy of sourcing natural gas supplies from various 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 the NWP provide some flexibility to buy from the lowest-cost basin, with certain limitations based on the primary capacity rights from each basin. Although PSE depends heavily on supplies from northern British Columbia, it also maintains pipeline capacity access to producing regions in the Rockies, the San Juan basin, and Alberta. Our pipeline capacity on the NWP currently provides 50 percent of our flowing natural gas supplies to be delivered north of our service territory and the remaining 50 percent south of our service territory.

Price and delivery terms tend to be very similar across supply basins. However, shorter-term prices at individual supply hubs may separate due to pipeline capacity shortages, operational challenges, or high local demands. This separation cycle can last several years but is often alleviated when additional pipeline infrastructure is constructed. We expect comparable pricing across regional supply basins over the 20-year planning horizon, with differentials primarily driven by differences in transportation costs and forecasted demand increases. We purchased the long-term supply pricing scenarios used in this analysis from Wood-Mackenzie, whose North American supply/demand model considers the non-synchronized cyclical nature of growth in production, demand, and infrastructure development to forecast monthly pricing in the supply basins accessed by PSE pipeline capacity.

We have always purchased our supply at market hubs. There are various transportation receipt points in the Rockies and San Juan basin, including Opal, Clay Basin, and Blanco. Alternate points, such as gathering system and upstream pipeline interconnects with NWP, allow some purchases directly from producers and marketers. Puget Sound Energy has several supply arrangements with major producers in the Rockies to purchase supply near the point of production. Adding upstream pipeline transportation capacity on Westcoast, TC Energy's Nova (TC-NGTL) pipeline, TC Energy's Foothills pipeline, and TC Energy's Gas Transmission NW (TC-GTN) pipeline to the company's portfolio also increased our ability to access supply in the more price-liquid producing areas in Canada.

Natural 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) supply contracts. Long-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, November through March. Near-term transactions supplement baseload transactions, particularly for the winter months. We estimate average load requirements for upcoming months and enter month-long or multimonth transactions to balance load. We offset daily positions with storage from Jackson Prairie, Clay Basin, day-ahead purchases, and off-system sales transactions. We use Jackson Prairies to balance intra-day positions. We continuously monitor natural gas markets to identify trends and opportunities to fine-tune our contracting, purchasing, and storage strategies.

2.4.5. Existing Demand-side Resources

Puget Sound Energy has provided demand-side resources to our customers since 1993. These energy efficiency programs operate following requirements established as part of the stipulated settlement of PSE's 2001 General Rate Case.[15] The programs primarily served residential and low-income customers through 1998. In 1999, we expanded them to include commercial and industrial customer facilities. We fund most natural gas energy efficiency programs using gas rider funds collected from customers.

Table E.4 shows that energy efficiency measures installed through 2021 have saved more than 6.6 million Dth, a reduction in CO_2 emissions of approximately 361,000 metric tons. We have achieved more than half of these savings since 2010. Savings per year have mostly ranged from 3 to 5 million therms, peaking at just over 6.3 million in 2013.

We establish energy savings targets and create programs to achieve those targets every two years. The 2020–2021 biennial program period concluded at the end of 2021. The current program cycle runs from January 1, 2022, through December 31, 2023, and has a two-year energy savings target of approximately 7.4 million therms. This goal was based on an extensive analysis of savings potentials and developed in collaboration with key external interested parties represented by the Conservation Resource Advisory Group and Integrated Resource Plan Advisory Group.

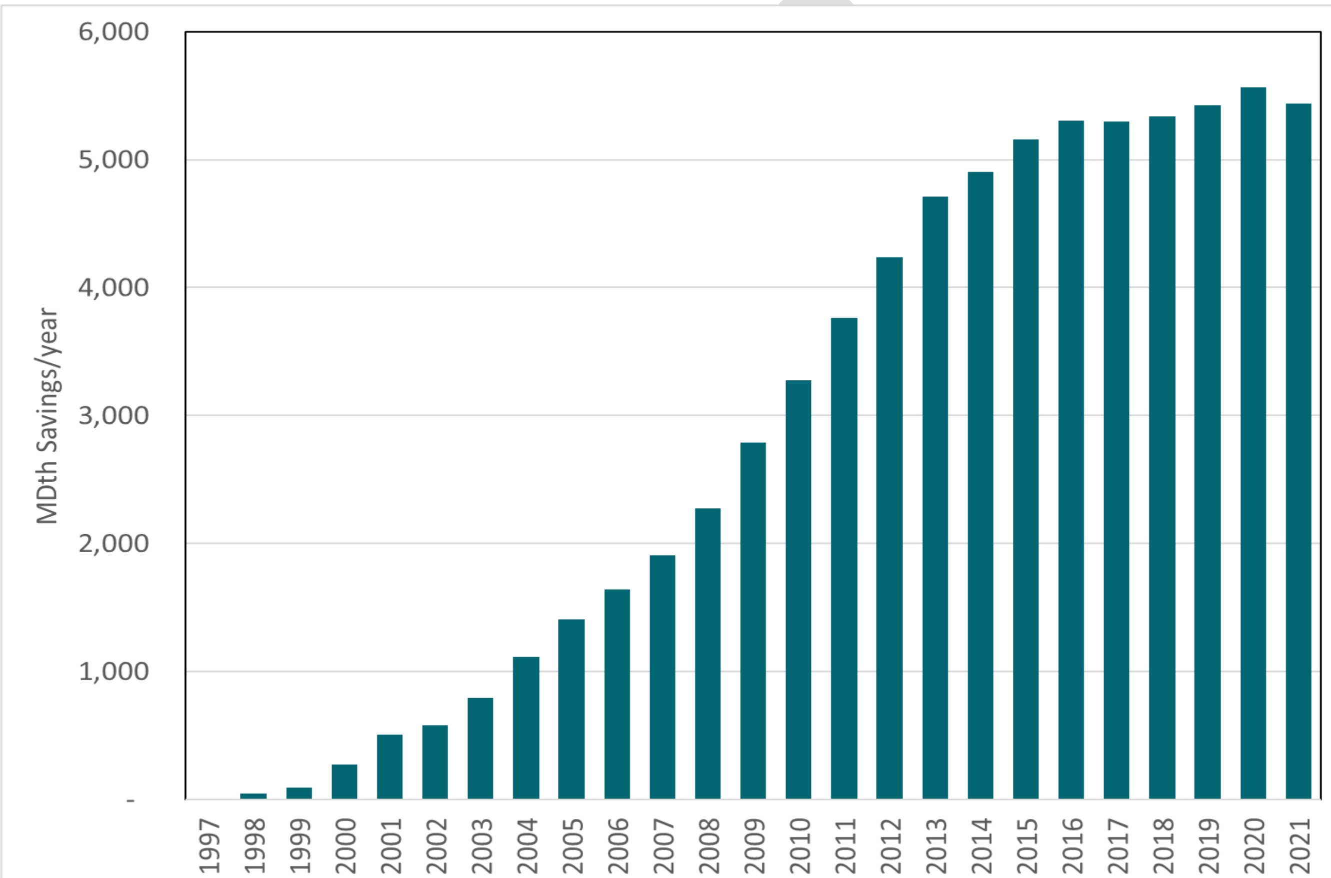
Puget Sound Energy spent more than $15.5 million for natural gas conservation programs in 2021 (the most recent complete program year) compared to $3.2 million in 2005. Spending over that period increased more than 35 percent annually. The low cost of natural gas and the rising cost of materials and equipment have put pressure on the cost-effectiveness of savings measures. We are collaborating with regional efforts to find creative ways to make the delivery and marketing of natural gas efficiency programs more cost-effective and to reduce barriers to promising measures that have not yet gained significant market share.

Table E.4 summarizes energy savings and costs for 2020–2023.

Table E.4: Natural Gas Sales Energy Efficiency Program Summary, 2020–2023
Total Savings and Costs

Program Year	Actual Savings (MDth)	Actual Cost ($ millions)	Target Savings (MDth)	Budget ($ millions)
2020	410.3	15.1	400	18.6
2021	236.4	15.8	338.9	19.4
2022-23	-	-	755.1	48.5

Figure E.2: Cumulative Natural Gas Sales Energy Savings from DSR, 1997–2021



3. Resource Alternatives

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

3.1. Resource Alternatives Considered

The driving force behind the process to develop this plan is the recently passed Climate Commitment Act (CCA) of 2021[5]. The CCA lays out a pathway to reducing emissions from gas utility operations that the Department of Ecology's (Ecology) rulemaking[6] will further define. We expanded the resource alternatives in this year's plan from previous Integrated Resource Plans to focus on emission compliance: renewable fuels such as biofuels[7] and green hydrogen, hybrid heat pumps, reducing (by not renewing) pipeline transport capacity where it makes sense to reduce sales portfolio costs, and energy efficiency.

Transporting natural gas from production areas or market hubs to PSE's service area entails assembling several specific pipeline segments and natural gas storage alternatives. We combined purchases from specific market hubs with various upstream and direct-connect pipeline alternatives and storage options to create versions that have different costs and benefits.

We have already contracted several renewable natural gas (RNG) sources and will explore the cost-effectiveness of more RNG resources to reduce emissions under the CCA. We are also working with outside parties in joint development agreements to explore hydrogen options for gas for power and sales loads. This 2023 Gas Utility IRP included green hydrogen options as a blending fuel to displace some natural gas.

Demand-side resources are a significant resource in our territory. Along with traditional energy-efficiency measures, our plan includes hybrid heat pumps as a conservation measure, significantly reducing gas use and emissions while providing backup fuel during peak winter periods. This approach minimizes the impact on the electrical grid while achieving significant reductions in emissions. Finally, this 2023 Gas Utility IRP also includes impacts from full electrification in a scenario where we ramped the technically achievable amount of electrification[8] into the portfolio as a must-take resource over this plan's study period.

We grouped the alternatives into seven broad combinations for analysis purposes. These combinations are discussed below. Note that demand-side resources are a different alternative we discuss later in this chapter.

We use the following acronyms in the descriptions:

- AECO: the Alberta Energy Company trading hub, also known as Nova Inventory Transfer (NIT)
- LP-Air: liquid propane-air (liquid propane is mixed with air to achieve a gas with the same heating value as natural gas)
- NWP: Williams Northwest Pipeline, LLC pipeline
- TC-Foothills: TCEnergy-Foothills BC (Zone 8) pipeline
- TC-GTN: TCEnergy-Gas Transmission-Northwest pipeline
- TC-NGTL: TCEnergy-NOVA Gas Transmission Ltd. pipeline
- Westcoast pipeline: Enbridge's Westcoast Energy Inc. pipeline

Transport pipelines that bring natural gas from production areas or market hubs to PSE's service area are generally assembled from several specific segments and/or natural gas storage alternatives. We join purchases from specific market hubs with various upstream and direct-connect pipeline alternatives and storage options to create combinations with different costs and benefits. On-system resources can also serve as peaking resources; they do not require transport pipeline capacity to deliver them to the demand centers.

Given that the Climate Commitment Act (CCA) is in effect, the existing supply resources will likely be adequate to serve the demand over the study period. The more likely trend will be a downward trajectory for the demand leading to surplus supply-side resources. This plan looks to optimize supply-side resources to minimize the system cost while meeting the emissions obligations under CCA and ensuring enough resources to serve ratepayers on peak winter days. This optimization includes reviewing transport pipeline contract renewals and potentially replacing pipeline capacity with on-system or storage resources, where we can bring such resources at a lower cost to the portfolio. When we reduce the volume of year-round available pipeline capacity relative to existing or increased storage capacity, we also need to verify that the new resource portfolio has adequate capacity to serve customer needs during winters that are colder than average — most peaking resources are only available for a few days per year. We must determine this before concluding that the revised portfolio is acceptable.

We analyzed nine supply-side alternatives in this plan.

Alternatives One–Six: Northwest Pipeline Renewals

Several contracts on the Northwest Pipeline (NWP) will be up for renewal after 2024 and within the 2023 Gas Utility IRP study period. Given that energy efficiency and hybrid heat pumps will reduce demand, it may be more cost-effective to reduce or allow to terminate (turn-back) some of the pipeline contracts to better align with the demand.

The renewals on the NWP are segments connecting all three major gas supply hubs: Sumas/Station 2, Rockies, and AECO. Table E.5 shows the timing of the contracts offered as renewal options in the portfolio model, an aggregation of contracts on that segment.

Table E.5: Timeline of Pipeline Capacity Offered for Renewal

Segment in Daily MDth	Hub	Nov 2024	Nov 2028	Nov 2030	Nov 2033
Sumas to PSE	Sumas	X			
Sumas to PSE	Sumas		X		
Sumas to PSE	Sumas			X	
Opal to Stanfield	Rockies	X			
Opal to Stanfield	Rockies		X		
Starr Rd to Plymouth	AECO				X

Alternative Seven: Plymouth Liquefied Natural Gas with Firm Delivery

This option includes 60 MDth capacity with a 15 MDth per day firm withdrawal of Plymouth LNG service and 15 MDth per day of primary firm NWP capacity from the Plymouth LNG plant to PSE. Puget Sound Energy's electric power generation portfolio currently holds this resource, which may be available for a one-time renewal in April 2024. While this is a valuable resource for the power generation portfolio, it may be a better fit in the natural gas sales portfolio and is offered in April 2024.

Alternative Eight: Swarr Vaporized Propane-air Upgrade

Alternative eight is an upgrade to the existing Swarr LP-Air facility. The 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 and could be available on three years' notice as early as winter 2028/29. We offered this alternative in 2028–2029., 2029-30 and 2030-31.

We considered two fuels for achieving CCA compliance: renewable natural gas (RNG) and green hydrogen.

Alternatives 9–15: Renewable Natural Gas

We considered seven renewable natural gas combinations in the portfolio analysis.

Table E.6: Timeline of Pipeline Capacity Offered for Renewal

Combination	RNG Contract	Source	Receipt Point	Max. MDTh/yr	Year Offered
9	RNG-physical N-1	WA	Sumas	1600	2024
10	RNG-physical N-2	WA	Sumas	1388	2025
11	RNG Attribute-1	N America	Sumas	3000	Annual
12	RNG Attribute-2	N America	Sumas	1000	Annual
13	RNG Attribute-3	WA	Stanfield	340	2024
14	RNG Attribute-4	N America	Sumas	8000	Annual
15	RNG- physical O-1	WA	On system	70	2024

Alternatives 16–18: Green Hydrogen

We have been working with various parties to jointly assess the development of an electrolyzer-based facility that will use renewable electricity to produce green hydrogen. We based this combination on green hydrogen used to blend into the gas distribution system, simultaneously displacing pipeline capacity on Northwest Pipeline. It assumes three combinations: a 5 percent blend by volume starting in 2028, an additional 5 percent in 2030, and a final 5 percent in 2032, for a total of 15 percent blended green hydrogen by volume in the gas system[1].

4. Storage and Peaking Capacity Alternatives

As we described in the existing resources section, PSE is a one-third owner and operator of the Jackson Prairie Gas Storage Project. Puget Sound Energy also contracts for capacity at the Clay Basin storage facility in northeastern Utah. Additional pipeline capacity from Clay Basin is unavailable, and we are not considering storage expansion. We did not analyze expanding storage capacity at Jackson Prairie in this plan, and do not believe we can mitigate the potential risks from expansion in the long run.

We considered the following storage alternatives for this plan.

4.1. Swarr

We discuss the Swarr LP-Air facility in the Existing Peaking Supply and Capacity Resources section. We are evaluating this resource alternative and are in the preliminary stages of designing the upgrade to Swarr's environmental, safety, and reliability systems and increasing production capacity to 30,000 Dth per day. We assumed the facility would be available on three years' notice for the 2028–2029 heating season.

Table E.7: Natural Gas Storage Alternatives Analyzed

Storage Alternatives	Description
Swarr LP-Air Facility Upgrade (Alternative 8)	Considers the timing of the planned upgrade for reliability and increased capacity (from 0 MDth/day to 30 MDth/day) beginning the 2028-29 heating season.
Plymouth LNG contract with NWP firm transportation (Alternative 7)	Considers acquisition of an existing Plymouth LNG contract and associated firm transportation for 15 MDth/day, beginning April 2024.

4.2. Natural Gas Supply Alternatives

As described earlier in this chapter, we expect natural gas supply and production to continue to expand in northern British Columbia and the Rockies as operators develop shale and tight gas formations using horizontal drilling and fracturing methods. With the expansion of supplies from shale gas and other unconventional sources at existing market hubs, we anticipate that adequate natural gas supplies will be available to support existing pipeline infrastructure from northern British Columbia via Westcoast or TC-NGTL, TC-Foothills, and TC-GTN or from the Rockies basin via NWP.

[1] 15 percent hydrogen by volume will displace approximately 5 percent of conventional natural gas in energy.

4.2.1. Renewable Natural Gas

Renewable natural gas (RNG) is captured from dairy waste, wastewater treatment facilities, and landfills. Although it is significantly more costly than conventional natural gas, RNG provides greenhouse gas benefits in two ways. Renewable natural gas reduces CO_2e emissions that might otherwise occur if the methane and/or CO_2 are not captured and brought to market, and it avoids the upstream emissions related to the production of the conventional natural gas that it replaces.

HB 1257 passed the Washington State legislature and became effective in July 2019; state officials also incorporated it in the Washington Utilities Transportation Commission (Commission) RNG Policy Statement they issued in December 2020. Puget Sound Energy conducted an RFI (Request for Information) to determine the availability and pricing of RNG supplies. After analysis and negotiation, we acquired a long-term supply of RNG from a recently completed and operational landfill project in Washington at a competitive price. We are providing RNG under a voluntary RNG program for PSE customers. We will incorporate RNG supply not utilized in PSE's voluntary RNG program(s) into our supply portfolio, displacing natural gas purchases as provided in HB 1257.

This 2023 Gas Utility IRP does not analyze hypothetical RNG projects connecting to the NWP or PSE's system and displacing conventional natural gas that would otherwise flow on NWP pipeline capacity. However, because of RNG's significantly higher cost, the minimal availability of sources, and the unique nature of each project, RNG is not suitable for generic analysis. We measure the benefits of RNG in CO_2e reduction, which are unique to each project. The incremental costs of new pipeline infrastructure to connect the RNG projects to the NWP or PSE system are also unique to each project. We will consider avoided pipeline charges realized by connecting acquired RNG directly to the PSE system, but this is not significant relative to the cost of the RNG commodity. Contract RNG purchases present known costs. However, many projects may not materialize absent a capital investment by PSE. Due to the very competitive RNG development market, including competition from the California compliance markets, we are not prepared to publicly discuss specific potential RNG projects. We will analyze and document individual projects as we pursue additional supplies.

The contract acquisition of landfill RNG will, within a few years, provide RNG equal to approximately 2 percent of PSE's current supply portfolio and as much as a 1.5 percent reduction in the carbon footprint of our natural gas system annually. We are planning significant additional investments in cost-effective RNG. We are confident that we can acquire sufficient RNG volumes to meet the needs of our future voluntary RNG program participants and even exceed the 5 percent cost limitation related to the RNG incorporated into the supply portfolio. To meet the expectations in the Commission's RNG Policy Statement, we will use staggered RNG supply contracts and project development timelines, resales in compliance markets, and other techniques to manage RNG costs while maximizing the availability of RNG in our portfolio and achieving meaningful carbon reductions.

4.2.2. Green Hydrogen

Green hydrogen is created through an electrolytic reaction using renewable power to split fresh water into its constituent hydrogen and oxygen atoms. The hydrogen is captured, pressurized, and transported via truck, pipeline, or rail to end users, while the oxygen is captured for industrial resale or safely vented into the atmosphere. Green hydrogen holds significant promise as an energy source and carrier, giving multiple industries a new solution to help them decarbonize.

Although hydrogen has always held promise as a clean energy source, the economics have historically been unfavorable compared to fossil fuels. The increasing adoption of grid-scale renewable power and the associated dislocation of supply and demand has altered the economic landscape for hydrogen over the last decade. As more renewables became connected, the frequency and duration of grid congestion increased, resulting in idled renewable power. Using that surplus of electricity to create hydrogen not only increases the capacity factor of the renewable resource but also allows for the seasonal storage of electricity, as hydrogen can be created when power is cheapest and used weeks or months later in a fuel cell or power plant when peak electrical demand calls require a dispatchable resource.

We are investigating supplier relationships and developing strategies to procure green hydrogen to support our natural gas operations' decarbonization and power generation portfolio. Creating green hydrogen relies on green power, providing a revenue-generating opportunity for PSE by installing new renewable sources and associated electrical infrastructure investments.

In the natural gas distribution system, PSE aims to inject green hydrogen directly into the system in the early 2030 timeframe. We are currently studying the technical and operational limits of hydrogen blending and anticipate an upper hydrogen limit of 15 percent by volume. Based on historical volumes of gas in the system, this equates to an annual hydrogen consumption of approximately 41,000 tonnes. The blending strategy that is currently under development will address the technical and operational characteristics of blending hydrogen, including the location of third-party electrolyzers, hydraulic characteristics of the gas distribution system, hydrogen storage, and impact on the electrical grid. We do not expect the industrial supply of green hydrogen to materialize in the region until 2028, and the ramp-up to a full 15 percent blend is likely to take several years.

Initial interest in power purchases for electrolyzers indicates that adequate regional supplies will support peak power generation and gas blending by up to 15 percent in the future. This interest and regulatory and political support appear to have created the right conditions to move this energy source from the fringes to a mainstream commodity over the next 20 to 30 years. Over the short term, we will continue to study market developments, engage with developers, and support adoption to ensure that the gains are permanent and long-lasting.

This plan assumes an electrolyzer plant that would come on line in the 2028 winter period and provide 5 percent of the blend volume, then another 5 percent in 2030, and another 5 percent in 2032 for a total of 15 percent by volume of blending into the gas distribution system. We relied on assumptions in the E3 Pacific Northwest report[2] as the basis for the cost curve for developing electrolyzer-based green hydrogen.

[2] https://www.ethree.com/wp-content/uploads/2020/07/E3_MHPS_Hydrogen-in-the-West-Report_Final_June2020.pdf

4.3. Demand-side Resource Alternatives

We first conduct a conservation potential assessment to develop demand-side alternatives for portfolio analysis. This study reviews existing and projected building stock and end-use technology saturations to estimate possible savings by installing more efficient commercially available technologies. The broadest savings measure from making these installations (or replacing old technology) is called the technical potential. This is 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 achievable levels when accounting for market barriers. To be consistent with electric measures, we assumed that all natural gas retrofit measures' achievability factors are 85 percent. Like electric measures, all natural gas measures receive a 10 percent conservation credit from the Power Act of 1980. We then organize the measures into a conservation supply curve, from lowest to highest levelized cost.

Next, we grouped individual measures on the supply curve into cost segments called bundles. For example, all measures with a levelized cost between $2.2 per Dth and $3.0 per Dth may be grouped into bundles and labeled Bundle 2. In the 2021 IRP, the highest cost bundle was Bundle 12, and this was a catch-all bundle with all measures costing above $15 per Dth. Initial portfolio runs showed that bundle 11 was the most cost-effective. Thus, we decided to expand bundle 12 into smaller segments. As a result, there are eighteen bundles in this plan.

From:

- Bundle 12: >$1.50/Th

To:

- Bundle 12: $1.50/Th–$1.75/Th
- Bundle 13: $1.75/Th–$2.00/Th
- Bundle 14: $2.00/Th–$2.25/Th
- Bundle 15: $2.25/Th–$2.50/Th
- Bundle 16: $2.50/Th–$2.75/Th
- Bundle 17: $2.75/Th–$3.00/Th
- Bundle 18: >$3.00/Th

The Codes and Standards bundle has zero cost associated with it because savings from this bundle accrue due to new codes or standards that take effect at a future date. This bundle is always selected in the portfolio, effectively representing a reduction in the load forecast.

Figure E.8 shows the price bundles and corresponding savings volumes in the achievable technical potential developed for this plan. The bundles are shown in dollars per therm, and the savings for each bundle shown in 2033 and 2050 are in thousand dekatherms per year (MDth/year). We developed these savings using PSE's weighted average cost of capital (WACC) as the discount rate.

We are trying to acquire as many cost-effective natural gas demand-side resources as we can as quickly as possible. We can alter the acquisitions or ramp rate of natural gas sales DSR by changing the speed at which we acquire discretionary DSR measures. In these bundles, the discretionary measures assume a 10-year ramp rate; they are acquired during the first 10 years of the study period. Because of this acceleration, there is a drop off in savings after the tenth year.

Table E.8: Natural Gas DSR Cost Bundles and Savings Volumes (MDth/year)

Bundle	2033	2050
Codes & Standards	2,751	6,744
Bundle 1: <$0.22	1,252	1,822
Bundle 2: $0.22–$0.30	1,288	1,894
Bundle 3: $0.30–$0.45	1,371	2,155
Bundle 4: $0.45–$0.50	1,373	2,158
Bundle 5: $0.50–$0.55	1,853	2,686
Bundle 6: $0.55–$0.62	1,903	3,177
Bundle 7: $0.62–$0.70	2,386	3,770
Bundle 8: $0.70–$0.85	3,568	6,594
Bundle 9: $0.85–$0.95	3,613	6,675
Bundle 10: $0.95–$1.20	4,198	7,708
Bundle 11: $1.20–$1.50	4,735	8,493
Bundle 12: $1.50–$1.75	5,893	11,145
Bundle 13: $1.75–$2.00	5,979	11,276
Bundle 14: $2.00–$2.25	6,219	11,587
Bundle 15: $2.25–$2.50	6,360	11,793
Bundle 16: $2.50–$2.75	6,511	11,984
Bundle 17: $2.75–$3.00	6,704	12,322
Bundle 18: $3.00–$99.00	9,477	16,499

➔ See Appendix C: Conservation Potential Assessment, for more detail on the measures, assumptions, and methodology used to develop DSR potentials.

In the final step, we used the natural gas portfolio model (GPM) to test the optimal level of demand-side resources in each scenario. To format the inputs for the GPM analysis, we further divided the cost bundles by market sector and weather and non-weather-sensitive measures. We added increasingly expensive bundles to each scenario until the GPM rejected bundles were as not cost-effective. The bundle that significantly reduced the portfolio cost was deemed the appropriate level of demand-side resources for that scenario. Figure E.3 illustrates the methodology described above.

Figure E.3: General Methodology for Assessing Demand-side Resource Potential

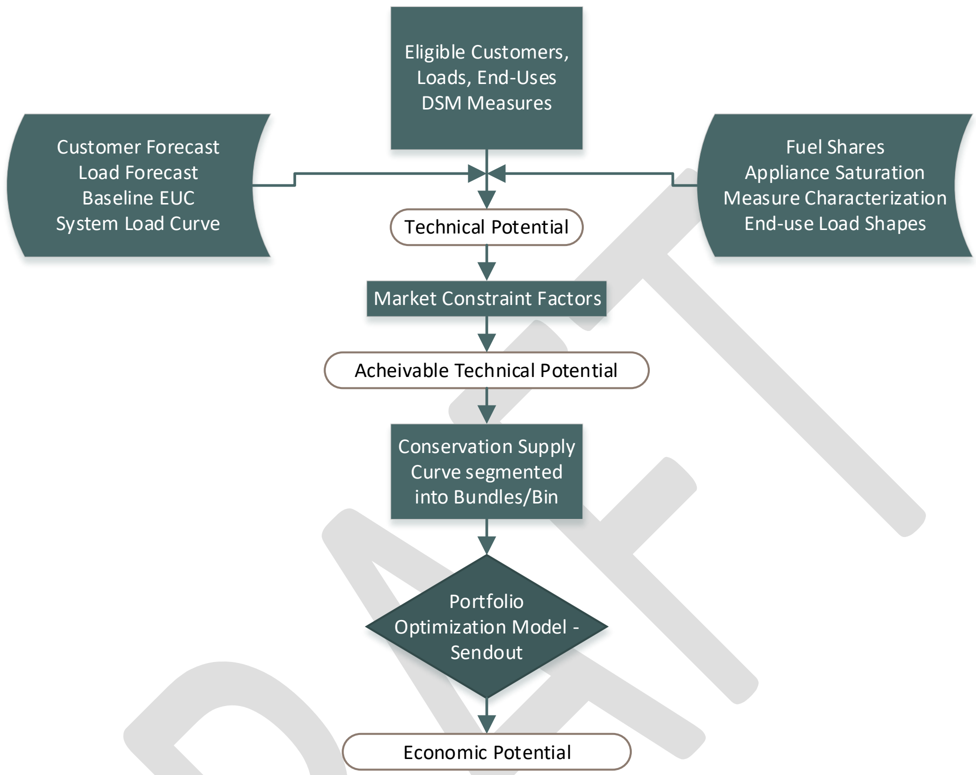


Figure E.4 shows the range of achievable technical potential among the eighteen cost bundles used in the GPM. It selects an optimal combination of each bundle in every customer class to determine the optimal level of demand-side natural gas resource for a particular scenario.

Figure E.4: Demand-side Resources — Achievable Technical Potential Bundles

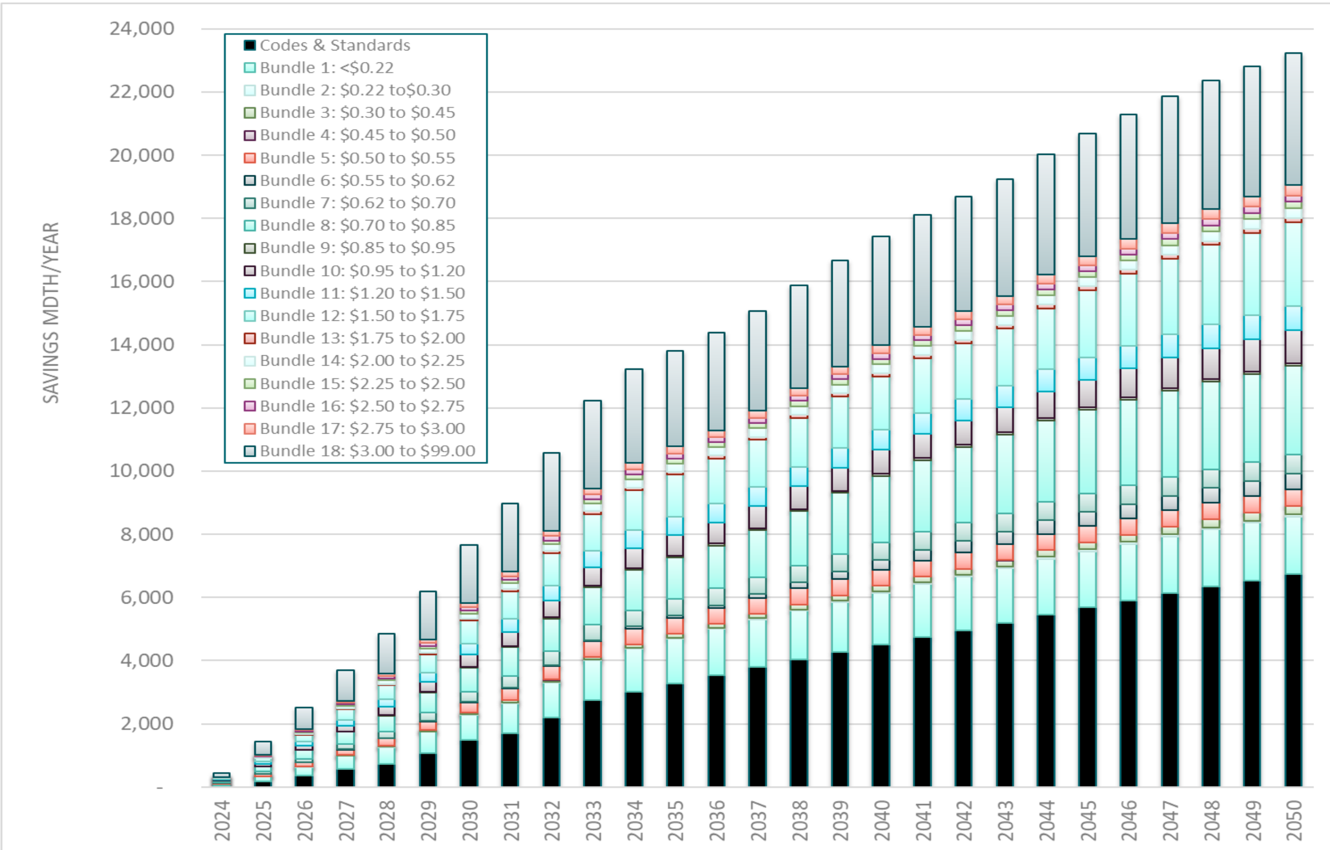


Figure E.5 shows DSR savings subdivided by customer class. We used this input format in the GPM for all bundles in all the 2023 Gas Utility IRP scenarios.

Figure E.5: Savings Formatted for Portfolio Model Input by Customer Class

Table E.9 shows DSR savings for transport customers who emit under 25,000 tons of carbon dioxide, which we included per the requirements of the CCA. These customers only use and pay for the delivery service on its distribution system and were not included in the portfolio modeling. The CPA consultant had an estimate of the energy efficiency available from these customers and provided a top-down energy efficiency potential for PSE. As very little information on end uses and loads is available to PSE, a more detailed study to determine the energy efficiency potential is warranted later per the CCA program requirements. The CPA consultant provided an economic screening based on the proxy avoided costs using the expected or mid-allowance carbon price, the social cost of greenhouse gases (SCGHG), and 2023 gas commodity costs.

Table E.9: Conservation Potential for Transport Customers with under 25,000 tons of Carbon (MDth/Year)

Description	2033	2050
Codes & Standards	0	0
Bundle 1: <$0.22	1771	2503
Bundle 2: $0.22 to$0.30	1814	2614
Bundle 3: $0.30 to $0.45	1957	3481
Bundle 4: $0.45 to $0.50	1959	3492
Bundle 5: $0.50 to $0.55	1961	3509
Bundle 6: $0.55 to $0.62	1979	3619
Bundle 7: $0.62 to $0.70	2017	3677
Bundle 8: $0.70 to $0.85	2044	3728
Bundle 9: $0.85 to $0.95	2048	3734
Bundle 10: $0.95 to $1.20	2075	3799
Bundle 11: $1.20 to $1.50	2322	5320
Bundle 12: $1.50 to $1.75	2357	5526
Bundle 13: $1.75 to $2.00	2367	5549
Bundle 14: $2.00 to $2.25	2381	5667
Bundle 15: $2.25 to $2.50	3575	8842
Bundle 16: $2.50 to $2.75	3680	9686
Bundle 17: $2.75 to $3.00	3702	9711
Bundle 18: $3.00 to $99.00	3764	9970

5. Climate Commitment Act — Electrification Scenarios in the CPA

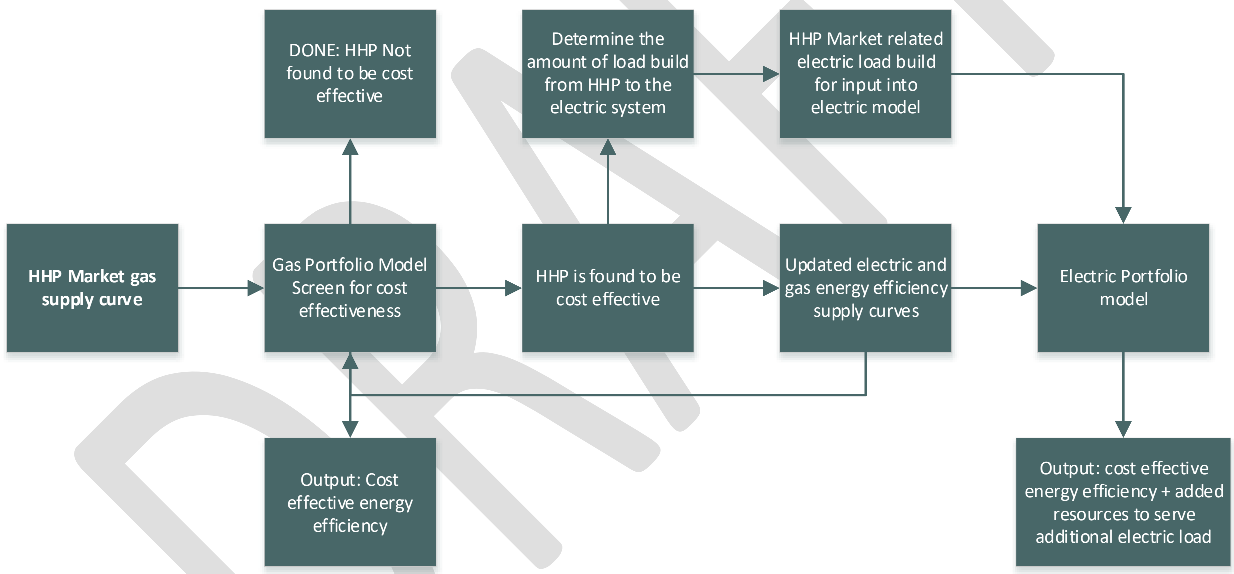
We studied various electrification scenarios to reduce emissions as mandated by the CCA. These combine gas conservation measures using hybrid heat pumps and direct conversion from gas to electric. We developed three scenarios in the CPA for input to this plan's analysis:

- Hybrid Heat Pump (HHP) Market
- Hybrid Heat Pump (HHP) Policy
- Full Electrification Policy

HHP Market: In this scenario, the CPA developed a supply curve using dual-fuel or hybrid heat pumps for space heating that uses gas for cold weather heating below 35 F when electric strip heating normally supports heating in a heat pump. This approach avoids the peak day spike on the electric grid from the electric strip heating element in a fully electric heat pump. Electric peak would require additional infrastructure investment on the electric grid to accommodate this peak load. Instead, the peak in an HHP is on the gas side, which the current infrastructure can accommodate.

The HHP Market supply curve was input into the gas model with all the measured costs, and the gas model screened it for cost-effectiveness. The cost-effective level from the gas model would then inform the electric load builds to be incorporated into the electric portfolio analysis and the adjustments needed to both the electric and gas energy efficiency supply curves. Figure E.6 shows the process flow for developing the appropriate, cost-effective energy efficiency and the load impacts on the gas and electric systems.

Figure E.6: Analytical Process for Evaluating HHP Market Options in the Gas and Electric System



HHP Policy: In this scenario, the CPA developed a supply curve that would electrify the gas end uses upon end-of-life replacement of end-use gas equipment. This scenario used dual-fuel or hybrid heat pumps for residential space heating that works as described above.

Unlike the HHP Market scenario, the HHP Policy adds some electric peak demand and keeps a gas peak load from the HHP:

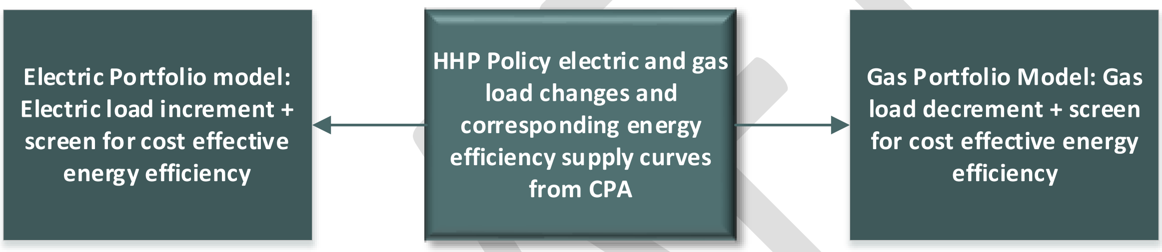
- The HHP Policy adds to the electric peak demand from the non-space heating residential end uses that are electrified.

- The HHP Policy adds electric peak demand from 30 percent of the industrial load assumed to be electrified plus 70 percent of the commercial load assumed to be electrified in the Conservation Potential Assessment (CPA). See Appendix C: Conservation Potential Assessment for more information.

Although the peak demand picture is mixed, keeps significant gas peaks demand, and adds some electric peak demand, the energy impacts in this scenario are different. The gas energy use declines significantly, and the electric energy load build is significant.

The analytical process for the HHP Policy scenario is simpler than the HHP market since we assume an end-of-life replacement without regard to the economic considerations. Our goal is to capture the total cost impact on the system for such an approach. In essence, the load is treated as an increment on the electric side and a decrement on the gas side, with the attendant load shape considerations.

Figure E.7: Analytical Process for Evaluating HHP Policy Options in the Gas and Electric System

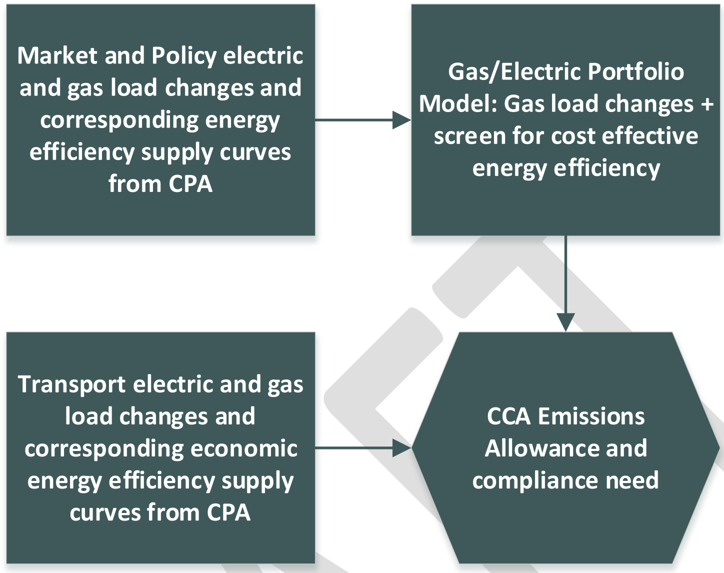


Full Electrification Policy*:* The third scenario assumes that gas end-use equipment is replaced with electric equipment on end-of-life, akin to a policy restricting gas appliance replacements with gas-using equipment. This assumes that residential space heating gas furnaces are replaced with a standard code-compliant electric heat pump. Such heat pumps, like most standard heat pumps, switch to electric resistance heat, often known as auxiliary heat, when the outside temperatures dip below 30-35 F. There are no cold weather heat pumps in this initial replacement, but there are more efficient heat pump enhancements in the energy efficiency supply curve that accompanies this load reduction/build option. The utility would incentivize the placement of a more efficient heat pump, just as it does with all the other end-use measures. Like the HHP Policy scenario, the electric demand increment and the gas load decrements are available simultaneously, as the loads are driven not by economics but by the policy. The analytical process is like the one for the HHP Policy. See Figure E.7.

We accompanied all three electrification scenarios with a supply curve for the small transport customers, those whose emissions are under 25,000 tons per year on average from 2015–2019. Transport customers are not gas sales customers and follow a separate analytical process. Since the transport customers' obligation for PSE is only carbon allowances, we could use the allowances to purchase energy efficiency offsets that would reduce emissions. The amount of energy efficiency available at the CCA allowance prices is economically screened in the CPA, and a final economic potential supply curve is provided in the CPA. We input this into the emissions compliance calculations to determine the net allowance needed.

➔ See Appendix C: Conservation Potential Assessment for more details.

Figure E.8: Developing the CCA Allowance Need



6. Resource Alternative Costs

Table E.10 summarizes resource costs and modeling assumptions for the pipeline alternatives considered in the 2023 IRP and Table E.11 summarizes resource costs and modeling assumptions for storage alternatives.

Table E.10: Renewal Pipeline Segment Costs

Alternative	From/To	Capacity Demand ($/Dth/Day)	Variable Commodity ($/Dth)	Fuel Use (%)	Earliest Available	Comments
NWP TF-1	Sumas to PSE	0.49	0.09	1.6	Nov. 2024	Contracts aggregated and offered in Nov 2024, Nov 2028 and Nov 2030
NWP TF-1	Stanfield to PSE	0.49	0.09	1.6	Nov. 2024	Contracts aggregated and offered in Nov 2024 and Nov 2028
NWP TF-1	Starr Road to PSE	0.49	0.09	1.6	Nov. 2034	-
NWP TF-1	Plymouth to PSE	0.15	0.09	1.6	Apr. 2023	Maximum 15 MDth/d, available from 3rd Parties effective Apr. 2023 associated with Plymouth LNG contract

Alternative	From/To	Capacity Demand ($/Dth/Day)	Variable Commodity ($/Dth)	Fuel Use (%)	Earliest Available	Comments

Note: The Capacity Demand Charge is an average rate over the study period

Table E.11: Resource Costs for Needle Peaking Alternatives

Alternative	Storage Capacity (MDth)	Maximum Withdrawal Capacity (MDth/day)	Days of Full Withdrawal (days)	Capacity Demand Charge ($/Dth/day)	Earliest Available	Comments
Plymouth LNG	241.7	15	16	0.0474	Apr. 2023	Existing plant - requires LT firm NWP capacity
Swarr	90	30	3	0.107	2027	Existing plant requiring upgrades- on-system, no pipeline required

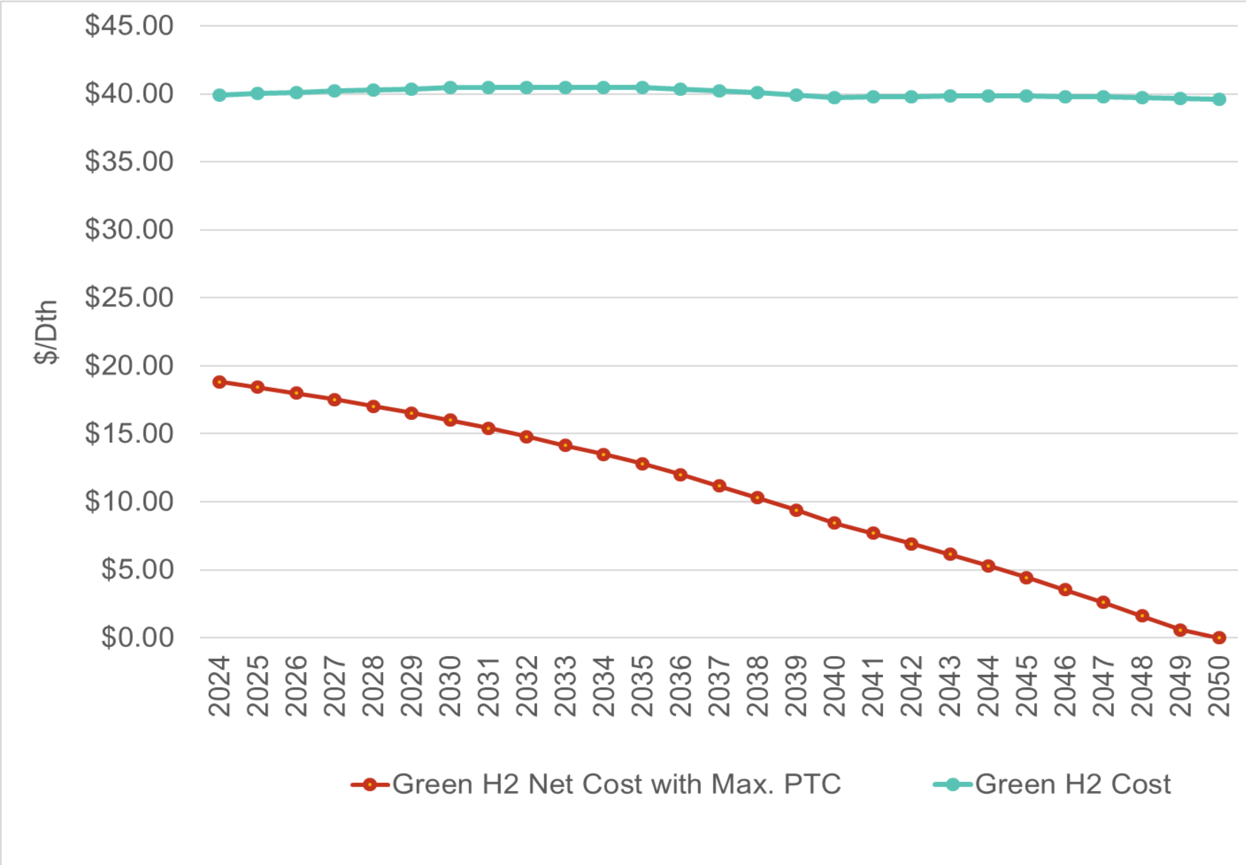
6.1. Green Hydrogen Costs

The federal government has introduced several powerful incentives recently to spur green hydrogen development, scalability, and adoption. In late 2021, the Bipartisan Infrastructure Law contained funding for regional hubs around the country that demonstrate how hydrogen suppliers and end-users can be connected at an industrial scale, laying the groundwork for future commercial opportunities. More recently, the Inflation Reduction Act (IRA) contained production tax credits that incentive the use of green power and unionized labor to create green hydrogen. If certain thresholds for power and labor are met, a $3 per kg production tax credit is available, which is approximately a 75% reduction compared to the non-PTO commodity cost. Other efforts, including the Department of Energy's Hydrogen Earth Shot, are designed to lower the non-subsidized cost of hydrogen to $1 per kg in one decade.

When comparing hydrogen to natural gas, a baseline of $8 per MMBtu of natural gas is roughly equivalent to $1 per kg of hydrogen. In other words, for the same energy content, a hydrogen supplier contract of $1 per kg would equate to purchasing natural gas at $8 per MMBtu, or 1,000,000 cu ft. Before the passage of the IRA, most cost curves showed a 2020 price point of $4 to $5 for hydrogen, with a relatively stable high price due to the lack of adoption and inability to reach economies of scale. The recent passage of the CCA effectively increases the price of natural gas over time. In conjunction with the IRA subsidies, hydrogen became cheaper than natural gas in the early 2030s. As the region passes through this window, demand will likely increase due to the lower fuel cost, ESG commitments, and regulatory mandates at the federal and state levels.

We based the price forecast in Figure E.9 on a dedicated renewable solar electricity source and the price forecast after applying the IRA incentive at the $3/kg of green hydrogen.

Figure E.9: Cost Curve for Washington-based Green Hydrogen Using an Electrolyzer



6.2. Renewable Natural Gas Costs

Table E.12 shows the levelized cost for the various RNG supply options that were modeled in the gas analysis.

Table E.12: Levelized cost of RNG

Alternative	RNG Contract	Source	Receipt Point	Max. MDTh/yr	Levelized Cost $/Dth	Year Offered
9	RNG-physical N-1	PNW	Sumas	1,600	$20.93	2024
10	RNG-physical N-2	PNW	Sumas	1,388	$19.53	2025
11	RNG Attribute-1	N. America	Sumas	3,000	$20.77	2024
12	RNG Attribute-2	N. America	Sumas	1,000	$21.71	2025
13	RNG Attribute-3	PNW	Stanfield	340	$20.25	2024
14	RNG Attribute-4	N. America	Sumas	8,000	$19.01	Annual
15	RNG-physical O-1	PNW	On system	70	$19.14	2024