LEGISLATIVE AND POLICY CHANGE

CHAPTER THREE

PUGET SOUND ENERGY

Contents

1. Introduction

State policy affecting the energy sector has changed rapidly in the last decade. Puget Sound Energy (PSE) continues to adapt planning processes to the quickly shifting policy landscape. This chapter outlines the major state and federal energy legislative and policy changes and how they informed the 2023 Gas Utility Integrated Resource Plan (2023 Gas Utility IRP).

On the state level, we incorporated rules from the Climate Commitment Act (CCA) and new building codes. We also included the known impacts of the federal Inflation Reduction Act (IRA) in the 2023 Gas Utility IRP.

2. Climate Commitment Act

In 2021, the Washington State legislature passed the Climate Commitment Act (CCA) establishing a comprehensive cap-and-invest program to reduce statewide greenhouse gas (GHG) emissions through a price on carbon. The law directed the Washington State Department of Ecology (Ecology) to develop rules to implement and administer the program beginning on January 1, 2023. As part of this process, Ecology adopted the final program rules on September 29, 2022.

2.1. Program

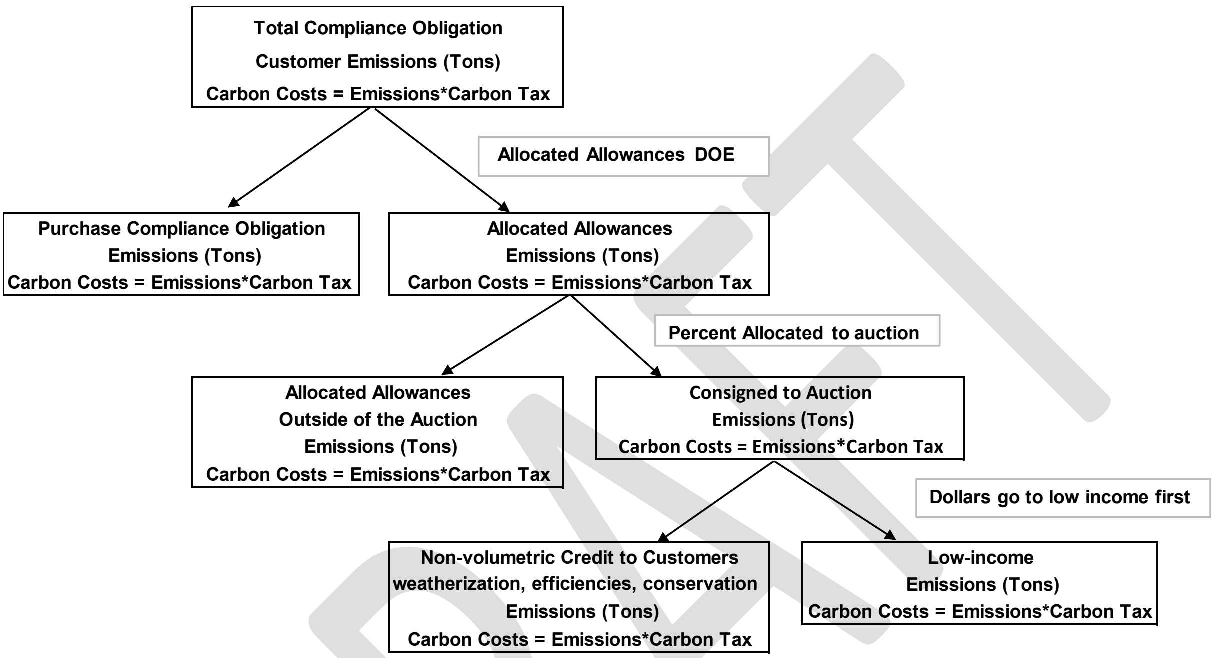
The cap-and-invest program sets an overall cap on state GHG emissions, which declines over time in line with the state's statutory GHG emissions limits to drive down pollution. Covered entities must report their GHG emissions to Ecology and obtain allowances to cover them. An allowance is a mechanism created by Ecology, equal to one metric ton of GHG emissions, and may be directly distributed by Ecology, purchased at auction, or traded with others in the program. The program's goal is to establish an overall cap on carbon emissions, then create a carbon marketplace for covered entities to find the most efficient means to reduce their emissions. The CCA mandates that the state equitably invest revenues raised through state-run allowance auctions in projects that reduce emissions and address climate resiliency and environmental justice, among other priorities.

2.2. Impacts and Actions

Gas utilities are required to comply with CCA. However, how the gas utilities comply with CCA could impact electric utilities, such as through targeted electrification activities. We include an electrification analysis and its results citing impacts on possible future electric infrastructure requirements in this 2023 Gas Utility IRP. The 2023 Gas Utility IRP analysis highlights the importance of a dual-fuel energy system as we transition to a low-carbon economy.

Gas utilities receive direct allocation of no-cost allowances (based on a 2015–2019 baseline) to protect ratepayers from price increases, and allowances will decline proportionally with the statewide cap. Starting in 2023, 65 percent of the no-cost allowances, increasing 5 percent annually to 100 percent by 2030, must be consigned to auction to benefit customers, prioritizing the elimination of additional cost burden on low-income customers. According to the law, revenues from allowances sold at auction must be returned by providing non-volumetric credits on ratepayer utility bills, prioritizing low-income customers, or used to minimize cost impacts on low-income, residential, and small business customers through actions that include, but are not limited to, weatherization, decarbonization, conservation and efficiency services, and bill assistance. The customer benefits from allowances consigned to auction must be in addition to existing requirements in statute, rule, or other legal requirements.

Figure 3.1 CCA Breakdown of Emission Allowances



(1) Over time as percentage of the baseline emissions starting at 95 percent in 2023 and decreasing by 7 percent annually until 2030. Starting in 2031 the decrease is 1.8 percent annually.

(2) The percent of allowances allocated to the auction starts at 65 percent in 2023 and increases to 100 percent by 2030.

Puget Sound Energy must comply with the CCA; as a result, we expect price impacts for all our customers because the CCA imposes a price on carbon. We will work hard to mitigate those impacts through decarbonization efforts and managing our allowances.

As shown in Figure 3.1, PSE is required to consign (or sell) no-cost allowances, starting at 65 percent in 2023, at Ecology's state-run auctions. Consignment requires that PSE reinvest these revenues for a specified set of purposes. Puget Sound Energy purchases the consigned allowances at auction, and Ecology returns the revenue to PSE with stipulations on how we use those funds. Puget Sound Energy must eliminate the additional cost burden to low-income customers from implementing the CCA with available revenues. We may provide non-volumetric rebates to customers, prioritizing low-income customers, or use those revenues toward other customer benefits beyond legal requirements, such as weatherization, decarbonization, conservation and efficiency services, or bill assistance. If we use consigned revenue for weatherization or energy efficiency beyond what is cost-effective, it would impact the load forecast and could affect the resource plan. We will reflect those effects in future IRPs when more information on the CCA implementation is available.

We expect to manage the remaining no-cost allowances, purchase additional allowances, and pursue other decarbonization strategies to cover our compliance obligation under the program. Puget Sound Energy will bill customers for compliance obligations under the CCA.

➔ A full explanation of the methodology and assumptions we used to model the impacts of the CCA is available in Chapter Four: Key Analytical Assumptions.

Please visit the Washington State Department of Ecology's CCA rulemaking website to learn more about this state program.

3. Technology, Codes, Standards, and Electrification

Energy efficiency technology and changing codes and standards impact customer choices and energy efficiency programs.

The two energy codes impacting PSE customers that we included in the 2023 Gas Utility IRP, the Washington State Energy Code (WSEC) and several city ordinances, are transitioning to include a focus on carbon emissions and energy efficiency. These changes emphasize the electrification of systems currently fueled by gas. Since February 2021, the 2018 WSEC no longer gives builders efficiency credits for new single-family homes that install gas space or water heating, instead giving them credits for installing heat pumps for heat and hot water.

In 2021, the Seattle Energy Code[1] created significant barriers to using gas for space and water heating in new commercial and multi-family buildings. With few exceptions, new buildings will use various types of heat pump technology to meet the demands of these systems. The Seattle Energy Code will affect the forecast demand for PSE's gas utility in Seattle, but the change in demand for electricity will impact Seattle City Light, the electric utility for the city of Seattle, not PSE's electric system.

Another provision included in the 2023 CPA is a statutory requirement (RCW 19.27A.160) that directs the WSEC revision process to achieve a 70 percent reduction in energy consumption by the year 2031 compared to a 2006 code baseline.[2]

The Washington State Building Codes Council (SBCC) has approved code changes to the 2021 WSEC that require builders to install electric heat pumps in new commercial and multi-family new construction in place of gas heating

[1] The cities of Bellingham and Shoreline also passed similar gas bans in their jurisdictions in 2022.

[2] RCW 19.27A.160 Residential and nonresidential construction — Energy consumption reduction — Council report. (1) Except as provided in subsection (2) of this section, residential and nonresidential construction permitted under the 2031 state energy code must achieve a seventy percent reduction in annual net energy consumption, using the adopted 2006 Washington state energy code as a baseline.

and cooling technologies and gives preference to electric heat pumps in the residential building codes for space and water heating. Officials adopted these proposals into the WSEC at the end of 2022; they will go into effect on July 1, 2023. If implemented, these changes will affect PSE by increasing the electric energy and peak demand more than currently forecasted. The change to the peak demand will be affected by the technology installed in these new buildings.

Although technology continues to provide innovation in how we meet demand in customer homes and buildings, it takes time for these changes to gain significant market penetration. Heat pump water heaters, for example, have been on the market for nearly a decade, but they are primarily limited to the new home market rather than the much larger existing home market. When code changes quickly, adoption issues arise and may include:

- The complexity of the design, operation, and maintenance of systems that have traditionally been hands-off.
- The lack of preparedness to install and maintain these systems in the installer community.
- The lack of robust examples and applications that have validated approaches, such as new building electrification, the sole use of heat pumps to serve space, and water heating in large-demand applications.

It also takes time to work out design flaws, build trust in the installer and trades community, and reduce costs so consumers can pay reasonable prices as we make these changes.

Despite the rapid pace of changing technology and codes and standards, we are committed to ensuring we make PSE customers aware of the opportunities to reduce energy use and their carbon footprints, advocating for intelligent changes to codes and standards, and working with our trade allies to understand and mitigate barriers to new technology adoption.

3.1. Impacts and Actions

The CPA included the following codes:

- Forecast of more efficiency codes per RCW 19.27A.160
- Gas restriction in city ordinances: Seattle, Shoreline and Bellingham
- Updates to the 2018 WSEC

The 2023 Gas Utility IRP includes electrification scenarios. In this plan and with input from interested parties, we ran a full electrification and hybrid heat pump scenario based on equipment burnout. More information about the detailed assumptions of this analysis is in Chapter Four. We look forward to refining this analysis in future IRP cycles.

Zero growth sensitivity: Washington State updated the 2021 WSEC in late 2022 after we completed the 2023 conservation potential assessment (CPA); however, we included informative policy scenarios. One scenario explored zero growth in gas customers. This scenario over-states the impact the building code would have if implemented, as it allows new gas customers with non-heating appliances, but it is a reasonable approximation of the impact. We also included two policy-based electrification scenarios in the CPA, and the accompanying electric analysis will be part of the 2023 Gas Utility IRP. We adopt hybrid heat pumps as a complete replacement in the residential customer classes in one scenario and electric heat pumps in the other.

4. Inflation Reduction Act

The federal Inflation Reduction Act (IRA or Act) was passed and signed into law in August 2022 and represented the single most significant federal investment in clean energy and climate-focused solutions in U.S. history, approximately $370 billion. The Act addresses climate change primarily by providing tax incentives and consumer rebates to move project developers and households towards lower-carbon or zero-carbon technologies. In the electric sector, the IRA provides subsidies for renewable electric generation. Impacts on gas utilities are associated with incentives for green hydrogen[3] and subsidies for individual customers for electric appliances, which could impact growth or conversions from gas to electric appliances. It is too early to understand how the IRP may affect the conversion of certain customers from gas to electric service — we will consider this in future IRPs.

4.1. Impacts and Actions

The 2023 Gas Utility IRP includes the IRA impact on green hydrogen. However, we did not address the IRA impact on customer appliance costs for two reasons. First, Congress passed the IRA after we completed the conservation potential assessment. Second, rulemakings are still required to clarify how the Act will impact appliance prices to end-use customers. We will include those impacts in future IRP analyses when the information becomes available. Future appliance subsidies may not affect future conservation potential assessments. Due to the use of a total resource cost test in Washington. However, such subsidies might impact customer decisions. We will factor in IRA subsidies when we consider customer behavior in future analyses.

5. Infrastructure Reliability

Gas transportation and distribution systems do not need to have the redundant capacity that electric distribution systems have because most gas infrastructure is underground, insulated from wind and storm damage. Equipment failure is rare, but it does occur, and there can be significant repercussions. For this reason, we build flexibility and resiliency into the system in four ways.

1. **A conservative planning standard:** Since we base PSE's peak day design standard on the coldest temperature on record for our service territory, and we do not often reach this extreme temperature, and it is even more rarely sustained, there is excess capacity in the system on most days.

[3] The existing production tax credit (PTC) and investment tax credit (ITC) are extended at full value through 2024. Existing PTCs and ITCs expire after 2024. In their place, functionally similar clean energy production tax credits and clean energy investment tax credits take effect with broader flexibility to capture a greater number of eligible technology-neutral energy sources. The new credits have similar value and definition as the prior credits if taxpayers meet prevailing wage and apprenticeship requirements. Taxpayers are allowed to elect which credit they choose when placing an eligible project into service.

2. **Cooperation with regional entities:** We applied the lessons learned from the October 2018 event discussed later in this document in the restructured Northwest Mutual Assistance Agreement (NWMAA). Members of the agreement utilize, operate, or control gas transportation and/or storage facilities in the Pacific Northwest or represent major loads on the system. Members pledge to work together to provide and maintain firm service during emergencies and restore normal service to their customers as quickly as possible when such events occur.

3. **Diverse transport resources**: Puget Sound Energy has built a gas transportation portfolio that intentionally sources gas equally from the north and south of our service territory to preserve flexibility during supply disruptions. We source approximately 50 percent of PSE's gas supply from Station 2 and Sumas to the north, and 50 percent from the Alberta Energy Company (AECO) and the Rockies connected to the south.

4. **Gas storage:** Including gas storage in the portfolio via Jackson Prairie, Clay Basin, Gig Harbor LNG, and Tacoma LNG contributes to flexibility and resiliency in several ways. Storage minimizes the need and costs associated with relying on long-haul pipelines to deliver gas on cold days; it allows PSE to purchase more gas in the typically less expensive summer season, and it can furnish gas supply in the event of a pipeline disruption. Two incidents illustrate how these strategies work in practice.

   - A 36-inch pipe on the Westcoast pipeline7 (Westcoast) between Station 2 and Sumas in central British Columbia (B.C.) ruptured in the early evening of October 9, 2018, shutting off gas flow from production points in northeast B.C to Sumas for over 30 hours. This rupture resulted in the loss of more than 800,000 Dth per day of Sumas supply. Coincidentally, the Jackson Prairie Storage Project was closed for scheduled maintenance at the time. Coordinating efforts through the Northwest Mutual Assistance Agreement, all gas pipelines, utilities, power plant operators, and major industrial customers affected worked together to add supply or shed load. Fortis BC, a large gas utility in southern British Columbia, was able to use some gas flowing on its pipeline from Alberta (Southern Crossing), and PSE, other utilities, and end-users took steps to reduce gas consumption or increase supply from their on-system storage.

     These combined efforts prevented a significant loss of pressure in the system, and by 2 p.m. on October 11, 2018, portions of the Westcoast pipeline system were back in service, and 38 percent of the normal gas volume from B.C. was flowing. Jackson Prairie personnel worked around the clock to complete the storage facility's planned maintenance ahead of schedule, providing important additional supply to ease the regional situation. Thanks to the combined efforts of Northwest Mutual Assistance participants, the incident lasted less than 48 hours; however, the extensive testing and recertification required to restore the gas flow from B.C. to 100 percent of capacity took over a year. Westcoast was allowed to operate its system at 100 percent by mid-November 2019.

   - In February 2019, while the Westcoast pipeline was still operating significantly below normal levels, the Jackson Prairie Gas Storage Project suffered a major compressor failure that reduced gas deliverability by approximately 250,000 Dth per day. The compressor was repaired and back online in less than 30 days, and the net effect of the outage was a reduction in total available storage withdrawals of only 750,000

Dth. Customers experienced no service interruption, but to compensate for the unavailable storage supplies, PSE and other entities that draw gas from the storage facility had to purchase additional flowing supply from the market when supply was low and demand, and therefore prices, were high.

Although quite rare, these incidents demonstrate the resilience of the region's gas transportation and storage system. Despite two significant failures, no firm residential or commercial customer was without gas, nor was there a loss of electrical service, which is increasingly dependent on the gas infrastructure. It is impossible to model random outages with our current modeling capabilities. However, these recent real-world experiences demonstrate that PSE's steps to prepare for occasional infrastructure failure have proven successful.

6. Supply Adequacy

As noted, Puget Sound Energy intentionally sources gas from the north and south of our service territory to preserve flexibility during supply disruptions. We source fifty percent of PSE's gas supply from Station 2 and Sumas to the north, and 50 percent from AECO and the Rockies connected to the south.

Puget Sound Energy holds firm capacity on Westcoast's system for approximately 50 percent of our needs from British Columbia to access gas supplies in the production basin in northern British Columbia rather than only at the Sumas market. 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.

When gas production in northeast B.C. increased substantially due to the shale revolution, a shortage of pipeline capacity developed as producers sought market outlets for the increased production. For the past several years, Westcoast has run at its maximum available capacity nearly year-round (limited by maintenance restrictions); so far, the result has been an adequate supply at Sumas in winter months when the pipeline is in normal operations and an excess in summer months.

After a recently completed expansion, West Coast is again fully contracted. However, in 2027, the Woodfibre LNG export facility is expected to begin production, utilizing approximately 300,000 Dth per day of gas supply from the Huntingdon B. C. (Sumas) market. Woodfibre has acquired the firm West Coast capacity necessary to serve their demand, and they will control their supply and destiny. The firm pipeline capacity they will use to access their gas supply is currently used to provide adequate and occasionally abundant supplies at the Sumas market hub to other customers. Once Woodfibre LNG commences production of LNG for the export market, the supply available for other customers at Sumas on most days will be dramatically reduced.

Because there is currently an equilibrium of firm supply and firm demand in peak winter periods and a surplus in summer periods, PSE, and others active in the Sumas market, believe there is a risk for shortages of supply at Sumas when Woodfibre begins operations in 2027.

As a result, there are three proposed pipeline expansions.

1. Fortis BC Energy proposed an expansion and new route for its Southern Crossing Pipeline to bring additional supplies from Alberta to Huntingdon/Sumas. The primary driver for the project is Fortis's desire to obtain some diversity of supply routing as risk mitigation after the 2018 Westcoast Pipeline failure. We expect Fortis would move forward with this project, even if no additional shippers signed on. If built, Fortis would likely turn back some of its current capacity on T-South, likely obviating the need for Westcoast to expand its facilities.

2. Westcoast Energy held an open season for additional T-South (Station 2 to Huntingdon/Sumas). The cost of this expansion will have a significant upward impact on the rates PSE pays for service on Westcoast due to Canadian regulatory policy requiring rolled-in rate making. However, the incremental volumes should eliminate any potential for shortfall. Puget Sound Energy and other Westcoast shippers will likely oppose the expansion of facilities if Fortis moves ahead on its project since capacity abandoned by Fortis could serve incremental demand on Westcoast. Also, the Vancouver market would be fully served, and there is no additional capacity available on the Northwest Pipeline to move gas further south.

3. Northwest Pipeline has proposed a project to expand its capacity from Stanfield interconnect with Gas Transmission NW (GTN) west through the Columbia Gorge and north to Sumas. The project would have three, maybe four purposes: move additional gas from Stanfield to the I-5 corridor and Huntingdon/Sumas for Fortis or others, reduce displacement requirements along the Columbia Gorge, and all, thereby potentially creating some additional southbound capacity from Sumas to Stanfield.

Details on all three of these projects are, at best, vague, but two things are certain: each is costly and will draw considerable attention in the decarbonization environment. We did not consider these projects in the current IRP because we are not actively pursuing additional pipeline capacity. However, we may consider joining a project if doing so could obtain more favorable capacity than the existing one without imposing high costs or risks on PSE customers. Any of these projects would likely alleviate any concerns over the reliability of the supply market at Huntingdon/Sumas.

We are confident we will be able to acquire adequate supplies at Sumas; however, we expect prices to be higher under cold-weather conditions.

We will continue to monitor developments in the northeast B.C. supply and capacity market and analyze the implications on an ongoing basis.

6.1. Actions

We are not studying the projects in detail in this 2023 Gas Utility IRP for the following reasons:

- Costs for each project are extremely high, and much will spread to non-participants.
- We could assure greater access to Station 2 by taking some of Fortis's excess Westcoast pipeline capacity and alleviate any concerns at Sumas.
- Puget Sound Energy's declining demand does not justify additional capacity to city-gate.

- Puget Sound Energy has sufficient capacity on the Northwest and Westcoast pipelines.
- Regional demand does not justify expansion beyond Fortis' new line.

7. Alternative Fuels Supply

The 2023 Gas Utility IRP evaluated alternative fuels to reduce carbon emissions. Although we assessed renewable gas in previous IRPs, this is the first time we evaluated the impact of incorporating green hydrogen into our distribution system. Blending green hydrogen into our existing distribution system was a new concept for PSE, and it is a new technology, and with that came additional risks we considered.

7.1. Green Hydrogen

Hydrogen is a highly flexible commodity chemical currently used in a wide range of industrial applications and poised to become an essential energy carrier in the power sector. Hydrogen is abundant in several feedstocks, including water, biomass, fossil fuels, and waste products, but requires a significant amount of energy to produce elemental hydrogen from these feedstocks. It is common practice to classify hydrogen with color to describe the feedstock and energy source used to make the hydrogen. Green hydrogen is the most attractive variety of hydrogen in the context of a clean energy transformation. Green hydrogen is typically produced from water electrolysis using low- or non-emitting energy sources to power the process.

Green hydrogen has the potential to act as a useful energy carrier to store and deliver low- or no-carbon energy to where and when it is needed. When wind and solar generation is plentiful, utilities can turn on electrolyzers to produce and store hydrogen. When demand is high and renewable generation is unavailable, the stored hydrogen may be combusted in a turbine or electrochemically reacted in a fuel cell to produce electricity. A key advantage green hydrogen has over other storage technologies (e.g., battery energy storage systems or pumped hydroelectric storage) is that hydrogen is stable over long periods, meaning utilities can store energy month to month instead of hour to hour as in other storage systems. This long storage period allows hydrogen to store excess energy in spring and autumn for use in the peak summer and winter seasons.

Despite its potential usefulness, the green hydrogen industry must overcome several obstacles before it can play a significant role in the power sector. Large-scale electrolyzers are an emerging technology with relatively few installations scattered across the globe. Research and development into scaling up production and reducing the costs of electrolyzers are necessary to produce the quantities of hydrogen needed to support the power sector. Powering large installations of electrolyzes will also require a large amount of low- or no-carbon electricity. The development of adequate quantities of wind, solar or other non-emitting generation and the transmission to move the power to the electrolyzers will be necessary. After production, hydrogen must be stored and transported. Pipelines are the obvious choice for storage and transportation, but dedicated pipelines will be needed for high-purity hydrogen storage and transport. Finally, to access the energy stored in hydrogen, existing combustion turbines will require modifications to accommodate the new fuel, or new technologies, such as fuel cells, will need to be researched and developed. These infrastructure-related hurdles add cost and require detailed long-term planning to successfully incorporate green hydrogen into the power system.

The 2022 IRA provided incentives that have dramatically reduced the cost barriers to establishing the infrastructure required to make green hydrogen an economically viable energy carrier for the power system. Production Tax Credits (PTCs) from the IRA could reduce hydrogen prices by up to $3 per kilogram[17], putting green hydrogen price forecasts on par with gas prices by the mid-2030s.

This development and additional momentum behind green hydrogen from the Department of Energy's Regional Clean Hydrogen Hubs[18] spurred PSE to include green hydrogen as a fuel source in the 2023 Gas Utility IRP. We will likely obtain green hydrogen as part of an offtake agreement from an independent fuel supplier; therefore, hydrogen is modeled simply as a fuel source available in the SENDOUT model. We assume a hydrogen blend into the local distribution system of up to 15 percent by volume. Supply is essential in modeling green hydrogen as a fuel source because it will take time to establish the required infrastructure. Based on our understanding and engagement in the nascent green hydrogen industry, it seems likely that significant quantities of hydrogen for gas system blending will become available in the year 2028.

Price is the final consideration required to model green hydrogen. We developed a hydrogen price forecast based on inputs from industry consultations. We also applied the maximum PTC benefit to the green hydrogen price, reflecting the incentives expected for green hydrogen development in the Pacific Northwest. Chapter Four illustrates the price forecast for green hydrogen in the SENDOUT model.

7.2. Renewable Natural Gas

The Washington legislature adopted HB1257 in 2019. Section 12 of the law, encourages utilities to incorporate renewable natural gas into their supplies used to serve all retail customers. In December of 2020, the UTC issued a policy statement on how utilities may incorporate RNG into their gas portfolio to serve customers[4].

Puget Sound Energy worked with the Commission and other interested parties to develop guidelines to implement the law's requirements. We also conducted a Request for Proposal (RFP) soon after the bill was passed to determine the availability and pricing of RNG supplies. After analysis and negotiation, PSE acquired a long-term supply of RNG from a recently completed and operational landfill project in Washington at a competitive price. We will incorporate RNG supply not utilized in PSE's voluntary RNG program(s) into PSE's supply portfolio, displacing gas purchases as provided for in HB 1257.

Renewable natural gas (RNG) is pipeline-quality biogas we can use as a substitute for conventional gas streams. Renewable gas is gas captured from dairy waste, wastewater treatment facilities, and landfills. The American Biogas Council ranks Washington State twenty-second in the nation for methane production potential from biogas sources, with the potential to develop 128 new biogas projects within the state. Renewable Natural Gas costs more than conventional gas; however, it provides greenhouse gas benefits in two ways: 1) by reducing CO_2e emissions that might otherwise occur if the methane and/or CO_2 is not captured and brought to market, and 2) by avoiding the upstream emissions related to the production of the conventional gas that it replaces.

[4] UTC Policy Statement: https://www.utc.wa.gov/casedocket/2019/190818/docsets

Renewable Natural Gas is not yet produced at utility scale in this region and will require developing supply sources and an infrastructure to deliver that supply to utilities. Market forces will likely direct RNG to gas utilities before it is used to generate energy. The electric sector has access to more mature renewable options that capture surplus energy than the gas sector. These options include hydro, wind, solar, geothermal, and energy storage systems. Gas utilities have few opportunities to decarbonize, so as they begin decarbonizing their systems in earnest, markets will probably pull RNG to gas utilities before it is used broadly as a generation fuel. Costs remain high to upgrade RNG to gas pipeline specifications and bring it to market. Another obstacle is that RNG currently generated in the U.S. is used chiefly as a transportation fuel because of federal and state programs such as the EPA's Renewable Fuel Standard (RFS) and California's Low Carbon Fuel Standard (LCFS), which provide more value through generating credits than when it is used for end-use consumption or to generate electricity. However, gas utilities can use the existing distribution network to deliver renewable fuel. This 2023 Gas Utility IRP analyzes local and national sources of RNG projects that would connect to the Northwest Pipeline (NWP) or PSE's system and displace conventional gas that would otherwise flow on NWP capacity. With the additional costs on carbon because of the Climate Commitment Act, the high cost of RNG may no longer be a barrier to leveraging the fuel source within the gas utility portfolio under specific scenarios.

We measure the benefits of RNG primarily 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 the connection of acquired RNG directly to the PSE system, but these savings are 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.

We are planning significant investments in cost-effective RNG supplies and believe there is value in being a proactive RNG buyer and/or producer in the region. We are confident that PSE can acquire sufficient RNG volume to meet the needs of our future voluntary RNG program participants. We believe PSE will exceed the 5 percent cost limitation related to the RNG incorporated into the supply portfolio[5]. To meet the expectations in the Commission 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 its portfolio and achieving meaningful carbon reductions.

7.3. Future Technologies

Although gas utilities do not have as many options as electric utilities to decarbonize, green hydrogen and RNG are steps toward a decarbonized pipeline. A significant amount of innovation is occurring in the decarbonization space, allowing for potential future opportunities to continue decarbonizing the gas system. The future technologies could include commercially viable technologies such as synthetic gas from direct air capture or waste carbon monoxide. This

[5] U-190818 – Policy Statement – RNG: https://apiproxy.utc.wa.gov/cases/GetDocument?docID=69&year=2019&docketNumber=190818

technology is not currently available, so we have not included it in this IRP. We will continue researching future decarbonization technologies and include those resource alternatives in subsequent IRPs as information and data are available.