KEY ANALYTICAL ASSUMPTIONS
CHAPTER FOUR

PUGET SOUND ENERGY

Contents

1. Introduction

This chapter describes the forecasts, estimates, and assumptions we developed for Puget Sound Energy's (PSE's) 2023 Gas Utility Integrated Resource Plan (2023 Gas Utility IRP) analysis. We also include electrification scenarios and their impacts on the gas and electric portfolio.

➔ Chapter Six: Gas Analysis contains the results of the electric impacts and details of the gas analyses.

For the IRP process we designed gas scenarios to test how different sets of economic conditions affect portfolio costs and risks, and then developed the data needed to model the scenarios. Scenario data inputs include the 2023 Gas Utility IRP demand forecast, price assumptions for gas and CO_2 costs, assumptions about cost and characteristics for existing and generic resources, and pipeline considerations.

We then developed portfolio sensitivities that start with the optimized, least-cost reference portfolio produced by the scenario analysis and change one resource, environmental regulation, or other condition at a time to examine the effect of that change on the portfolio. We analyzed eight sensitivities for the gas analysis.

The time horizon for this IRP is 2024–2050. We expanded the gas analysis from the traditional 20-year period to better understand the implications of the Climate Commitment Act (CCA).

2. Gas Analysis

Passage of the CCA in 2021 added emissions compliance to the existing IRP goals of meeting the system energy and peak resource needs. The 2023 Gas Utility IRP gas analysis evaluates resource alternatives to fill future resource needs on a peak design day[1] while incorporating initial CCA allowances prices resulting from the Department of Ecology's (Ecology) *Summary of market modeling and analysis of the proposed Cap and Invest Program* study released in July 2022.[2]

Puget Sound Energy does not plan for and provide natural gas commodity supply or upstream transportation capacity for small transport customers, which are thus not included in the gas analysis. These customers have their own contracts for gas supply and upstream transportation, PSE only provides delivery via its distribution network.

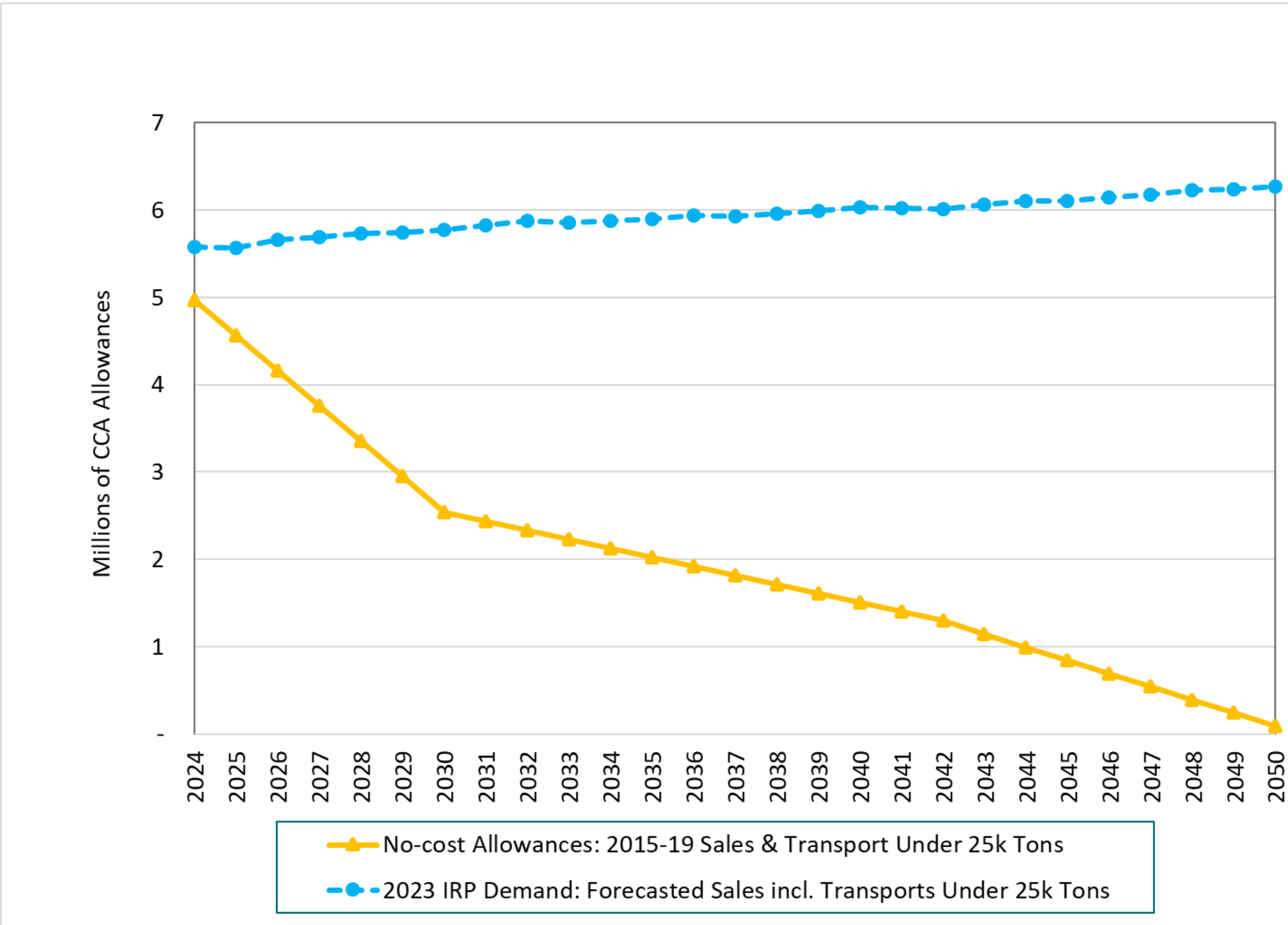
This IRP portfolio analysis optimizes the system costs and resource needs to meet compliance (a) through the purchase of allowances, a price cap, and/or (b) enforcing a hard emissions reduction, or emissions cap, or (c) a combination of allowance purchases and emissions reductions.

1 The current design standard ensures that we plan PSE supply to meet firm loads on a 13° design peak day, corresponding to a 52-heating degree day (HDD)

2 https://ecology.wa.gov/DOE/files/4a/4ab74e30-d365-40f5-9e8f-528caa8610dc.pdf; see pages 9 and 10.

➔ For more information about the CCA, please refer to Chapter Three: Legislative and Policy Change.

Figure 4.1: PSE CCA Allowance and 2023 Gas Utility IRP Gross Demand Forecast before Demand-side Resources



2.1. Gas Analysis Assumptions

Integrated Resource Plan (IRP) analyses encompass a long-term planning horizon. For this IRP, we examined scenarios that extend 27 years into the future. To conduct such an analysis, we mostly rely on forecasts we developed using reasonable assumptions about the future because of the long-term changing nature of input variables. These assumptions help us construct a potential future, and through the IRP analysis, we can study the impact of various future scenarios on the gas system. This section reviews the key variables and their assumptions used in this IRP.

2.1.1. PSE Customer Demand

The graphs below show the peak and annual energy demand forecasts for gas service without including the effects of demand-side resources (DSR). The gas peak demand forecast is for a one-day temperature of 13° Fahrenheit (F) at

SeaTac airport. The demand forecast for the 2023 Gas Utility IRP includes the impacts of climate change. The impact of climate change on the forecast reduced the energy forecast due to decreasing heating degree days from warmer average temperature trends in the winter. Although experts expect the average temperature to increase, our analysis reaffirmed the design temperature's extreme low of 13° F due to the increasing extreme temperature ranges.

Energy Demand Forecast

The energy demand forecasts include sales (delivered load) plus system losses.

➔ See Chapter Five: Demand Forecast for a discussion of the impact of climate change in the forecast.

In addition to the 2023 Gas Utility IRP base (mid) demand forecast, based on the fiscal year 2022 load forecast, we specifically developed a zero-gas growth scenario for the 2023 Gas Utility IRP. That scenario restricts the demand forecast to no new gas customers after 2026. Even though no current policy restricts new gas customers, this scenario assumes there could be a policy approved to limit the addition of new gas customers, and it assumes the earliest this could occur is in 2026.

Figure 4.2: 2023 Gas Utility IRP Gas Sales Peak Day Demand Forecast before DSR — Zero-growth and Mid-growth

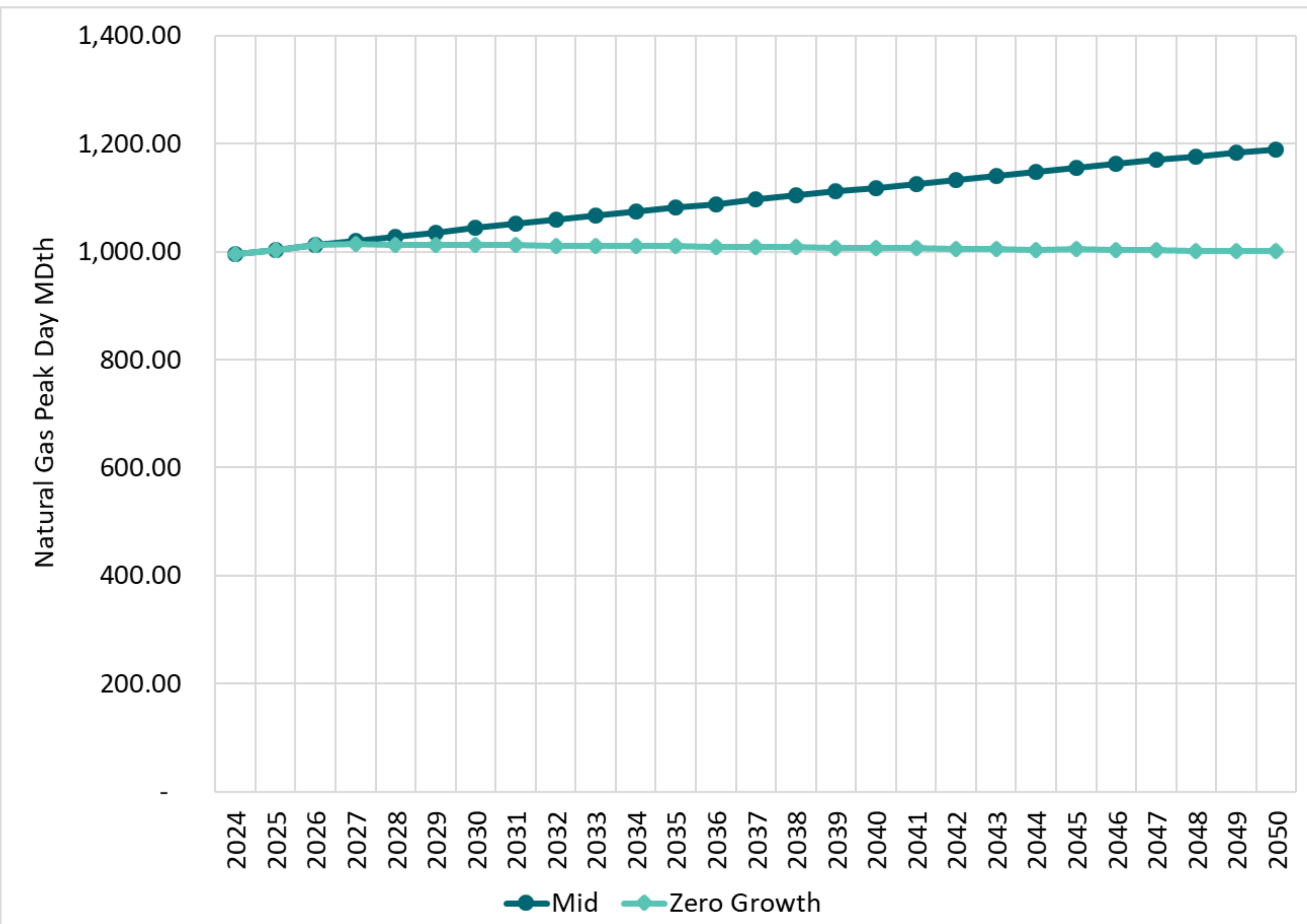
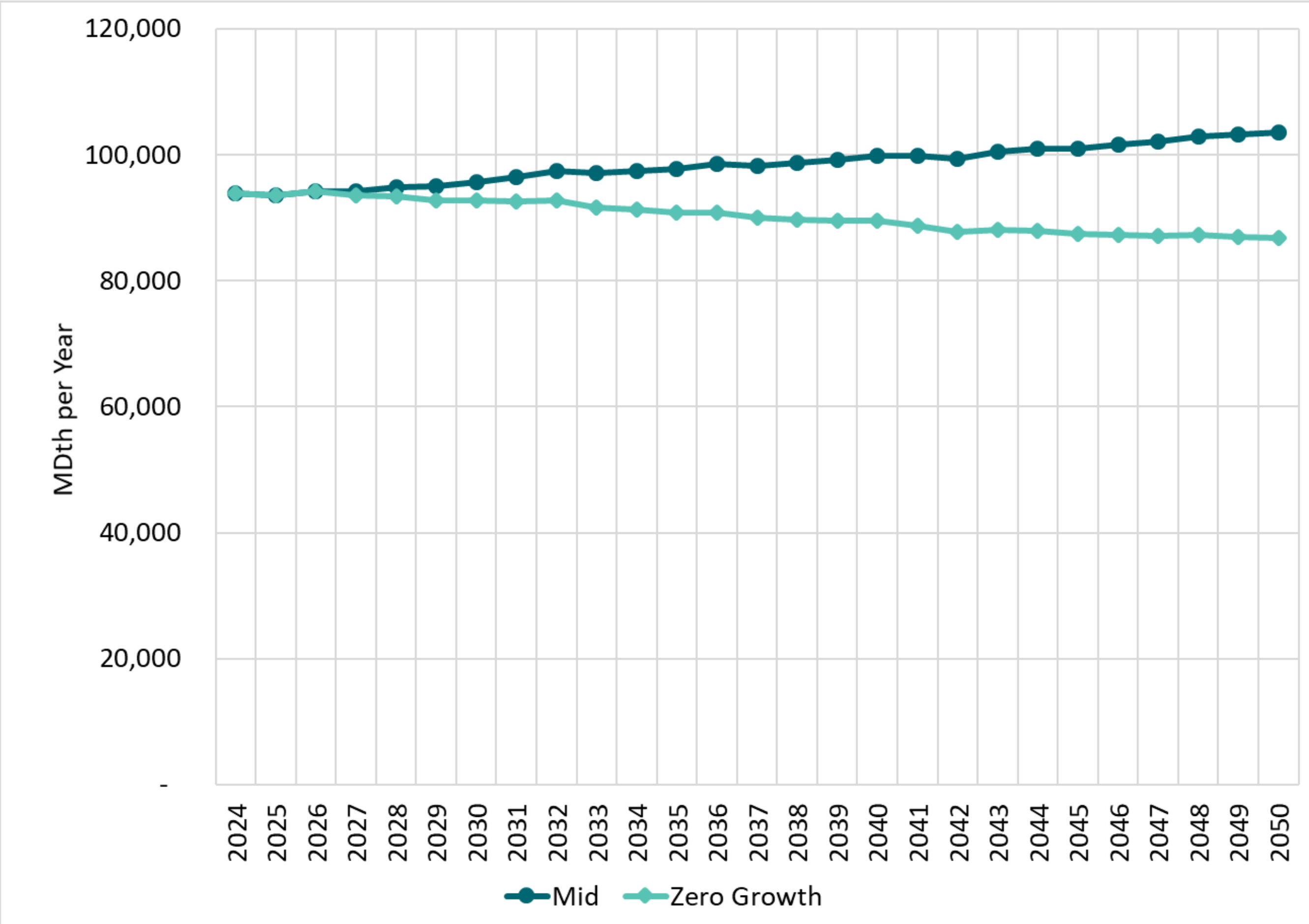


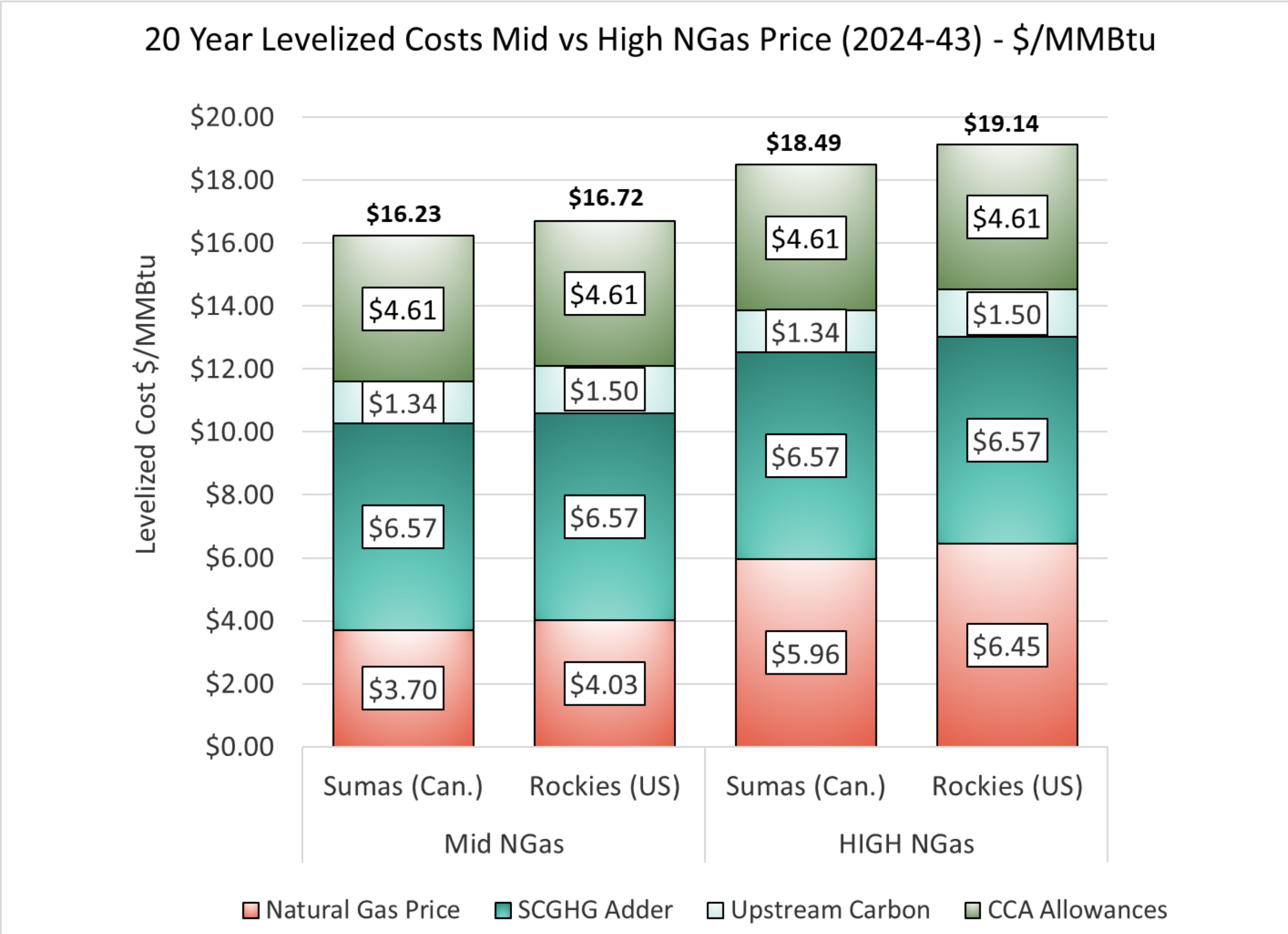
Figure 4.3: 2023 Gas Utility IRP Annual Gas Sales Demand Forecast before DSR — Zero-growth and Mid-demand



2.1.2. Total Natural Gas Cost Input

We constructed the total natural gas price from natural gas commodity price, greenhouse gas costs, and CCA prices. We show the total natural gas costs in Figure 4.4 and discuss the details of these three components in the following section.

Figure 4.4: Levelized Total Costs of Natural Gas Used in the 2023 Gas Utility IRP



Natural Gas Prices

We use a combination of forward market prices and fundamental forecasts acquired in spring 2022[3] from the energy research consultancy Wood Mackenzie[4] for natural gas price assumptions.

- Beyond 2029, the 2023 Gas Utility IRP uses the Wood Mackenzie long-run natural gas price forecast published in May 2022.
- From 2024–2028, the 2023 Gas Utility IRP uses the three-month average of forward market prices from May 12, 2022. Forward market prices reflect the price of natural gas purchased at a given time for future delivery.

For the years 2029 and 2030, we used a combination of forward market prices from 2028 and selected Wood Mackenzie prices from 2029 to minimize abrupt shifts when transitioning from one dataset to another.

3 The spring 2022 forecast from Wood Mackenzie is updated to account for economic and demographic changes stemming from the post COVID-19 pandemic impacts.

4 Wood Mackenzie is a well-known macroeconomic and energy forecasting consultancy whose gas market analysis includes regional, North American, international factors, and Canadian markets and liquefied natural gas exports.

- In 2029, the monthly price is the sum of two-thirds of the forward market price for that month in 2028 plus one-third of the 2031 Wood Mackenzie price forecast for that month.
- In 2030, the monthly price is the sum of one-third of the forward market price for that month in 2028 plus two-thirds of the 2031 Wood Mackenzie price forecast for that month.

We used two natural gas price forecasts in the scenario analyses.

Mid Natural Gas Prices: The mid natural gas price forecast uses the three-month average of forward market prices from May 12, 2022, and the Wood Mackenzie fundamentals-based long-run natural gas price forecast published in May 2022.

High Natural Gas Prices: The high natural gas price forecast uses the three-month average of forward market prices from May 12, 2022, and an adjusted Wood Mackenzie fundamentals-based long-run natural gas price forecast published in May 2022. To adjust the Wood Mackenzie forecast, we used the data from the 2021 Power Plan[5] high price forecast and applied them to the most recent fundamentals forecast.

Figure 4.5 illustrates the range of 20-year levelized natural gas prices used in the 2023 Gas Utility IRP analysis.

5 https://www.nwcouncil.org/2021powerplan_natural-gas-price-forecast/

Figure 4.5: Levelized Natural Gas Prices, 2023 Gas Utility IRP

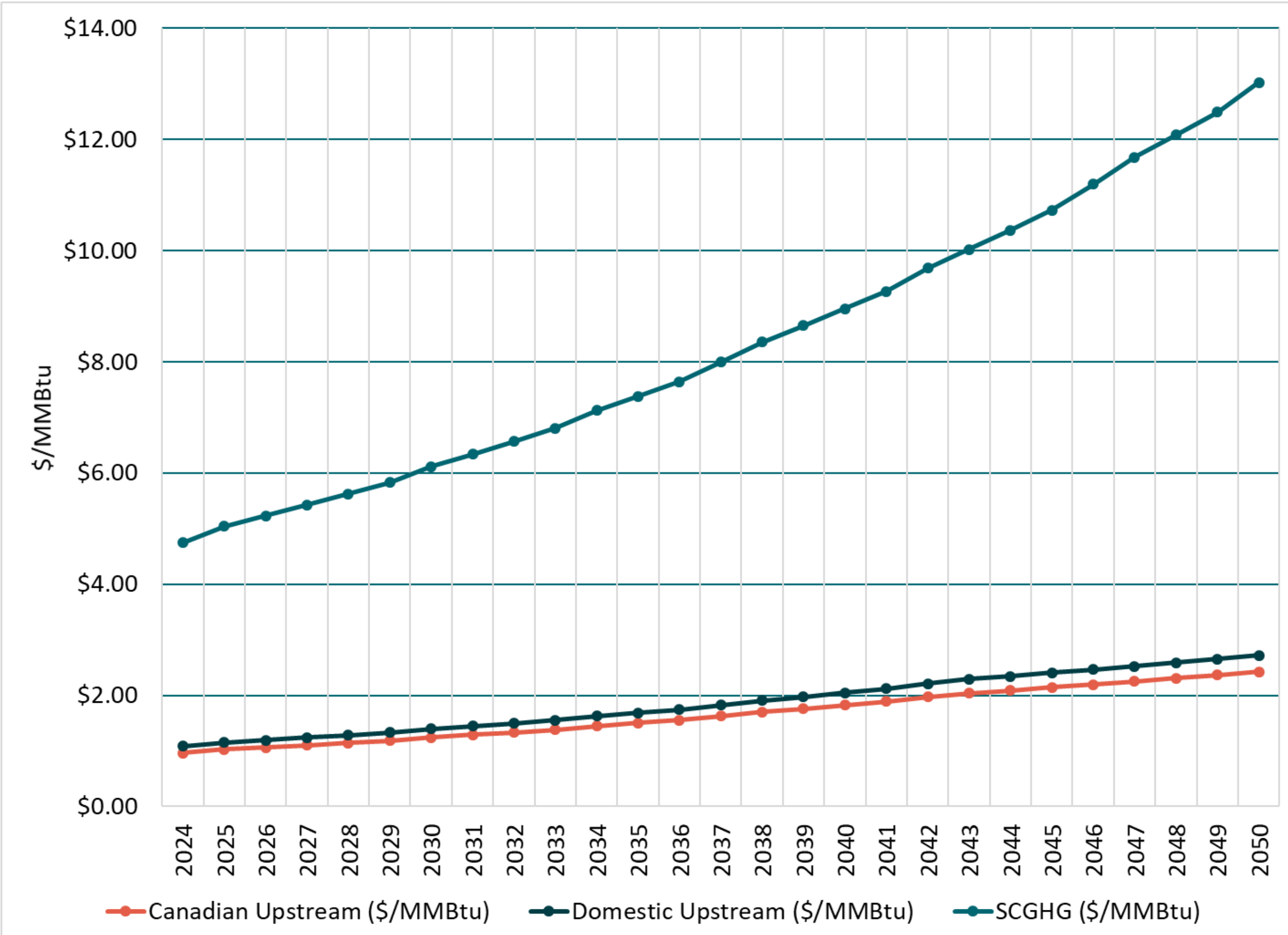
Greenhouse Gas Price Inputs

Washington State RCW 80.28.380[6] requires that the natural gas analysis include the cost of greenhouse gases when we evaluate the cost-effectiveness of natural gas conservation targets. The greenhouse gases must include upstream emissions. We add the Social Cost of Greenhouse Gases (SCGHG) to the natural gas commodity price to implement this requirement.

Per RCW 80.28.395,[7] we based the SCGHG on the Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document, August 2016 update. That document projects a 2.5 percent discount rate, starting with $62 per metric ton (in 2007 dollars) in 2020, and lists the CO_2 prices in real dollars and metric tons. The Commission provides a gross domestic product deflator adjusted social cost of carbon dioxide in 2020 dollars.[8] We revised the prices for inflation (nominal dollars). This cost ranges from $89 per metric ton in 2024 to $245 per metric ton in 2050**.** We then converted this to a dollars per MMBtu value, as shown in Figure 4.6.

6 RCW 80.28.380
7 RCW 80.28.395
8 https://www.utc.wa.gov/regulated-industries/utilities/energy/conservation-and-renewable-energy-overview/clean-energy-transformation-act/social-cost-carbon

Figure 4.6: Social Cost of Greenhouse Gases Used in the 2023 Gas Utility IRP ($/MMBtu)



The upstream emission rate represents the carbon dioxide, methane (CH_4), and nitrous oxide releases associated with the extraction, processing, and transport of natural gas along the supply chain. We converted these gases to carbon dioxide equivalents (CO_2 Intergovernmental Panel on Climate Change Fourth Assessment (AR4) 100-year global warming potentials (GWP) protocols.[9]

We based the cost of upstream CH_4[10] on data from the Puget Sound Clean Air Agency (PSCAA). The agency used two models to determine these rates: GHGenius[11] and GREET.[12] Emission rates developed in the GHGenius model apply to natural gas produced and delivered from British Columbia and Alberta, Canada. The GREET model uses

9 Both the EPA and the Washington Department of Ecology direct reporting entities to use the AR4 100-year GWPs in their annual compliance reports, as specified in table A-1 at 40 CFR 98 and WAC 173-441-040.

10 Proposed Tacoma Liquefied Natural Gas Project, Final Supplemental Environmental Impact Statement, Ecology and Environment, Inc., March 29, 2019.

11 GHGenius. (2016). GHGenius Model v4.03. Retrieved from http://www.ghgenius.ca/.

12 GREET. (2018). Greenhouse gases, Regulated Emissions and Energy use in Transportation; Argonne National Laboratory.

U.S.-based emission attributes and applies to natural gas produced and delivered from the Rockies basin, reflected in Table 4.1.

Table 4.1: Upstream Natural Gas Emissions Rates

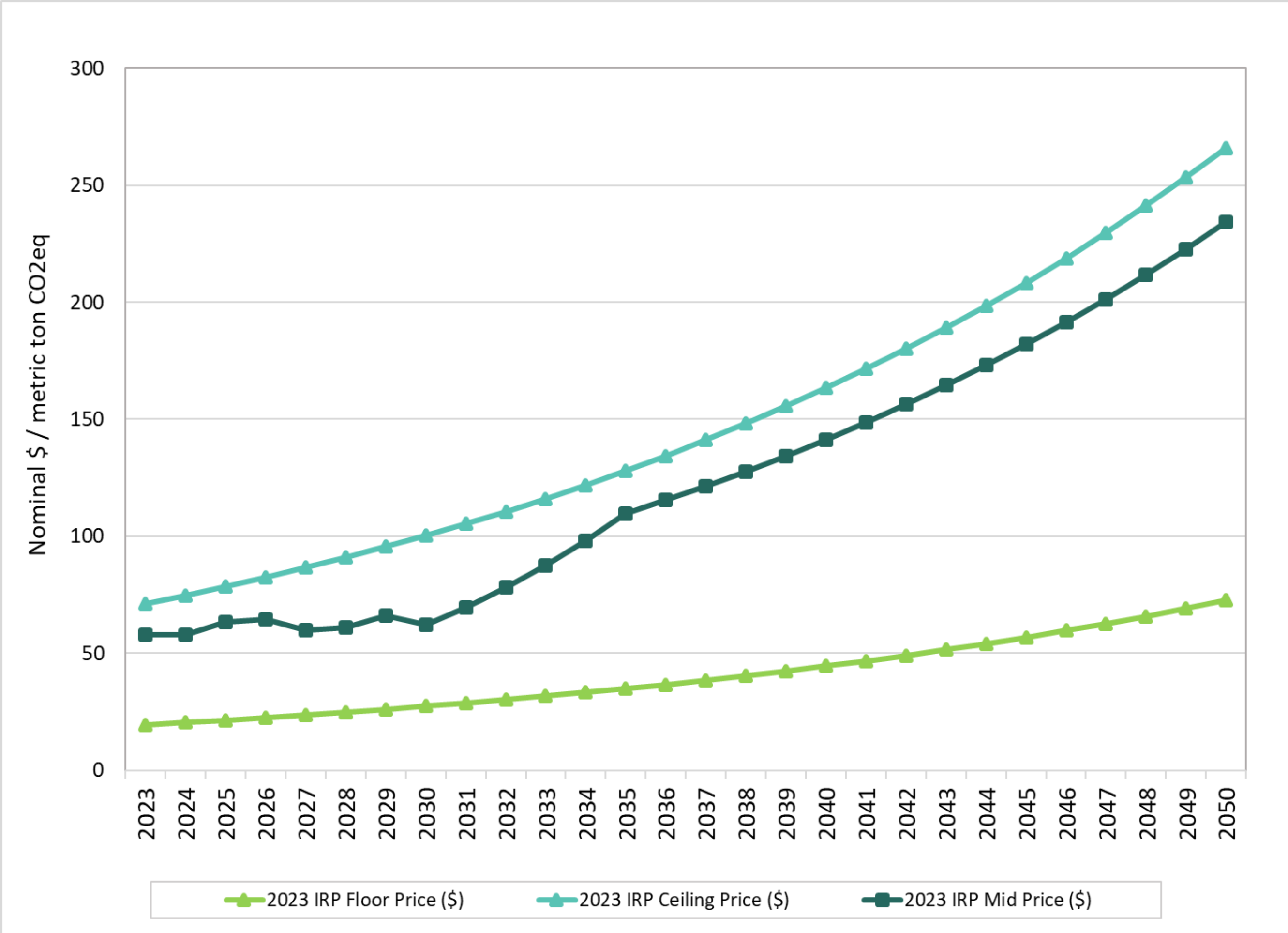
Model	Upstream Segment (g/MMBtu)	End-use Segment Combustion (g/MMBtu)	Emission Rate Total (g/MMBtu)	Upstream Segment CO^2e (%)
GHGenius	10,803	+ 53,060	= 65,203	20.40
GREET	12,121	+ 53,060	= 66,521	22.80

Climate Commitment Act Allowance Price

Puget Sound Energy included the CCA allowance prices for greenhouse gas emissions as an adder to the gas price forecast. Figure 4.7 presents the CCA allowance prices used in the gas portfolio model. The mid-CCA allowance price is a combination of two price forecasts, one from Ecology and one from the California Energy Commission (CEC). The ceiling and floor CCA allowance price forecasts are taken from the Ecology's market study released July 1st of 2022.[13]

13 https://ecology.wa.gov/DOE/files/4a/4ab74e30-d365-40f5-9e8f-528caa8610dc.pdf page 9: "Price ceiling – Covered entities can purchase any number of allowances they need for compliance at the price-ceiling price. Hence, the market price for allowances will not exceed this ceiling. In line with the proposed program rules, the analysis assumes a price ceiling starting at $71 per MT CO2e in 2023, growing at 5% per year, consistent with current rules in the California – Quebec market."

Figure 4.7: CCA Allowance Prices in the 2023 Gas Utility IRP



Notes:

1. A price ceiling unit is an allowance issued by Ecology at a fixed price to limit price increases.
2. The annual auction Floor is the minimum price at which bids are accepted during an auction.
3. We created the mid allowance price using a hybrid pricing scheme. We based the pre-2030 period on the forecast from Ecology. The post-2030 period prices represent the California Energy Commission 2021 forecast, modeling the future connection between the two carbon markets.[14]

2.1.3. Demand-side Resources

Energy efficiency, transportation, and storage are critical resources for gas utilities. We modeled the following generic resources as potential portfolio additions in this analysis.

[14] 2021 Integrated Energy Policy Report (ca.gov)

➔ See Chapter Six: Gas Analysis, for detailed descriptions of the resources listed here, and Appendix C: Conservation Potential Assessment for detailed information on demand-side resource potentials.

Energy Efficiency Measures

Energy efficiency measures reduce the level of energy used to accomplish a given amount of work. We group the wide variety of energy efficiency measures available into three categories: retrofit programs that have shorter lives; lost opportunity measures that have longer lives, such as high-efficiency furnaces; and codes and standards that drive down energy consumption through government regulation. Codes and standards impact the demand forecast, but have no direct cost to utilities.

Electrification Measures

We included three pathways to electrification in this IRP[15]:

- Market Hybrid Heat Pump (HHP): A market-based solution in which we used an HHP supply curve to determine unit cost-effectiveness.
- Policy Full Electrification: A policy-based method in which the demand is electrified based on an end-of-equipment-life replacement requirement. Whenever heat pumps are installed, this pathway assumes they are standard efficiency units.
- Policy HHP: A policy-based approach in which the demand is electrified based on an end-of-equipment-life replacement requirement. This approach assumes the electrification of end-use gas loads in all customer classes by using HHP to replace space heating for residential customers.

We show an overview of the process PSE used to develop the electrification analysis in Figure 4.8.

➔ For additional details on the electrification analysis, please refer to Chapter Six: Gas Analysis and Appendix F: Gas Analytical Methodology and Results.

[15] For more details of the electrification supply curves we used in the 2023 Gas Utility IRP, assumptions around hybrid heat pumps, how much electrification we assumed in each customer class and more, see Appendix C: Conservation Potential Assessment. See Chapter 6: Gas Analysis and Appendix F: Gas Analytical Methodology and Results for a detailed discussion of the electrification analytical process for both the gas and electric portfolio models.

Figure 4.8: Electrification Process in 2023 Gas Utility IRP

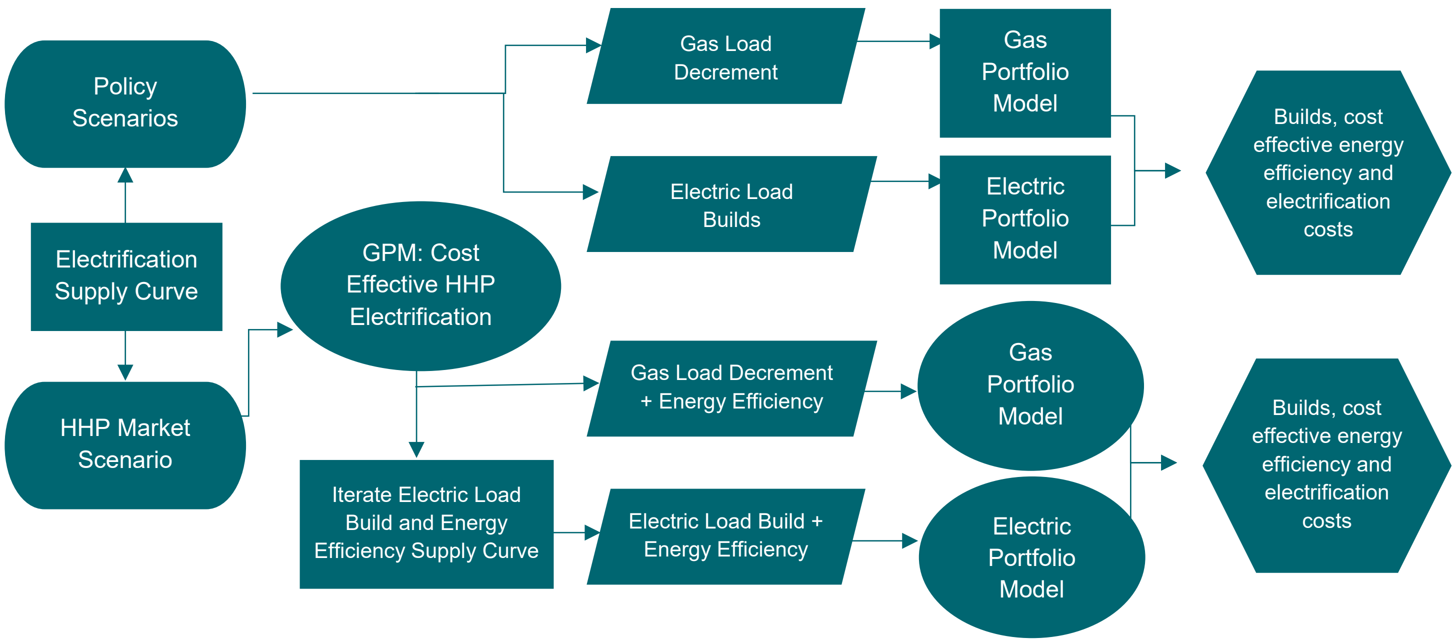
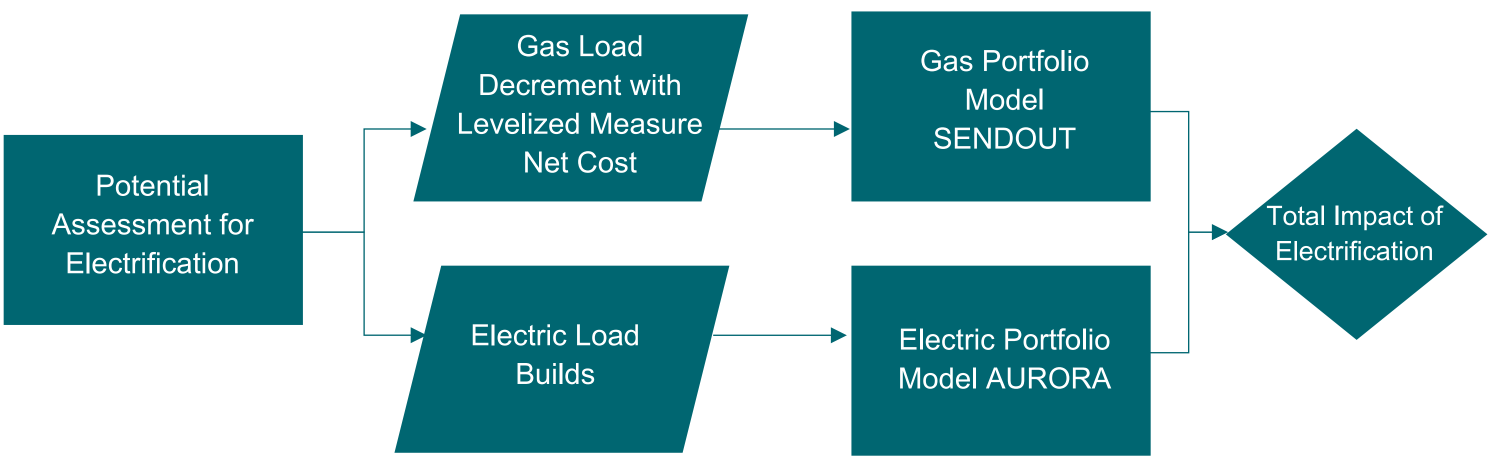


Figure 4.9: Overview of Electrification Analytical Process



The market HHP approach looks to augment existing gas furnaces with a cost-effective electric heat pump that can serve as the primary heating and cooling resource and restricts the gas furnace to operate only on winter peak days when the outdoor temperature is below 35° F.[16] This approach significantly reduces the emissions from conventional gas. We modeled it as a gas conservation measure. Running the gas furnace on cold winter days eliminates any

[16] Continued improvement of heat pump technology has enabled efficient operations at lower temperatures, however most are still locked out below 30° F and, for the purposes of the 2023 Gas Utility IRP, will not have an impact on the electric system which has a normal winter design temperature of 27° F.

additional load on the electric grid during these periods when the electric system of generation, transmission, and distribution is also reaching its peak capacity.

A variation on the market HHP is the policy HHP, which results in more electrification over time and achieves a greater emissions reduction with a lower impact on the electric grid during winter peak. This scenario includes electrifying all other end uses in a home, such as water heaters, cooking appliances, and dryers. As a policy case, the gas to electric conversion is achieved upon burnout and hence there is no cost-effectiveness element to consider.

The third policy scenario is a complete electrification pathway that involves switching from gas to electric fuels by replacing the gas furnaces at the end of their life cycles with electric-only heat pumps. This scenario includes electrifying all other end uses in a home, such as water heaters, cooking appliances, and dryers. Unlike the HHP Policy scenario, this measure eliminates gas use for residential space heating on peak days and that load shifts to the electric system. This peak demand requires additional electric generation, transmission, and distribution resources. Different kinds of electric space heating appliances impact the electric system differently; for example, cold weather heat pumps mitigate electric peak impacts, while electric resistance heating extenuates peak impacts. We will examine the effect of upgrading from a standard heat pump to a cold weather heat pump in the electric portfolio analysis as a conservation measure. Whatever electric appliance a (former) gas customer selects, the impact on the gas utility's load is the same: the load disappears.

2.1.4. Supply-side Resources

Transport pipelines that bring gas from production areas or market hubs to PSE's service area are generally assembled from several specific segments and/or storage alternatives. We joined 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 since they do not require transport pipeline capacity to deliver them to the demand centers.

Given the CCA, the existing supply resources will likely be adequate to serve the demand over the study period. The more likely trend will be a downward demand trajectory leading to surplus supply-side resources. This IRP aims to optimize its 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 effort includes reviewing transport pipeline contract renewals and potentially replacing pipeline capacity with on-system resources when we can add such resources at a lower cost to the portfolio.

The following section describes the nine supply-side alternatives we analyzed for the 2023 Gas Utility IRP.

Alternatives One through Six: Northwest Pipeline Renewals

Several pipeline contracts on the Northwest Pipeline (NWP) will be up for renewal between 2024 and 2033. Given that energy efficiency and possibly hybrid heat pumps will reduce demand, it may be more cost-effective for PSE to forgo some of these pipeline contract renewals to better align with the anticipated demand.

These NWP pipeline segments connect all three major gas supply hubs: Sumas/Station 2, Rockies, and AECO. Table 4.2 summarizes the segments due for renewal and offered as renewal options in the portfolio model. These segments represent an aggregation of contracts in that major segment.

Table 4.2: Timeline of Pipeline Capacity Offered for Renewal

Alternative	Segment	Hub	Nov 2024	Nov 2028	Nov 2030	Nov 2034
1	Sumas to PSE	Sumas/Station 2	x	-	-	-
2	Sumas to PSE	Sumas/Station 2	-	x	-	-
3	Sumas to PSE	Sumas/Station 2	-	-	x	-
4	Stanfield to Plymouth	Rockies	x	-	-	-
5	Stanfield to Plymouth	Rockies	-	x	-	-
6	Starr Road to Plymouth	AECO	-	-	-	x

Alternative Seven: Plymouth Liquefied Natural Gas with Firm Delivery

This option includes 60 MDth of capacity with a 15 MDth per day firm withdrawal of Plymouth LNG service and 15 MDth per day of firm NWP capacity from the Plymouth Liquid Natural Gas (LNG) plant to PSE. The Northwest Pipeline in southern Washington, across the Columbia River from Umatilla, OR, has owned and operated the Plymouth LNG plant since the 1970s. The facility provides up to 300 MDth/day vaporization to contracting parties. Puget Sound Energy's electric power generation portfolio currently holds this tiny sliver of this resource, which is available for a one-time renewal from Northwest Pipeline in April 2024. While this is a valuable resource for the power generation portfolio, it may better fit the natural gas sales portfolio.

Alternative Eight: Swarr Liquid Propane-air Upgrade

Alternative eight is an upgrade to the existing Swarr Liquid Propane (LP)-air facility. The upgrade would make the plant operational and also 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 2027/28.

2.1.5. Alternative Fuel Resources

We considered two alternative fuels to achieve CCA compliance: renewable natural gas (RNG) and green hydrogen.

Alternative Nine - Fifteen: Renewable Natural Gas

Renewable natural gas (RNG) is pipeline-quality biogas that can substitute for conventional natural gas streams. Renewable natural gas is captured from dairy waste, wastewater treatment facilities, and landfills.

We considered the seven renewable natural gas alternatives in the portfolio analysis shown in Table 4.3.

Table 4.3: Renewable Natural Gas Alternatives Modeled

Alternative	RNG Contract	Source	Receipt Point	Max. MDTh/yr	Year Offered
9	RNG-physical N-1	WA	Sumas	1600	2024

Alternative	RNG Contract	Source	Receipt Point	Max. MDTh/yr	Year Offered
10	RNG-physical N-2	WA	Sumas	1388	2025
11	RNG Attribute-1	N. America	Sumas	3000	2024
12	RNG Attribute-2	N. America	Sumas	1000	2025
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

Alternative Sixteen - Eighteen: 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 and gas sector. Hydrogen is abundant in several feedstocks including water, biomass, fossil fuels, and waste products, but it 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 produce the hydrogen. Green hydrogen is the most attractive variety of hydrogen in the context of a clean energy transformation. Green hydrogen is typically made from water electrolysis using low- or non-emitting energy sources to power the process. Puget Sound Energy has been working with various parties to jointly develop an electrolyzer-based facility that will use renewable electricity to produce green hydrogen.

We based this alternative scenario on blending green hydrogen into the gas distribution system, simultaneously displacing pipeline capacity on the Northwest Pipeline. This scenario 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 15 percent blended green hydrogen by volume in the gas system.[17]

2.1.6. Natural Gas Resource Build Constraints

Natural gas resource build constraints assume that natural gas pipeline contracts are renewed at fixed times in multi-year blocks to reflect the reality of the renewal process. There is inherent lumpiness in natural gas pipeline renewals since yearly releasing pipelines in small increments is not practical. Thus, the model is constrained to evaluate pipeline renewal contracts the year they are up for renewal, but some resources have more flexibility.

2.1.7. Inflation Reduction Act

In August of 2022, the federal government enacted cross-cutting legislation, the Inflation Reduction Act (IRA), which significantly focused on clean energy, including conservation, renewable energy, green hydrogen, and electrification. Consistent with the IRA, we incorporated the production tax credit related to green hydrogen at $3/kg in this 2023 Gas Utility IRP. Other provisions in the law were not directly incorporated in this gas IRP because the implementing rules are not complete. For more details, see Chapter Six: Gas Analysis. We will continue to assess the IRA during the rulemaking process and expect to incorporate additional aspects of the law in the next gas IRP.

[17] 15 percent hydrogen by volume will displace approximately 5 percent of conventional natural gas in energy.

2.1.8. Gas Delivery System Planning Assumptions

The assumption for the 2023 Gas Utility IRP is that the PSE natural gas delivery system in western Washington is unconstrained. This assumption holds because of a robust delivery system planning approach and related long-range system infrastructure plan that includes transmission and distribution system upgrades and non-pipe alternatives. The high level process and assumptions are shown below. Refer to Appendix G: Gas Delivery System Planning for a detailed description of the planning process.

Table 4.4: Delivery System Planning Operating Model

Assumptions	Description
Peak Hour Demand Growth	Uses county demand forecast based on historic load patterns of zip codes with adjustment for known point loads
Energy Efficiency	Highly optimistic 75 percent and 100 percent targets included
Resource Interconnections	Known interconnection requests included
Pipeline Safety and Aging Infrastructure	Known risk-based concerns included in analysis
Interruptible/Behavior-based Rates	Known opportunities to curtail during peak included
Distributed Energy Resources/Manual Intervention	Known controllable devices are included where possible such as compressed natural gas injection at low-pressure areas or bypassing valves
Low-carbon Fuel Enablement	Estimated impact of lower heat content fuels on meeting demand
System Configurations	As designed
Compliance and Safety Obligations	Meet all regulatory requirements, including Federal PHMSA and pipeline safety WAC codes, such as addressing low-pressure concerns or over-pressure events, and materials verification on transmission assets

2.1.9. Transmission and Distribution Benefits of Electrification

We assumed customers would convert to standard heat pumps in the electrification analysis. Although the least-costly appliance choice for a customer is resistance heat, we assume standard heat pumps will be the appliance of choice. We then reflect the option to upgrade to a high efficiency or cold climate heat pump as an electric conservation program in the electric portfolio model. To reflect the potential electric infrastructure costs in the gas modeling, we applied the same transmission and distribution (T&D) cost we used for electric conservation programs. We also followed this approach in the electric portfolio modeling with potential electric conservation measures, including high efficiency or cold weather heat pumps. The T&D benefit, also known as an avoided cost, is a benefit added to resources that reduce the need to develop new transmission and distribution lines. The T&D benefit is our forward-looking estimate of our T&D system costs under a scenario where electrification requirements and electric vehicles drive substantial electric load growth. Studies of the electric delivery system identified capacity constraints on the transmission lines, substations, and distribution lines that serve PSE customers from increased load growth due to electrification and electric vehicle adoption. We used the estimated cost for the infrastructure upgrades required to mitigate these capacity constraints and the total capacity gained from these upgrades to calculate the benefit value. The 2023 Gas Utility IRP included a T&D benefit of $74.70/kW-year for distributed energy resource (DER) batteries, also known as the T&D capital deferral cost. We forecasted this estimated $74.70/kW-year based on PSE's additional transmission and delivery system needs under such a scenario. This result is a significant increase from the $12.93/kW-year we used in the 2021 IRP, which was a backward-looking estimate from historical expenses for incremental capacity upgrades.

We applied the T&D capital deferral cost to the following demand-side resources:

- Electrification measures that reduce the gas loads and increase electric loads increase. This increased demand on the electric system is a cost to build T&D capacity to serve the additional demand; in this case, we do not defer the capacity expense. We reflect these T&D costs in the gas reduction associated with the electrification measure supply curves developed as part of the Conservation Potential Assessment (CPA). See Appendix C: Conservation Potential Assessment for more details.

- Energy efficiency and demand response measures see this as a benefit, as a reduction in peak demand leads to deferred T&D upgrades. The impact on demand response measures is more pronounced than energy efficiency since these are capacity-focused measures.

2.2. Gas Scenarios

We create scenarios to test how different economic conditions affect portfolio costs and risks. We created these scenarios from the inputs used in the 2023 Gas Utility IRP analysis. The 2023 Gas Utility IRP does not predict which scenario is more likely than another; thus, one should not interpret a reference scenario as the most likely. Instead, the reference scenario is the scenario against which we compare and test other scenarios and sensitivities.

In the 2023 Gas Utility IRP, we created two scenarios for the gas portfolio analysis to test how different combinations of two fundamental economic conditions — customer demand and natural gas prices — along with GHG emissions compliance requirements under the CCA would impact the least-cost mix of resources**.** We summarize the two scenarios in Table 4.5 and describe their parameters in the following sections.

Table 4.5: 2023 Gas Utility IRP Natural Gas Analysis Scenarios

Parameter	Reference Case Scenario One	Electrification — State Energy Strategy Scenario Two
Limit Emissions Without Regard to Price[1]	Price	Follow SES line
Allowance Price[1]	Mid	Floor
Renewable Fuel Source Location	North America	North America
Heating Load Shift[3]	Economic	Force in the electrification supply curve
Demand[2]	2023 Gas IRP Base (Mid)	Zero by 2050
Gas Growth?	Yes	Yes
Gas Price[2]	Mid	Mid

Notes:
1. CCA
2. Typical Gas IRP parameters
3. In the reference scenario this was hybrid heat pumps and in the electrification scenario it is full electrification

1: Reference Case

The reference case (scenario 1) is a set of assumptions against which we compared assumptions from other scenarios and sensitivities.

Parameters in scenario one:

- **Allowance Price:** The CCA price for emissions exceeding the allowance allocation is assumed to be the Mid price. The allowance price is reflected in the total cost of conventional natural gas as an adder, with the other GHG adders (see Figure 4.5).
- **Demand and Gas Growth:** This parameter applies the 2023 Gas IRP Base (or Mid) demand forecast with the gas growth. Additionally, we aligned and calibrated the conservation supply curve to the 2023 Gas IRP Base (Mid) Demand Forecast in Figure 4.2.
- **Gas Prices and Alternate Fuels:**
  - We applied the natural gas prices and CO_2 adder Mid natural gas prices, a combination of forward market prices, and Wood Mackenzie's fundamental long-term base forecast.
  - We reflected the costs of upstream CO_2 emissions as a price adder to the natural gas price.
  - We reflected the social cost of greenhouse gases as a price adder to the natural gas price.
  - We included renewable natural gas and green hydrogen in the resource alternatives supply curve.
- **Heating Load Shift:** This parameter reflects the potential reduction of end-use natural gas by substituting hybrid heat pumps as a cost-effective conservation measure.
- **Limit Emission without Regard to Price:** In the reference scenario, once the cost effective resource alternatives have been added, some of which also reduce emissions, net additional CCA allowances above the no-cost allowance line are bought to meet the requirements of the CCA. For details regarding the CCA, please refer to Chapter Three: Legislative and Policy Change.
- **Renewable Fuel Source Location:** We source renewable natural gas from the Pacific Northwest.

2: Electrification — State Energy Strategy

In scenario two, we modeled an electrification policy to align with assumptions from Washington State's Energy Strategy (SES).[18] We assumed mid-growth in customer gas demand. Demand declines with increasing penetration of electrification, reaching targeted emissions of 95 percent below the 1990 level and net zero emissions by 2050. Puget Sound Energy worked with the consulting firm Cadmus to develop peak and annual load curves for electrification. The development of the electrification adoption curve assumed policy would force customers to replace their gas appliances with electric heat pumps (or other electric end uses) when their existing equipment reaches the end of life. Cadmus provided the supporting supply curve for conservation based on the electric load increase and gas load decrease. We modeled the load curves in the gas portfolio with the software SENDOUT and used AURORA for the

[18] https://www.commerce.wa.gov/growing-the-economy/energy/2021-state-energy-strategy. "The 2021 State Energy Strategy is designed to provide a roadmap for meeting the state's greenhouse gas emission limits. Enacted in 2020, the law commits Washington to limits of 45 percent below 1990 levels by 2030, 70 percent below 1990 levels by 2040 and 95 percent below 1990 levels with net zero emissions by 2050."

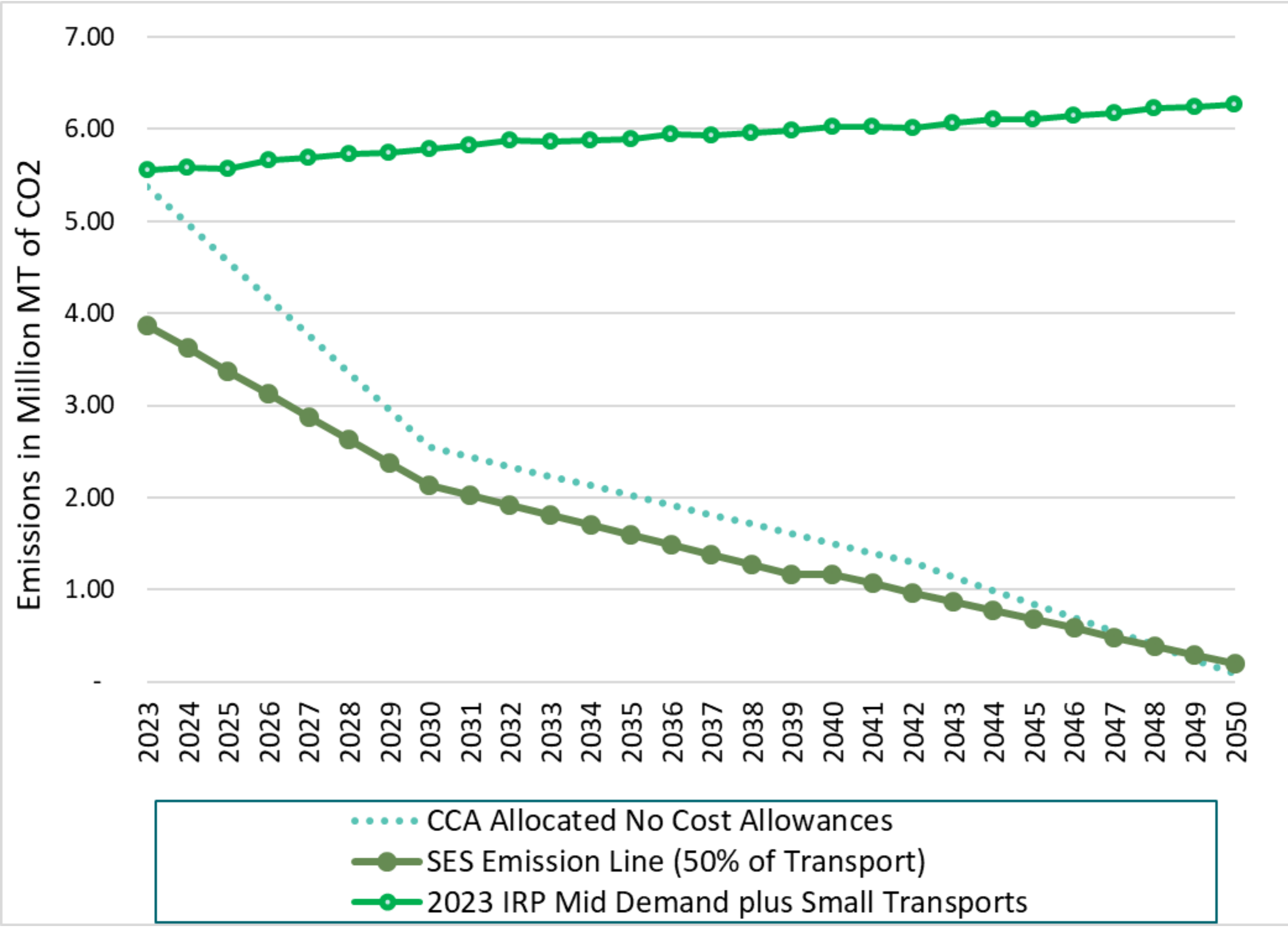
electric portfolio. For details on the inputs, assumptions, and modeling approach we used in AURORA, please refer to PSE's 2023 Electric Progress Report.

➔ For more information on the electrification analysis, please refer to Chapter Six: Gas Analysis and Appendix F: Gas Analytical Methodology and Results.

Parameters in scenario two:

- **Allowance Price:** We assumed the CCA allowance price for emissions exceeding no-cost allowances is the floor price. In this scenario, when we focus compliance on physical emissions reductions, there will be no demand for allowances. However, based on the electrification adoption curve, this scenario will still have to buy net additional allowances at the floor price to serve customers.
- **Demand:** We applied the 2023 Gas IRP Base (Mid) Demand Forecast with gas growth; see Figure 4.2.
- **Demand-side Resources:** We aligned and calibrated the conservation supply curve to the 2023 Gas IRP zero-growth demand forecast in Figure 4.2.
- **Gas Prices and Alternate Fuels**
  - We applied natural gas prices and the CO_2 adder Mid natural gas prices, a combination of forward market prices and Wood Mackenzie's fundamental long-term base forecast.
  - We reflected the costs of upstream C_{O2} emissions as a price adder to the natural gas price. We reflected the social cost of greenhouse gases as a price adder to the natural gas price. We included renewable natural gas and green hydrogen in the supply curve.
- **Heating Load Shift:** This parameter assumes replacing natural gas space, water heating equipment, and other gas end uses with electric options at the end of their life without regard to cost-effectiveness.
- **Limit Emission without Regard to Price:** This parameter reflects the case where physical GHG emissions are limited to emissions reduction constraints as defined by the SES. See Figure 4.10. This forces reduction in emissions towards the SES constraint or until a physical feasibility limit is reached. If the physical limit is reached before the SES constraint, net additional allowances are purchased to meet compliance.
- **Renewable Fuel Source Location:** We source renewable natural gas from the Pacific Northwest.

Figure 4.10: SES Emissions Pathway



2.3. Gas Portfolio Sensitivities

Sensitivities start with the optimized, least-cost reference scenario portfolio produced in the scenario analysis. We then change a single resource, environmental regulation, or other condition to examine the effect of that variable on the portfolio. We summarize the sensitivities in Table 4.5 and describe them further in the following sections.

Table 4.5: 2023 Gas Utility IRP Sensitivities

#	Name	CCA Constraint Parameter (CCA)	Allowance Price (CCA)	Renewable fuel source location	SCGHG Added?	Demand[1]	Gas Price[1]
1	Reference Case	Price	Mid	PNW	No	Mid (F22)	Mid
A	Allowance Price High	Price	Ceiling[2]	PNW	No	Mid (F22)	Mid
B	Allowance Price Low	Price	Floor[2]	PNW	No	Mid (F22)	Mid

#	Name	CCA Constraint Parameter (CCA)	Allowance Price (CCA)	Renewable fuel source location	SCGHG Added?	Demand[1]	Gas Price[1]
C	Limit Emissions Without Regard to Price	No-cost Allowance Line[2]	Floor[2]	PNW	No	Mid (F22)	Mid
D	Alternative Fuel Location WA	Price	Mid	North America[2]	No	Mid (F22)	Mid
E	HHP Policy	Price	Mid	PNW	No	Mid (F22) - policy driven HHP adoption[2]	Mid
F	Zero gas growth	Price	Mid	PNW	No	Zero gas growth after 2026[2]	Mid
G	High Gas Price	Price	Mid	PNW	No	Mid (F22)	High[2]

Notes:

1. Typical Gas Utility IRP parameters
2. Changes compared to the reference case.

A: Allowance Price High

This sensitivity tests the impacts of a high ceiling allowance price.

Baseline Assumption: We use the mid CCA allowance price.

Sensitivity: We applied the ceiling allowance price as provided by Ecology in the most recent draft rulemaking.

B: Allowance Price Low

This sensitivity tests the impacts of a low floor allowance price.

Baseline Assumption: We applied the mid CCA allowance price.

Sensitivity: We applied the floor allowance price as provided by Ecology in the most recent draft rulemaking.

C: Limit Emissions Without Regard to Price

This sensitivity forces the GHG emissions at the no-cost allowance trajectory under the CCA and assumes a CCA allowance price as the floor price. It is important to note that this parameter is theoretical. The current CCA policy requires Ecology to offer allowances. Sensitivities limited by emissions do not reflect the least-cost approach.

Baseline Assumption: We applied the mid CCA allowance price that allows the purchase of allowances to meet compliance.

Sensitivity: We applied the floor allowance price as provided by Ecology in the most recent draft rulemaking and forced the emissions to be limited to the no-cost allowance amount to use the resource alternatives to minimize emissions and therefore, we will purchase less CCA allowances at the floor price to meet compliance.

D: Alternate Fuel Location to PNW

In this sensitivity, we modeled a constraint on alternate renewable fuel sources to those within the Pacific Northwest and applied it to RNG and green hydrogen.

Baseline Assumption: The portfolio allows the purchase of alternate fuels from North America.

Sensitivity: In this sensitivity, we limit alternate fuels to a supply curve representing the availability and prices within the Pacific Northwest region.

E: Hybrid Heat Pump Policy

This sensitivity models a policy whereby the hybrid heat pump is the preferred technology to electrify existing gas space heating loads at the end of the gas equipment's life for PSE residential customers. The other end uses and non-residential loads are electrified.

Baseline Assumption: The portfolio model chooses a cost-effective amount of hybrid heat pumps as gas conservation measures for residential space heating and electrification for other end uses.

Sensitivity: We assumed gas space heating end uses in the residential sector would be electrified to hybrid heat pumps upon the equipment's end of life, and all other end uses would be electrified at the end of their life. We made assumptions on the limits to electrification in the commercial and industrial sectors.

➔ For more information on the electrification supply curve, please refer to Appendix C: Conservation Potential Assessment.

F: Zero Gas Growth

This sensitivity looks at the impact of zero-gas customer growth.

Baseline Assumption: We assumed the 2023 Gas IRP demand forecast, also known as the Mid demand forecast.

Sensitivity: We used a demand growth forecast based on zero-gas customer growth.

G: High Gas Prices

This sensitivity looks at the impact of a high gas price forecast on the portfolio.

Baseline Assumption: We assumed a Mid natural gas price forecast.

Sensitivity: We used a high natural price forecast.