2023 GAS UTILITY INTEGRATED RESOURCE PLAN

Chapters 1–6

PUGET SOUND ENERGY

2023 GAS UTILITY INTEGRATED RESOURCE PLAN

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PSE PUGET SOUND ENERGY

About PSE

As Washington State's oldest local energy company, Puget Sound Energy serves more than 1.2 million electric customers and more than 900,000 natural gas customers in ten counties. Our service territory includes the vibrant Puget Sound area and covers more than 6,000 square miles, stretching from south Puget Sound to the Canadian border, and from central Washington's Kittitas Valley west to the Kitsap Peninsula.

A subsidiary of Puget Energy, PSE meets the energy needs of its customers, in part, through incremental, cost-effective energy efficiency, procurement of sustainable energy resources, and far-sighted investment in the energy-delivery infrastructure. PSE employees are dedicated to providing great customer service and delivering energy that is safe, dependable and efficient. For more information, visit pse.com.

Our electric service territory includes all of Kitsap, Skagit, Thurston and Whatcom counties, and parts of Island, King (not Seattle), Kittitas, and Pierce (not Tacoma) counties.

Our natural gas service territory includes parts of King (not Enumclaw), Kittitas (not Ellensburg), Lewis, Pierce, Snohomish, and Thurston counties.

Figure 1.1 below shows PSE's electric and gas service territories.

Figure 1.1 Puget Sound Energy Natural Gas and Electric Service Territories

PUGET SOUND ENERGY

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DEFINITIONS & ACRONYMS

PUGET SOUND ENERGY

Term/Acronym	Definition
ADMS	Advanced Distribution Management System, a computer-based, integrated platform that provides the tools to monitor and control distribution networks in real time.
AECO	Alberta Energy Company, a natural gas hub in Alberta, Canada.
AMI	Advanced metering infrastructure
AMR	Automated meter reading
aMW	The average number of megawatt-hours (MWh) over a specified time period; for example, 175,200 MWh generated over the course of one year equals 20 aMW (175,200 / 8,760 hours).
Base Scenario	In an analysis, a set of assumptions that is used as a reference point against which other sets of assumptions can be compared. The analysis result may not ultimately indicate that the Base Scenario assumptions should govern decision-making.
Bcf	Billion cubic feet
BTU	British thermal units
CCA	Climate Commitment Act
CCS	Carbon capture and sequestration
CDD	Cooling degree day
CEAP	Clean Energy Action Plan
CEC	California Energy Commission
CEIP	Clean Energy Implementation Plan
CETA	Clean Energy Transformation Act
CHP	Combined heat and power
C&I	Commercial and industrial
CNG	Compressed natural gas
CO^2	Carbon dioxide
CO2e	Carbon dioxide equivalents
CPA	Conservation potential assessment
CPI	Consumer price index
CRAG	PSE's Conservation Resource Advisory Group
C&S	Codes and standards
DOE	Department of Ecology
DER	Distributed energy resources
Demand response	Flexible, price-responsive loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost.
Demand-side resources	These resources reduce demand. They include energy efficiency, distribution efficiency, generation efficiency, distributed generation, and demand response.
DER	Distributed energy resources. Electricity generators like rooftop solar panels that are located below substation level.
DERMS	Distributed Energy Resource Management System

Term/Acronym	Definition
Deterministic analysis	Deterministic analysis identifies the least-cost mix of demand-side and supply-side resources that will meet need, given the set of static assumptions defined in the scenario or sensitivity.
DSP	Delivery System Planning
DSR	Demand-side resources
Dth	Dekatherms
Dual fuel	Refers to peakers that can operate on either natural gas or distillate oil fuel.
EAG	PSE's Equity Advisory Group
EE	Energy efficiency
Energy need	The difference between forecasted load and existing resources.
ESG	Environmental Social and Governance
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse gas
GPM	Gas portfolio model
GRC	General Rate Case
HB 1257	Clean Buildings for Washington Act
HDD	Heating degree day
HIC	Highly impacted communities
HVAC	Heating, ventilating and air conditioning
IRA	Inflation Reduction Act
IRP	Integrated resource plan
ITC	Investment tax credit
LNG	Liquified natural gas
MDQ	Maximum daily quantity
MDth	One thousand dekatherms or 10,000 therms
MMBtu	Million British thermal units
MMtCO2e	Million metric tons of CO2 equivalent
NO_x	Nitrogen oxides
NPCC	Northwest Power & Conservation Council
NPV	Net present value
NWGA	Northwest Gas Association
NWP	Northwest Pipeline
Peak need	Electric or gas sales load at peak energy use times.
PGA	Purchased gas adjustment
PNUCC	Pacific Northwest Utilities Coordinating Committee
PNW	Pacific Northwest
Portfolio	A specific mix of resources to meet gas sales or electric load.

Term/Acronym	Definition
PSE	Puget Sound Energy
PTC	Production Tax Credit, a federal subsidy for production of renewable energy that applied to projects that began construction in 2013 or earlier. When it expired at the end of 2014, it amounted to $23 per MWh for a wind project's first 10 years of production.
RCW	Revised Code of Washington
Revenue requirement	Rate Base x Rate of Return + Operating Expenses
RFP	Request for proposal
RHA	Renewable Hydrogen Alliance
RNG	Renewable natural gas
Scenario	A consistent set of data assumptions that defines a specific picture of the future; takes holistic approach to uncertainty analysis.
SCC	Social cost of carbon, also called SCGHG, social cost of greenhouse gases
SCGHG	Social cost of greenhouse gases
SENDOUT	The deterministic gas portfolio model used to help identify the long-term, least-cost combination of integrated supply- and demand-side resources that will meet stated loads.
Sensitivity	A set of data assumptions based on the Mid Scenario in which only one input is changed. Used to isolate the effect of a single variable.
SO^2	Sulfur dioxide
Supply-side resources	Resources that generate or supply electric power, or supply natural gas to natural gas sales customers. These resources originate on the utility side of the meter, in contrast to demand-side resources.
TCPL-Alberta	TransCanada's Alberta System (also referred to as TC-AB)
TCPL-British Columbia	TransCanada's British Columbia System (also referred to as TC-BC)
TC-Foothills	TransCanada-Foothills Pipeline
TC-GTN	TransCanada-Gas Transmission Northwest Pipeline
TC-NGTL	TransCanada-Nova Gas Transmission Pipeline
TF-1	Firm gas transportation contracts, available 365 days each year.
TF-2	Gas transportation service for delivery or storage volumes generally intended for use during the winter heating season only.
Transport customers	Customers who acquire their own natural gas from third-party suppliers and rely on the natural gas utility for distribution service.
WACC	Weighted average cost of capital
WUTC	Washington Utilities and Transportation Commission

EXECUTIVE SUMMARY

CHAPTER ONE

Contents

1. Introduction

Puget Sound Energy (PSE) is Washington State's largest and oldest utility, serving more than 870,000 residential, commercial, and industrial natural gas customers in six counties through more than 26,000 miles of PSE-owned gas mains and service lines. We share our customers' concern for the environment and expectations for uncompromised reliability, affordability, and safety.

The existing pipeline system provides energy to our customers every day of the year to heat their homes and drive their businesses. Electric infrastructure, from wiring in homes, businesses, schools, and other facilities, to distribution systems, transmission systems, and electric generation, have all been sized around a robust gas system that delivers more energy annually in the Pacific Northwest than the electric system. We believe it is essential to decarbonize gas as much as practical while maintaining safety and reliability throughout all our systems to continue to meet the needs of our customers in the coming decades.

This resource plan begins to consider the impacts of the Climate Commitment Act and the associated effects on greenhouse gas emissions. Our analysis shows policy makers may need to deploy complementary policies and tools in the coming years to better position us to achieve our aspirational Beyond Net Zero Carbon goals. We will continue engaging with interested parties on policies that support our commitment to decarbonization.

2. Resource Planning Foundations

The 2023 Gas Utility Integrated Resource Plan (2023 Gas Utility IRP) is a planning exercise that evaluates how a range of potential future outcomes could affect our ability to meet our customers' natural gas supply needs. The analysis considers policies, costs, economic conditions, and the physical energy system. This 2023 Gas Utility IRP proposes the starting point for deciding what future resources we may or may not procure.

Throughout the resource planning process for this plan, we focused on the following key objectives, which lay the foundation for this and all future resource plans:

- Ensure adequate gas supply to meet customer demand
- Meet Climate Commitment Act (CCA) requirements
- Understand the impacts of building electrification on PSE's gas and electric utilities
- Understand the impacts of green hydrogen and renewable natural gas (RNG)

This plan does not make resource or program implementation decisions. This IRP is a long-term view of what appears to be cost-effective based on the best information we have today about the future. We repeat the gas IRP analysis every two years to adjust for new forecasts and account for technology, clean fuel, resource cost, and regulatory changes.

➔ See Chapter Three: Legislative and Policy Change for more information regarding CCA and other regulatory changes.

3. Change Drivers

We developed this report during a time of extraordinary change as policymakers, the utility industry, and the public confront the challenge of climate change and work toward decarbonizing the gas sector. These regulatory changes and valuable feedback from interested parties influenced the 2023 Gas Utility IRP.

3.1. Regulatory Changes

This IRP includes updates that respond to new legislation and regulations enacted since PSE's 2021 Gas Utility IRP. These new laws include the CCA, the City of Seattle's limits on natural gas in large commercial and residential buildings, Washington State building code efficiency improvements as of May 2022, and portions of the Inflation Reduction Act (IRA). We studied the impact of the CCA on the gas portfolio in two ways: as a price cap and as an emissions cap. We also studied electrification scenarios to reduce emissions and meet the requirements of the CCA.

The Washington State Legislature passed the CCA in 2021, and significant portions went into effect on January 1, 2023. The CCA is a cap-and-invest program that places a declining limit on the quantity of greenhouse gas emissions generated within Washington State. The CCA established a marketplace to trade allowances of permitted emissions, and the resulting market created an opportunity cost for emitting greenhouse gases. The CCA has two pathways to reduce PSE gas customers' emissions. First, the CCA makes a direct price impact that drives decarbonization. We put a direct price on greenhouse gases (GHG) and the social cost of GHG (SCGHG) in this IRP, resulting in more conservation, RNG, and green hydrogen that will drive down emissions. The second impact of the CCA is new revenue from consigned allowances. In the consignment process, PSE's customers will pay for allowances, but the Department of Ecology (Ecology) will return a large portion of the revenue to PSE, an amount that diminishes over time. We must first use the consigned allowance revenue to eliminate bill impacts on low-income customers.

The Washington Utilities and Transportation Commission (Commission) has jurisdiction over how much of the remaining consigned allowance revenue we refund customers, on a non-volumetric basis or used for specified decarbonization activities. Because the CCA is relatively new legislation, the Commission has not provided guidance yet for how gas utilities, including PSE, should allocate consigned allowance revenue between those categories. This IRP does not examine how PSE will use the consigned allowance revenue. Because of the consignment process, there may be a situation in which PSE must purchase allowances from the auction, which will impact customer bills except for low-income customers. This direct price impact from the CCA allowances was included in the gas analysis and increased the marginal cost of gas which drove the cost effectiveness of conservation, RNG, and green hydrogen.

In August of 2022, the federal government enacted cost-cutting legislation, the Inflation Reduction Act (IRA), which significantly focused on clean energy, including conservation, renewable energy, green hydrogen, and electrification.

We incorporated as much of the IRA as possible[1]; however, because the law was enacted late in our planning process, we could not consider all the nuances of the bill. We will continue to study the impacts of the IRA for the 2025 IRP.

➔ Please find detail on these changes in Chapter Three: Legislative and Policy Change.

3.2. Public Feedback

Public participation in our Gas IRP process helped shape our work to develop the gas preferred portfolio and resource plan. Members of the public gave us valuable input on ways to improve public participation and the feedback processes. We implemented real-time improvements during this cycle and are assessing the process for the next IRP. The following sections outline how feedback from interested parties influenced this IRP and may influence future IRP cycles.

➔ Appendix A: Public Participation contains additional detailed information about public feedback in this IRP cycle.

3.2.1. Climate Change Impacts

This plan incorporates climate change in the energy and peak demand forecast for the first time. We heard from interested parties that it is critical to include climate change because it affects future demand and needs, and we agree. Before this IRP, we used temperatures from the previous 30 years to model the expected normal temperature for the future. This approach was a common utility practice but did not recognize predicted climate change. Climate scientists recently developed climate model projections for the region and made them available to PSE to calculate a normal temperature assumption that reflects climate change. Incorporating climate change impacts into temperature assumptions in the plan will improve our model predictions. We will incorporate future refinements of climate change methodology in our IRP analysis as we learn more and study the topic.

➔ Please refer to Chapter Five: Demand Forecast for details regarding how we incorporated climate change into our demand forecast.

3.2.2. Electrification Analysis

As part of the analysis for this IRP, we evaluated the impacts of electrification on the gas and electric portfolio. We found that electrification would significantly increase energy costs on a system level. In addition to the cost of electrification equipment, a portion of this change is due to reduced demand, costs to sustain the gas system and

[1] The 2023 Gas IRP preferred portfolio includes the IRA production tax credits (PTC) for green hydrogen.

concurrently growing capacity on the electric system with additional infrastructure. The cost to increase resources and infrastructure on the electric system is greater than the social cost of greenhouse gases[2] saved by electrifying the gas loads. Converting gas appliances to electric can be expensive, and no policies currently address who will pay such expenses. From a societal perspective, therefore, it may cost more to electrify gas loads than society saves from the reduced emissions, as represented by the social cost of greenhouse gases. The 2021 IRP was the first time we examined electrification in the Gas IRP; we refined and updated this analysis for the 2023 Gas Utility IRP and will continue to refine and update it in future IRP cycles.

3.2.3. Embedding Equity

When considering equity in resource planning, it is important to note that no specific guidance exists today to inform how we should embed equity into our 2023 Gas Utility IRP. We recognize, however, that although resource planning is not a decision-making process, it presents opportunities to view critical elements of our work through an equity lens and to make progress toward our equity goals.

For this IRP, we adjusted the cost-effectiveness threshold for low-income conservation programs, an adjustment we made in past IRPs. We took additional steps to consider equity for the gas utility by including spatial analysis of vulnerable populations in the conservation potential assessment, consistent with the low-income programs. We also initiated a conversation with interested parties, including our Equity Advisory Group (EAG), which will continue into the 2025 IRP cycle.

We expect to expand equity considerations in the 2025 Gas Utility IRP and beyond by applying lessons learned from equity work across PSE and identifying desired outcomes and goals.

3.2.4. Zero-growth Scenario

We considered feedback from interested parties in response to the draft 2023 Gas Utility IRP and made the zero-growth scenario the preferred portfolio for the final 2023 Gas Utility IRP. Zero-growth demand results in a slight decrease in forecasted GHG emissions and increased pipeline contracts that we do not need to renew.

3.2.5. Accessibility and Plain Language

While creating the 2023 Gas IRP, we took measures to improve the accessibility of our written IRP documents, public meetings, and website content. In this and future IRPs, we are committed to removing participation barriers and attracting more members of the public into the resource planning process. We are continuously evaluating our content and working to improve readability and accessibility for all while encouraging interested members of the public to get involved in our planning processes.

[2] The social cost of greenhouse gasses (SCGHG) is the societal cost of emitting carbon. If a reduction of carbon costs more than the SCGHG, then as a society we are paying more to reduce carbon than the damage caused by emissions.

4. Resource Plan

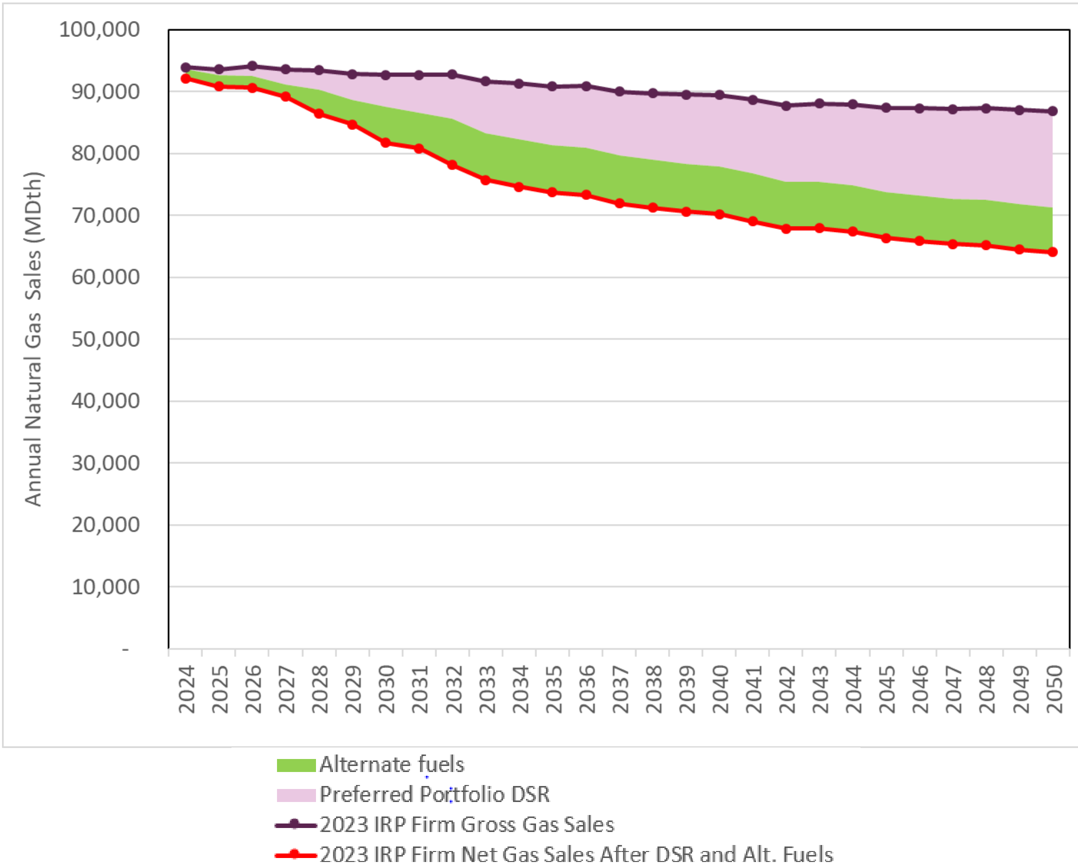
The resource plan results from robust IRP analyses developed with input from interested parties. It meets the requirements of the Washington Administrative Code (WAC) and is informed by deterministic and stochastic portfolio analysis.

➔ See Chapter Two: Resource Plan for the complete discussion of the resource plan.

4.1. Gas Resource Need

This IRP shows that between now and 2050, the models expect demand for natural gas to decline after the impact of cost-effective conservation. Figure 1.1 shows the zero-growth load forecast net of demand-side resources (DSR) and how much of that annual need we expect to meet with alternative fuels in the preferred portfolio. We based this analysis on Ecology's current sourcing footprint within the Pacific Northwest. The decline in natural gas needed due to these resources also lowers the net additional allowances needed under the CCA.

Figure 1.1: Natural Gas Sales Net DSR and Alternate Fuels — Resource Plan



4.2. Gas Resource Additions Forecast

The preferred plan includes changes to gas sales resources, as illustrated in Table 1.1. We discuss these changes in Chapter Two: Resource Plan. In the gas analysis, we must meet peak use during the winter heating seasons, which drives most resource decisions. Our winter heating season is from November to February; as a result, a single gas year spans parts of two years. For example, 2024 represents the gas system year from November 2024 through October 2025.

Table 1.1: Resource Additions by Type and Time (Capacity in MDth/day)

Resource (MDth/d)	2024	2030	2040	2050
Energy Efficiency	7	61	127	172
Swarr Propane Plant	0	30	30	30
Plymouth LNG	15	15	15	15
Pipeline Renewals	(59)	(142)	(195)	(195)
RNG PNW Regional	0	0	0	0
RNG On-system	0	1	2	2
Green H2 — Gas Blending	0	9	14	14
Net Supply Resources	**(44)**	**(87)**	**(134)**	**(134)**

➔ For details regarding how we developed the resource plan, refer to Chapter Two: Resource Plan.

5. Gas Short-term Action Plan

The following are the short-term actions we must take to meet the preferred portfolio:

- Acquire cost-effective conservation.
- Acquire cost-effective RNG and green hydrogen as commercially available.
- Assess the commercial viability of contracting for Plymouth LNG supply from Northwest Pipeline's existing facility in Southeastern Washington as a substitute for year-round pipeline capacity.
- Continue engagement to develop and deliver on a plan to incorporate equity considerations into the 2025 Gas Utility IRP meaningfully.
- Determine the least-valuable contracts to inform a pipeline de-contracting strategy.
- Examine the implications and viability of upgrading Renton's Swarr propane air-injection system to determine if this will be a commercially viable alternative.
- Follow rulemaking process of the Inflation Reduction Act
- Implement the general rate case settlement that includes a decarbonization study, a targeted electrification pilot, and a targeted electrification strategy.
- Stay engaged in the CCA rulemaking and regulation to understand the use of consigned revenues

➔ For more details on the resource plan, please refer to Chapter Two: Resource Plan.

RESOURCE PLAN
CHAPTER TWO

PSE PUGET SOUND ENERGY

Contents

1. Introduction

Puget Sound Energy (PSE) is committed to a clean energy future. This 2023 Gas Utility Integrated Resource Plan (2023 Gas Utility IRP) is the first planning cycle that examines the impact of Washington State's Climate Commitment Act (CCA). In this IRP, we analyzed how a wide range of allowance prices under the CCA and the social cost of greenhouse gas (SCGHG) on direct and indirect emissions would reduce PSE's natural gas emissions. We tested electrification scenarios for this plan, but electrifying gas demand is not cost-effective even at the CCA ceiling price. Our analysis does not include secondary impacts from the CCA, such as emission reduction activities from incremental conservation, electrification, and renewable natural gas and green hydrogen we may undertake because of price increases or other actions resulting from allowance revenue.

As part of integrating equity considerations into resource planning, we included a spatial analysis of vulnerable populations in the conservation potential assessment. We are committed to expanding our understanding and consideration of equity in resource planning in future IRPs.[1]

Puget Sound Energy's (PSE's) preferred portfolio results from robust analyses developed with input from interested parties, and it meets the Washington Administrative Code requirements. To create the preferred portfolio, we examined how several different future conditions, or scenarios, would impact the least-cost set of resource decisions. Feedback from participants in the public input process significantly influenced the conditions we included in the scenario models.

Public feedback also significantly influenced our decision to use the zero-growth sensitivity as the basis for the preferred portfolio. This approach aligns with the recent movement in state building codes and city ordinances passed in 2022 that restrict gas additions.

More information about the preferred plan is in the following sections in this chapter.

2. Preferred Portfolio and Resource Plan

We based the preferred portfolio on the zero-growth sensitivity, which assumes no new gas customer growth as the basis for its demand forecast. The lower demand over time reduces supply-side resources because of the reduced year-round pipeline capacity from not renewing some capacity contracts. The pipeline non-renewals are partly from reduced resource need from lowered demand and partly from displacement by other cost-effective resources alternatives, such as needle peaking resources,[2] conservation, and on-system alternate fuels such as RNG and green hydrogen.

1 As described in Chapter One: Executive Summary, we will further address equity in the 2025 Gas Utility IRP. Find details of the analysis in Appendix C: Conservation Potential Assessment.

2 A needle peaking resource has limited availability and serves for short durations of time to support system reliability.

2.1. Resource Plan

As a result of our analyses for this IRP and our preferred portfolio, we developed an action plan divided into near-term and long-term action items. We added several new priorities in this IRP to some of the near-term things we identified in past IRP cycles, such as acquiring cost-effective conservation.

Near-term Priorities (2024–2029):

- Acquire Plymouth Liquid Natural Gas (LNG) capacity rights and the 15 MDth/day deliverability on the Northwest Pipeline
- Continue engagement to develop and deliver on a plan to incorporate meaningful equity considerations in the 2025 Gas Utility IRP
- Continue to acquire cost-effective conservation
- Continue to assess non-pipe alternatives on the gas distribution system
- Determine technical feasibility impacts and other issues of upgrading the Swarr propane-air injection facility
- Explore which expiring pipeline contracts would be feasible to let expire rather than renew
- Follow the rulemaking process for the Inflation Reduction Act
- Participate in green hydrogen development in the Pacific Northwest (PNW)
- Purchase allowances to meet CCA compliance requirements and rule on use of consigned revenues
- Reduce emission profile by exploring Renewable Natural Gas (RNG) within the PNW and outside the region

Long-term Priorities (2030–2050):

- Explore clean technology and fuel such as direct air capture, green hydrogen, and RNG
- Reduce transport pipeline capacity contracts when the gas sales portfolio becomes surplus from decreasing loads

2.2. Preferred Portfolio Summary

To create the preferred portfolio, we first performed a gas analysis which determined a reference portfolio that provided a least-cost baseline. We then ran additional scenarios and sensitivities that provided a picture of the portfolio under varying conditions. The portfolio runs focused on fuel costs, carbon costs, and demand changes. We based the preferred portfolio on a combination of the results and information gleaned from the different scenarios and sensitivities, not on one scenario. Our work was a subjective exercise attempting to thread a needle through the policy and economic landscapes to develop a portfolio that best meets the policy objectives while minimizing portfolio cost and risk.

We based the preferred portfolio on the zero-growth sensitivity. That sensitivity assumed no customer growth and mid-gas and mid-CCA allowance prices.[3] Table 2.1,[4] a summary of the preferred portfolio, shows net negative supply-side resources. The portfolio does not require us to renew some firm pipeline contracts because of lower demand after conservation and lower-cost new peaking resources. Additionally, renewable fuels delivered on the PSE system do not require pipeline capacity, so we do not have to renew pipeline contracts to meet winter peaks. This diversified resource mix of PSE-owned resources helps maintain a flexible gas portfolio while ensuring enough resources to meet customer needs regardless of changes in customer demand.

Table 2.1: Preferred Portfolio Resource Additions by Type and Time (Capacity in MDth/day)

Resource (MDth/d)	2024	2030	2040	2050
Energy Efficiency	7	61	127	172
Swarr Propane Plant	0	30	30	30
Plymouth LNG	15	15	15	15
Pipeline Renewals	(59)	(142)	(195)	(195)
RNG PNW Regional	0	0	0	0
RNG On-system	0	1	2	2
Green H2 /Gas Blending	0	9	14	14
Net Supply Resources	**(44)**	**(87)**	**(134)**	**(134)**

2.2.1. Energy Efficiency

We based the energy efficiency supply curve in the preferred portfolio on the zero-demand forecast; thus, it has a slightly lower achievable technical potential than in the reference portfolio. The lower demand in the preferred portfolio lowers the cost point on the supply curve, up to which conservation is cost-effective. The overall result is slightly lower cost-effective conservation than in the reference portfolio and a slightly lower cost bundle on the supply curve.

Figure 2.1 shows the preferred portfolio's peak day contribution from cost-effective programmatic conservation and codes and standards.

3 Mid CCA Price is a blend of the Washington Department of Ecology's (Ecology) expected allowance price in the near-term and the California Energy Commission's (CEC) long-term expected price.

4 Since most of the regional RNG is received at the gas hubs and displaces natural gas only, it does not show up in the resource builds in Figure 2.1 and Table 2.1. We show only the on-system RNG that displaced transport pipeline resources.

Figure 2.1: Preferred Portfolio Cost-effective Peak Day Savings — Program and Codes and Standards

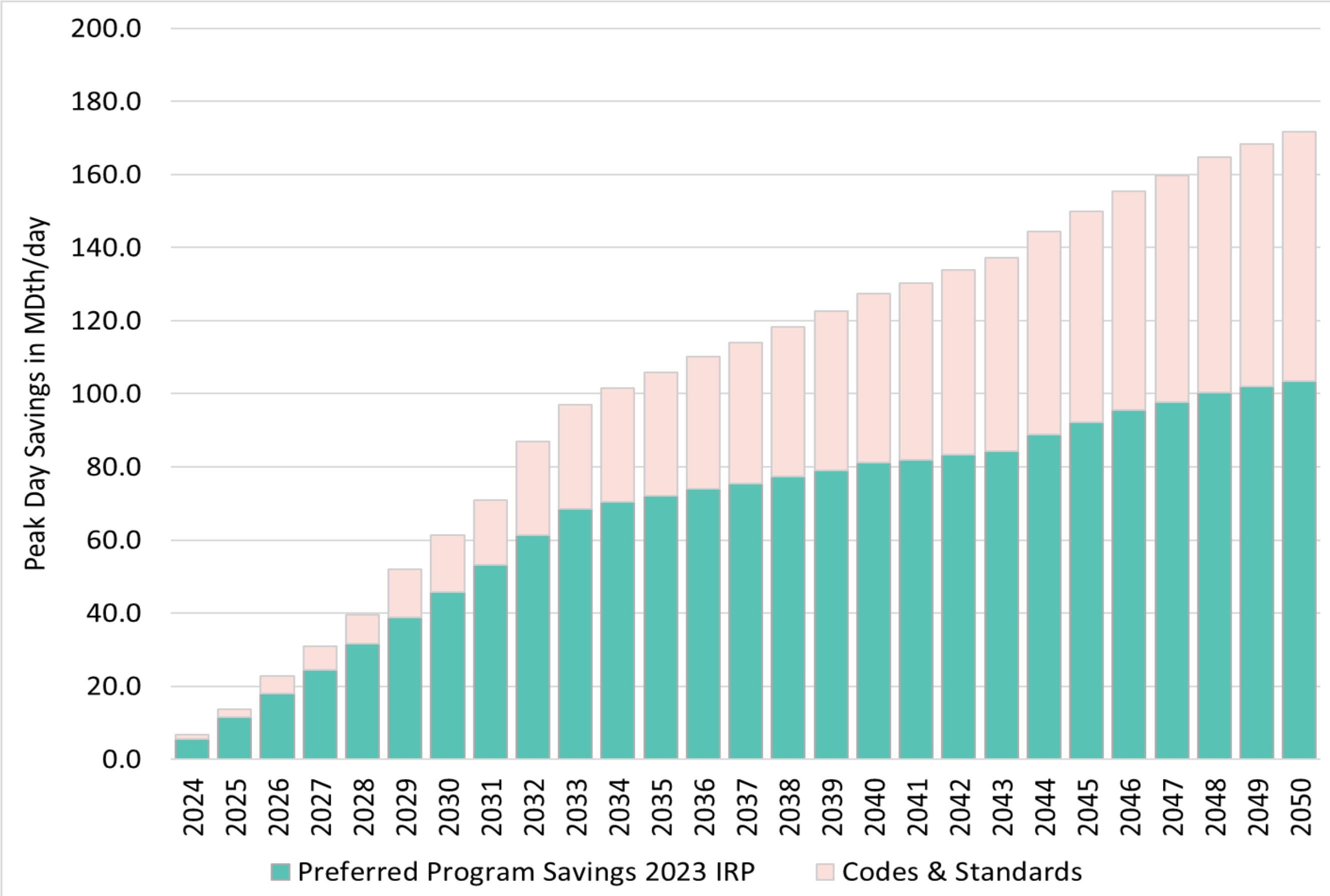


Figure 2.2 compares the cost-effective programmatic conservation to the reference portfolio. We see peak-day savings declines after 2033, beyond which there is no contribution from new gas customers and retrofit measures based on the zero-gas growth assumption in the preferred portfolio.

Figure 2.2: Cost Effective Peak Day Program Savings – Preferred vs. Reference Portfolio

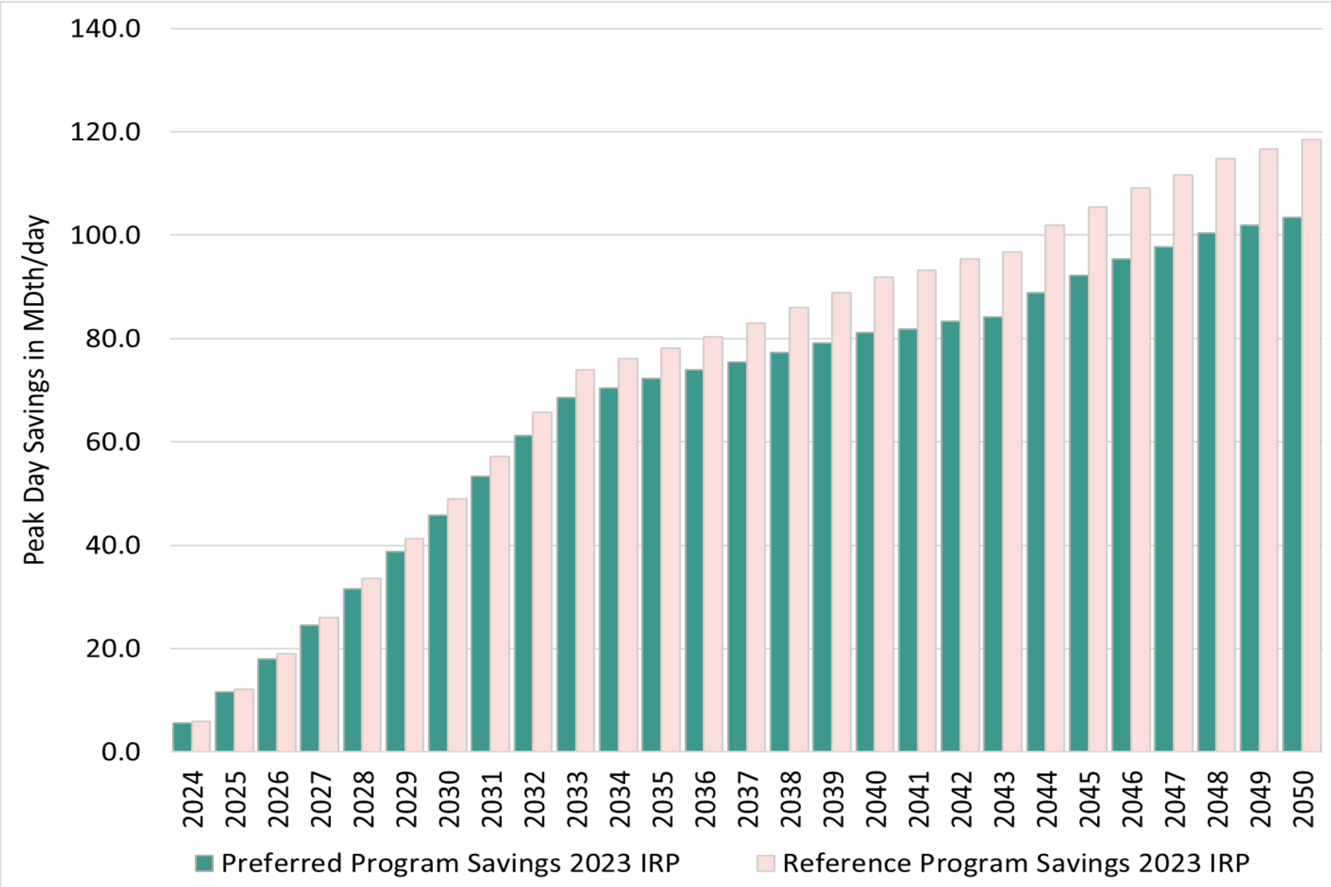


Figure 2.3 shows the energy savings per year for the cost-effective utility program bundles in the preferred portfolio, including the codes and standards savings.

Figure 2.3: Preferred Portfolio Cost Effective Annual Saving — Programs vs. Codes and Standards

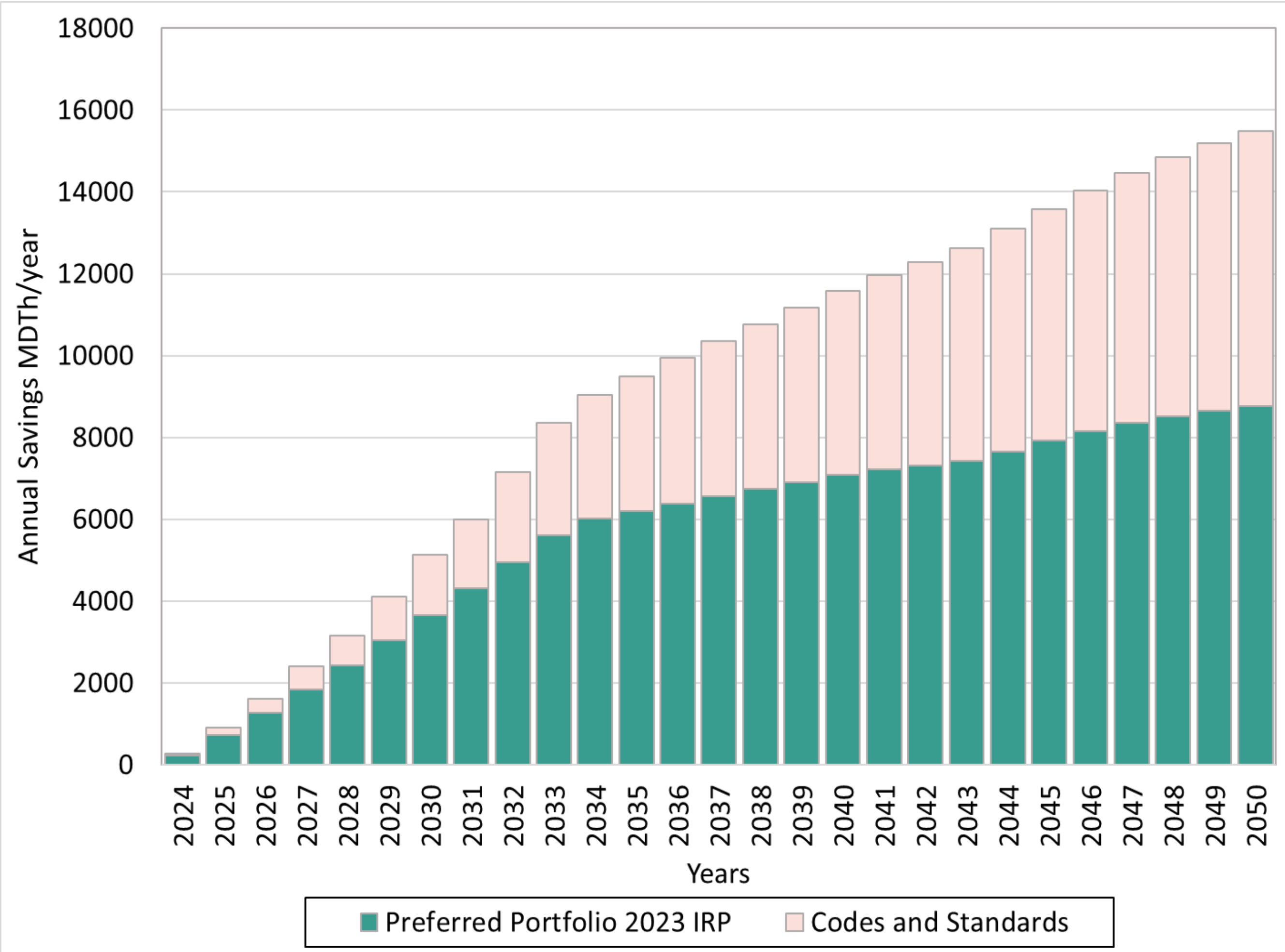
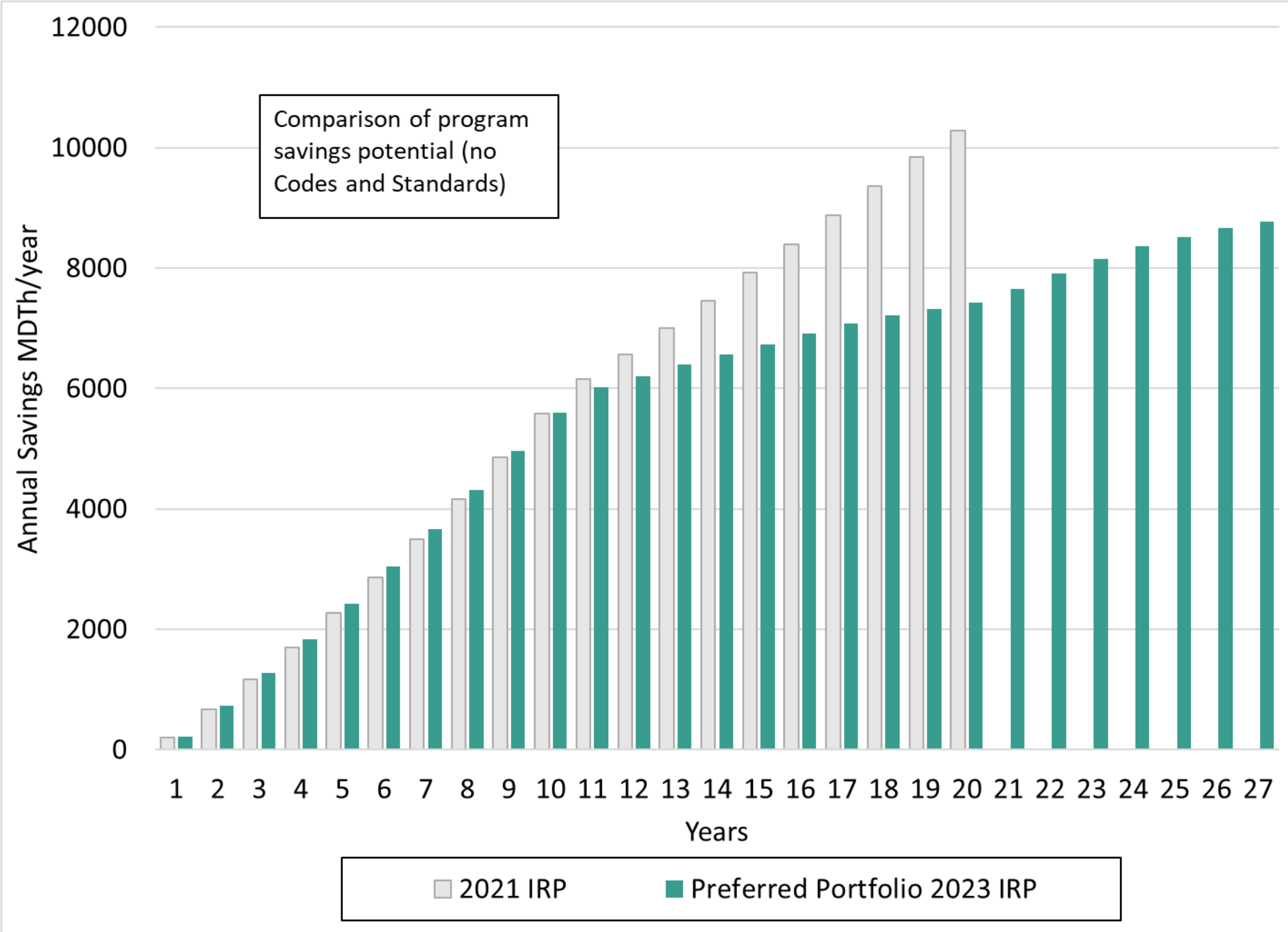


Figure 2.4 compares the cost-effective program annual energy savings in the preferred portfolio against the savings from 2021 Gas Utility IRP. The savings diverge after 2033 because we based the 2023 Gas Utility IRP preferred portfolio on a zero-growth demand and the lack of energy efficiency savings associated with new construction.

Figure 2.4: Cost-effective Energy Efficiency Annual Savings — 2023 Gas Utility IRP versus 2021 Gas Utility IRP



2.2.2. Swarr

The Swarr vaporized propane-air (LP-Air) facility provides firm natural gas supplies on short notice for relatively short periods. Generally a last resort due to their relatively higher variable costs, these resources help meet extreme peak demand during the coldest hours or days. Swarr is a needle-peaking resource that will ensure reliability on cold days, unlike a pipeline resource available year-round.

The Swarr facility is currently out of service pending upgrades to reliability, safety, and compliance systems. An upgrade would have a maximum output of 30 MDth a day available for four days of continuous capacity to the PSE system.

A critical element that makes this resource cost-effective is that it is not a new build; however there may be some additional costs associated with the operations that are not fully reflected in this IRP, they will require some additional assessments that are planned as part of the short-term action plan. This facility will not be operating until 2028. This relatively long lead time will allow us to comprehensively assess the facility, including any impacts or equity-related concerns.

2.2.3. Plymouth LNG

This option includes 70.5 MDth per day firm the Plymouth LNG service and 15 MDth per day firm NWP pipeline capacity from the Plymouth LNG plant. Puget Sound Energy's electric power generation portfolio currently holds this resource, and it may be available for renewal for periods beyond April 2023. Although this is a valuable resource for the power generation portfolio, it may be a better fit for the gas sales portfolio.

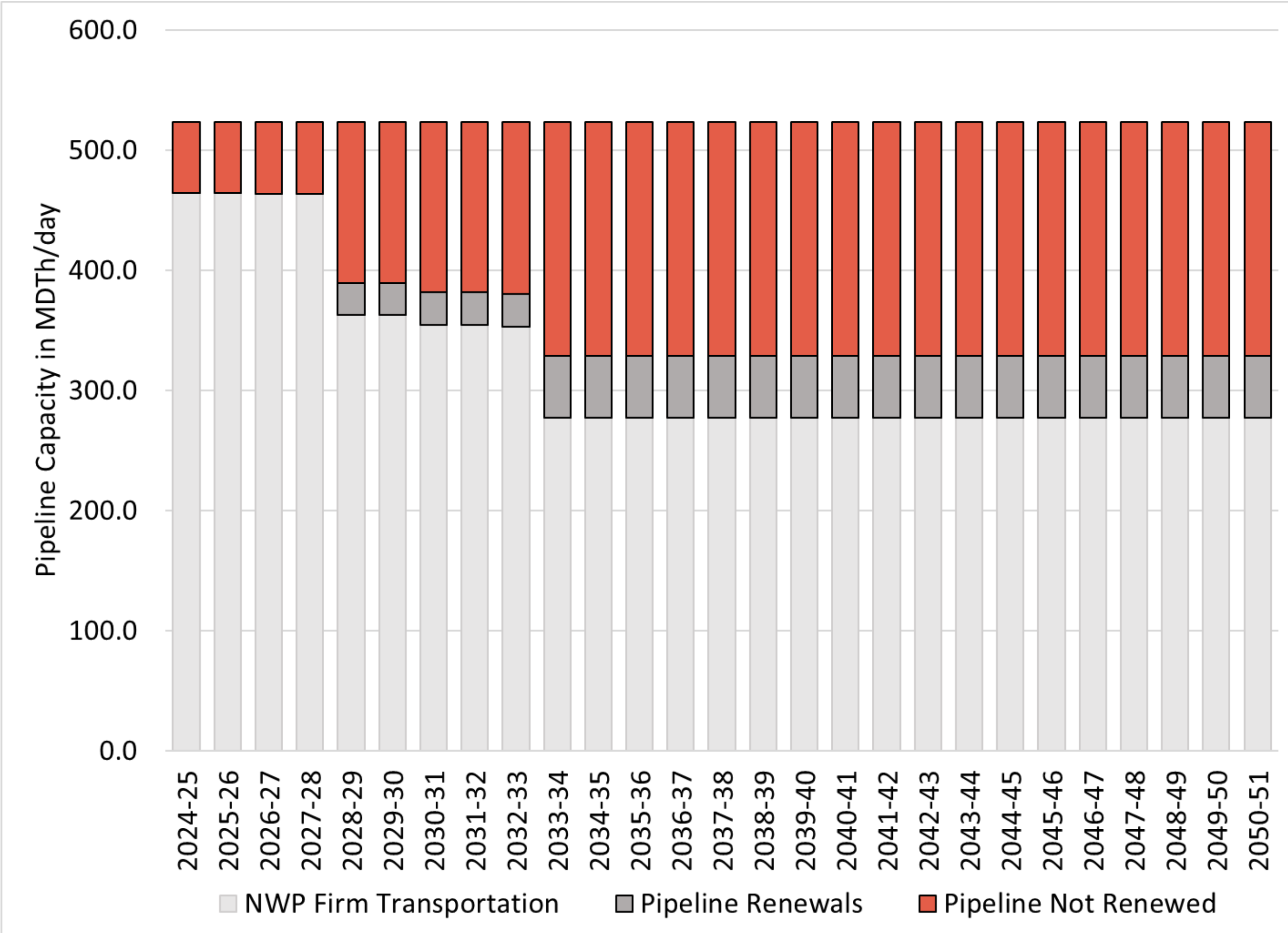
As in the case of Swarr, the Plymouth LNG facility provides short-term availability, mainly for peak and system reliability use; it can provide 15 MDth a day for slightly over four days.

2.2.4. Non-renewed Transmission Pipeline Capacity

In a departure from prior IRPs, where we assumed existing pipeline capacity would be renewed annually, in this analysis, the annual renewal was a resource alternative so renewals could compete with other supply and demand-side resources. We bundled multiple pipeline contracts to specific periods on segments from Sumas in the north and south, connecting via the Gas Transmission Northwest (GTN) to the Alberta Energy Company's (AECO) hub and the Rockies, and added them to the models for optional renewal.[5]

[5] The actual unwinding of some of the pipeline contracts vary in capacity and timing than the simplified approach in the gas modeling shows. There are requirements in the covenants to balance capacity between the north and south segments of the pipelines that we did not consider in this study. This study focused on transmission pipeline connecting to the PSE load or system. Capacity not renewed will also have implications for renewals on the upstream segments. Pipeline demand charges for the remaining pipeline will likely be realigned with the new capacity and will likely increase, these impacts were not included in the 2023 Gas Utility IRP.

Figure 2.5: Transmission Pipeline Capacity Not Renewed in the Preferred Portfolio



2.2.5. Renewable Natural Gas (RNG)

We categorized RNG by geographical location,[6] system location, and characteristic of the RNG (commodity plus attribute[7] or attribute only) as follows:

1. **RNG PNW Region**, with commodities and attributes delivered at the gas hubs. This RNG would displace natural gas and therefore had no increment to the pipeline capacity required to deliver the RNG to the PSE system.

2. **On-System RNG,** with commodity and attributes delivered on the PSE system. Since this RNG is delivered on the distribution system, it displaces an equivalent amount of transmission pipeline capacity.

[6] The default geographical location was PNW as stipulated in the CCA rules. We tested the North American sourcing in a sensitivity. See Chapter Four: Key Analytical Assumptions for more details.

[7] RNG is composed of the commodity and environmental attributes, which are the value associated with the environmental benefits inherent in RNG. These attributes are often sold separately and can be purchased to clean up conventional natural gas.

3. **RNG Attributes,** only the environmental attributes, sourced from the PNW, are purchased and with associated gas delivery from the Stanfield hub. We paired this resource with gas from the hub so it does not reduce or increase transmission pipeline capacity needs.

The reference scenario and the preferred portfolio's default sourcing geography was limited to the Pacific Northwest (PNW).

Table 2.2 shows the cost-effective RNG in the preferred portfolio. We included the existing RNG for informational purposes only; it was not part of the resource alternatives tested in the 2023 Gas Utility IRP.

Table 2.2: Cost-effective RNG in the Preferred Portfolio

Preferred Portfolio 2023 IRP	2030 Annual Energy (MDth/year)	2050 Annual Energy (MDth/year)	2030 Peak Day Capacity (MDth/day)	2050 Peak Day Capacity (MDth/day)
RNG PNW Region	0	0	0	0
On-system RNG	400	900	1.1	5.3
RNG Attributes	0	0	0	0
Existing RNG	1,940	1,180	2.5	3.2

2.2.6. 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 to end users via truck, pipeline, or rail. 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 decarbonize.

We are working with partners to develop green hydrogen in the region and anticipate it will be available starting in 2028. Regional green hydrogen capacity will expand as production gears up post-2028. The IRP assumed a third of the final 15 percent by volume[8] blend into the natural gas system will become available in 2028, another third in 2030, and the last third in 2032. All this would be within the eligibility period of the Inflation Reduction Act (IRA) incentives, which were built into the costs for green hydrogen (see Appendix E: Existing Resources and Alternatives). We assumed the green hydrogen would be delivered on PSE's distribution network, so no pipeline transmission capacity is needed or can be displaced.

8 Fifteen percent by volume is well within the range most agree is viable without adverse impacts on end use appliances (see Northwest Energy Efficiency Alliance (NEEA) | Hydrogen-Ready page iv: "*In general, the compilation of different studies indicates that there are limited performance impacts on existing appliances up to 20% hydrogen, and recent evidence suggests the value could be higher.*") Report can be found: https://neea.org/resources/hydrogen-ready-appliances-assessment-report. Fifteen percent by volume corresponds to an approximate 5 percent by energy. The green hydrogen was included in the portfolio models on an energy basis.

After considering the IRA incentives, we found green hydrogen was a cost-effective resource in all the scenarios and sensitivities.

Table 2.3: Cost-effective Green Hydrogen in Preferred Portfolio

Preferred Portfolio	Green Hydrogen (MDth/year)	Green Hydrogen (MDth/day)
2024–2025	0	0
2030–2031	3,460	9.48
2045–2046	5,190	14.22
2050–2051	5,190	14.22

3. Rationale for the Preferred Portfolio

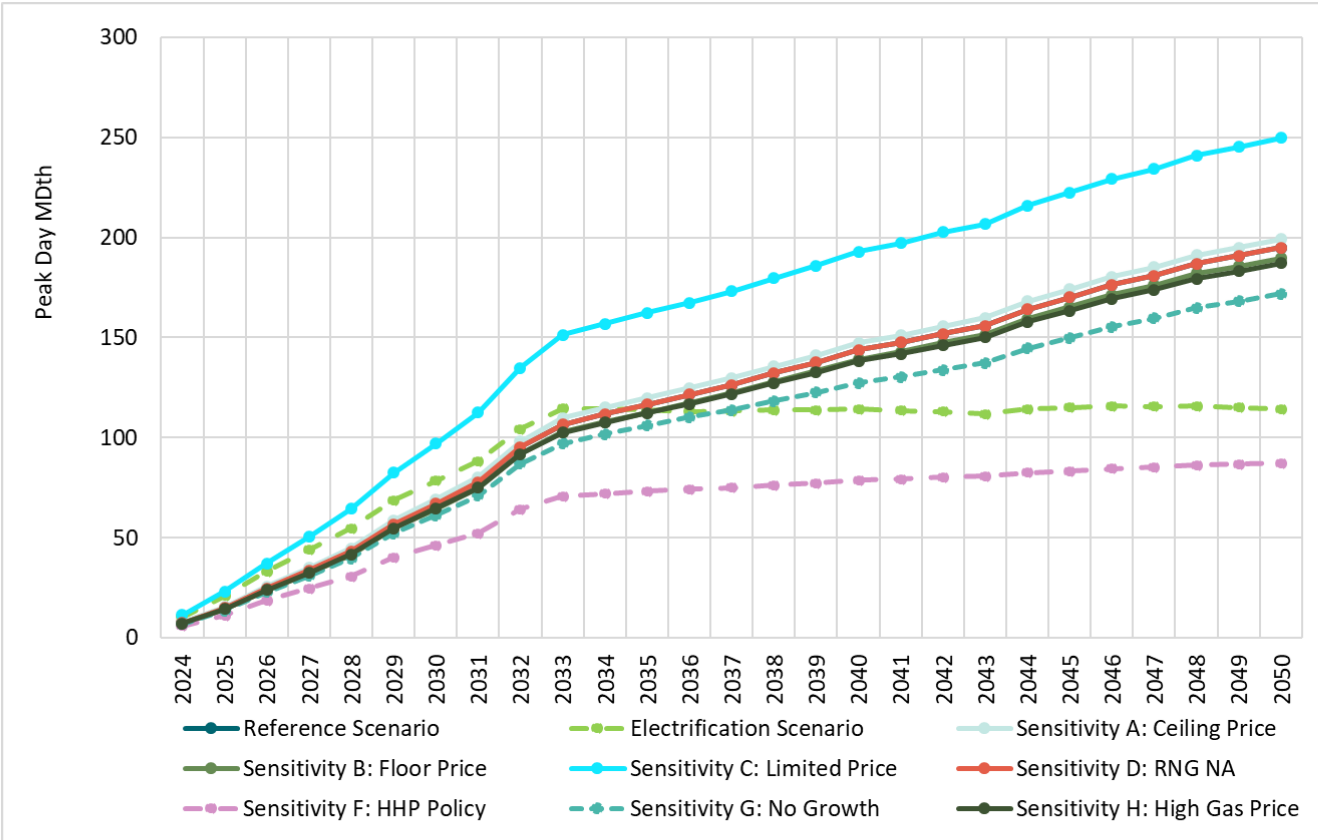
The least-cost portfolio from the zero-growth sensitivity guided us to the final preferred portfolio. The feedback we received from several parties influenced the decision to use the zero-growth sensitivity on our draft resource plan. We all agreed that the zero-growth sensitivity is more reasonable than a forecast that did not include the latest building code revisions. While codes and standards do not eliminate all growth from a risk perspective, the zero-growth assumption is closer to what we expect in the future than the base demand forecast. While the least cost plan from the Zero Growth sensitivity drove this preferred portfolio, we examined all the portfolio analyses to inform our decision. The following goes through each portfolio decision to explain why each element is reasonable.

➔ Please see Chapter Six: Gas Analysis and Appendix F: Gas Analysis Results for detailed modeling results.

3.1. Conservation Demand-side Resources

We based the conservation supply curve for the preferred portfolio on zero-demand growth; it had no conservation related to new construction. This conservation assumption is consistent with zero-demand growth; a demand-growth-based conservation supply curve would not be appropriate as it would create inconsistent modeling inputs by overstating the conservation available when the demand is expected to lower. Figure 2.6 shows the cost-effective conservation by scenarios and sensitivities. The preferred portfolio is the lowest of the non-electrification scenarios, as opposed to electrification, where the gas demand reduction from fuel switching diminishes conservation potential.

Figure 2.6: Cost-effective Conservation by Scenario and Sensitivity



Cost-effective energy efficiency moved in direct proportion to natural gas prices, demand growth, and electrification. Table 2.4 is a tabular representation of Figure 2.6.

Table 2.4: Conservation Savings Range at Peak by Scenarios and Sensitivities (MDth/day)

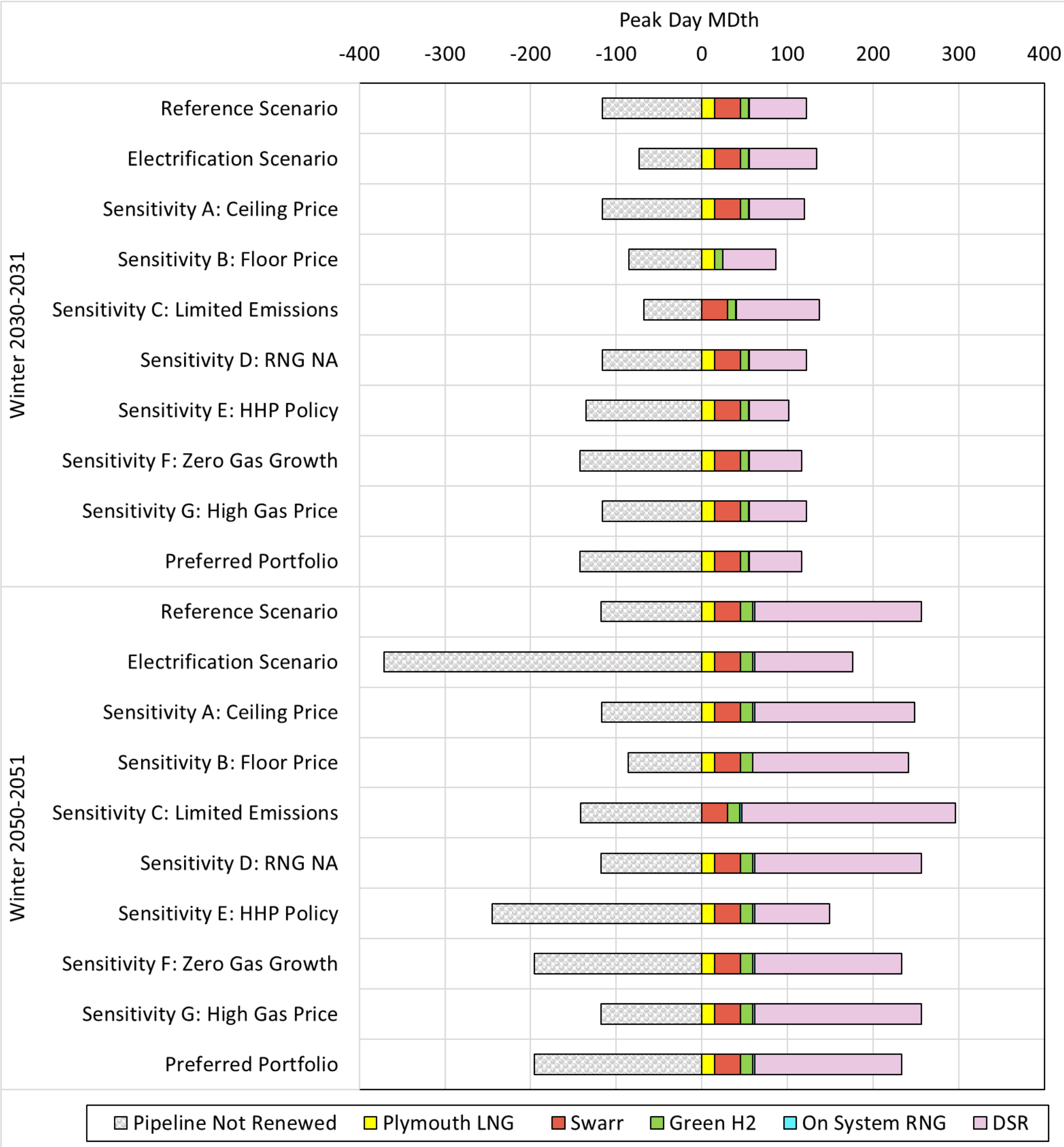
Scenario/Sensitivity	2024	2030	2040	2050
Reference Scenario	7	67	144	195
Electrification Scenario	10	78	114	114
Sensitivity A: Ceiling Price	7	64	138	187
Sensitivity B: Floor Price	7	62	134	182
Sensitivity C: Limited Price	11	97	193	250
Sensitivity D: RNG NA	7	67	144	195
Sensitivity E: Hybrid Heat Pumps (HHP) Policy	6	46	79	87
Sensitivity F: Zero Growth	7	61	127	172
Sensitivity G: High Gas Price	7	65	138	187
Preferred Portfolio	7	61	127	172

➔ Details on the load forecast are in Chapter Five: Demand Forecast, and impacts of conservation across the various scenarios and sensitivities in Chapter Six: Gas Analysis.

3.2. Supply-side Resources

Figure 2.7 shows the portfolio additions' results to serve the peak day. The figure includes supply-side resource additions for the winter 2024–2025, 2030–2031, and 2050–2051 periods of the study.

Figure 2.7: Portfolio Additions – Including Supply Side Resources



The supply-side resources — upgrades to the Swarr Propane Plant, renewing the Plymouth Liquid Natural Gas (LNG) peaker contract, and pipeline capacity not renewed — are present in all the scenarios and sensitivity portfolio resource additions.

There are no near-term resource decisions except for Plymouth LNG. The lead time to acquire the Plymouth LNG peaker contract is short, so we must decide whether to add this contract before 2024. We show Swarr in the preferred portfolio as a need in 2030. Pipeline capacity release would begin as soon as 2024. The SENDOUT model simulates a simplified de-contracting approach, so the actual rate of returning these pipeline contracts may vary based on the terms and conditions of each contract (see Appendix E: Existing Resources and Alternative Table E.5)

3.2.1. Swarr Propane Plant

Upgrades to PSE's propane injection facility, Swarr, are the least-cost resource in all scenarios and sensitivities (see Figure 2.10), even in the electrification cases. Driven by the low cost of upgrading the facility instead of keeping year-round pipeline capacity, the simple payback is less than three years. This resource would have made it into any preferred portfolio choice, and we included it here.

3.2.2. Plymouth LNG

The Plymouth LNG peaker contract is the least-cost resource in all scenarios and sensitivities (see Figure 2.10), except the Limited Emissions sensitivity, even in the electrification cases. Like, Swarr, this is a relatively low-cost resource compared to keeping year-round pipeline capacity. This resource is, therefore, a logical choice to include in the preferred portfolio.

3.2.3. Pipeline Capacity

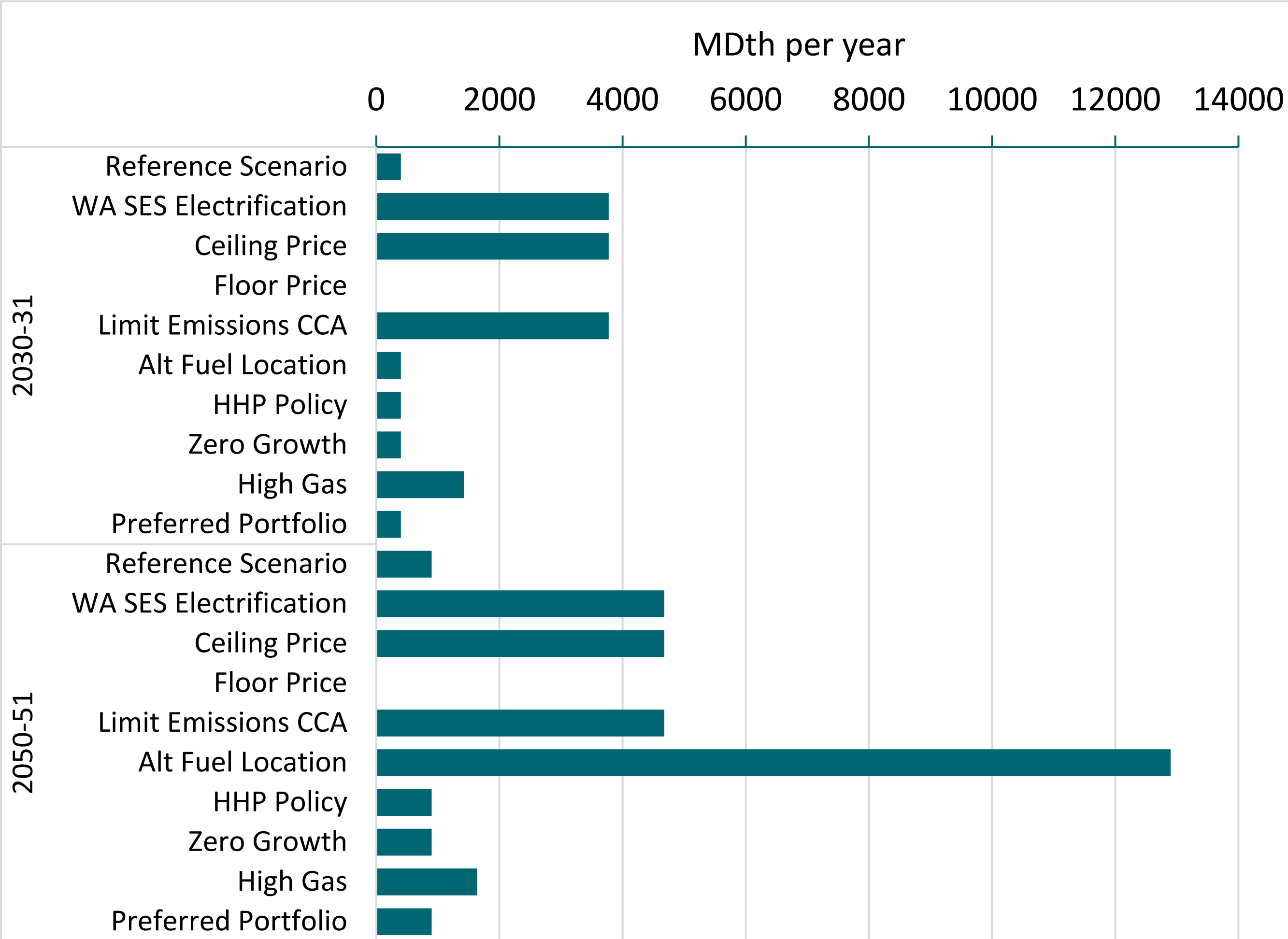
Northwest Power contract renewals are the shock absorber for demand uncertainty. The model shows we must renew fewer pipeline capacity contracts in the scenarios where demand is low (see Figure 2.7). This approach provides a significant amount of flexibility as the future unfolds. Furthermore, many contracts roll over year-to-year, so PSE does not have to make those decisions today.

3.2.4. Renewable Natural Gas (RNG)

Renewable natural gas is mainly price sensitive. As Figure 2.8 shows, more RNG is cost-effective in scenarios and sensitivities where the CCA or gas prices are higher, except for the limited emissions sensitivity, in which the model prioritized all emission-reducing resources before adding CCA allowances for CCA compliance.

The floor price sensitivity is the only sensitivity in which RNG is lower than the preferred portfolio. In most cases, the RNG is either the same or more than in the preferred portfolio. The preferred portfolio at the lower end avoids the risk of overbuilding, and if total gas costs increase, it can add more RNG as needed.

Figure 2.8: Cost effective RNG — Scenarios and Sensitivities by Annual Energy



3.2.5. Green Hydrogen

Green hydrogen is cost-effective in all the scenarios and sensitivities; thus, it would be included in any preferred portfolio. The amount of green hydrogen needed will be lowest in electrification scenarios as demand declines, and the 15 percent blend limit by volume leads to a lower need for green hydrogen. We do not expect green hydrogen to be available for four or five years, allowing time to study the blend quantity and other issues needed to develop this new fuel source.

4. Portfolio Costs

Portfolio costs reflect the new resources' total cost and the portfolio's operating costs, including all CCA allowance costs.[9] The distribution system is not part of the SENDOUT model, so we did not include costs for the distribution

[9] We removed the social cost of greenhouse gases (SCGHG) with the upstream emissions from the portfolio costs shown here.

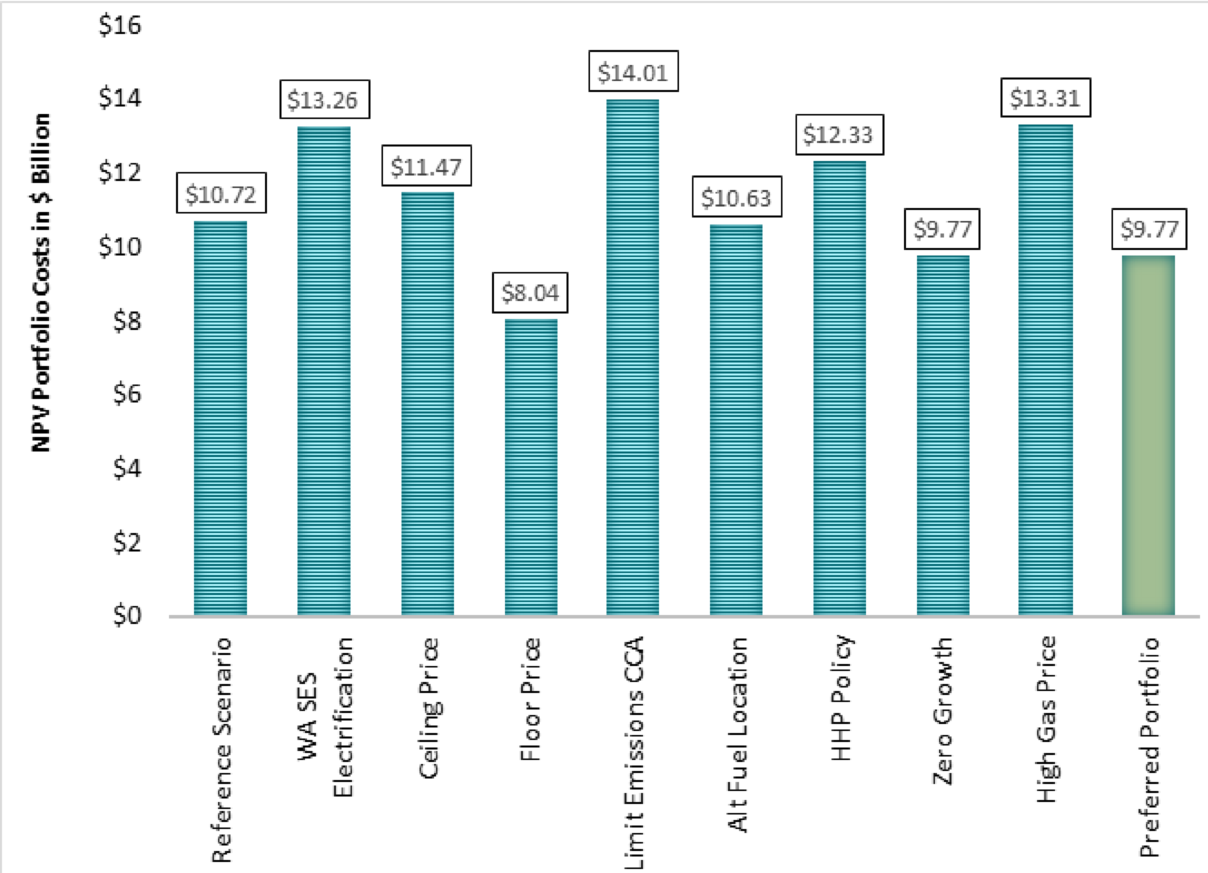
systems. Similarly, we did not include the capital cost of the existing resources such as Jackson Prairie, Gig Harbor LNG, Tacoma LNG, and even portions of the reusable part of Swarr in this cost.

The electrification scenario and the HHP policy electrification sensitivity include costs associated with the electric system's expanded capacity to serve the additional electric demand. The Limited Emissions CCA sensitivity also comprises the market HHP electrification; however, it also has a higher amount of net additional allowances needed to meet CCA requirements, since this electrification sensitivity, unlike the policy cases, only included the hybrid heat pumps as a conservation measure, so it has the highest portfolio cost.[10]

Figure 2.12 shows the portfolio cost in net present value (NPV) and offers the range of costs for all the scenarios and sensitivities. The cost of the preferred portfolio is the second lowest cost and above only the Floor Price sensitivity. The preferred portfolio cost is lower than the Reference Scenario's net present value (NPV) by about $1 billion due to the lower demand.

[10] The WA SES Electrification scenario benefits from the Floor price assumption, a mid-CCA price in this scenario was not run, else it may have been the highest cost of any of the scenarios or sensitivities.

Figure 2.9: Total Portfolio Costs (NPV in 2024$ (Billions))



4.1. Electrification Costs

Electrification costs include measure-related costs and electric system costs. The impact on the gas system cost will consist of a reduction in gas costs offset by costs associated with decommissioning. Decommissioning costs are not included in this study, but could be a consideration in future IRPs. We captured the gas cost reductions in the portfolio costs discussed as a net cost of measure cost and gas reductions.

We developed the measure costs as outputs of the CPA, which are in Appendix C: Conservation Potential Assessment. We developed the equipment cost assumptions from a contractor and builder survey as part of the CPA, and the results are in Appendix C, page A-12. We included measure costs in the gas supply curve inputs to the portfolio analysis; the electric costs are an output of the electric portfolio analysis.

Table 2.5: Electrification Costs by Policy in $ Billions

Electrification Policy	Measure Cost	Electric System Cost	Total Cost
Full electric	5.40	3.37	8.77
Hybrid Heat Pump	3.81	1.44	5.25

These costs do not reflect the cost of any IRA incentives. We need more clarity regarding how we should incorporate these incentives into the total resource cost test used to evaluate conservation measure cost-effectiveness. In this analysis, electrification costs are high, and their corresponding portfolio costs are greater than scenarios and sensitivities that buy net additional CCA allowances.

4.2. Unrestricted RNG Sourcing

In the preferred portfolio, we restricted RNG to the PNW region. If RNG is unrestricted and we could source it from North America, it would provide additional cost-effective emissions reductions in the preferred portfolio. See Figure 2.11 and Table 2.6.

Table 2.6: Emissions Reduction in Metric Tons — Regional RNG vs. Nationally-sourced RNG (Scenario One vs. Sensitivity D)

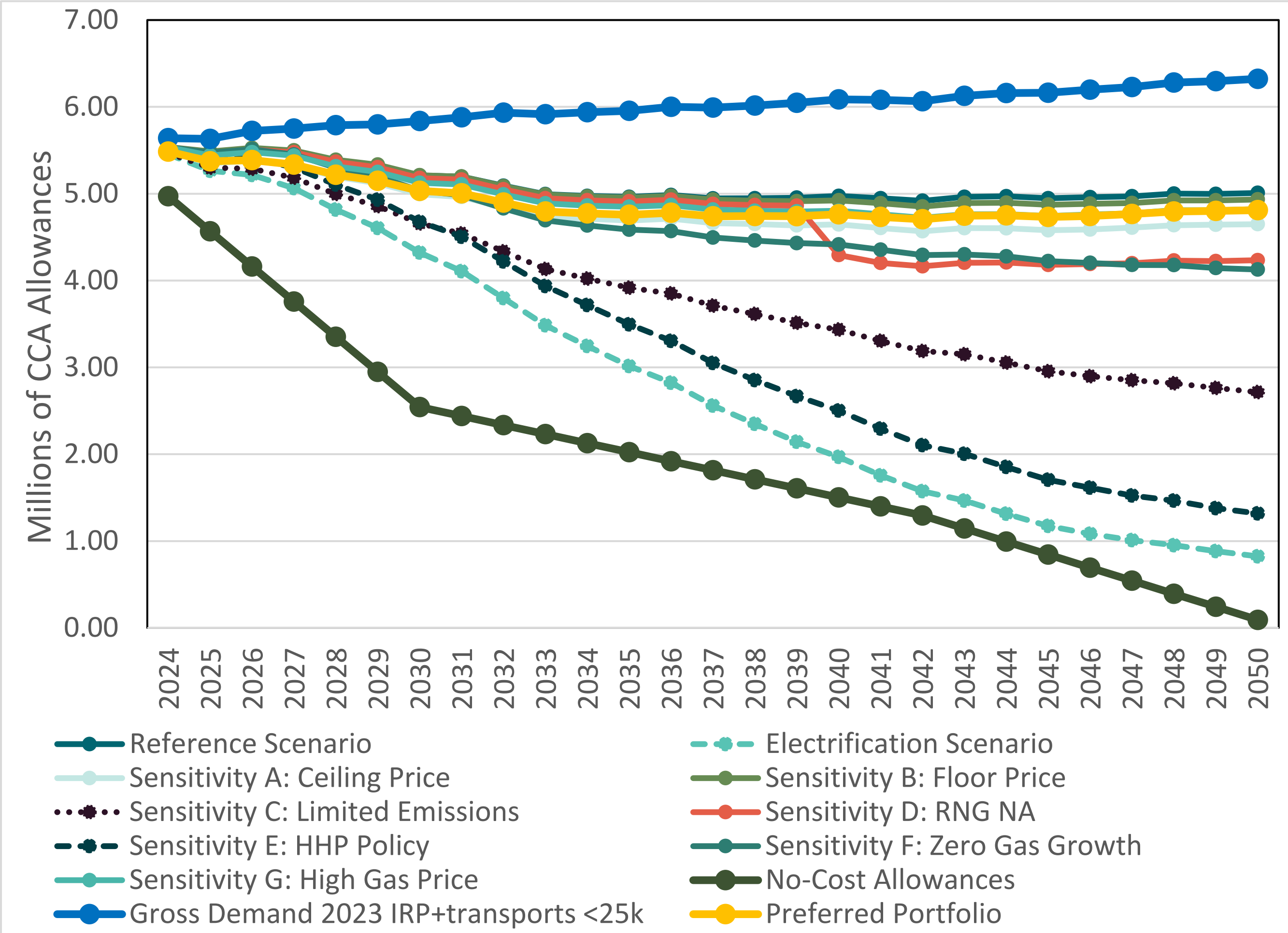
Geographic Footprint	Emissions Reductions 2030	Emissions Reductions 2045
PNW RNG	123,000	120,000
National RNG	123,000	750,000

The nationally sourced RNG in Sensitivity D also has a lower portfolio cost in net present value than the reference scenario by about $93 million in 2024.

5. Emissions Reduction Potential

We included several resource alternatives in the portfolio analysis that would reduce emissions: energy efficiency, hybrid heat pump systems, electrification, regional RNG, and green hydrogen. The gas portfolio model chose from these resources, with the exception of the policy electrification cases where electrification was force into the model, such that the resulting cost of the portfolio is less than the cost without these resources. Figure 2.10 shows the emissions reductions and net additional allowances needed to meet the CCA requirements in each scenario and sensitivity.

Figure 2.10: CCA Allowances by Scenarios and Sensitivities



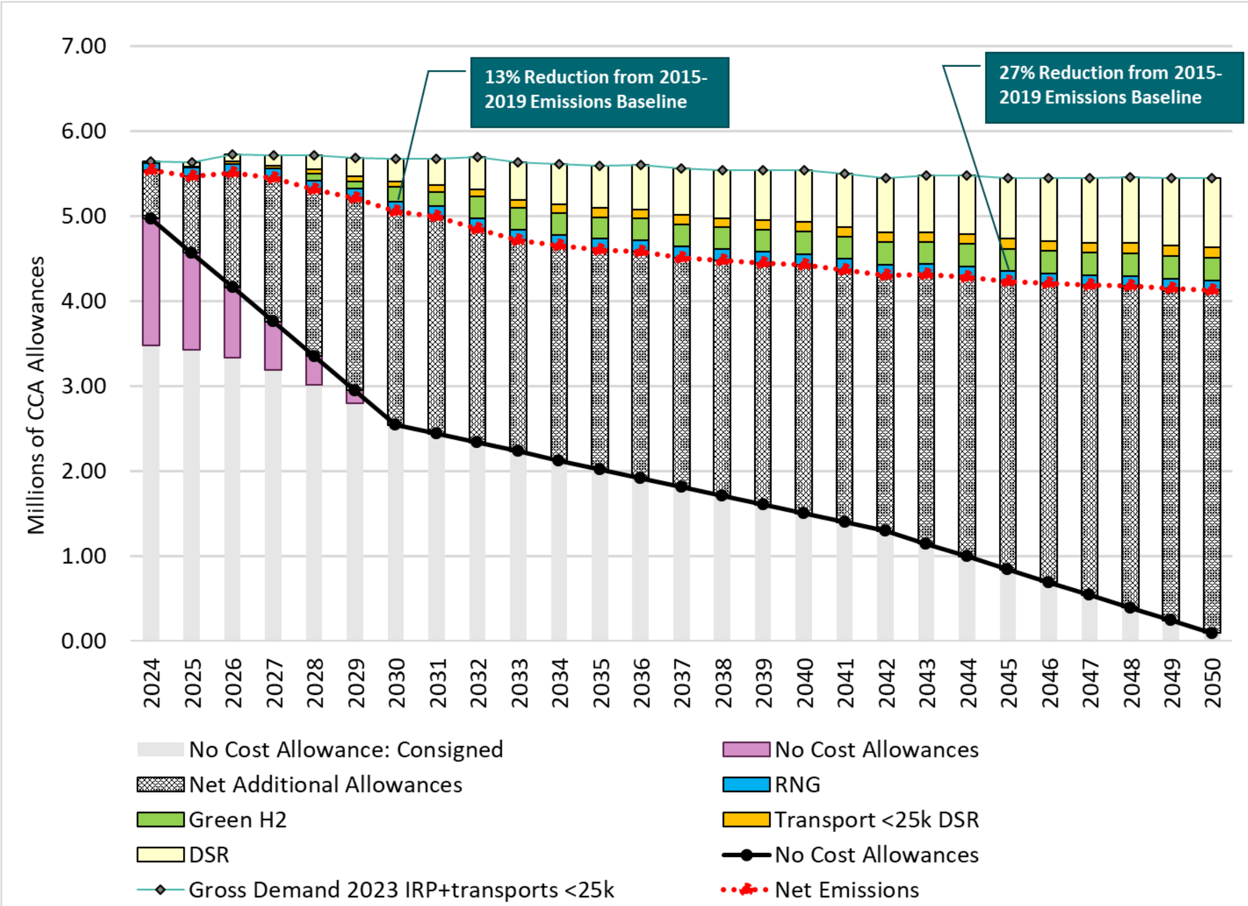
There are limits to resource alternatives that can yield emissions reductions. Energy efficiency is chosen on the supply curve price point that is still cost-effective.[11] Green hydrogen has a practical upper limit of around 15–20 percent for blending into the gas system by volume without significant infrastructure changes. The two electrification cases, the electrification scenario and the HHP policy sensitivity, represent cases where the model replaced all the gas end-use equipment on burnout. We included no IRA incentive in the scenario costs. The CCA allowance pathways in Figure 2.10 represent a theoretical maximum limit of equipment replacement. Please note that the uptake of electric equipment will not likely achieve a perfect 100 percent replacement. Hence the emissions reductions shown for the electrification cases are theoretical maximums, and the actual reduction will probably be less. How much less will be determined by a combination of market, financial, and policy dynamics.

The preferred portfolio shown in Figure 2.11 results from the least-cost portfolio analysis and the impacts of the most likely policies and other external factors we currently know. The preferred portfolio reduces emissions by 13 percent

[11] See Appendix E: Existing Resources and Alternatives for more details on the cost-effective conservation selected in the preferred portfolio and other gas scenarios.

by 2030 from the emissions baseline at the start of the first compliance period in 2023 and achieves a 27 percent reduction by 2045.

Figure 2.11: Emissions Reduction and Net Additional Allowances Needed in the Preferred Portfolio



LEGISLATIVE AND POLICY CHANGE

CHAPTER THREE

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 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. The law directed the Washington State Department of Ecology (Ecology) to develop rules to implement and administer the program beginning on January 1, 2023. Ecology adopted the final program rules on September 29, 2022, and they went into effect on October 30, 2022. 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 GHG emissions. We will work to mitigate those impacts through decarbonization efforts and managing our allowances.

In this report, we discuss no-cost and consigned allowances. No-cost allowances are issued by Ecology and can be use directly for compliance. Consigned allowances are no-cost allowances provided to PSE by Ecology that must be sold at auction. The CCA law restricts the use of the associated auction allowance revenue to certain actions that benefit customers.

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. Covered entities, such as PSE, must report 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.

2.2. Impacts and Actions

Gas utilities are required to comply with the CCA. In the 2023 Gas Utility IRP, we included three potential CCA allowance costs to analyze the impact of CCA compliance on PSE. We based the three CCA allowance costs on price curves in the *Final Regulatory Analysis*[1] report published by the Department of Ecology: Mid or Expected CCA price, Ceiling price and Floor price. The Ceiling and Floor prices we used are identical to the information provided by the report. However, we derived the Mid CCA price for the IRP from a combination of the Expected CCA price from 2024–2030 in the Ecology report and then transitioned to the California Energy Commission's (CEC) forecast for

[1] https://apps.ecology.wa.gov/publications/documents/2202047.pdf

California allowance prices for 2030–2050, based on the assumption that the CCA will eventually link to the California Cap-and-Trade Program.

Under the CCA, gas utilities receive direct allocation of no-cost allowances[2] (based on a 2015–2019 baseline). These no-cost allowances decline proportionally with the statewide cap established under RCW 70A.45.030.[3] The reductions apply in the emissions cap scenarios in the IRP, as discussed.

The IRP scenarios studied the impacts on the gas portfolio in two ways:

1. Using a price cap: physical emission reductions are prioritized based on the least-cost addition of resources and then balanced with net additional allowances to meet CCA requirements.
2. Using an emissions cap: resource additions are prioritized without regard to cost to maximize physical emissions reduction before net additional allowances are allowed to balance the portfolio to meet CCA requirements.

The IRP also studied electrification scenarios as a means of reducing emissions to meet the requirements of the CCA. However, electrification also affects the electric utility. We include the results of the electrification analysis with impacts on the gas and the electric utility in this 2023 Gas Utility IRP. This analysis highlights the importance of a dual-fuel energy system as we transition to a low-carbon economy.

Another resource examined in this IRP is alternate fuels such as renewable natural gas (RNG) and green hydrogen. These are fuels determined to have no emissions compliance obligation under the CCA.

➔ A full explanation of the methodology and assumptions we used to model the impacts of the CCA is 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 included in the 2023 Gas Utility IRP, the Washington State Energy Code (WSEC), and several city ordinances are transitioning to 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

2 Some of the no-cost allowances are consigned to auction and are to be used as per provisions in RCW 70A.65.130 (2).

3 RCW 70A.45.030

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[4] 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 2031 compared to a 2006 code baseline.[5]

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 construction in place of gas heating 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 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. Therefore, the impact on demand is gradual. 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 codes change 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.

4 The cities of Bellingham and Shoreline also passed similar gas bans in their jurisdictions in 2022.
5 RCW 19.27A.160

3.1. Impacts and Actions

The CPA included the following codes:

- Forecast of more efficiency codes per RCW 19.27A.160[5]
- Gas restriction in city ordinances: Seattle, Shoreline, and Bellingham
- Updates to the 2018 WSEC

The 2023 Gas Utility IRP includes a zero-gas growth sensitivity: Washington State updated the 2021 WSEC in late 2022 after we completed the 2023 CPA; however, we included informative policy scenarios. One scenario explored zero growth in gas customers. This scenario overstates the impact the proposed 2021 WSEC 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.

The 2023 Gas Utility IRP included two policy-based electrification scenarios in the CPA. The electrification scenarios were examined in the gas and electric portfolio models, and the results of both are presented in the 2023 Gas Utility IRP. In one scenario, we adopt hybrid heat pumps as a complete replacement for existing heating systems in the residential customer classes and the other scenario adopts electric heat pumps.

Finally, the 2023 Gas Utility IRP evaluated alternative fuels to reduce GHG 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.

We include these scenarios to understand the potential impact on demand. By law, PSE must supply customer demand, so we must understand and predict the outcome of those factors that may impact future demand.

4. Inflation Reduction Act

The federal Inflation Reduction Act (IRA) 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 IRA addresses climate change primarily by providing tax incentives and consumer rebates to move project developers and households toward lower-carbon or zero-carbon technologies. Impacts on gas utilities are associated with incentives for green hydrogen[6] 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 IRA may affect the conversion of certain customers from gas to electric service[7] — we will consider this in future IRPs.

[6] A maximum production tax credit (PTC) of $3/kg for green hydrogen became available in 2023 and will go for ten years (2032). https://www.congress.gov/bill/117th-congress/house-bill/5376/titles.

[7] Applications for states to request these funds won't be available until the middle of 2023 with funds likely not available to the public until early 2024.

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 CPA. 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 or may not affect future CPA due to the use of a total resource cost test in Washington[8]. Additionally, such subsidies might impact customer decisions, which could impact loads. We will factor in IRA subsidies when considering customer behavior in future analyses.

5. Washington Clean Buildings Act

The Washington Clean Buildings Act (HB 1257) became law during the 2019 legislative session. HB 1257 establishes a standard to improve the energy performance of large commercial buildings. It includes new natural gas conservation requirements that address the growing demand for gas to heat building space and water. Utilities must also expand programs to make renewable natural gas available to customers who want to purchase it. Section 12 of the law encourages utilities to incorporate renewable natural gas into their supplies to serve all retail customers. In December 2020, the Washington Utilities and Transportation Commission (Commission) issued a policy statement on how utilities may incorporate RNG into their gas portfolio to serve customers.[9]

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 Act became law 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 will incorporate RNG supply not utilized in PSE's voluntary RNG program(s) into PSE's supply portfolio, displacing natural gas purchases as provided for in HB 1257.

5.1. Impacts and Actions

We are planning significant investments in cost-effective RNG supplies and believe being a proactive RNG buyer and/or producer in the region is valuable. Our analysis indicates that PSE can acquire sufficient RNG volume to meet the needs of our future voluntary RNG program participants, our portfolio and achieving meaningful carbon reductions.

[8] This question is being considered under the UTC staff investigation - UE-210804.

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

KEY ANALYTICAL ASSUMPTIONS

CHAPTER FOUR

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.

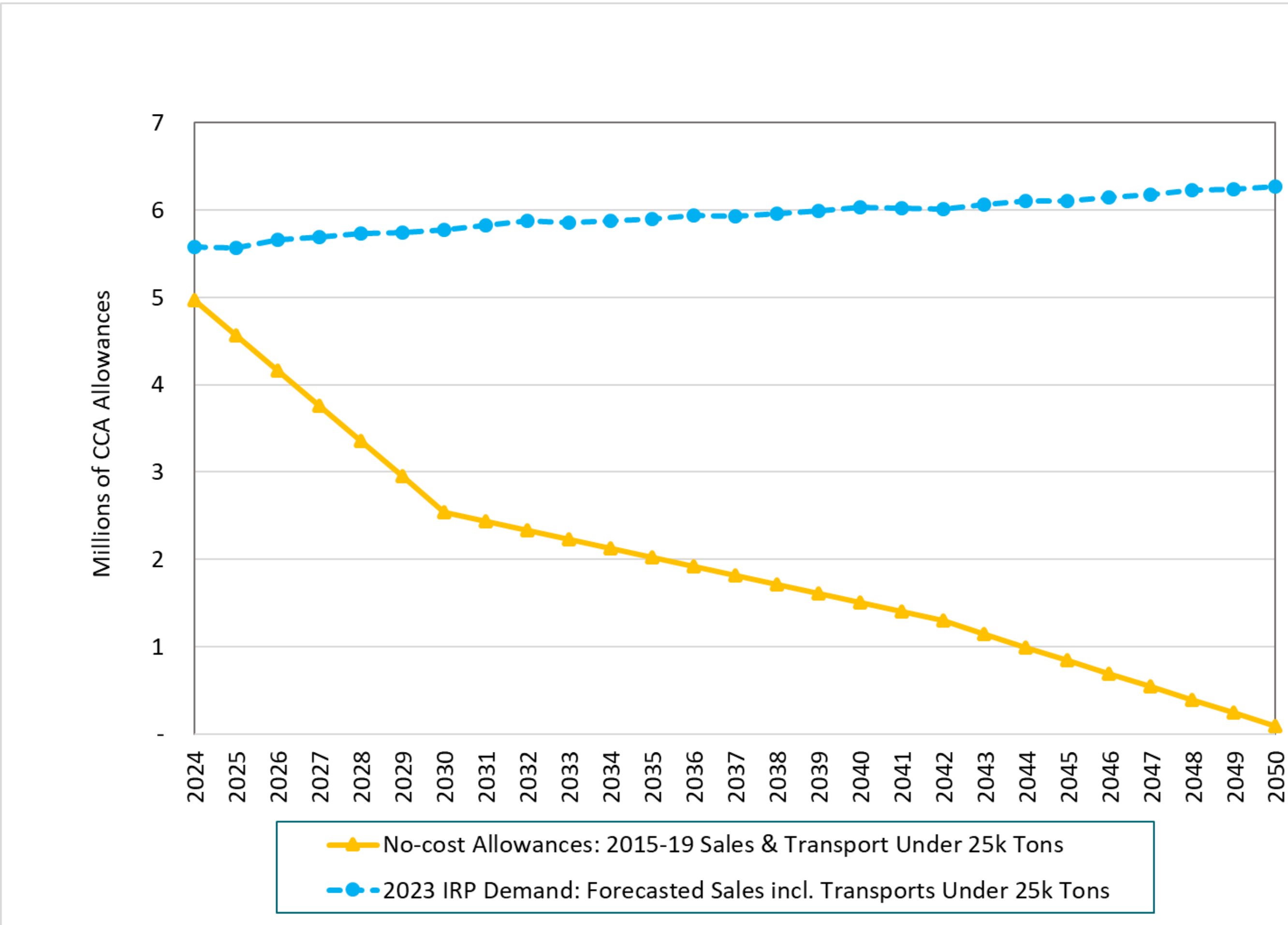
This IRP portfolio analysis optimizes the system costs and resource needs to meet compliance (a) through the purchase of allowances, a price cap, and/or (b) enforcing a hard emissions reduction, or emissions cap, or (c) a combination of allowance purchases and emissions reductions.

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

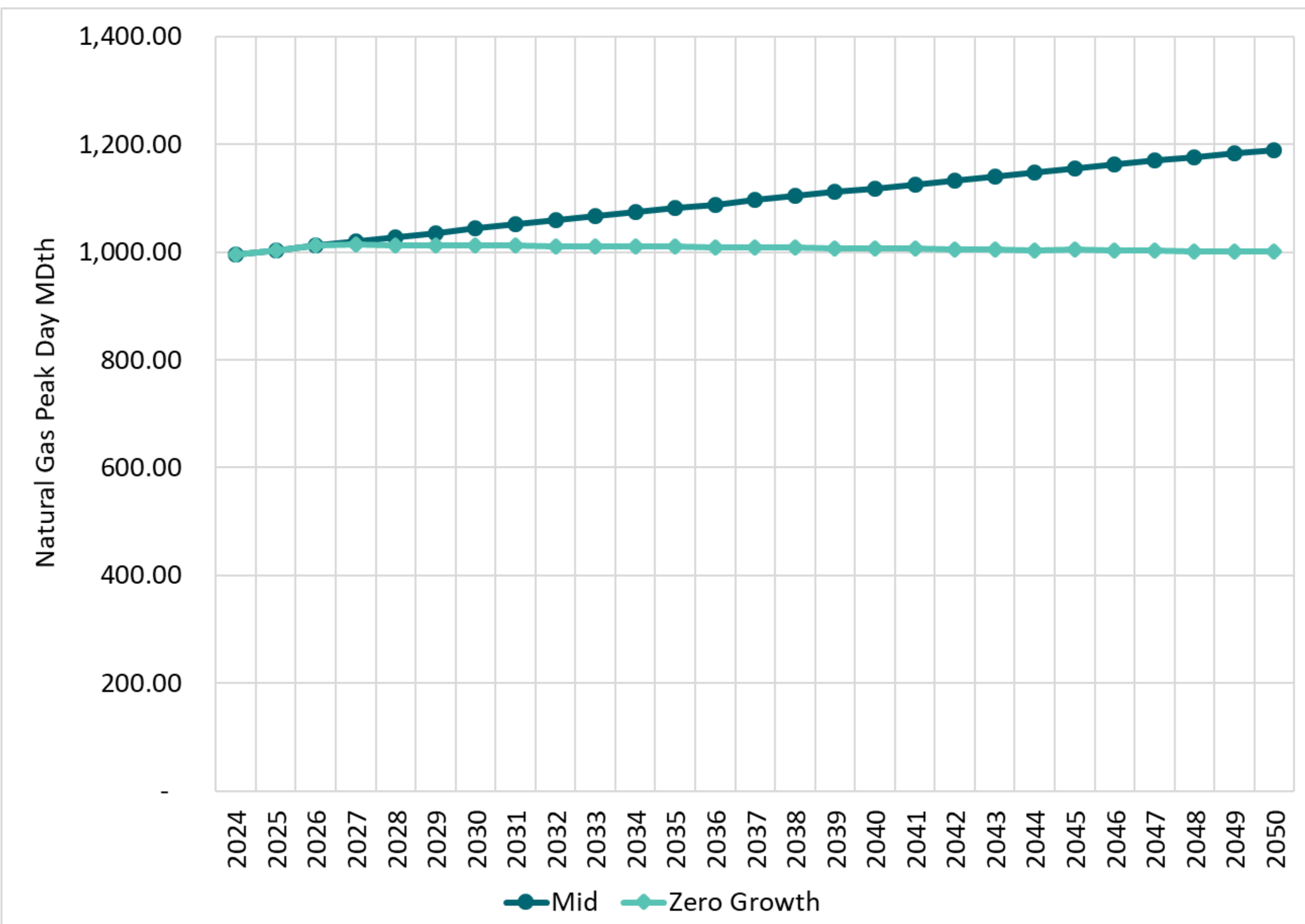
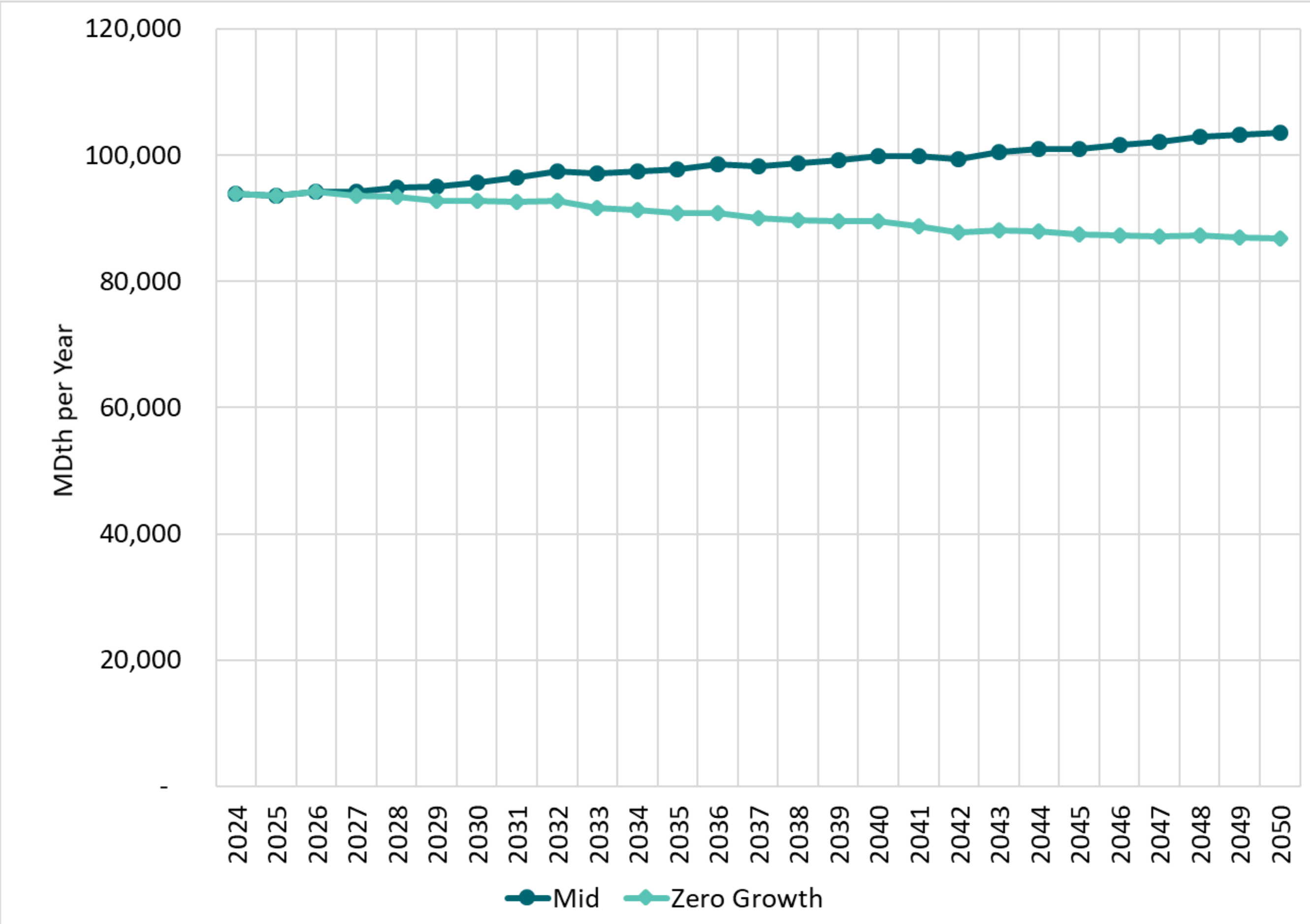


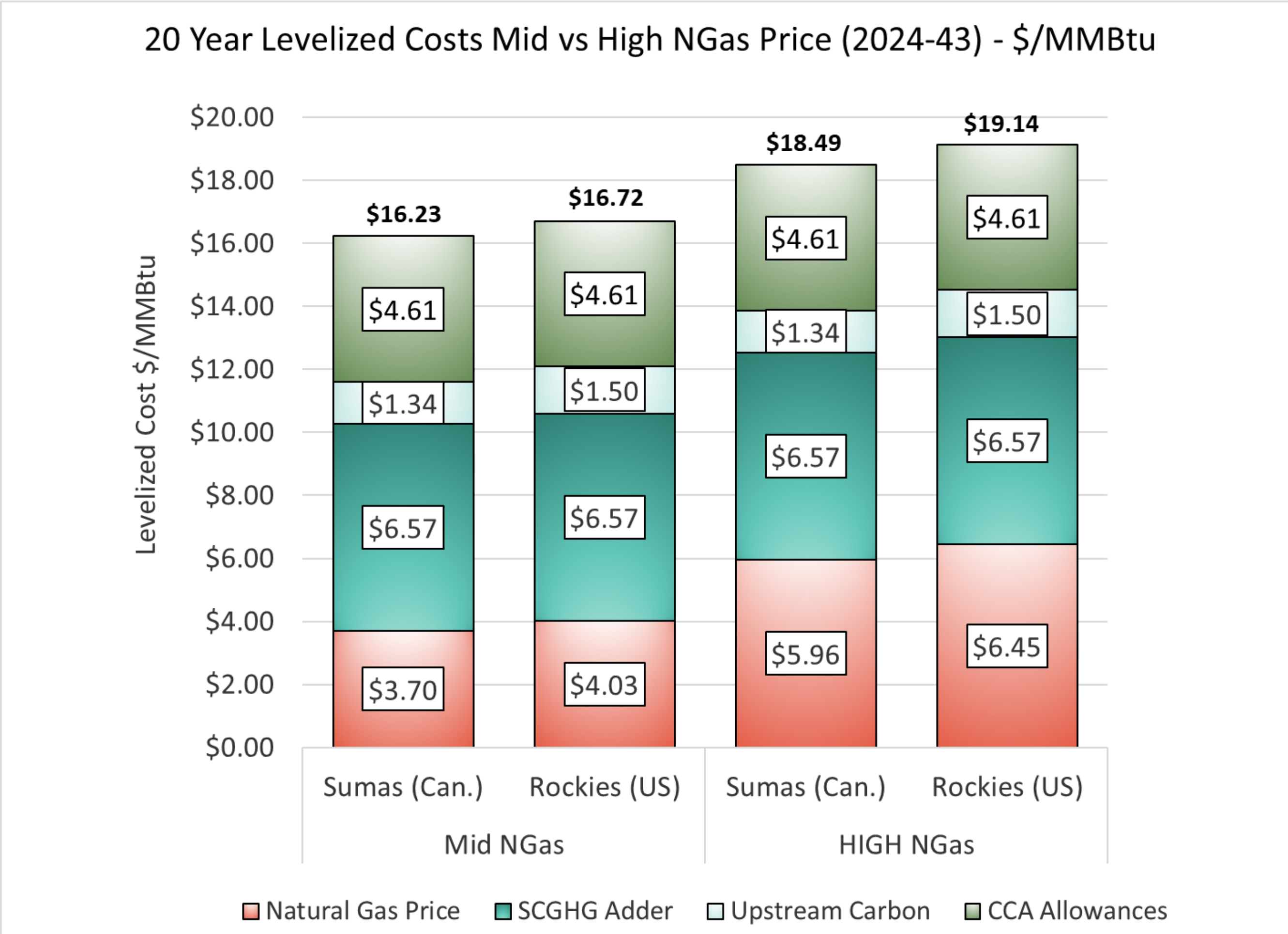
Figure 4.3: 2023 Gas Utility IRP Annual Gas Sales Demand Forecast before DSR — Zero-growth and Mid-demand



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.

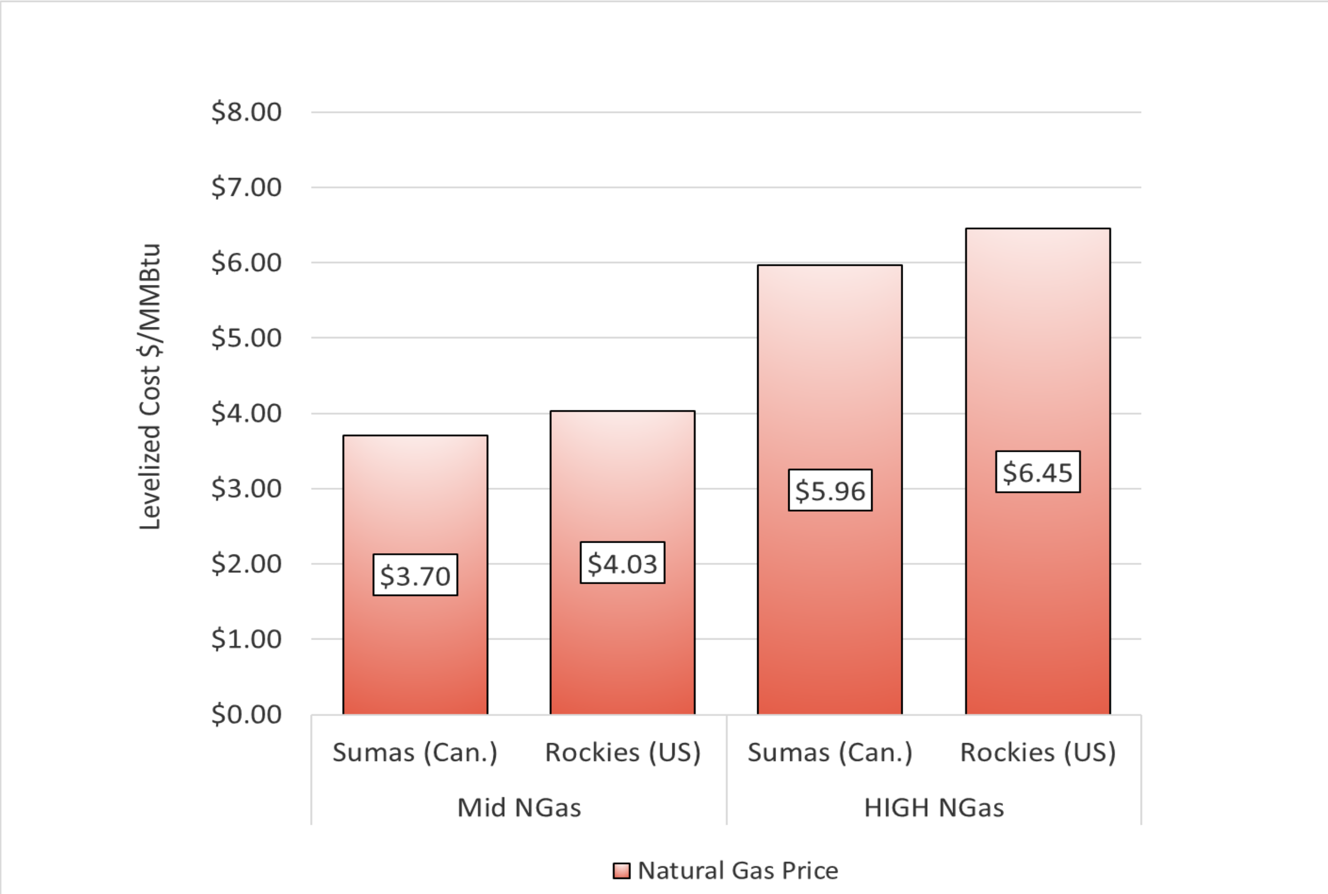
Mid Natural Gas Prices: The mid natural gas price forecast uses the three-month average of forward market prices from May 12, 2022, and the Wood Mackenzie fundamentals-based long-run natural gas price forecast published in May 2022.

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



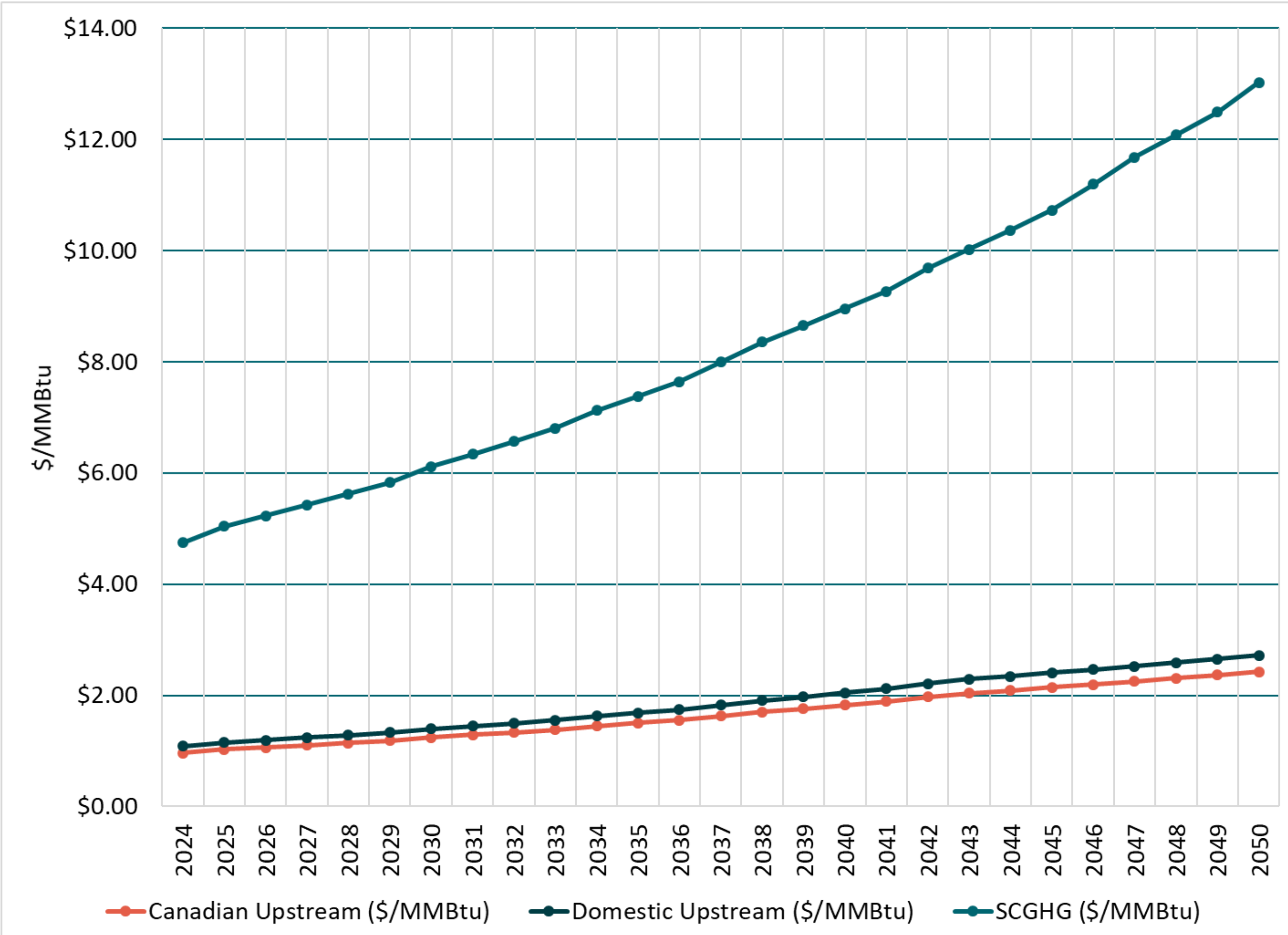
Greenhouse Gas Price Inputs

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

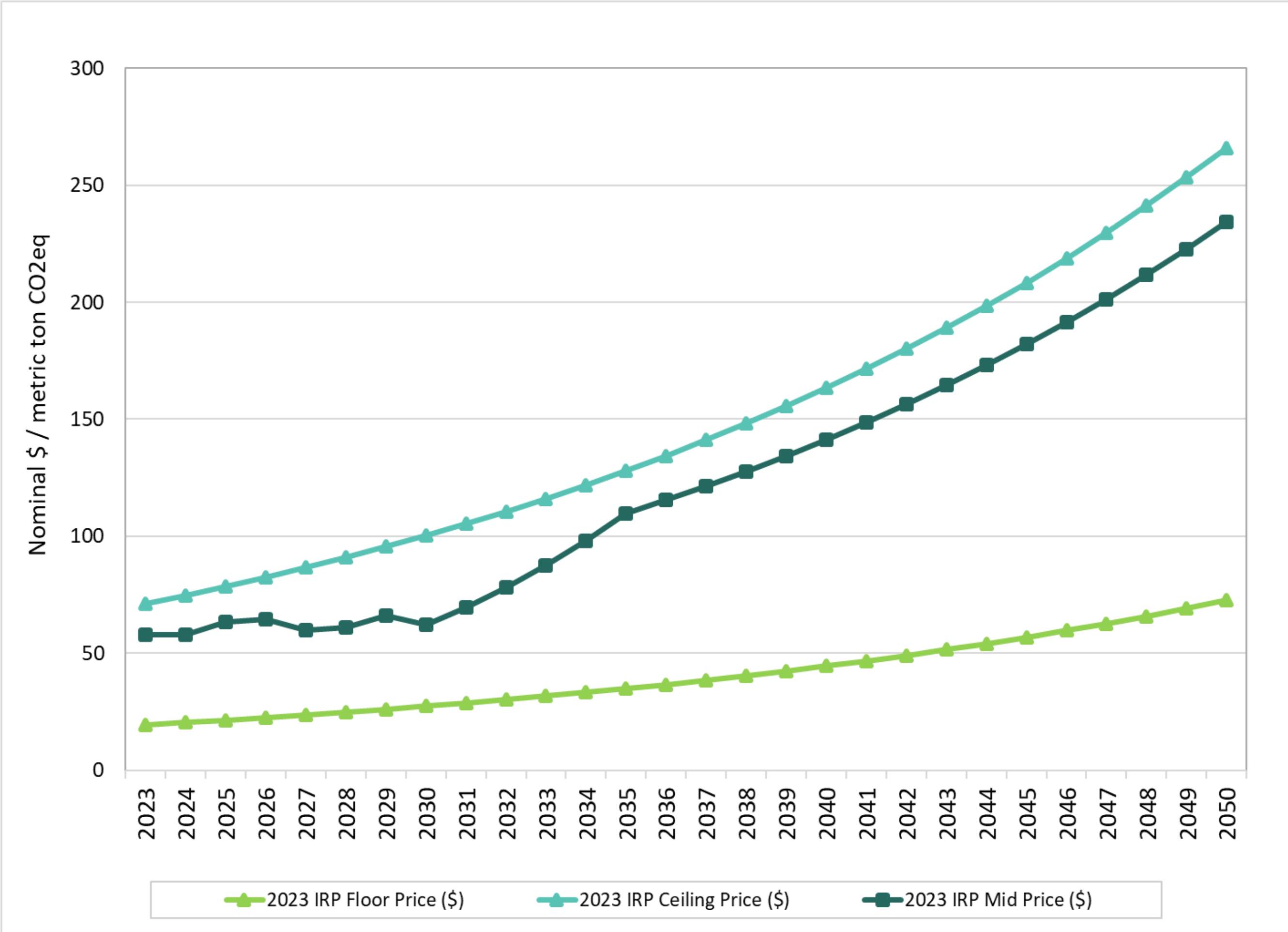
Model	Upstream Segment (g/MMBtu)	End-use Segment Combustion (g/MMBtu)	Emission Rate Total (g/MMBtu)	Upstream Segment CO^2e (%)
GHGenius	10,803	+ 53,060	= 65,203	20.40
GREET	12,121	+ 53,060	= 66,521	22.80

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

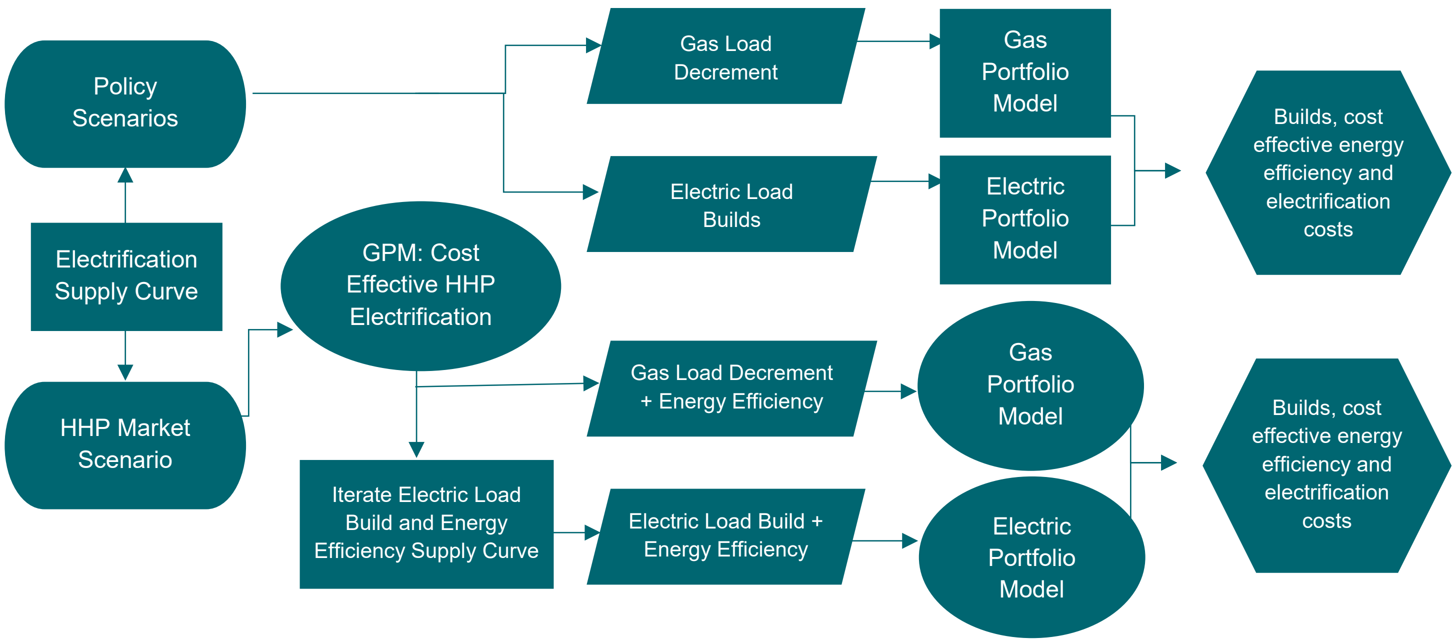
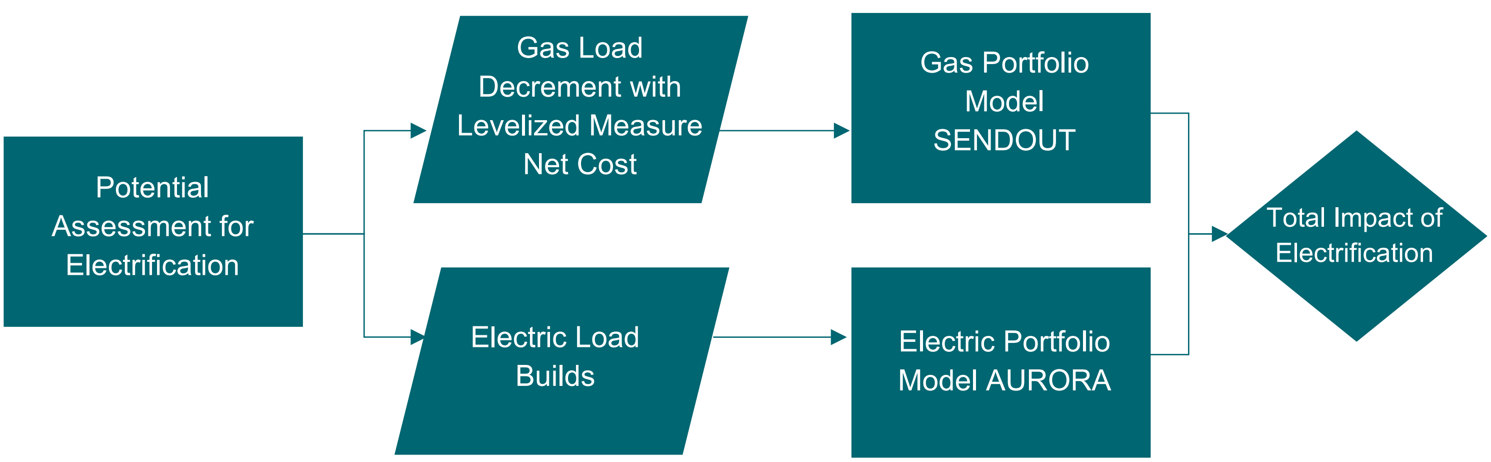


Figure 4.9: Overview of Electrification Analytical Process



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."

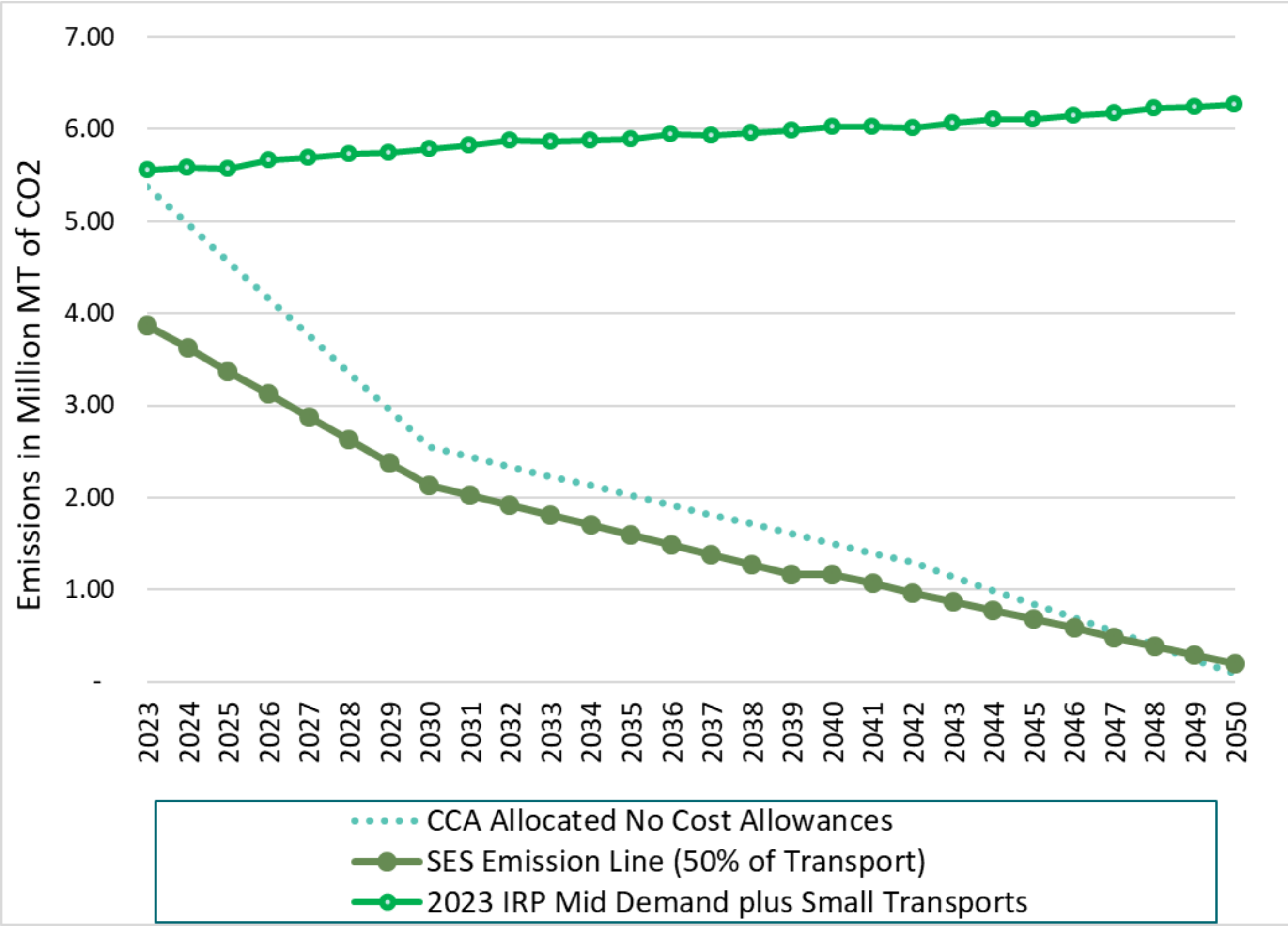
electric portfolio. For details on the inputs, assumptions, and modeling approach we used in AURORA, please refer to PSE's 2023 Electric Progress Report.

➔ 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.

DEMAND FORECAST

CHAPTER FIVE

Contents

1. Introduction

Puget Sound Energy (PSE) developed demand forecasts for the 2023 Gas Utility Integrated Resource Plan (2023 Gas Utility IRP) to estimate the amount of gas required to meet customer needs from 2024 to 2050. These forecasts focus on two dimensions of demand: energy demand and peak demand.

- Energy demand is the total amount of gas needed to meet customer needs in a year.
- Peak demand is the amount of gas needed to serve customer needs on the coldest day of the year.

Climate change already affects how our customers use energy, and we anticipate that impact will increase. We expect summer and winter average temperatures to get warmer. This report's energy and peak demand forecasts incorporate climate change temperature effects for the first time. Our customers, indeed, all of us, feel the impact of climate change every day, and this data is a crucial component of our energy planning.

This IRP base demand forecast is the expected outcome before we apply additional demand-side resources (DSR). The 2023 base energy demand forecast is lower than the 2021 IRP base demand forecast because this IRP includes the temperature effects of climate change on demand. The 2021 IRP did not consider the impacts of climate change, which lower energy demand considerably.

Although climate change is expected to increase temperatures on average, the extreme low temperature that we need to plan for remains consistent at 13°F. Therefore, this IRP peak demand is very similar to the 2021 IRP peak demand because the design peak temperature did not change between the two forecasts.

Climate Change

We incorporated climate change into the demand forecast for the first time in this 2023 Gas Utility IRP. We heard from interested parties that addressing climate change is critical and we agree. We also know climate change will affect future demand and needs. The team included climate change in the base demand forecast and in other analyses such as the stochastic scenarios.

Table 5.1: Drivers Included and Not Included in the Base Demand Forecasts

Drivers	Demand Forecast Before Additional DSR	Demand Forecast After Additional DSR
Climate change temperatures	Yes	Yes
PSE energy efficiency programs for 2022–2023	Yes	Yes
Codes and standards effects through 2023, including Seattle gas ban	Yes	Yes
PSE energy efficiency programs for 2024 and beyond	No	Yes
Codes and standards for 2024 and beyond including Seattle and Shoreline gas bans	No	Yes
Additional electrification	No	Note: To be analyzed with scenarios
Effects of the Climate Commitment Act	No	Yes
Effects of the Inflation Reduction Act	No	No

We also prepared a zero-customer growth scenario with no new customer growth after 2026. This analysis created a slightly declining energy demand forecast and an almost flat design peak forecast. We used this scenario to project future demand with less gas in PSE's service area. As noted in Table 5.1, we created the demand forecast before we were able to incorporate the impacts of the Inflation Reduction Act (IRA). The IRA will likely lead to lower gas demand since it incentivizes the use of heat pumps. We will account for the IRA's impacts in future demand forecasts.

1.1. Impacts of Demand-side Resources

We saw a significant demand reduction when we applied forward projections of additional DSR savings, as shown in Table 5.2. However, we must start with forecasts that do not include forward projections of DSR savings to identify the most cost-effective amount of DSR to include in the resource plan.

Throughout this chapter, charts labeled before additional DSR reflect only DSR measures and regional effects from policies that limit the use of natural gas before the study period begins in 2024. These charts do not reflect Climate Commitment Act (CCA) effects. Charts labeled after additional DSR reflect the cost-effective amount of DSR identified in this IRP and the impacts of new codes and standards, including the effects of policies that limit the use of natural gas in 2024 and after, and additional DSR resulting from the CCA.

Why does PSE forecast demand before DSR?

The demand forecast before DSR shows us the projected demand assuming no resource actions are taken. This provides the demand that can be managed with demand-side resources and can be used to determine which actions are cost-effective resource decisions.

What if no one acted to change how we use energy?

We have already changed how we use energy, so this is not a future we anticipate. PSE expects to continue incentivizing DSR. Federal, state, and local governments will continue changing energy codes and standards, and we expect consumers to continue adopting heat pump technology. But how much of this will occur, and how will it change the demand forecast? To answer this question, we start with the assumption of no DSR and treat DSR as a resource in the modeling process.

Table 5.2: Effect of Demand-side Resources on Demand Forecasts

2023 Gas Utility IRP Zero-Customer Growth Forecast in 2050	Before Additional DSR	After Additional DSR
Gas Energy Demand (MDth)	86,816	70,348
Gas Peak Demand (MDth)	1,001	809

2. Climate Change

This IRP incorporates climate change in the base energy and peak demand forecast for the first time. Before this IRP, PSE used temperatures from the previous 30 years to model the expected normal temperature for the future. We then held this normal temperature constant for each future model year. This old approach was a common utility practice but does not recognize predicted climate change.

Climate Change

There are currently no industry standards or best practices for incorporating climate change into a demand forecast. Puget Sound Energy is excited to include climate change in this 2023 Gas Utility IRP and lead future refinements and the evolution of this methodology.

The methodology for incorporating climate change in this IRP is our first step, and we expect it will evolve. PSE is unaware of industry standards or best practices for integrating climate change into a demand forecast. This section provides a detailed description of how we developed a normal temperature assumption.

2.1. Priorities First

Puget Sound Energy heard and heeded the clear message from interested parties that climate change is a high priority, and we should incorporate its effects into our planning processes. It is essential to consider climate change in resource planning because temperature impacts the amount of heating fuel used throughout the year. Over time, we expect less overall heating demand because of a general average warming trend. We used regional data recently developed by climate change scientists to calculate a normal temperature assumption that reflects climate change.

We are incorporating climate change into the demand forecast in several ways:

- Energy demand forecast
- Peak demand forecast
- Stochastic analysis

The climate projections used in the forecast were part of a recent study conducted by the River Management Joint Operating Committee (RMJOC). The RMJOC consists of the Bonneville Power Administration, the U.S. Army Corps of Engineers, and the U.S. Bureau of Reclamation. This committee worked with climate scientists to produce many downscaled climate models and hydrologic models for the Northwest region as part of their long-term planning.[1] The RMJOC chose 19 downscaled models. Each model is on the representative concentration pathway (RCP) of 8.5. An RCP is a forecast of the amount of warming to the Earth. RCP 8.5 is a common warming forecast used by climate scientists. It represents more warming than other common warming forecasts, such as RCP 4.5 or RCP 6.0.

The Northwest Power and Conservation Council (NWPCC) then chose three of the 19 models to work with: CanESM2_BCSD, CCSM4_BCSD, and CNRM-CM5_MACA. The NWPCC chose these three models because they

1 River Joint Management Operating Committee (RMJOC): Bonneville Power Administration, United State Army Corps of Engineers, United Stats Bureau of Reclamation (2018). Climate and Hydrology Datasets for RMJOC Long-Term Planning Studies: Second Edition (RMJOC-II) Part 1: Hydroclimate Projections and Analyses, https://www.bpa.gov/-/media/Aep/power/hydropower-data-studies/rmjoc-ll-report-part-l.pdf.

reflect a wide range of temperatures and hydrologic conditions over time. PSE decided to use the three climate model projections that the NWPCC used.

2.2. Determine Normal Temperatures

Since there is no industry standard approach to integrating climate change, we had to determine how to incorporate this data into our forecasts. The following section explains how we approached the challenge and the questions we asked. We also presented these questions and the analysis results to the public on January 20, 2022, and asked them for feedback on our approach.

2.2.1. What Is Normal and Why We Need It

When PSE models demand, we study the relationship between historical demand and historical temperatures because the temperature significantly impacts demand. Then, to create a demand forecast, PSE must make assumptions about future temperatures to create a future demand forecast. We refer to the assumed future temperatures as normal temperatures. For energy forecasting, the average heating degree day (HDD) for a month expresses the new normal temperature. We used a 1-in-50 occurrence of a given temperature to forecast peak demand. Design peak examines daily loads under extreme cold weather conditions.

We wanted to achieve three goals when we created new normal temperatures:

1. Incorporate future temperature data into the assumptions for the base demand forecasts. We provided a scenario in the 2021 IRP with climate change temperatures but incorporated it into this report's base demand energy and the base demand peak forecasts.
2. Produce the demand forecast in the framework necessary for planning. Integrated Resource Plan analyses have specific input requirements. For example, we could have run the demand forecast with the climate data from the three models, but this would have created three base forecasts. Instead, we created one demand forecast because we need a single outcome as a reference case.
3. Develop an objective temperature normal, which includes deciding what data to use.

2.2.2. Which Data Do We Use?

We considered the following questions when we decided what data to use to define a new normal temperature:

1. **Should we use one climate model to predict future temperatures, or should we use all three models the NWPCC chose to create the new normal?**

   Since the three models the NWPCC used show a wide range of possible climate outcomes, we used all three to capture the broadest possible range of results.

2. **Should the forecasted new normal temperature include historical data, forecasted climate model data, or some combination of the two?**

   Recent historical data is a way to link climate change data to what has occurred recently in the region. For example, in 2021, PSE's service area saw unprecedented hot temperatures, including 107° F at Seattle-

Tacoma International Airport on June 28, 2021. However, the climate models did not predict a temperature this high until 2035. Incorporating recent actual data helped us determine where the forecast should start.

Based on this assessment, we used historical data and forecasted temperatures to calculate a new normal temperature.

3. **How many years of data should we include to calculate this new normal?**

   In past IRPs, we estimated the normal temperature using the last 30 years of temperatures to calculate the base energy demand forecast. This methodology created a relatively stable normal, with minor year-to-year changes. Forecasts that use five- or 10-year derived normal temperatures can have much larger swings in the normal data point from year to year, creating difficulties for planning. Therefore, we opted to use a 30-year analysis centered on the year of interest. We used forecast temperatures from the prior 15 and the upcoming 15 years for each year in the calculation. We calculated this for each year of the forecast.

4. **Should the forecasted new normal temperatures be flat, as used in past IRPs, or should the forecast reflect a trend?**

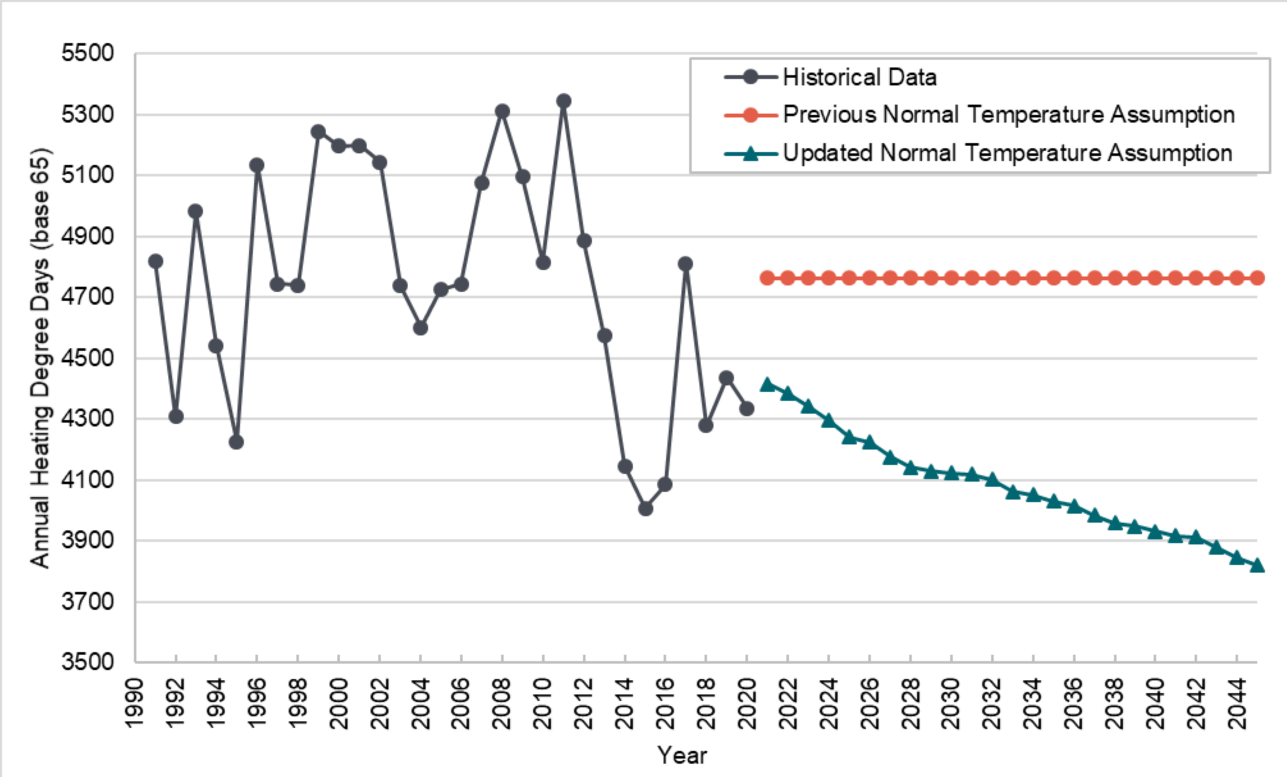
   We needed to reflect average temperatures warming over time, so the normal energy forecast reflected this with increasing average temperatures in the winter.

2.3. Normal Temperature for Energy Demand Forecast

We incorporated the normal temperatures into the base energy demand forecast models through heating degree days (HDDs). Heating degree days are a standard way to express temperatures to measure how much heating demand a customer may use in response to a given daily temperature. We calculate degree days using a base temperature, typically 65° F, and the average daily temperature. For HDDs, we calculate the value as the amount the daily temperature is below 65° F. For example, a 70° F-day will have 0 HDDs, while a 30° F-day will have 35 HDDs, using a base of 65° F. PSE used the three climate models described and historical temperatures to create HDDs. We used the HDDs to model future energy demand. The climate models and historical data are from the National Oceanic and Atmospheric Administration's (NOAA's) Sea-Tac Airport station.

Previously, we calculated HDDs by using the most recent 30 years of recorded temperatures and used that static calculation through the forecast period, creating a flat normal temperature. For this IRP, PSE calculated the HDDs for each forecast year using a different set of temperatures. We calculated HDDs for each forecast year using temperatures from the prior 15 years and temperatures from the future 15 years, including the year of interest. If the preceding 15 years included years from which historical temperatures were available, then we used the historical data. We used temperatures from the three climate models for future years. Figure 5.1 shows an example of the old and the new normal temperatures, which include climate change.

Figure 5.1: Heating Degree Days, Previous Normal Temperature, and Current Normal Temperature Assumptions (HDD base temperature 65º F)



➔ See Appendix D: Demand Forecasting Models, for more information about calculating the HDDs that went into the demand forecast.

2.4. Design Temperature for Peak Demand Forecast

We do not plan the gas peak demand to a normal or average temperature but for a design peak temperature. Puget Sound Energy defines the design peak temperature as one with a 1-in-50 chance of occurrence per year. When we incorporated climate change into the design peak temperature, we used the same considerations we described for the energy forecast. This allowed us to:

1. Incorporate future temperatures into the design temperature forecast.
2. Ensure the temperature is in the proper framework for planning.
3. Ensure the new calculation is objective.

We used all three models and historical data to calculate the design day. However, to calculate a design day, we had to balance having enough data to calculate a 1-in-50 chance of occurrence while not using too much historical data that could be outdated. To get enough years of data to evaluate a 1-in-50 peak occurrence, we used historical data from 2010 to 2019 and data from the three climate change models for 2020 to 2049. Therefore, we used 98 observations to calculate the peak temperature with a 1-in-50 chance of occurring. Based on this analysis, the 1-in-50 winter design peak temperature was 13° F. This forecast is the same as the previous design temperature, which used 79 observations to calculate the design day temperature. We held this design temperature constant for the forecast period because rolling the calculation forward could create an unstable design peak standard.

Table 5.3: Design Temperature, Previous Design Temperature, and Current Design Temperature

Design Day Temperature	Years in Calculation	Number of Observations	1-in-50 Daily Temperature (ºF)
Old Design	1950–2019	79	13
New Design Incorporating Climate Change	2010–2049	98	13

➔ See Appendix D: Demand Forecasting Models, for a detailed discussion of the climate change temperature calculations.

3. Gas Demand Forecast

In the following section, we describe the highlights of the base and zero-customer growth demand forecasts developed for PSE's gas sales service.

➔ We summarize the population and employment assumptions for the base forecasts in the Details of the Natural Gas Forecast section and explain them in detail in Appendix D: Demand Forecasting Models.

We included only demand-side resources acquired under the current 2022–2023 biennium conservation programs. In 2024 and beyond, the gas portfolio analysis helps determine the most cost-effective level of DSR to include in the gas sales portfolio.

3.1. Gas Energy Demand

The 2023 Gas Utility IRP base demand forecast is a forecast of both firm[2] and interruptible[3] demand because this is the volume of gas that PSE is responsible for securing and delivering to these customers. For delivery system

2 Firm customers have an agreed-upon capacity for the producer or pipeline to supply natural gas, establishing a high priority for the fuel requested. We cannot curtail the supply or delivery of natural gas under a firm contract except under unforeseeable circumstances.

3 Interruptible customers, also called non-firm customers, have lower-priority fuel supply arrangements. Under these contracts, we may stop or curtail the flow of natural gas if firm contract holders use the available capacity or if other interruptible customers outbid the power plant. Interruptible contracts are less expensive than firm contracts, reflecting the higher risk of disrupted fuel receipts.

planning, however, transport demand must be included in total demand; transport customers[4] purchase their gas elsewhere but contract with PSE for delivery.

In this IRP base demand forecast, we project gas energy demand before additional DSR grows at a 0.4 percent average annual growth rate (AARG) from 2024 to 2050; this would increase demand from 93,942 MDth in 2024 to 103,611 MDth in 2050 (Figure 5.2). This rate is lower than the annual growth rate of 0.8 percent we identified in the 2021 IRP base demand forecast. The growth rate is lower than the 2021 IRP base demand forecast because we incorporated warming during the heating season from climate change in this forecast. We did not include the warming effects of climate change in the 2021 IRP base demand forecast.

Before additional DSR, the 2023 IRP zero-customer growth forecast projects a -0.3 percent average annual growth rate (Table 5.4).

[4] Transport customers, in the gas industry, are customers who acquire their gas from third-party suppliers and rely on the utility for distribution. It does not refer to natural gas-fueled vehicles.

Figure 5.2: Gas Energy Demand Forecast before Additional DSR Base and Zero-customer Growth Scenarios, Without Transport Load (MDth)

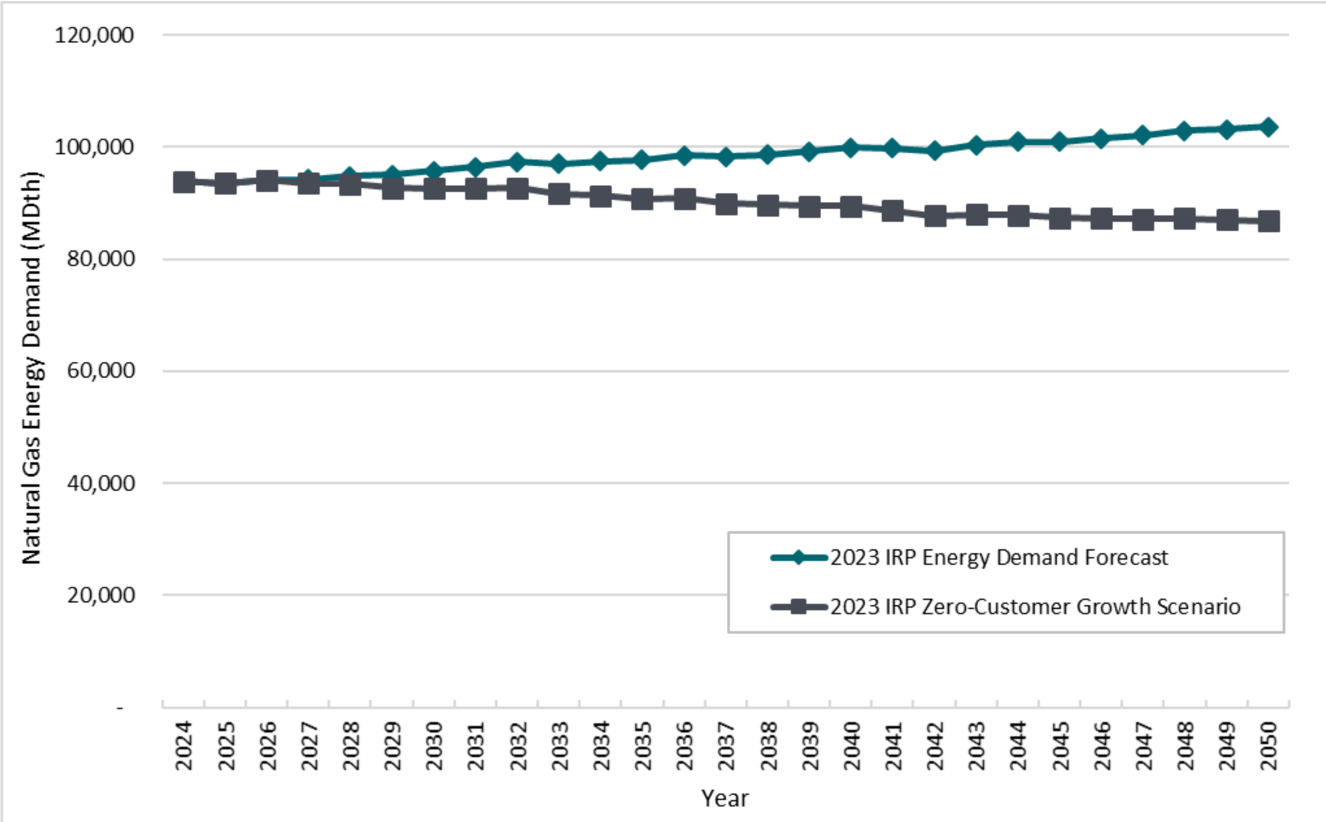


Table 5.4: Gas Energy Demand Forecast before Additional DSR Base and Zero-customer Growth Scenarios without Transport (MDth)

Scenario	2024	2030	2035	2040	2045	2050	AARG 2024–2050 (%)
Base Demand Forecast	93,942	95,728	97,695	99,919	101,033	103,611	0.4
Zero-customer Growth Demand Forecast	93,942	92,673	90,806	89,468	87,372	86,816	-0.3

3.2. Gas Peak Demand

We modeled the gas design peak day at the day's 13° F average temperature. We included only firm sales customers when forecasting peak gas demand, not transport and interruptible customers. For peak gas demand, this IRP base demand forecast projects an average increase of 0.7 percent per year from 2024 to 2050; peak demand would rise from 995 MDth in 2024 to 1,189 MDth in 2050. The zero-customer growth demand forecast projects a 0.0 percent annual growth rate (Figure 5.3 and Table 5.5).

Figure 5.3: Gas Peak Day Demand Forecast before Additional DSR
Base and Zero-customer Growth Scenarios (13 Degrees, MDth)

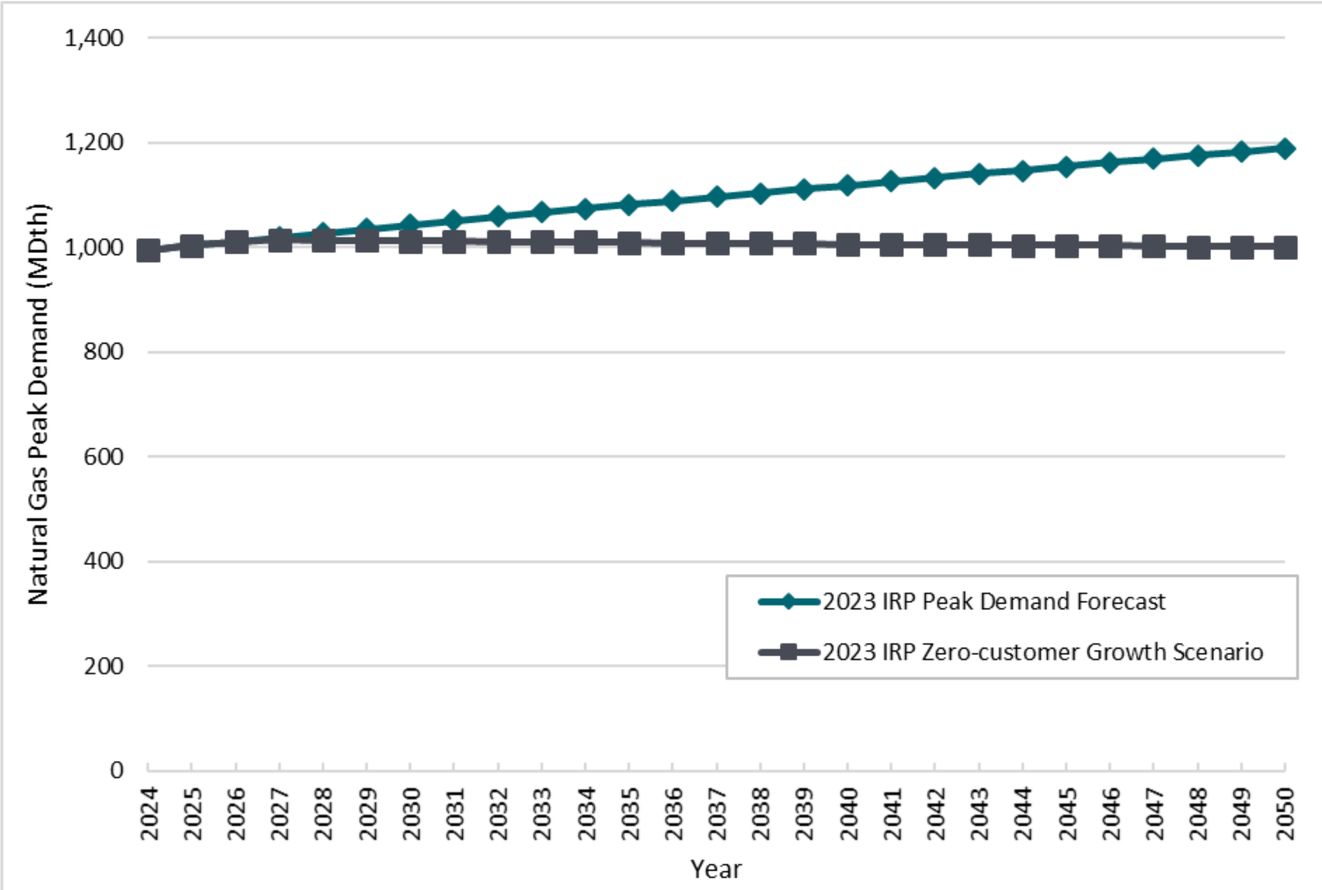
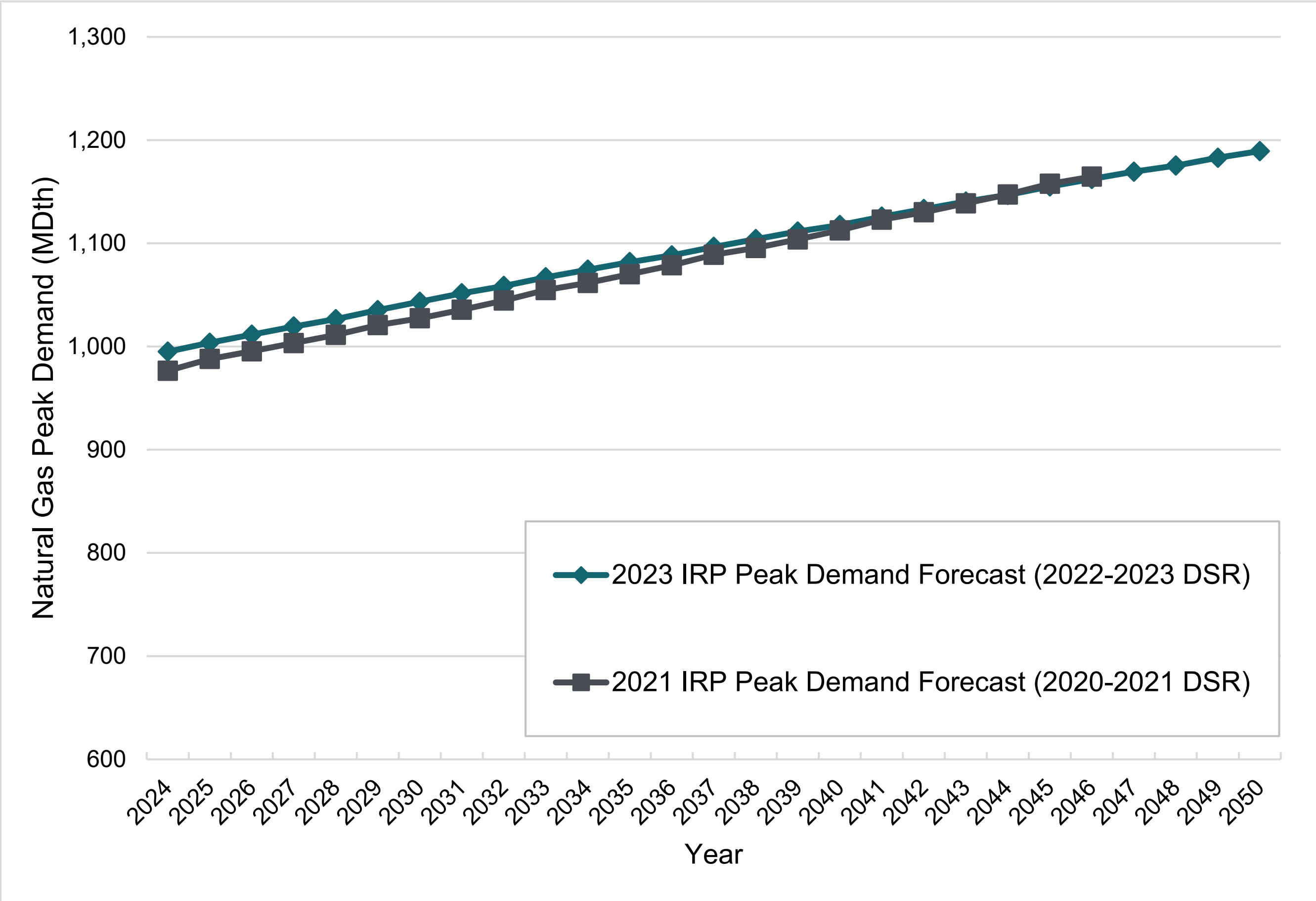


Table 5.5: Gas Peak Day Demand Forecast before Additional DSR
Base and Zero-customer Growth Scenarios (13 Degrees, MDth)

Scenario	2024	2030	2035	2040	2045	2050	AARG 2024–2050 (%)
Base Demand Forecast	995	1,043	1,082	1,118	1,155	1,189	0.7
Zero-customer Growth Demand Forecast	995	1,013	1,010	1,006	1,004	1,001	0.0

The peak demand growth rate in the 2023 base forecast is slightly lower than that in the 2021 base forecast (0.8 percent), but the peak demand starts higher than the 2021 IRP peak demand. The slight change in the peak demand forecast is because we included a snow day variable in the peak model. See the Updates to Inputs and Equations section for a description of the snow day variable. Also, climate change did not change the design peak temperature, so the peak demand did not change when we included climate change. See the Climate Change section for a description of climate change assumptions for the design peak temperature.

Figure 5.4: Firm Gas Peak Day Forecast before Additional DSR
2023 Gas Utility IRP Base Peak Demand Forecast versus 2021 IRP Base Peak Demand Forecast
Daily Annual Peak (13 Degrees, MDth)



3.3. Impacts of Demand-side Resources Illustrated

As explained at the beginning of this chapter, the gas demand forecasts include only demand-side resources implemented through December 2023 since the demand forecast helps determine the most cost-effective level of DSR to include in the portfolio. To examine the effects of DSR on energy and peak forecasts, the cost-effective amount of DSR determined in this IRP is applied to the energy demand (without transport) and peak demand forecast for 2024 to 2050. We determined the preferred portfolio and the cost effective DSR for the zero-customer growth scenario, therefore we show the zero-customer growth scenario and the zero-customer growth scenario after DSR in this section.

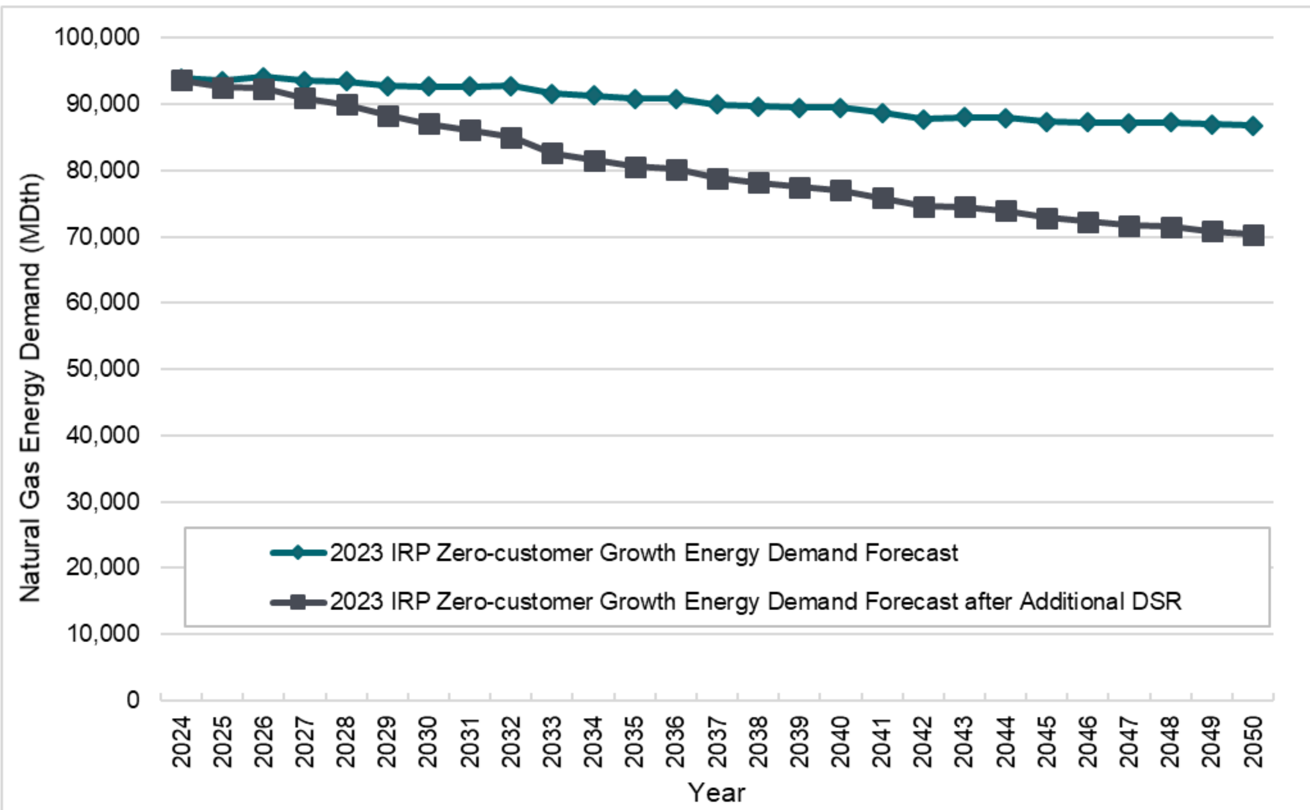
➔ For more details on the DSR analysis, see Chapter Six: Gas Analysis, and Appendix C: Conservation Potential Assessment.

To account for the 2017 general rate case,[5] we also applied an additional five percent of DSR for that period. We use forecasts with DSR internally for financial and system planning decisions. We illustrate the results in Figures 5.5 and 5.6.

When we applied the DSR bundles chosen in this IRP portfolio analysis:

- Gas zero-customer growth energy demand in 2050 is reduced by 19 percent to 70,348 MDth.
- Gas zero-customer growth energy demand will decline at an average annual rate of 1.1 percent from 2024 to 2050.

Figure 5.5: Gas Zero-customer Growth Energy Demand Forecast, before Additional DSR and after Additional DSR



When we applied the DSR bundles chosen in this IRP portfolio analysis to the zero-customer growth demand:

- Gas system peak demand in 2050 is reduced by 19 percent to 809 MDth.
- Gas system peak demand will decrease at an average annual rate of 0.76 percent from 2024 to 2050.

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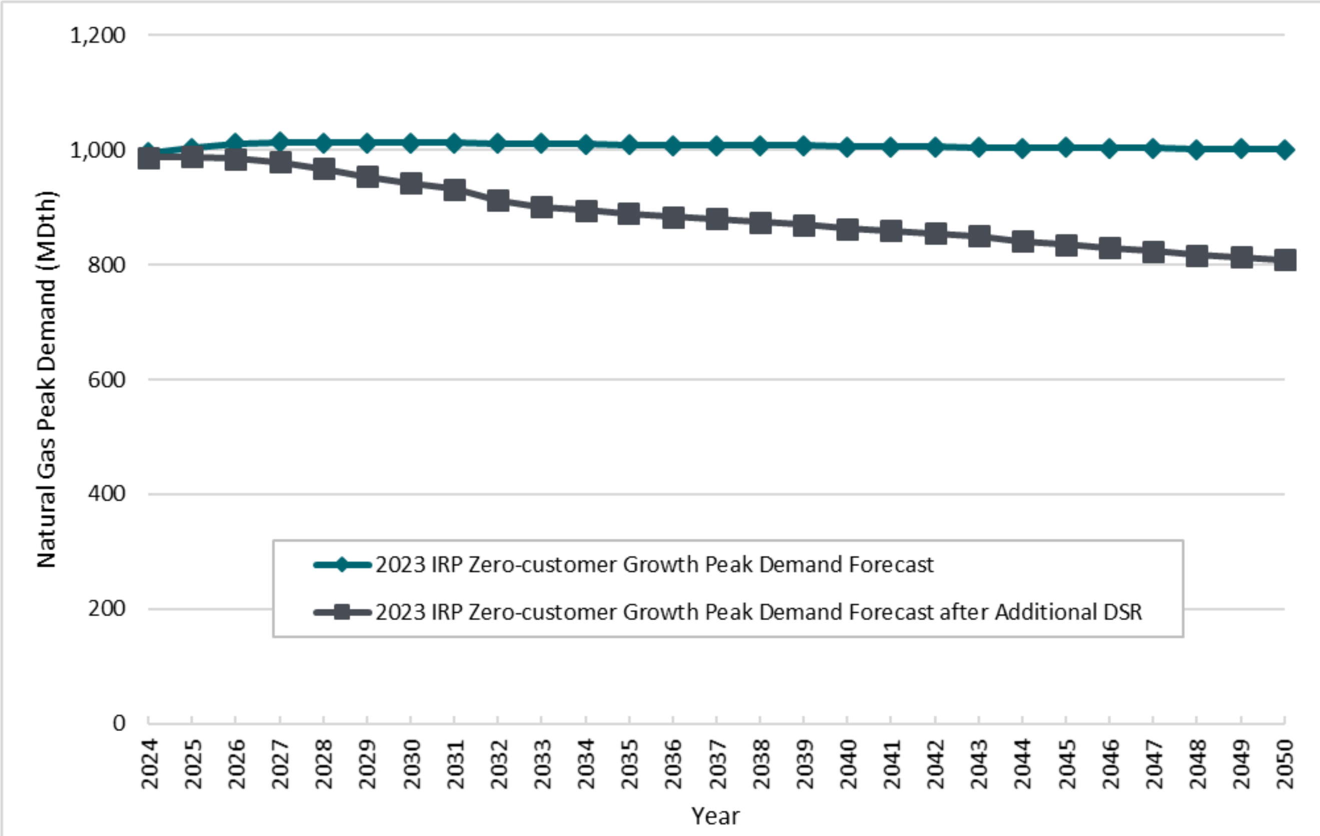
[5] Final Order Rejecting Tariff Sheets; Approving and Adopting Settlement Stipulation; Resolving Contested Issues; and Authorizing and Requiring Compliance Filing, Dockets UE-170033 and UG-170034 (consolidated), Washington Utilities and Transportation Commission. Page 85 Line 250.

Figure 5.6: Natural Gas Base Peak Demand Forecast, before Additional DSR and after Additional DSR



Unlike prior IRPs, this IRP also includes electrification as part of the CCA scenarios; we determined the impact of these scenarios on the demand forecast in the gas portfolio modeling, and they are an output of that analysis.

➔ We discuss these impacts of electrification on the demand forecast in Chapter Six: Gas Analysis.

3.4. Details of the Gas Forecast

The gas forecast is comprised of demand from several different classes. The firm classes are residential, commercial, industrial, commercial large volume, and industrial large volume. The interruptible classes are commercial and industrial. Transport classes are commercial firm, commercial interruptible, industrial firm, and industrial interruptible. Residential customers are approximately 93 percent of PSE's gas customers and are expected to grow by 0.9 percent per year. Commercial customers are about 6.5 percent of PSE's customers and are expected to grow at 0.2 percent per year. Between now and 2050, we expect demand from these classes to grow at 0.6 percent and 0.4 percent annually.

We describe the details for each customer class in Appendix D: Demand Forecasting Models.

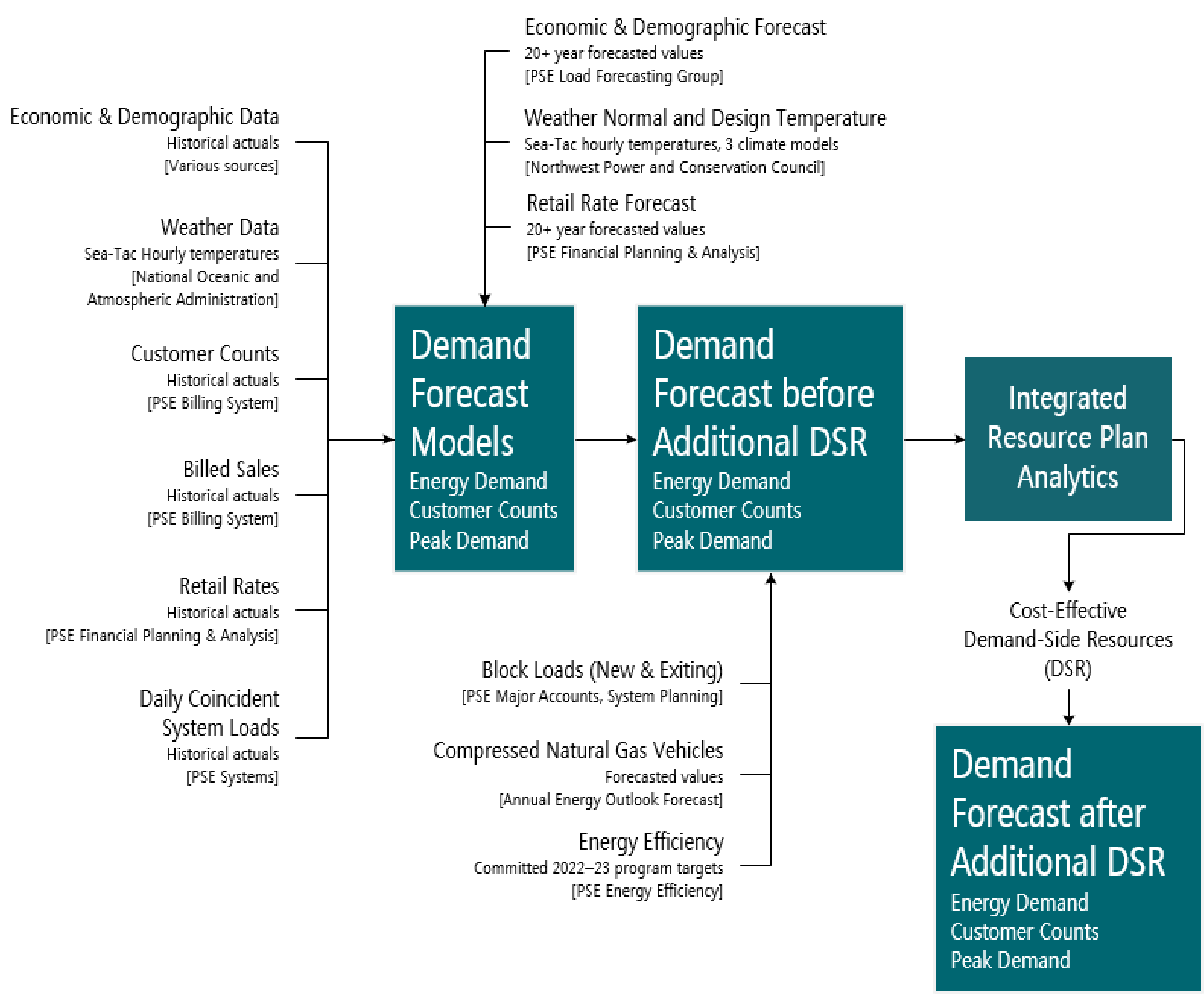
4. Methodology

We identify relationships between historical growth and historical conditions to forecast customer demand. Therefore, we can use forecasted future conditions to forecast future growth. The following section discusses how we forecast demand.

4.1. Forecasting Process

Puget Sound Energy's regional economic and demographic model uses national and regional data to forecast total employment, employment types, unemployment, personal income, households, and consumer price index (CPI) for the PSE gas service area. For this analysis, we used regional economic and demographic data from county-level information from various sources. This financial and demographic information is combined with other PSE internal information to produce energy and peak demand forecasts for the service area. We illustrate the demand forecasting process in Figure 5.7 and list the economic and demographic input data sources in Table 5.6.

Figure 5.7: Puget Sound Energy Demand Forecasting Process



We divide customers into classes that use energy for similar purposes and at comparable retail rates to forecast energy sales and customer counts. We model the different classes separately using variables specific to their usage patterns. Customer classes include firm: residential, commercial, industrial, commercial large volume and industrial large volume; interruptible: commercial and industrial; and transport: commercial firm, commercial interruptible, industrial firm, and industrial interruptible.

We used multivariate time series econometric regression equations to derive historical relationships between trends and drivers. We then forecasted the number of customers and use per customer by class or service level. We multiplied these to arrive at the billed sales forecast. The main drivers of these equations include population, retail rates, weather, total employment, manufacturing employment, and CPI. Demand, presented in this chapter, is calculated from sales, and includes losses in addition to sales. We base weather inputs on temperature readings from Sea-Tac Airport and include historical and forecasted temperatures, including the effects of climate change. We also projected peak system demand by examining the historical relationship between actual peaks, the temperature at peaks, and the economic and demographic impacts on system demand.

➔ See Appendix D: Demand Forecasting Models, for detailed descriptions of the econometric methodologies used to forecast billed energy sales, customer counts, peak loads, and forecast uncertainty.

Table 5.6: Sources for County Economic and Demographic Data in the Economic and Demographic Model

County-level Data	Source
Labor force, employment, unemployment Rate	U.S. Bureau of Labor Statistics (BLS)
Total non-farm employment and breakdowns by type of employment	WA State Employment Security Department (WA ESD), using data from the Quarterly Census of Employment and Wages
Personal income	U.S. Bureau of Economic Analysis (BEA)
Wages and salaries	U.S. Bureau of Economic Analysis (BEA)
Population	WA State Employment Security Department (WA ESD)
Households and household size, single- and multi-family	U.S. Census
Aerospace employment, Regional Consumer Price Index (CPI)	Puget Sound Economic Forecaster

We obtain U.S. economic and demographic data from Moody's Analytics. We applied the following Moody's inputs to PSE's economic and demographic model: GDP, industrial production index, employment, unemployment rate, personal income, wages and salary disbursements, CPI, housing starts, population, conventional mortgage rate, and three-month T-bill rate.

4.2. Zero-customer Growth Scenario

We developed a zero-customer growth scenario to analyze how the gas portfolio would be affected when no new gas customers were added to the system. In this scenario, we added zero-customers to the system after 2026. This analysis only affects residential and commercial classes as industrial customers are declining. The underlying economic and demographic forecasts are the same as the base forecast and the zero-customer growth scenario assumes zero growth in new customers is due to policy decisions.

➔ Analysis with the zero-customer growth scenario is available in Chapter Six: Gas Analysis.

4.3. Stochastics

We developed stochastic simulations with stochastic outputs from our economic and demographic model and future temperatures from three climate models. The stochastic simulations reflect variations in key regional economic and demographic variables such as population, employment, and income. The simulations also vary the equations to include potential modeling variances. Stochastic scenarios also use future temperatures from the CanESM2_BCSD, CCSM4_BCSD, and CNRM-CM5_MACA models, reflecting higher or lower temperature conditions. We sampled forecasted temperature years 2020 to 2049 from the three climate models. We used temperature changes and economic and demographic data to create 250 stochastic draws.

We then ran the 250 gas stochastic scenarios in SENDOUT, a gas supply planning and asset valuation tool.

➔ Detailed descriptions of the stochastic scenarios are available in Chapter Six: Gas Analysis. See Appendix D: Demand Forecasting Models, for a detailed discussion of the stochastic simulations.

4.4. Updates to Inputs and Equations

The following section summarizes updates to the demand forecast inputs and equations made since the 2021 IRP.

4.4.1. Climate Change Forecast

Previous IRPs used the most recent 30 years of historical temperatures to predict temperatures for the forecast period. In this IRP, we used the three climate change models the Northwest Power and Conservation Council (NWPCC) used to forecast future temperatures.

➔ See the Climate Change section of this document for more details on how we used climate models in the forecast.

4.4.2. Peak Model Updates

We used a new variable in the peak model for this IRP to improve the forecasted peak usage. In this IRP, PSE incorporated a snow day variable in the peak model as part of the standard process improvement of our models. This binary variable was 1 if it was snowing during the day or if there was snow on the ground. The variable was 0 if there was no snow. This variable was significant in the peak model and helped account for the fact that usage can be different on a snow day compared to a cold day with no snow.

4.4.3. Code Updates

The 2018 Washington State energy code change and the Seattle policy to limit natural gas use were effective in 2021 and 2022, respectively. The effects of these two code changes through 2023 were considered in this forecast before additional DSR to understand better the forecast's starting point in 2024. The conservation potential assessment (CPA) determined the effects of these code changes starting in 2024 and included the statutory requirement for the Washington State code cycle to make the code more stringent in terms of energy use. The law requires that the Washington State code be improved in each code cycle update to achieve a 70 percent reduction in energy use by 2031 compared to the 2006 code baseline. Therefore, a small amount of these code changes is in the demand forecast before additional DSR, but most of this code change will be accounted for in the after additional DSR forecast.

5. Key Assumptions

To develop PSE’s demand forecasts, we made assumptions about economic growth, energy prices, weather, and loss factors, including certain system-specific conditions. We describe these and other assumptions in the next section.

5.1. Economic Growth

Economic activity has a significant effect on long-term energy demand. Although the energy component of the national gross domestic product (GDP) has been declining over time, gas is still a significant input into various residential end uses such as space heating, water heating, cooking, and clothes drying. Therefore, growth in the residential building stock directly impacts the demand for gas over time. Commercial and industrial sectors also use gas for space heat and water heating. Gas is also an essential input in many industrial production processes. Economic activities in the commercial and industrial sectors are crucial indicators of the overall trends in gas consumption.

5.2. National Economic Outlook

Because the Puget Sound region is a major commercial and manufacturing center with solid links to the national economy, this IRP demand forecast begins with assumptions about what is happening in the broader U.S. economy. Puget Sound Energy relies on Moody’s Analytics U.S. Macroeconomic Forecast, a long-term forecast of the U.S. economy for economic growth rates. We used the November 2021 Moody’s forecast for this IRP. The Moody’s forecast predicts:

- The economy will be tethered to the COVID-19 pandemic in 2021.

- The economy will continue to recover with a return to full employment in 2023, and labor force participation will continue to increase as workers get healthy and children are vaccinated.
- The recovery will continue through 2025. After 2025, Moody's predicts the economy will grow modestly over the long term.
- United States Gross Domestic Product (GDP) will continue to grow over the forecast period with a 2.0 percent average annual growth from 2024 to 2050. This growth rate is lower compared to Moody's forecast used in the 2021 IRP, which projected a 2.2 percent average yearly growth. Some of the 2021 IRP growth was from the projected recovery from COVID-19.

Moody's identified possible risks that could affect the accuracy of this forecast:[6]

- COVID-19 is still unpredictable in its effects on the economy; more waves that elude the vaccine could halt the recovery.
- In the near term, supply constraints could cause the economy to grow less quickly.
- Rising long-term interest rates could cause a slump in the economic recovery.
- The congressional stimulus for COVID-19 could be smaller than predicted or not provide the expected economic boost.

5.3. Population Outlook

The Washington State Employment Security Department (WA ESD) average annual growth rate for the counties that make up the gas service area is 0.97 percent from 2024 to 2050. This growth rate is down slightly from the 1.0 percent growth rate forecast in the 2021 IRP for 2022 to 2045.

5.4. Regional Economic Outlook

Puget Sound Energy prepares regional economic and demographic forecasts using econometric models based on historical financial data for the counties in PSE's service area and the macroeconomic forecasts for the United States.

Our gas service area stretches from south Puget Sound to upper Snohomish County and from central Washington's Kittitas Valley west to Seattle and Olympia. We serve more than 860,000 gas customers in six counties.

Within PSE's service area, demand growth is uneven. Growth in the high-tech, information technology, or retail (including online retail) sectors drives most of the economic progress. Supporting industries like leisure and hospitality employment are also growing. Job growth is concentrated in King County, which accounts for more than half of the system's gas sales demand today. Other counties are growing, but typically more slowly, and have added fewer jobs.

5.5. Gas Service Area Outlook

We used the following forecast assumptions in this IRP base demand forecast.

[6] Moody's Analytics (2021, November) Forecast Risks. Precis U.S. Macro. Volume 26 Number 8.

- An inflow of 1.32 million new residents (by birth or migration) will increase the local area population to 5.98 million by 2050, for an average annual growth rate of 0.97 percent. This growth rate is slightly lower than the 2021 IRP forecast, which projected an average annual population growth of 1.0 percent that would have resulted in 5.45 million gas service area residents by 2041.
- Employment will grow at an average annual rate of 0.6 percent between 2024 and 2050, which is slower than the annual growth rate forecasted in the 2021 IRP of 1.2 percent. The employment growth rate in the 2021 IRP included the recovery from the COVID-19 recession, leading to a higher growth rate.
- Local employers will create about 406,000 total jobs between 2024 and 2050, compared to about 555,000 jobs forecasted in the 2021 IRP between 2022 and 2041.
- Manufacturing employment will decline by 0.2 percent annually on average between 2024 and 2050 due to outsourcing manufacturing processes to lower wage or less expensive states or countries and the continuing trend of capital investments that create productivity increases.
- Population and employment growth rates are less closely aligned as the economy grows quickly from the COVID-19 recovery and the area experiences retirements from the baby boomer generation.

We show the population and employment forecasts for PSE's gas service area in Table 5.7.

Table 5.7: Population and Employment Growth, Gas Service Counties (1,000s)

Model Driver	2024	2030	2035	2040	2045	2050	AARG 2024–2050 (%)
Population	4,656	4,958	5,201	5,416	5,642	5,979	0.97
Employment	2,348	2,470	2,562	2,635	2,704	2,755	0.6

5.6. Weather

In this IRP, we incorporated climate change temperatures from three climate models to calculate the normal temperatures for the base energy demand forecast. The design peak temperature for the base peak demand forecast also includes climate change.

➔ The Climate Change section of this chapter and Appendix D: Demand Forecasting Models discuss how we created this forecast.

5.7. COVID-19 Impacts

We incorporated COVID-19 adjustments to the forecast in 2022 but made no additional adjustments in 2023 and later, above and beyond the effects of the economic forecast that was incorporated into the demand forecast using the macroeconomic variables. The result was an economic recovery through 2025, with lingering effects from the recession persisting throughout the remainder of the forecast. There is a great deal of uncertainty around the steady state level of residential and commercial usage once behaviors developed during the pandemic settle.

PSE performed stochastic simulations that varied the economic forecast around this base, including simulations with better and worse economic outcomes. Since the IRP determines the resource need starting in 2024, the stochastic simulations show alternative ways the pandemic could resolve in the future.

5.8. Gas Decarbonization

This IRP considers the effects of gas decarbonization, which includes the impact of Seattle's and Shoreline's policies that limit natural gas use in commercial and large multi-family buildings. This IRP also considers the current Washington State energy code change that encourages residential builders to install electric space heating and water heating equipment instead of gas.

The base demand forecast considers the effects of the Seattle policy and the 2018 Washington State energy code change from 2022 to 2023. For years 2024 and beyond, the CPA will estimate the effects of local policies, the current Washington State energy change, and future Washington State energy code changes. Other decarbonization effects on the gas system, such as the Climate Commitment Act, were considered through the SENDOUT modeling process but are not included in the base demand forecast before additional DSR.

5.9. Loss Factors

The gas loss factor in this IRP is 0.93 percent. The loss factors assumed in the demand forecast are system-wide average losses during normal operations for the past two to three years and are updated annually.

5.10. Block Load Additions

Beyond typical economic change, the demand forecast also considers known major demand additions and deletions that we would not account for through normal demand growth. These are major infrastructure projects or changes to usage by a large customer. These additions or deletions to the forecast are called block loads, and they use the information provided by PSE's system planners or major account representatives. The gas forecast includes a block load in the transport class, which does not affect the firm and interruptible class demand modeled in this IRP.

5.11. Transport Customers

We call customers who purchase their gas from other suppliers, transport customers; they rely on PSE for distribution services. We removed transport customers from the forecast before determining the supply-side resource need because PSE is not responsible for acquiring supply resources for transport customers. However, we analyzed smaller transport customers in this IRP to assess their energy efficiency potential.

5.12. Interruptible Loads

For several gas utility customers, all or part of their demand is interruptible demand. We assumed interruptible gas demand would be curtailed when forecasting peak gas demand.

5.13. Compressed Gas Vehicles

We added compressed natural gas (CNG) vehicles to this IRP base demand forecast. The CNG vehicle forecast included buses, rail, light-duty, medium-duty, and heavy-duty vehicles. In 2024, this adds 229 MDth to the forecast. We expect this demand to grow at an average annual rate of 5.4 percent, based on the Annual Energy Outlook 2021 published by the U.S. Department of Energy.

5.14. Retail Rates

We included retail energy prices — what customers pay for energy — as explanatory variables in the demand forecast models because they affect customer choices in the long run. These choices impact the efficiency level of newly acquired appliances, how customers use those appliances, and the type of energy source they use to power them. The energy price forecasts draw on information obtained from internal and external sources.

6. Previous Demand Forecasts

The following section compares actual peak demand to previous IRP forecasts. This section also identifies reasons prior forecasts may be off from current weather-normalized actual peaks.

6.1. Peak Demand Forecasts Compared to Actual Peaks

Weather-normalized actual gas peak demand is compared to the gas peak forecasts after additional DSR from 2011, 2013, 2015, 2017, 2019,[7] and 2021 IRPs in Figure 5.8 and Table 5.13. We show the difference in the normalized actual values compared to the previous IRPs in Table 5.8.

[7] A formal IRP report was not filed by PSE in 2019. On October 28, 2019, the Washington Utilities and Transportation Commission Staff filed a Petition for Exemption from WAC 480-100-238 pursuant to WAC 480-07-100 until December 31, 2020. On November 7, 2019 the Commission held an Open Meeting concerning this matter and subsequently issued Order 2, exempting PSE (and other investor-owned utilities in Washington) from WAC 480-100-238. Pursuant to Order 2, PSE filed an IRP Progress Report in 2019.

Figure 5.8: Observed Weather Normalized Gas Peak Demand Compared to Previous IRP Forecasts

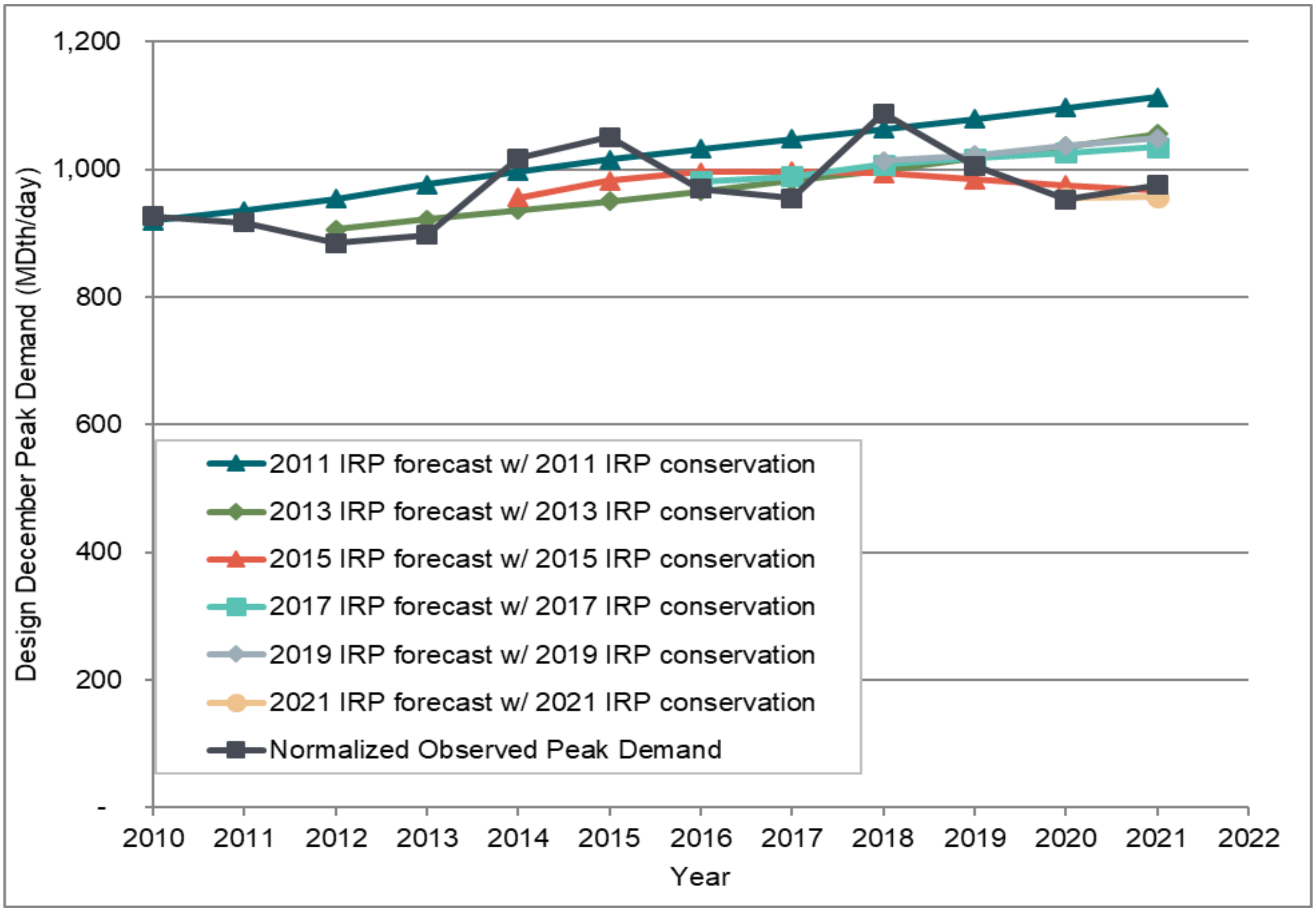


Table 5.8: Weather Normalized December Gas Peak Demand and Percent Difference from Previous IRP Forecasts

Year	2011 (%)	2013 (%)	2015 (%)	2017 (%)	2019 (%)	2021 (%)
2010	-0.7	-	-	-	-	-
2011	2.0	-	-	-	-	-
2012	7.8	2.4	-	-	-	-
2013	8.8	2.7	-	-	-	-
2014	-2.0	-7.9	-5.6	-	-	-
2015	-3.4	-9.6	-6.1	-	-	-
2016	6.4	-0.4	3.2	1.2	-	-
2017	9.7	2.8	5.0	3.6	-	-
2018	-2.3	-8.2	-8.2	-7.4	-6.9	-
2019	7.3	1.1	-1.7	1.1	1.6	-
2020	15.0	8.7	2.8	7.6	8.8	0.2
2021	14.1	8.2	-0.3	6.1	7.5	-1.8

6.2. Reasons for Forecast Variance

As explained throughout this chapter, we based this IRP peak demand forecasts on forecasts of key demand drivers, including expected economic and demographic behavior, DSR, customer usage, and weather. When forecasts of these drivers diverge from observed actual behavior, so does this IRP forecast. As forecasts age, assumptions and conditions may change, so we expect older forecasts to be farther off from observed actuals than more recent forecasts. We explain these differences in the next section.

6.2.1. Economic and Demographic Forecasts

Economic and demographic factors are key drivers for this IRP peak demand forecast. After the 2008 recession hit the U.S., many economists, including Moody's Analytics, assumed the economy would recover sooner than it did. Experts pushed out a complete recovery with each successive forecast as the U.S. economy failed to return to its previous state. The charts below compare Moody's estimates of U.S. housing starts and population growth incorporated in the 2011 IRP through the 2019 IRP with actual U.S. housing starts and population growth.

Moody's optimistic forecasts of housing starts and population growth during the recession led to over-estimated forecasts of customer counts. Since the 2019 IRP, we no longer used estimates of housing starts as a driver in the demand forecast. Instead, we now use population projections based on WA ESD data to forecast the population in PSE's service area. For comparison, we include Moody's forecast of housing starts and population from May 2020 and Nov 2021 in Figures 5.9 and 5.10.

Although the Moody's forecast we used in the 2019 IRP predicted a softening of the economy in 2020, it did not forecast the magnitude of the effects of the COVID-19 pandemic. Therefore, the Moody's forecasts we used before the 2021 IRP likely overestimated economic growth in 2020, 2021, and 2022. We will probably not know the full extent of the pandemic's repercussions on the economy and energy demand during this IRP cycle.

Figure 5.9: Moody's Forecasts of U.S. Housing Starts Compared to Actual U.S. Housing Starts

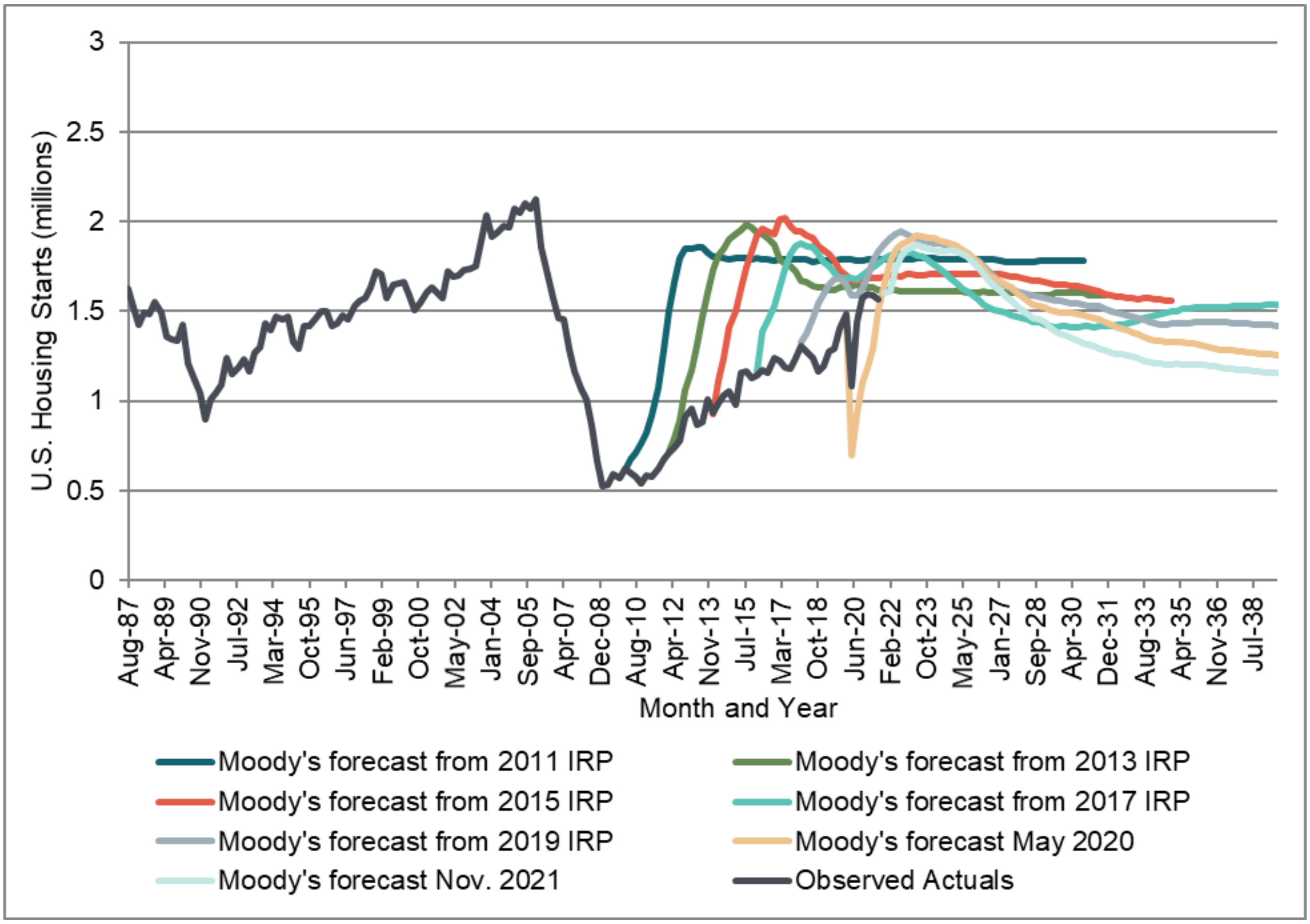
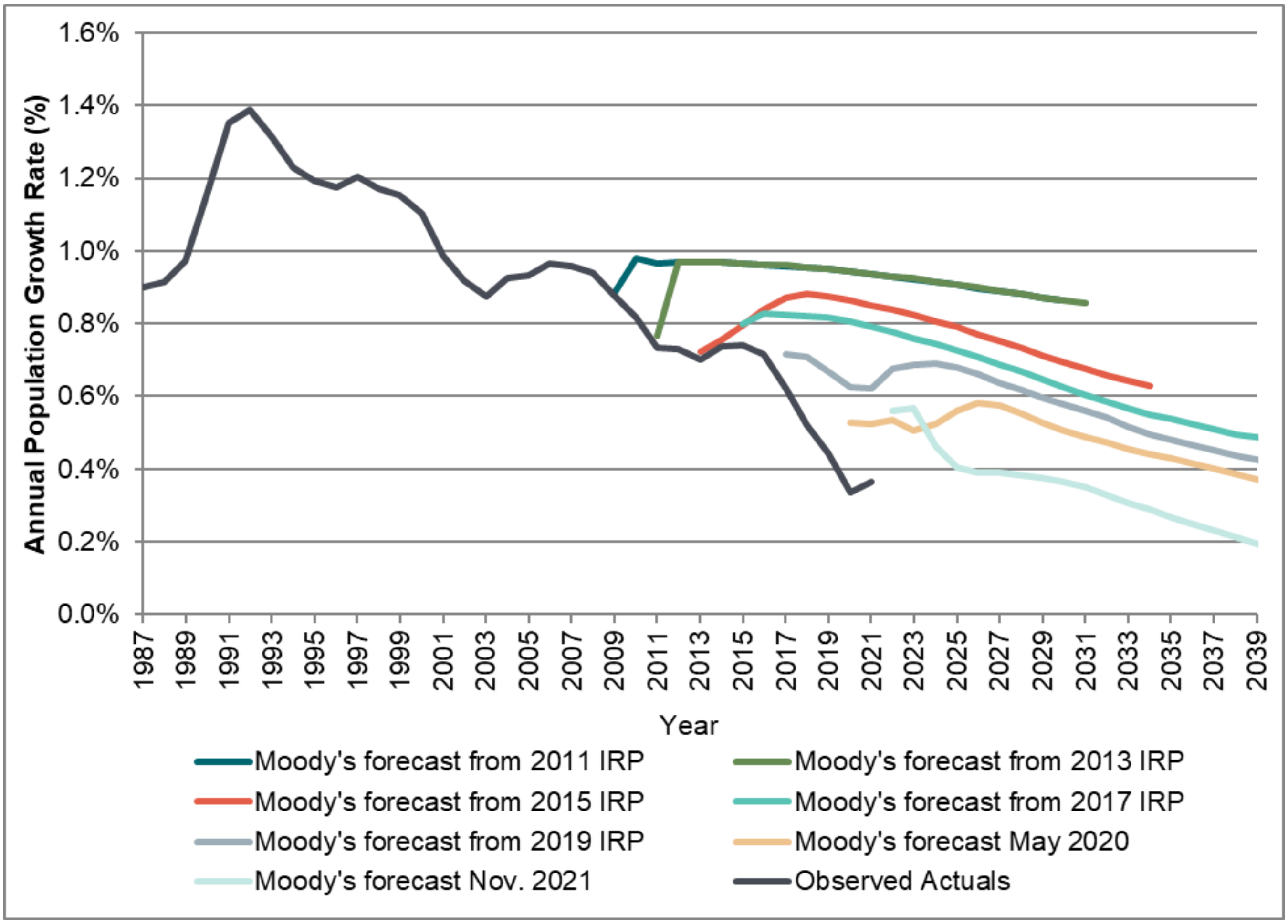


Figure 5.10: Moody's Forecasts of U.S. Population Growth Compared to Actual U.S. Population Growth



6.2.2. Demand-side Resources and Customer Usage

For the comparison in Figure 5.8 of weather-normalized peak observations to this IRP peak demand forecasts after additional DSR, we assumed that the forecasted DSR was implemented. However, consumers can adopt energy-efficient technologies above and beyond what utility-sponsored DSR programs and building codes and standards incentivize. This consumer behavior leads to more actual DSR taking place than forecasted. Additionally, DSR programs can change over time. We can choose programs that were not cost-effective in the past and not included in the optimal bundle in a later IRP as cost-effective. This approach can make an older forecast dated, making the forecast of DSR too low and, therefore, the demand forecast after additional DSR too high.

Also, due to the 2017 General Rate Case (GRC), PSE accelerates gas DSR by five percent each year. This accelerated DSR is an additional DSR that we did not consider in IRPs before 2017.

6.2.3. Normal Weather Changes

Normal weather assumptions change from forecast to forecast. From 2011 to the 2021 IRP, we updated the normal weather assumption by rolling off two older years and incorporating two new years of weather data into the 30-year average. Normal heating degree days have been declining, and the forecast of energy demand with normal weather has changed. In this IRP, we incorporated climate change into the normal definition, significantly changing the 2023 Gas Utility IRP base demand forecast.

Over time our customers' weather sensitivity has been changing. As consumers implement energy efficiency measures, customers use less energy at a given temperature, including peak temperatures. More recent forecasts reflect this change in weather sensitivity better than older forecasts.

6.2.4. Non-design Conditions during Observed Peaks

We model normalized peak values using the peak forecasting model. This model uses peak values from each month to create a relationship between peak demand, monthly demand, and peak temperature. However, some of the observed December peaks shown occurred on atypical days rather than typical days. For example, peaks in 2013 and 2017 fell on weekends. Peaks in 2010, 2012, and 2015 fell on New Year's Day, and the 2019 peak fell on Boxing Day (the day after Christmas). Usage on these days will likely differ from use on a typical non-holiday weekday peak. When these dates are weather normalized, they may not line up with the forecasted values since the usage patterns are atypical.

6.2.5. Service Area Changes

Effective January 2022, the city of Seattle banned gas in multi-family residential new construction over three stories and in commercial new construction. New construction in Seattle drove new customer growth in the residential and commercial classes, increasing the peak. Therefore, when comparing the forecasts for 2011, 2013, 2015, 2017, 2019, and 2021 IRPs to today's actuals, those forecasts are expected to be higher than the actual peak demand.

GAS ANALYSIS

CHAPTER SIX

Contents

1. Introduction

This chapter explains the gas analysis we conducted for Puget Sound Energy's (PSE's) 2023 Gas Utility Integrated Resource Plan (2023 Gas Utility IRP).

2. Infrastructure Reliability

Gas transportation and distribution systems do not need 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.

2. **Cooperation with regional entities:** Members of the Northwest Mutual Assistance Agreement (NWMAA) utilize, operate, or control gas transportation and storage facilities in the Pacific Northwest (PNW) 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. We applied the lessons learned from the October 2018 event discussed later in this chapter in the restructured NWMAA.

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 can furnish gas supply in the event of a pipeline disruption.

The following two incidents illustrate how these strategies work in practice.[1] The Westcoast pipeline, between Station 2 and Sumas in central British Columbia (BC), ruptured in the early evening of October 9, 2018, shutting off gas flow from production points in northeast BC 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. Coordinating their efforts through the NWMAA, all gas pipelines, utilities, power plant operators, and major industrial customers affected worked together to add supply or shed load. FortisBC, a large gas utility in southern British Columbia (BC), used some gas flowing on its pipeline from Alberta (Southern Crossing). Puget

[1] Westcoast Pipeline is operated by Westcoast Energy, a subsidiary of Enbridge, Inc.

Sound Energy, 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 BC 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 NWMAA members, the incident lasted less than 48 hours; however, the extensive testing and recertification required to restore the gas flow from BC 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 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 rare, these incidents demonstrate the resilience of the region's gas transportation and storage system and the importance of building resiliency and flexibility in the system to maintain reliability when incidents occur. 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 prove that PSE's steps to prepare for occasional infrastructure failure are successful.

3. 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 BC 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, Westcoast 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 Westcoast 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 currently provides adequate and occasionally abundant supplies to other customers at the Sumas market hub. 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 winter and a surplus in summer, PSE, and others active in the Sumas market, believe there is a risk for supply shortages at Sumas when Woodfibre begins operations in 2027.

As a result, there are three proposed pipeline expansions:

1. FortisBC 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 will move forward with this project, even if no additional shippers sign 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 the 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 no additional capacity is 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 purposes: move additional gas from Stanfield to the I-5 corridor and Huntingdon/Sumas for Fortis or others, and reduce displacement requirements along the Columbia Gorge, potentially creating 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 we obtain more favorable capacity without imposing high costs or risks on PSE customers. Any of these projects would likely alleviate concerns over the reliability of the supply market at Huntingdon/Sumas.

We are confident we can 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.

3.1. Recommendations

No actions are currently needed. We are not studying the pipeline expansion projects discussed in the prior section in this 2023 Gas Utility IRP for the following reasons:

- Costs for each project are extremely high.
- Puget Sound Energy has sufficient capacity on the Northwest and Westcoast pipelines.
- Puget Sound Energy's declining demand does not justify additional capacity to city-gate.
- Regional demand does not justify expansion beyond Fortis' new line.
- We could assure greater access to Station 2 by taking some of Fortis's excess Westcoast pipeline capacity and alleviate any concerns at Sumas.

4. Resource Need

Peak day demand drives PSE's gas sales, which occurs in the winter when temperatures are lowest, and heating needs are highest. 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] Two primary factors influence demand — peak day demand per customer and the number of customers. The heating season and the number of lowest-temperature days in the year remain relatively constant, and use per customer is growing slowly,[3] so the most significant factor we currently utilize to determine peak load growth is the increase in customer count.[4]

This 2023 Gas Utility IRP analysis modeled two customer demand forecasts over the 27-year planning horizon: the 2023 Gas IRP Mid-(reference) demand forecast and the 2023 Gas Utility IRP zero-growth demand forecast.[5] We tested whether we needed to renew existing pipeline contracts in both cases.

In the zero-growth demand forecast, we have sufficient firm resources to meet peak day need throughout the study period if we assume we will automatically renew existing pipeline contracts. Without pipeline renewals, we will need more resources in the winter of 2025–2026.

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2 Heating degree days (HDDs) are the number of degrees relative to the base temperature of 65° Fahrenheit. A 52 HDD is calculated as 65° less the 13° temperature for the day.

3 The 2023 demand forecast incorporates climate change. Although energy consumption declines over the IRP study period, the peak day forecast did not change with this update. See Chapter Four: Key Analytical Assumptions for more detailed discussion of the demand forecast.

4 The 2021 Gas Utility IRP demand forecast projects the addition of approximately 9,000 natural gas sales customers annually on average.

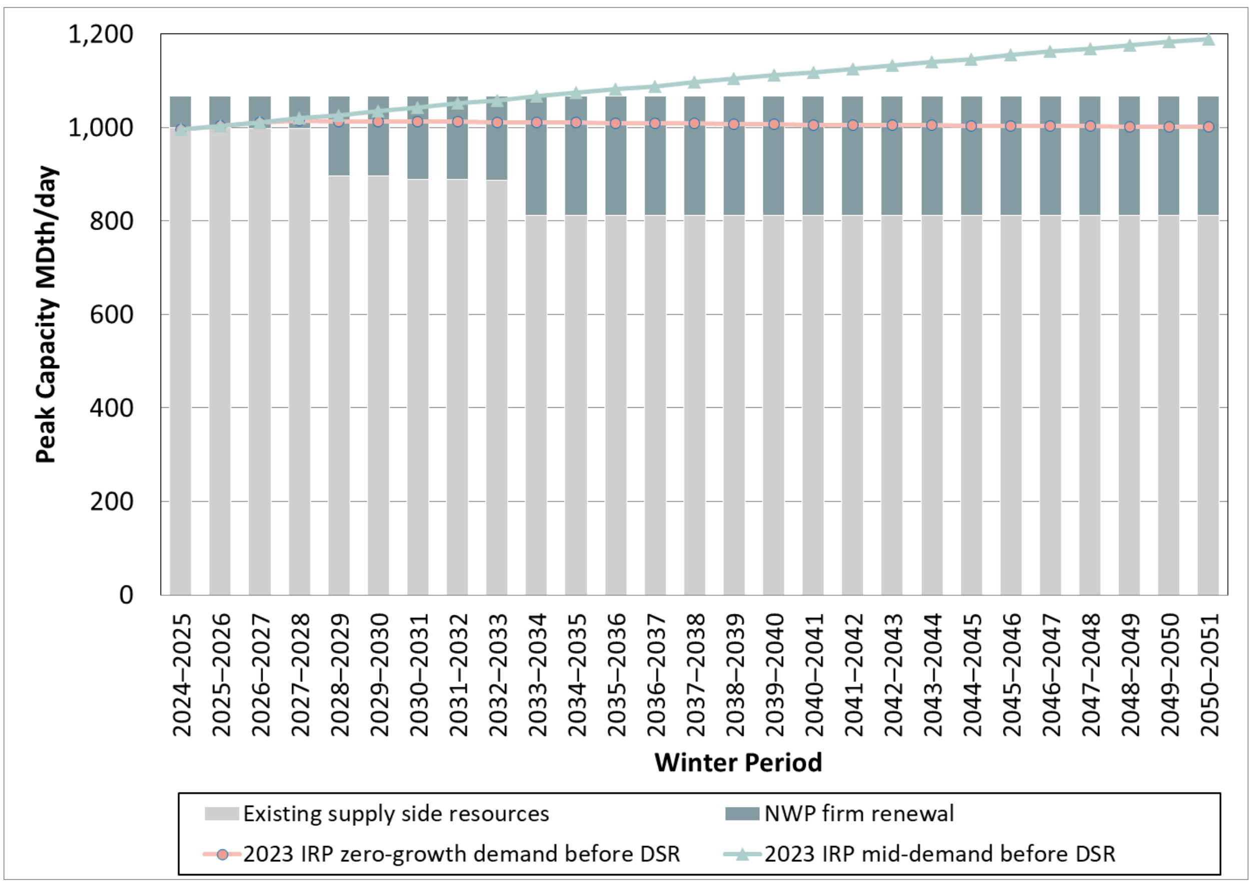
5 The zero-growth demand forecast consists of no new customers after 2026. We discuss the 2023 Gas Utility IRP demand forecasts in detail in Chapter Five: Demand Forecasts.

In the Mid-(reference) demand forecast, the first resource need occurs in the winter of 2030–2031, assuming we renew existing pipeline contracts. If we assume no pipeline renewals, the need arises in the winter of 2025–2026.

Figure 6.1 illustrates the gas sales peak resource need over the 29-year planning horizon for the two demand forecasts modeled in this IRP. Figure 6.2 shows the resource need surplus or deficit for the Mid-demand forecast.

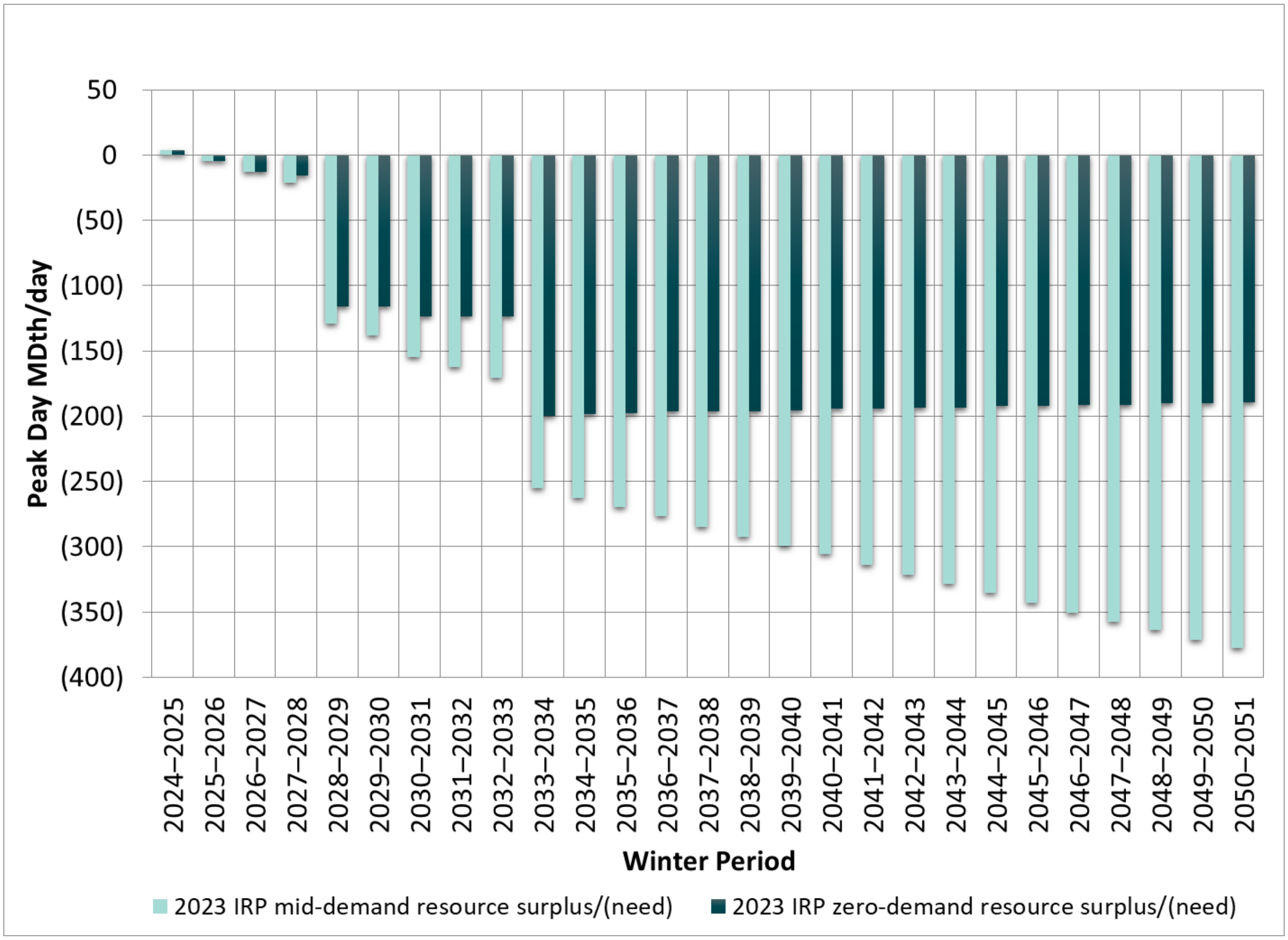
In Figure 6.1, the lines rising toward the right indicate peak day customer demand before additional demand-side resources (DSR),[6] and the bars represent existing resources for delivering natural gas supply to our customers. These resources include contracts transporting natural gas on interstate pipelines from production fields, storage projects, and on-system peaking resources. We also show contract expirations and renewals. If demand declines or we have significant surplus resources, we will evaluate whether pipeline renewal or release makes sense for the gas sales portfolio. We will also consider if lower-cost resources can replace year-round pipeline capacity and reliably serve customers. The gap between demand and existing resources is the resource need.

Figure 6.1: Gas Sales Peak Resource Need before DSR, Existing Resources Compared to Peak Day Demand



[6] One of the major tasks of the IRP analysis is to identify the most cost-effective amount of conservation to include in the resource plan. To accomplish this, it is necessary to start with demand forecasts that do not already include forward projections of additional conservation savings. Therefore, the IRP natural gas demand forecasts include only DSR measures implemented before the study period begins in 2022. These charts and tables are labeled before DSR.

Figure 6.2: Gas Sales Peak Resource Need Surplus/Deficit
in Mid- and Zero-demand Forecast before Pipeline Renewals and DSR



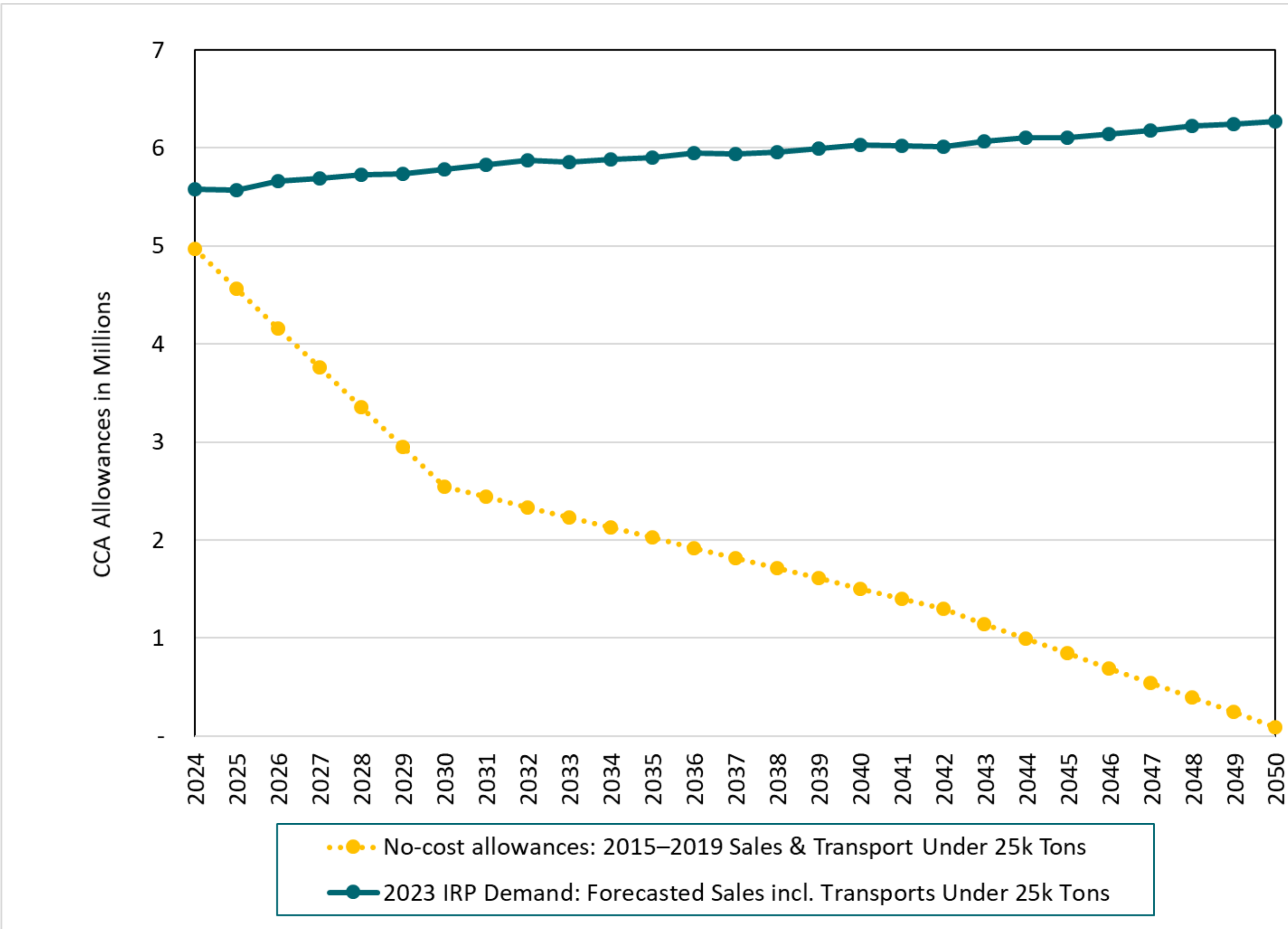
5. Climate Commitment Act

In 2021 the Washington State Legislature passed the Climate Commitment Act (CCA), which created a cap and invest program to reduce carbon dioxide emissions within specific sectors of the economy, including gas utilities. The program rules, developed by the Department of Ecology (Ecology), went into effect on January 1, 2023. The final rules were proposed on September 29, 2022, and adopted on October 30, 2022.

➔ For details on the CCA, please refer to Chapter Three: Legislative and Policy Change.

This 2023 Gas Utility IRP draws on the rulemaking documents to establish the emissions baseline and allowance[7] allocation forecast. This report uses the CCA allowance price forecasts to determine the cost of compliance in various scenarios and sensitivities described later in this chapter. We show the no-cost allowances for PSE in Figure 6.3. We show allowance data throughout this chapter to distinguish between no-cost allowances and net additional allowances.

Figure 6.3: Gas No-Cost Allowance Forecast (Department of Ecology, September 29, 2022)[8]



6. Risks to Natural Gas Supply

Suppliers import natural gas to the Pacific Northwest, mainly from British Columbia and the Rocky Mountain region. Disruptions to natural gas transportation infrastructure present a risk to reliable gas supply in the area.

The Enbridge Westcoast Energy pipeline failure in October 2018 highlighted how heavily the utility FortisBC and the British Columbia Utilities Commission (BCUC) relied on the pipeline for supply from the northeastern portion of

7 Allowance is an authorization to emit up to one metric ton of carbon dioxide equivalent.

8 The no-cost allowances line is based on the gas sales customers plus transport gas customers with emissions less than 25,000 tons per year. We removed Emissions Intensive Trade Exposed (EITE) gas sales customers from the gas sales to calculate the no-cost allowances line.

British Columbia. Concurrently, natural gas utility Woodfibre LNG announced a final investment decision and a partnership with Enbridge (Westcoast pipeline's parent company) to build and operate an export facility. Woodfibre gas demand will pull 300 MDth/day out of the Sumas market hub using previously acquired firm capacity. The Woodfibre capacity on the Westcoast pipeline brought 300 MDth to the Sumas market daily; without it, Sumas may become less liquid, very volatile, and may experience supply shortages on some days. This situation has produced a growing concern over the availability of uncommitted gas at Sumas when Woodfibre starts up in 2027. As discussed in the previous section, the Westcoast pipeline and Northwest Pipeline have proposed expansions to their systems.

7. Delivery System Planning

Puget Sound Energy uses delivery system planning to ensure the pipeline delivery system can deliver gas safely, reliably, and on demand. We must also meet all regulatory requirements that govern the system and ensure we build equity into planning analysis.

The objectives of energy delivery system planning are to:

- Be prepared for and deliver service through various operating models, including leveraging behind-the-meter assets, acting as an owner-operator, and partnering with third parties and customers.
- Be transparent about decision-making and processes in collaboration with external stakeholders and customers.
- Deliver flexible, segmented, and tailored value propositions that meet our customers' needs.
- Ensure we embed equity and affordability in planning and decision-making.
- Improve system performance making it more safe, reliable, resilient, smart, and flexible at optimal cost.
- Incorporate new technology and solutions to meet system needs, including non-pipe alternatives (NPA).
- Operate and maintain the system safely and efficiently daily, annually, and in real-time with all fuels.
- Prepare for and deliver lower carbon fuels to customers, including renewable natural gas (RNG) and hydrogen-blended natural gas.
- Proactively identify trends and influence regulatory and legislative policy to help achieve the above objectives.

Meeting system needs and PSE's decarbonization goals requires a flexible planning framework, a modern energy delivery system, a focus on research, and continuous improvement.

→ For more details on our delivery system planning model and 10-year investment strategy, see Appendix G: Delivery System Planning.

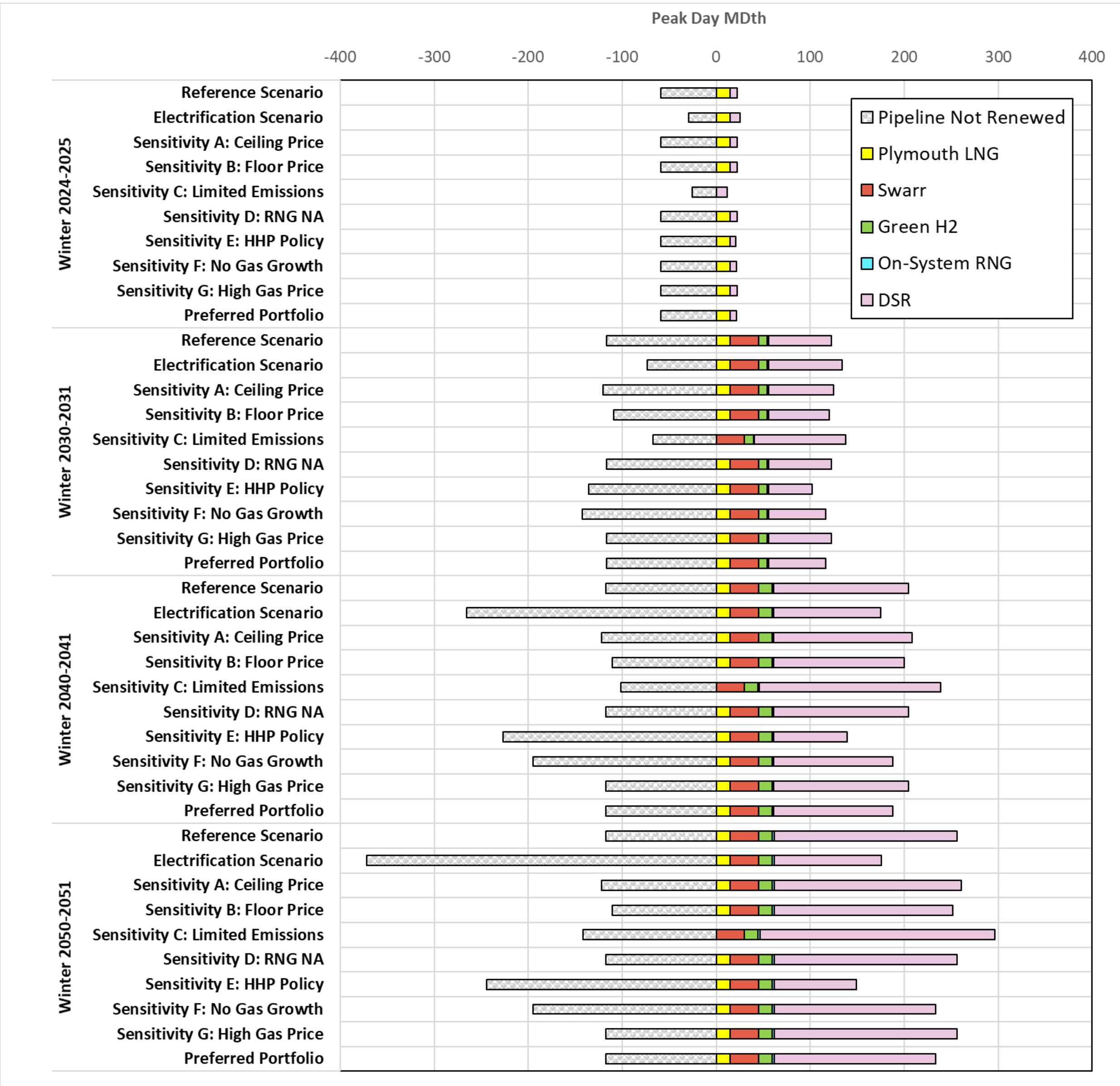
8. Gas Sales Analysis Results

This section discusses the results of the gas portfolio modeling that looked at the scenarios and sensitivities outlined in Chapter Four: Key Analytical Assumptions. We discuss critical findings under resource additions, followed by details of the scenarios and sensitivities.

8.1. Resource Additions: Scenarios and Sensitivities

In this section, we discuss the deterministic runs for each scenario and sensitivities in SENDOUT, the gas portfolio model and summarize the results in Figure 6.4. We also review some of the key findings from the results.

Figure 6.4: Resource Additions by Scenarios and Sensitivities



The following key findings from this evaluation will guide us as we develop PSE's long-term resource strategy and provide background information for resource development activities over the first two years of the study period.

- Cost-effective energy efficiency does not vary much across several sensitivities. Therefore, there is a reduced risk of overbuilding or underbuilding this resource. The zero-growth gas sensitivity does not decrease the cost-effective energy efficiency savings from the reference scenario based on a mid-growth demand.

- Emissions reductions are relatively small in all scenarios and sensitivities except those where the emissions are physically constrained not to exceed the amount covered through no-cost allowances. Green hydrogen is cost-effective in all scenarios and sensitivities when considering the benefits of production tax credits (PTCs) under the Inflation Reduction Act (IRA) of 2022.
- In the reference scenario, the natural gas sales portfolio is short of resources beginning in winter 2031–2032 and each year after. In contrast, the zero-growth sensitivity is long (has no resource need) over the entire study period.
- Renewable Natural Gas (RNG) is price sensitive, and more of it is cost-effective in the scenario and sensitivities with carbon constraints or the higher ceiling CCA allowance price. Renewable Natural Gas (RNG) sourced from North America could triple the cost-effective amount in the price sensitivities with higher ceiling CCA allowance costs compared to regionally constrained RNG.
- In the reference scenario, we met resource needs primarily with energy efficiency. The increased cost of gas drives cost-effective energy efficiency higher on the 2023 supply curve than in the 2021 Gas Utility IRP. The amount, or physical volume of cost-effective energy efficiency, is about the same as in the 2021 Gas Utility IRP.
- In all scenarios, some pipeline capacity that is up for renewal before the 2033 period is not renewed and instead displaced with energy efficiency and peaking resources from the Swarr and the Plymouth liquid natural gas (LNG) plants.
- The Swarr and the Plymouth LNG plants are cost-effective across most sensitivities.
- The total gas costs are higher due to the added CCA allowance price. Price adders for greenhouse gas emissions quadrupled the total cost of the gas on the margin: SCGHG with upstream emissions and CCA allowances.[9]

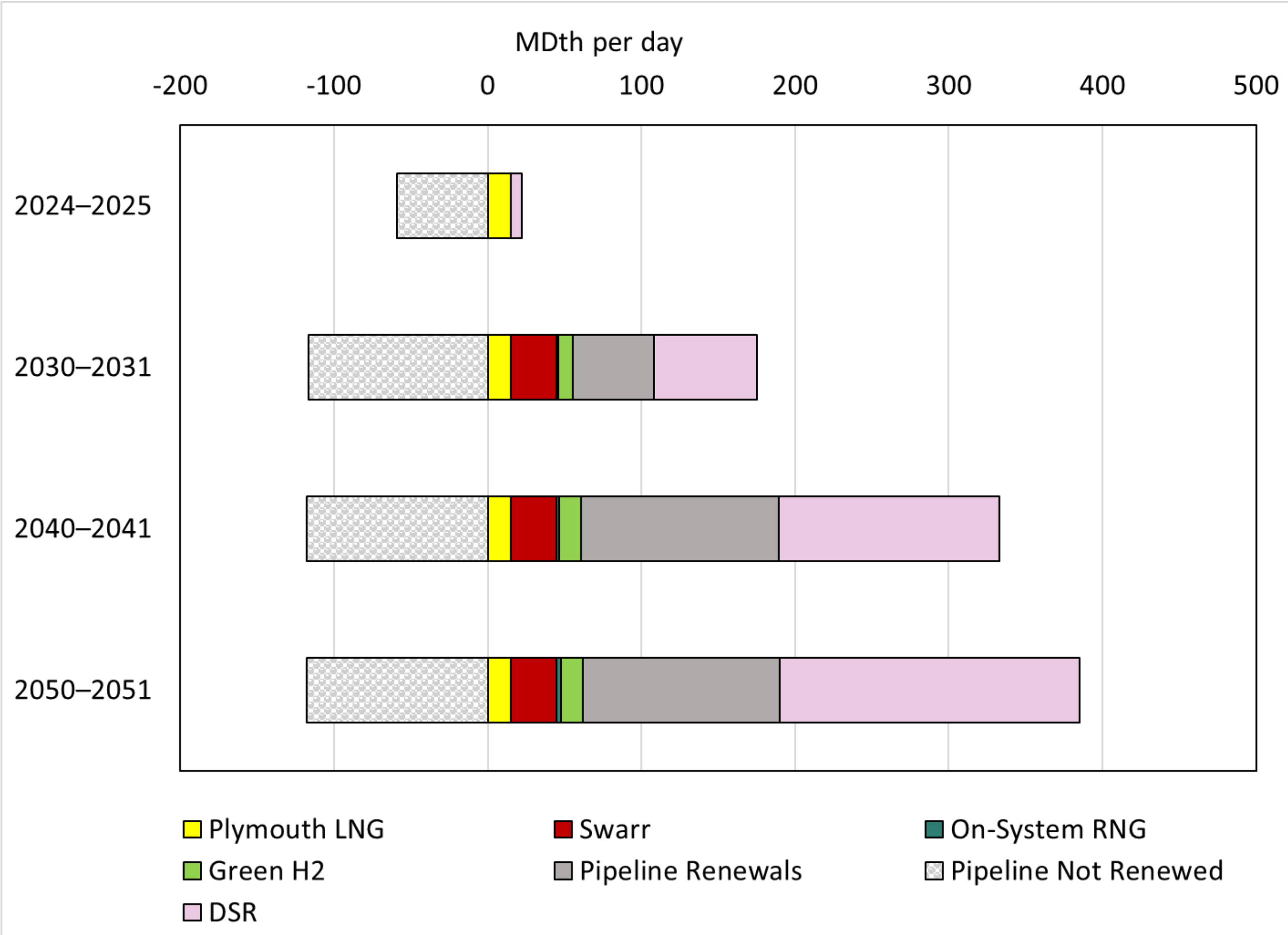
8.2. Reference Scenario

The reference scenario is the less constrained of the two scenarios where we optimized inputs in the gas portfolio model. We modeled two resource options on the demand side: energy efficiency and hybrid heat pumps (HHP). We input both supply curves in the gas model. Since the HHP supply curve has an electrification component, any cost-effective capacity additions would demand the energy efficiency supply curve be adjusted and reiterated through the model. But the results show that the HHP is not cost-effective, so no such iteration was necessary.

Similarly, a cost-effective HHP selection would have also led to an iteration to determine the electric load build and incremental energy efficiency associated with the load build for a corresponding electric analysis to identify the resources needed to serve the additional electric load. But since we did not select any HHP in the gas model, no electric analysis was triggered. We show the results of the reference portfolio resource builds for our gas portfolio analysis in Figure 6.5.

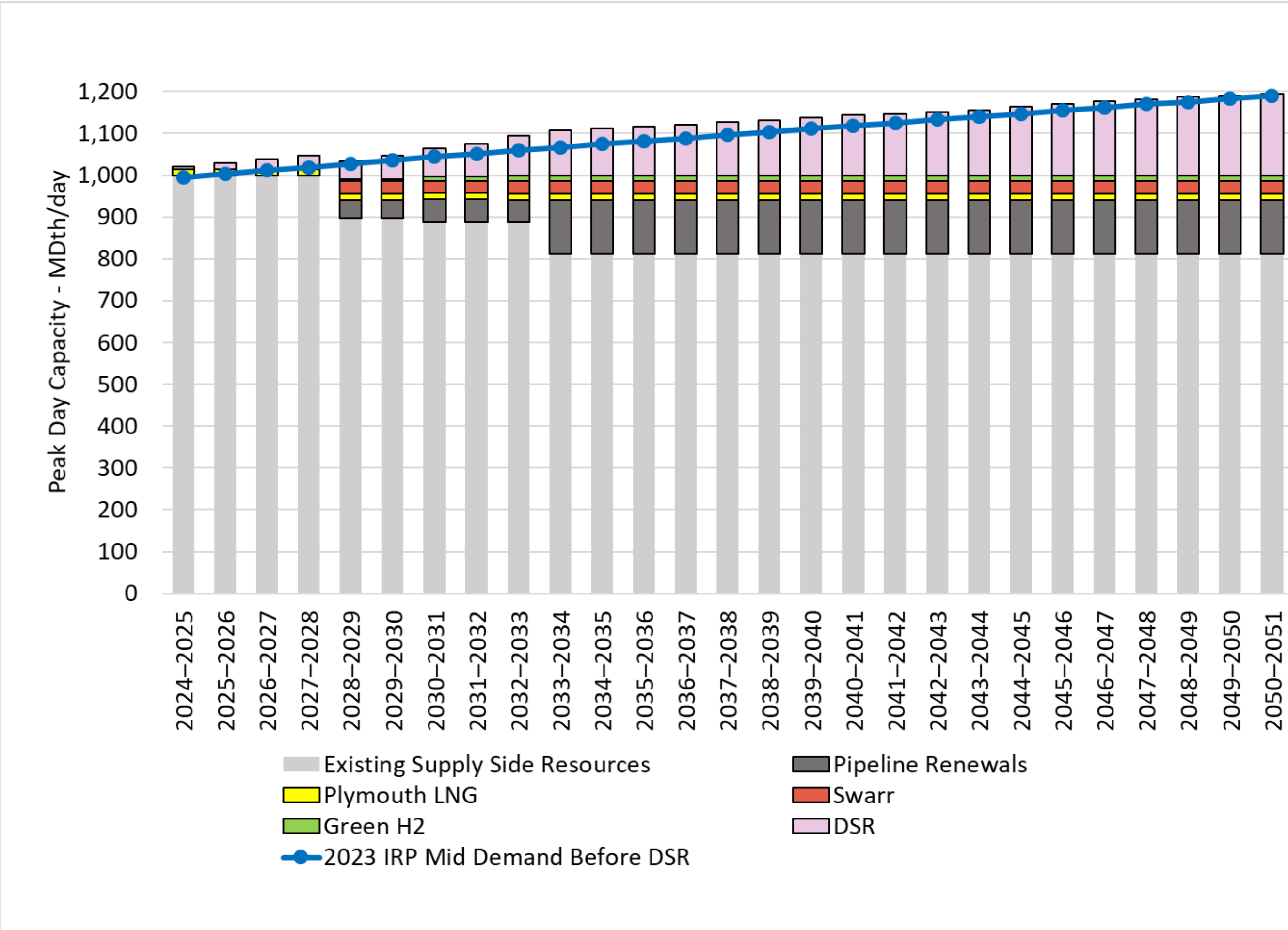
[9] The 20-year levelized cost of gas from Sumas is approximately $3.70. With the carbon adders, the total cost approaches $16.00. See Chapter Four for additional discussion on how we developed the gas costs used in the 2023 Gas Utility IRP analysis.

Figure 6.5: Scenario One: Reference Portfolio Resource Additions — Peak Day



We show the resource additions for our gas portfolio analysis in Figure 6.6

Figure 6.6: Resource Additions by Type and Period



Conservation was a significant resource addition impacted by the higher total gas costs and marginal avoided capacity of the pipeline renewals. As a result, the model chose not to renew some of the pipeline capacity contracts. The other resources displacing the pipeline contracts were Plymouth LNG and Swarr, which were more cost-effective than paying for year-round pipeline capacity.

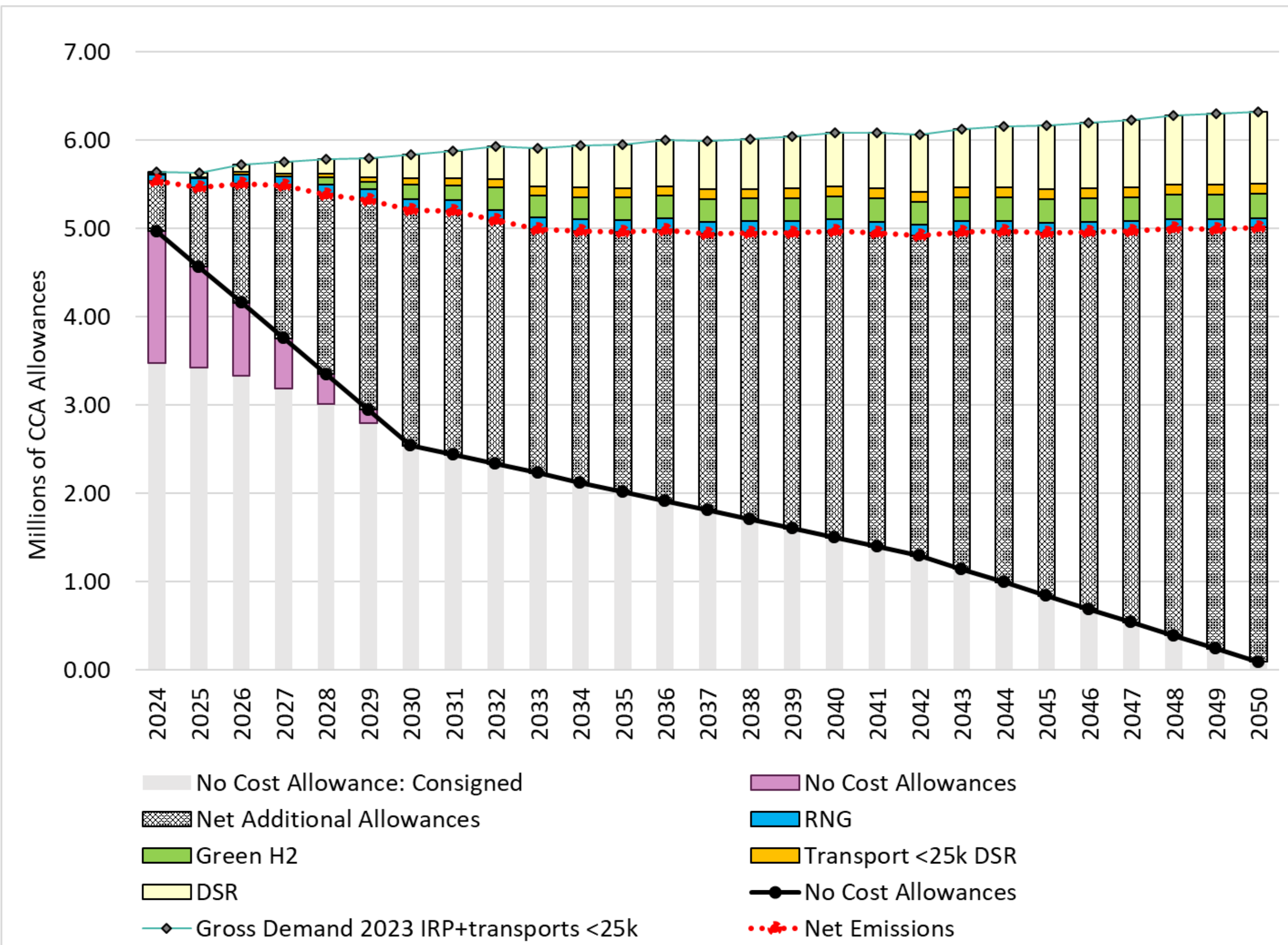
We modeled two alternate fuels for the gas portfolio, RNG (biomethane fuels) and green hydrogen. These options were limited to the Pacific Northwest (PNW), which impacted the RNG potential; casting a wider net throughout North America would make significantly more RNG available to the gas model. Total gas costs with the expected CCA allowance price are slightly less than most regional RNG. Therefore, most of the regional RNG was not cost-effective, except for the contract on the PSE system, which avoids the added pipeline transport costs. Hence, the model selected only one contract with this characteristic.

The model selected green hydrogen, a resource aided by the PTCs offered through the IRA, in 2028, when it will be available, and all the subsequent additions in 2030 and 2032. The regional limitation in this report did not impact green hydrogen because we only considered a PSE system resource. Regional sourcing may become an issue in future IRPs if cost-effective green hydrogen resources are only available outside the PNW.

According to the analysis, the gas system is long if we renew all the existing pipeline contracts. If we treat pipelines as a resource that competes with other options for renewal to determine the least cost option, the model only renews some of the pipeline capacity offered for renewal. In the reference scenario, most of the Rockies hub segment is not renewed. This pipeline capacity is replaced with conservation and needle peaking alternatives: the Swarr propane plant and capacity on Plymouth LNG with associated pipeline capacity for delivery to the PSE system.

We show the reference scenario emissions reductions in conjunction with the CCA-no-cost allowances in Figure 6.7. Energy efficiency[10] is the most significant contributor to emissions reductions, followed by green hydrogen and on-system RNG, which is too small to be visible on the chart. Purchased CCA allowances are the most cost-effective option for meeting the remaining CCA emissions compliance obligations at the expected price. In this scenario, the physical emissions are reduced by seven percent in 2030 compared to the emissions in 2023, at the start of the first compliance period, and reduced by 10 percent in 2045. We achieve the remaining compliance obligation through the purchase of CCA allowances.

Figure 6.7: Emissions Reduction Reference Scenario



[10] The chart shows emissions reductions from energy efficiency related to the transport customers. We estimated these reductions using PSE avoided costs as a proxy because we do not know the avoided costs for the transport customers.

8.3. Gas Portfolio Sensitivities

Sensitivities start with the optimized, least-cost reference scenario portfolio produced in the scenario analysis. We change a single resource, environmental regulation, or other condition to examine the effect of that variable on the portfolio. We summarized the sensitivities in Table 6.1 and described them in the following sections.

Table 6.1: 2023 Gas Utility IRP Sensitivities

#	Sensitivity Name	CCA Constraint Parameter	CCA Allowance Price	Renewable Fuel Source location	SCGHG Added?	Demand**	Gas Price**
1	Reference Case	Price	Mid	PNW	No	Mid (F22)	Mid
A	Allowance Price High	Price	Ceiling*	PNW	No	Mid (F22)	Mid
B	Allowance Price Low	Price	Floor*	PNW	No	Mid (F22)	Mid
C	Limit Emissions Without Regard to Price	No-Cost Allowance Line*	Floor*	PNW	No	Mid (F22)	Mid
D	Alternative Fuel Location WA	Price	Mid	North America*	No	Mid (F22)	Mid
E	HHP Policy	Price	Mid	PNW	No	Mid (F22) - policy-driven HHP adoption*	Mid
F	Zero gas growth	Price	Mid	PNW	No	Zero gas growth after 2026*	Mid
G	High Gas Price	Price	Mid	PNW	No	Mid (F22)	High*

Notes:

* Indicates change as compared to the reference case

** Typical Gas IRP parameters

A — CCA Allowance Price High

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

Baseline Assumption: We used the mid-CCA allowance price.

Sensitivity: We applied the ceiling allowance price provided by the Department of Ecology (Ecology)[11] in this sensitivity.

Portfolio Results:

- The high allowance price makes all the regional RNG offered cost-effective, including on-system, delivered contracts, and RNG products that are unbundled regional attributes available at the early part of the study. These offerings, except for the on-system RNG, were not cost-effective in the reference scenario, and this

[11] https://ecology.wa.gov/DOE/files/4a/4ab74e30-d365-40f5-9e8f-528caa8610dc.pdf page 9

sensitivity shows that if allowance prices are higher, acquiring RNG is a cost-effective way to reduce emissions to achieve CCA compliance.

- The higher allowance price also selected slightly more energy efficiency in the portfolio model. The peak contribution was higher by 4 MDth[12] a day on peak day by 2050.

B — CCA Allowance Price Low

This sensitivity tests the impacts of a low allowance price.

Baseline Assumption: We applied the mid-CCA allowance price.

Sensitivity: We applied the floor allowance price as provided by Ecology[13].

Portfolio results

- The floor allowance price lowers the total cost of conventional gas; thus, this portfolio renews slightly more pipeline capacity or retains more existing pipeline capacity compared to the reference portfolio.
- The lower total gas costs also result in lower energy efficiency being cost-effective, lower by 5 MDth (50,000 therms) a day in 2050.

C — Limiting Emissions Without Regard to Price

This sensitivity minimizes greenhouse gas emissions with the resource options in the gas model before it purchases above the no-cost allowance trajectory under the CCA to fill the gap with additional allowance purchases at the floor price. It is essential to call out 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 and allowed for the purchase of net additional allowances to meet compliance.

Sensitivity: We first forced the emissions to be minimized with the resource options and then balanced the remaining gap between the no-cost allowances and the reduced emissions by purchasing net additional allowances at the floor price.

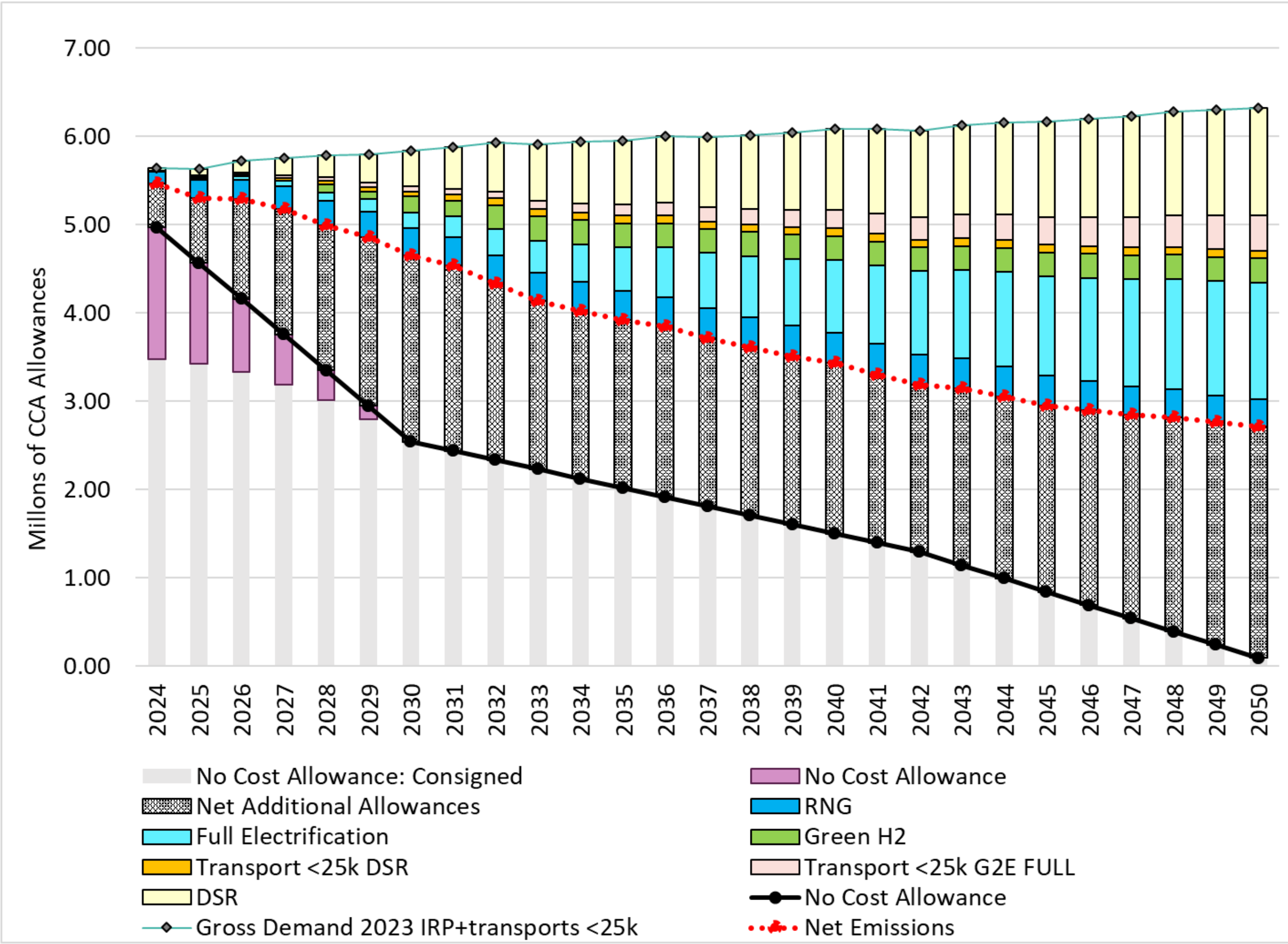
Portfolio results:

- The maximum amount of alternate fuels is selected and contributes to reducing emissions.
- The physical limit on emissions to the no-cost allowance trajectory maximizes the resource additions to reduce the emissions to attain the emissions target; there are not enough resources available, especially in the early years. That gap eventually must be filled with the purchase of CCA allowances at the floor price.
- The portfolio selects all the energy efficiency; this is the second largest reduction in emissions.
- The portfolio selects all the hybrid heat pumps in the market-driven supply curve. These hybrid heat pumps reduce emissions significantly and are the most significant contributor to reducing emissions, see Figure 6.8.

[12] One MDth is equal to 10,000 therms.
[13] https://ecology.wa.gov/DOE/files/4a/4ab74e30-d365-40f5-9e8f-528caa8610dc.pdf

- Compared to the baseline emissions from 2015–2019, the total reductions are 22 percent lower in 2030 and 79 percent lower by 2050.

Figure 6.8: Emissions under Sensitivity C – Limited Emissions



D — Alternate Fuel Sourcing RNG Not Limited to PNW[14]

This sensitivity removes the constraint on sourcing alternate renewable fuels from the PNW to include North America; this applies to RNG.

Baseline Assumption: RNG is limited to a supply curve representing the availability and prices within the PNW.

Sensitivity: In this sensitivity, the portfolio allows the purchase of RNG outside of PNW from all regions within North America.

Portfolio results:

[14] We only have considered green hydrogen within the PNW, so this sensitivity is limited to RNG.

- The portfolio selects 12,000 MDth per year or 38 Mdth per day of RNG attributes sourced from outside the PNW starting in 2040.
- This results in a savings in NPV of $93 Million in 2024 dollars over the reference scenario, where RNG is restricted to regional sourcing.

E — Hybrid Heat Pump (HHP) Adoption Policy

This sensitivity models a policy where the hybrid heat pump is the preferred technology to electrify existing gas space heating loads at the end of the equipment life of PSE residential customers. The other end uses in residential and non-residential sectors are also assumed to be electrified.

Baseline Assumption: The portfolio model chooses the cost-effective amount of hybrid heat pump systems as gas conservation measures for residential space heating and electrification for other end uses. This sensitivity uses the conservation supply curve from the reference scenario. We offered the option not to renew pipeline contracts before 2033; all pipeline contracts were assumed to renew after 2033.

Sensitivity: The portfolio model forces the replacement of residential gas furnaces with hybrid heat pump systems and electrification for other end uses. We also electrified the commercial and industrial sectors where feasible (see the Gas DSR report in Appendix E: Existing Resources and Alternatives for more details). The reference scenario's conservation supply curve is modified to reflect the diminishing gas loads. We extended pipeline renewals for all contracted capacity beyond 2033 to allow the portfolio model to optimize it around a gas demand that will decline significantly due to the HHP policy.

Portfolio results:

- Cost-effective conservation is lower because: (1) The conservation supply curve based on the HHP adoption policy has lower potential savings than in the reference scenario due to declining demand, and (2) the cost-effective result occurs at a lower cost point on the supply curve than in the reference scenario.
- Pipeline renewals are lower in the years after 2033 than the reference scenario,[15] as more end uses are electrified, and peak gas loads decline from the electrification of the non-hybrid heat pumps. However, significant pipeline capacity is maintained in the electrification scenario to provide gas on peak days to serve the hybrid heat pump systems designed to run on gas when the outdoor temperature drops below 35F.[16] Figure 6.9 shows the resource builds.

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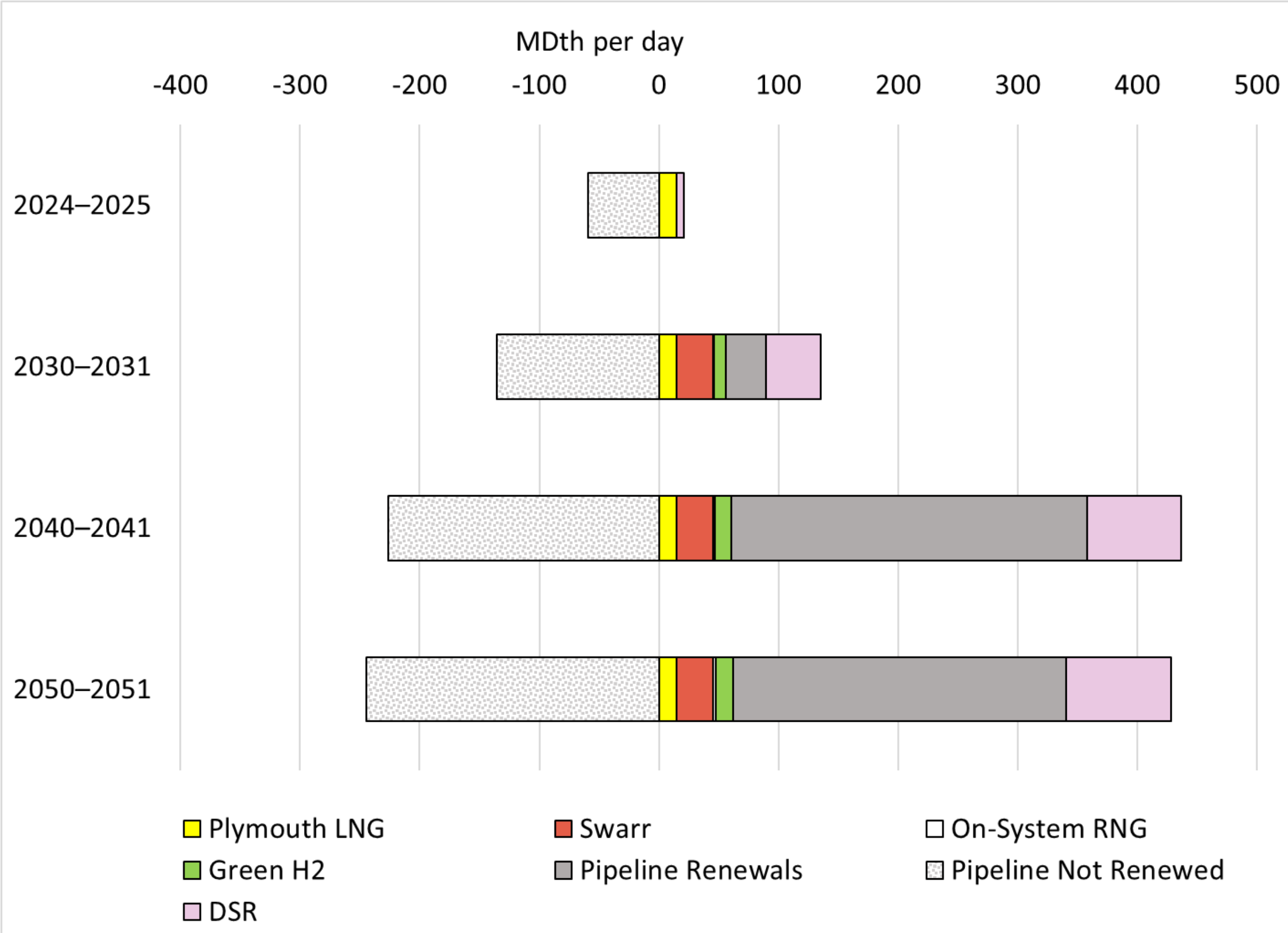
[15] In the reference scenario, we assumed all existing pipeline capacity beyond 2033 will be renewed and so it does not show up as renewal pipeline capacity on the resource build chart, but it is more that is being renewed under the HHP Policy sensitivity.

[16] The assumption for the switchover temperature is 35F, there are some heat pumps that can operate down to 30F, however since the electric system normal design peak is 28F this switchover temperature is not relevant if it is at 30 or 35F the electric system will not experience the peak load from the hybrid heat pump.

Figure 6.9: Resource Builds for HHP Policy Sensitivity



F — Zero Gas Growth

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

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

Sensitivity: Used a demand growth forecast based on zero gas customer growth.

Portfolio results:

- The lower demand results in more pipeline capacity not being renewed.
- The resource additions are the same as in the reference scenario, except for the pipeline renewals and conservation. More pipeline capacity is not renewed, and lower conservation results are mainly due to the lower achievable technical potential in the supply curve, even though the conservation cost point on the supply curve is essentially the same as the reference scenario.

G — High Gas Prices

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

Baseline Assumption: We assumed Mid natural gas price forecast.

Sensitivity: Use a high natural gas price forecast.

Portfolio results: The resulting portfolio has the identical resource additions as the reference scenario, but the total portfolio costs are higher than the reference scenario.

8.4. Electrification Analysis Results

The electrification analysis consisted of model runs in the gas and electric models. There were two cases in which there was conversion to electric loads, and we analyzed the impacts on both the gas and electric portfolio:[17]

1. Electrification: This is an electrification policy scenario where all residential end uses are converted to electricity, and 70 percent of the end uses in the commercial sector and 30 percent in the industrial sector are assumed to be feasible to convert to electricity.[18] We treated the end-use conversions as a must-take or policy case where mandates dictate that the gas equipment must be changed to electric at the end of its useful life. We tested this in scenario 2: Electrification — WA State Energy Strategy.[19]

2. Hybrid heat pump (HHP) Policy: This policy case is the same as the electrification policy above, except that it uses hybrid heat pump systems for space heating end use in the residential sector.

Electrification in this context assumes that a policy restricts the replacement or addition of gas equipment to serve end-use loads. Gas end uses eventually become electrified. We assumed that some residual segments in the commercial and industrial sectors are unsuitable for electrification. In the commercial sector, this is approximately 30 percent of the loads; in the industrial sector, it is roughly 70 percent. We developed the end-of-life replacement of gas equipment and assumptions around sector-level electrification as part of the conservation potential assessment (CPA) work. Appendix E: Existing Resources and Alternatives provides more details on this process.

A key feature of this scenario is that we forced electrification into the gas and electric models. The CPA provided forecasts for the load reduction on the gas system and load builds on the electric system. We also updated the energy-efficiency supply curves to reflect the changing load characteristics.

We account for the electric transmission and distribution (T&D) costs associated with the electrification as part of the levelized cost in the gas supply curve associated with electrification (there was no T&D cost for the HHP policy case).

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[17] There was an electrification option with a hybrid heat pumps for residential space heating as an economic choice in the reference and the sensitivities (except the HHP Policy sensitivity). None of the sensitivities, except the limited emissions selected the HHP option. The limited emissions sensitivity selected the HHP since physical emissions reduction was prioritized over allowance purchases in this sensitivity. In essence the HHP was forced into the portfolio.

[18] See Appendix C: Conservation Potential Assessment for more details.

[19] The WA State Energy Strategy (https://www.commerce.wa.gov/growing-the-economy/energy/2021-state-energy-strategy/) follows a more stringent path to reducing emissions. This assumption was included with the electrification scenario.

The electric system-related costs related to the increased resource additions to serve the added electric energy and peak load were an output of the electric portfolio model. The analysis considered gas savings and non-energy impacts as benefits. We detailed these costs in the CPA and summarized them in Table 6.5.

Table 6.5: Electrification Levelized Costs in the Gas Analysis[20]

Included Costs	Benefits Netted Out
Present Value (PV) of Capital Cost of Equipment Conversion	PV of Natural Gas Avoided
Program Cost (HVAC equipment program admin-adder based on EE potential estimates, all other end-uses based on 21% of equipment conversion cost)	PV of Conservation Credit (10% of conserved natural gas energy)
Added Electric T&D Costs (for non-hybrid systems)	PV of Non-Energy Impacts
Panel Upgrade Cost	N/A

8.4.1. Electrification Scenario — Gas Results

Table 6.6 shows our assumptions in the gas portfolio model followed by a discussion of the run results.

Table 6.6: Electrification Scenario

Scenario #	Scenario Name	CCA Constraint Parameter	CCA Allowance Price	Renewable Fuel Source Location	Renewable Fuel Heating Load Shift	Demand*	Gas Growth?*	Gas Price*
2	Electrification-State Energy Strategy (SES)	Follow SES line	Floor	PNW	Force in Cadmus Electrification Results	Mid (F22)	Yes	Mid

Notes:

* Typical Gas IRP parameters

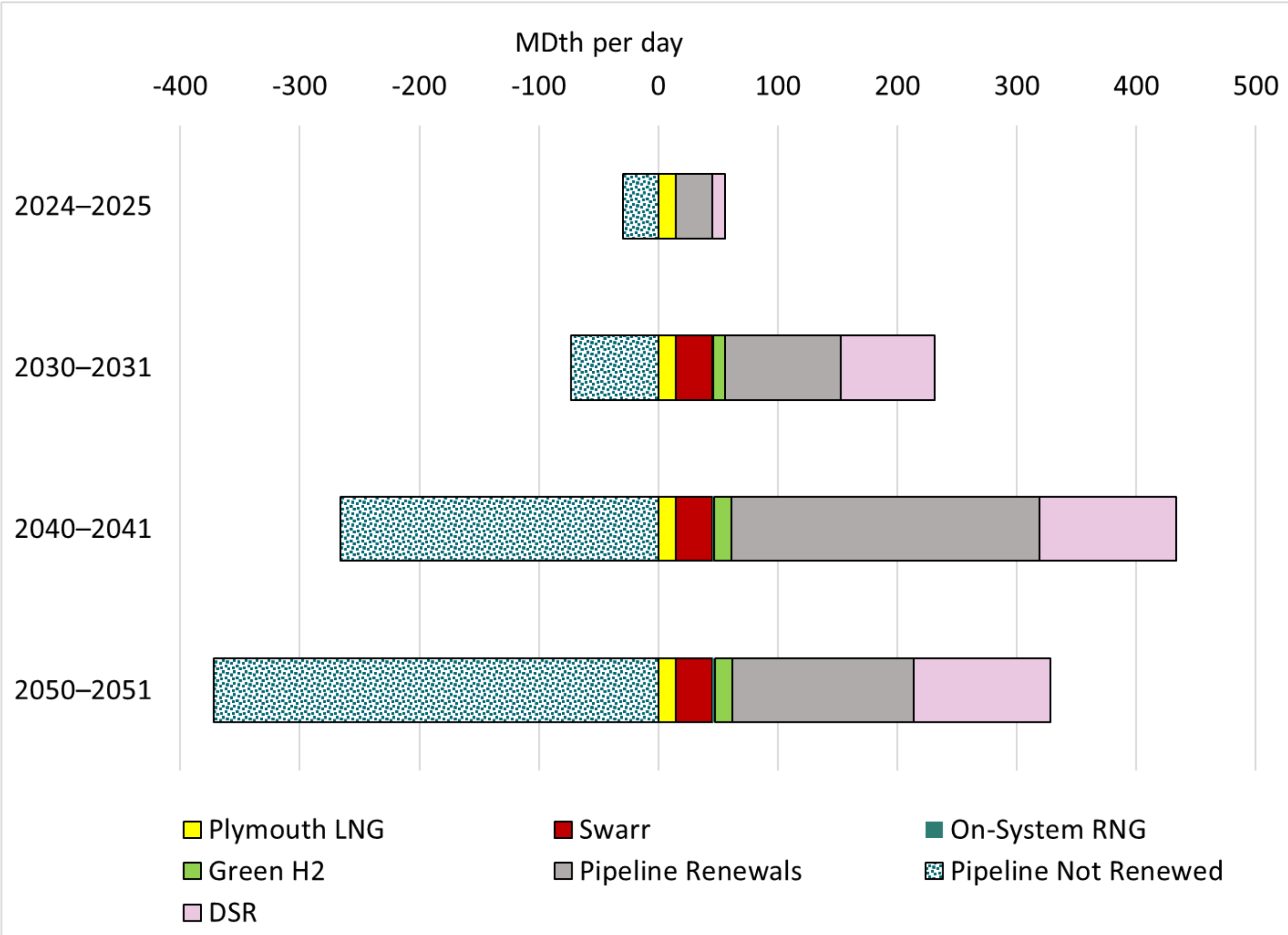
The gas analysis of this scenario assumes a Washington State Energy Strategy (WASES) as the physical emissions limit such that all electrification,[21] conservation, renewable fuels are maximized, and emissions minimized. We made any remaining load and emissions compliant with allowances purchased at a floor price.

We show the resource builds in Figure 6.15. In this scenario, we added pipeline capacity held by PSE beyond 2033 for renewal, and the gas model selected the renewals to rationalize the need. A significant portion of the pipeline capacity is not renewed by 2050. The peaking resources Swarr and Plymouth LNG are chosen in the reference scenario, while all the alternative fuels, RNG and green Hydrogen, are selected in the electrification scenario. Conservation is lower because the supply curve reflected the electrification and had a smaller achievable technical potential.

[20] We did not capture the additional costs to serve the energy and peak needs of the electric loads in the gas analysis, these are outputs of the electric portfolio analysis and discussed in the electric portion of the electrification analysis that follows.

[21] In the electrification scenario, it is not feasible to convert all the end uses in the commercial and industrial sectors. See Appendix E Conservation Potential Assessment for details of the electrification supply curve.

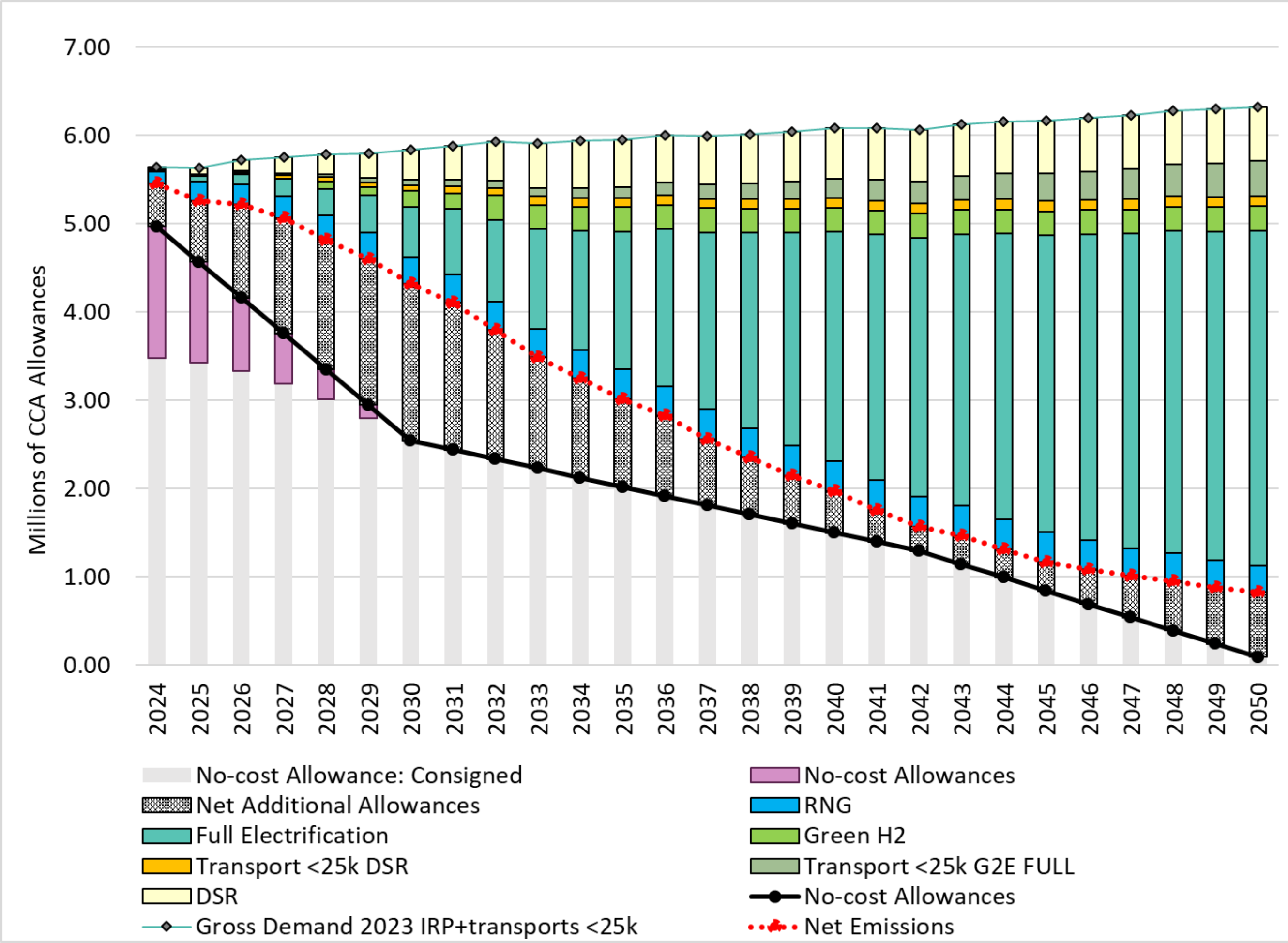
Figure 6.10: Electrification Scenario Portfolio Resource Additions — Peak Day



We show the emissions reductions related to the CCA-no-cost allowances in Figure 6.14. Since the Washington State Energy Strategy (WA SES) pathway is below the CCA no-cost allowance line, the no-cost allowances will cover the emissions between the WA SES and the CCA trajectory. The emissions above the no-cost allowance line and the physical emissions reduction are covered by net additional allowances purchased at the floor price. Electrification is the most significant contributor to emissions reductions, followed by conservation and alternate fuels.

Even with the electrification of the PSE system, the resulting emissions reductions will not be enough to bring emissions at or below the WA SES trajectory, and we will have to supplement them with net additional allowance purchases for CCA compliance.

Figure 6.11: Emissions Reduction Electrification Scenario



8.4.2. Electrification Scenario — Electric Results

For this report, PSE conducted two electrification scenarios to examine the impacts on the electric system of customers switching over from gas to electric. The two scenarios include a full electrification scenario where all end uses are electric, including electric heat pumps for residential space heating, and a hybrid heat pump case. This scenario is the same as the electrification, except the model assumed a dual-fuel hybrid heat pump served the residential space. For a complete discussion on assumptions and modeling parameters, see Chapter Four: Key Analytical Assumptions.

The electric portfolio results for electrification are the mirror image of the peak capacity, and load shed on the gas system. Hybrid Heat Pumps have a dual role as part of a decarbonization strategy by reducing gas usage and providing peak capacity backup to the electric system at lower temperatures. There is only a marginal difference in load between the electrification and HHP scenarios; however, the electrification scenario will require an additional 2,400 MW in peak capacity by 2045 compared to the HHP scenario. (See Figure 6.12 below.) The electrification scenario total portfolio cost with the social cost of greenhouse gases is \$24.71 billion, and the HPP scenario is \$23.43 billion resulting in a difference of \$1.28 billion. (See Table 6.7) These results indicate that the HHP strategy will be the more cost-effective for achieving significant decarbonization results.

Table 6.7: Net Present Value of the Portfolio Cost (Billions $)

Cost Item (Billions $)	Reference	Electrification	Hybrid Heat Pump
Portfolio Cost	$17.8	$20.23	$19.98
Social Cost of Greenhouse Gases	$3.31	$3.74	$3.84
Incremental T&D Cost	$0.00	$0.74	$0.18
Total	$21.11	$24.71	$23.43

As mentioned, both electrification cases increase the electric peak need, especially in later years. The electrification scenario requires 7,800 MW of peak capacity by 2045, almost a 3,000 MW increase from the reference portfolio. The HPP scenario requires a more modest 5,400 MW of peak capacity; increasing the peak capacity need only 500 MW from the electric reference portfolio. This result speaks to the effectiveness of the hybrid systems in relieving stress on the electric system during peak hours. Figure 6.12 illustrates the growing winter peak capacity needed over time because of the electrification cases.

Figure 6.12: Electrification Winter Peak Demand Impacts

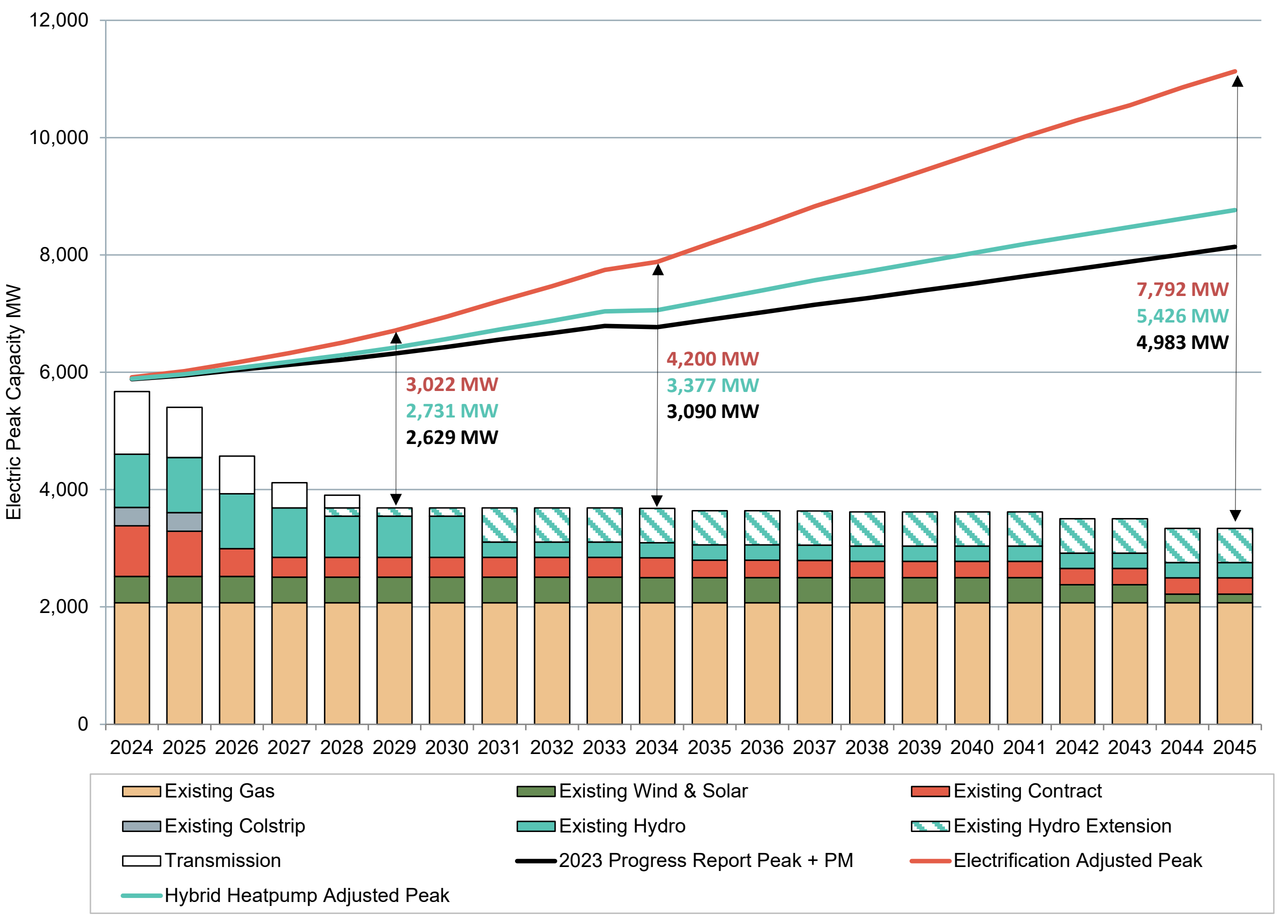
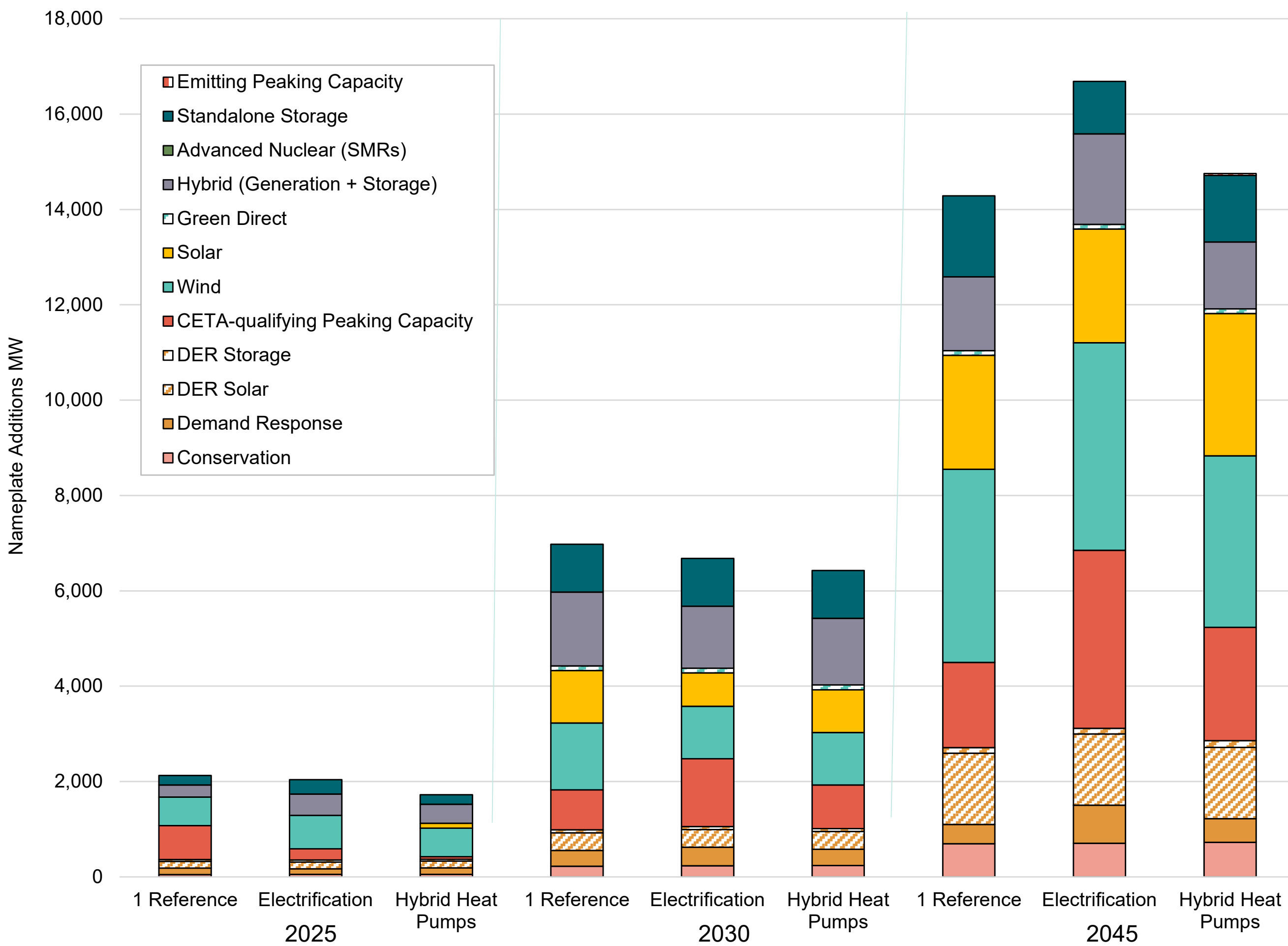


Figure 6.13 details the cumulative capacity added to the portfolios in 2025, 2030, and 2045 to meet the increasing peak need. The full electrification scenario builds almost 2,000 MW more CETA-qualifying peaking capacity by 2045, while

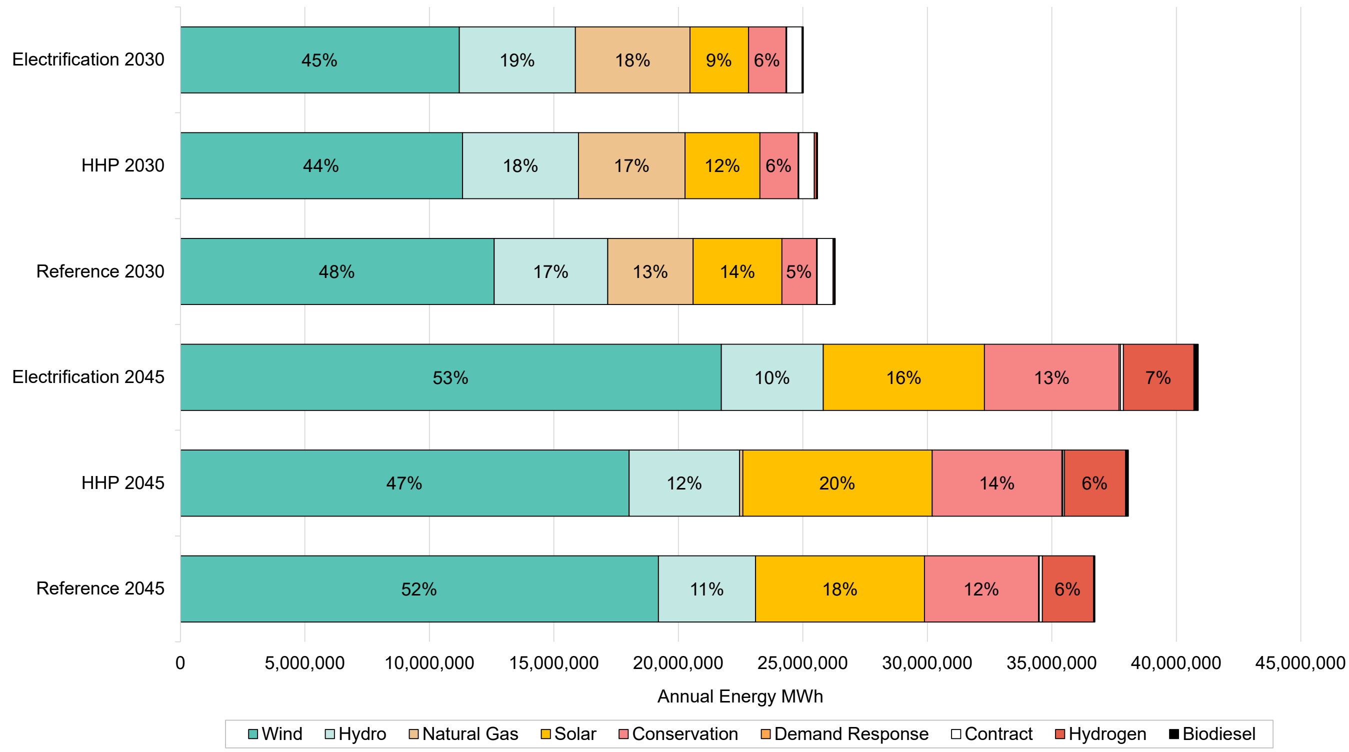
the HHP scenario results in nearly 600 MW more. The electrification and HHP scenarios build 600 and 300 MW less of standalone storage, respectively, slightly more demand response and less conservation by the end of the planning horizon, and both add more capacity overall than the reference case. There is limited resource movement in other categories, and it does not change by more than a couple of hundred megawatts in each direction by 2045.

Figure 6.13: Nameplate Resource Additions



There is minimal difference in load between the electrification scenario and the HHP policy scenario. The electrification scenario projected a 2045 load is 39.2 million MWh, while the HPP scenario projects 38.9 million MWh. For context, the demand for the reference case in 2045 is 32.4 million MWh. A 150 MW wind project could fill the load difference between the electrification and the HHP scenarios. Figure 6.19 details the energy contributions by fuel type in 2030 and 2045 among all three study cases, excluding unspecified market purchases and sales because the fuel source isn't traceable for those resources. The reference portfolio produces more energy in 2030 than both electrification scenarios, which is the opposite of the demand trend. This result is because the reference case is a net energy exporter in 2030, while both the HHP and electrification scenarios are net importers to meet customer demand. Moving to 2045, the energy production of the electrification and HHP scenarios easily surpass the reference case due to capacity added in 2031–2045. Figure 6.14 also reflects the higher renewable and non-emitting energy production required to meet the increased loads for the electrification and HHP scenarios.

Figure 6.14: Annual Energy Production



→ For more detailed data and information on the electrification scenarios, see Appendix F: Gas Methodology and Results.