GAS ANALYSIS

CHAPTER SIX

Contents

1. Introduction

More than 860,000 customers in Washington State depend on Puget Sound Energy (PSE) for safe, reliable, and affordable gas utility services. This chapter explains the gas analysis conducted for the 2023 Gas Utility Integrated Resource Plan (2023 Gas Utility IRP).

2. Resource Need

Puget Sound Energy's gas sales need is driven by peak day demand, which occurs in the winter when temperatures are lowest, and heating needs are highest. The current design standard ensures that we plan PSE supply to meet firm loads on a 13° design peak day, corresponding to a 52-heating degree day (HDD).[1] Two primary factors influence demand — peak day demand per customer and the number of customers. The heating season and the number of lowest-temperature days in the year remain relatively constant, and use per customer is growing slowly[2], so the most significant factor we currently utilize to determine peak load growth is the increase in customer count.[3]

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 IRP zero-growth demand forecast.[4] In both cases, we tested whether we needed to renew existing pipeline contracts.

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

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 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)[5], and the bars represent existing resources for delivering natural gas supply to our customers. These resources include contracts to transport natural gas on interstate pipelines from production fields, storage projects,

[1] Heating degree days (HDDs) are defined as 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.

[2] 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 for more detailed discussion of the demand forecast.

[3] The 2021 IRP demand forecast projects the addition of approximately 9,000 natural gas sales customers annually on average.

[4] 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.

[5] 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.

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

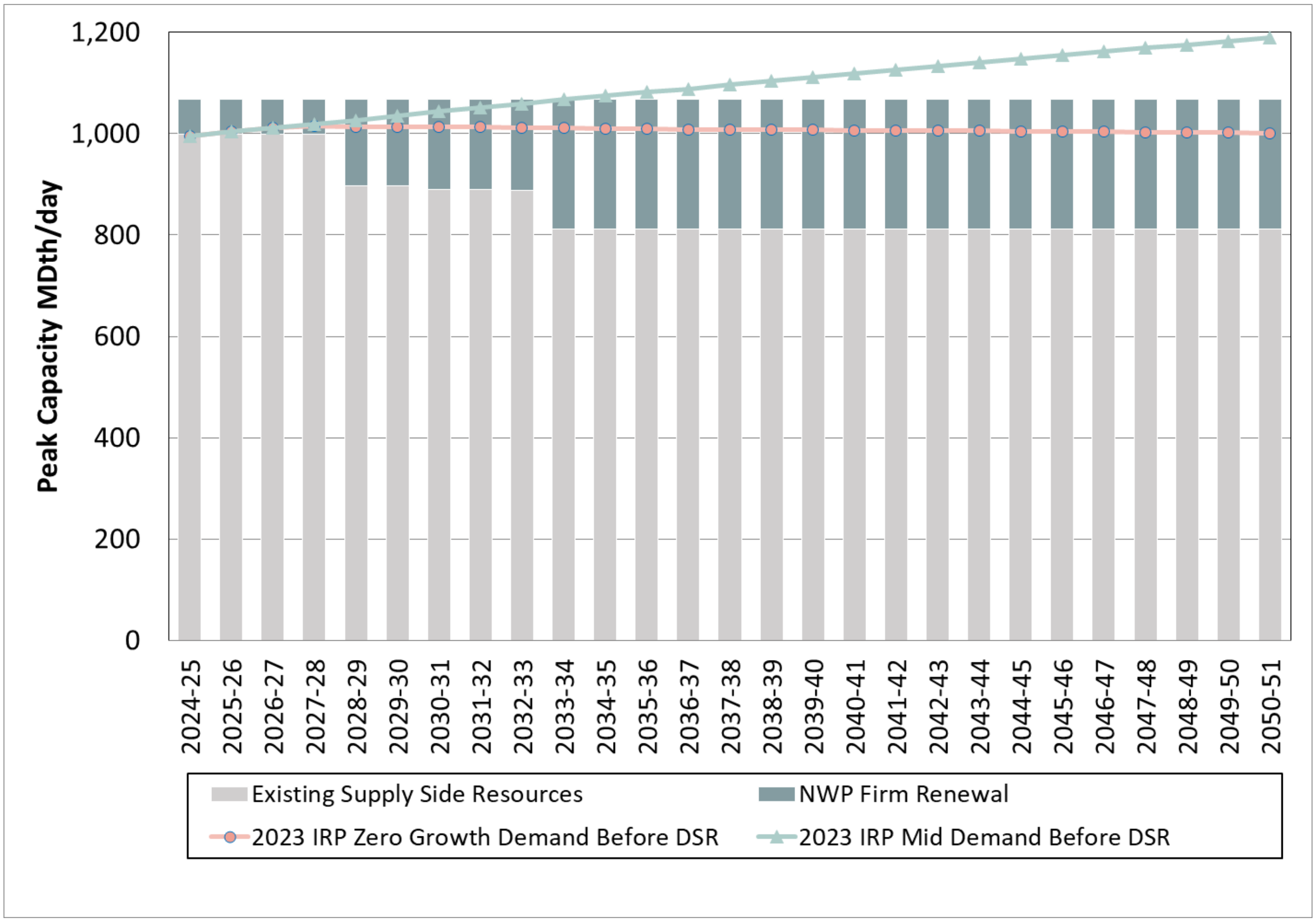
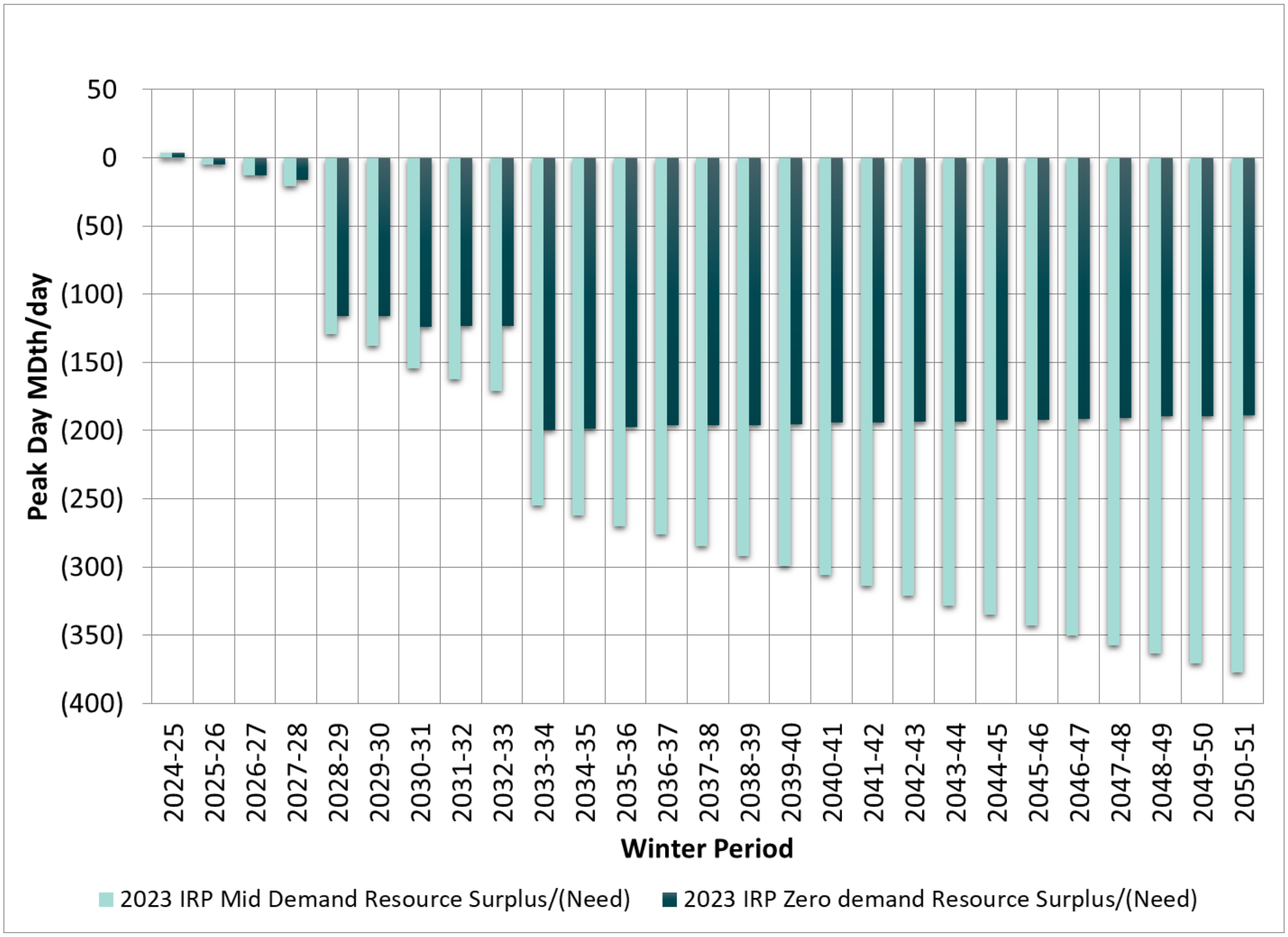


Figure 6.2: Gas Sales Peak Resource Need Surplus/Deficit
in Mid- and Zero-demand Forecast before Pipeline Renewals and DSR



3. Impacts on Portfolio Analysis

3.1. Climate Commitment Act

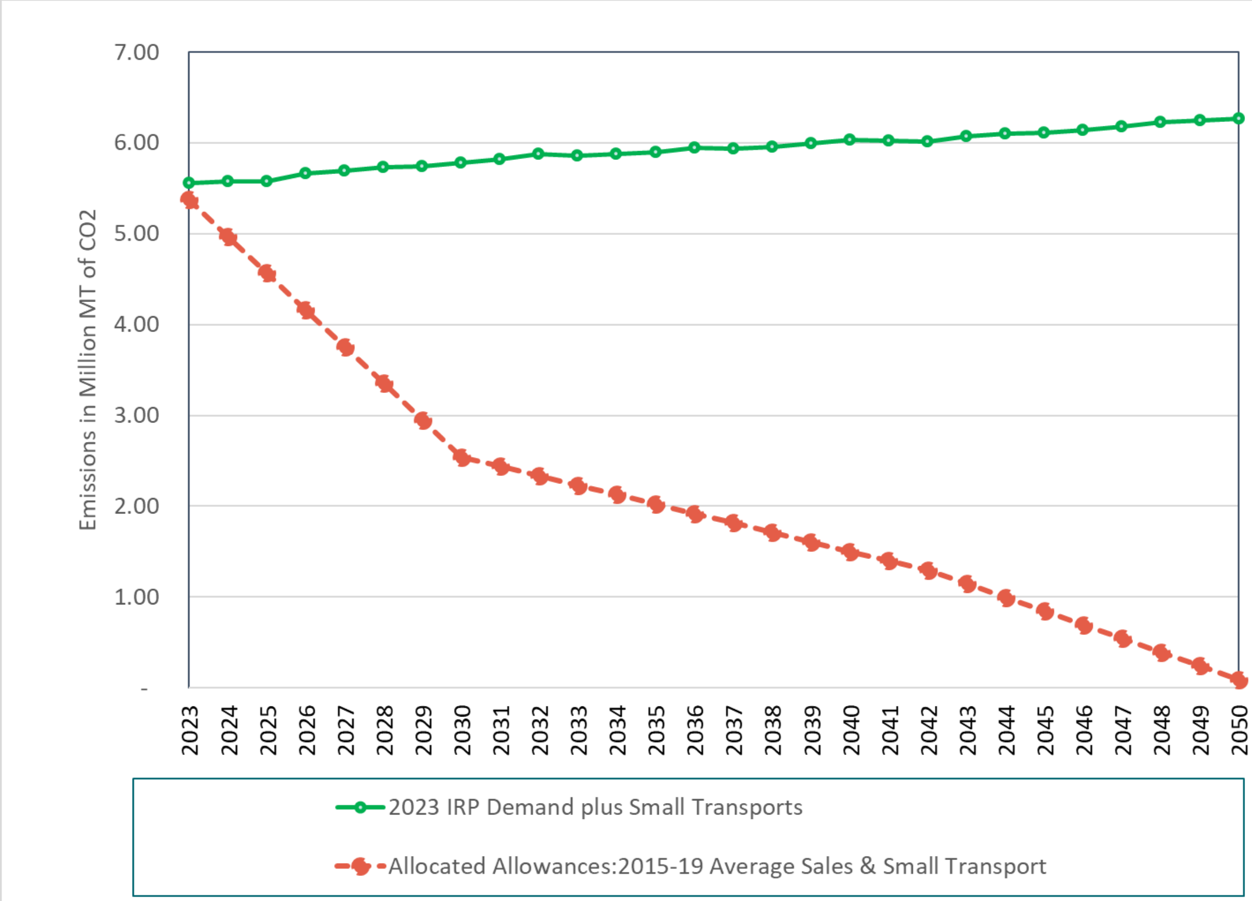
In 2021 the Washington State Legislature passed the Climate Commitment Act (CCA), which created a cap and invest program to reduce carbon dioxide emissions within specific sectors of the economy, including gas utilities. The program rules, developed by the Department of Ecology (Ecology), went into effect 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[6] allocation forecast. It uses the carbon allowance price forecasts to determine the cost of compliance in various scenarios and sensitivities described later in this chapter. We show the allocated allowances for PSE in Figure 6.3. We show allocated allowance data throughout this chapter to separate allocated allowances from paid allowances.

[6] Allowance is an authorization to emit up to one metric ton of carbon dioxide equivalent.

Figure 6.3: Gas Allocated Allowance Forecast (Department of Ecology, September 29, 2022)[7]



3.2. 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 Fortis BC and the British Columbia Utilities Commission (BCUC) relied on the pipeline for supply from the northeastern portion of 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

[7] The allocated 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 allocated allowances line.

growing concern over the availability of uncommitted gas at Sumas when Woodfibre starts up in 2027. The Westcoast pipeline and Northwest Pipeline have proposed expansions to their systems.

3.3. 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.

The objectives of energy delivery system planning are to:

- Anticipate and drive solutions that enable a future where new energy sources are renewable, and many are distributed.
- 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' unique 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 these objectives.

Meeting these needs and PSE's decarbonization goals requires a flexible planning framework, a modern energy delivery system, a focus on research, and continuous improvement. Delivery system planning (DSP) is the structured approach to analyze delivery system needs and potential solutions, prioritize the portfolio, and ensure that we create customer benefits and equity.

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

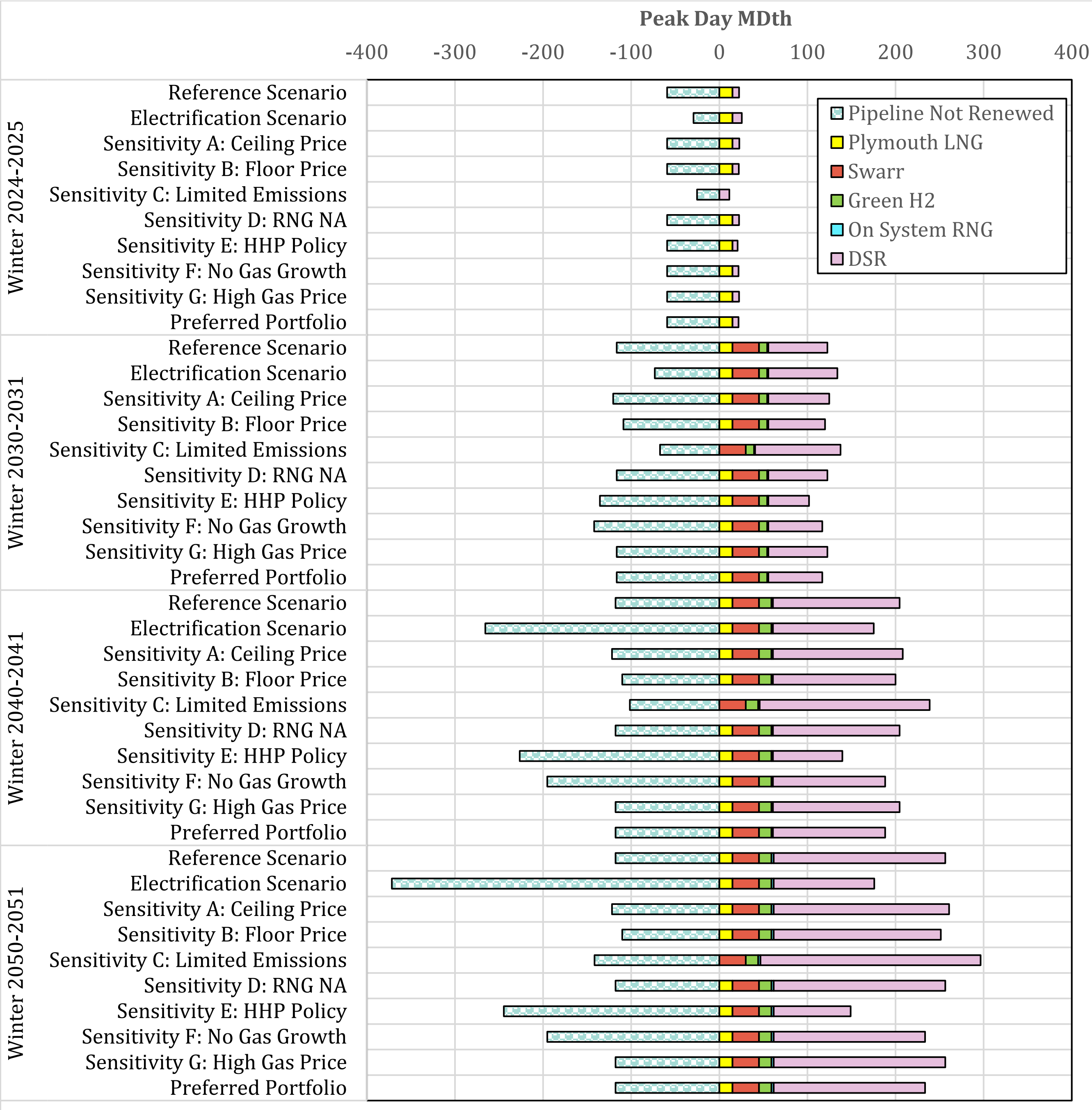
4. Gas Sales Analysis Results

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

4.1. 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 the scenarios and sensitivities where the emissions are not physically constrained to the allocated allowance line.
- Green hydrogen, with the benefits of production tax credits (PTCs) under the Inflation Reduction Act (IRA or Act) of 2022, is cost-effective in all scenarios and sensitivities.
- 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 carbon allowance price. Renewable Natural Gas (RNG) sourced from North America could triple the cost-effective amount in the price sensitivities with higher ceiling carbon allowance 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 IRP. The amount, or physical volume of cost-effective energy efficiency, is about the same as in the 2021 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 carbon allowance price. Carbon adders quadruple the total cost of the gas on the margin: SCGHG with upstream emissions and carbon allowances[8].

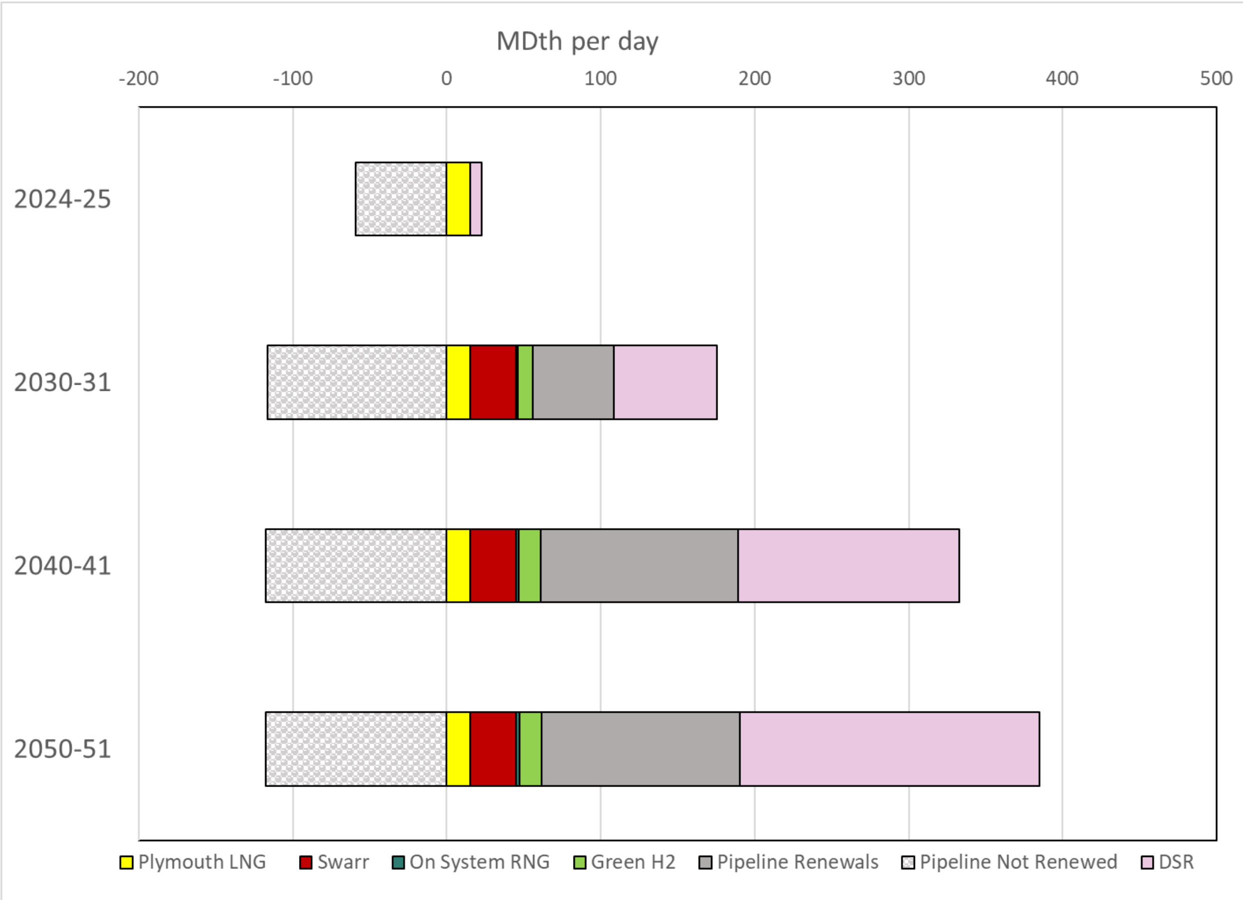
4.2. Reference Scenario

The reference scenario is the lesser constrained of the two, where we optimized inputs in the gas portfolio model. There were two 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 had an electrification component, any cost-effective capacity additions would demand that 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 no HHP was selected 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.

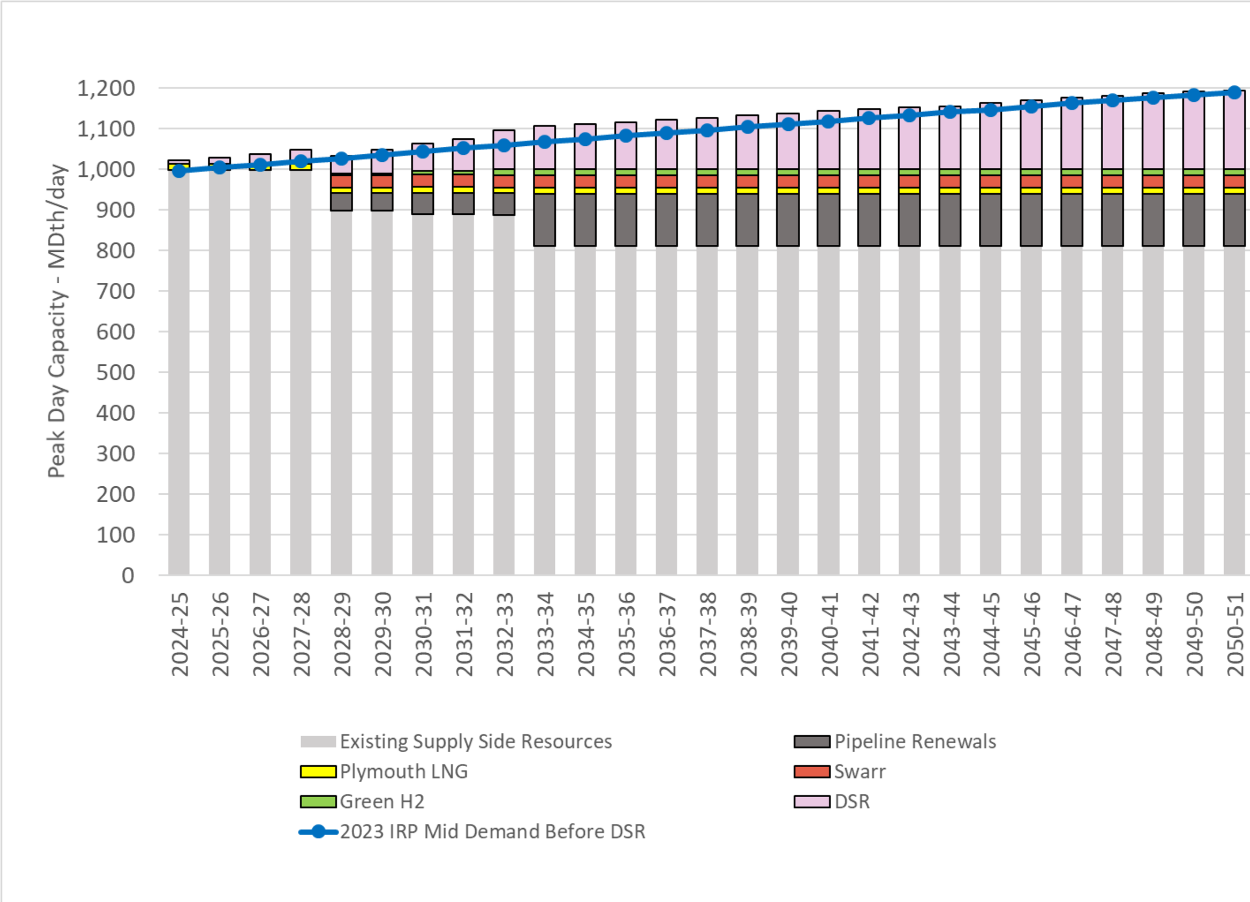
[8] The 20-year levelized cost of gas from Sumas is approximately $3.70. With the carbon adders, the total cost approaches $16.00. See Chapter Four for additional discussion on how we developed the gas costs used in the 2023 Gas Utility IRP analysis.

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, we did not renew some of the pipeline capacity. The other resource displacing the pipeline was the needle peakers, 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, which are 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 carbon 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, we selected only one of the contracts that had this characteristic.

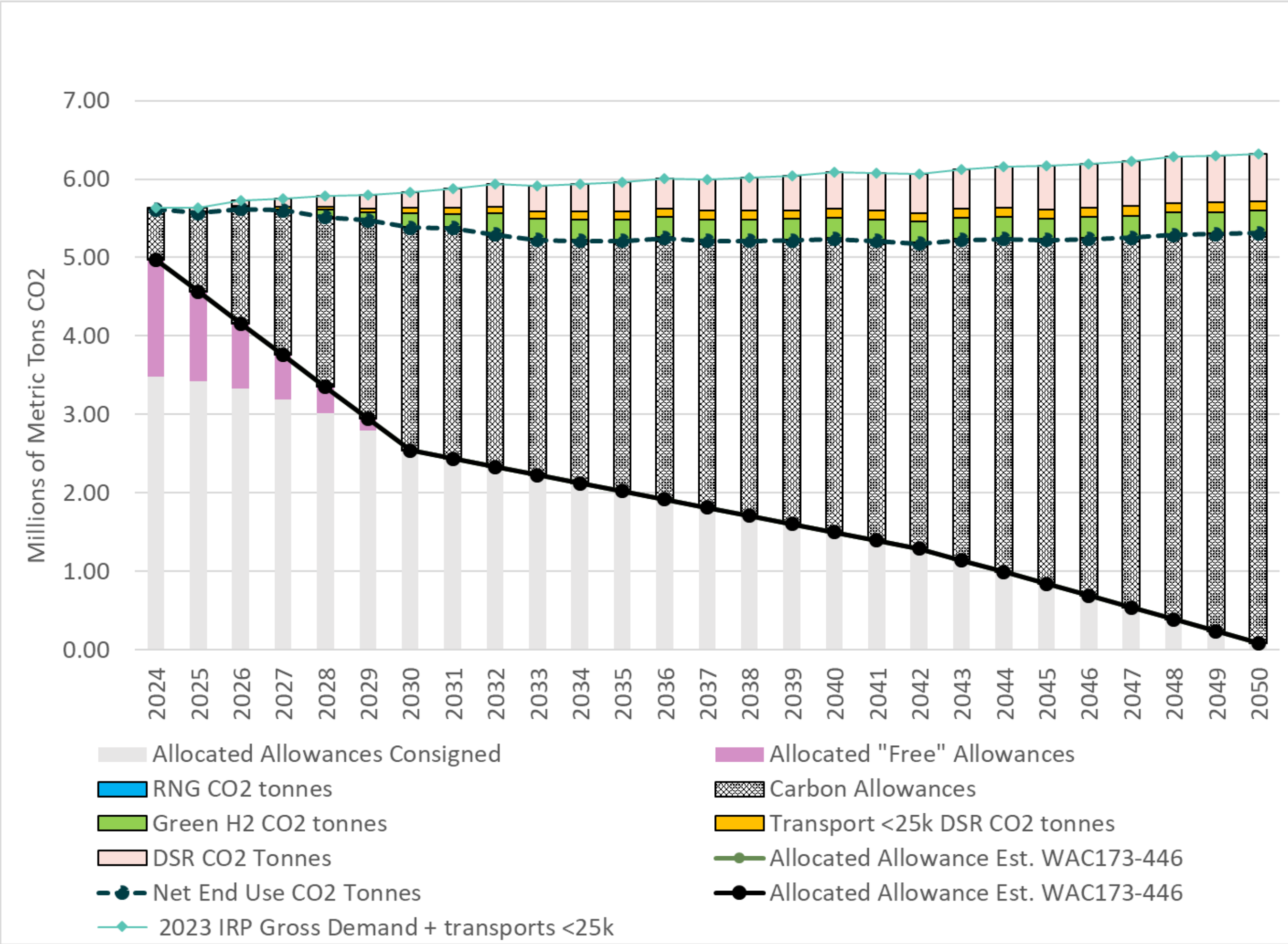
We selected green hydrogen, a resource aided by the PTCs offered through the IRA, in 2028, when it will be available, and all the subsequent additions in 2030 and 2032. The regional limitation in this report did not impact green hydrogen because we only considered a PSE system. This regional sourcing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

The gas system is long if we renew all the existing pipeline contracts, and the resource need gets pushed out. However, if we treat pipelines as a resource that competes with other options for renewal to determine the least cost option, only some of the pipeline capacity offered for renewal is renewed. The Rockies hub segment gives up most of the renewals offered. We replaced this pipeline capacity 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 under the CCA-allocated allowances in Figure 6.7. Energy efficiency[9] is the biggest contributor to emissions reductions, followed by green hydrogen and on-system RNG, which is too small to be visible on the chart. Purchased carbon 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 7 percent in 2030 compared to the emissions allowances in 2023, at the start of the first compliance period, and reduced by 10 percent in 2045. We achieve the balance through the purchase of carbon allowances.

[9] 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.

Figure 6.7: Emissions Reduction Reference Scenario



4.3. 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		Renewable Fuel		Typical Gas IRP Parameters	
		Carbon Constraint Parameter	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	Allocated 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

4.3.1. A — Carbon Allowance Price High

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

Baseline Assumption: We used the mid carbon allowance price.

Sensitivity: In the most recent draft rulemaking, we applied the ceiling allowance price as provided by the Department of Ecology (Ecology).

Portfolio Results:

- The high allowances price makes all the regional RNG we offered cost-effective, including on-system, delivered contracts, and a regional attribute 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 sensitivity shows that if we mid allowance prices to be high, acquiring RNG is a cost-effective way to reduce emissions toward the CCA goals.
- The higher allowance price also selected slightly more energy efficiency in the portfolio model. The peak contribution was higher by 4 MDth a day on peak day by 2050.

4.3.2. B — Carbon Allowance Price Low

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

Baseline Assumption: We applied the mid carbon allowance price.

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

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 a day in 2050.

4.3.3. C — Limiting emissions without regard to price

This sensitivity minimizes carbon emissions with the resource options in the gas model before it purchases above the allocated 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.

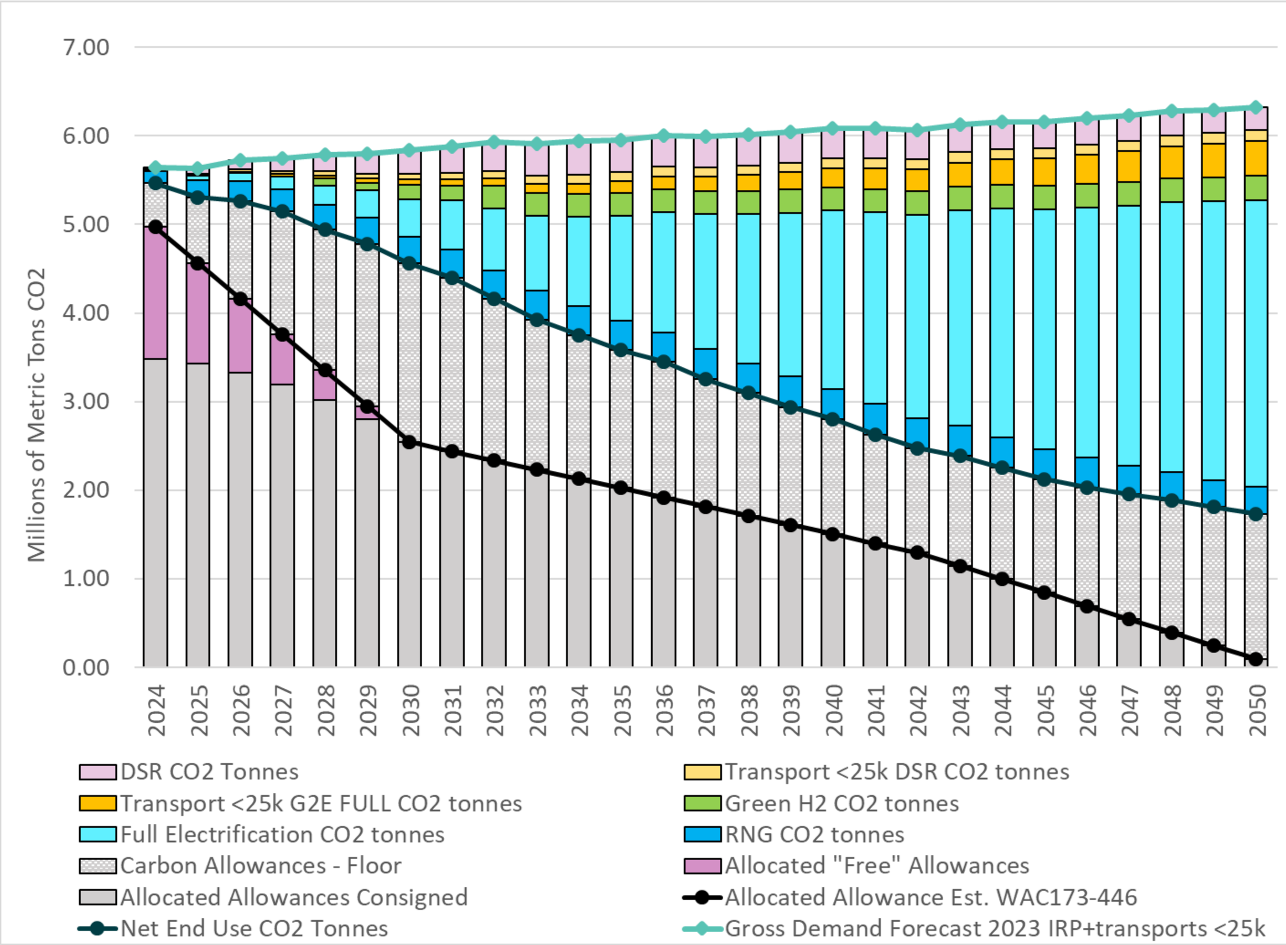
Baseline Assumption: We applied the mid carbon allowance price and allows for the purchase of allowances to meet compliance.

Sensitivity: We first forced the emissions to be minimized with the resource options and then balanced the remaining gap between the allocated allowances and the reduced emissions with the purchase of allowances at the floor price.

Portfolio results:

- The maximum amount of the alternate fuels is also selected and contributes to reducing emissions.
- The physical limit on emissions to the allocated 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 carbon allowances at the floor price.
- The portfolio selects all the energy efficiency and 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 greatest contributor to reducing emissions, see Figure 6.8.
- 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



4.3.4. D — Alternate Fuel Sourcing Not Limited to PNW

This sensitivity model removes the constraint of sourcing alternate renewable fuels from the PNW to include North America; this applies to RNG and green hydrogen.

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

Sensitivity: In this sensitivity, alternate fuels are limited to a supply curve representing the availability and prices within the PNW.

Portfolio results:

- The green hydrogen is unchanged from the reference scenario as we considered no source outside WA in the 2023 Gas Utility IRP.
- The portfolio selected 12,000 MDth per year or 38 Mdth per day of RNG attributes sourced from outside the PNW starting in 2040 paired with Sumas gas.

- This results in a savings in NPV of $93 Million in 2024 dollars over the reference scenario, where RNG is restricted to regional sourcing.

4.3.5. 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 will be electrified.

Baseline Assumption: The portfolio model chooses the cost-effective amount of the hybrid heat pumps 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 only pipeline renewals before 2033.

Sensitivity: The portfolio model forces replacement of residential gas furnaces with hybrid heat pumps and electrification for other end uses. We also electrified the commercial and industrial sectors where feasible (see the Gas DSR report in Appendix E for more details). The reference scenario's conservation supply curve is modified to reflect the diminishing gas loads. We extended the pipeline renewals beyond 2033 as the load will decline significantly.

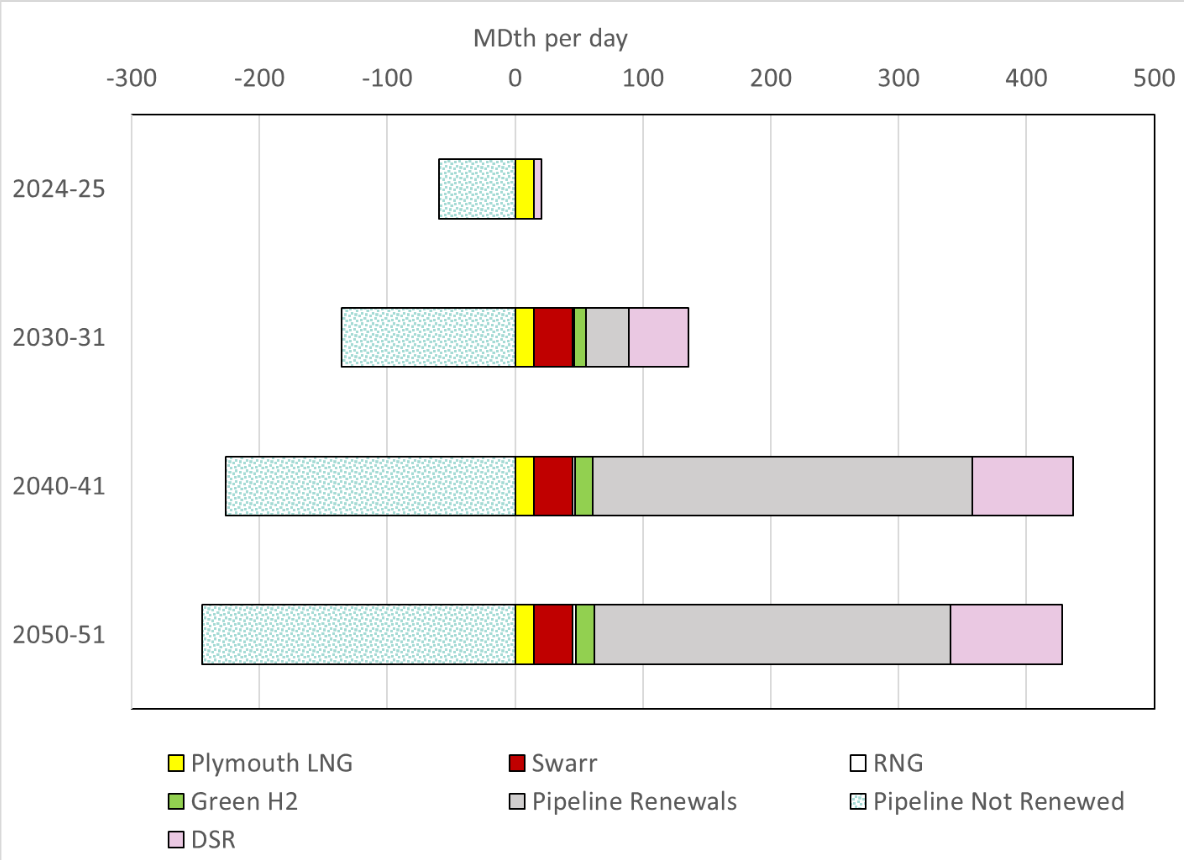
Portfolio results:

- The conservation supply curve has lower potential savings than in the reference scenario, as the balance between declining load and cost-effective results in the cost point being slightly lower than in the reference scenario.
- Pipeline renewals are lower in the years after 2033 than the reference scenario[10], 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 pumps designed to run on gas when the outdoor temperature drops below 35F[11]. Figure 6.9 shows the resource builds.

[10] In the reference scenario, we assumed all existing pipeline capacity beyond 2033 will be renewed and so 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.

[11] 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's 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



4.3.6. 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: Use 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.

4.3.7. 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.

4.4. Preferred Portfolio

The preferred portfolio is created from the gas analysis after we run all the scenarios and sensitivities and a complete picture of the portfolios under varying conditions starts to emerge. The preferred portfolio is a subjective exercise in trying to thread a needle through the policy and economic landscapes to develop a portfolio that will best meet the policy objectives while also trying to minimize portfolio cost and risk.

We based the preferred portfolio on the reference scenario with the following changes: high ceiling allowance price and the conservation targets for the zero-growth gas demand.[12] There are two reasons we incorporated these changes in the preferred portfolio:

1. Demand for allowances will likely exceed supply. The results of the gas portfolio modeling show that the least-cost portfolio is one in which we meet compliance with the CCA by purchasing allowances. We expect demand for the allowances will be high as regional local distribution companies (LDCs) and Emissions Intensive Trade Exposed (EITE) entities look to meet their emissions compliance obligations. This competition for allowances leads to a bias that they will be issued at the ceiling price.

2. Demand for gas will slow. Building code changes and legislative focus on reducing fossil fuel emissions will likely restrict gas use growth. To account for this unknown impact, we used the conservation targets from sensitivity F, zero-growth, described later in this chapter, to create the preferred portfolio.

The portfolio with a ceiling price and zero-growth demand conservation chooses the lower amount of energy efficiency. More regional renewable natural gas (RNG) is cost-effective over the reference scenario.

[12] See Chapter Four for a discussion of the reference scenario.

Figure 6.10: Preferred Portfolio Resource Additions — Peak Day

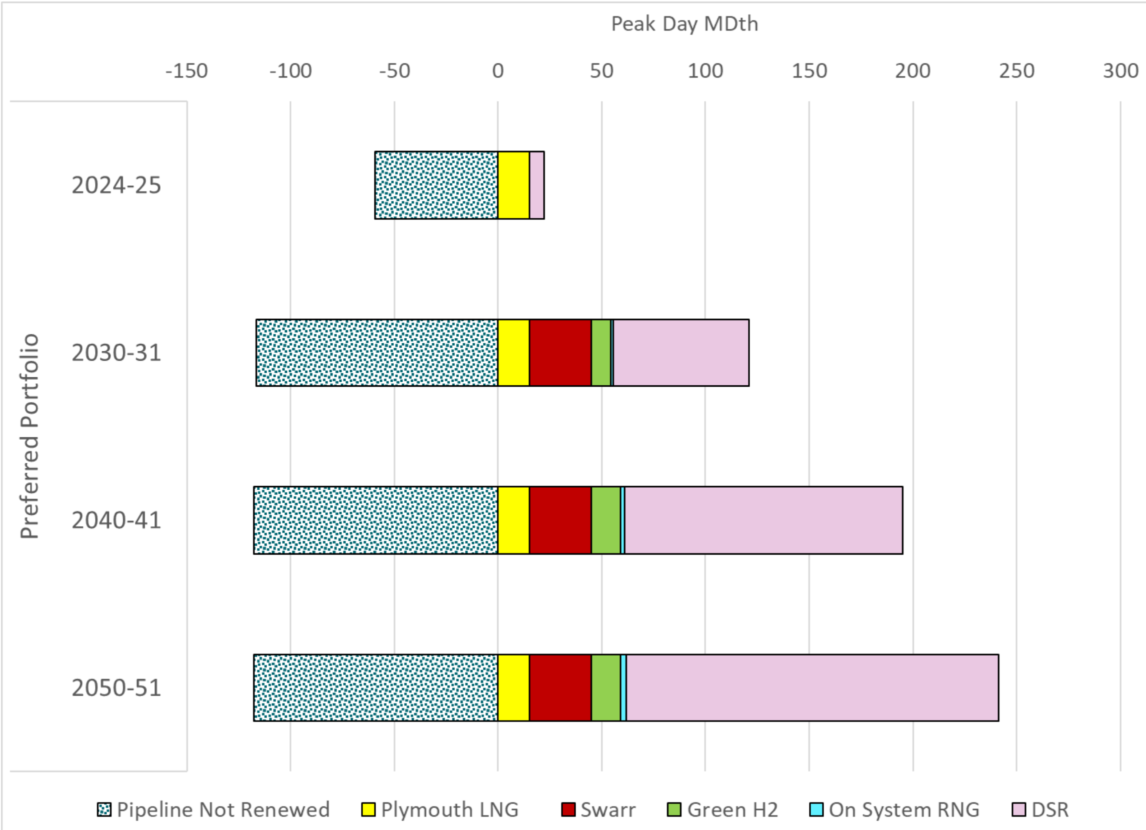


Figure 6.10 shows the resource additions for the Preferred Portfolio and Table 6.2 below shows the resource additions in a tabular format.

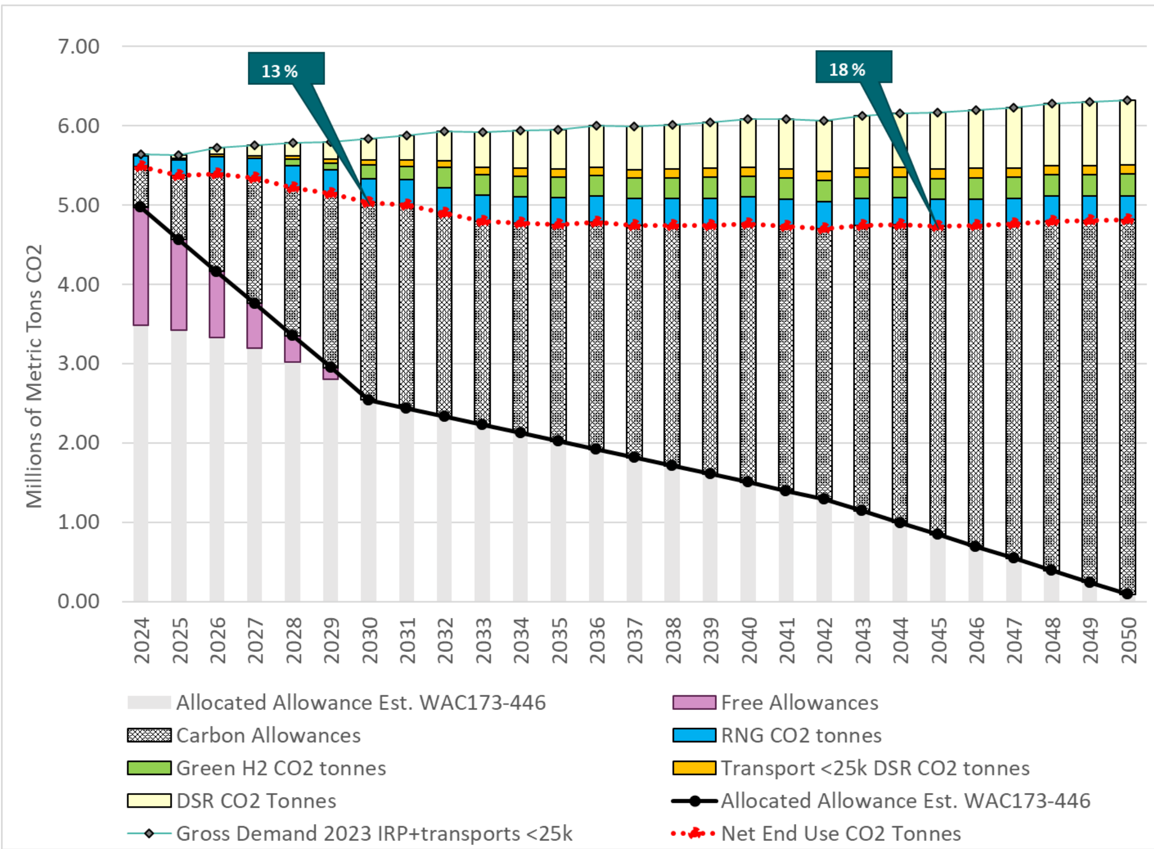
Table 6.2: Resource Additions by Type and Period (MDth/Day)

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	-120	-122	-122
RNG PNW Regional	3	9	11	10
RNG On-system	0	1	2	2
Green H2 — Gas Blending	0	9	14	14
Net Supply Resources	**-44**	**-65**	**-61**	**-60**

4.4.1. Emissions Reduction Potential

We included several resource alternatives in the portfolio analysis that would reduce emissions: energy efficiency, hybrid heat pumps, regional RNG, and green hydrogen. The gas portfolio model chose from these resources such that the resulting cost of the portfolio is less than the cost without these resources. Figure 6.11 shows the results. Figure 6.6 shows the forecasted emissions path under the CCA

Figure 6.11: Emissions Reduction in the Preferred Portfolio to CCA Allocated Allowances



The preferred portfolio will reduce emissions by 13 percent by 2030 from the emissions allocated at the start of the first compliance period in 2023 and by 18 percent reduction by 2045.

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[13]: green hydrogen, has a practical upper limit of around 15-20% for blending into the gas system by volume without significant infrastructure changes. The one exception is RNG, while it is also a relatively scarce resource, we restricted this resource even further to sourcing it from the Pacific Northwest. However, if RNG is unrestricted and we can source it from North America, it would provide additional cost-effective emissions reductions in the preferred portfolio. See Figure 6.12.

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

Figure 6.12: Additional RNG Available when Sourced Nationally - Sensitivity D

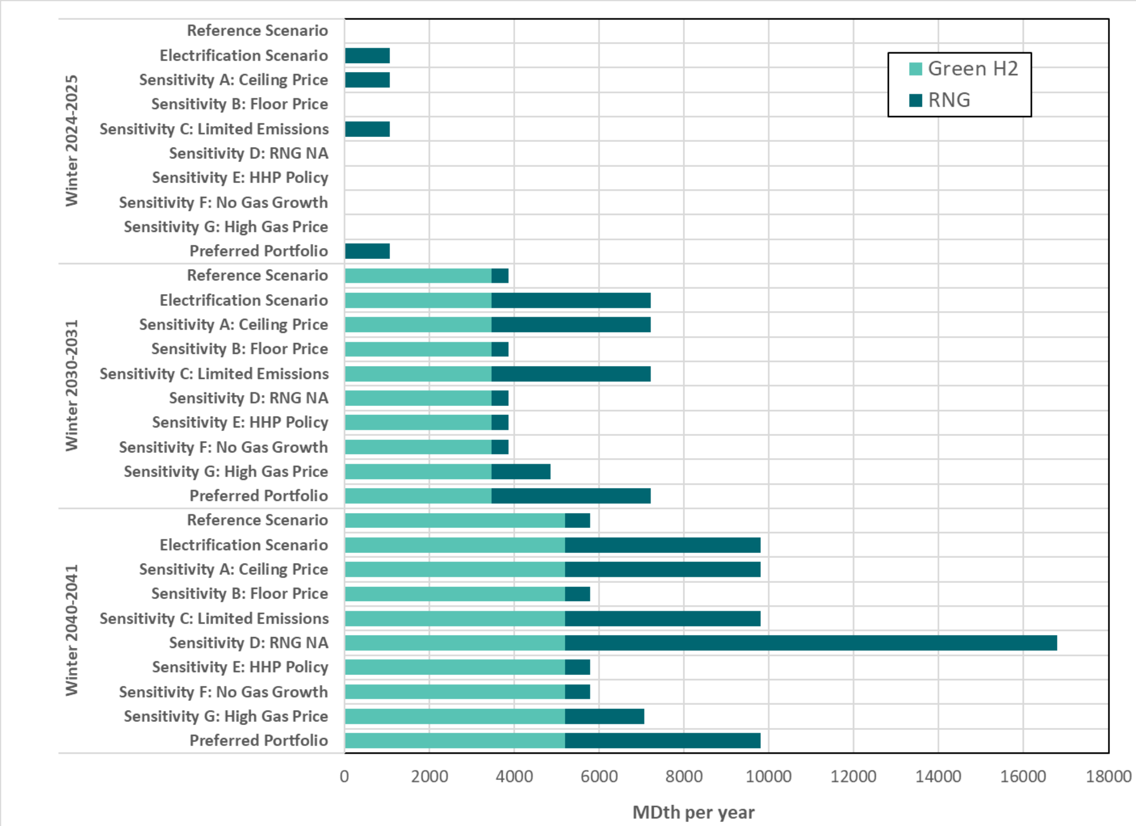


Table 6.3: Emissions Reduction in Metric Tons - Regional RNG vs. Nationally Sourced RNG (Scenario One vs. Sensitivity D)

Category	Emissions Reductions	Emissions Reductions
Geographic Footprint	2030	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.

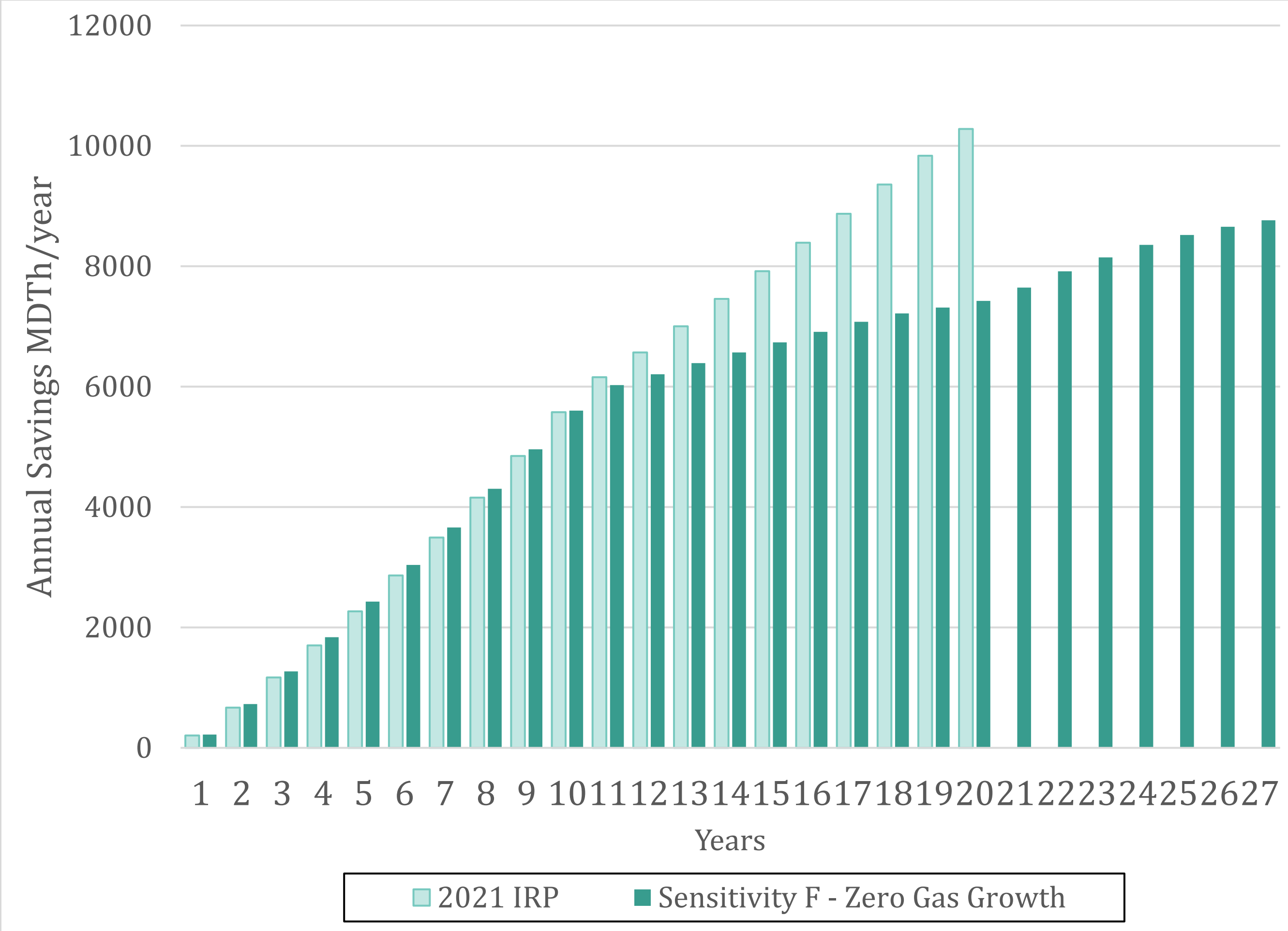
4.4.2. Cost-effective Energy Efficiency

Energy efficiency is one of the best options for reducing portfolio costs, risks, and emissions because more efficient behavior and equipment have a direct impact on cutting emissions. Because of the higher cost of gas that includes carbon adders, such as the social costs of greenhouse gases (SCGHG) with upstream emissions and carbon allowances, more energy efficiency is cost-effective. And more expensive energy efficiency is more cost-effective than in previous PSE IRPs. Table 6.4 shows details of the price on the supply curve and volume of energy efficiency that is cost-effective in the 2023 and 2021 preferred portfolios.

Table 6.4: Cost-effective Bundles in the 2023 IRP Compared to the 2021 IRP

Sector	Year	Bundle	Price Range, $/Th
Residential Firm	2023	13	$1.75 to $2.00
Commercial Firm	2023	13	$1.75 to $2.00
Commercial Interruptible	2023	0	NA
Industrial Firm	2023	10	$0.95 to $1.20
Industrial Interruptible	2023	10	$0.95 to $1.20
Residential Firm	2021	9	$0.85 to $0.95
Commercial Firm	2021	9	$0.85 to $0.95
Commercial Interruptible	2021	6	$0.55 to $0.62
Industrial Firm	2021	9	$0.85 to $0.95
Industrial Interruptible	2021	9	$0.85 to $0.95

Figure 6.13: Cost-effective Energy Efficiency — Annual Savings at the Source, Intra-year Ramped



4.4.3. Non-renewed Transmission Pipeline Capacity

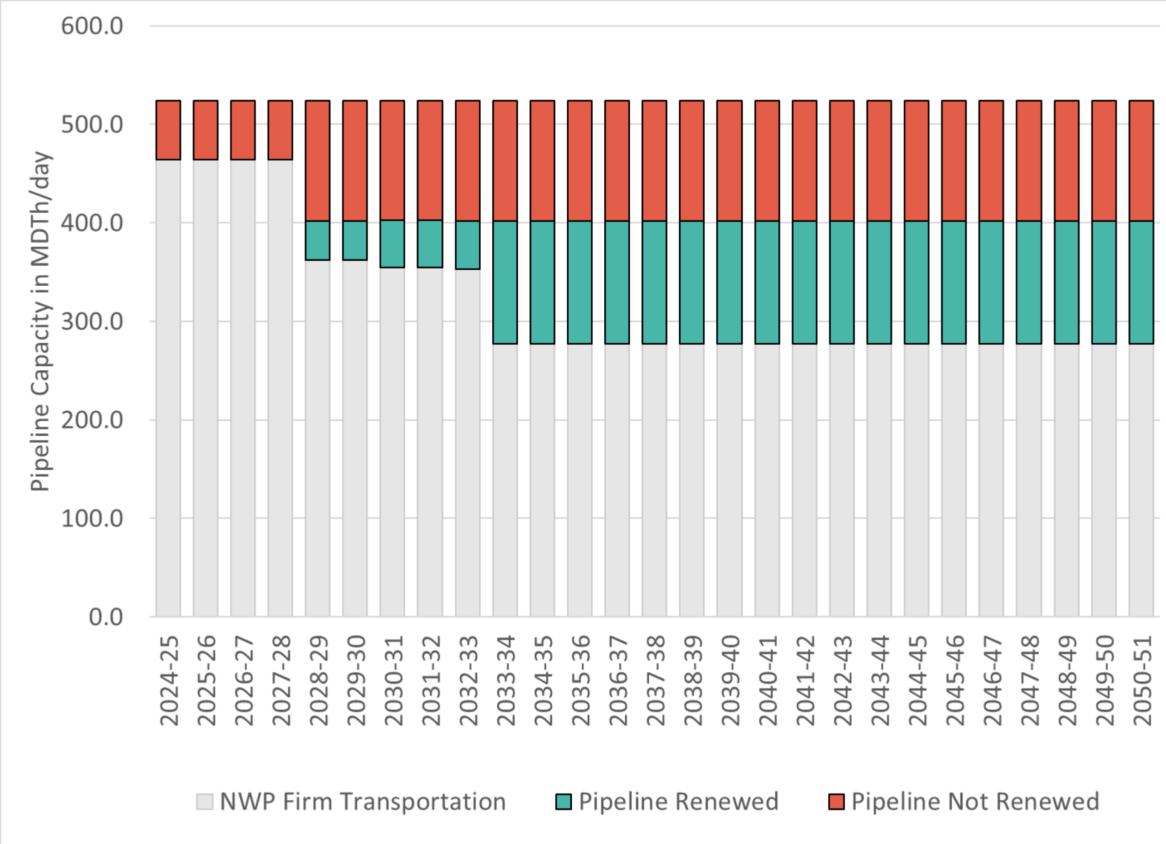
In a departure from prior IRPs, where we assumed existing pipeline capacity would be renewed annually, in the 2023 Gas Utility IRP, the annual renewal was a resource alternative so renewals could compete with other supply and demand-side resources. We bundled multiple pipeline contracts to specific periods 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 renewal.[14] [15] [16]

[14] 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.

[15] 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.

[16] 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 IRP.

Figure 6.14: Transmission Pipeline Capacity Not Renewed in the Preferred Portfolio



4.5. 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 electric, whereas only 70 percent of the end uses in the commercial sector and 30 percent in the industrial sector are feasible to convert to electric18. The end use conversions are treated as a must take or policy case where the gas equipment is mandated to be changed to electric at the end of its life.

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

[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.

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 not suitable 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 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 included the transmission and distribution (T&D) costs associated with the electrification as part of the gas forecasts. 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. On the benefits side were the gas savings and non-energy impacts. We detailed these costs in the CPA and summarized them in Table 6.5.

Table 6.5: Electrification Levelized Costs in the Gas Analysis[19]

Included Costs	Benefits Netted Out
PV 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

4.5.1. Electrification Scenario — Gas Results

The following assumptions were input into the gas portfolio model that generated the results that follow:

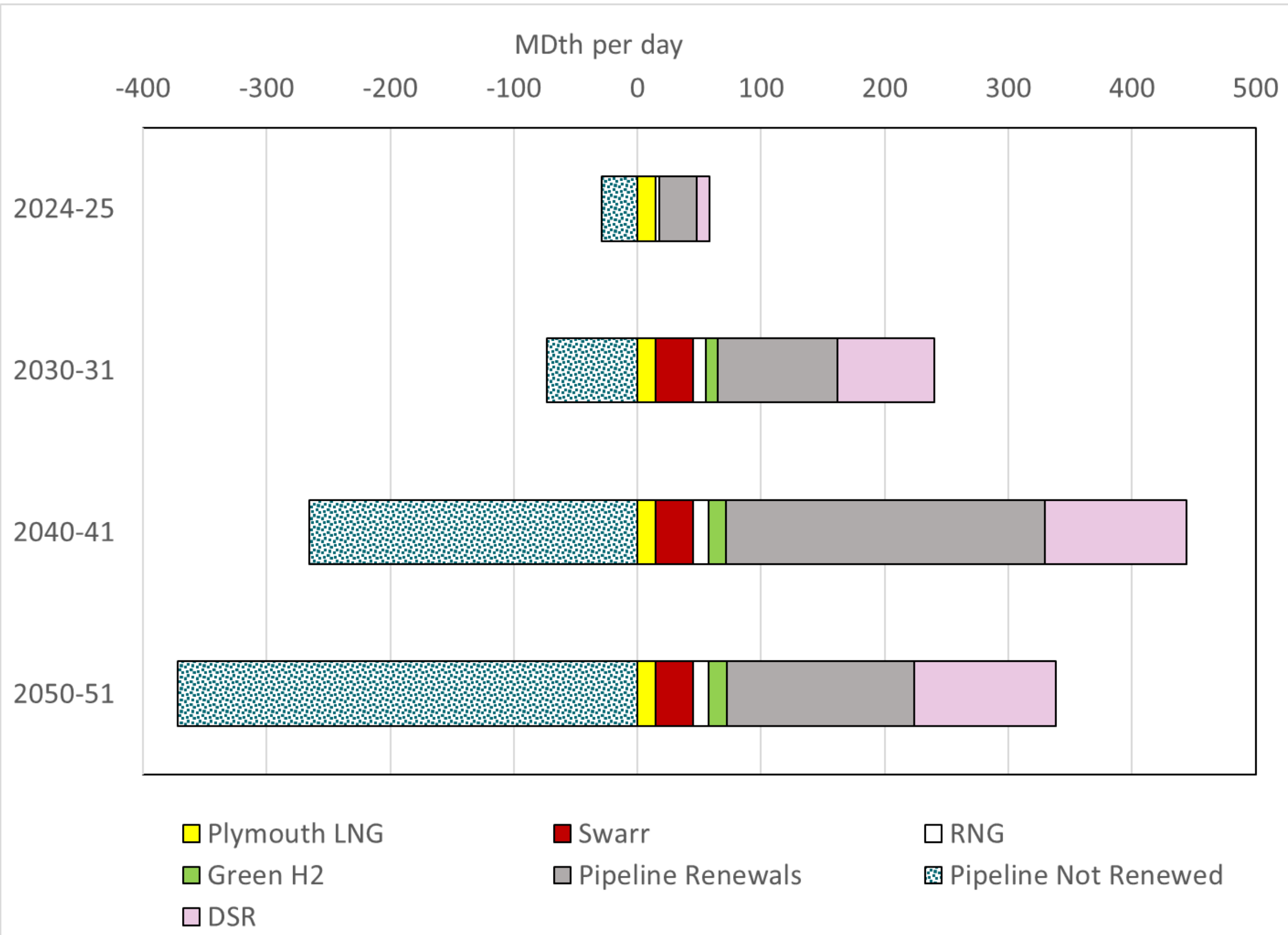
Scenario #	Scenario Name	CCA				Typical Gas IRP Parameters		
		Carbon Constraint Parameter	Allowance Price	Renewable Fuel Source Location	Heating Load Shift	Demand	Gas Growth?	Gas Price
2	Electrification - State Energy Strategy (SES)	Follow SES line	Floor	PNW	Force in Cadmus Electrification Results	Mid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

[19] 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.

The gas analysis of this scenario assumes a Washington State Energy Strategy (WASES) as the physical emissions limit such that all electrification[20], conservation, and renewable fuels are maximized, emissions are minimized, and 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 selected as 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.

Figure 6.15: Electrification Scenario Portfolio Resource Additions – Peak Day.



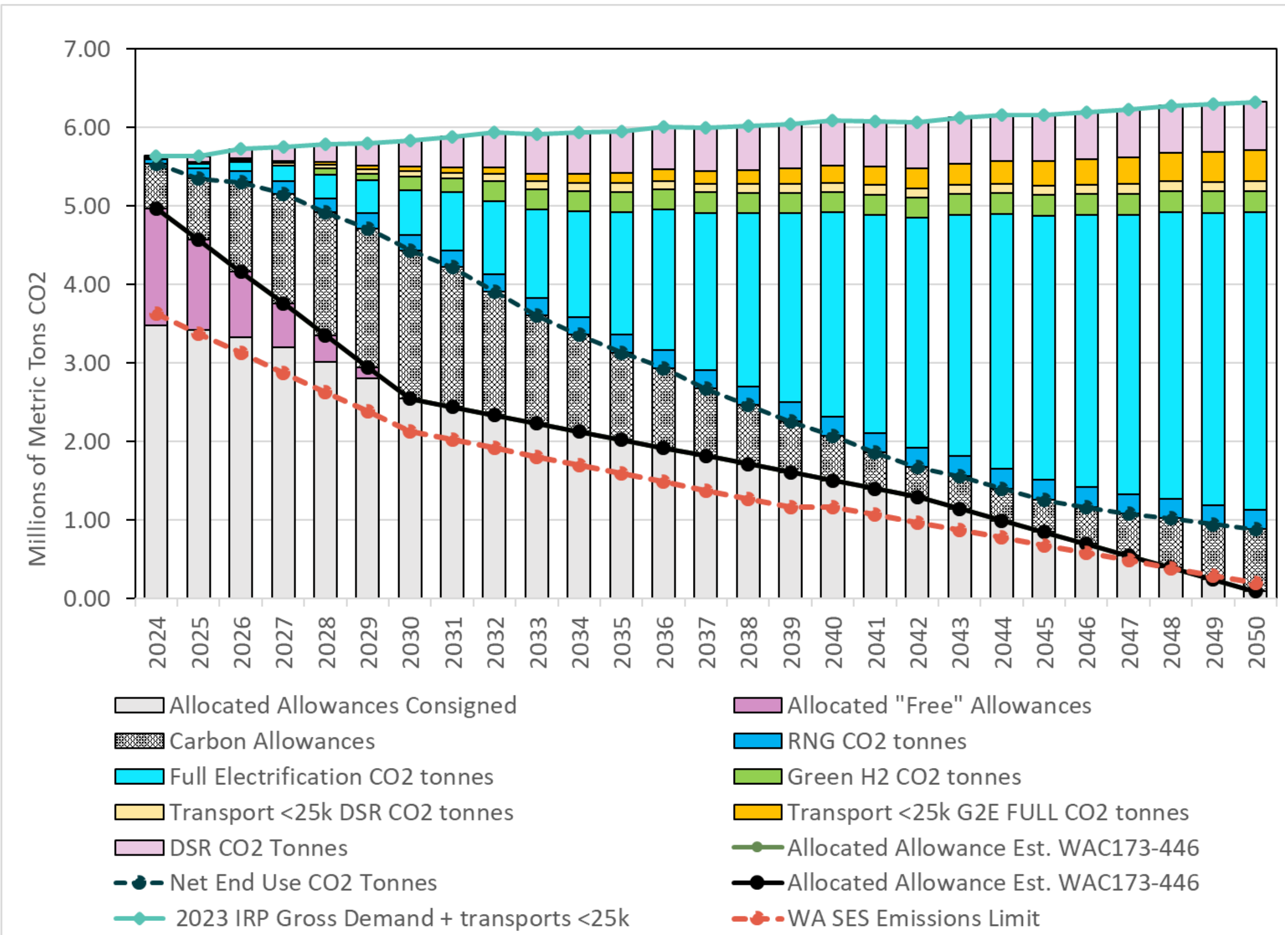
We show the emissions reductions related to the CCA-allocated allowances in Figure 6.14. Since the Washington State Energy Strategies (WA SES) pathway is below the CCA allocated allowance line, the allocated allowances will cover

[20] In the electrification scenario, not all the end uses in the commercial and industrial sectors are feasible for conversion. See Appendix E Conservation Potential Assessment for details of the electrification supply curve.

the emissions between the WA SES and CCA trajectory. The emissions above the allocated allowance line and the physical emissions reduction are covered by allowances purchased at the floor price. A lack of surprise electrification is the biggest contributor to emissions reductions, followed by conservation and alternate fuels.

Even with the electrification of the PSE system, the emissions reductions will not be enough to bring emissions at or below the WA SES trajectory and need to be supplemented with allowance purchases.

Figure 6.16: Emissions Reduction Electrification Scenario



4.5.2. Electrification Scenario — Electric Results

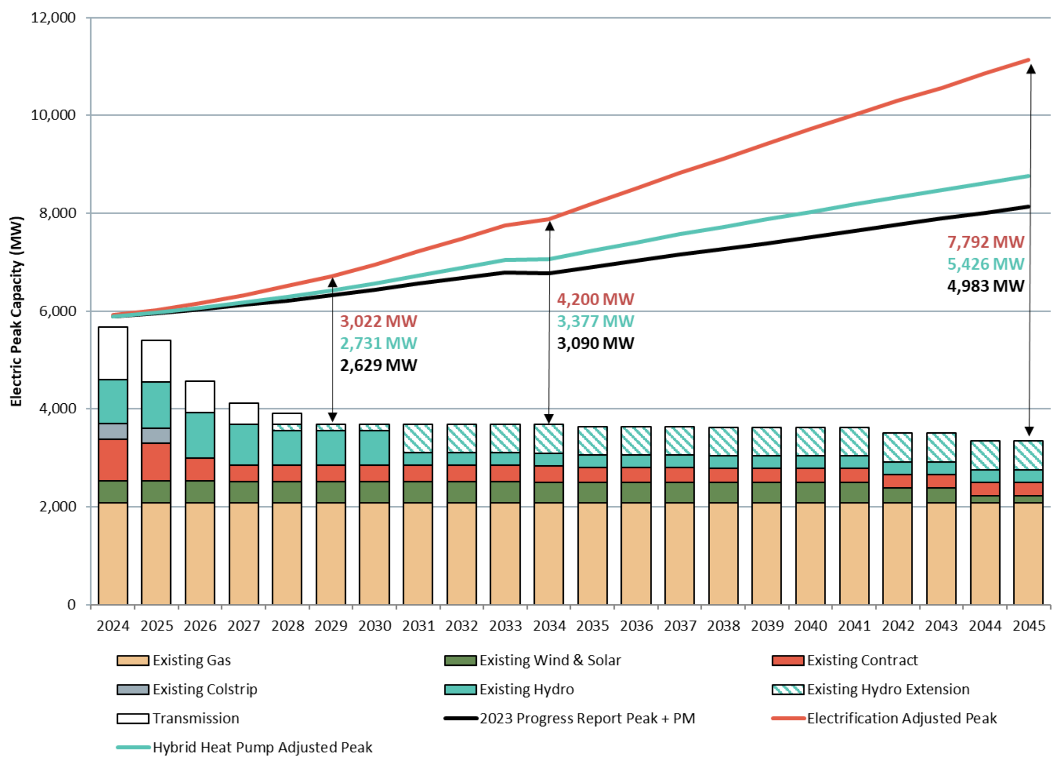
The electric portfolio results for electrification are the mirror image of the peak capacity and load that is being shed on the gas system. HHP has a dual role in decarbonization strategy by reducing gas usage but also provides peak capacity back up to electric system at lower temperatures. There is marginal difference in load between the Electrification and the HHP scenario. However, the Electrification scenario will require an additional 2400 MW in peak capacity as compared to the HHP scenario. (See Figure 6.17 below) The Electrification scenario total portfolio NPV cost with the Social Cost of Carbon is $24.71 billion and the HPP scenario is $23.43 billion resulting in a difference of $1.28 billion. (See Table 6.6) It seems that the HHP strategy will be the more cost-effective way to achieve significant decarbonization results. See below for details of the analytical results of the gas decarbonization strategy on the electric portfolio.

Table 6.6: Net Present Value of the Portfolio Cost

Revenue Requirement			
Cost Item	**Reference**	**Electrification**	**Hybrid Heat Pump**
Portfolio Cost	$17.80	$20.23	$19.38
Social Cost of Carbon	$3.31	$3.74	$3.87
Incremental T&D Cost	$0.00	$0.74	$0.18
Total	**$21.11**	**$24.71**	**$23.43**

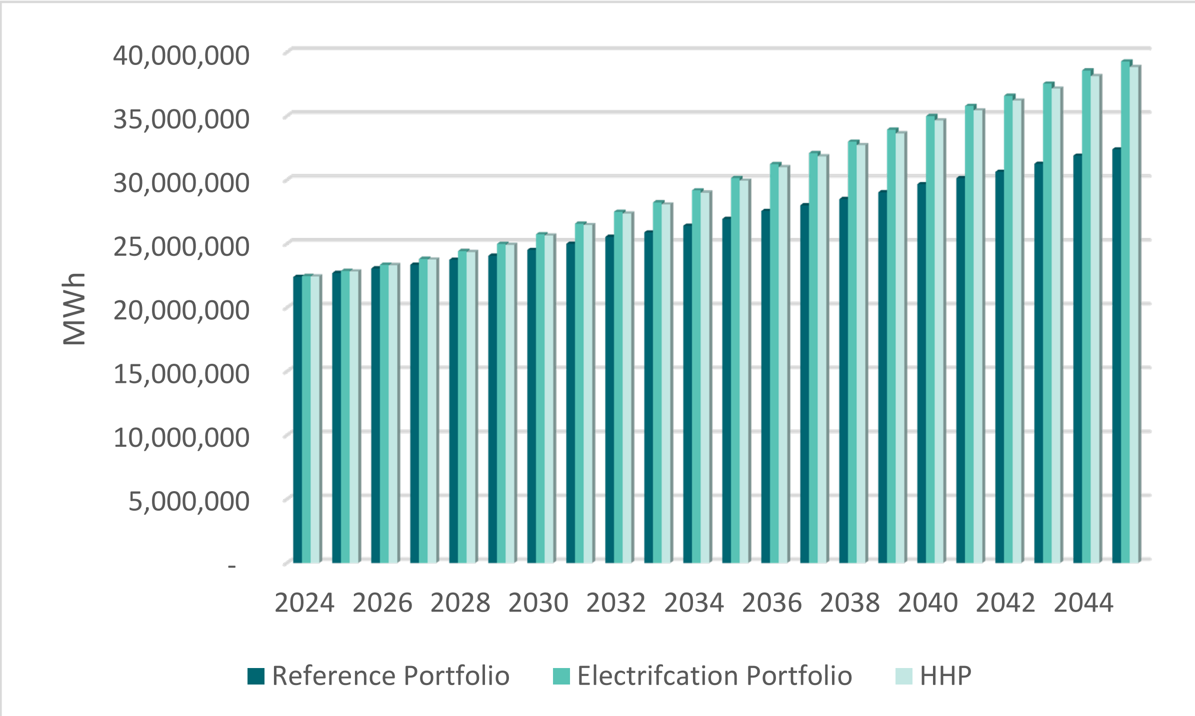
The Electrification scenario requires 7,800 MW of peak capacity increasing the deficit 3,000 MW from the Reference portfolio. The HPP scenario requires 5,400 MW of peak capacity increasing the deficit 500 MW from the Reference portfolio.

Figure 6.17: Electrification winter Peak Demand Impacts



There is minimal difference in load between the electrification scenario and HHP policy scenario. The electrification scenario projected 2045 load is 39.2 million MWh, HPP scenario is 38.9 million MWh, and the Reference case is 32.4 million MWh. To put this in perspective, the load difference between the Electrification and the HHP scenario could be filled in by 150 MW wind project.

Figure 6.18: Electrification Energy Demand Impacts



Electrification scenarios add 1,400 MW of peaking resources. The majority of the deficit is met by 1,100 MW of CETA compliant resources and to a lesser extent increased wind conservation and demand fills in the rest of the gap.

Figure 6.19: Portfolio Additions Peak Capacity 2045

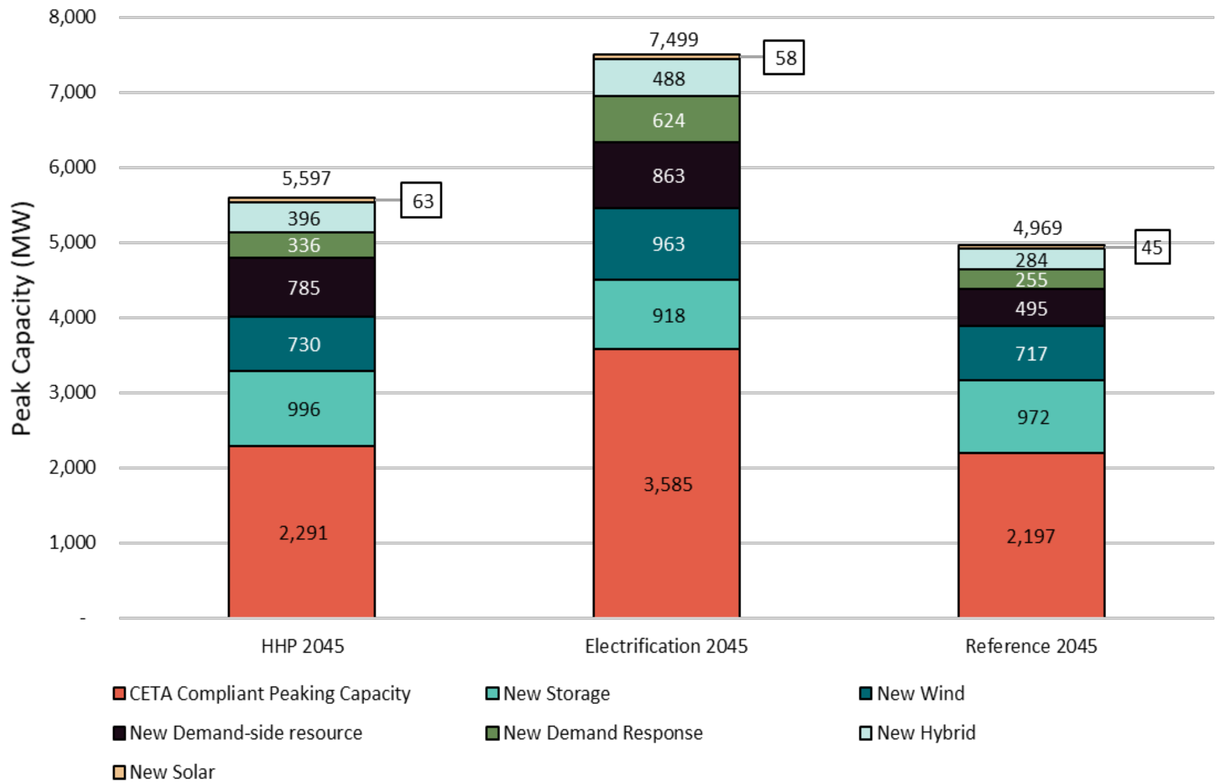
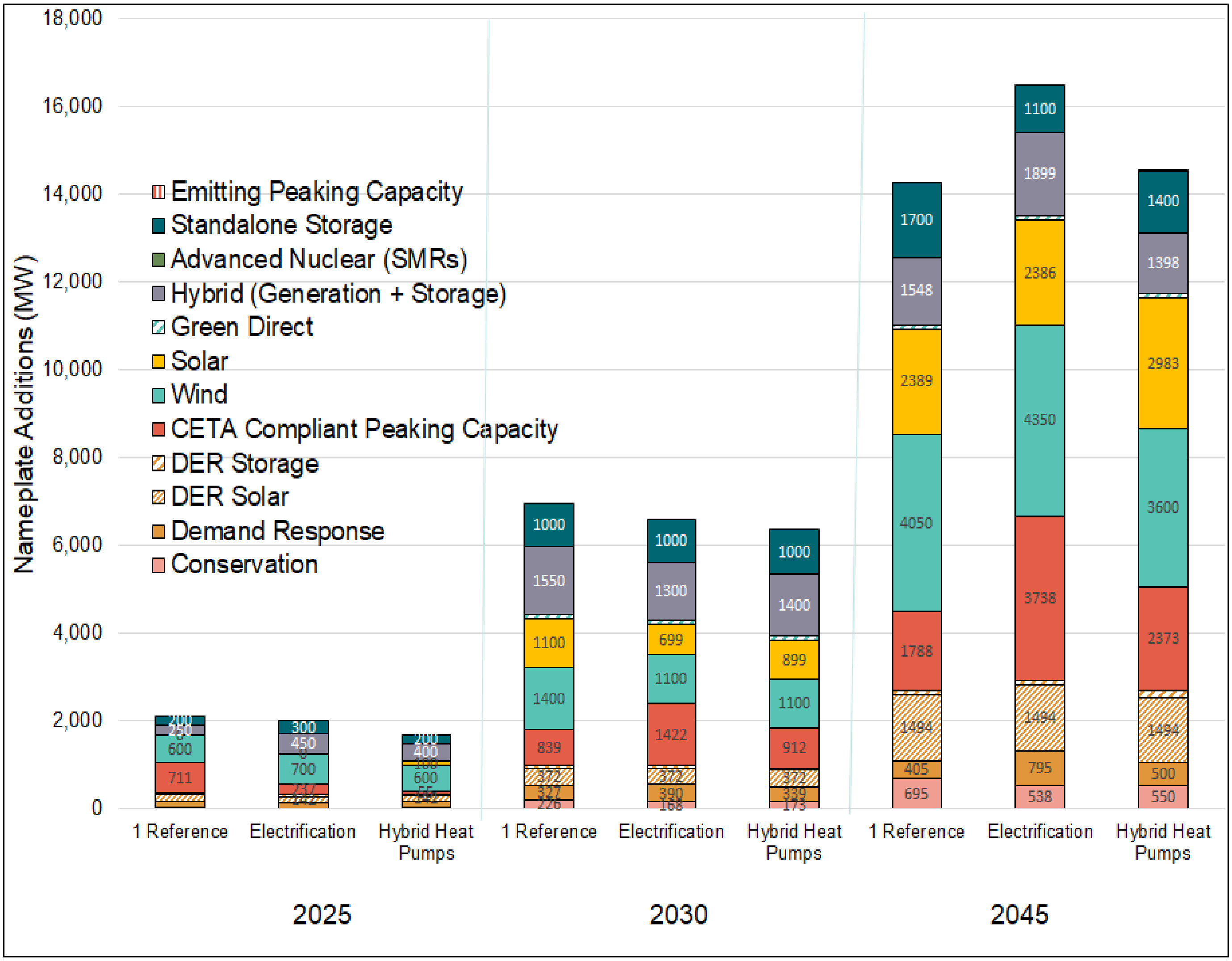
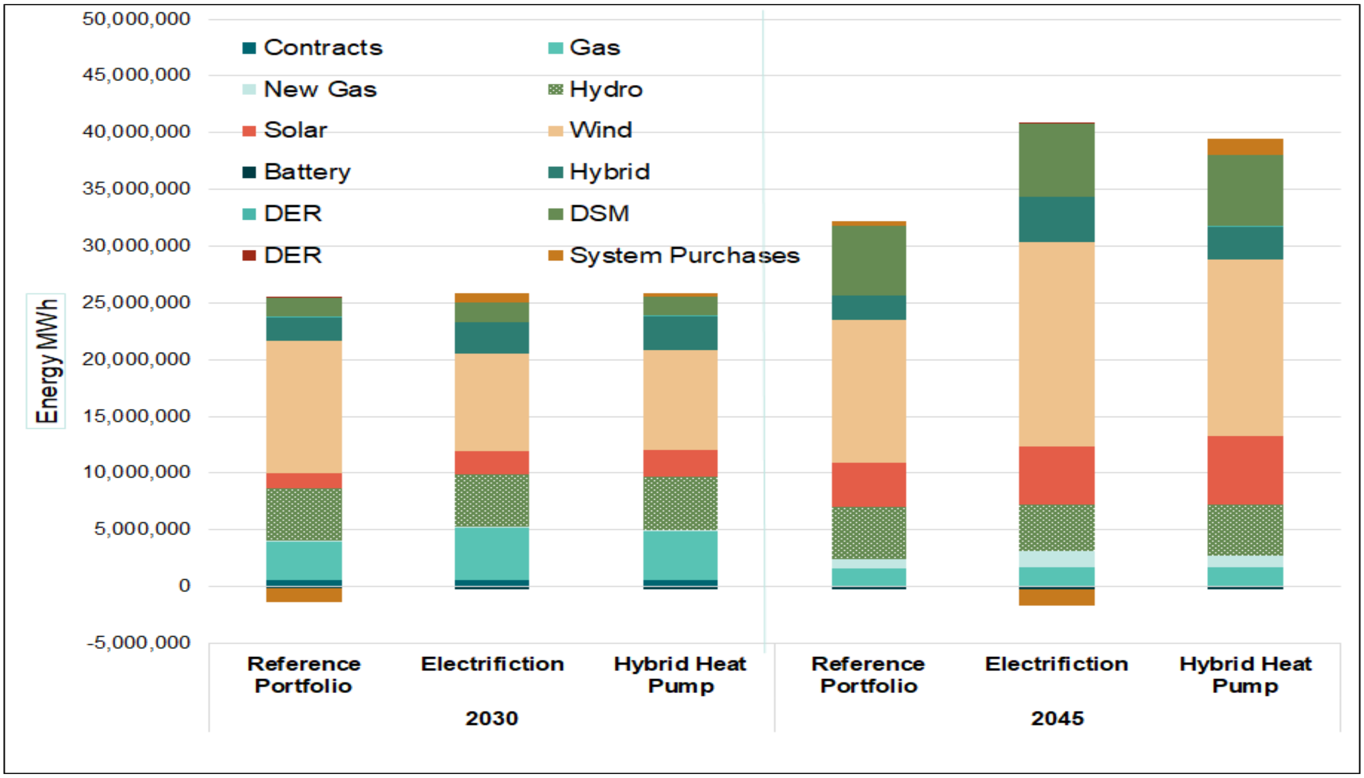


Figure 6.20: Nameplate Resource Additions



The Electrification bar chart reflects the higher renewable energy required to meet the increased load for the Electrification and HHP scenario.

Figure 6.21: Energy Production



The intent of the electrification is to lower overall emissions via renewable energy on the electric side of the business. Emissions initially increase due to the added load to the electric system, but over time, decrease to meet CETA requirements.

Figure 6.22: Electric portfolio emissions