Appendices

NW Natural®

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Appendix A – Integrated Resource Plan Requirements and Action Plan Updates

A.1 NW Natural's 2025 Integrated Resource Plan – Oregon Compliance

NW Natural's 2025 IRP complies with the current Oregon IRP Guidelines as described in the table below. The Company notes that the OPUC has recently opened a rulemaking docket (OPUC docket AR 669) to modernize IRP guidelines and associated Oregon Administrative Rules (OARs).

Table A-1: NW Natural's 2025 IRP Oregon Compliance

Citation	Requirement	NW Natural Compliance	Chapter
Order No. 07-047, 08-339			
Guideline 1(a)	All resources must be evaluated on a consistent and comparable basis.	NW Natural uses a site-specific cost of service model to estimate the PVRR of NW Natural owned resources. Existing non-NW Natural owned resources' costs are based on current tariff rates and future resource costs are developed using estimates from the owner of those facilities. NW Natural leveraged an external consultant to forecast costs associated with electrification, alternative fuels, and natural gas prices. NW Natural uses avoided costs to evaluate the cost effectiveness of Demand-side resources.	5, 6, 7, 8, 9, 10, 11, 12, Appendix K
	Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.	Chapters 6, 7, and 8 focus on demand-side, emissions compliance, and supply-side, respectively. The supply-side options considered in Chapter 8 range from interstate pipeline capacity from multiple providers and NW Natural's Mist underground storage to various types of renewable natural gas, imported LNG, including satellite LNG facilities sited at various locations within NW Natural's service territory. For those resources evaluated as being	6, 7, 8, and 11

Citation	Requirement	NW Natural Compliance	Chapter
		sufficiently viable to be included in resource portfolio optimization, NW Natural clearly defines each resource's estimated in-service date before which the respective resource is unavailable for selection as part of a resource portfolio. This IRP evaluates several supply-side and demand-side resources. Chapter 5 discusses the avoided cost framework for evaluating demand-side resources and Chapter 6 discusses the demand-side resources. Chapter 8 discusses supply-side resource options. Chapter 7 discusses compliance resources options to meet GHG compliance obligations in both Oregon and Washington over the planning horizon and is a major focus for this IRP. NW Natural has additionally considered technologies which are not currently widely available but have been identified for continued monitoring and future assessment. These opportunities are discussed in Chapter 11.	
	Consistent assumptions and methods should be used for evaluation of all resources.	NW Natural uses a site-specific cost of service model to estimate the PVRR of NW Natural owned resources. Existing non-NW Natural owned resources use their current tariff rates and future resources costs are developed using estimates from the owner of those facilities. NW Natural uses avoided costs to evaluate the cost effectiveness of Demand-side resources (energy efficiency and demand response) and supply-side resources (most	9

Citation	Requirement	NW Natural Compliance	Chapter
		notably the low carbon gas evaluation methodology). Compliance resources are also evaluated on a PVRR basis.	
	The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.	NW Natural uses a real after-tax discount rate of 3.87 percent in this IRP, which it derives using the currently authorized values associated with its cost of capital in Oregon. The Company incorporates a 2.55 percent annual rate of inflation, which it estimated using methods with which the Commission is familiar. Note that a real after-tax discount rate of 3.39 percent was used by ETO in their DSM savings potential analyses included in Chapter 6. As discussed in Chapter 6 of this IRP, ETO and energy savings forecasts need to be completed prior to NW Natural's resource optimization analysis.	6 and 9
Guideline 1(b)	Risk and Uncertainty must be considered.	Risk and uncertainties are addressed through scenario and stochastic variable analysis.	
1.b.2 (note that 1.b.1 applies to electric utilities)	At a minimum, utilities should address the following sources of risk and uncertainty: Natural gas utilities: demand (peak, swing, and base load), commodity supply and price, transportation availability and price, and cost to comply with any regulation of greenhouse gas emissions.	Risk and uncertainty are intrinsic characteristics in long-term planning. NW Natural performed a risk analysis including both a stochastic analysis and a wide range of sensitivities to evaluate the impact of risk and uncertainty. More specifically, NW Natural analyzed demand uncertainty (peak, swing, and baseload) by using deterministic load forecasts. The Company analyzed weather uncertainty, gas price uncertainty, and alternative fuel cost and supply uncertainty in its stochastic analysis. Due to the degree of uncertainty of loads, policy, costs, and resources, NW Natural develops a reference case, supplemented by a range of cases, stochastic	2, 4, 5, 6, 7, 8, 9, and 11

Citation	Requirement	NW Natural Compliance	Chapter
		simulation, and risk analysis to inform this IRP. Chapter 5 includes commodity price risk reduction values and GHG compliance cost risk reduction values as avoided cost components to address risks associated with gas prices and GHG compliance resources, respectively. Chapter 9 contains the discussion of the Company's risk analysis, assumptions, and results.	
	Utilities should identify in their plans any additional sources of risk and uncertainty.	NW Natural also discusses the impacts of complying with recently passed GHG emissions regulation and the uncertainty associated with the levels of the cost of compliance and potential emissions reduction alternatives. NW Natural has also modeled different sources of renewable resources, including instruments such as CCIs (OR) and Allowances (WA), and renewable resources such as RNG, hydrogen, CCUS, and synthetic methane. Chapter 7 discusses compliance options for recent GHG emissions regulations. NW Natural also examines electrification and emerging technologies such as geothermal. Chapter 10 and 11 also qualitatively address risks from electrification that are not quantified in the electrification study.	7, 9, 10, and 11
Guideline 1(c)	The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers. The planning horizon for analyzing resource choices should be at least 20	The primary goal of this IRP is the selection of a portfolio of resources with the best combination of expected costs and risks over the planning horizon. The analysis considers all costs that could reasonably be included in rates over the long-term, which extends beyond the planning horizon and the life of	9

Citation	Requirement	NW Natural Compliance	Chapter
	years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.	the resource. The robustness of the expected costs was evaluated in the stochastic risk analysis.	
	Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.	NW Natural uses PVRR as the key cost metric in this IRP and includes analysis of current and estimated future costs of both long- and short-lived resources.	9
	To address risk, the plan should include, at a minimum:		
1.c.1	Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.	NW Natural assesses both the variability of costs and the severity of bad outcomes in the risk analysis which includes both a stochastic and sensitivity analysis.	9
1.c.2	Discussion of the proposed use and impact on costs and risks of physical and financial hedging.	NW Natural provides retail customers with a bundled gas product including gas storage by aggregating load and acquiring gas supplies through wholesale market physical purchases that may be hedged using physical storage or financial transactions. The following goals guide the physical or financial hedging of gas prices: 1) reliability; 2)	Appendix F

Citation	Requirement	NW Natural Compliance	Chapter
		lowest reasonable cost; 3) rate stability; 4) cost recovery; and 5) environmental stewardship.	
	The utility should explain in its plan how its resource choices appropriately balance cost and risk.	NW Natural uses a probabilistic peak planning standard to accurately capture risk in its resource selection. Further, the Company augments its deterministic least cost portfolio optimization with a rigorous risk analysis, and its underlying forecasts of weather and gas price variables with stochastic elements. NW Natural considered not only economic data in its assessment of resource options, but also the likelihood of alternative resources being available, analysis of demand and price forecasting, and the reliability benefits associated with certain resources. NW Natural uses this same process to balance costs and risks for compliance resources. The action items in NW Natural's Action Plan are low-regret resource choices that reflect the findings from the full IRP analysis that balance risks and costs.	1, 4, 5, 6, 7, 8, and 9
Guideline 1(d)	The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	This IRP includes compliance plans to meet Oregon's Climate Protection Plan and other policies that promote GHG emissions reductions. The Company's underlying gas price forecast, provided by an outside consultant, includes the cost of compliance with most recently known environmental regulations. The Company includes an emissions forecast associated with the considered resource portfolios and explicitly models the outcomes of disparate policy futures. The Company considers a variety of scenarios and sensitivities, including a growth	3, 5, 6, 7, 8, and 9

Citation	Requirement	NW Natural Compliance	Chapter
		recovery scenario where population and housing trend upward relative to the Reference Case and multiple scenarios examining varying levels of electrification. As always, NW Natural works closely with Energy Trust of Oregon to acquire all cost-effective energy savings available for customers and continues to work to fully value the system benefits of demand-side resources.	
Guideline 2(a)	The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.	NW Natural provided the public considerable opportunities for participating in the development of the Company's 2025 IRP. Enhancements to public participation were focused on creating a more accessible and inclusive process. These opportunities included an Open House, Technical Working Group (TWG) meetings, a Public Engagement Webinar (PEW), office hours, and outreach to community partners. We also held two public fairs through community partners. Requests for feedback were made throughout the IRP development with the Company providing multiple channels for such input. The Company website was enhanced to include more details on the development process including how one can become involved in NW Natural's IRP. The website further contains the dates, recordings, and associated presentations for the 2025 IRP meetings, the draft 2025 IRP (which will be replaced with the final 2025 IRP upon filing), and previous	3, Appendix I

Citation	Requirement	NW Natural Compliance	Chapter
		IRPs. NW Natural, additionally, notified customers of the 2025 IRP via customer specific communication channels, such as e-newsletters and bill notices. Chapter 3 and Appendix I provide details on public participation efforts.	
Guideline 2(b)	While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.	As evidenced by materials included in the plan, NW Natural has put forth all relevant non-confidential information necessary to produce a comprehensive plan.	1-13
Guideline 2(c)	The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.	NW Natural provided an initial draft plan for public review in two flights. The first was made available on June 13, 2025 followed by the second flight on June 25, 2025. Both were made available on its website and submitted to Commission Staffs and stakeholders.	3, Appendix I

Citation	Requirement	NW Natural Compliance	Chapter
		The public was made aware of the draft release and request for feedback during each Technical Working Group, and through a notice via the IRP email distribution list. Further, the Company also described the process in which the public can review and comment upon the draft during community engagements and through partner outreach. Customers additionally received a notice on their bills announcing the draft release. Finally, the action plan contained within the draft plan was discussed at the final 2025 IRP Technical Working Group meeting held on June 26, 2025.	
Guideline 3(a)	The utility must file an IRP within two years of its previous IRP acknowledgement order.	NW Natural's 2022 IRP was acknowledged by the Commission on August 2, 2023; see Order No. 23-281 in Docket No. LC 79.	
Guideline 3(b)	The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.	NW Natural will comply with this guideline.	
Guideline 3(c)	Commission Staff and parties should complete their comments and recommendations within six months of IRP filing.	NW Natural looks forward to working with Commission Staff and interested parties in a review of this plan.	
Guideline 3(d)	The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the	NW Natural is prepared for this process.	

Citation	Requirement	NW Natural Compliance	Chapter
	plan before issuing an acknowledgment order.		
Guideline 3(e)	The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.	NW Natural is prepared to receive direction from the Commission regarding analysis required in its next IRP.	
Guideline 3(f)	Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.	NW Natural plans to file an annual report as required.	
Guideline 3(g)	Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that: 1) Describes what actions the utility has taken to implement the plan; 2- Provides an assessment of what has changed since the acknowledgment order that affects the action plan,	NW Natural acknowledges this guideline.	

Citation	Requirement	NW Natural Compliance	Chapter
	including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and 3-Justifies any deviations from the acknowledged action plan.		
Guideline 4	At a minimum the plan must include the following elements:		
Guideline 4(a)	An explanation of how the utility met each of the substantive and procedural requirements.	This appendix is intended to comply with this guideline by providing an itemized response to each of the substantive and procedural requirements.	Appendix A
Guideline 4(b)	Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions	The IRP's growth recovery scenario analyzes a higher level of customer growth than expected in the Reference Case. The IRP also analyzes scenarios of varying levels electrification, which constitute low growth for the gas system. Due to the degree of uncertainty of loads, policy, costs, and resources, this IRP develops a reference case, then uses a range of cases, stochastic simulation, and risk analyses to inform its action plan until the next IRP. Chapter 9 provides the stochastic load risk analysis results.	4, 9
Guideline 4(c)	For electric utilities …	Not applicable to NW Natural's gas utility operations.	
Guideline 4(d)	For natural gas utilities, a determination of the peaking, swing and baseload gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and	NW Natural utilized the PLEXOS® optimization model as discussed with Staff and stakeholders throughout the 2025 IRP Technical Working Group meetings. NW Natural analyzes on an integrated basis gas supply, transportation, and storage, along with demand-side resources to reliably meet peak, swing,	9, Appendix B, G, and H

Citation	Requirement	NW Natural Compliance	Chapter
	identification of gas supplies (peak, swing and baseload), transportation and storage needed to bridge the gap between expected loads and resources.	and base-load system requirements. For this IRP, NW Natural utilizes a 90% probability coldest winter planning standard augmented with a five-day cold weather event that peaks on day three, which includes the probabilistically established planning standard day, against which to evaluate the cost and risk trade-offs of various supply- and demand-side resources available to PLEXOS®. NW Natural's integrated resource planning reflects the Company's evaluation and selection of a planning standard which provides reliability for customers. Resulting resource portfolios provide the best combinations of expected costs and associated risks and uncertainties for the utility and its customers.	
Guideline 4(e)	Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology.	NW Natural determined the best resource mix by studying supply-side options currently used such as pipeline transportation contracts, gas supply and renewable natural gas contracts, and alternative options such as additional capacity or infrastructure enhancements. The Company also considered future developments such as pipeline enhancements, renewable natural gas projects, power-to-gas (a suite of technologies that use electrolysis in an electrolyzer to separate water molecules into oxygen and hydrogen), and other compliance resources. Chapters 7 and 8 discuss the various supply-side and compliance resource options and their costs. NW Natural compiled demand-side resource options with assistance from the ETO for Oregon, and these	2, 5, 6, 7, 8

Citation	Requirement	NW Natural Compliance	Chapter
		options are identified in Chapter 6. Further, Chapter 6 discusses various efficient end use equipment.	
Guideline 4(f)	Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs.	NW Natural uses a planning standard that uses statistics and Monte Carlo simulation of the demand drivers to set a standard that the company's resource capacity can serve the highest firm sales demand day going into each future winter with 99% certainty. PLEXOS® is used to determine the least-cost, least-risk portfolio, and a scenario and stochastic risk analysis is completed to stress test the portfolio. The Synergi Gas™ software package also provides the Company with the opportunity to evaluate performance of the distribution system under a variety of conditions, particularly meeting peak day customer demand conditions while maintaining system stability. Chapter 12 discusses the approach the Company uses to provide reliable service at the distribution system planning level.	4, 7, 8, 9, and 12
Guideline 4(g)	Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered.	Chapter 9 describes alternative resource mix scenarios and forward-looking sensitivities involving commodity availability, commodity cost, transportation cost, and/or load forecast inputs evaluated in the IRP. The Company also included expected GHG policy compliance costs in its price forecasts and analyzed sensitivities related to compliance costs. Further, NW Natural factored compliance costs explicitly into the determination of the Company's avoided cost, which in turn factored into the identification of cost-effective demand-side	3, 4, 5, 6, 7, 8, and 9

Citation	Requirement	NW Natural Compliance	Chapter
		resources and on-system resources such as renewable natural gas.	
Guideline 4(h)	Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations — system-wide or delivered to a specific portion of the system.	As described above and in more detail in the Plan, NW Natural designed numerous alternate resource mix scenarios, where each scenario allows for changes to the supply-side, demand-side, and compliance resources available for selection. Chapter 9 and associated appendices document the resource portfolio options evaluated in this IRP.	9
Guideline 4(i)	Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties.	Chapter 9 discusses the results of the stochastic risk analysis and tests the robustness of the expected resource choice over a slate of future environments that represent uncertainty of natural gas and compliance resource prices, weather, policy, and resource costs.	9
Guideline 4(j)	Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results.	Chapter 9 discusses the results of the stochastic risk analysis and tests the robustness of the expected resource choice over a slate of future environments that represent uncertainty of natural gas and compliance resource prices, weather, and resource costs.	9
Guideline 4(k)	Analysis of the uncertainties associated with each portfolio evaluated.	Chapter 9 discusses the results of the stochastic risk analysis tests the robustness of the expected resource choice over a wide slate of future environments that represent uncertainty of natural gas and compliance resource prices, weather, and resource costs. Chapter 9 also includes a discussion of the uncertainties associated with the evaluated portfolios.	9

Citation	Requirement	NW Natural Compliance	Chapter
Guideline 4(l)	Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers.	Chapter 9 discusses the results of the stochastic risk analysis and selection of the resource portfolio.	9
Guideline 4(m)	Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation.	NW Natural does not believe its resource strategy is inconsistent with current state or federal energy policies. There are potential barriers to implementation that may relate to the ultimate availability and timing of certain incremental resources selected for the Company's selected portfolio due to facility siting/permitting challenges, market viability, and other challenges.	2, 7, 8, and 9
Guideline 4(n)	An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.	Chapter 1 presents NW Natural's multi-year action plan, which identifies the short-term actions the Company intends to pursue within the next two to four years. Chapter 13 discusses the action plan in greater detail.	1, 13
Guideline 5	Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in	Chapter 8 discusses fuel transportation costs, including pipeline transmission line costs and facilities costs. Chapter 7 discusses emission compliance resources, including alternative fuels.	7, 8

Citation	Requirement	NW Natural Compliance	Chapter
	remote locations, acquiring alternative fuel supplies, and improving reliability.		
Guideline 6(a)	Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.	NW Natural worked with ETO in Oregon to analyze the potential energy savings that could be cost-effectively procured within the Company's service territory through 2050. The studies determined the achievable potential by analyzing customer demographics together with energy efficiency measure data. NW Natural and ETO review these assumptions annually when ETO plans its program budget for the subsequent calendar year.	6
Guideline 6(b)	To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.	NW Natural's Schedule 301, Public Purposes Funding Surcharge, contains a special condition requiring NW Natural to work with ETO every year to determine if the funding level is appropriate to meet the subsequent year's therm savings targets. NW Natural identifies specific annual savings targets in its action plan.	1, 13
Guideline 6(c)	To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should: 1) determine the amount of conservation resources in the best cost/ risk portfolio without regard to any limits on funding of conservation programs; and 2) identify the preferred portfolio and action plan consistent with the	See response to Guideline 6(b)	

Citation	Requirement	NW Natural Compliance	Chapter
	outside party's projection of conservation acquisition.		
Guideline 7	Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).	NW Natural offers interruptible rates which account for approximately 24 percent of the Company's throughput. This allows NW Natural to reduce system stress during periods of unusually high demand. In the 2022 IRP Action Plan, NW Natural was tasked to scope a residential and small commercial demand response program and file by 2024. While several DR pathways were explored, a system-wide Bring Your Own Thermostat ("BYOT", or "Thermostat Rewards" as branded) program was identified as the best opportunity to create a demand response program that targets residential and small commercial customers. The system-wide program can be leveraged to support future locational DR programs and hence to comply with the condition for action item acknowledgement as recommended by OPUC Staff.	
Guideline 8	See Amended Guideline 8 through ORDER NO. 08-339		
Guideline 8 (a)	BASE CASE AND OTHER COMPLIANCE SCENARIOS: The utility should construct a base-case scenario to reflect what it considers to be the most likely regulatory compliance future for carbon dioxide (CO_2), nitrogen oxides, sulfur oxides, and mercury emissions. The utility also should develop several compliance	NW Natural explicitly incorporates expected regulatory compliance costs in its analyses. Due to the degree of uncertainty of loads, policy, costs, and resources, for this IRP NW Natural develops a reference case, supplemented by a range of cases, stochastic simulations, and risk analyses to inform its action plan until the next IRP. For each scenario, NW Natural estimates emissions and costs over the timespan of the analysis, as well as optimizes the	3, 5, 7, and 9

Citation	Requirement	NW Natural Compliance	Chapter
	scenarios ranging from the present CO_2 regulatory level to the upper reaches of credible proposals by governing entities. Each compliance scenario should include a time profile of CO_2 compliance requirements. The utility should identify whether the basis of those requirements, or "costs," would be CO_2 taxes, a ban on certain types of resources, or CO_2 caps (with or without flexibility mechanisms such as allowance or credit trading or a safety valve). The analysis should recognize significant and important upstream emissions that would likely have a significant impact on its resource decisions. Each compliance scenario should maintain logical consistency, to the extent practicable, between the CO_2 regulatory requirements and other key inputs.	least cost and least risk selection of compliance resources. NW Natural designed its scenarios and sensitivities to be logically cohesive and capture a wide range of possible outcomes.	
Guideline 8 (b)	TESTING ALTERNATIVE PORTFOLIOS AGAINST THE COMPLIANCE SCENARIOS: The utility should estimate, under each of the compliance scenarios, the present value of revenue requirement (PVRR) costs and risk measures, over at least 20 years, for a set of reasonable alternative portfolios from which the	Chapter 9 discusses the results of the stochastic risk analysis and tests the robustness of the expected resource choice over a wide slate of future environments that represent uncertainty of policy and compliance costs.	9

Citation	Requirement	NW Natural Compliance	Chapter
	preferred portfolio is selected. The utility should incorporate end-effect considerations in the analyses to allow for comparisons of portfolios containing resources with economic or physical lives that extend beyond the planning period. The utility should also modify projected lifetimes as necessary to be consistent with the compliance scenario under analysis. In addition, the utility should include, if material, sensitivity analyses on a range of reasonably possible regulatory futures for nitrogen oxides, sulfur oxides, and mercury to further inform the preferred portfolio selection.		
Guideline 8 (c)	TRIGGER POINT ANALYSIS. The utility should identify at least one CO2 compliance “turning point” scenario which, if anticipated now, would lead to, or "trigger" the selection of a portfolio of resources that is substantially different from the preferred portfolio. The utility should develop a substitute portfolio appropriate for this trigger-point scenario and compare the substitute portfolio's expected cost and risk performance to that of the preferred	NW Natural evaluated numerous scenarios, including aggressive load reductions due to full electrification. NW Natural’s analysis of this scenario includes portfolio selection based on a least cost, least risk approach optimized in PLEXOS®, which the Company then compares to the benchmark set in the Reference Case.	9

Citation	Requirement	NW Natural Compliance	Chapter
	portfolio - under the base case and each of the above CO2 compliance scenarios. The utility should provide its assessment of whether a CO2 regulatory future that is equally or more stringent than the identified trigger point will be mandated.		
Guideline 8 (d)	OREGON COMPLIANCE PORTFOLIO: If none of the above portfolios is consistent with Oregon energy policies (including state goals for reducing greenhouse gas emissions) as those policies are applied to the utility, the utility should construct the best cost/risk portfolio that achieves that consistency, present its cost and risk parameters, and compare it to those of the preferred and alternative portfolios.	NW Natural's preferred portfolio is consistent with Oregon energy policies.	2, 9
Guideline 9	Direct Access Loads.	Not applicable to NW Natural's gas utility operations.	
Guideline 10	Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves a best cost/risk portfolio for all their retail customers.	This plan studies the supply-side needs for NW Natural's complete service territory, which includes customers in Oregon and Washington.	
Guideline 11	Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with	NW Natural analyzes gas supply, transportation, and storage on an integrated basis, along with demand-side resources to reliably meet peak, swing, and	4, 9

Citation	Requirement	NW Natural Compliance	Chapter
	demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.	base-load system requirements. For this IRP, NW Natural utilizes a 90% probability coldest winter planning standard augmented with a historic five-day cold weather event that peaks on day three, which includes the probabilistically established planning standard day, against which to evaluate the cost and risk trade-offs of various supply- and demand-side resources available to PLEXOS®. NW Natural's integrated resource planning reflects the Company's evaluation and selection of a planning standard which provides reliability for customers. Resulting resource portfolios provide the best combinations of expected costs and associated risks and uncertainties for the utility and its customers.	
Guideline 12	Distributed Generation. Electric utilities should…	Not applicable to NW Natural's gas utility operations.	
Guideline 13(a)	Resource Acquisition. An electric utility should…	Not applicable to NW Natural's gas utility operations.	
Guideline 13(b)	Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment.	Appendix F describes NW Natural's Gas Acquisition Plan (GAP), detailing the Company's strategies and practices for acquiring gas supplies. The primary objective of the Gas Acquisition Plan (GAP) is to ensure gas supplies are sufficient to meet firm customer demand. To meet this objective, NW Natural's primary goal is reliability, followed by lowest reasonable cost, rate stability, and cost recovery.	Appendix F

A.2 Recommendations from the 2022 Integrated Resource Plan – OPUC

As an outcome of NW Natural's 2022 IRP Staff developed 43 recommendations. These were adopted, modified, or rejected through Order 23-281. NW Natural identified seven of Staff's 43 recommendations that specifically requested information by or in NW Natural's 2022 IRP Update and two additional recommendations that indirectly apply to the IRP Update. NW Natural filed the 2022 IRP Update on August 5, 2024 and filed a second update (IRP Update #2) on August 21, 2024, responding to each recommendation. This Appendix includes Staff's recommendation, NW Natural's response in the LC 79 docket, NW Natural's IRP Update #2 response, Staff's Implementation of IRP Update Recommendations and NW Natural's response for addressing outstanding recommendations in this IRP.

Recommendation 1: The Commission should direct the Company to include four years of planning detail in its next Action Plan.
Recommendation 1 was not adopted by the Commission.

Recommendation 2: Staff recommends acknowledgement of Action Item 1 to acquire deliverability from Mist Recall and citygate deals.
NW Natural Response in LC 79 Final Comments: NW Natural supports Staff's recommendation 2. NW Natural plans our system capacity resources to be able to serve customers in the event of uncommon and extreme winter weather. Acquiring Mist Recall or citygate deals ensures that we have the necessary supplies to reliably serve our customers during weather events when it would be the most dangerous for customers to lose service.
NW Natural IRP Update Response: After confirming it was still needed, NW Natural signed a city gate deal for 20,000 Dth/day of deliverability to meet design peak demand for the 2023-2024 winter. Updates to the peak day forecast and firm resource stack show another design day deficit of 20,000 Dth/day for the 2024-2025 winter. NW Natural recalled 20,000 Dth/day of Mist deliverability to meet this deficit for this upcoming winter.
NW Natural Updated Response in LC 86: NW Natural recalled 20,000 Dth/day of deliverability for the 2024-2025 winter and another 15,000 Dth/day of deliverability was recalled meeting peak day requirements for the upcoming 2025-2026 winter.

Recommendation 3: Staff recommends the Commission acknowledge the Portland Cold Box replacement.
NW Natural Response in LC 79 Final Comments: NW Natural supports Staff's recommendation 3. In our stochastic risk analysis, the Portland LNG Cold Box was selected in all 500 draws, many of which have drastic declines in NW Natural's customer base. The

Portland LNG Cold Box is needed to support reliable service for a wide range of potential levels of electrification going into the future. Our Reply Comments include more detail about why this Action Item should be acknowledged.
NW Natural IRP Update Response: The Company is awaiting the results of the facility seismic vulnerability assessment, required by the new DEQ Fuel Tank Seismic Stability Rules, before proceeding forward with the cold box replacement.
NW Natural Updated Response in LC 86: The Company has placed this project on hold as it awaits the results of the facility seismic vulnerability assessment, required by the new DEQ Fuel Tank Seismic Stability Rules (OAR 340-300-0000.) The Company expects to complete the Portland LNG Plant seismic vulnerability assessment by 2027.

Recommendation 4: For future IRPs, the Company's portfolio modeling must consider non-renewal of unneeded firm delivery capacity contracts upon expiration and the retirement of other capacity resources as appropriate.
NW Natural Response in LC 79 Final Comments: NW Natural is receptive to Staff's recommendation and NW Natural will explore retirement, transfer and/or other potential alternatives for reducing capacity resources for utility customers as appropriate. The Portland LNG Cold Box is a key example of how non-renewal for a firm delivery resource is entered into the model as an option for the model to decommission if not needed, as seen in Scenario #6. Apart from this example, this recommendation has implications for other resources such as Mist Recall, where historically Mist assets have been transferred from Interstate Storage to the utility at depreciated costs. Staff's recommendation suggests analyzing the reverse circumstances, where if NW Natural experiences a decline in peak day requirements, Mist assets could be transferred away from the utility at depreciated costs.
NW Natural IRP Update Response: The work to incorporate non-renewal options and asset transfer options into the optimization model is on-going. As mentioned in NW Natural Final Comments, the Company is receptive to this recommendation, but this will require significant modeling adjustments. The Company looks forward to working with Staff and discussing what is possible for inclusion in the 2025 IRP and thereafter.
NW Natural Updated Response in LC 86: The options to capacity release of upstream pipeline contracts in the resources optimization model (PLEXOS®) have been included and modeled in this IRP. The PLEXOS® model optimizes these contracts in all scenarios such that there are cost savings associated avoiding the fixed demand charges of any contracts that are no longer cost-effective for customers to continue paying.

Recommendation 5: Staff recommends the Commission acknowledge Action Item 3 for residential and commercial demand response subject to the condition that the Company includes in its demand response filing a discussion of how the Company's

residential and commercial demand response program will interact with and support any future locational demand response program.
NW Natural Response in LC 79 Final Comments: NW Natural supports recommendation 5. Per the 2022 IRP, NW Natural intends to include assessing geographical-targeted demand response (GeoDR) as part of its upcoming residential and small commercial demand response program and will include information on GeoDR as part of its program filing.
NW Natural IRP Update Response: NW Natural assessed the potential demand response programs and looked across the country to understand how other gas utilities are implementing demand response programs. A bring your own thermostat (BYOT) program was determined to be the highest value program to focus efforts to implement. The IRP Update lays out the timeline and work that has been required for program research, vendor selection (both DERMS and EM&V service providers), and vendor contracting. NW Natural is in the process of contracting with service providers to enable a "bring your own thermostat" (BYOT) demand response program to begin enrollment this coming Fall.
NW Natural Updated Response in LC 86: NW Natural assessed the potential demand response programs and looked across the country to understand how other gas utilities are implementing demand response programs. A system-wide Bring Your Own Thermostat ("BYOT", or "Thermostat Rewards" as branded) program was determined to be the highest value program to focus efforts to implement. The 2022 IRP Update lays out the timeline and work that has been required for program research, vendor selection (both DERMS and EM&V service providers), and vendor contracting. This program was first tested during the 2024-2025 winter. These targeted efforts could potentially include: • Targeted marketing of the BYOT program • Increased enrollment incentives • Increased participation incentives Targeted efforts will be successful as a non-pipeline alternative if the targeted program, in addition to delaying the pipeline investments, can boost customer enrollment, increase participation during events, and increase retention of participants for customers located in constrained areas of our distribution system. See more detail on the BYOT program in Chapter 6.

Recommendation 6: Staff recommends acknowledgement of Action Item 4 to work with Energy Trust to acquire efficiency in 2023 and 2024.

NW Natural Response in LC 79 Final Comments: NW Natural supports recommendation 6. NW Natural appreciates Staff's thoughtful engagement on the issue and recognition of the collaboration between Energy Trust and the Company that made the higher amount of efficiency in the near term, as specified in Action Item 4, possible.
NW Natural IRP Update Response: The Energy Trust of Oregon (Energy Trust) acquired 5.5 million therms of first year savings in 2023 in Oregon. 1.5 million therms of first year savings have been achieved through Q1 of 2024.
NW Natural Updated Response in LC 86: The Energy Trust of Oregon (Energy Trust) acquired 5.5 million therms of first year savings in 2023 in Oregon. 5.7 million therms of first year savings have been achieved in 2024.

Recommendation 7: Staff recommends non-acknowledgment of the SB 98 RNG acquisition under Action Item 5 because acquisition of CCIs is a significantly less costly and risky method of complying with the CPP.
NW Natural Response in LC 79 Final Comments: NW Natural appreciates the time and effort that Staff has spent on this issue. However, as detailed in Section 1.1, NW Natural strongly disagrees with Staff and recommends the Commission acknowledge Action Item 5. Action Item 5 is the result of analysis to support Senate Bill 98 (SB 98) and the Commission's rules to implement it. The 2022 IRP demonstrates least-cost/least-risk compliance with the Climate Protection Plan (CPP) while recognizing that the CPP does not revise or supersede SB 98. Please see Part 3 for additional clarifications on modeling SB 98 in the IRP.
NW Natural IRP Update Response: At the time of the 2022 IRP deliberation, the CPP was still in effect and Action Item #5 was not acknowledged by the OPUC. Given the Commission's decision to not acknowledge the action item and the ongoing uncertainty of compliance with a DEQ program intended to reduce emissions, NW Natural slowed its RNG procurement. The Company does not expect to achieve the voluntary target of 5% outlined in SB 98 by the end of 2024. The risk from policy and regulatory uncertainty, and not RNG availability, has limited NW Natural's efforts to making faster progress toward Oregon's SB 98 RNG voluntary targets. RNG availability continues to grow throughout the country and NW Natural is still engaging in these markets.
NW Natural Updated Response in LC 86: See Chapter 9 for a discussion about how NW Natural will first purchase CCIs while incorporating limited amounts of near-term RNG purchases.

Recommendation 8: Staff recommends acknowledgement of Action Item 7 to purchase CCIs, conditional on the Company using CCIs and RTCs in combination in the most economical way possible to meet compliance flexibility needs, as informed by the decision on Action Item 5 and near-term SB 98 procurement
NW Natural Response in LC 79 Final Comments: NW Natural recommends that Action Item 5 and Action Item 7 be acknowledged as included in NW Natural's IRP. See the response to Staff Recommendation 7 above. For clarification, NW Natural interprets holding RTCs as delivering RNG to customers. Additionally, NW Natural has clarified with Staff that this Staff recommendation

means that if CCI purchases alone can be used for the Company's incremental compliance needs without exceeding the CCI limits of the program, then only CCIs should be purchased so long as they are cheaper than RNG. In the near-term, it is highly likely that CCIs alone could be used for compliance in the near-term if the Commission decides not to acknowledge Action Item 5. NW Natural's position on this issue is elaborated upon in Section 1.1.
NW Natural IRP Update Response: The CPP was invalidated in December of 2023 prior to any CCIs being available for purchase. If the proposed CPP is approved and CCIs are available, NW Natural will include them in its analysis as a potential compliance resource in its 2025 IRP.
NW Natural Updated Response in LC 86: See Chapter 9 for NW Natural's preferred resource strategy (PRS) which relies on CCI purchases for CPP compliance.

Recommendation 9: Staff recommends acknowledgement of Action Item 8 to uprate the Forest Grove Feeder, subject to certain conditions regarding forward looking distribution system planning and hydrogen-blend readiness.
NW Natural Response in LC 79 Final Comments: NW Natural supports Staff's recommendation for acknowledgment of the Forest Grove Feeder. NW Natural disagrees with Staff's condition for an expert third party evaluator to validate NW Natural's uprate plans for pressure control equipment for a hydrogen blend compatibility. Pressure modeling is fundamental to the utility's core business model, expertise, and what the Company does day in and day out. Chapter 8, Section 8.5.5 of the IRP specifically addresses the proposed uprate's compatibility for a hydrogen blend. NW Natural maintains that the Company's engineers are experts in pressure modeling, inclusive of analyzing hydrogen blending, and a third-party validation of our uprate plans is unnecessary and will only add costs to our customers. See Part 3 for additional information.
Recommendation 9 (modified and adopted): Staff recommends acknowledgement of Action Item 8 to uprate the Forest Grove Feeder, subject to certain conditions regarding forward looking distribution system planning and hydrogen- blend readiness. The Company is not required to engage a third-party expert to validate the uprate plans for pressure control equipment. (Order No. 23-281 at 16)
NW Natural IRP Update Response: The Company is in the planning phase and construction is scheduled for completion in Q3 of 2026.
NW Natural Updated Response in LC 86: The Company is in the planning phase and construction is scheduled for completion in late 2026 or 2027.

Recommendation 10: Future distribution system planning should include a cost benefit analysis for non-pipe alternatives that reflects an avoided GHG compliance cost element consistent with a high-cost estimate of future alternative fuels prices.

NW Natural Response in LC 79 Final Comments: NW Natural does not support recommendation 10. This recommendation conflicts with IRP Guideline 1: resources be evaluated on a fair and consistent basis. The Company believes that if this recommendation were to be adopted for NW Natural alone it would lead to inconsistent application of the IRP Guidelines across utilities. If the Commission accepts this recommendation it should apply to all distribution system planning in the state for all utilities, electric and gas. NW Natural recommends that exceptions or alterations to the Guidelines, like this recommendation, be applied consistently to all utilities and be addressed in a docket to review the IRP Guidelines that includes all stakeholders and energy utilities regulated by the Commission. More detail on this is provided in Section 1.4.
Recommendation 10 (clarified and adopted): In the analysis of how such programs and other solutions may avoid future investments – non-pipes alternatives analysis- we interpret Staff Recommendation 10 to require that the analysis include high-cost estimates of future alternative fuels prices; we agree that such a scenario or sensitivity would be very important to justifying pipeline investments, but clarify that we do not mandate it as the only scenario or sensitivity relevant to the analysis and decision. (Order No. 23-221 at 16)
NW Natural IRP Update Response: NW Natural will apply avoided costs as estimated benefits when evaluating non-pipeline solutions and continues to raise the concern that avoided cost should be applied consistently across different demand-side resources. Avoided costs currently incorporates one component called the "Risk Reduction Value" that currently applies value for the avoided risk of higher-than-expected natural gas future prices. NW Natural believes it is appropriate to include a similar value for the risk of higher-than-expected GHG compliance costs for all demand-side resources. NW Natural has proposed this recommendation with Staff through the UM 1893 process and will discuss the idea at our technical working groups.
NW Natural Updated Response in LC 86: NW Natural developed an avoided cost component for the "risk reduction value" for avoided compliance resources. This component recognized that in the same way there is a risk reduction value for avoided commodity costs, there is also a risk reduction value for avoided GHG compliance costs, which could be uncertain and volatile. NW Natural has proposed this recommendation with Staff through the UM 1893 process, presented it to Staff and stakeholders through the UM 1893 docket, and discussed it during Technical Working Group 5. This value would be applied consistently across all avoided cost analysis, such as Energy Trust's standard cost-effectiveness tests along with the evaluation for non-pipeline solutions.

Recommendation 11: In future IRPs, NW Natural should include a system map with an associated database containing information about feeders, in-service dates of pipes, and lowest recent observed pressures.
NW Natural Response in LC 79 Final Comments: NW Natural does not support this Recommendation. The Transportation Security Administration of the US Department of Homeland Security has advised against providing these types of maps at a certain level of

detail due to the fact they could be misused by terrorists and providing this information could be deemed a national security threat. Furthermore, setting aside the security risk, having in-service dates and pressure readings of pipes would not help stakeholders achieve their stated aim to assist in "system pruning," even if one were to agree that "system pruning" is appropriate (NW Natural does not). Pipelines require testing for safety along timeline intervals determined by regulators and are not replaced once they reach a certain age. Finally, the data being requested does not exist in the form that Staff recommends. Utilities utilize group method accounting and depreciation. Utilities do not track every asset or the specific depreciable life of each asset.
Recommendation 11 (modified and adopted): In future IRPs, NW Natural should include a database containing information about feeders, in-service dates of pipes, and lowest recent observed pressures. (Order No. 23-281 at 17)
NW Natural IRP Update Response: NW Natural is in the process of developing the database. Observed pressure data is not available for every pipeline and can only be provided for locations where pressure recording devices collecting that data are present.
NW Natural Updated Response in LC 86: Maps are provided in Chapter 12 for Creswell, McMinnville, and Dallas, which are the three locations the Company focuses on in the 2025 Forward Looking Distribution System Plan. Observed pressure data is being recorded in these locations to verify the accuracy of the Synergi modeling. During TWG 8, the Company described its distribution system planning process and reinforcements standards. During the discussion the Company described how it monitors areas thought to have a potential need using multiple tools including CMM, Synergi, and in the field monitoring (SCADA, EPPR). Additionally, cold day contingency planning was described including a review of internal operations meetings with examples of off- system and on-system management. Items reviewed within TWG 8 align with Staff's TWG Implementation of IRP Update Recommendations comments such that the Company advised that raw data on feeders and pipes may not be helpful to stakeholders, rather it would be more helpful to describe the process of studying feeders, pipes, and pressure data to understand where there is a need.

Recommendation 12: Staff requests that the Company, before the next IRP, provide statistical evidence of the significance of the variables that influence demand, and hence pressure, at a specific temperature.
NW Natural Response in LC 79 Final Comments: NW Natural does not object to this recommendation. However, NW Natural has already provided statistical evidence that, beyond temperature, wind speeds, solar radiation, day of the week, holidays, inclement weather, and school or business closures also impact demand, and therefore, impact expected pressures during extreme cold events.
NW Natural IRP Update Response: NW Natural provides this analysis at the system level. Please see table *B.5 Peak Day Forecast Modelling* in Appendix B of the 2022 IRP. We show that other factors (i.e., demand drivers) beyond temperature do impact total

system demand. These demand drivers will impact demand to various degrees across locations on the system. However, the Company is limited in the data that can be used to conduct this type of analysis at specific locations. To further complicate this recommendation, most of the historical data that could be used to correlate historical pressure readings with these demand drivers for specific locations will reflect interruptible customers not being interrupted. This is one reason why we rely on the system modeling, via Synergi, to analyze the distribution system at peak conditions with interruptible customers turned off. NW Natural will continue to work with Staff on this Recommendation.
NW Natural Updated Response in LC 86: The Company discussed weather and climate impacts in Technical Working Group 4. Additionally, see table B-8 that conducts a system-wide regression for our peak day analysis. This table includes statistical evidence of numerous factors that influence demand and can be used to evaluate demand impacts at any temperature below 59°F.

Recommendation 13: Staff requests that the Company, in the IRP Update, provide rationale backed by practical examples of the deployment of CNG or LNG trailers as short-term mitigation measures, including information requested by Staff in LC 79 Final Comments.
NW Natural Response in LC 79 Final Comments: NW Natural is not opposed to providing information about the potential risks and benefits of deploying CNG or LNG trailers as a system planning tool for distribution system constraints. However, the Company has already provided the reasons why it is does not view these trailers as a sustainable or reliable planning solution on Page 22 of 78 NW Natural OPUC LC 79 Final Reply Comments. NW Natural provided its rationale for the determination that using CNG or LNG trailers as a systematic tool to alleviate distribution system constraints during cold weather events is not feasible in its response to OPUC DR 162, which states: *While mobile CNG/LNG storage can be used to alleviate smaller scale issues on the distribution system, NW Natural does not view mobile CNG/LNG as a viable medium- or long-term solution to alleviate sizeable distribution system weaknesses like currently exists in Forest Grove. Permanently citing a delivery point for CNG or LNG trucks to deliver gas to inject into the system during cold events and buying and maintaining the trucks to deliver the gas to the area, while also likely being more expensive than the uprate project, is considered by NW Natural operations experts as rather risky given that it would likely require relying on the ability of trucks to safely navigate to the area during extreme cold events that often correspond with dangerous road conditions. Furthermore, seeking to deploy mobile CNG/LNG to different locations on the distribution system as weaknesses arise would lead to an unsustainable situation through time where mobile CNG/LNG would be relied upon to be injected into numerous locations on the distribution system during peak events. Also, while it might be technically correct to deem mobile CNG/LNG as a "non-pipeline" alternative it would be, in NW Natural's view, incorrect to deem mobile CNG/LNG as more forward-thinking or avoiding*

the need for infrastructure in comparison to a pipeline uprate project. For these reasons, NW Natural did not develop a detailed cost estimate for mobile CNG/LNG as an alternative for the Forest Grove area.
NW Natural IRP Update Response: The Company has contracted with and is in the process of onboarding an engineering consulting firm to prepare a study for satellite and trucking of CNG and LNG supply. A purpose of this study is to inform the Company at which threshold satellite or trucking of CNG and LNG could be feasible for the system as a supply-side non-pipeline alternative. In the interim, the Company provides the following information: The two CNG trailers that NW Natural owns are not large enough to fully support the areas identified in the Forward-Looking Plan. NW Natural's two CNG trailers can supplement supply during a small part of a morning peak usage period but then need to be refilled before the demand shortfall is satisfied. In preliminary discussions with a CNG and LNG tanker supplier NW Natural has learned that to procure tanker supply services the Company will need to rent the tanks (filled with gas) for the winter months, so the tankers are on site and ready for usage when the additional supply is needed. The CNG and LNG trucking supply study will provide more background on the usage of CNG and LNG storage vessels supplied by third party vendors, their costs and operational considerations (LNG boiloff disposal, instrumentation and controls, staffing, etc.) The delay in responding to this recommendation was driven by NW Natural's decision to pursue a third-party study to inform its analysis of using CNG/LNG as a potential NPA for projects with existing supply deficits, rather than relying on the Company's analysis on this topic, which was not accepted by Staff.
NW Natural Updated Response in LC 86: Targeted Liquid Natural Gas (LNG) and Compressed Natural Gas (CNG) trailers can be deployed to support areas of the natural gas distribution system experiencing low pressures. These trailers are mobile supply sources, delivering gas directly into the system at an injection location where the CNG and LNG can be used to avoid distribution system outages. LNG and CNG trailers are required to be staged and connected to the NW Natural System before cold weather events begin. Natural gas used from these LNG and CNG trailers must be sourced from external facilities and transported to the site. This requires advanced coordination and financial commitment with external suppliers for the trailers to be full of fuel and available during the winter months. As discussed with Staff in the Implementation of IRP Update Recommendations, during TWG 8, the Company provided a discussion of an independent CNG and LNG trucking study which was still underway at that time. Per Staff's expectations, an overview of the Statement of Work, expected outcomes, and status of the study was shared during the TWG. Beyond the specifics of the study, the Company also shared the risks and benefits of CNG/LNG trucking as a system planning tool for distribution system constraints.

In Chapter 12 and Appendix J, the Company provides an overview of trucking as well as a discussion about a recently completed CNG and LNG trucking study.

Recommendation 14: Staff requests that the Company explore with stakeholders prior to its IRP Update the Company's Contingency Plan in preparation for cold days with a potential for detrimental events occurring, including information requested by Staff in LC 79 Final Comments.
NW Natural Response in LC 79 Final Comments: The Company does not object to this recommendation. The Company will share its high demand contingency plan guidelines for upcoming cold weather days with stakeholders prior to the next IRP Update.
NW Natural IRP Update Response: NW Natural provided a summary of the Company's distribution system cold day contingency planning in the IRP Update. In Staff Final Comments, Staff asks us to provide responses to five bulleted questions in support of a response to Recommendation 14, which we do here. **Staff Questions:** *"What constitutes an emergency? What constitutes a risk event?"* **NW Natural Response:** In general, NW Natural considers an emergency event to be an event where a third party, or natural forces, have damaged a pipeline thereby creating a safety hazard, system outage and a possible loss of service to customers. In terms of cold weather planning, NW Natural considers an emergency event to be loss of service to customers. The process to relight customers, once they have lost gas service due to loss of pipeline pressure, can be a multi-day event. If the cold weather remains for more than one day, a loss of service due to low pressure can re-occur multiple times during the cold weather event. Cold weather increases the safety risk to customers due to loss of heat, and increases safety risk to employees who respond to emergencies due to poor road and working conditions. NW Natural considers a risk to be any uncertainty that presents the possibility of a negative outcome (event). In terms of cold weather planning, a risk is a known uncertainty that could lead to the loss of gas service to a customer(s) if the uncertainty were to occur. Examples of risks identified during cold weather event planning are: • weather conditions that exceed forecast weather conditions

- impacts to upstream gas supply (interstate pipeline supply)
- equipment failures affecting ability to withdraw from storage or move gas through gas distribution systems (compressors, pressure regulators, etc.)
- customer usage in excess of historical usage
- energy content in gas sources falls below that used in system planning analyses

In an attempt to reduce risk in advance of cold weather, our Engineering System Modeling team conducts an annual review of the distribution system for a peak cold weather event to identify existing and potentially new low-pressure areas. These known, expected low pressure areas are documented internally, and this knowledge is transferred to others within the Company's Operations Department. As cold weather forecasts become known, the System Modeling team again reviews these known cold areas with personnel in the Company's Operations Department. Possible targeted interruptible customer curtailments are identified. Possible operational measures, such as by-passing key pressure regulator stations, or slight outlet pressure adjustments to pressure regulator stations are discussed in efforts to maximize reliability for customers.

Staff Questions:
"What criteria should be met to trigger contingency actions (include District Regulator bypass or interruptible load)"

"Who or What would make the decision for this action? For example, is the trigger of interruptible load decided by Company personnel or automated?"

NW Natural Response:
NW Natural operations personnel perform contingency actions when necessary to maximize the performance of our gas distribution system during cold weather events. All decisions made to enact contingency actions are made by Company personnel.

Cold weather contingency action planning draws upon operational experiences from previous winters. With each passing winter NW Natural's personnel from Operations and Engineering review system performance to note areas of low pressure. Contingency plans will be discussed for pressure regulators that supply gas to a large area, or areas that are the single supply for Class B distribution systems (operating pressures less than 60 psig), when NW Natural has observed and/or modeled low pressures is these areas.

In the warmer months, some pressure regulator station outlet pressure settings are adjusted downward, as full system pressures are not necessary for all areas of our system. Seasonal adjustment of pressure regulator set-points allows Gas Control to move gas through our system in a desirable manner. For example, to move gas from Molalla and or Deer Island Gate Stations to Mist for injection into underground storage, or to help achieve send out of our LNG tailgas during the liquefaction cycle at our Portland LNG facility.

Operations also enacts contingency actions to manage targeted interruptible customer loads when necessary to fully, or partially, curtail interruptible customer(s) on our system during cold weather, or other operational or maintenance needs. For evaluation of the specific interruptible loads on NW Natural's distribution system, the Company aligns with our system reinforcement guidelines. If targeted interruptible customer loads are modeled to cause our system to experience more than a 40 percent pressure drop for the upcoming cold weather event, then our System Modeling team determines how much load curtailment from interruptible customers is required. If the system is expected to reach or exceed 40 percent pressure drop, with the targeted interruptible customer loads fully interrupted then our System Modeling staff communicates to our Major Accounts Services Team (MAST) staff which customers should be fully interrupted during the cold weather event. Likewise, if System Modeling determines that that our system will not reach or exceed 40 percent pressure drop with full targeted load interruptions, then partial interruptions are determined for the targeted interruptible customers, with the daily or hourly allowable curtailment flow rates for the proposed targeted interruptible customer loads determined in advance of applicable cold weather. Our MAST staff communicates the curtailed flow rate and time duration requirements to the targeted interruptible customer.

Staff Question:
"How often were these contingency actions (regulator bypassing or interruptible load) taken to alleviate the distribution system pressure in Forest Grove in the last five years? Please provide the dates and times of each action, duration of each action, and recorded temperature and district regulator inlet pressure when the action was taken? "

NW Natural Response:
In LC 79 Staff Final Comments staff notes the instances where regulator bypassing occurred. As Staff noted, NW Natural did not interrupt the two small interruptible commercial customers served by the Forest Grove Feeder. The regulator bypassing summarized in Staff's Final Comments, were the only instances of regulator bypassing within the last five years.

In Section 8.3.2 of the LC 79 2022 IRP NW Natural noted that we began to utilize the Customer Management Module (CMM) in 2021, and we used CMM to model the Forest Grove Feeder. CMM more accurately models local system loads, and the resulting pressures based on historical customer specific usage, rather than use localized averages of large geographic areas, as we had done during previous hydraulic modeling simulations. The winter of 2020/2021 was the first winter that an Electronic Portable Pressure Recorder (EPPR) was utilized, and this was the first winter we became aware that the pressure at the inlet to the Forest Grove city district regulator (at the end of the Forest Grove Feeder), were low enough that the pressure drop on the line exceeded 40%. Using a formal cold weather planning procedure that NW Natural Engineering Department has enacted since the 2022 IRP, NW Natural will plan to interrupt the two small commercial customers served by the Forest Grove Feeder until such time as we have completed the work to raise the operating pressure (uprate) of the Forest Grove Feeder.

Staff Question:
"Are there any provisions to work with non-interruptible large load customers to constrain their flow rates to ride through peak hour events as a viable contingency option? Has the Company considered a tariff that, instead of requiring customers to be interrupted completely at peak hours, requires customers to reduce their usage by a certain amount at peak hours? Has the Company inquired as to whether customers would be open to a partial usage reduction at peak hours, instead of a complete interruption as in the current interruptible tariff? Is there a program to let customers, especially non-weather dependent customers, know that a cold day event is imminent to give them the change to voluntarily reduce their gas usage? "

NW Natural Response:
NW Natural's existing tariff allows us to fully or partially curtail interruptible customers as needed for supply or system pressure needs as per the Company's system reinforcement standards, as discussed in NW Natural's response to Staff's second bullet question above. NW Natural has not inquired as to whether firm customers would be open to a partial usage reduction at peak hours since large load customers already have the option to select blocks of firm supply along with blocks of interruptible supply. For these mixed tariff customers, the Company can fully or partially curtail the interruptible block of supply. See more details in response to recommendation #15.

NW Natural does not currently have a program that would inform non-weather dependent customers that a cold weather event is imminent, and they have the option to voluntarily reduce their gas usage. This would be considered a behavioral demand response program. NW Natural is open to exploring such a program with the proper measurement and verification procedures to validate any peak energy savings. However, the potential for industrial firm customers to participate in such a program could be limited. Customers are choosing to pay higher rates for firm service to fit their production processes. Reducing their natural gas

usage leads to reduced production, which could mean temporary loss of profit and/or employment. Behavioral programs are likely to be more effective with residential segments that revolve around energy services for comfort rather than business requirements.
NW Natural Updated Response in LC 86: NW Natural provided a summary of the Company's distribution system cold day contingency planning in the IRP Update. In Staff Final Comments, Staff asked the Company to provide responses to the above-quoted five questions in support of a response to Recommendation 14. These responses can be found in full in the LC-79 docket on the Oregon Public Utilities Commission website. Additionally, and consistent with Staff's Implementation of IRP Update Recommendation, NW Natural discussed cold weather contingency planning during Technical Working Group 8. The TWG presentation and recording are available on NW Natural's website.

Recommendation 15: In the forward-looking distribution system planning included in future IRPs, NW Natural should consider in its study of non-pipe alternatives whether it could develop an operational flow tariff for reductions of peak usage on the constrained portion of the distribution system with different price and load reduction requirements than the current interruptible tariff.
NW Natural Response in LC 79 Final Comments: NW Natural already deploys the type of interruptible option described by Staff in this section of their comments and has for many years. Large commercial and industrial customers can choose firm service for some portion of their load and interruptible service for the rest. NW Natural refers to this type of customer as a "base block" customer and currently has 37 base block customers. GeoDR via incremental interruptibility from customers in a constrained area on the distribution system would require special contracts for these customers based upon location specific avoided costs and could provide certain customers a windfall due to geographic happenstance, something NW Natural believes warrants further discussion around equity.
NW Natural IRP Update Response: NW Natural's major accounts services team works with large industrial customers to inform them of their options. Customers choose the rate schedule that best fits their business. As stated in the Company's LC 79 final comments, this includes options for base blocks of firm deliveries which is flexible to their needs. NW Natural has historically looked at large firm customer load in constrained areas and whether paying these customers to switch to an interruptible load could avoided a system reinforcement project as a non-pipeline solution. NW Natural will continue to evaluate this as an option and will balance this opportunity against potential issues with such a tariff offering.

NW Natural Updated Response in LC 86: NW Natural's Near Term Action Plan proposes to provide geo-targeted behavioral demand response offerings to large commercial and industrial customers in the Creswell, Dallas and McMinnville areas. Unlike the interruptible rate schedule, the participating commercial and industrial customers need to curtail their gas usage during the DR event period only and performance-based incentives will be provided for their load reduction.

Recommendation 16: Toward the goal of facilitating forward-looking distribution planning, NW Natural should provide a 10-year distribution system plan in its next IRP Update, as the Company indicated it plans to do.
NW Natural Response in LC 79 Final Comments: The Company will provide a copy of our most recent 10-year distribution system plan in the next IRP Update, as detailed in the IRP.
NW Natural IRP Update Response: NW Natural provided its 2024 Forward Looking Plan in Appendix C of LC 79 2022 IRP Update #1. This Forward-Looking Plan identifies five areas within NW Natural's distribution system for investigation and monitoring that may require a large system reinforcement or non-pipeline alternative effort to provide reliable service to firm sales and transportation customers.
NW Natural Updated Response in LC 86: NW Natural provided its 2024 Forward Looking Plan as Appendix C of the 2022 IRP Update, filed on August 5, 2024 in docket LC 79. This Forward-Looking Plan identified five areas within NW Natural's distribution system for investigation and monitoring that may require a large system reinforcement or non-pipeline alternative effort to provide reliable service to firm sales and transportation customers. After further investigation, three of those five areas warranted non-pipeline solutions be pursued. The Forward-Looking Plan and NPAs were discussed with stakeholders during TWG 8. Chapter 12 discusses forward-looking distribution planning along with potential pipeline and non-pipeline options as well as the Company's preferred options. The Company coordinates with ETO on specific efforts such as GeoTEE. A memorandum from ETO is included in Appendix J on this topic as it relates to the three areas identified within this Forward-Looking Plan.

Commission Order No. 23-281 By the time of its next IRP Update filing, we expect NW Natural to file its initial distribution system plan, which should include alternatives analysis at least five years ahead for areas in which investments may be needed **Recommendation 17:** In future IRPs, Staff recommends that when NW Natural is monitoring areas in the distribution system where system reinforcements may be needed in the future, whenever possible, ample time should be allowed for evaluation and analysis of GeoTEE and Geographically Targeted Demand Response (GeoDR), among other alternative solutions.
NW Natural Response in LC 79 Final Comments: NW Natural supports Staff's recommendation and this is the primary driver why the Company has been transitioning to a forward-looking distribution system planning process. NW Natural discusses this concept

in the 2016 IRP, 2018 IRP, and in the GeoTEE pilot filing. This transition has been a major change from just-in-time planning and will allow more lead time for targeted efforts such as GeoTEE if found to be a cost-effective option. Please see Part 3 for supplemental information supporting NW Natural's position on this recommendation.
NW Natural IRP Update Response: NW Natural has identified 5 areas under investigation in its 2024 Forward Looking Plan and has reached out the Energy Trust to analyze the feasibility and cost of implementing a GeoTEE effort in these areas. Additionally, NW Natural is in the process of implementing a system wide residential and small commercial demand response program this upcoming 2024-2025 winter. Once this program is established, a GeoDR evaluation can leverage data from the system-wide program.
NW Natural Updated Response in LC 86: NW Natural has identified five areas under investigation in its 2024 Forward Looking Plan and has reached out to Energy Trust to analyze the feasibility and cost of implementing a GeoTEE effort in these areas. Additionally, NW Natural implemented a system wide residential and small commercial demand response program during the 2024-2025 winter. NW Natural anticipates using this program to leverage data from the system-wide program for GeoDR evaluation.

Commission Order No. 23-281 In addition, by the time NW Natural's next IRP is filed, we expect the company either to have its GeoTEE program ready to implement or have an RFP ready to issue to the market for feeder-based load reduction. **Recommendation 18:** In the near-term, if NW Natural's geographical load reduction programs are not available to alleviate forward-looking distribution system constraints, then a peak load reduction RFP should be issued to third parties.
NW Natural Response in LC 79 Final Comments: As described in the IRP, NW Natural anticipates GeoTEE and GeoDR load reduction programs to be available for consideration by the next IRP. However, if these programs are not available, NW Natural will issue an RFP for geographically targeted demand response to third parties for consideration in alternatives analyses.
Recommendation 18 (adopted modification): By the next IRP filing, if NW Natural's geographical load reduction programs are not available to alleviate forward-looking distribution system constraints, then a peak load reduction RFP should be issued to third parties. (Order No. 23-281 at 16)
NW Natural IRP Update Response: NW Natural anticipates its GeoTEE and GeoDR load reduction programs will be available for consideration in the next IRP.
NW Natural Updated Response in LC 86: See Chapter 12 for GeoTEE and GeoDR evaluation in the three areas identified in the forward-looking plan. Additional details are also provided in Appendix J.

Recommendation 19: In future IRPs, for multimillion dollar upgrade projects presented, NW Natural needs to demonstrate that its system reinforcement guidelines and customer delivery requirements represent a realistic risk of loss of load. For example, given that the Company's system reinforcement guidelines are based on a 40 percent pressure drop equivalent to a pipeline at 80 percent of its capacity, under what circumstances would an unexpected weather or load event result in use of the additional 20 percent of peak capacity that could lead to a loss of load event?
NW Natural Response in LC 79 Final Comments: NW Natural has already provided substantial detail to support its System Reinforcement Standards. The support for these criteria was provided in the 2018 IRP and reviewed by Staff and stakeholders in detail. In the Staff Report in the 2018 IRP Staff noted that it requested – and received – "an in-depth explanation of the engineering basis for NW Natural's high-pressure distribution system reinforcement standards." The response to OPUC DR 95 and OPUC DR 52 in NW Natural's 2018 IRP (LC 71), where this information was provided, is included as Appendix A. As such, NW Natural is not opposed to providing this information in future IRPs.
NW Natural IRP Update Response: NW Natural has routinely provided support its System Reinforcement Standards and will continue to provide this information in future IRPs.
NW Natural Updated Response in LC 86: Standards are discussed in the Distribution System Planning Criteria Section of Chapter 12 and were presented to Stakeholders in Technical Working Group 8.

Recommendation 20: In future IRPs, NWN should provide an RNG procurement scoring methodology and associated modeling details, including up to date and accurate table(s) that list all sources of data inputs to the RNG acquisition model, as well as a narrative description of all updates and changes.
NW Natural Response in LC 79 Final Comments: NW Natural agrees to continue to articulate its approach to evaluating and securing RNG resources both within the RFP process and outside of it, and to fully share that approach in future IRPs. The RNG market is not a liquid market, and so while NW Natural endeavors to use the best available information and recent RFP responses to forecast RNG prices for purposes of the IRP, the actual resources available for the Company to execute at any given time may look different from what national analyses of the RNG market suggest. While the current RNG portfolio being considered by the Company can and does inform IRPs, the Company will continue to leverage analysis from third party resources to ensure we are reflecting the best available information about the market.
NW Natural IRP Update Response: This work is underway.
NW Natural Updated Response in LC 86: To assist in evaluating which RNG projects to pursue, NW Natural uses its risk adjusted incremental cost methodology established in UM 2030. This methodology is used to assess the ratepayer costs and benefits of

NW Natural-owned RNG projects and third-party RNG contracts. A risk-adjusted incremental cost model is completed for each opportunity and is based on data such as volume, term, price, and assessed risk. Details on NW Natural's RNG evaluation methodology, incremental cost workbook, and evaluation process are detailed in Appendix K. Table K-3 describes the inputs to the incremental cost model along with the update frequency.

Recommendation 21: If the Company updates its RNG procurement approach from what was included in its most recent acknowledged IRP, the Company should notify the Commission of the changes in its IRP Update. The update should include, at a minimum, where inputs and assumptions differ from those in its most recently acknowledged IRP and provide rationale for all changes.
NW Natural Response in LC 79 Final Comments: The Company does not object to this recommendation. If NW Natural updates its RNG procurement approach the Company will include these changes in its IRP Update and include the information requested by Staff.
NW Natural IRP Update Response: NW Natural continues to refine its evaluation processes, as noted in the response to Recommendation 20, and will notify the Commission when that is finalized. The Company's approach to procuring RNG will not fundamentally change as a result of this work. NW Natural applies its risk adjusted incremental cost methodology to all potential utility RNG investments and RNG purchase opportunities. The Company develops its portfolio of RNG purchase opportunities by conducting an annual Request for Proposal as well as evaluating other opportunities that arise outside of the RFP process throughout the year. The least-cost, least-risk resource or investment opportunities are then recommended for selection based on the UM 2030 approved methodology. In discussions with Staff prior to filing the IRP Update, NW Natural mentioned that it is in the process of trying to simplify the tool used for RNG evaluation process to improve transparency. This work is on-going.

NW Natural Updated Response in LC 86: The Company's RFP procurement approach includes the following steps: • Verify General Qualifications • Calculate Risk-adjusted Incremental Cost • Determine Short List • Score Proposals RNG procurement strategy was shared during TWG 6 and is discussed in detail in Chapter 7. Appendix K provides the Company's resource evaluation methodology for low emissions gas resources including a discussion of the incremental cost workbook as well as the RFP evaluation process. The following improvements have been made to the Incremental Cost Workbook: Avoided costs are updated annually, a new scenario tab was created where critical variables can be adjusted outside of the 5th and 95th percentile (capital expenditures, operations and maintenance costs, production), an investment tax credit scenario was created, and an on-system bundled model was created to simplify inputs and outputs which reduces the amount of formulas to track. NW Natural added a risk scoring matrix to the offtake evaluation process (as shown in Chapter 7).

Recommendation 22: In the next IRP, NW Natural should discuss whether and how the RNG projects secured since the last IRP are in the best interest of ratepayers, including a discussion on how the various project types and associated deal structures (buy vs build) share costs, benefits, and risk across ratepayers and shareholders.
NW Natural Response in LC 79 Final Comments: NW Natural does not support this recommendation. The Company is willing to provide detail of all existing projects delivering – or contracted to deliver in the future – RNG to NW Natural customers in the next IRP as it has done in the 2022 IRP. Furthermore, the Company will continue to include how it evaluates whether RNG resources are in the best interests of customers via updates to its Renewable Gas Evaluation Methodology (Appendix K in the 2022 IRP) in each IRP, including information requested in Staff Recommendation 20. However, NW Natural does not believe IRPs are the appropriate venue to demonstrate how projects that are already delivering RNG or are contractually obligated to deliver RNG are in the best interest of ratepayers. NW Natural believes that prudency evaluations in annual purchased gas adjustment (in the case of "offtake" agreement RNG) and the RNG automatic adjustment clause (in the case of development RNG) are the appropriate dockets to demonstrate why these projects are in the best interest of ratepayers.
Recommendation 22 (modified and adopted): In its next IRP, NW Natural shall provide a table of its existing RNG projects, including the type of project and the deal structure, similar to the table that PacifiCorp provides in its filings.[1] (Order No. 23-281 at 12)
NW Natural IRP Update Response: NW Natural will include this table in its next IRP. In NW Natural's 2022 IRP, the Company included a section titled "6.4.8 Existing RNG Contracts" that included a table 6.16 of all the existing RNG that the Company had at

the time of filing the IRP, inclusive of feedstock, contract type, and projected near-term volumes. NW Natural is working with Staff to review this table and align on approach for the next IRP.

Figure 6.16: Current RNG Contracts

Projects	Feedstock	Type	Projected Volumes (MMBtu/year)		
			2022	2023	2024
Element Markets NYC	Wastewater	Offtake	182,502	365,000	365,000
Archaea Offtake Portfolio	Landfill	Offtake	-	500,000	500,000
Tyson – Lexington[1]	Food & Brewery	Development	86,202	86,000	86,000
Tyson – Dakota City	Food & Brewery	Development	0	113,529	199,219
Wasatch Resource Recovery	Livestock	Offtake	63,606	91,250	91,250

NW Natural Updated Response in LC 86: Table 7.6 in Chapter 7 provides a table of its existing RNG contracts. It includes the type of project and the deal structure, similar to the table that PacifiCorp provides in its filings (Order No. 23-281 at 12, Table 6.16).

Recommendation 23: NW Natural should convene a stakeholder group immediately following the conclusion of the IRP to establish a transport customer efficiency program in time to be able to report on its status in the 2024 IRP update.

NW Natural Response in LC 79 Final Comments: NW Natural supports this recommendation. Staff and NW Natural are on the same page regarding the importance of energy efficiency (EE) to NW Natural's CPP compliance strategy and the immediate need Page 25 of 78 NW Natural OPUC LC 79 Final Reply Comments for stakeholder engagement on the progress of the energy efficiency program for transportation customers. NW Natural proactively moved the ball forward on transport EE programs by including the first conservation potential assessment (CPA) for Oregon customers on transportation schedules in the 2022 IRP. NW Natural will schedule a stakeholder workshop in the summer to discuss next steps to establishing transport customer EE programs

NW Natural IRP Update Response: See page 8 of the 2022 IRP Update.

NW Natural Updated Response in LC 86: NW Natural partnered with Energy Trust of Oregon to deliver the interim transportation energy efficiency program. The 2024 program was approved on June 11, 2024 with a budget capped at $700,000. The 2025 program became effective on February 19, 2025. Offerings were limited to Energy Trust's Standard Track offerings, in which customers may apply for incentives from a list of measures that have deemed savings associated. The total program budget for 2025 was capped at $1.13 million with a potential for an additional $0.5 million in reserve funding. Transportation programs were discussed with stakeholders during TWG 5 and are discussed in more detail in Chapter 6.

Recommendation 24: NW Natural, in the development of a transport customer efficiency program for 2024, should explore and share findings regarding an incentive that would adequately incentivize efficiency, but would not be applied as a flat, per therm rate to usage reductions for operational, economic, or other reasons.
NW Natural Response in LC 79 Final Comments: NW Natural supports this recommendation. To this end, avoided cost values and their derived cost effectiveness assessment metrics appropriate for transportation EE programs have been listed among the core agenda for the above-mentioned upcoming stakeholder workshop to be held this summer. At this workshop, NW Natural is open to insights and feedback from all stakeholders and in addition, NW Natural is seeking further direction from the Commission on how a fair and adequate incentive should be designed to incentivize transportation customers to achieve EE savings without causing potential equity issues to other customer groups. It is also NW Natural's intention to include a proposed incentive design in the development of the transportation customer EE program for 2024. This is in alignment with NW Natural's response to AWEC Request 1 "that transportation energy efficiency should follow the same cost-effectiveness calculations as other EE so as to maintain an apples-to-apples comparison.
Recommendation 24 (modified and adopted): Staff, the Energy Trust of Oregon, and other interested entities shall present information in a public meeting on the status of efforts to create a transportation customer efficiency program, including any barriers the Commission may assist in overcoming. (Order No. 23-281 at 18)
NW Natural IRP Update Response: On October 31, 2023, NW Natural presented an update on the transportation program development to the Public Utility Commission of Oregon. The update included an overview of the proposed program, the status of contracting and data transfer agreements, and an expected timeline for program roll-out. On June 11, 2024, the Commission adopted Staff's recommendation supporting NW Natural's Advice No. 23-29E, establishing a transportation customer energy efficiency program.
NW Natural Updated Response in LC 86: The 2025 program became effective on February 19, 2025. NW Natural presented to stakeholders on the Transportation Customer Efficiency Program in TWG 5. The Program is discussed in further detail in Chapter 6.

Recommendation 25: Staff recommends the Company reach out to AWEC to discuss whether the value of interruptible customers is being adequately represented in the IRP and make any appropriate updates in the 2022 IRP Update.
NW Natural Response in LC 79 Final Comments: NW Natural will reach out to AWEC to discuss whether the value of interruptible customers is being adequately represented in the IRP and discuss potential updates for the next IRP Update.
NW Natural IRP Update Response: NW Natural reached out to AWEC regarding this issue but has yet been able to meet with them about these concerns. NW Natural will continue to pursue this discussion.
NW Natural Updated Response in LC 86: The Company has begun working with AWEC to explore opportunities to expand the program for other large commercial and industrial customers in these areas with area-specific rate schedules that provide higher incentives than the existing rate. Such efforts were shared with stakeholders during TWG 5 and TWG 8.

Recommendation 26: The next IRP should include modeling of all relevant distribution system costs and capacity costs, including additional projects that would be needed in high load scenarios as well as costs that would not be incurred in lower load scenarios.
NW Natural Response in LC 79 Final Comments: Staff is mistaken that this information is not included in the 2022 IRP. This IRP is the first IRP to include this information as part of the rate impact analysis in any IRP filed with the OPUC. That this first attempt, while somewhat rudimentary, was made in the IRP and detailed in the IRP discovery process and the Company's Reply Comments. Part 3 provides more information on the work that was done and how the costs varied across scenarios by variation in load. The Company is committed to improving upon this analysis in the next IRP. NW Natural believes that having these costs included and varied with load should be a consistent expectation across all utilities filing IRPs in the state and is best addressed through a review of the IRP Guidelines.
NW Natural IRP Update Response: This work is underway.
NW Natural Updated Response in LC 86: In this IRP, the Company included incremental commodity, capacity, and compliance costs. Cost of Service analysis was also used where applicable. However, and as discussed in the Executive Summary, more analysis needs to be done to understand what additional savings may accrue relative to NW Natural specific gas infrastructure for varying levels of natural gas customers. In a scenario where 90 percent of the residential customer base is electrified, further investigation is necessary to identify what infrastructure and company operations would still be required to serve the remaining ten percent of customers. The Company discusses this in the Electrification section of the Executive Summary and includes some additional information to provide some context.

Recommendation 27: The Company should provide NPVRR for each portfolio in the next IRP and a breakdown of portfolio NPVRR into cost categories in workpapers filed with the IRP.
NW Natural Response in LC 79 Final Comments: Staff's Final Comments requests in its support for this recommendation: *the Company provide a clear breakout of costs by type and by year in the next IRP. For example, categories could include distribution LEA, distribution system upgrade, supply side resources, capacity resources, and demand response.* NW Natural did provide Staff and Stakeholders with the relevant costs by year that need to be considered for system resource planning, including total gas costs, investment costs in capacity resources, investments costs in incremental demand-side actions, and total compliance costs. This was done for every scenario and every Monte Carlo draw. Additionally, estimates for the remaining annual revenue requirement, which would include costs associated with distribution LEA and distribution system upgrades, were also in the work papers provided, and factored into the bill impact analysis for each scenario. NW Natural will work with Staff to better clarify the cost categories that they are interested in seeing more clearly presented in the next IRP.
NW Natural IRP Update Response: This work is underway.
NW Natural Updated Response in LC 86: NPVRR for compliance costs by each sensitivity are provided in Figure 9.7. These costs are broken out by compliance resource. Section 11.1.1 show box-and-whisker plots of NPVRR cost for varying components (fixed and variable costs, electrification costs, and compliance costs) across the 50 draws for the PRS, S6 – Hybrid, and S7 – All Electric scenarios. These costs are aggregated in Figure 11.11. Specific values for these figures are also provided in the workpapers.

Recommendation 28: In the next IRP, Staff recommends that the Company be required to do a Monte Carlo analysis of the top scenarios rather than across scenarios.
NW Natural Response in LC 79 Final Comments: NW Natural does not support this recommendation. We see its recommended approach as more limiting in information and value. Staff states that the: *current approach makes it difficult to analyze how the NPVRR of a portfolio resulting from a low RNG price scenario would respond to an unexpected change in load or the adoption of gas heat pumps* As shown in detail in Part 3 for this recommendation, we can use the outputs from the IRP to assess this very question and show the implications of high and low heat pump adoption in a low RNG price environment. Because of the approach we took, we can put this analysis together from the outputs of the Monte Carlo analysis despite it not being requested early in the IRP process. Therefore, the outputs from the IRP can be beneficial beyond the IRP process, with less regret of not having conducted specific sensitivities within a single scenario. NW Natural recommends continuing to implement its current approach in the next IRP of

treating all key variables as uncertain in our Monte Carlo analysis. See Part 3 for supplemental information to support the Company's position on this recommendation.
NW Natural IRP Update Response: The terms *portfolio* and *scenario* are often used interchangeably by Staff and stakeholders, however; NW Natural see a critical distinction between the use of these two terms: • A scenario is a defined set of inputs that present a specific outlook of the future. • A portfolio is a set of resources that are acquired by the utility. The PLEXOS® model is designed to select the least cost portfolio given a specific set of inputs (i.e., scenario). Monte Carlo analysis can be used to randomly vary key uncertainties and PLEXOS® can solve for the least cost portfolio for each random future. The Commission has expressed an interest in viewing a specific portfolio of resources and measuring how that portfolio performs under different futures. A simple example might be an RNG only approach. This circumvents the algorithm in PLEXOS® that selects the least cost portfolio. In other words, a fixed resource portfolio selection such as an RNG only compliance portfolio, must be a higher costs portfolio relative to a model where resource selection adapts to input changes. NW Natural is not opposed to conducting this type of fixed portfolio analysis and recognizes there could be valuable learnings that can be generated from these types of analysis. However, the Company cannot be expected to produce outputs for every conceivable combination of fixed resource portfolios, deterministic scenario inputs, and stochastic inputs. **To meet expectations, the Company needs clarity from Staff:** 1. What set of resource portfolios should be tested; 2. What scenarios should be tested (either pulled from the last IRP or new); 3. What uncertainties should be treated as random and tested (see Table 7.4: Stochastic Variables for Risk Analysis). The approach taken in the 2022 IRP was to run 9 scenarios and separately run a stochastic analysis across all the key uncertainties that feed into the IRP analysis. The outputs of the PLEXOS® software solved for the optimal least cost portfolio of resources for each of the 9 scenario and each of the 500 random (stochastic) futures. This methodology provided a vast amount of data on a wide range of potential futures. NW Natural maintains that this method was an appropriate method for evaluating the risk of the Action Items requested in the Action Plan.

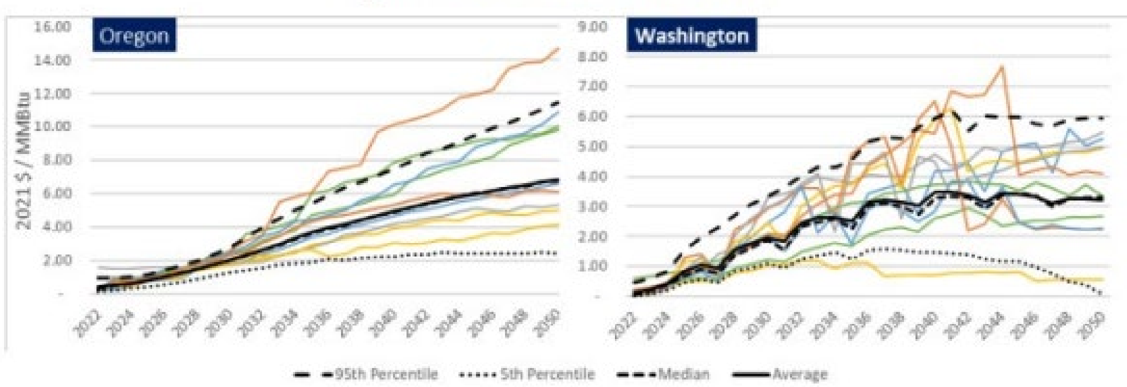
The Company has reached out to Staff for guidance on how to structure scenarios and stochastic analysis and will work with stakeholders through our technical working group process. NW Natural will continue to adapt and balance IRP complexity, time constraints to complete analysis, and stakeholder accessibility.
NW Natural Updated Response in LC 86: Please see Section 11.1.1.3 for a 50 draw Monte Carlo analysis for the PRS, S6, and S7. Additionally, due to technical issues, the Company was limited in how many Monte Carlo analyses it could perform and sought guidance from Staff as to how to prioritize the Monte Carlo analysis. These sections reflect the agreed-upon risk analyses. Distribution of cost categories are shown by box-plot graphs in this section.

Recommendation 29: NW Natural's next IRP should provide metrics comparing the severity and variability of risk in key portfolios.

NW Natural Response in LC 79 Final Comments: Staff references risk metrics and methods deployed by PacifiCorp and PGE for evaluating investment decisions. Please see Part 3 for further discussion about the fundamental differences and similarities between the investment decisions being considered by NW Natural and the investment decisions electric utilities are facing.

In general, NW Natural is receptive to Staff's asking for risk metrics in the next IRP but points out that the dispersion graphs that are provided in the 2022 IRP are the risk metrics comparing the severity and variability of costs for compliance with the CPP. Figure 7.13 specifically shows the severity and variability of the weighted cost of decarbonization for complying with the CPP.

Figure 7.13: Monte Carlo Total WACOD



NW Natural OPUC LC 79 Final Reply Comments NW Natural believes the 2022 IRP has sufficiently analyzed the risks and severity of bad outcomes for meeting SB 98 targets and complying with the CPP. This risk analysis has informed the decisions that we are asking to be deliberated in our Action Plan.
NW Natural IRP Update Response: NW Natural will work with Staff to seek further guidance and clarification regarding what metrics should be included in the IRP during the development of its IRP.
NW Natural Updated Response in LC 86: Please see Section 11.1.1.3 for a 50 draw Monte Carlo analysis for the PRS, S6, and S7. NW Natural met with Staff during the development of this IRP and discussed desired metrics for this IRP. This includes distributions for present value revenue requirement of the modeled costs and heat maps reflecting the quantities and types of compliance resources selected.

Recommendation 30: To explore the potential benefits of dual fuel heat pumps, the Company's next IRP should include an in-depth study of dual fuel heat pump potential and the effects of dual fuel technology on peak and average load on the gas system.
NW Natural Response in LC 79 Final Comments: Staff is mistaken that the 2022 IRP does not provide an in-depth study of the potential for dual-fuel heat pumps. NW Natural's IRP is the first IRP in the region to evaluate this resource in detail. Each scenario and Monte Carlo Simulation has a different penetration of dual-fuel heat pumps, and the impact of the heat pumps is analyzed at the daily level depending on temperature – including the peak forecast driving capacity needs in that scenario or stochastic draw, as NW Natural detailed in discovery. NW Natural has packaged this information to specifically highlight key results relative to dual-fuel heat pumps in the 2022 IRP in Part 3. NW Natural is supportive of efforts to assess the potential for dual-fuel heat pumps and is committed to advancing this issue further in processes that are expected to take place before the next IRP.
NW Natural IRP Update Response: Without granular individual customer consumption data, it has been difficult to identify existing dual-fuel customers on our system. NW Natural uses external sources from NEAA and NREL to develop usage patterns for dual-fuel customers. This work is in progress.
NW Natural Updated Response in LC 86: Please see Chapters 10, 11, and 13 for detailed information on Dual Fuel Heat Pumps. Additionally, NW Natural dedicated a full scenario (S6) to dual fuel heat pumps as a counterfactual for an all-electric scenario. Figure 11.1 illustrates the potential benefits over an all-electric buildings scenario. As a result, NW Natural is requesting acknowledgement of two hybrid heating system action items in this 2025 Action Plan.

Recommendation 31: In the next IRP, the Company's reference case load forecast should better reflect current local, state, and federal policies.

NW Natural Response in LC 79 Final Comments: NW Natural disagrees with Staff's assertion that that the reference case should "better" reflect current local, state, and federal policies in its reference case. NW Natural stands by how we defined the reference case in the 2022 IRP to reflect historical trends, such that the impact from transformative policies can be measured against a "business-as-usual" future. NW Natural is receptive to recommendations that our reference case should reflect existing policies, including any resolutions or legislation that is enacted, but does not take immediate effect. However, at time of filing the 2022 IRP, no cities in our Oregon service territory had passed resolutions restricting natural gas. We re-iterate that the reference case is not a base case or NW Natural's expectation of the future. The Company maintains that it would be improper to bake in assumptions about future political outcomes into the reference case, which is used to be able to show how action (like complying with the CPP) compares to the historical trend continuation reference case. We also maintain that the reference case is appropriate for scenario analysis that is used to compare differences in key inputs across scenarios and to set a baseline to evaluate the impact of future policies. Please see Part 3 for further discussion.
NW Natural IRP Update Response: NW Natural will reflect current local, state, and federal policies in the IRP. The Company notes that the policy landscape is fluid, and the Company must lock-down load forecasts several months before filing the IRP to accommodate additional IRP modeling that relies on the forecast.
NW Natural Updated Response in LC 86: The Company continues to note the tension between the need to lock down the load forecast with the reality that the policy environment is dynamic. As such, the Company believes that the demand variation scenarios provide a sufficient range of forecasts to understand how the Company would adapt resource planning in times of uncertainty. See Chapter 4 for details on NW Natural's load forecast.

Recommendation 32: In the next IRP, NW Natural should clearly show which load reductions are because of efficiency and which are because of electrification.
NW Natural Response in LC 79 Final Comments: Staff is mistaken that a breakdown of load reductions was not included in the 2022 IRP. A detailed breakdown was included in the workpapers provided to stakeholders in this process, as the Company detailed through discovery. For the next IRP NW Natural will include more breakdowns of the sources of load reductions for the graphs included in the IRP document itself relative to efficiency vs electrification.
NW Natural IRP Update Response: NW Natural will continue to balance the inherent complexity of an IRP with accessibility and will work to address Staff's request.
NW Natural Updated Response in LC 86: The full difference between the Reference Case load forecast and the load forecasts for scenarios S5, S6, and S7 is attributable to building electrification and small levels of industrial electrification. Note that in the

Reference Case customer count forecast, the Company models a loss rate but does not have sufficient information determine the cause of a customer leaving the gas system as it would be due to demolition, abandonment, or electrification.

Recommendation 33: The Company should update its avoided costs to reflect that SB 98 RNG is voluntary and can be avoided with efficiency.
NW Natural Response in LC 79 Final Comments: NW Natural can update the avoided costs to reflect the Commission's decision on Action Item 5 after that decision is made. NW Natural disagrees with Staff's view that RNG for SB 98 can be avoided with energy efficiency given that SB 98 is a target based upon gas deliveries. NW Natural uses the marginal resource needed for CPP compliance as the avoided compliance cost and maintains this is appropriate. In the near-term, this is the cost of CCIs (regardless of modeling SB 98 or not) and is what is reflected in the near-term avoided compliance costs filed in the IRP. There is a slight change in timing of when the marginal CPP compliance resource changes from CCI's to RNG if SB 98 is modelled. For more details about the avoided cost calculation and reasons why SB 98 RNG cannot be avoided with efficiency, see the Company's response to this recommendation in Part 3.
NW Natural IRP Update Response: Since the invalidation of CPP, NW Natural has recommended reverting back to using the social cost of carbon for avoided compliance cost in its UM 1893 filing.
NW Natural Updated Response in LC 86: NW Natural has updated its avoided cost methodology to use the maximum of either the social cost of carbon or the marginal GHG compliance cost. For Oregon, this equates to using the marginal compliance cost for CPP, which is higher than the social cost of carbon throughout the planning horizon. The Company's avoided costs, as presented in Chapter 5, reflect that RNG purchased under SB 98 are voluntary goals and decided on project-by-project bases, and these decisions would not be impacted by varying levels of energy efficiency. This was discussed with stakeholders during TWG 5.

Recommendation 34: The Company should provide an updated Appendix K which correctly describes the Company's modeling for RNG projects.
NW Natural Response in LC 79 Final Comments: NW Natural provided an updated Appendix K with the IRP Addendum filed on March 27th, 2023.
NW Natural IRP Update Response: No further comments.
NW Natural Updated Response in LC 86: No further comments.

Recommendation 35: In the next IRP, the Company should provide support for risk modeling approach (i.e. lognormal vs normal risk distributions, ignoring upside risks) and ensure this topic is discussed in a technical working group meeting for the next IRP.
NW Natural Response in LC 79 Final Comments: NW Natural will discuss this topic in a Technical Working Group stakeholder workshop for the next IRP and provide support for the approach in the next IRP.
NW Natural IRP Update Response: This work is on-going and will be shared at a technical working group. Recommendations, feedback, and external sources on how other utilities are creating underlying risk distributions is welcome at any time.
NW Natural Updated Response in LC 86: See chapters 4, 7, 8, 9, and 11 for stochastic input modeling for weather, gas prices, compliance resources prices, and compliance resource availability and corresponding results. Stochastic inputs were discussed in Technical Working Groups 4 and 9. Additional details can be found in Appendix G.

Recommendation 36: In the next IRP, the Company should standardize their approach to selecting risk values such that modeling could be duplicated and ensure this topic is discussed in a technical working group meeting for the next IRP.
NW Natural Response in LC 79 Final Comments: NW Natural supports this recommendation and has also been integrating approaches to selecting risk values into the aforementioned (Recommendation 20) internal RNG acquisition policy. Each deal or project opportunity will have different structural or contractual elements that may not lend itself to a prescriptive approach to risk values, but the Company will endeavor to develop “buckets” for different elements of risk that most projects’ risk values will fall into. NW Natural also agrees to further discuss this topic in future Technical Working Groups.
NW Natural IRP Update Response: This work is underway. In addition to the risk-adjusted incremental cost model, a separate risk scoring mechanism is currently being developed to further analyze potential offtake opportunities. Draft risk categories include financial, constructability, counterparty risk, marketability, contract remedies, interconnect/feedstock/gas rights, and bidder experience. Each category will be scored based on the specified criteria to arrive at a total risk score. This score will be considered along with the results of the incremental cost model to identify those opportunities that will provide the greatest benefit to customers.
NW Natural Updated Response in LC 86: NW Natural discusses a risk scoring mechanism to analyze potential offtake opportunities in Chapter 7. Evaluation categories include financial risk, constructability risk, counterparty risk, marketability, contract/legal risk, interconnect/feedstock/gas rights, and bidder experience. Each category is scored based on the specified criteria to arrive at a total risk score. This score is considered along with the results of the incremental cost model to identify those opportunities that will provide the greatest benefit to customers. This was discussed with stakeholders in Technical Working Group 6.

Recommendation 37: The Company should provide an explanation for why it does not consider downside risks in its models and demonstrate that this approach results in least-cost, least-risk resources.
NW Natural Response in LC 79 Final Comments: After a discussion with stakeholders about customer risk-aversion as it relates to utility bills in detail at a Technical Working Group stakeholder workshop for the 2018 IRP, the risk-adjusted approach applied in Appendix K was detailed in the 2018 IRP. Including the risk that resources may turn out to be cheaper than expected (noted by Staff here as "downside risks") would move the calculation away from a risk averse perspective on customer preferences to more risk-neutral or risk-loving perspective. Noting that assessing customer risk preferences is needed to develop a risk-adjusted approach highlights that what is "least-risk" is unavoidably a matter of perspective. That said, NW Natural will discuss this issue in its next IRP Update and is open to including "downside risks" in its risk-adjusted calculations if stakeholders agree it is a better representation of customer preferences.
NW Natural IRP Update Response: NW Natural will continue to work with stakeholders regarding downside risk modeling. NW Natural evaluates the cost, price, and volume uncertainties of potential resources within the incremental cost model. The model assesses the statistical risk and is determined by internal research on the specific project. When evaluating risk for an opportunity, NW Natural utilizes third party opinions to supplement project due diligence done internally. The NW Natural potential RNG resource portfolio tracks various metrics including incremental cost to compare all resources to identify least-cost, least-risk resources for purchase.
NW Natural Updated Response in LC 86: NW Natural developed the risk adjustment methodology to develop a consistent metric for evaluating risk across different types of evaluation. This metric is used consistently for risk reduction value for avoided cost calculations, evaluating RNG opportunities, and evaluating supply-side resources. It is difficult or nearly impossible to ascertain an exact risk tolerance profile of customers. The Company is open to feedback on alternative methods that would improve alignment with customers' preferences. Additionally, the Company notes that this risk metric is only one metric used in decision making and does not always determine the outcome. If an option has significant down-side risk, the Company will take that into consideration, but has not formally developed a risk metric to calculate down-side risk.

Recommendation 38: For the next IRP, the Company should provide an analysis that would examine high-cost RNG, hydrogen, and synthetic gas as a sensitivity. The cost estimates should be on the higher end of recent, relevant publicly available forecasts, and the Company should provide the sources used for each cost forecast.
NW Natural Response in LC 79 Final Comments: NW Natural has included reasonable estimates based upon estimates from third party forecasts on the higher end of costs for RNG, hydrogen, and synthetic gas in its stochastic Monte Carlo draws, all 500 of which could be viewed as a "sensitivity." The higher end of these estimates in the near-term included in the Monte Carlo analysis

are not only higher than most third-party estimates, but higher than actual resources NW Natural could contract today. The estimates used for these resources were the result of a comprehensive literature review, engagement in numerous organizations specializing in RNG and hydrogen-based fuels, and actual resources being considered for acquisition for NW Natural customers, all of which were provided in detail through discovery. NW Natural will continue to include ranges for all relevant cost inputs in the next IRP, including estimates on the higher end of available forecasts. NW Natural's Reply Comments detailed the ranges for these resources included in stochastic Monte Carlo draws in the IRP to show that estimates considered high priced by Staff are included in these ranges.
NW Natural IRP Update Response: NW Natural is contracting with a consultant to produce costs and technical potential estimates and ranges for a variety of other alternative fuels to be evaluated for the next IRP.
NW Natural Updated Response in LC 86: Please see Scenario **S1.c** in section 9.4.1.1. Please also see Appendix E for the alternative fuels study.

Recommendation 39: For the next IRP, the Company should provide a literature review of RNG price and availability forecasts.
NW Natural Response in LC 79 Final Comments: NW Natural conducted a comprehensive literature review and has been actively engaged in the RNG market for a few years. This is the basis for the estimate of price and availability in the IRP, as was detailed in the discovery process in this IRP. NW Natural is open to working with Staff to understand the type of literature review it would like to see in the next IRP, but it would be incorrect to say that a literature review was not conducted for the input assumptions in the IRP related to RNG prices and availability.
NW Natural IRP Update Response: This work is in progress. NW Natural will work to get further clarification on what criteria a sufficient literature review will be evaluated on.
NW Natural Updated Response in LC 86: Please see Appendix E.1.

Recommendation 40: In the next IRP, the Company should refine its cost estimate for green hydrogen by modeling a resource with a precise capacity, utilization rate, and a precise quantity of renewable energy available to it at a given price. These assumptions should be shared in the Technical Working Group process and in the IRP itself.
NW Natural Response in LC 79 Final Comments: NW Natural agrees that modeling green hydrogen with a precise capacity and utilization rate is very important. NW Natural included this in the 2022 IRP and will include it in the next IRP. Because all the hydrogen costs are modeled from dedicated resources, the capacity factor and utilization rate are built into the cost estimate. Costs are developed based on the levelized cost of energy (LCOE), which includes an assumed capacity factor in the calculation. Additionally, NW Natural determined there is no practical limit of hydrogen supply to NW Natural customers. This conclusion is

based on the relatively small amount of hydrogen that NW Natural would need relative to the entire potential hydrogen market in the country. Green hydrogen cost assumptions were shared as part of the IRP process, but more information on calculations and electricity sources could be shared in Technical Working Groups for the next IRP.
NW Natural IRP Update Response: NW Natural is contracting with a consultant to produce costs and technical potential estimates and ranges for a variety of other alternative fuels to be evaluated for the next IRP, including green hydrogen.
NW Natural Updated Response in LC 86: See Appendix E for the Alternative Fuels Study. These results were shared at TWG 6.

Recommendation 41: For the IRP Update, NW Natural should engage a third-party expert to assist in estimating the cost of syngas. Workpapers supporting the updated estimate should be filed with the IRP Update.
NW Natural Response in LC 79 Final Comments: The Company disagrees with Staff's recommendation that a third-party need to be engaged to assist in estimating the cost of synthetic methane. The Company has utilized an abundance of quality, objective, third-party resources to formulate cost estimates for synthetic methane. NW Natural has transparently provided the sources it found most compelling in its literature review of hydrogen and methanation estimates through the discovery process. NW Natural acknowledges it may make sense to engage a third-party for some analyses, which in fact, the Company has done in this case, including accessing information through subscription services. The Company is concerned, however, that there are not clear guidelines regarding when a third-party should be engaged directly rather than third-party sources used (as is typical of most key input assumptions in an IRP), and that the layering on of additional consultants may only add unnecessary costs to customers.
NW Natural IRP Update Response: NW Natural is contracting with a consultant to produce costs and technical potential estimates for syngas along with estimates for a variety of other alternative fuels to be evaluated for the next IRP. The delay was caused by the development of a scope of work, interviewing potential consultants, approving the selection of a consultant, negotiating terms and conditions, and then conducting the work. Having syngas as a stand-alone resource study might have resulted in a timelier work-product but combining this effort with evaluation of other alternative fuels will provide a comprehensive assessment all alternative fuels into an efficient workstream for the next IRP, and be more cost-effective for our customers.
NW Natural Updated Response in LC 86: Alternative fuels including syngas were presented at TWG 6. The completed Alternative Fuels Study is provided in Appendix E and described in Chapter 7.

Recommendation 42: In the next IRP Technical Working Group process, NW Natural should provide an estimate of the capacity in MW of electrolyzers, renewable generation, and methanation equipment needed in each year for several key portfolios. The Company should also provide the cost and quantity of CO2 needed in each year in key portfolios to support syngas production.

The Company should request feedback from participants regarding the likelihood of these resources being readily available and consider applying any emerging technology availability discount at that time.
NW Natural Response in LC 79 Final Comments: NW Natural agrees that estimates of the capacity in MW of electrolyzers, renewable generation, and methanation equipment are important and that is why they are included in the hydrogen cost assumptions, which feed into the synthetic methane assumptions, and in the synthetic methane cost assumptions. NW Natural provided this information through the DR process, but it could be included earlier in the Technical Working Group process for the next IRP. Page 215 of the IRP discusses synthetic methane assumptions in depth. In summary, the IRP only models synthetic methane that comes from renewable hydrogen. Hydrogen is the primary cost component for creating synthetic methane, however, the cost of methanation is also required to get a synthetic gas estimate. The response to OPUC DR 137 includes several of the studies that were part of the literature review conducted on methanation and used to develop the methanation costs in the IRP, which recognize the state of the technology in developing the cost estimates. As described in the discovery process, the estimate used for the cost of methanation in the 2022 IRP is from a technology called direct air capture, which means capturing carbon from the atmosphere directly. Given that air is available anywhere on earth, there is no practical limitation to the CO2 feedstock used for direct air capture technologies.
NW Natural IRP Update Response: NW Natural is contracting with a consultant to produce costs and technical potential estimates and ranges for a variety of other alternative fuels to be evaluated for the next IRP, including syngas.
NW Natural Updated Response in LC 86: See Appendix E for the Alternative Fuels Study. These results were shared at TWG 6.

Recommendation 43: The Commission should indicate whether risk sharing will be considered at cost recovery for any future SB 98 RNG projects.
NW Natural Response in LC 79 Final Comments: NW Natural does not support this recommendation. The Commission has already addressed this issue in NW Natural's recent general rate case order, which was issued last October. In that order, the Commission approved an RNG automatic adjustment clause (Schedule 198). Under Schedule 198, the Company and its customers share the risk of any difference between the annual forecasted cost of its RNG investments and its actual costs. Specifically, any difference is subject to an earnings test deadband that is set at 50 basis points below and 50 basis points above authorized ROE. Given that the Commission has already addressed RNG risk sharing by approving an automatic adjustment clause with "modifications offered by Staff and CUB [that] are necessary to achieve a reasonable risk balance [e.g., the earnings test above]", Staff's recommendation is unnecessary.

NW Natural also believes it is inappropriate to consider any changes to Schedule 198 or any other rate recovery mechanism in an IRP docket. Rather any changes to these rate mechanisms should be done in proceedings specific to the existing RNG rate mechanisms involved and not through a generic IRP docket. NW Natural strongly believes that ratemaking should not occur in an IRP, especially when the Commission already addressed the issue that concerns Staff and was previously raised by Staff in a rate case, less than a year ago.
NW Natural IRP Update Response: This recommendation was not adopted.
NW Natural Updated Response in LC 86: No further comments.

A.3 NW Natural's 2025 Integrated Resource Plan – Washington Compliance

NW Natural's 2025 IRP complies with the current Washington IRP Guidelines as described in the table below.

Table A-2: NW Natural's 2025 IRP - Washington Compliance

Rule	Requirement	Plan Citation
WAC 480-90-238(4)	Work plan filed no later than 12 months before next IRP due date.	NW Natural filed its initial work plan on May 1, 2024. The Company filed an updated work plan on October 4 (Docket: UG – 240312).
WAC 480-90-238(4)	Work plan outlines content of IRP.	The work plan outlined the content of the 2025 IRP.
WAC 480-90-238(4)	Work plan outlines method for assessing potential resources (see LRC analysis below).	The workplan outlines the methodology used in developing the 2025 IRP. NW Natural developed and integrated demand forecasts, weather patterns, natural gas price forecasts, and demand- and supply-side resources, including emissions compliance resources, into gas supply and planning optimization software. The modeling results guided NW Natural toward the lowest reasonable cost and risk resource portfolio.
WAC 480-90-238(5)	Work plan outlines timing and extent of public participation.	The work plan outlines the timing and extent of public participation. The schedule of public participation is detailed in Table 3 of the updated work plan. Beginning in October 2024, the schedule includes an IRP Open House, six Technical Working Groups with each divided into two parts, two Energy Resource Fairs, and two Public Engagement Webinars. The work plan also details other modes of participation, including office hours and a dedicated resource planning webpage containing the dates, recordings, and associated presentations for the 2025 IRP meetings, the draft 2025 IRP (which will be replaced with the final 2025 IRP upon filing), and previous IRPs. NW Natural, additionally, notified customers of

Rule	Requirement	Plan Citation
		the 2025 IRP via customer specific communication channels, such as e-newsletters and bill notices.
WAC 480-90-238(4)	Integrated resource plan submitted within two years of previous plan.	NW Natural filed its 2022 IRP on September 23, 2022, which was acknowledged on August 22, 2023 (Docket: UG – 210094). On September 25, 2023, NW Natural filed a Petition for Exemption from WAC 480-90-238(4) for one year, which was granted on December 22, 2023 (Docket: UG - 230783).
WAC 480-90-238(5)	Commission issues notice of public hearing after company files plan for review.	Pending.
WAC 480-90-238(5)	Commission holds public hearing.	Pending.
WAC 480-90-238(2)(a)	Plan describes mix of natural gas supply.	Chapter 8 outlines currently held and available supply-side resource options including existing and proposed interstate pipeline capacity from multiple providers, NW Natural's Mist underground storage, offtakes, imported LNG, and satellite LNG facilities. In addition, Chapter 7 describes the mix of supply-side emissions compliance options, such as RNG, Hydrogen blending, and Synthetic Methane.
WAC 480-90-238(2)(a)	Plan describes conservation supply.	Chapter 6 documents how NW Natural determined the achievable potential of demand-side management (DSM) within its service territory through 2050. Chapter 5 presents Avoided Costs.
WAC 480-90-238(2)(a)	Plan addresses supply in terms of current and future needs of utility and ratepayers.	NW Natural analyzed current demand and examined uncertainty regarding future demand (peak, swing, and baseload) by using deterministic load forecasts. NW Natural develops a range of customer needs through scenarios and stochastic simulation, through a risk analysis to inform its action plan until the next IRP. The Company analyzed weather uncertainty, gas price uncertainty, cost of compliance uncertainty, load, and resource-costs uncertainty in its

Rule	Requirement	Plan Citation
		stochastic analysis. Finally, NW Natural analyzed the impacts of complying with GHG emissions regulation and the uncertainty associated with the levels of the cost of compliance and emissions reduction options.
WAC 480-90-238(2)(a) &(b)	Plan uses lowest reasonable cost (LRC) analysis to select mix of resources.	NW Natural considered the strictly economic data assessed by the PLEXOS® model; the likely availability of certain resources such as imported or satellite LNG; scenario analysis of demand and gas prices; and the results of an extensive risk analysis to various factors to ensure consideration of resource uncertainties and costs of risks when developing the plan. After considering all these factors, the Company selected a near-term preferred portfolio given the various futures and identified resources consistent with that portfolio for that specific future acquisition. The PLEXOS® model also analyzed the emissions compliance options based on price and risk, including compliance instruments such as Allowances (WA) and CCIs (OR) and supply side alternatives such as RNGs and Hydrogen. These are also incorporated into NW Natural's preferred portfolio.
WAC 480-90-238(2)(b)	LRC analysis considers resource costs.	Chapter 9 identifies the costs of supply-side resource portfolios for each of multiple possible futures. A fundamental task associated with this is the estimation of the revenue requirements associated with discrete supply-side resources, including commodity prices. Chapter 9 discusses the results of the stochastic risk analysis and tests the robustness of the expected resource choice over a wide slate of future environments that represent uncertainty of natural gas prices, weather, alternative fuel costs and availability.

Rule	Requirement	Plan Citation
WAC 480-90-238(2)(b)	LRC analysis considers market-volatility risks.	NW Natural developed several different risk analyses through a range of scenarios and stochastic simulation to examine risks associated with uncertainty regarding natural gas prices and price volatility, as well as availability of renewable natural gas and other compliance resources. These sensitivities evaluated higher levels of avoided costs, different natural gas price paths over the planning horizon, and the effects of alternative futures, including involving varying levels of electrification. NW Natural used the results of these sensitivities to inform its resource acquisition plan.
WAC 480-90-238(2)(b)	LRC analysis considers demand side uncertainties.	Chapters 5, 6, and 9 discuss DSM's effect on the supply-side resource mix. Chapter 12 discusses demand-side resources within the context of Distribution System Planning.
WAC 480-90-238(2)(b)	LRC analysis considers resource effect on system operation.	Chapter 9 discusses the multiple scenarios studied in this plan.
WAC 480-90-238(2)(b)	LRC analysis considers risks imposed on ratepayers.	The primary goal of this IRP is the selection of a portfolio of resources which comply with state and federal environmental regulations and have the best combination of expected costs and risks over the planning horizon. The analysis considers all costs that could reasonably be included in rates over the long-term, which extends beyond the planning horizon and the life of the resource. NW Natural performed a risk analysis including both a stochastic analysis and a wide range of sensitivities to evaluate the impact of risk and uncertainty. The Company analyzed weather uncertainty, gas price uncertainty, cost of compliance uncertainty, load, and resource-costs uncertainty in its stochastic analysis. NW Natural also discusses the impacts of complying with GHG emissions regulation and the uncertainty associated with the levels of the

Rule	Requirement	Plan Citation
		cost of compliance and emissions reduction options. Chapter 9 contains the discussion of the Company's risk analysis, assumptions, and results.
WAC 480-90-238(2)(b)	LRC analysis considers public policies regarding resource preference adopted by Washington state or federal government.	NW Natural discusses state and federal policies in Chapter 2. NW Natural explicitly incorporates expected regulatory compliance costs in its analyses. Due to the degree of uncertainty of loads, policy, costs, and resources, for this IRP develops a reference case, supplemented by a range of cases, stochastic simulations, and risk analyses to inform its action plan until the next IRP. This IRP includes compliance plans to meet Washington's Climate Commitment Act (CCA) and other policies that promote GHG emissions reductions. The Company utilized outside consultants to forecast CCA allowance and offset prices emissions compliance, as well as supply-side emissions compliance options. The Company includes an emissions forecast associated with the considered resource portfolios and explicitly models the outcomes of disparate policy futures including varying electrification scenarios. Chapter 9 describes alternative resource mix scenarios and forward-looking sensitivities involving commodity availability, commodity cost, transportation cost, and/or load forecast inputs evaluated in the IRP. The Company also included expected GHG policy compliance costs in its price forecasts and analyzed sensitivities related to compliance costs. Further, NW Natural factored compliance costs explicitly into the determination of the Company's avoided cost, which in turn factored into the identification of cost-effective demand-side resources and on-system resources such as renewable natural gas.

Rule	Requirement	Plan Citation
WAC 480-90-238(2)(b)	LRC analysis considers cost of risks associated with environmental effects including emissions of carbon dioxide.	As stated above, NW Natural explicitly incorporates expected regulatory compliance costs in its analyses. The Company's underlying gas price forecast, provided by an outside consultant, includes the cost of compliance with the most recently known environmental regulations. The Company includes an emissions forecast associated with the resource portfolios considered, and explicitly models the outcomes of disparate policy futures, including varying electrification scenarios. Chapter 9 describes alternative resource mix scenarios and forward-looking sensitivities involving commodity availability, commodity cost, transportation cost, and/or load forecast inputs evaluated in the IRP. The Company also includes expected GHG policy compliance costs in its price forecasts and analyzed sensitivities and risk reduction values related to compliance costs.
WAC 480-90-238(2)(b)	LRC analysis considers need for security of supply.	Chapter 7 and Appendix F discuss supply and common gas purchasing practices, respectively. The primary objective of the Gas Acquisition Plan (GAP) is to ensure gas supplies are sufficient to meet firm customer demand. To meet this objective, NW Natural’s primary goal is reliability, followed by lowest reasonable cost, rate stability, and cost recovery.
WAC 480-90-238(2)(c)	Plan defines conservation as any reduction in natural gas consumption that results from increases in the efficiency of energy use or distribution.	The Plan defines energy reductions from DSM programs in the Company's service territory as the reduction of gas consumption resulting from the installation of a cost-effective conservation measure. Conservation measures increase the efficiency of energy use or distribution.
WAC 480-90-238(3)(a)	Plan must include a range of forecasts of future natural gas demand in firm and interruptible markets for each customer class that examine the effect of economic	A range of demand forecasts for each customer class were included in the plan that analyze economic forces on the consumption of natural gas. For example, the growth scenario examines the economic impact of changes in population,

Rule	Requirement	Plan Citation
	forces on the consumption of natural gas and that address changes in the number, type and efficiency of natural gas end-uses.	housing starts, and employment on demand, while other scenarios examine changes in demand from various levels of electrification. Changes in the number, type, and efficiency of natural gas end-uses are included in risk analysis using a range of load forecasts and avoided costs, while scenario analysis includes changes in the number of natural gas end-uses and impacts from emerging uses such as hybrid systems with electric heat pumps and gas furnace back-ups.
WAC 480-90-238(3)(b)	Plan includes an assessment of commercially available conservation, including load management.	Chapter 6 provides a discussion of conservation and demand-side resources. With respect to demand-side load management, NW Natural foresees continuing to shave peak load requirements when and where necessary by curtailing interruptible customers, dispatching DR events in the BYOT program, continuing with EE offerings, and is exploring other avenues of DSM. Since the filing of the 2022 IRP, NW Natural has also taken steps to engage with stakeholders to develop offerings for transportation customers.
WAC 480-90-238(3)(b)	Plan includes an assessment of currently employed and new policies and programs needed to obtain the conservation improvements.	Chapter 6 details how NW Natural delivers energy efficiency programs that offer customers incentives for implementing cost effective demand-side management measures. Applied Energy Group (AEG) conducted a Washington Conservation Potential Assessment and Energy Trust of Oregon has a summary of Oregon EE and Conservation Programs that are both reported in Chapter 9. NW Natural's low-income energy efficiency programs, OLIEE and WALIEE, are also discussed in the chapter.
WAC 480-90-238(3)(c)	Plan includes an assessment of conventional and commercially available nonconventional gas supplies.	NW Natural determined the best resource mix by studying supply-side options currently used, such as pipeline transportation contracts and gas supply and renewable natural gas contracts; as well as alternative options such as additional capacity or infrastructure enhancements. The Company also

Rule	Requirement	Plan Citation
		considered future developments such as pipeline enhancements, renewable natural gas projects, power-to-gas (a suite of technologies that use electrolysis in an electrolyzer to separate water molecules into oxygen and hydrogen), among other compliance resources. Chapters 7 and 8 discuss the various supply-side and compliance resource options and their costs.
WAC 480-90-238(3)(d)	Plan includes an assessment of opportunities for using company-owned or contracted storage.	NW Natural assessed its Mist underground storage, Jackson Prairie underground storage, imported LNG, as well as satellite LNG facilities located at various locations within the Company's service territory as resource options.
WAC 480-90-238(3)(e)	Plan includes an assessment of pipeline transmission capability and reliability and opportunities for additional pipeline transmission resources.	Chapter 8 discusses NW Natural's assessment of pipeline capability, reliability, and additional pipeline resources.
WAC 480-90-238(3)(f)	Plan includes a comparative evaluation of the cost of natural gas purchasing strategies, storage options, delivery resources, and improvements in conservation using a consistent method to calculate cost-effectiveness.	NW Natural determined the best resource mix by studying supply-side options currently used such as pipeline transportation contracts, gas supply and renewable natural gas contracts, as well as alternative options such as additional capacity or infrastructure enhancements. The Company also considered future developments such as pipeline enhancements, renewable natural gas projects, power-to-gas (a suite of technologies that use electrolysis in an electrolyzer to separate water molecules into oxygen and hydrogen), and other compliance resources. Chapters 7 and 8 discuss the various supply-side and compliance resource options and their costs. NW Natural compiled demand-side resource options with assistance from the ETO as well as AEG, and these options are identified in Chapter 6.

Rule	Requirement	Plan Citation
		Utilizing PLEXOS®, the Company determined the least cost resource mix through linear programing optimization as well as performed various sensitivities in its risk analysis, which are discussed in Chapter 9.
WAC 480-90-238(3)(g)	Plan includes at least a 10-year long-range planning horizon.	The long-range plans NW Natural discusses in this IRP span more than a 10-year planning horizon, with plans out to 2050.
WAC 480-90-238(3)(g)	Demand forecasts and resource evaluations are integrated into the long-range plan for resource acquisition.	This IRP integrates demand forecasts and resource evaluations with the cost, risk, and capabilities of alternative resource portfolios into a long-term plan for resource acquisition.
WAC 480-90-238(3)(h)	Plan includes a two-year action plan that implements the long-range plan.	The Action Plan in this IRP details NW Natural's actions related to supply-side, compliance, and demand-side resource acquisition over the next two to four years of the planning horizon.
WAC 480-90-238(3)(i)	Plan includes a progress report on the implementation of the previously filed plan.	Chapters 6, 7, 8, and 9 discuss progress on both the demand- and supply-side activities since the last previously filed plan. Appendix A discusses progress on Action Items and other key updates since the last previously filed plan.
WAC 480-90-238(5)	Plan includes description of consultation with commission staff. (Description not required).	WUTC Commission Staff were invited to all 2025 IRP related engagements including the Technical Working Groups, of which commission staff participated regularly. The Company additionally consulted with and responded to Staff questions throughout the plan's development. NW Natural documents public participation in Chapter 3 and Appendix I.
WAC 480-90-238(5)	Plan includes a description of completion of work plan. (Description not required)	The Multi-Year Action Plan in Chapter 1 and Chapter 13 and the public participation outlined in Chapter 3 and Appendix I serve to document NW Natural's successful completion of the work plan.

A.4 Recommendations from the 2022 Integrated Resource Plan – WUTC

As an outcome of filing the 2022 IRP in WUTC docket UG-210094, Staff developed a set of recommendations in their report {DATE}. These were included as an attachment to the Commission's Acknowledgement Letter, serviced on August 22, 2023[1]. NW Natural has numbered WUTC Staff's recommendations for ease of reference. The Company's 2025 IRP has been docketed in UG-240312.

Recommendation 1: Staff recommends that NW Natural expand the emerging technologies evaluation in future analyses to include non-gas appliances and to consider such appliances in the context of price competitiveness compared to gas technologies.
UG-240312 Response: NW Natural used an outside contractor to conduct an electrification study that includes varying levels of air source heat pump deployment, water heat pump, and electric stove deployment. The results of the electrification study incorporated into Scenarios 5, 6, and 7 discussed in Chapter 10.

Recommendation 2: Staff questions what impacts modeling price uncertainty could have on NW Natural's portfolio selections, especially as it relates to the price competitiveness of natural gas and impacts on customer counts. Further, Staff recommends additional discussion on this topic within the Advisory Group during the next IRP cycle.
UG-240312 Response: NW Natural plans to select the least-cost, least-risk resource permitted within the regulatory frameworks the Company is subject to. The Company does not have sufficient information to forecast the price elasticity of end-use equipment for our customers. However, under the electrification scenarios covered in this IRP, the Company is able to examine the impact of low customer counts on the gas system. Scenario planning was discussed in TWG 3. Please also see the section in Chapter 11 on price elasticity.

Recommendation 3: For future improvement, Staff recommends that NW Natural develop clear criteria for the selection of climate models and discuss within the Advisory Group.
UG-240312 Response: NW Natural engaged a third-party consultant to help with the climate model selection process. On November 21, 2024, NW Natural presented its climate model in TWG 3.

[1] A corrected letter was serviced on August 24, 2023 in the same docket.

Recommendation 4: Staff commends NW Natural for evaluating transportation customer conservation potential during its most recent conservation potential assessment conducted in 2021, well before the CCA established gas companies as the point of regulation for transportation customer emissions.
UG-240312 Response: The Company thanks Staff for this comment. As discussed in Chapter 6, the Company continues to work on efficiency programs for its transportation customers.

Recommendation 5: In the next IRP, Staff recommends that NW Natural further analyze the risks imposed on rate payers in these scenarios, ratepayer responses to these risks, and the corollary risk of over investment and stranded assets.
UG-240312 Response: The Company does not have sufficient information to forecast the price elasticity of end-use equipment for our customers. However, under the electrification scenarios covered in this IRP, the Company is able to examine the impact to the gas system of lower customer counts and reduced energy use. See Chapter 11 for a discussion about price elasticity.

Recommendation 6: Staff recommends that NW Natural further evaluate and consider the use of the Washington State Building Code Council's statutory obligations as a basis for their current customer growth expectations for scenarios rather than projecting historical trends forward.
UG-240312 Response: Current Washington State Building Codes are incorporated into the Reference Case customer count forecast. The Company notes that Washington Ballot Initiative I-2066, which impacts state building codes, was passed, subsequently found unconstitutional, and is currently in litigation (to be reviewed by the Washington State Supreme Court). While the appeal plays out, a separate lawsuit arguing that the codes are invalid under I-2066 is on hold.

Recommendation 7: Staff recommends that NW Natural analyze possible customer responses to future changes in price-competitiveness of NW Natural's services. Staff recommends that NW Natural commit to holding robust discussions about the future availability of green hydrogen.

UG-240312 Response: The Company does not have sufficient information to model consumer choice in the face of future price competitiveness as both gas and electric rates incorporate costs to achieve CCA compliance. Specifically, the Company does not have the data needed to accurately measure medium-run price elasticity that would capture customer end-use equipment selection in response to gas and electric utility rates. See Chapter 11 for a discussion about price elasticity. However, under the electrification scenarios covered in this IRP, the Company is able to model the effects on the gas system of substantially decreased customer counts and overall energy usage. The Company evaluates the technical potential and cost of green hydrogen in this IRP and includes it as a resource option in its planning model. NW Natural presented its plans regarding Green Hydrogen as part of TWG 6.

Recommendation 8: Staff recommends that NW Natural consider incorporating an electrification strategy into its next IRP. Staff encourages NW Natural to refer to the most recent general rate case orders for Avista Corporation and Puget Sound Energy for context on how the Commission has ordered those two utilities to consider electrification in their next natural gas IRPs.
UG-240312 Response: NW Natural incorporated electrification scenarios into the 2025 IRP. NW Natural hired an outside consultant to conduct an extensive review of the all-in costs of electrification and the impacts to utility customers. NW Natural's electrification study includes three electrification scenarios—modest electrification, hybrid electrification, and full electrification. Electrification is discussed in detail in Chapter 10.

Recommendation 9: Staff recommends that the Company include the cost of electricity in the unbundled price path charts to ensure NW Natural is adequately considering electric fuel switching options, conservation measures available, and the price-competitiveness of the services they provide.
UG-240312 Response: NW Natural's electrification study, discussed in Chapter 10, looks at the all-in cost of electrification. Please chapters 10 and 11 for more detailed information.

Recommendation 10: Staff recommends discussing the benefits of two Tranches in the next IRP cycle within the Advisory Group.
UG-240312 Response: In the 2025 IRP, NW Natural expanded its RNG analysis beyond the two-tranche approach from the 2022 IRP. This updated analysis is contained in Chapter 7. Renewable Natural Gas was discussed in TWG 6.

Recommendation 11: While this guidance was referring to specific programs, Staff encourages the Company to consider modeling a range of CI scores as part of a modeling sensitivity or sensitivities. RNG represents a key component of NW Natural's resource portfolio in the 2022 IRP, and while there is no regulatory structure in place to incentivize low-CI RNG projects, Staff encourages the Company to work with its Advisory Group(s) to consider how it might develop a method which incorporates and appropriately values the CI scores of RNG when evaluating resources in the IRP process.
UG-240312 Response: According to RCW 70A.65.080 7(d), emissions from the combustion of biomass or biofuels are exempt from coverage by the CCA. Lifecycle carbon intensities are included in the Alternative Fuels Study but not included in the resource selection model, which selects the least cost resources to comply with the CCA.

Recommendation 12: Staff strongly encourages NW Natural to provide a written and, where appropriate, graphic analysis of greenhouse gas emissions, sources and size of greenhouse gas emissions, and explicitly state assumptions used by NW Natural in their analysis of greenhouse gas emissions.
UG-240312 Response: NW Natural has provided written and graphic analysis of greenhouse gas emissions. Emissions are discussed in Chapters 2 and 4.

Recommendation 13: Staff recommends that NW Natural analyze the difference in low-income energy efficiency program outcomes and discuss it with the advisory group.
UG-240312 Response: Energy Trust of Oregon (ETO) evaluated low-income energy efficiency programs. This analysis is in Chapter 6 of the IRP and was covered by ETO in TWG 5.

Recommendation 14: Staff recommends that NW Natural put a greater emphasis on editing.
UG-240312 Response: The Company's 2025 IRP incorporates Staff's recommendation.

A.5 Update on Action Items from the 2022 Integrated Resource Plan

Table A-3: Action Item Updates

	#	Action Item Description	Status
System Capacity Resources	1	Acquire 20,000 Dth/day of deliverability from either recalling Mist, a city gate deal, or a combination of both for the 2023-24 gas year. Based upon updated load forecast in upcoming IRP updates recall Mist capacity as required for the 2024-25 and 2025-26 gas years.	After confirming it was still needed, NW Natural signed a city gate deal for 20,000 Dth/day of deliverability to meet design peak demand for the 2024-2025 winter. Updates to the peak day forecast and firm resource stack show another design day deficit of 20,000 Dth/day for the 2024-2025 winter. NW Natural recalled 20,000 Dth/day of Mist deliverability to meet this deficit for this upcoming winter.
	2	Replace the Cold Box at the Portland liquified natural gas (LNG) facility for a targeted in-service date of 2026 at an estimated cost of $7.5 to $15 million.	The Company has placed this project on hold as it awaits the results of the facility seismic vulnerability assessment, required by the new DEQ Fuel Tank Seismic Stability Rules (OAR 340-300-0000.) The Company expects to complete the Portland LNG Plant seismic vulnerability assessment by 2027.
	3	Scope a residential and small commercial demand response program to supplement our large commercial and industrial programs and file by 2024.	In the 2022 IRP Action Plan, NW Natural included an item to scope a residential and small commercial demand response program and file by 2024. While several DR pathways were explored, a system-wide Bring Your Own Thermostat ("BYOT", or "Thermostat Rewards" as branded) program was identified as the best opportunity to create a demand response program that targets residential and small commercial customers. The system-wide program can be leveraged to support future locational DR programs and hence to comply with the condition for action item acknowledgement as recommended by OPUC Staff. This program was first tested during the 2024-2025 winter. More details on the BYOT program are provided in Chapter 6.

Oregon Emissions Compliance	4	Working through Energy Trust of Oregon, acquire 5.7 – 7.8 million therms of first year savings in 2023 and 6.7 – 8.9 million therms of first year savings in 2024, or the amount identified by the Energy Trust board.[2]	The Energy Trust of Oregon (Energy Trust) acquired 5.5 million therms of first year savings in 2023 and 5.7 million therms in 2024 in Oregon.
	5	In Oregon, to achieve SB 98 targets, seek to acquire 3.5 million Dths of renewable natural gas (RNG) in 2024 and 4.2 million Dths of RNG in 2025, representing 5% and 6% of normal weather sales load in 2024 and 2025.	The Commission did not acknowledge this action item.
	6	Work with Energy Trust of Oregon, the Alliance of Western Energy Consumers and other stakeholders to develop energy efficiency programs for transportation schedule customers by 2024.	NW Natural launched its initial Transportation EE program in partnership with the Energy Trust of Oregon (ETO) during the summer of 2024. At the time, Oregon's Climate Protection Program (CPP) had been invalidated and was undergoing rule making. The first two years of the program are intended to enable NW Natural and ETO to lay the groundwork for future program years. In 2025, NW Natural continues to partner with ETO to deliver their standard incentives to customers on transportation schedules. Standard incentives apply to projects that have deemed savings and do not require a site-specific assessment.
	7	In Oregon, purchase Community Climate Investments representing any additional Climate Protection Plan (CPP) compliance needs for years 2022 and 2023 in Q4 2023 and	The CPP was invalidated. Hence, Community Climate Investments were not available during the time periods specified in Action Item. 7. NW Natural describes its near-term plans regarding CPP compliance in Chapter 13.

[2] These numbers in the action item included total energy efficiency forecasted by Energy Trust, with therm savings from updating building codes and market transformation. Energy Trust forecasted 5.4 million therms as claimable savings from Energy Trust for 2024.

		for year 2024 in Q4 2024 based upon actual emissions to ensure compliance with the 2022-2024 compliance period.	
Distribution System	8	In Oregon, uprate the Forest Grove Feeder (also known as the McKay Creek Feeder) to be in service for the 2025 gas year at an estimated cost of $3.0 to $7.0 million.	The Company is in the planning phase and construction is scheduled for completion in late 2026 or 2027.
Washington Emissions Compliance	9	In Washington, acquire carbon offsets compliant with the Climate Commitment Act's Cap-and-Invest program for 5% of expected weather emissions in year 2023 and 2024. Seek to acquire additional offsets representing 3% of expected weather emissions allowed for CCA compliance on tribal lands, and if they can be acquired for a lower price than the program allowance price floor for years 2023 and 2024, acquire these offsets.	NW Natural was not able to acquire carbon offsets due to limited availability. NW Natural will continue to monitor the development of the CCA-compliant offset market and plans to acquire them when they compare favorably to other CCA compliance resources.
	10	In Washington, to support HB 1257, seek to acquire 600,000 Dths of renewable natural gas (RNG) in 2024 and 800,000 Dths of RNG in 2025, representing 6% and 8% of normal weather compliance gas in 2024 and 2025.	In 2024, NW Natural acquired 0 dths of RNG in 2024 and intends to acquire 95,500 dths of RNG in 2025, representing 0% and 1% of normal weather compliance.

	11	In Washington, purchase emissions allowances equal to emissions at an estimate of the 95th percentile of need for annual compliance net of voluntary RNG, carbon offsets, and freely allocated but not consigned allowances.	NW Natural continues to purchase allowances in alignment with Action Item 11 to comply with the Climate Commitment Act.
	12	Working through Energy Trust of Oregon, acquire 275,000-370,000 therms of first year savings in 2023 and 276,000-310,000 therms of first year savings in 2024, or the amount approved through WUTC Biennial Energy Efficiency Plan.	NW Natural, via its work with program partners, acquired 304,054 therms of first year savings in 2023 and 440,856 therms of first year savings in 2024.
	13	Work with Energy Trust of Oregon, the Alliance of Western Energy Consumers and other stakeholders to develop energy efficiency programs for transportation and industrial sales schedule customers by 2024.	NW Natural launched its initial Transportation EE program in partnership with the Energy Trust of Oregon (ETO) during the summer of 2024. In 2025, NW Natural continues to partner with ETO to deliver their standard incentives to customers on transportation schedules. Standard incentives apply to projects that have deemed savings and do not require a site-specific assessment.

Appendix B – Resource Requirements

B.1 Customer Count Forecast Technical Details

The State of Oregon's Office of Economic Analysis (OEA) was the data source of the exogenous variables used in the four econometric customer forecasting models as specified in Equations (1) to (4) in the 2025 IRP. OEA forecasts Oregon population, housing starts, and employment over a ten-year period. Since the 2025 IRP forecasts out to 2050, NW Natural extends OEA forecasts to 2050 using a combination of methods. Oregon population forecast data was extended using the linear trend of the last three years of the OEA forecast (2030-2033). Oregon housing starts forecast data was extended using the log trend of the last three years of the OEA forecast (2031-2034). Oregon total nonfarm employment forecast data was extended using an ARIMA model with Oregon population as the exogenous variable.

Oregon Residential: ARIMA (0,2,2)

$$\Delta^2 OR\ customers_t = \alpha + \beta_1 \frac{(\Delta OR\ starts_t + \Delta OR\ starts_{t-1} + \Delta OR\ starts_{t-2})}{3} + \sum_{j=1}^{2} \theta_j \epsilon_{t-j} + \epsilon_t \quad (1)$$

Washington Residential: ARIMA (0,2,2)

$$\Delta^2 WA\ customers_t = \alpha + \beta_1 \Delta OR\ starts_t + \sum_{j=1}^{2} \theta_j \epsilon_{t-j} + \epsilon_t \quad (2)$$

Oregon Commercial: ARIMA (0,2,1)

$$\Delta^2 \ln(OR\ customers_t) = \alpha + \beta_1 \Delta OR\ pop_t + \sum_{j=1} \theta_j \epsilon_{t-j} + \epsilon_t \quad (3)$$

Washington Commercial: ARIMA (0,1,1)

$$\Delta WA\ customers_t = \alpha + \beta_1 \Delta OR\ emp_t + \sum_{j=1} \theta_j \epsilon_{t-j} + \epsilon_t \quad (4)$$

The dependent and independent variables used in the equations are defined in Table B-1. Estimated parameters of the equations are reported in Table B-2.

Table B-1: Dependent and Independent Variables in Equations (1) – (4)

Equation	Dependent Variable	Independent Variable
(1) Oregon Residential	Oregon Residential Customer Change	Oregon Housing Starts Change
(2) Washington Residential	Washington Residential Customer Change	Oregon Housing Starts Change
(3) Oregon Commercial	Oregon Commercial Customer Change	Oregon Population Change
(4) Washington Commercial	Washington Commercial Customer Change	Oregon Total Nonfarm Employment Change

Table B-2: Parameter Estimates for Equations (1) – (4)

Equation	α	β_1	θ_1	θ_2
(1) Oregon Residential	-279.7***	439.1**	-0.11	-0.89
(2) Washington Residential	-85.4	208.9***	-0.42	-0.58
(3) Oregon Commercial	0.002	-0.07	-1.0	-
(4) Washington Commercial	111.2**	1.1**	0.93	-
Significance level: *p<0.1, **p<0.05, ***p<0.01.				

Despite having no significant variable coefficients, the model selected for Oregon commercial produced the lowest AIC of 25 estimated ARIMA models. This model is akin to a linear exponential smoothing model, which is not dependent on the exogenous variable (Oregon population), and instead relies on the moving average of past prediction errors and a trend component to capture the rate of change of the time series.

B.1.1 Allocation

For purposes of planning associated with the 2025 IRP, NW Natural has 12 load centers – ten in Oregon and two in Washington (Figure 4.1 in Chapter 4). The customer count forecast results in four customer forecasts, each at the state level: Oregon residential, Oregon commercial, Washington residential, and Washington commercial. As NW Natural has a need to forecast customers not only at the system and statewide levels, but also at more granular distribution levels, the Company uses an allocation method to convert the four state-level forecasts into load center forecasts. Additionally, customer forecasts at the state-level represent year-end totals and peak load forecasts require monthly forecasts of customers, so the Company also uses an allocation method to transform year-end customer values into monthly values.

B.1.1.1 Allocation to Components of Customer Change

NW Natural models separate usage profiles for existing customers, new construction customer additions, and conversion customer additions. Customer losses are reflected in existing customer counts, which typically decline over time.

State-level customer forecasts are distributed to components using a combination of component forecasts with a true-up process at the end to match state-level forecasts. New construction customer additions are forecasted using the same ARIMA models as those used for the associated state-level forecasts, except for Oregon commercial new construction additions, which are forecasted using the exponential trend of the combined historical time series and forward-looking time series from the near-term forecast (1990-2026). Residential conversion customer additions are also forecasted using the exponential trend of the combined historical time series and forward-looking time series, while commercial conversion customer additions are forecasted using the exponential trend of only the historical time series. Existing customer changes, or losses, are forecasted using the logarithmic trend of the combined historical time series and forward-looking times series along with shorter historical time series to place more emphasis on recent trends, which are assumed to better represent future trends than using the full historical series. Ratios from the combined component forecasts are then applied to state-level forecasts to ensure the component forecasts sum to state-level totals.

B.1.1.2 Allocation to Months

State-level customer forecasts are developed using annual time series datasets, which are forecasted annually over the forecast horizon (2024-2050). The annual time series datasets are based on monthly customer count time series data, which allows for the calculation of monthly growth shares to allocate annual customer forecasts to months. Monthly growth shares are based on the entirety of available time series data from 2008-2023, excluding 2020 and 2021 due to atypical patterns from the COVID-19 pandemic. Monthly share coefficients are created by regressing monthly shares on months, then summed and normalized to sum to unity. These monthly share series are applied to the four state-level customer forecasts to allocate change in customers to each month.

B.1.1.3 Allocation to Load Centers

NW Natural allocates month-over-month changes from state-level by month to load center by month by factoring ten-year growth shares of each load center where ten-year growth of each load center is divided by the state's ten-year growth from 2013 to 2023. These allocations are made separately for each of the four state-level customer forecasts.

Table B-3 shows the average annual rates of customer change by load center and state for residential and commercial customers over the 2024-2050 planning horizon. It should be noted that NW Natural has only provided service to Coos Bay for two decades and there may be relatively greater potential for customer change through conversions from other fuels in this load center than in other parts of the service territory.

Table B-3: Reference Case Average Annual Customer Change Rates (2024-2050)

Load Center	Residential	Commercial
Albany	0.39%	0.19%
Astoria	0.41%	0.18%
Coos Bay	1.11%	1.57%
Eugene	0.46%	0.43%
Lincoln City	0.36%	0.00%
Portland (Central, East, West)	0.37%	0.22%
Salem	0.45%	0.41%
The Dalles (OR)	0.53%	0.14%
Oregon Total	**0.39%**	**0.27%**
The Dalles (WA)	0.55%	0.17%
Vancouver	0.94%	1.54%
Washington Total	**0.93%**	**1.50%**

B.1.2 State Results

Figure B-1: Oregon Residential Customers – Reference Case

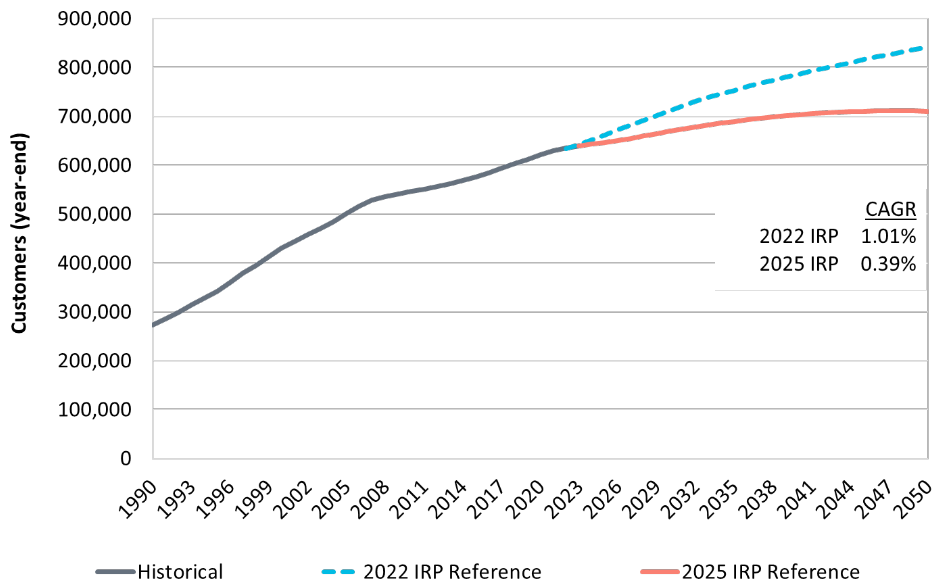


Figure B-2: Washington Residential Customers – Reference Case

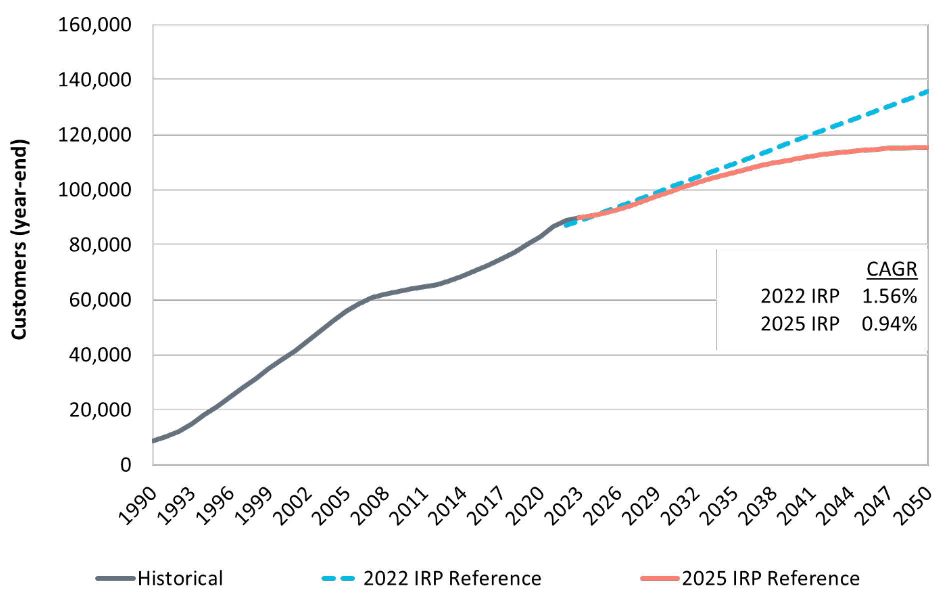


Figure B-3: Oregon Commercial Customers – Reference Case

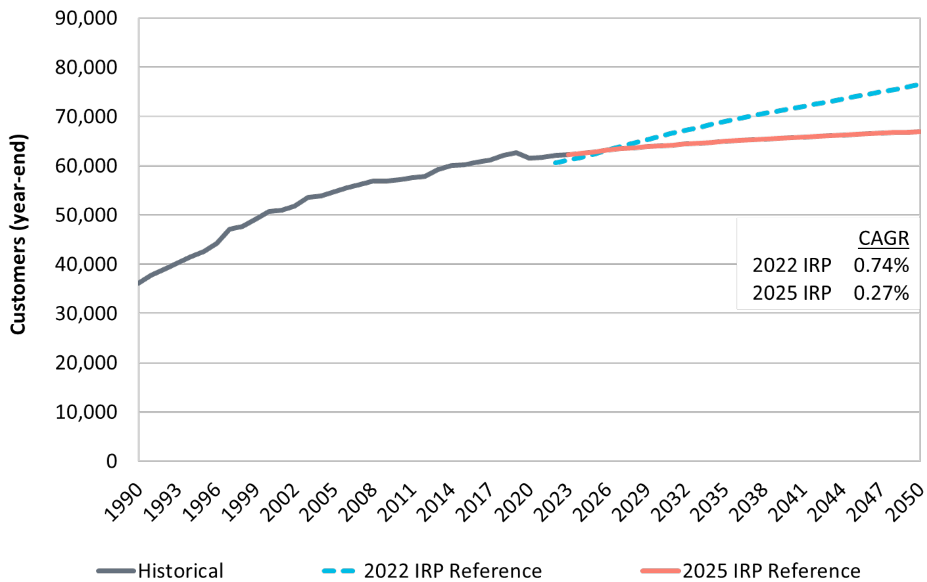
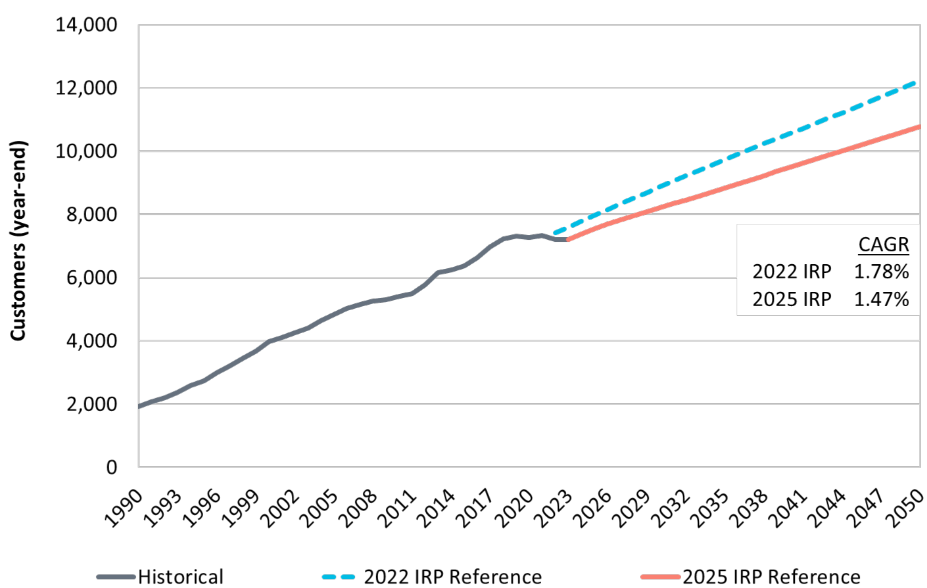


Figure B-4: Washington Commercial Customers – Reference Case



B.2 Climate Change Adjusted Weather Forecasts Technical Details

ICF utilizes a 30-year moving average methodology to develop the time series forecast of load center HDDs (with base 58°F), for each month of the year, for the period 2025-2050. The 30-

year window used in the averaging gradually transitions the relative weight of backward-looking to forward-looking data until the window is centered on the current iteration year. Years prior to the most recently available weather station data with full coverage (2022) are entirely retrospective (i.e., based entirely on the preceding 30-year period). Each subsequent year after 2022 incorporates progressively more forward-looking data (relative to the current iteration year) until the averaging window is centered on the current iteration year.

For example, HDD estimates for 2022 are based on the period 1993-2022 (i.e., 30 years of retrospective data). In contrast, HDD estimates for 2023 are based on the period 1995-2024 (i.e., 29 years of retrospective data and one year of prospective data). HDD estimates for 2024 are based on the period 1997-2026 (i.e., 28 years of retrospective data and two years of prospective data). This rolling pattern continues until 2037, where the window (2023-2052) equally weights years behind and ahead of the target year (i.e., 15 years of retrospective data and 15 years of prospective data). This equal weighting scheme continues thereafter and through the forecast horizon (2050).[3]

This window averaging was applied to stacks of the full 22-member climate model ensemble (i.e., each monthly average value is based on 660 samples—30 years x 22 models). This approach increases the statistical power of the estimates relative to a hierarchical approach, incorporates climate model uncertainties into the estimates, and minimizes interannual variability in the final time series. To further minimize interannual variability, a five-year moving average is also applied to the final ensemble-averaged time series. The approach was applied independently to the annual time series of each month in the year (i.e., Jan. 2025, Jan. 2026, … Jan. 2050). These methods were applied to two SSP emissions scenarios (SSP2-4.5 and SS3-7.0). The resultant load center HDDs, for SSP2-4.5, are provided in Table B-4.

[3] To ensure proper weighting is retained between backward-looking and forward-looking data, values taken from the observed historical record are duplicated in the averaging to match the number of members in the climate model ensemble (i.e., observed data is duplicated 22-fold).

Table B-4: Forecasted Reference Case HDDs by Load Center

Year	Albany	Astoria	Coos Bay	The Dalles	Eugene	Lincoln City	Portland Central	Portland East	Portland West	Salem	Vancouver
2025	2,649	2,633	2,283	3,091	2,790	2,587	2,491	2,571	2,907	2,646	2,559
2026	2,642	2,620	2,270	3,057	2,777	2,585	2,478	2,546	2,903	2,633	2,541
2027	2,624	2,599	2,246	3,021	2,752	2,567	2,452	2,519	2,885	2,614	2,516
2028	2,613	2,584	2,224	2,988	2,731	2,549	2,431	2,495	2,865	2,594	2,489
2029	2,603	2,569	2,200	2,958	2,706	2,528	2,408	2,476	2,841	2,569	2,465
2030	2,585	2,544	2,167	2,929	2,674	2,490	2,380	2,451	2,803	2,540	2,433
2031	2,567	2,518	2,134	2,902	2,637	2,453	2,351	2,423	2,761	2,510	2,407
2032	2,538	2,482	2,093	2,874	2,598	2,404	2,313	2,384	2,716	2,475	2,376
2033	2,503	2,440	2,052	2,841	2,553	2,343	2,276	2,346	2,667	2,439	2,344
2034	2,464	2,406	2,010	2,813	2,515	2,285	2,239	2,313	2,618	2,408	2,314
2035	2,427	2,374	1,978	2,785	2,481	2,227	2,205	2,283	2,576	2,382	2,285
2036	2,380	2,342	1,948	2,757	2,443	2,164	2,174	2,258	2,535	2,356	2,252
2037	2,344	2,318	1,923	2,732	2,417	2,112	2,148	2,240	2,503	2,337	2,227
2038	2,306	2,294	1,904	2,714	2,393	2,059	2,126	2,223	2,470	2,319	2,203
2039	2,270	2,266	1,878	2,690	2,367	2,014	2,103	2,200	2,439	2,297	2,176
2040	2,238	2,243	1,859	2,672	2,348	1,979	2,084	2,182	2,415	2,280	2,156
2041	2,221	2,229	1,846	2,663	2,334	1,954	2,071	2,168	2,396	2,267	2,143
2042	2,200	2,214	1,833	2,647	2,319	1,939	2,055	2,151	2,379	2,255	2,129
2043	2,187	2,203	1,825	2,635	2,305	1,927	2,043	2,139	2,365	2,245	2,117
2044	2,174	2,192	1,816	2,622	2,293	1,917	2,034	2,125	2,355	2,232	2,106
2045	2,162	2,180	1,806	2,609	2,279	1,906	2,022	2,110	2,340	2,222	2,096
2046	2,149	2,167	1,793	2,598	2,267	1,893	2,009	2,097	2,325	2,210	2,085
2047	2,137	2,154	1,781	2,584	2,255	1,884	1,998	2,083	2,313	2,199	2,076
2048	2,123	2,141	1,771	2,572	2,244	1,870	1,986	2,066	2,299	2,188	2,063
2049	2,110	2,129	1,759	2,559	2,229	1,854	1,975	2,054	2,285	2,176	2,053
2050	2,098	2,115	1,745	2,547	2,217	1,844	1,962	2,039	2,274	2,164	2,043

B.3 Residential and Small Commercial Use Per Customer Model Technical Details

Table B-5 presents the estimated coefficients, by load center, for the residential and small commercial existing market segment. These parameters are utilized in equation (1) to produce average UPC estimates.

Table B-5: Existing UPC Model Coefficient Estimates

State	Load Center	Rate Class	Market Segment	K_1	Y_1	b_1	K_2	Y_2	b_2	K^*
OR	ALB	R	EXIST	68	0.38	0.00	50	9.32	-0.15	58.34
OR	AST	R	EXIST	63	0.46	0.00	58	9.17	-0.15	59.08
OR	COOS	R	EXIST	62	0.38	0.00	56	9.59	-0.16	59.37
OR	DALO	R	EXIST	67	1.02	-0.01	50	7.24	-0.11	61.76
OR	EUG	R	EXIST	68	1.43	-0.01	50	8.78	-0.14	58.77
OR	LC	R	EXIST	60	0.49	0.00	54	8.94	-0.15	56.05
OR	PORC	R	EXIST	68	1.20	-0.01	55	9.73	-0.15	60.89
OR	PORE	R	EXIST	66	1.78	-0.02	54	11.01	-0.17	60.57
OR	PORW	R	EXIST	68	1.17	-0.01	50	10.65	-0.18	57.15
OR	SAL	R	EXIST	66	1.51	-0.01	50	10.21	-0.17	57.88
WA	DALW	R	EXIST	67	1.02	-0.01	50	7.24	-0.11	61.76
WA	VAN	R	EXIST	66	1.36	-0.01	51	9.57	-0.15	59.36
OR	ALB	C	EXIST	63	2.43	0.00	52	39.81	-0.65	57.19
OR	AST	C	EXIST	64	3.72	0.00	57	29.76	-0.45	57.49
OR	COOS	C	EXIST	62	3.60	0.00	55	45.03	-0.69	59.69
OR	DALO	C	EXIST	62	6.07	-0.05	52	36.90	-0.57	58.42
OR	EUG	C	EXIST	61	10.92	-0.11	50	44.95	-0.71	56.84
OR	LC	C	EXIST	60	5.51	0.00	51	33.86	-0.52	54.77
OR	PORC	C	EXIST	62	10.38	-0.10	50	48.96	-0.77	57.90
OR	PORE	C	EXIST	68	2.43	0.00	53	46.06	-0.72	60.58
OR	PORW	C	EXIST	68	2.84	0.00	50	49.36	-0.82	56.96
OR	SAL	C	EXIST	61	8.94	-0.09	50	46.07	-0.75	56.40
WA	DALW	C	EXIST	62	6.07	-0.05	52	36.90	-0.57	58.42
WA	VAN	C	EXIST	67	10.21	-0.10	54	41.58	-0.65	57.48

Table B-6 presents the estimated coefficients, by state, for the residential and small commercial conversions and new construction market segments. These parameters are utilized in equation (1) to produce average UPC estimates.

Table B-6: Conversion, Multifamily New Construction, and Single Family New Construction UPC Model Coefficient Estimates

State	Load Center	Rate Class	Market Segment	K_1	Y_1	b_1	K_2	Y_2	b_2	K^*
OR	-	R	CONV	68	0.97	-0.01	57	6.77	-0.11	59.96
OR	-	R	MFNC	65	0.22	0.00	50	3.28	-0.06	52.70
OR	-	R	SFNC	68	0.31	0.00	55	8.14	-0.13	60.75
OR	-	C	CONV	68	3.71	0.00	50	51.19	-0.81	58.39
OR	-	C	NC	67	4.84	0.00	50	100.69	-1.66	57.69
WA	-	R	CONV	68	0.19	0.00	56	5.42	-0.08	62.27
WA	-	R	MFNC	60	0.51	-0.01	58	1.20	-0.02	56.72
WA	-	R	SFNC	60	1.32	-0.02	58	4.96	-0.08	60.52
WA	-	C	CONV	68	2.10	0.00	51	25.10	-0.40	57.14
WA	-	C	NC	68	3.26	0.00	56	48.35	-0.69	65.75

Figure B-5 presents the average first-year UPC estimates, by state, for residential existing, conversions, multifamily new construction, and single family new construction market segments. These UPC estimates do not incorporate exogenous energy efficiency savings.

Figure B-5: Average First-year Residential Demand by State

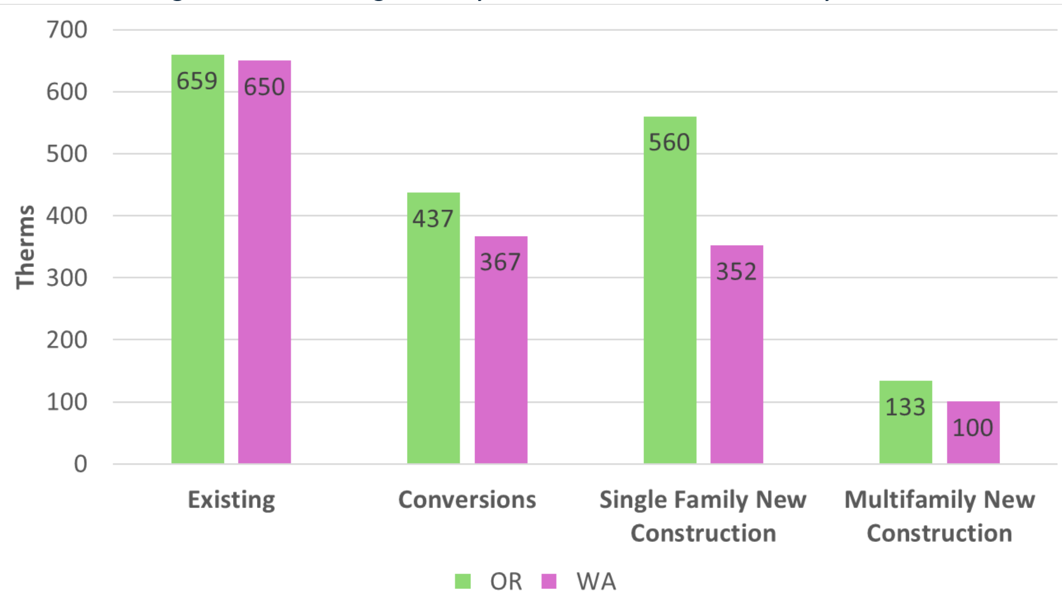
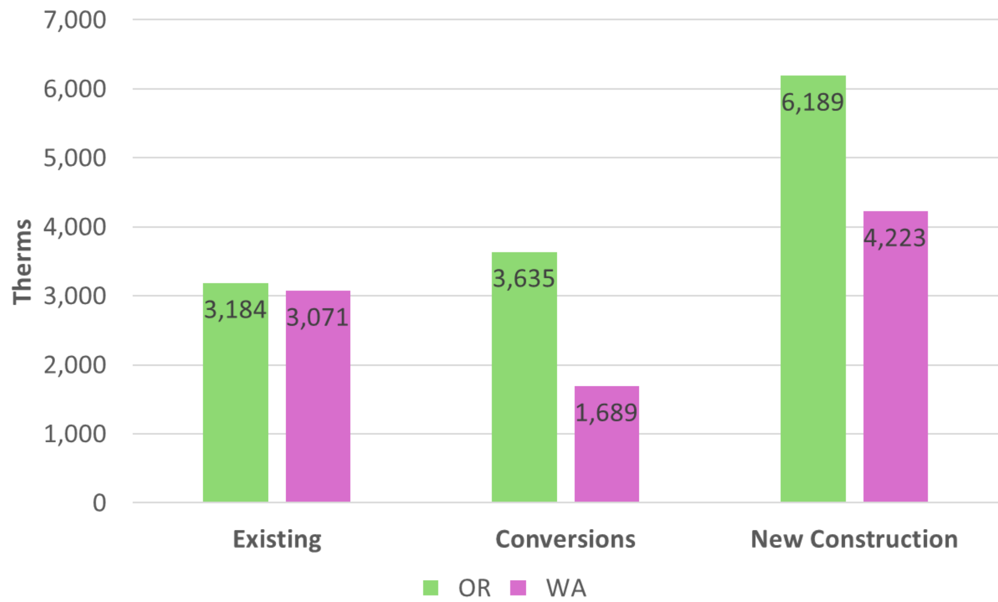


Figure B-6 presents the average first-year UPC estimates, by state, for small commercial existing, conversions, and new construction market segments. These UPC estimates do not incorporate exogenous energy efficiency savings.

Figure B-6: Average First-year Small Commercial Demand by State



B.4 Industrial and Large Commercial Load Forecast Model Technical Details

Table B-7 presents the estimated coefficients for the industrial load growth and large commercial load growth models, respectively. Each model consists of an intercept and single regression factor. Historical U.S. industrial production data is used to estimate industrial load growth.[4] *Ln Ind Pro* is the natural log difference (growth) of U.S. annual industrial production data. Historical Oregon information sector is used to estimate large commercial load growth.[5] *Ln Inf Sec* is the natural log difference (growth) of annual Oregon information sector data. P-values are provided directly below the coefficient estimates in parentheses.

Forecasted U.S. industrial production and Oregon information sector data is also provided by OEA from 2024-2039. To extend the forecast through 2050, the compound annual growth rate of each macroeconomic variable is calculated using the five most recent forecast years (2029-2034) and applied to its respective macroeconomic variable through the forecast horizon.

[4] Historical U.S. industrial production data is obtained from OEA and spans 1994-2023.
[5] Historical Oregon information sector data is obtained from OEA and spans 2010-2023.

Table B-7: Industrial and Large Commercial Coefficient Estimates

Parameter	Industrial Load Growth	Large Commercial Load Growth
Intercept (α)	-0.01689 *(0.06)*	-0.01736 *(0.46)*
Ln Ind Pro (β)	0.72387 *(0.00)*	- -
Ln Inf Sec (β)	- -	1.92589 *(0.04)*

B.5 Peak Day Forecast Modeling Details

Monte Carlo simulations rely on repeated sampling of demand explanatory variables to model demand risk. While the Monte Carlo method itself does not rely on any distributional assumptions about the underlying distribution of data, NW Natural imposes empirical assumptions on the distributions of explanatory variables to conform with historical observations. Generating a large range of variable combinations results in a design peak day demand corresponding to the 99th percentile of predicted outcomes.

Specifically, the Monte Carlo simulations utilize an empirical distribution of system-weighted cold temperatures data (1938-2023). Moreover, each simulation assigns empirical probabilities the peak day demand will fall on a particular month (Nov., Dec., Jan., or Feb.), weekday vs. weekend, and/or a federal holiday. Conditional on the Winter month selected, water temperature is simulated from a normal distribution whose mean and standard deviation are derived from that month's historical data. Wind speed, solar radiation, and snow depth predictions are conditional on the simulated air temperature.[6] The simulated values for each of these three explanatory variables are drawn from a normal distribution whose mean and standard deviation are the predicted value and the standard error of that predicted value, respectively. Further, the simulated value for snow depth is also conditional on the empirical probability of a cold weather day experiencing snowfall.

Explanatory variable values from each simulation are plugged into the peak day linear regression model (whose coefficients are provided below) in conjunction with the forecasted annual customer count to yield an estimate of demand. Uncertainty/variation from the model is then subsequently applied to the estimate to produce a final dekatherm estimate. In total, one million simulations are conducted and the 99th percentile demand outcome represents the peak day planning standard for NW Natural.

[6] The solar radiation prediction is also conditional on the Winter month selected.

Table B-8 presents the estimated coefficients of the peak day regression model with associated p-values. Variables are reported in the following units: temperature/bull run river temperature in degrees Fahrenheit, wind speed in miles per hour, solar radiation in watt per square meter, and snow depth in inches.

Table B-8: Daily System Regression Model Coefficients

Main Effects		Interaction Effects	
Variable	**Coefficient Estimate**	**Variable**	**Coefficient Estimate**
Intercept	621,434 *(0.00)*	Temperature x Previous Day Temp	144 *(0.00)*
Temperature	-11,464 *(0.00)*	Temperature x Customer Count	-0.01 *(0.00)*
Previous Day Temperature	-8,958 *(0.00)*	Temperature x Wind Speed	-62 *(0.00)*
Customer Count	0.92 *(0.00)*	Temperature x Snow Depth	492 *(0.01)*
Wind Speed	6,341 *(0.00)*	Temperature x Friday	643 *(0.00)*
Solar Radiation	-6 *(0.00)*	Temperature x Saturday	838 *(0.00)*
Snow Depth	-22,016 *(0.00)*	Temperature x Sunday	904 *(0.00)*
Friday	-39,746 *(0.00)*	Temperature x Holiday	1,286 *(0.00)*
Saturday	-61,977 *(0.00)*	*P-values shown in parentheses*	
Sunday	-58,826 *(0.00)*		
Holiday	-70,769 *(0.00)*		
COVID-19 Closure	-8,721 *(0.00)*		
Bull Run River Temperature	-1,131 *(0.00)*		

B.6 Reference Case Demand Details

Table B-9: Reference Case – Annual Load by State

	Oregon (Therms)					Washington (Therms)				
Year	Residential Forecast (EE)	Small Commercial Forecast (EE)	Large Commercial Forecast (EE)	Industrial Sales Forecast (EE)	Industrial Transport Forecast (EE)	Residential Forecast (EE)	Small Commercial Forecast (EE)	Large Commercial Forecast (EE)	Industrial Sales Forecast (EE)	Industrial Transport Forecast (EE)
2025	421,224,853	195,754,529	66,304,525	89,391,955	342,013,189	58,327,887	22,580,712	5,364,375	3,935,611	18,668,647
2026	419,400,110	195,438,498	64,730,877	89,157,584	341,774,764	58,206,596	22,927,835	5,276,067	3,943,333	19,032,751
2027	416,365,202	194,572,748	63,298,882	87,330,809	337,269,344	57,981,071	23,191,835	5,206,539	3,897,866	18,771,662
2028	413,571,233	192,848,762	62,064,915	85,658,014	333,385,723	57,758,202	23,382,151	5,153,703	3,859,647	18,544,983
2029	410,588,999	190,878,509	60,909,200	84,118,579	330,122,545	57,565,756	23,575,935	5,108,018	3,827,963	18,348,322
2030	406,341,405	188,420,095	59,747,100	82,486,823	326,542,953	57,189,263	23,721,659	5,063,104	3,793,071	18,133,490
2031	401,630,733	185,787,971	58,517,755	80,702,029	322,574,013	56,861,890	23,895,319	5,015,910	3,753,642	17,896,559
2032	395,715,090	182,608,962	57,221,895	78,769,044	318,319,853	56,409,692	24,034,868	4,968,435	3,711,242	17,646,353
2033	389,397,785	179,265,191	55,974,990	76,786,093	314,210,037	55,915,387	24,174,288	4,929,394	3,669,344	17,399,033
2034	382,939,971	175,964,791	54,381,347	74,794,033	310,321,387	55,372,577	24,305,023	4,863,701	3,629,863	17,164,934
2035	376,450,065	172,842,165	52,998,565	72,831,969	306,608,949	54,844,729	24,476,235	4,817,075	3,592,094	16,939,267
2036	369,814,249	169,894,799	51,633,238	70,897,064	302,945,600	54,210,774	24,646,367	4,771,307	3,555,024	16,719,006
2037	363,626,617	167,557,230	50,307,385	69,019,465	299,480,336	53,683,696	24,871,543	4,726,369	3,518,632	16,504,001
2038	356,810,280	165,565,979	49,039,854	67,224,868	296,075,490	53,141,369	25,124,843	4,682,262	3,482,914	16,294,438
2039	350,029,296	163,906,482	47,844,222	65,531,671	292,757,503	52,550,941	25,362,965	4,638,938	3,447,836	16,090,022
2040	343,553,540	162,767,435	46,728,234	63,950,222	289,457,405	51,974,797	25,585,657	4,596,499	3,413,471	15,891,281
2041	337,632,071	162,156,493	45,696,687	62,486,810	286,331,947	51,591,875	25,914,218	4,554,719	3,379,649	15,696,751
2042	331,501,528	161,677,989	44,741,680	61,130,350	283,722,682	51,163,965	26,237,728	4,513,515	3,346,307	15,507,557
2043	325,776,027	161,569,556	43,870,376	59,890,356	281,140,538	50,672,356	26,536,044	4,472,811	3,313,389	15,322,298
2044	320,202,254	161,654,919	43,177,158	58,895,288	278,527,450	50,541,309	26,970,932	4,435,766	3,283,231	15,143,985
2045	314,457,581	161,724,693	42,603,548	58,064,837	276,054,117	50,405,583	27,421,406	4,399,030	3,253,349	14,969,794
2046	308,653,934	161,749,877	42,056,817	57,272,323	273,549,653	50,254,169	27,869,804	4,362,599	3,223,740	14,822,641
2047	303,106,633	161,880,849	41,513,284	56,485,429	271,083,692	50,116,536	28,345,729	4,326,477	3,194,406	14,678,132
2048	297,417,654	161,996,734	40,972,915	55,704,100	268,583,488	49,898,862	28,793,295	4,290,652	3,165,337	14,536,018
2049	291,841,790	162,128,899	40,435,685	54,928,286	266,221,101	49,704,435	29,274,768	4,255,223	3,136,606	14,396,361
2050	286,344,043	162,187,514	39,901,571	54,157,947	263,828,364	49,488,577	29,760,395	4,220,081	3,108,131	14,258,108

Table B-10: *Reference Case* – Design Peak

Design Peak Day		
Year	**Gas Year**	**Dth/Day**
2025	2025-26	1,032,269
2026	2026-27	1,037,202
2027	2027-28	1,040,670
2028	2028-29	1,044,745
2029	2029-30	1,047,102
2030	2030-31	1,051,599
2031	2031-32	1,050,925
2032	2032-33	1,053,338
2033	2033-34	1,052,593
2034	2034-35	1,052,718
2035	2035-36	1,051,698
2036	2036-37	1,050,139
2037	2037-38	1,048,129
2038	2038-39	1,046,073
2039	2039-40	1,043,251
2040	2040-41	1,042,487
2041	2041-42	1,040,329
2042	2042-43	1,037,306
2043	2043-44	1,037,424
2044	2044-45	1,037,639
2045	2045-46	1,037,708
2046	2046-47	1,039,262
2047	2047-48	1,039,076
2048	2048-49	1,040,933
2049	2049-50	1,042,055
2050	2050-51	1,044,299

B.7 Growth Recovery Demand Details

The Growth Recovery scenario is based on increased demand and higher customer count forecasts resulting from higher forecasts of independent variables used in the long-term econometric models (Table B-1). Forecasts of these variables (population, housing starts, and employment) are lower in the 2025 IRP than they were in the 2022 IRP and much lower than historical trends. The higher forecasts utilized in the Growth Recovery scenario are based on growth rates from OEA's September 2021 Economic and Revenue Forecast – the same forecast that provided forecasts of the same variables used in the econometric models of the 2022 IRP Reference Case customer count forecast. Essentially, the Growth Recovery scenario assumes that population, housing start, and employment trends revert to growth rates forecasted in September 2021, which are lower than historical growth rates but higher than growth rates in the 2025 IRP Reference Case. For example, the compound annual growth rate of Oregon population forecasted in the 2025 IRP Reference Case is 0.55 percent, while it is 0.83 percent under the Growth Recovery scenario, which is still lower than the historical rate of the last decade of 1.02 percent.

Appendix C – Avoided Costs

C.1 Levelized Avoided Costs by Component and State

Table C-1: Levelized Avoided Costs by Component and State

Year	Real (2024$)									
	Infrastructure Costs				Commodity Costs		Environmental Compliance Costs			
	Supply ($/Dth/Day)	Washington Distribution ($/Dth/Hour)	Oregon Distribution ($/Dth/Hour)	System Distribution ($/Dth/Hour)	Gas and Transport Costs ($/Dth)	Commodity Risk Reduction Value ($/Dth)	Oregon Carbon Compliance Cost ($/Dth)	Compliance Risk Reduction Value ($/Dth)	Washington Carbon Compliance Cost ($/Dth)	Compliance Risk Reduction Value ($/Dth)
2025	$0.182	$1.060	$0.306	$0.379	$2.957	$0.558	$8.038	$0.000	$6.623	$0.000
2026	$0.182	$1.060	$0.306	$0.379	$3.444	$0.781	$8.055	$0.000	$6.720	$0.000
2027	$0.182	$1.060	$0.306	$0.379	$3.586	$0.874	$8.122	$2.752	$6.816	$0.000
2028	$0.182	$1.060	$0.306	$0.379	$3.581	$0.875	$20.240	$3.573	$7.027	$0.000
2029	$0.182	$1.060	$0.306	$0.379	$3.214	$0.976	$20.257	$5.950	$7.334	$0.024
2030	$0.182	$1.060	$0.306	$0.379	$3.005	$1.008	$14.014	$5.405	$7.655	$0.041
2031	$0.182	$1.060	$0.306	$0.379	$3.028	$1.042	$14.032	$4.954	$7.991	$0.058
2032	$0.182	$1.060	$0.306	$0.379	$3.173	$1.121	$17.359	$4.946	$8.343	$0.074
2033	$0.182	$1.060	$0.306	$0.379	$3.185	$1.096	$17.376	$4.975	$8.713	$0.089
2034	$0.000	$1.060	$0.306	$0.379	$3.324	$1.085	$17.254	$4.738	$9.099	$0.093
2035	$0.000	$1.060	$0.306	$0.379	$3.492	$1.249	$17.271	$4.577	$9.504	$2.597
2036	$0.000	$1.060	$0.306	$0.379	$3.662	$1.266	$17.333	$3.914	$9.934	$2.498
2037	$0.000	$1.060	$0.306	$0.379	$3.802	$1.357	$17.355	$3.669	$10.383	$2.412
2038	$0.000	$1.060	$0.306	$0.379	$3.867	$1.361	$20.868	$2.702	$10.855	$2.333
2039	$0.000	$1.060	$0.306	$0.379	$3.873	$1.395	$20.890	$2.754	$11.348	$0.911
2040	$0.000	$1.060	$0.306	$0.379	$3.831	$1.443	$21.022	$2.837	$11.865	$1.489
2041	$0.000	$1.060	$0.306	$0.379	$3.832	$1.387	$21.040	$2.606	$12.402	$0.583
2042	$0.000	$1.060	$0.306	$0.379	$3.833	$1.481	$21.117	$0.904	$12.965	$0.499
2043	$0.000	$1.060	$0.306	$0.379	$3.917	$1.512	$21.134	$1.301	$13.556	$0.389
2044	$0.000	$1.060	$0.306	$0.379	$3.971	$1.438	$21.341	$1.269	$14.175	$0.284
2045	$0.000	$1.060	$0.306	$0.379	$4.011	$1.564	$21.359	$1.249	$14.824	$0.177
2046	$0.000	$1.060	$0.306	$0.379	$4.035	$1.541	$21.491	$1.810	$15.509	$0.171
2047	$0.000	$1.060	$0.306	$0.379	$4.172	$1.551	$21.513	$1.780	$16.228	$0.273
2048	$0.000	$1.060	$0.306	$0.379	$4.107	$1.549	$21.676	$1.773	$16.981	$0.179
2049	$0.000	$1.060	$0.306	$0.379	$4.192	$1.589	$21.698	$1.905	$17.771	$0.187
2050	$0.000	$1.060	$0.306	$0.379	$4.066	$1.830	$21.850	$1.814	$18.600	$0.196
Levelized	**$0.084**	**$1.060**	**$0.306**	**$0.379**	**$3.569**	**$1.184**	**$17.216**	**$3.002**	**$10.296**	**$0.562**

Table C-2: Levelized Avoided Costs by Component and State

Year	1	2	3	4	5	6	7	8
	Oregon GHG Compliance Costs				Washington GHG Compliance Costs			
	Compliance Resource Costs ($/Dth)	Marginal Compliance Resource	SCC of Supply Chain Emissions ($/Dth)	Total Compliance Costs ($/Dth): 1 + 3	Compliance Resource Costs ($/Dth)	Marginal Compliance Resource	SCC of Supply Chain Emissions ($/Dth)	Total Compliance Costs ($/Dth): 5 + 7
2025	$6.850	CCI	$1.188	$8.038	$5.436	Social Cost of Carbon	$1.188	$6.623
2026	$6.850	CCI	$1.205	$8.055	$5.515	Social Cost of Carbon	$1.205	$6.720
2027	$6.900	CCI	$1.222	$8.122	$5.594	Social Cost of Carbon	$1.222	$6.816
2028	$19.000	Near-term RTC Purchase	$1.240	$20.240	$5.787	Allowance Purchase	$1.240	$7.027
2029	$19.000	Near-term RTC Purchase	$1.257	$20.257	$6.077	Allowance Purchase	$1.257	$7.334
2030	$12.740	LFG-Mid	$1.274	$14.014	$6.381	Allowance Purchase	$1.274	$7.655
2031	$12.740	LFG-Mid	$1.292	$14.032	$6.700	Allowance Purchase	$1.292	$7.991
2032	$16.050	LFG-Mid	$1.309	$17.359	$7.035	Allowance Purchase	$1.309	$8.343
2033	$16.050	LFG-Mid	$1.326	$17.376	$7.386	Allowance Purchase	$1.326	$8.713
2034	$15.910	LFG-Mid	$1.344	$17.254	$7.756	Allowance Purchase	$1.344	$9.099
2035	$15.910	LFG-Mid	$1.361	$17.271	$8.143	Allowance Purchase	$1.361	$9.504
2036	$15.950	LFG-Mid	$1.383	$17.333	$8.551	Allowance Purchase	$1.383	$9.934
2037	$15.950	LFG-Mid	$1.405	$17.355	$8.978	Allowance Purchase	$1.405	$10.383
2038	$19.440	SM-Biomass	$1.428	$20.868	$9.427	Allowance Purchase	$1.428	$10.855
2039	$19.440	SM-Biomass	$1.450	$20.890	$9.898	Allowance Purchase	$1.450	$11.348
2040	$19.550	SM-Biomass	$1.472	$21.022	$10.393	Allowance Purchase	$1.472	$11.865
2041	$19.550	SM-Biomass	$1.490	$21.040	$10.913	Allowance Purchase	$1.490	$12.402
2042	$19.610	SM-Biomass	$1.507	$21.117	$11.459	Allowance Purchase	$1.507	$12.965
2043	$19.610	SM-Biomass	$1.524	$21.134	$12.031	Allowance Purchase	$1.524	$13.556
2044	$19.800	SM-Biomass	$1.541	$21.341	$12.633	Allowance Purchase	$1.541	$14.175
2045	$19.800	SM-Biomass	$1.559	$21.359	$13.265	Allowance Purchase	$1.559	$14.824
2046	$19.910	SM-Biomass	$1.581	$21.491	$13.928	Allowance Purchase	$1.581	$15.509
2047	$19.910	SM-Biomass	$1.603	$21.513	$14.624	Allowance Purchase	$1.603	$16.228
2048	$20.050	SM-Biomass	$1.626	$21.676	$15.356	Allowance Purchase	$1.626	$16.981
2049	$20.050	SM-Biomass	$1.648	$21.698	$16.123	Allowance Purchase	$1.648	$17.771
2050	$20.180	SM-Biomass	$1.670	$21.850	$16.929	Allowance Purchase	$1.670	$18.600
Levelized	**$15.837**		**$1.379**	**$17.216**	**$8.916**		**$1.379**	**$10.296**

C.2 Avoided Costs by End Use and State

Table C-3: Avoided Costs by End Use and State

	Oregon Total Avoided Costs by End Use (2024$)						Washington Total Avoided Costs by End Use (2024$)					
	Residential Space Heating	Commercial Space Heating	Water Heating	Cooking	Process Load	Interruptible Load	Residential Space Heating	Commercial Space Heating	Water Heating	Cooking	Process Load	Interruptible Load
2025	$18.15	$18.57	$13.66	$13.78	$13.25	$13.20	$23.28	$24.74	$13.44	$14.22	$12.52	$12.39
2026	$18.55	$18.97	$14.41	$14.58	$14.05	$14.00	$23.77	$25.23	$14.28	$15.11	$13.41	$13.28
2027	$21.89	$22.31	$17.78	$17.94	$17.40	$17.36	$24.11	$25.57	$14.65	$15.47	$13.77	$13.65
2028	$35.79	$36.21	$31.97	$32.17	$31.63	$31.58	$24.01	$25.47	$14.84	$15.70	$14.00	$13.87
2029	$37.95	$38.37	$34.28	$34.51	$33.97	$33.93	$23.90	$25.36	$14.88	$15.77	$14.07	$13.94
2030	$30.34	$30.77	$26.62	$26.85	$26.31	$26.26	$24.14	$25.60	$15.06	$15.95	$14.25	$14.12
2031	$29.76	$30.18	$26.18	$26.43	$25.90	$25.85	$24.41	$25.87	$15.49	$16.40	$14.70	$14.57
2032	$33.60	$34.02	$30.08	$30.33	$29.80	$29.75	$25.01	$26.47	$16.14	$17.05	$15.35	$15.22
2033	$33.63	$34.05	$30.12	$30.37	$29.83	$29.79	$25.41	$26.87	$16.55	$17.46	$15.76	$15.63
2034	$32.05	$32.47	$29.61	$29.85	$29.38	$29.35	$24.66	$26.12	$16.87	$17.77	$16.13	$16.02
2035	$32.16	$32.58	$29.81	$30.06	$29.58	$29.55	$28.13	$29.59	$20.43	$21.33	$19.69	$19.59
2036	$31.93	$32.35	$29.38	$29.60	$29.13	$29.10	$28.92	$30.38	$21.02	$21.90	$20.26	$20.15
2037	$31.89	$32.31	$29.39	$29.61	$29.14	$29.11	$29.53	$30.99	$21.67	$22.56	$20.92	$20.81
2038	$34.72	$35.14	$32.26	$32.49	$32.02	$31.98	$29.99	$31.45	$22.17	$23.07	$21.42	$21.32
2039	$34.83	$35.25	$32.38	$32.61	$32.14	$32.11	$28.99	$30.45	$21.20	$22.09	$20.45	$20.34
2040	$35.13	$35.56	$32.63	$32.86	$32.38	$32.35	$30.27	$31.73	$22.41	$23.30	$21.66	$21.55
2041	$34.83	$35.25	$32.34	$32.56	$32.09	$32.06	$29.79	$31.25	$21.95	$22.83	$21.19	$21.09
2042	$33.01	$33.44	$30.64	$30.88	$30.40	$30.37	$30.29	$31.75	$22.56	$23.46	$21.82	$21.72
2043	$33.62	$34.04	$31.22	$31.46	$30.99	$30.96	$30.97	$32.43	$23.22	$24.12	$22.48	$22.37
2044	$33.73	$34.16	$31.39	$31.63	$31.16	$31.13	$31.45	$32.91	$23.76	$24.66	$23.02	$22.91
2045	$33.84	$34.27	$31.56	$31.81	$31.34	$31.31	$32.16	$33.62	$24.53	$25.44	$23.80	$23.69
2046	$34.66	$35.08	$32.33	$32.58	$32.10	$32.07	$32.97	$34.43	$25.28	$26.19	$24.55	$24.44
2047	$34.87	$35.29	$32.49	$32.73	$32.25	$32.22	$34.08	$35.54	$26.36	$27.25	$25.61	$25.51
2048	$34.85	$35.27	$32.58	$32.83	$32.35	$32.32	$34.62	$36.08	$26.99	$27.91	$26.26	$26.16
2049	$35.23	$35.65	$32.89	$33.13	$32.66	$32.63	$35.70	$37.16	$28.02	$28.92	$27.28	$27.17
2050	$35.36	$35.78	$33.07	$33.33	$32.85	$32.82	$36.69	$38.15	$29.05	$29.97	$28.33	$28.22
velized	**$31.26**	**$31.68**	**$28.18**	**$28.40**	**$27.90**	**$27.86**	**$27.65**	**$29.11**	**$19.21**	**$20.09**	**$18.42**	**$18.31**

C.3 Total Avoided Costs by End Use and Year

Figure C-1: Oregon Total Avoided Costs by End Use and Year

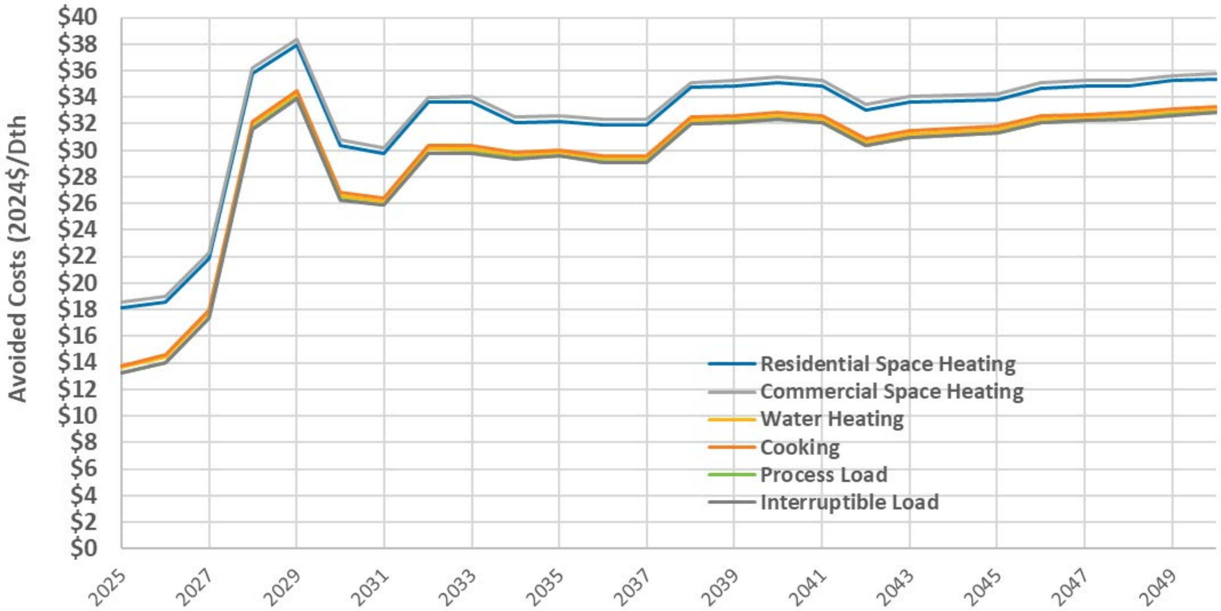


Figure C-2: Washington Total Avoided Costs by End Use and Year

Appendix D – Demand-Side Resources

D.1 Deployment Summary

See following pages for tables provided by Energy Trust of Oregon (ETO).

Table D-1: Oregon Deployment Summary 2025-2034

Program	Deployment Category	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
New Buildings	Com-New Buildings	219,105	220,614	222,153	223,723	225,324	226,958	207,830	198,139	190,650	202,599
	NEEA - Market Tx	191,441	247,277	295,138	327,044	350,974	373,967	395,204	415,649	436,051	455,541
Existing Buildings (no MF)	Com-Replacement	490,776	515,314	541,080	568,134	596,541	626,368	655,215	681,498	682,850	698,219
	Com-SEM	559,409	587,379	616,748	647,586	679,965	713,963	768,740	833,911	875,393	886,123
	Com-Retrofit	919,128	963,225	1,009,504	1,038,961	1,069,295	1,100,530	1,100,397	1,145,341	1,150,724	1,113,891
Industrial	Ind-Retrofit	1,166,693	1,187,114	1,208,001	1,229,368	1,251,227	1,273,592	1,340,429	1,468,547	1,571,992	1,641,137
	Ind-SEM	95,283	95,283	95,283	95,283	95,283	95,283	103,887	106,181	105,965	103,250
	Ind-Replacement	109,423	112,706	116,087	119,570	123,157	126,851	131,008	134,365	137,022	139,238
Residential New	Res-Manufactured New Homes	1,370	1,182	1,360	1,360	1,360	1,360	2,867	4,924	7,723	11,504
	Res-SF New Homes	500,686	555,746	775,117	858,837	820,296	1,094,085	1,061,793	1,015,583	965,290	912,752
	Res-Market Transformation	161,106	178,953	256,257	285,409	270,012	360,133	334,814	320,243	304,384	287,817
Residential Existing	Res-Smart Thermostat	169,390	172,778	176,234	179,758	183,354	187,021	296,303	363,961	440,250	522,465
	Res-Thermostat Optimization	2,702	2,973	3,270	3,597	3,597	3,597	5,449	6,278	7,180	8,137
	Res-WaterHeat	15,382	19,585	20,624	21,655	22,738	23,875	33,834	46,531	62,532	82,657
	Res-Shell	240,395	252,415	265,036	278,288	292,202	306,812	411,858	498,794	599,657	714,492
	Res-Space Heating	233,963	245,661	255,487	255,487	255,487	255,487	315,460	381,266	451,491	524,136
Multifamily	MF-Retrofit	102,427	107,549	112,926	118,041	123,396	129,002	121,643	115,475	103,710	88,231
	MF-Replacement	50,065	52,569	55,197	57,957	60,855	63,898	69,986	75,585	80,606	81,626
Other	Large-Project Adder	-	-	184,319	184,319	184,319	184,319	184,319	184,319	184,319	184,319
	Total	**5,228,744**	**5,518,322**	**6,209,821**	**6,494,377**	**6,609,381**	**7,147,100**	**7,541,034**	**7,996,592**	**8,357,790**	**8,658,135**

Table D-2: Oregon Deployment Summary 2035-2044

Program	Deployment Category	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
New Buildings	Com-New Buildings	214,487	204,776	223,393	216,279	220,737	243,546	242,618	232,924	235,258	240,813
	NEEA - Market Tx	474,290	492,346	509,979	527,154	543,917	560,311	576,368	592,118	607,586	622,794
Existing Buildings (no MF)	Com-Replacement	724,865	740,361	691,648	574,803	500,728	388,998	351,283	305,832	302,941	305,334
	Com-SEM	862,638	806,470	724,143	625,587	521,616	421,538	331,736	255,437	193,298	113,565
	Com-Retrofit	1,038,385	933,395	811,466	685,394	565,586	458,705	367,341	274,598	147,934	65,030
Industrial	Ind-Retrofit	1,664,452	1,636,702	1,558,543	1,436,858	1,283,508	1,112,865	939,001	773,434	623,990	259,407
	Ind-SEM	98,036	90,722	81,886	72,190	62,279	52,693	43,828	35,923	8,071	-
	Ind-Replacement	140,936	142,217	143,170	143,872	144,386	143,684	134,309	134,568	121,890	81,636
Residential New	Res-Manufactured New Homes	16,566	23,246	31,898	42,803	24,734	535	638	744	823	877
	Res-SF New Homes	861,440	808,903	756,978	704,850	652,723	600,391	548,264	495,525	443,603	391,069
	Res-Market Transformation	271,637	255,070	238,697	222,260	205,822	189,321	172,884	156,254	139,881	123,316
Residential Existing	Res-Smart Thermostat	605,716	682,750	744,465	781,375	785,971	755,262	692,317	605,788	507,418	408,724
	Res-Thermostat Optimization	9,122	10,878	12,909	15,231	17,845	20,734	23,851	27,109	-	-
	Res-WaterHeat	107,668	138,882	177,649	225,461	283,869	354,321	437,923	535,109	645,263	766,379
	Res-Shell	842,145	979,780	1,122,417	1,262,663	1,390,834	1,495,687	1,565,882	1,592,037	1,568,915	1,497,017
	Res-Space Heating	596,777	666,852	732,004	790,404	840,945	883,276	917,692	944,938	965,998	981,924
Multifamily	MF-Retrofit	71,396	55,302	41,315	29,998	21,315	14,907	5,461	-	-	-
	MF-Replacement	76,347	79,102	81,347	85,864	87,470	87,613	86,987	73,061	62,927	62,892
Other	Large-Project Adder	184,319	184,319	184,319	184,319	184,319	184,319	184,319	184,319	184,319	184,319
	Total	**8,861,222**	**8,932,074**	**8,868,225**	**8,627,365**	**8,338,604**	**7,968,706**	**7,622,701**	**7,219,718**	**6,760,116**	**6,105,095**

Table D-3: Oregon Deployment Summary 2041-2050

Program	Deployment Category	2045	2046	2047	2048	2049	2050	Total
New Buildings	Com-New Buildings	247,257	248,280	249,435	250,701	252,050	253,457	**5,913,106**
	NEEA - Market Tx	622,794	622,794	622,794	622,794	622,794	622,794	**12,731,909**
Existing Buildings (no MF)	Com-Replacement	332,127	337,830	316,577	251,546	246,752	285,524	**12,713,144**
	Com-SEM	-	-	-	-	-	-	**12,025,246**
	Com-Retrofit	56,069	48,445	40,926	33,828	27,408	21,820	**16,187,327**
Industrial	Ind-Retrofit	-	-	-	-	-	-	**24,626,859**
	Ind-SEM	-	-	-	-	-	-	**1,536,607**
	Ind-Replacement	66,836	11,952	12,981	14,011	15,033	16,037	**2,716,944**
Residential New	Res-Manufactured New Homes	905	910	897	871	838	802	**183,097**
	Res-SF New Homes	344,757	303,929	267,936	236,205	208,233	183,573	**16,368,565**
	Res-Market Transformation	108,712	95,838	84,488	74,482	65,662	57,886	**5,221,337**
Residential Existing	Res-Smart Thermostat	318,405	241,344	179,019	130,604	94,107	67,193	**10,291,971**
	Res-Thermostat Optimization	-	-	-	-	-	-	**184,459**
	Res-WaterHeat	897,382	1,034,412	1,172,693	1,307,282	1,433,922	1,549,696	**11,417,322**
	Res-Shell	1,382,893	1,237,910	1,075,856	910,218	752,046	608,870	**23,145,118**
	Res-Space Heating	993,197	995,210	1,001,183	1,000,736	999,220	747,958	**17,232,240**
Multifamily	MF-Retrofit	-	-	-	-	-	-	**1,362,092**
	MF-Replacement	57,009	52,846	24,991	5,717	5,709	5,700	**1,583,925**
Other	Large-Project Adder	184,319	184,319	184,319	184,319	184,319	184,319	**4,423,661**
	Total	**5,612,662**	**5,416,018**	**5,234,094**	**5,023,314**	**4,908,092**	**4,605,627**	**179,864,928**

D.2 Measure Levels

See following pages for tables provided by Energy Trust of Oregon (ETO).

Table D-4: Oregon 20-Year Cumulative Potential (Commercial)

Sector	Measure Name	Measure Type	End Use	20-year Cumulative Technical Potential (therms)	20-year Cumulative Achievable Potential (therms)	20-year Cumulative Cost-Effective Potential (therms)	% of Total Sector C/E Potential	Average Levelized Cost ($/therm)
Commercial	Com - Smart Thermostats GAS SPHT	Retrofit	Heating	2,822,258	2,398,919	2,398,919	6%	$2.86
Commercial	Com - Automatic Conveyor Broiler Gas	Replace on Burnout	Cooking	1,998,603	1,698,812	1,698,812	4%	-$0.28
Commercial	Com - Automatic Conveyor Broiler Gas - NEW Only	New Construction	Cooking	185,768	157,903	157,903	0%	-$0.28
Commercial	Com - Condensing Boiler GAS SPHT	Replace on Burnout	Heating	2,464,483	2,341,259	2,341,259	6%	$0.61
Commercial	Com - Condensing Boiler GAS SPHT - NEW only	New Construction	Heating	1,052,763	1,000,125	1,000,125	3%	$0.66
Commercial	Com - Condensing Furnace GAS SPHT	Replace on Burnout	Heating	218,223	185,490	185,490	0%	$1.39
Commercial	Com - Condensing Furnace GAS SPHT - NEW only	New Construction	Heating	22,707	19,301	19,301	0%	$2.21
Commercial	Com - Condensing Gas Instantaneous Water Heater GAS WHT	Replace on Burnout	Water Heating	163,491	138,967	138,967	0%	$0.45
Commercial	Com - Condensing Gas Instantaneous Water Heater GAS WHT - NEW only	New Construction	Water Heating	78,036	66,330	66,330	0%	$0.47
Commercial	Com - Condensing Gas RTU GAS SPHT	Replace on Burnout	Heating	1,742,136	1,480,815	1,480,815	4%	$1.52
Commercial	Com - Condensing Gas Storage Water Heater GAS WHT	Replace on Burnout	Water Heating	219,557	186,623	184,799	0%	$0.89
Commercial	Com - Condensing Gas Storage Water Heater GAS WHT - NEW only	New Construction	Water Heating	64,683	54,981	54,871	0%	$0.80
Commercial	Com - Condensing Gas Water Heating Boiler GAS WHT	Replace on Burnout	Water Heating	852,892	810,247	810,247	2%	$0.13
Commercial	Com - DHW Circulator Pumps/Controls GAS WHT	Retrofit	Water Heating	2,567	2,438	-	0%	$5.18
Commercial	Com - Eff. Clothes Washer Gas WH	Replace on Burnout	Appliance	92,924	78,986	78,986	0%	$0.63
Commercial	Com - Eff. Clothes Washer Gas WH - NEW Only	New Construction	Appliance	8,990	7,642	7,642	0%	$0.61
Commercial	Com - Eff. Gas Clothes Dryer	Replace on Burnout	Appliance	908,455	772,187	772,187	2%	$0.03
Commercial	Com - Eff. Gas Clothes Dryer - NEW Only	New Construction	Appliance	82,328	69,979	69,979	0%	$0.03
Commercial	Com - Efficient Windows GAS SPHT	Retrofit	Weatherization	864,177	734,551	-	0%	$27.48
Commercial	Com - Efficient Windows GAS SPHT - NEW only	New Construction	Weatherization	902,708	767,302	323,399	1%	$3.84
Commercial	Com - EMS GAS SPHT	Retrofit	Behavioral	3,786,758	3,218,744	3,218,744	8%	$1.95
Commercial	Com - Full Advanced Rooftop Controls Retrofit GAS SPHT	Retrofit	Ventilation	1,740,835	1,479,710	1,479,710	4%	$4.67
Commercial	Com - Gas Absorption HPWH GAS WHT	Replace on Burnout	Water Heating	1,932,292	1,642,448	1,642,448	4%	$0.34
Commercial	Com - Gas Absorption HPWH GAS WHT - NEW only	New Construction	Water Heating	689,321	585,923	585,923	2%	$0.33
Commercial	Com - Gas Fired Heat Pump GAS SPHT	Replace on Burnout	Heating	1,112,393	945,534	945,534	2%	$1.49
Commercial	Com - Gas Fired Heat Pump GAS SPHT - NEW only	New Construction	Heating	542,990	461,541	461,541	1%	$1.49
Commercial	Com - Gas RTU Advanced Tier 1 Package Upgrade GAS SPHT	Retrofit	Heating	2,424,387	2,060,729	2,060,729	5%	$2.01
Commercial	Com - Gas Steamer	Replace on Burnout	Cooking	140,681	119,579	119,579	0%	$0.00
Commercial	Com - Gas Steamer - NEW Only	New Construction	Cooking	13,983	11,886	11,886	0%	$0.00

Table D-4 – continued: Oregon 20-Year Cumulative Potential (Commercial)

Sector	Measure Name	Measure Type	End Use	20-year Cumulative Technical Potential (therms)	20-year Cumulative Achievable Potential (therms)	20-year Cumulative Cost-Effective Potential (therms)	% of Total Sector C/E Potential	Average Levelized Cost ($/therm)
Commercial	Com - Modulating Burner GAS SPHT	Retrofit	Heating	2,923,050	2,484,592	2,484,592	6%	$2.02
Commercial	Com - NC Package (10% Better than Code)	New Construction	Other	2,697,709	2,293,053	1,923,930	5%	$4.57
Commercial	Com - Ozone Laundry Systems GAS WH	Retrofit	Other	2,122,928	1,804,489	1,804,489	5%	-$1.42
Commercial	Com - Ozone Laundry Systems GAS WH - NEW Only	New Construction	Other	167,558	142,424	142,424	0%	-$1.42
Commercial	Com - Pipe Insulation Space Heating Boiler	Retrofit	Heating	1,937,623	1,646,979	1,646,979	4%	$0.94
Commercial	Com - Pipe Insulation Space Heating Boiler , Z1	Retrofit	Heating	31,283	26,591	26,591	0%	$0.65
Commercial	Com - Pool Heaters Indoor	Replace on Burnout	Water Heating	26,978	25,629	25,629	0%	$1.03
Commercial	Com - Pool Heaters Outdoor	Replace on Burnout	Water Heating	32,339	30,722	30,722	0%	$0.00
Commercial	Com - Rack Oven - Gas - Double	Replace on Burnout	Cooking	272,773	231,857	-	0%	$1.89
Commercial	Com - Rack Oven - Gas - Double - NEW Only	New Construction	Cooking	34,149	29,026	-	0%	$1.89
Commercial	Com - Refrig - New Display Cases with Doors GAS SPHT	Replace on Burnout	Refrigeration	2,150,247	1,827,710	1,827,710	5%	$0.60
Commercial	Com - Refrig - New Display Cases with Doors GAS SPHT - NEW only	New Construction	Refrigeration	526,530	447,551	447,551	1%	$0.60
Commercial	Com - Refrig - Retrofit Doors to Open Display Cases GAS SPHT	Retrofit	Refrigeration	1,891,632	1,607,887	1,607,887	4%	$0.88
Commercial	Com - Roof Insulation R0 Base GAS SPHT, Z1	Retrofit	Weatherization	1,696,670	1,442,170	1,442,170	4%	$0.70
Commercial	Com - Roof Insulation R0 Base GAS SPHT, Z2	Retrofit	Weatherization	25,889	22,006	22,006	0%	$0.47
Commercial	Com - Roof Insulation R5 Base GAS SPHT, Z1	Retrofit	Weatherization	254,371	216,216	216,216	1%	$2.08
Commercial	Com - Roof Insulation R5 Base GAS SPHT, Z2	Retrofit	Weatherization	4,469	3,798	3,798	0%	$1.20
Commercial	Com - Thin Triple Pane Windows GAS SPHT	Retrofit	Weatherization	273,731	232,671	-	0%	$27.56
Commercial	Com - Thin Triple Pane Windows GAS SPHT - NEW only	New Construction	Weatherization	259,453	220,535	-	0%	$30.53
Commercial	Com - Two Stage Valve for Com Gas Dryer	Retrofit	Other	1,015,910	863,523	863,523	2%	$0.58
Commercial	Com - Two Stage Valve for Com Gas Dryer - NEW Only	New Construction	Other	79,863	67,883	67,883	0%	$0.58
Commercial	Com - VFD Kitchen Vent Hood GAS SPHT	Retrofit	Heating	1,052,067	894,257	894,257	2%	$2.57
Commercial	Com - VFD Kitchen Vent Hood GAS SPHT - NEW Only	New Construction	Heating	92,874	78,943	78,943	0%	$2.57
Commercial	Com - Wall Insulation GAS SPHT, Z1	Retrofit	Weatherization	2,305,470	1,959,649	-	0%	$0.88
Commercial	Com - Wall Insulation GAS SPHT, Z2	Retrofit	Weatherization	37,996	32,296	-	0%	$0.54
Commercial	Com - Zero Net Energy	New Construction	Other	1,655,635	1,407,290	905,787	2%	$12.92

Table D-5: Oregon 20-Year Cumulative Potential (Industrial)

Sector	Measure Name	Measure Type	End Use	20-year Cumulative Technical Potential (therms)	20-year Cumulative Achievable Potential (therms)	20-year Cumulative Cost-Effective Potential (therms)	% of Total Sector C/E Potential	Average Levelized Cost ($/therm)
Industrial	Ind - Advanced Wall Insulation	Retrofit	Weatherization	293,466	249,446	-	0%	$8.77
Industrial	Ind - Ceiling/Roof Insulation	Retrofit	Weatherization	3,267,663	2,777,514	2,777,514	10%	$0.75
Industrial	Ind - Custom Boiler	Retrofit	Process Heating	3,630,984	3,086,336	3,086,336	11%	$0.30
Industrial	Ind - Custom Controls (Gas)	Retrofit	Process Heating	1,503,991	1,278,392	-	0%	$6.74
Industrial	Ind - Custom HVAC (Gas)	Retrofit	HVAC	1,276,841	1,085,315	1,085,315	4%	$1.10
Industrial	Ind - Custom O&M	Retrofit	Process Heating	1,000,929	850,789	850,789	3%	$0.06
Industrial	Ind - Custom Process (Gas)	Retrofit	Process Heating	6,503,183	5,527,705	5,527,705	19%	$0.39
Industrial	Ind - Gas-fired HP Water Heater	Replace on Burnout	Water Heating	1,135,575	965,239	965,239	3%	$0.42
Industrial	Ind - Greenhouse - Condensing Unit Heater	Retrofit	Process Heating	88,959	75,615	75,615	0%	$0.43
Industrial	Ind - Greenhouse - Controller	Retrofit	Process Heating	147,102	125,036	125,036	0%	$0.23
Industrial	Ind - Greenhouse - IR Poly Film	Retrofit	Process Heating	264,459	224,790	224,790	1%	$0.23
Industrial	Ind - Greenhouse - Under Bench Heating	Retrofit	Process Heating	424,971	361,225	361,225	1%	$0.37
Industrial	Ind - Greenhouse Condensing Boiler	Replace on Burnout	Process Heating	160,050	136,042	136,042	0%	$1.90
Industrial	Ind - Heat Recovery	Retrofit	HVAC	2,987,474	2,539,353	2,539,353	9%	$0.23
Industrial	Ind - Pipe Insulation	Retrofit	Process Heating	2,056,231	1,747,796	1,747,796	6%	$0.36
Industrial	Ind - Process Insulation	Retrofit	Process Heating	916,019	778,616	778,616	3%	$0.63
Industrial	Ind - Radiant Heating (Gas)	Replace on Burnout	Process Heating	1,258,156	1,069,432	1,069,432	4%	$0.95
Industrial	Ind - SEM (Gas)	Retrofit	Process Heating	1,807,773	1,536,607	1,536,607	5%	$0.35
Industrial	Ind - Steam Trap Maintenance	Retrofit	Process Heating	2,375,858	2,019,479	2,019,479	7%	$0.04
Industrial	Ind - Wall Insulation (Gas)	Retrofit	Process Heating	3,722,272	3,163,931	3,163,931	11%	$1.12
Industrial	Ind - Water Heating	Replace on Burnout	Process Heating	895,709	761,353	761,353	3%	$0.96
Industrial	Ind - Greenhouse - Thermal Curtain	Retrofit	Process Heating	309,830	263,356	263,356	1%	$0.41

Table D-6: Oregon 20-Year Cumulative Potential (Residential)

Sector	Measure Name	Measure Type	End Use	20-year Cumulative Technical Potential (therms)	20-year Cumulative Achievable Potential (therms)	20-year Cumulative Cost-Effective Potential (therms)	% of Total Sector C/E Potential	Average Levelized Cost ($/therm)
Residential	Res - Cond Boiler heating GAS SPHT	Replace on Burnout	Heating	103,588	88,050	88,050	0%	$0.27
Residential	Res - AFUE 95%+ Furnace GAS SPHT	Replace on Burnout	Heating	11,993,309	10,194,313	10,194,313	14%	$0.91
Residential	Res - Attic insulation (R0-R11 starting condition) GAS SPHT- RET	Retrofit	Weatherization	6,103,677	5,188,126	5,188,126	7%	$0.59
Residential	Res - Attic insulation (R12-R18 starting condition) GAS SPHT- RET	Retrofit	Weatherization	5,999,434	5,099,519	5,099,519	7%	$1.06
Residential	Res - Attic insulation R-60 GAS SPHT, Z1	Retrofit	Weatherization	1,274,664	1,083,465	1,083,465	1%	$9.10
Residential	Res - Attic insulation R-60 GAS SPHT, Z2	Retrofit	Weatherization	19,768	16,803	16,803	0%	$5.93
Residential	Res - Ceiling insulation - Multifamily R49 GAS SPHT, Z1	Retrofit	Weatherization	4,806	4,085	4,085	0%	$1.19
Residential	Res - Ceiling insulation - Multifamily R49 GAS SPHT, Z2	Retrofit	Weatherization	49	41	41	0%	$1.19
Residential	Res - Cellular Shades GAS SPHT	Retrofit	Weatherization	224,369	190,714	-	0%	$9.62
Residential	Res - Condensing Furnaces (MF) GAS SPHT	Replace on Burnout	Heating	568,857	540,415	540,415	1%	$0.43
Residential	Res - Dmd Ctrl Recirc. GAS WHT	Retrofit	Water Heating	1,560	1,482	1,482	0%	$0.44
Residential	Res - Duct Sealing MH GAS SPHT	Retrofit	Weatherization	11,939	10,148	10,148	0%	$1.69
Residential	Res - Eff Clotheswasher MF Common GAS WHT	Replace on Burnout	Water Heating	16,773	14,257	14,257	0%	-$6.84
Residential	Res - Eff Clotheswasher MF Common GAS WHT - NEW only	New Construction	Water Heating	2,262	1,923	1,923	0%	-$6.84
Residential	Res - Elec Hi-eff Clotheswasher GAS WHT	Replace on Burnout	Water Heating	1,086,681	923,679	923,679	1%	-$5.02
Residential	Res - Elec Hi-eff Clotheswasher GAS WHT - NEW only	New Construction	Water Heating	6,547	5,565	5,565	0%	-$5.02
Residential	Res - Energy Star Gas Clothes Dryer	Replace on Burnout	Appliance	79,707	75,722	75,722	0%	$1.14
Residential	Res - Energy Star Gas Clothes Dryer - NEW only	New Construction	Appliance	298	283	283	0%	$1.14
Residential	Res - Floor insulation GAS SPHT	Retrofit	Weatherization	15,475,765	13,154,401	13,154,401	18%	$1.11
Residential	Res - Floor Insulation Multifamily GAS SPHT, Z1	Retrofit	Weatherization	53,921	45,833	45,833	0%	$1.34
Residential	Res - Floor Insulation Multifamily GAS SPHT, Z2	Retrofit	Weatherization	726	617	617	0%	$1.00
Residential	Res - Gas Absorption Heat Pump Water Heater GAS WHT	Replace on Burnout	Water Heating	14,439,285	12,273,392	12,273,392	17%	$0.46
Residential	Res - Gas Fired HP (>100% Eff) GAS SPHT	Replace on Burnout	Heating	2,061,404	1,752,193	-	0%	$3.95
Residential	Res - Gas Fired HP (>100% Eff) GAS SPHT - NEW only	New Construction	Heating	59,660	50,711	40,456	0%	$2.01
Residential	Res - Gas Fireplace - 75+ FE w/ ignition GAS SPHT - NEW only	New Construction	Heating	20,461	17,392	17,392	0%	$0.00
Residential	Res - Gas Storage Water Heater (All Tank Sizes) GAS WHT	Replace on Burnout	Water Heating	916,713	779,206	779,206	1%	$0.83
Residential	Res - Gas Storage Water Heater (All Tank Sizes) GAS WHT - NEW only	New Construction	Water Heating	9,235	7,850	7,850	0%	$0.83
Residential	Res - Market Transformation NH AVG ELEC SPHT DHW - Gas Only - NEW only	New Construction	Weatherization	83,688	79,503	-	0%	$8.69
Residential	Res - Market Transformation NH GAS SPHT DHW - Avg. Elec Mixed Market - NEW only	New Construction	Weatherization	2,407,290	2,286,925	2,286,925	3%	$1.26
Residential	Res - Market Transformation NH GAS SPHT DHW - Gas Only - NEW only	New Construction	Weatherization	3,028,717	2,877,281	2,877,281	4%	$1.09

Table D-6 – continued: Oregon 20-Year Cumulative Potential (Residential)

Sector	Measure Name	Measure Type	End Use	20-year Cumulative Technical Potential (therms)	20-year Cumulative Achievable Potential (therms)	20-year Cumulative Cost-Effective Potential (therms)	% of Total Sector C/E Potential	Average Levelized Cost ($/therm)
Residential	Res - MF Window to rated between U-0.22 to U-0.30 GAS SPHT, Z1	Retrofit	Weatherization	319,925	271,936	271,936	0%	$3.22
Residential	Res - MF Window to U-0.22 or lower GAS SPHT, Z1	Retrofit	Weatherization	49,144	41,772	41,772	0%	$1.31
Residential	Res - MH Early Retirement GAS SPHT	Retrofit	Heating	203,018	172,565	172,565	0%	$5.51
Residential	Res - Multifamily Commercial Size Condensing Tank Water Heater GAS WHT	Replace on Burnout	Water Heating	57,205	54,345	54,345	0%	$0.28
Residential	Res - Multifamily Commercial Size Condensing Tank Water Heater GAS WHT - NEW only	New Construction	Water Heating	9,642	9,160	9,160	0%	$0.28
Residential	Res - Multifamily Pipe Insulation GAS WHT	Retrofit	Water Heating	356,776	303,260	303,260	0%	$0.44
Residential	Res - New MH - Energy Star GAS SPHT, Z1 - NEW only	New Construction	Weatherization	33,596	31,916	31,916	0%	$1.44
Residential	Res - New MH - Energy Star GAS SPHT, Z2 - NEW only	New Construction	Weatherization	339	322	322	0%	$1.44
Residential	Res - Path 2 GAS WHT Space Heat - Avg. Elec Mixed Market - NEW only	New Construction	Water Heating	623,854	592,662	592,662	1%	$1.54
Residential	Res - Path 2 GAS WHT Space Heat - Gas Only - NEW only	New Construction	Water Heating	5,472,897	5,199,252	5,199,252	7%	$0.87
Residential	Res - Path 3 AVG ELEC WHT Space Heat - Gas Only - NEW only	New Construction	Water Heating	5,141,055	4,884,002	4,884,002	7%	$1.88
Residential	Res - Path 3 GAS WHT Space Heat - Avg. Elec Mixed Market - NEW only	New Construction	Water Heating	30,432	28,910	28,910	0%	$15.86
Residential	Res - Path 3 GAS WHT Space Heat - Gas Only - NEW only	New Construction	Water Heating	3,147,139	2,989,782	2,989,782	4%	$1.46
Residential	Res - Path 4 AVG ELEC SPHT DHW - Gas Only - NEW only	New Construction	Heating	38,040	36,138	36,138	0%	$11.11
Residential	Res - Path 4 GAS SPHT DHW - Avg. Elec Mixed Market - NEW only	New Construction	Heating	529,116	502,660	502,660	1%	$2.33
Residential	Res - Path 4 GAS SPHT DHW - Gas Only - NEW only	New Construction	Heating	754,597	716,868	716,868	1%	$1.98
Residential	Res - Path 5 Emerging Super Efficient Whole Home AVG ELEC SPHT DHW - Gas Only - NEW only	New Construction	Heating	21,105	17,939	17,939	0%	$18.40
Residential	Res - Path 5 Emerging Super Efficient Whole Home GAS SPHT DHW - Avg. Elec Mixed Market - N	New Construction	Heating	654,026	555,922	555,922	1%	$3.56
Residential	Res - Path 5 Emerging Super Efficient Whole Home GAS SPHT DHW - Gas Only - NEW only	New Construction	Heating	813,244	691,257	691,257	1%	$2.90
Residential	Res - Wall insulation R-30 GAS SPHT, Z2	Retrofit	Weatherization	43,519	36,991	36,991	0%	$2.30
Residential	Res - Window Replacement Tier 2 (U-0.20 - 0.23) GAS SPHT	Replace on Burnout	Weatherization	599,202	509,322	509,322	1%	$2.73
Residential	Res - Window Replacement Tier 2 (U-0.20 - 0.23) GAS SPHT - NEW only	New Construction	Weatherization	1,783	1,516	1,516	0%	$2.73

D.3 Low Income Energy Efficiency Outreach Plan

The following pages provide the Low Income Energy Efficiency Outreach Plan.

Communications to NW Natural customers with limited incomes

NW Natural®

Purpose of NW Natural's Energy Efficiency Program

Improve the energy efficiency, energy savings and comfort of homes for customers with limited incomes in Oregon and Southwest Washington.

Connect these customers with free heating and weatherization upgrades and services to:

- Lower gas bills
- Lower gas use
- Reduce service disconnections
- Deliver core values of caring, environmental stewardship and safety

Audience

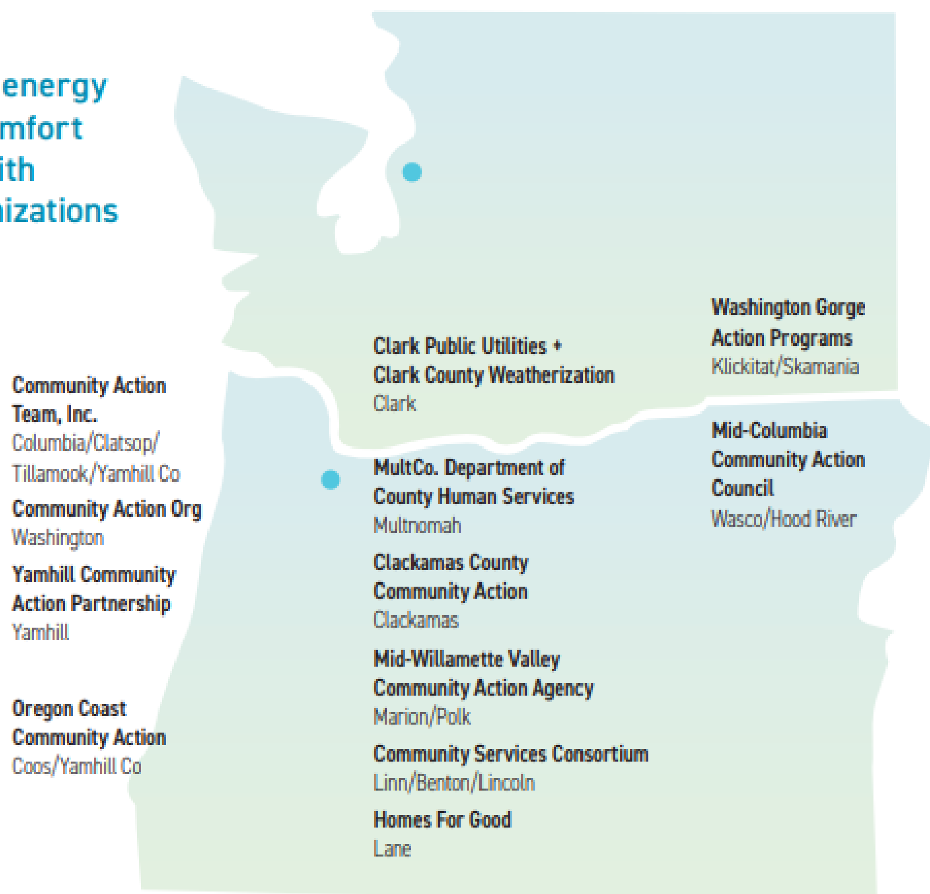
NW Natural customers who qualify for financial assistance from one of two programs, depending on gross annual income.

For customers with low incomes, Oregon Low-income Energy Efficiency (OLIEE) and Washington Low-income Energy Efficiency (WALIEE) income guidelines are the same as the Oregon and Washington Housing and Community Service's Low Income Home Energy Assistance weatherization program. Customers qualify for free weatherization services if their household income is at or below 80% of area median income.

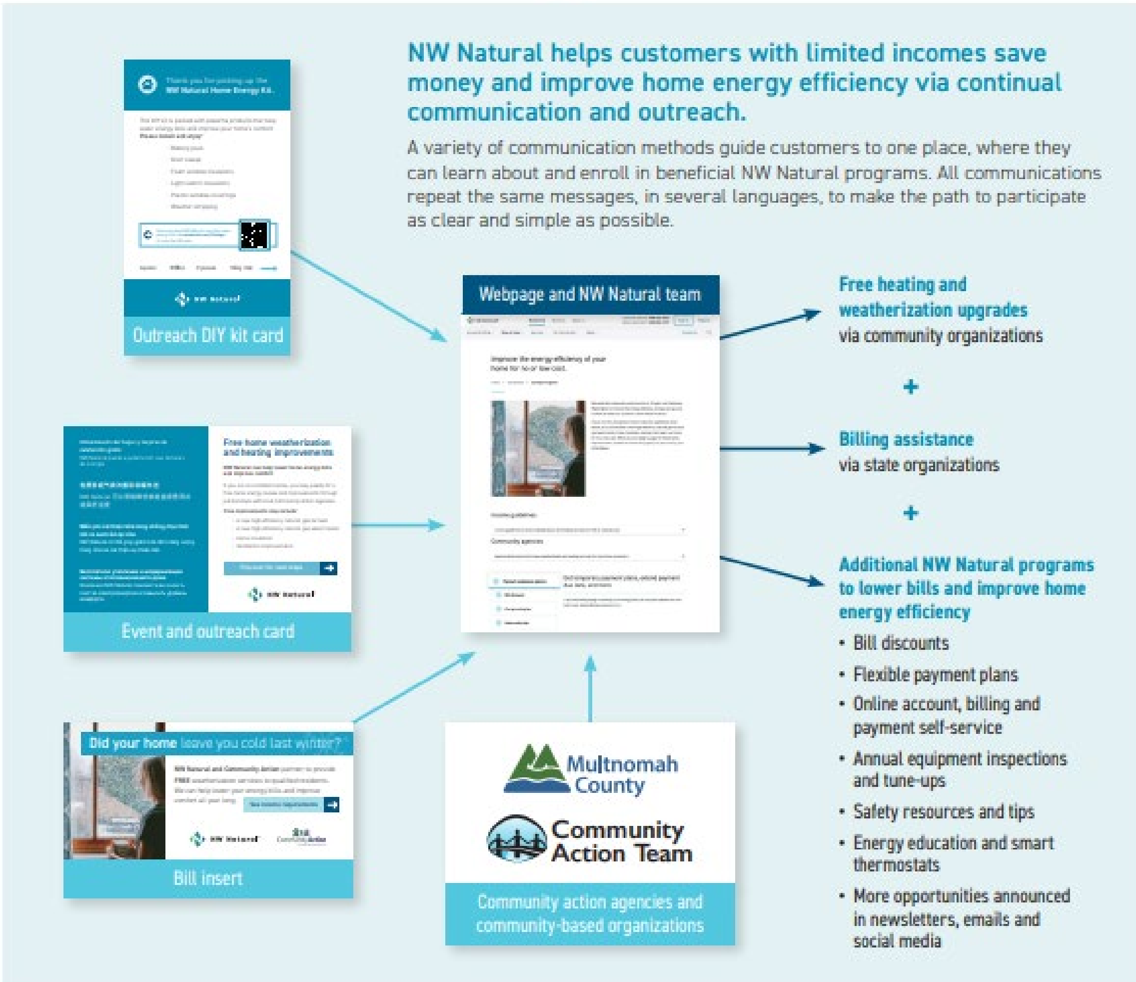
Customers receive assistance and improvements by working with Community Agencies listed at nwnatural.com/Savings.

We also serve customers with moderate incomes through Savings Within Reach, offered in partnership with Energy Trust of Oregon. Savings Within Reach provides increased incentives to help offset the cost of insulation and heating upgrades. Customers receive assistance and improvements by working with Energy Trust of Oregon Savings Within Reach contractors.

Improving home energy efficiency and comfort in partnership with community organizations



Communications, outreach and engagement



Key messages repeat throughout communications

- NW Natural can help lower your energy bills.
- We partner with community agencies to provide free heating and weatherization services for qualifying incomes.
- We can help improve comfort all year long.

Communications cross-promote additional NW Natural services that can help lower bills even more

- NW Natural Bill Discount Program: You could save 15% to 85% on your monthly bill.
- NW Natural payment assistance options: Get temporary payment plans, extend payment due date, and more.
- Energy-saving tips: Ways to help lower energy bills and gas use at home.
- Natural gas home safety tips.

In addition, Bill Discount Program materials cross-promote these same services, as well as contact information for electric utilities to save on electric bills.

Multiple languages: English, Spanish, Vietnamese, Russian, Chinese (simplified)

QR code to web page for income qualifications, community agencies and additional resources

Appendix E – Emissions Compliance Resources

E.1 Renewable Natural Gas Literature Review

The following pages provide Literature Review on RNG availability and pricing.

Renewable Natural Gas

Availability and Pricing

July 2025

Prepared for:

Northwest Natural

Table of Contents

1 Introduction

Renewable natural gas (RNG) is sold as a fuel into various end-use markets. The most common end use has been the transportation sector because of the value generated by environmental commodities, namely Renewable Identification Numbers (RINs) from the federal Renewable Fuel Standard (RFS) and credits in California's Low Carbon Fuel Standard (LCFS). RNG is also sold into other markets, particularly to gas utilities, corporate or voluntary buyers, and as a feedstock for other fuels (e.g., biomethanol). Outside of the on-road transportation sector, the RNG market lacks liquidity and transparency, especially as it relates to pricing.

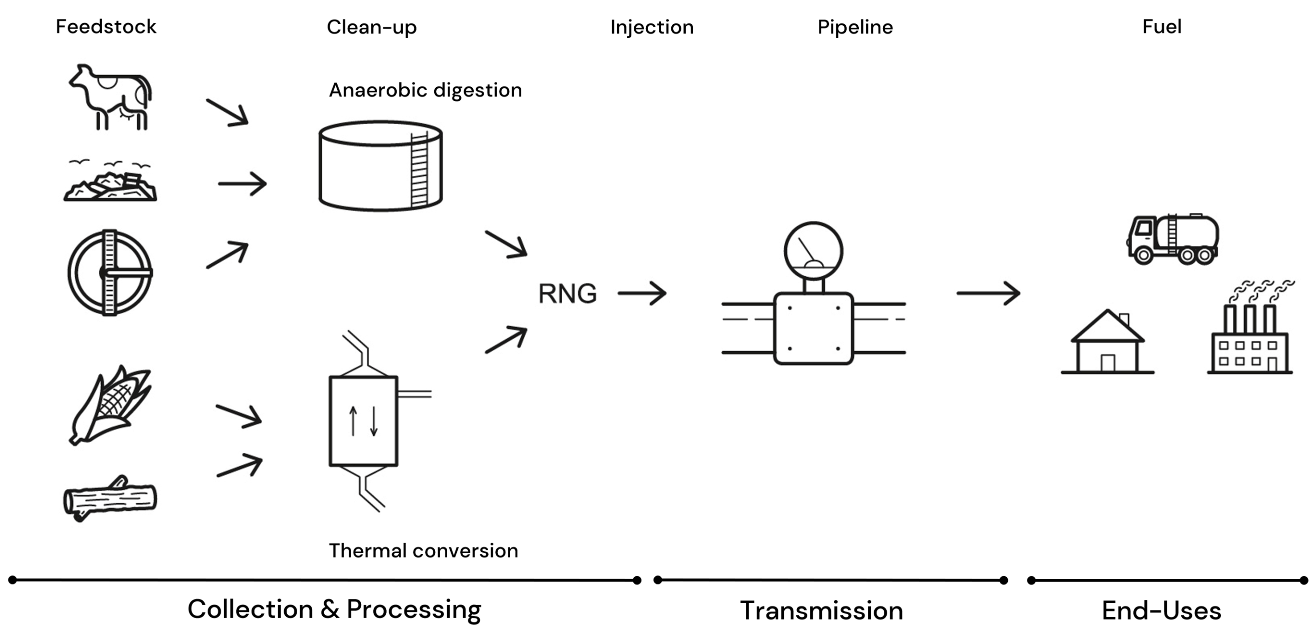
Section 4.9.1 of Staff Final Comments in the matter of NW Natural's Integrated Resource Plan from 2022 (Docket No. LC 79) outlines concerns by Oregon Public Utilities Commission Staff regarding the availability and pricing of RNG. This discussion ends with the development of *Recommendation 39* that reads "For the next IRP, the Company should provide a literature review of RNG price and availability forecasts." This document follows directly from the language in Section 4.9.1 and the associated recommendation. ICF prepared this literature review with respect to RNG availability and RNG pricing based on publicly available information.

2 RNG Availability

2.1 RNG Production Pathways

ICF considers two production pathways for RNG as viable in the near-term future (i.e., 2030): anaerobic digestion and thermal conversion (see figure below).

Figure 1. Overview of RNG Production



ICF notes that RNG can also be produced via other pathways, like the methanation of green hydrogen with biogenic carbon dioxide. This pathway is not considered in this report.

Anaerobic digestion is when microorganisms break down organic material in an environment without oxygen. The initial process generally takes place in a controlled environment, referred to as a digester or reactor, including landfill gas facilities. When organic waste, a biosolid, or livestock manure is introduced to the digester, the material is broken down over time (e.g., days) by microorganisms, and the gaseous products of that process contain a large fraction of methane and carbon dioxide. The biogas requires capture, subsequent conditioning and upgrade before pipeline injection. The conditioning and upgrading helps to remove any contaminants and other trace constituents, including siloxanes, sulfides and nitrogen, which cannot be injected into common carrier pipelines, and increases the heating value of the gas for injection.

Biomass thermal conversion occurs via processes like gasification or pyrolysis to produce RNG and occurs over multiple steps. In thermal conversion, there is generally a feedstock pre-processing step to prepare the feedstock for thermal treatment. In the next step, gasification (or pyrolysis) generates synthetic gas (syngas), consisting largely of hydrogen and carbon monoxide, and trace amounts of methane and carbon dioxide. The syngas is then sent for filtration and purification to remove excess dust or ash generated during the gasification (or pyrolysis) stage, and to remove potential contaminants like hydrogen sulfide and carbon dioxide. In the final step, methanation occurs, whereby the upgraded syngas is converted to methane and dried prior to pipeline injection.

2.2 Feedstocks for RNG Production

RNG can be produced from a variety of renewable feedstocks. Generally, ICF considers at least the following feedstocks when evaluating RNG production (see Table 1): animal manure, food waste, landfill gas, wastewater at water resource recovery facilities, agricultural residues, energy crops, forestry and forest product residues, and municipal solid waste.

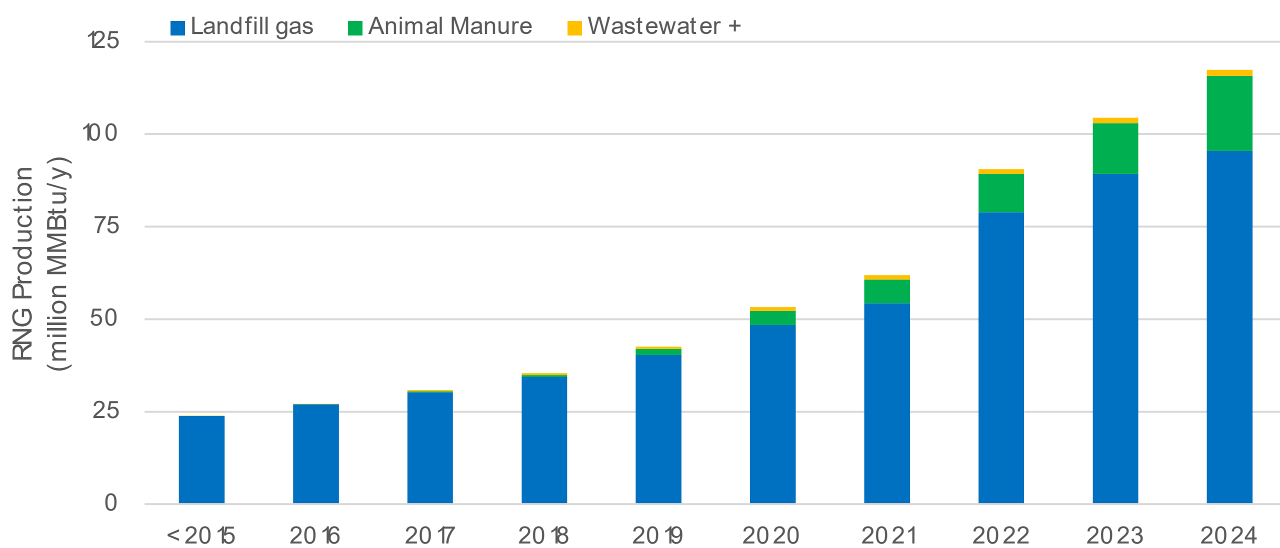
Table 1. RNG Feedstock Types

Feedstock	Description
Animal manure	Manure produced by livestock, including dairy cows, beef cattle, swine, sheep, goats, poultry, and horses.
Food waste	Commercial, industrial and institutional food waste, including from food processors, grocery stores, cafeterias, and restaurants.
Landfill gas	The anaerobic digestion of organic waste in landfills produces a mix of gases, including methane.
Wastewater	Wastewater consists of waste liquids and solids from household, commercial, and industrial water use; in the processing of wastewater, a sludge is produced, which serves as the feedstock.
Agricultural residue	The material left in the field, orchard, vineyard, or other agricultural setting after a crop has been harvested. Inclusive of unusable portion of crop, stalks, stems, leaves, branches, and seed pods.
Energy crops	Inclusive of perennial grasses, trees, and annual crops that can be grown to supply large volumes of uniform and consistent feedstocks for energy production.
Forestry and forest product residue	Biomass generated from logging, forest and fire management activities, and milling. Inclusive of logging residues, forest thinnings, and mill residues. Also, materials from public forestlands, but not specially designated forests (e.g., roadless areas, national parks, wilderness areas).
Municipal solid waste	Refers to the biogenic fraction of waste that would be landfilled after diversion of other waste products (e.g., food waste or other organics), including paper and paperboard, and yard trimmings.

2.3 Current RNG Supply Estimates

ICF estimates that domestic RNG production capacity is about 115-120 million MMBtu/y,[1] from landfills, animal manure digesters, and wastewater facilities (which also includes some source separated food waste facilities), and has sustained a compound annual growth rate of about 20% since 2015.

Figure 2. RNG Production Capacity in the United States



The transportation sector has accounted for the greatest part of RNG demand—at least 80%—since 2012. In the last several years, however, there has been an increase in RNG demand from sectors like utilities and voluntary buyers focused on decarbonization.

2.3.1 Renewable Thermal Certificates as Indicator of Availability

The U.S. lacks a national certification program for the environmental attributes of RNG. Conversely, renewable electricity has multiple registries and certifications for Renewable Energy Certificates or RECs. While some renewable fuel certification programs exist, such as the Green-e Renewable Fuels program, they are limited in scope and insufficient for broad market participation.

M-RETS started as a platform to track renewable energy production via RECs. Today, it has expanded and offers a North American tracking system for renewable thermal credits or certificates (RTCs) that can—and does—support the work of certification schemes like Green-e. M-RETS facilitates RTC markets by issuing a unique, traceable digital certificate (i.e., one RTC) for every dekatherm or MMBtu of verified renewable energy recorded on the platform. The M-RETS platform provides more than just the ability to track RNG volumes; it also provides for—but does not require—the ability to track carbon pathways and CI values from documentation associated with each certificate. Once issued, M-RETS users can choose to transfer (buy/sell), retire, import, or export RTCs. M-RETS users can retire certificates either to comply with state mandates and/or to fulfill their voluntary commitments, while preventing the risk of double counting. M-RETS registers projects in all U.S. states and Canadian provinces and will support imports and exports with any registry in North America that meets its specific security and operational requirements for avoiding double counting.

The M-RETS RTC platform launched January 1, 2020, and shortly thereafter issued certificates. This system saw the public sale and claim by a Fortune 50 corporate client not too long after.[1] In 2020, Oregon established the first program that required

[1] *MMBtu = million British thermal units.* Based on ICF analysis of data from the EPA's Landfill Methane Outreach Program, the RNG Coalition, Argonne National Laboratory, EPA's Moderated Transaction System, and the California LCFS program.

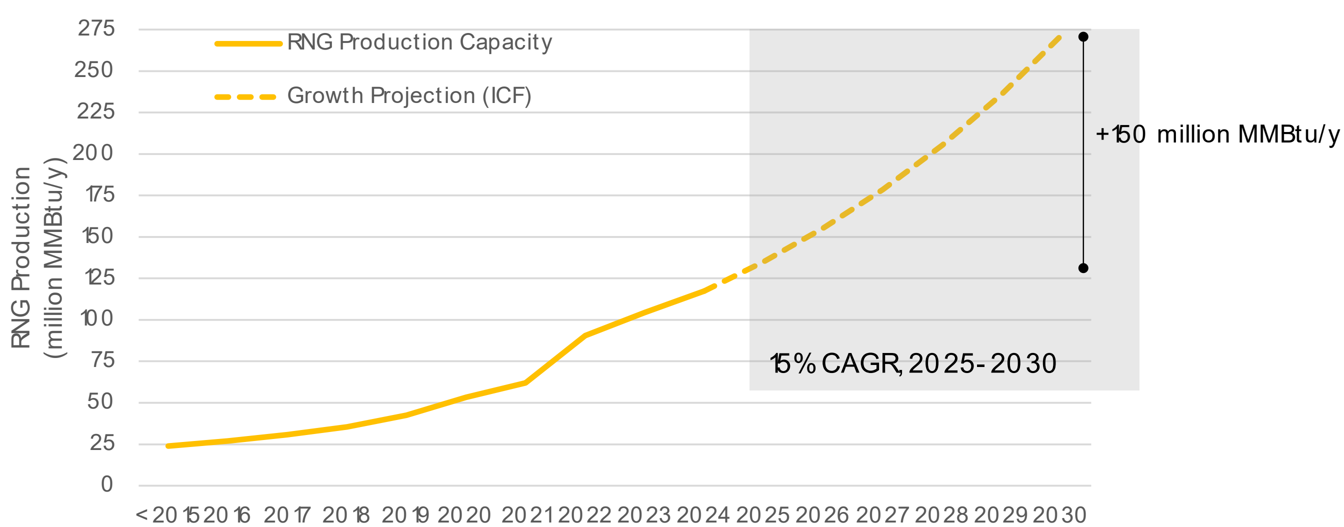
the use of M-RETS through Senate Bill 98, under which the Oregon Public Utilities Commission adopted the M-RETS RTC platform as a compliance tool. California subsequently adopted M-RETS as the recognized compliance tool for implementing Senate Bill 1440.[1] The California Public Utilities Commission now requires "biomethane producers to track injections into the pipelines through the M-RETS platform" as part of Senate Bill 1440 compliance.[1] In 2022, both Oregon and Washington adopted the use of M-RETS to track RNG under their respective state clean fuel programs.

Despite progress made by M-RETS and the increased acceptance of RTCs as a market-based mechanism to acquire the environmental attributes of low-carbon fuels like RNG, the voluntary market still lacks liquidity, with lack of transparency on pricing and volumes. That said, there are about 75-80 RNG facilities registered as RTC generators with M-RETS, with most generators reporting from landfills (and there is a single RTC generator listed that produces an RTC via hydrogen). ICF estimates that this represents a total annual output of
45-55 million MMBtu/y registered as generators of RTCs.[2]

2.4 Estimating Near-Term RNG Availability

ICF developed a near-term estimate of RNG supply. Based on ICF analysis and research, including an analysis of announced projects (that are not yet operational), we anticipate that RNG supply will achieve a compound annual growth rate of at least 15%-20% to 2030, slightly lower than what has been achieved over the last 5-7 years. Based on current RNG production levels of around 115-120 million MMBtu capacity in place at the end of 2024, we estimate an *additional RNG supply* of about 150-240 million MMBtu/y by 2030, for a total of 270 to 370 million MMBtu/y.

Figure 3. Forecasted RNG Supply, 2025-2030 (million MMBtu/y)



For the purposes of this study, ICF did not explicitly forecast RNG supply by feedstock. At a high level, ICF anticipates that RNG from landfill gas will continue to be the largest contributor to RNG supply, and that there will be modest growth in RNG from animal manure, and that there will be a higher growth rate in food waste and wastewater projects out to 2030.

These estimates are comparable with those conducted by others. For instance,

- In 2024, Wood Mackenzie forecasted that RNG production from landfill gas would double by 2030 (it is about 85-90 million MMBtu/y today).[3]

[2] ICF analysis.
[3] "Trashing your way to a cleaner future: landfill gas as a feedstock for RNG in North America", Wood Mackenzie, 2024.

- In 2024, cCarbon estimated that the market would expand from about 71.5 million MMBtu in 2022 to about 160 million MMBtu in 2030.[4]
- In April 2025, ING Research indicated that they expect RNG production to increase by a factor of 2.3 by 2030.[5]

2.5 Estimating Mid- to Long-Term RNG Availability

ICF developed an estimate of mid- to long-term RNG supply by considering the availability of key feedstocks that can be used in anaerobic digestion pathways or in thermal conversion pathways. ICF used a combination of resources—including those listed in the table below—to develop a low and high estimates of RNG availability. Each scenario considers various

Table 2. List of Data Sources for RNG Feedstock Inventory

Feedstock for RNG	Resources for Assessment
Animal manure	• US Environmental Protection Agency (EPA) AgStar Project Database • US Department of Agriculture (USDA) Census of Agriculture, 2022
Food waste	• US Department of Energy (DOE) 2023 Billion-Ton Report (BT23) • Bioenergy Knowledge Discovery Framework (KDF)
Landfill gas	• US EPA Landfill Methane Outreach Program (LMOP) • Environmental Research & Education Foundation (EREF)
Wastewater	• US EPA 2022 Clean Watersheds Needs Survey (CWNS) • Water Environment Federation
Agricultural residue	• US DOE 2023 Billion-Ton Report • Bioenergy Knowledge Discovery Framework
Energy crops	• US DOE 2023 Billion-Ton Report • Bioenergy Knowledge Discovery Framework
Forestry and forest product residue	• US DOE 2023 Billion-Ton Report • Bioenergy Knowledge Discovery Framework
Municipal solid waste	• US DOE 2023 Billion-Ton Report • Waste Business Journal

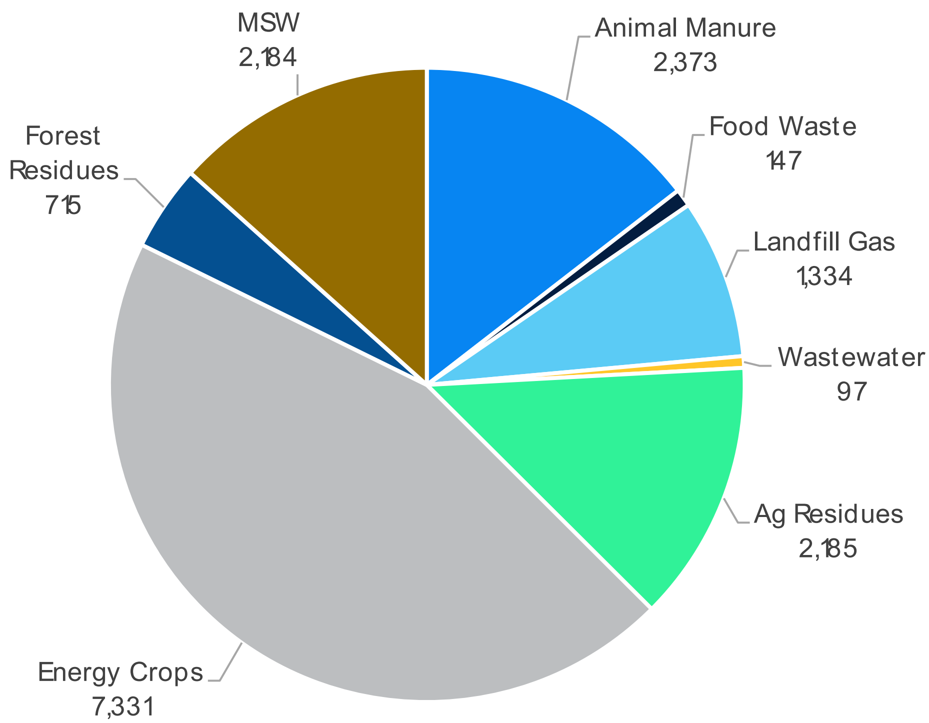
ICF first characterized the technical RNG production potential from the feedstocks outlined above. The technical potential estimates reflect the total maximum RNG that could be produced from the 100% utilization of all feedstocks, irrespective of practical, economic or market constraints on feedstock availability or production capacity. The technical potential is a theoretical maximum of RNG production potential and is a starting point to create specific scenarios to estimate availability, rather than a realistic supply scenario in and of itself. A variety of technical and economic constraints are applied to develop these scenarios, which are discussed in more detail below. Figure 4 summarizes the maximum theoretical RNG potential for

[4] North American Renewable Natural Gas Outlook 2030, cCarbon, January 2024. ICF notes that the 2022 RNG production estimate of 71.5 million MMBtu in 2022 was low based on our estimates and that this is the lowest 2030 production estimate that ICF found in its literature review.

[5] Renewable natural gas: growing significance in a niche market. Available online at: https://think.ing.com/articles/renewable-natural-gas-growing-significance-in-a-niche-market/. ICF notes that ING Research estimates a total of about 14 billion cubic meters by 2030, up from about 6 billion cubic meters—this estimate is a high starting point suggesting that RNG production is currently about 220 million MMBtu annually.

each conventional biomass-based feedstock and production technology across the United States. This total represents over 16,000 million MMBtu/y[6] of natural gas per year. For reference, the annual natural gas usage in the country's residential sector was about 4,530 million MMBtu (4,397,467 million cubic feet) in 2024.[7]

Figure 4. US RNG Technical Potential by Biogenic Feedstock (million MMBtu/y)



ICF developed RNG supply or availability estimates for two scenarios in this analysis for each feedstock in the RNG inventory (available at the national, census division, and state levels). The RNG production potential included in this analysis is based on an assessment of multiple factors, including but not limited to demand, feedstock costs, technological development, and the policies in place that might support RNG project development. ICF assessed the RNG resource potential of the different feedstocks that could be realized, given the necessary market considerations. The two scenarios for each feedstock—with varying assumptions that influence the level of feedstock utilization relative to the RNG inventory—defined by ICF are as follows:

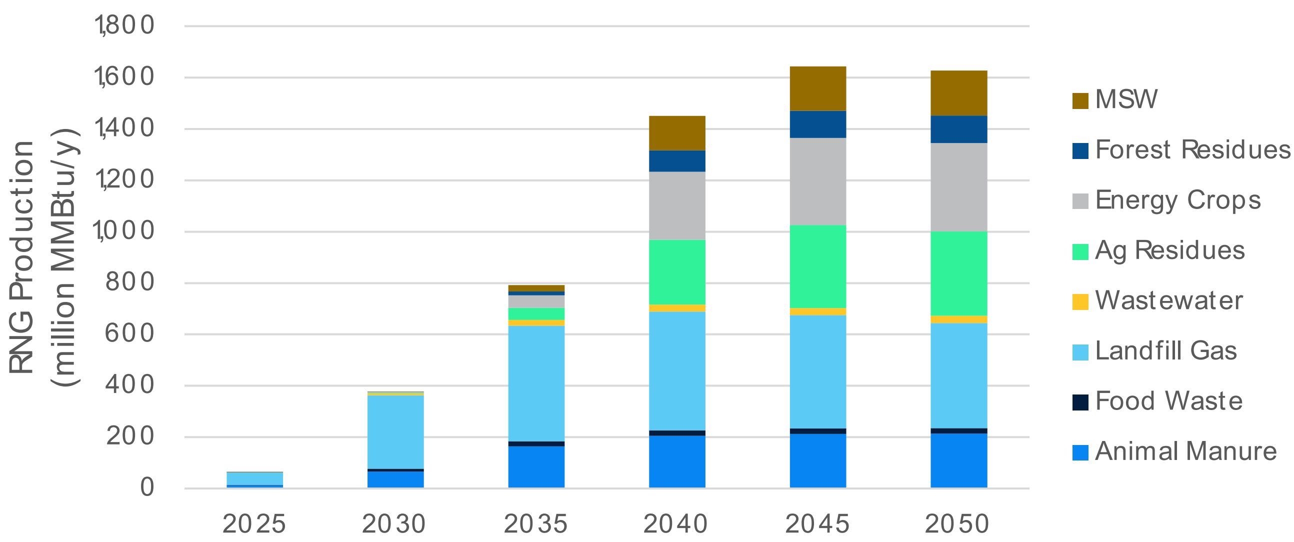
- **Low Scenario**. Represents a low level of feedstock utilization. Utilization levels depending on feedstock, with a range from 30% to 60% for feedstocks that were converted to RNG using anaerobic digestion technologies. The utilization rate of feedstocks for thermal gasification in this scenario is between 5% to 30% of the biomass available at moderate biomass prices. Overall, the Low Scenario captures 10% of the technical potential for RNG production from aggregated feedstock supply (see Figure 4).
- **High Scenario.** Represents balanced assumptions regarding feedstock utilization. Utilization ranges from 50% to 80% for feedstocks that were converted to RNG using anaerobic digestion technologies. The utilization rates of feedstocks for

[6] 1 million MMBtu is equivalent to about 1 billion cubic feet (BCF) of natural gas.
[7] U.S. Energy Information Administration: Natural Gas Consumption by End Use, https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm

thermal gasification in this scenario are 15% to 50% of the biomass available at moderate prices. Overall, the High Scenario captures 23% of the technical potential for RNG production from aggregated feedstock supply (see Figure 4).

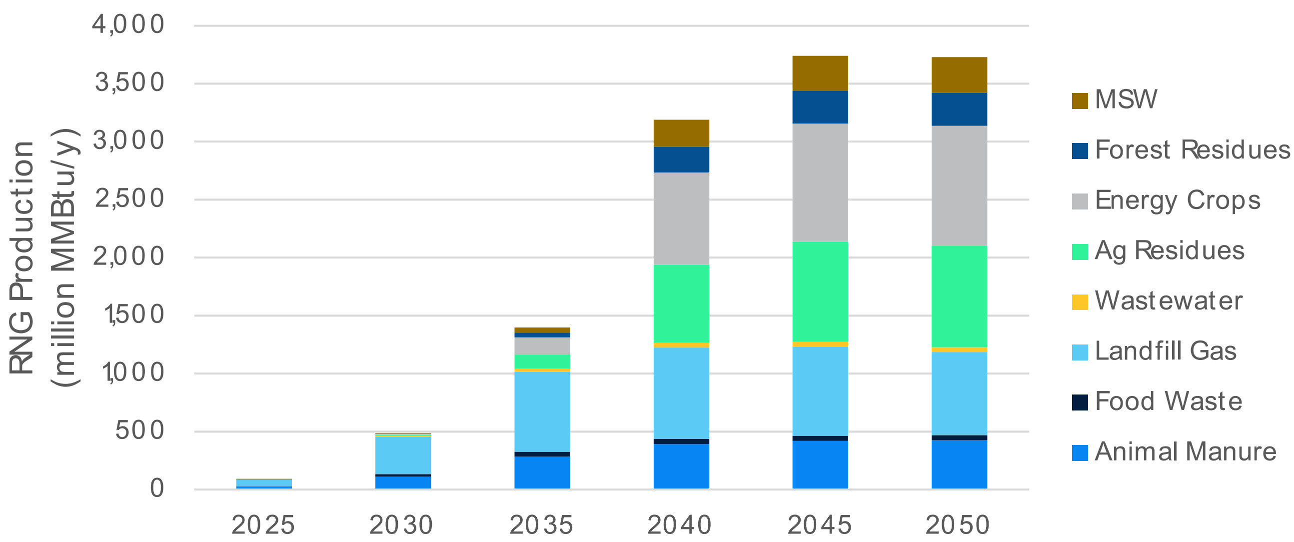
In the Low Scenario (Figure 5), RNG production via anaerobic digestion of feedstocks drives deployment to 2035, with landfill gas making up a large proportion of RNG supply potential and then declining out to 2050. Commercialization of the thermal gasification production technology after 2035 sees the increased deployment of feedstocks expected to utilize that technology, with agricultural residues and energy crops a larger share of total potential. Overall, the Low scenario delivers a maximum supply of about 1,600 million MMBtu/y, or 10% of aggregated biomass feedstock that could be used for RNG production.

Figure 5. Low Scenario Annual RNG Supply, 2025-2050 (million MMBtu/y)



Similar to the Low Scenario, the High Scenario assumes RNG production is driven by anaerobic digestion of feedstocks in the next decade, but with an increased deployment of RNG via thermal gasification of biomass taking place post-2035 (Figure 6). The increased utilization of biomass—including agricultural residues, energy crops and to a lesser extent MSW—helps to increase RNG production potential in the High Scenario. Nearly 70% of RNG is derived from biomass thermal gasification in 2050 in the High Scenario. The High Scenario utilizes 20% of available biomass, delivering maximum annual RNG production of 3,728 million MMBtu/y.

Figure 6. High Scenario Annual RNG Supply, 2025-2050 (million MMBtu/y)



The International Energy Agency (IEA) published an Outlook for Biogas and Biomethane: A global geospatial assessment in May 2025. ICF analysis of the IEA work indicates that they are estimating RNG potential of about 3,760 million MMBtu per year from a combination of what they refer to as biowaste, manure, crop residue, and woody biomass.[8] These categories map to ICF's analysis, with landfill gas, food waste, and wastewater serving as a proxy for biowaste, agricultural residues serving as a proxy for crop residues, and forest residues serving as a proxy for woody biomass. Table 3 below shows the breakdown of the long-term production potential from ICF's High Scenario and the scenario presented by the IEA (for the United States).[9]

Table 3. RNG Potential (million MMBtu/y) Estimated by ICF and IEA

	RNG Potential (million MMBtu/y)	
Feedstock (ICF / IEA)	**ICF, High**	**IEA Potential**
Animal manure / Manure	426	665
Food waste, Landfill gas, Wastewater / Bio-Waste	802	924
Agricultural Residues / Crop residue	874	1,540
Forestry Residues / Woody Biomass	286	627

3 RNG Pricing

An explicit index for RNG pricing has not emerged as of the preparation of this report. However, RNG that is contracted in the non-transportation market tends to look to existing environmental commodity markets for directional pricing. More specifically, RNG used in the transportation sector can generate value via RINs from the federal RFS and credits in the

[8] IEA, Outlook for Biogas and Biomethane: A global geospatial assessment, May 2025.

[9] The IEA estimate is provided in units of billion cubic meters. To convert the IEA estimateICF assumed 35.347 standard cubic feet per cubic meter, and that there are 1,036 Btu per standard cubic feet.

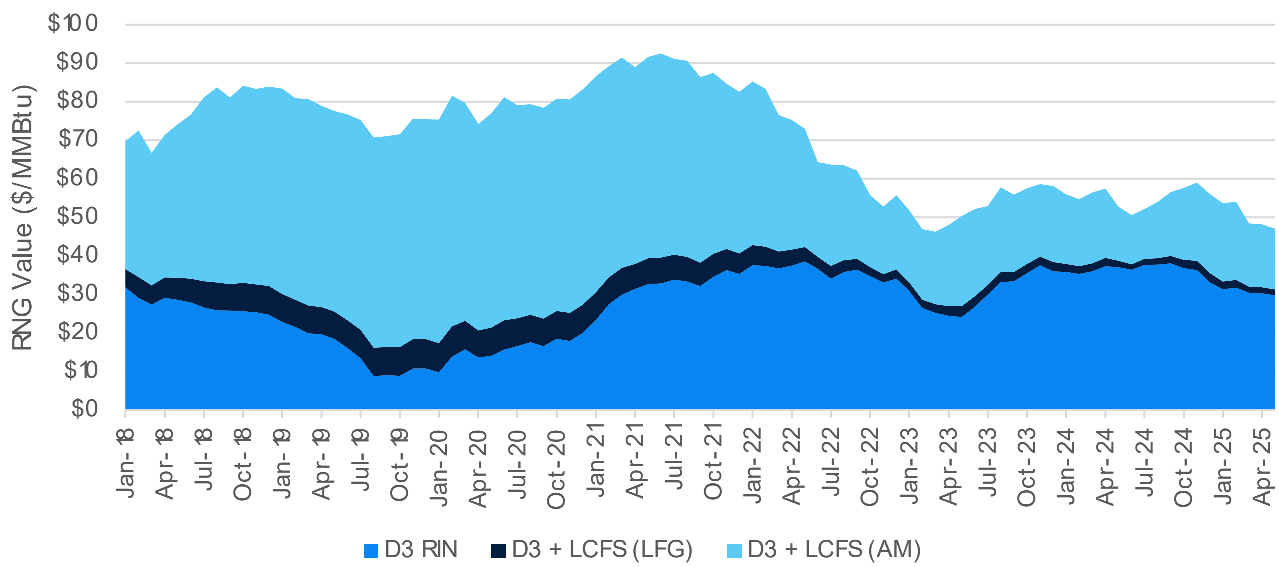
California LCFS program. These markets, however, come with merchant risk and experience volatility tied to regulatory uncertainty, so RNG pricing in fixed offtake or similar agreements tends to be discounted to these other environmental commodity markets, with the RNG producer accepting a lower (fixed) price for reduced risk. In the first subsection below, ICF provides an overview of historical environmental commodity pricing for the sake of reference; and in the section subsection below, ICF reviews publicly available information regarding RNG pricing.

3.1 Environmental Commodity Pricing

Figure 7 below shows the value of RINs in the federal RFS and credits in the California LCFS program from 2018 to present. RNG derived from landfill gas, wastewater facilities, and from animal waste is considered a cellulosic biofuel under the RFS program and generates a D3 RIN. Each RIN is equivalent to a gallon of ethanol and is defined in statute as having 77,000 Btu per gallon or per RIN on a lower heating value (LHV) basis. RIN prices are converted to a more common metric in the natural gas industry, dollar per million Btu ($/MMBtu), by multiplying the RIN price ($/RIN) and a constant of 11.727.[10]

In the California LCFS program, the value to the RNG is based on the credit price (reported in dollars per metric ton, $/t), the carbon intensity of fuel (CI, reported in grams of carbon dioxide equivalent per megajoule of energy, gCO_2e/MJ) and the carbon intensity of the benchmark against which credits are generated, which changes each year. For the sake of simplicity, ICF shows the value of the California LCFS in units of $/MMBtu for RNG derived from landfill gas assuming a CI of 45 gCO_2e/MJ and RNG derived from dairy manure assuming a CI of -250 gCO_2e/MJ.

Figure 7. Value of Environmental Commodities to RNG (nominal, $/MMBtu)



The D3 RIN value (in **blue**) would be realized for RNG delivered into the transportation sector anywhere in the United States. The total value of delivering RNG from landfill gas and RNG from animal manure to California is shown in **dark blue** and **light blue**, respectively.

3.2 RNG Pricing—Results of Literature Review

The value derived via the environmental commodities outlined in the previous sub-section requires that the RNG be used as a transportation fuel, and that it be used in California. While most RNG derived from animal manure is likely still being used as a transportation fuel in California because of its attractive carbon intensity (and associated value from credit generation),

[10] The constant is derived by taking one million Btu and dividing by 77,000 Btu and then converting to the higher heating value (HHV) basis, which is more common for the natural gas industry. The formula is 1,000,000 Btu / 77,000 Btu x 0.902 HHV/LHV = 11.727 RINs per MMBtu.

RNG from landfill gas, wastewater, and other waste resources (e.g., food waste) is increasingly looking to non-transportation markets like utilities or voluntary buyers because the transportation market for compressed and liquefied natural gas (CNG and LNG, respectively) is approaching saturation with RNG. As such, RNG seeks new market opportunities, like utility use. ICF conducted a literature review to develop a range of likely RNG pricing estimates. ICF's literature review is summarized in Table 4 below. Note that all prices are reported in the year in which the reference was provided.

Table 4. Summary of Literature Review Findings for RNG Pricing (all pricing is nominal, $/MMBtu)

Source / Year	Pricing Range ($/mmBtu)	Description
Energy Vision 2019	$12-$23	Energy Vision indicates a price range of $12-$23/MMBtu based on a "combination of data points", including stakeholder engagement and work with Argonne National Laboratory. They report that this price range is indicative of "long-term procurement contracts, largely dependent on the size and type of production facility and organic waste feedstocks being processed."
Vinson & Elkins 2021	$12-$18	The firm reported having "seen prices in the range of $12.00 to $18.00 per MMBtu for gas and associated credits."
EcoEngineers 2022	$20	EcoEngineers, via S&P, reportedly conducted a survey of 450 producers and found that "many companies are beginning to draw around $20/MMBtu for RNG sold into voluntary markets on a long-term basis."[11]
Kinder Morgan 2022	$20-$25	Same S&P article, with a Kinder Morgan VP communicating that "while RNG sold to utilities, manufacturers and other end users in the voluntary market is marketable between $20-$25/MMBtu …"
SusGlobalEnergy 2023	$20	SusGlobal Energy announced that they reached commercial terms on a 10-year agreement to sell RNG at a price of $20/MMBtu. The supply will be sourced from organic waste anaerobic digesters in Belleville and Hamilton, Ontario.
Rabobank 2024	$20-25	Rabobank included this estimate as a check-in point after publishing a review of the state of the RNG market.
FortisBC 2024-2025	$18-$20	FortisBC allows customers to select a designated RNG blend of 100% at a cost of CN$9.23/GJ—equivalent to $7.11/mmBtu. However, this is a subsidized cost of RNG, because all customers receive a 3% blend. The actual RNG pricing for FortisBC contracts is reported in the range of CN$23-26/GJ.
Énergir 2024-25	$17-$18	Énergir's RNG supply rate is set annually as part of the rate case filed each year with Régie de l'énergie. As of October 1, 2024, that price was set at CN$22.65/GJ. There is no indication that this is a subsidized price, as this value exceeds Énergir's regulatory obligation.

[11] Note that neither the survey that EcoEngineers conducted, the recipients of the survey, nor the responses have been shared publicly. Rather, the article includes a quote from an EcoEngineers employee relaying the results.

Source / Year	Pricing Range ($/mmBtu)	Description
Southern California Gas / Organic Energy Solutions 2025	> $26	California's SB 1440 established a RNG procurement requirement for gas utilities. The Tier 1 Advice Letter is required for prices up to $17.70/MMBtu, which was reported at the time as "the average cost of biomethane." Southern California Gas Company executed the first agreement under SB 1440 in March 2025 with Organic Energy Solutions. Though the exact price is unknown, the request was filed as a Tier 3 Advice Letter, indicating the price exceeds $26/MMBtu.
OPAL Fuels via Hart Energy 2025	$20	In an interview with Hart Energy, an OPAL Fuels executive provided an indicative price of $20/MMBtu for contracts with utilities.
Waste Management 2025	$28-$29	Waste Management reports that that about 50% of projected RNG sales for 2025 have already been contracted at a blended average price of $28.80/MMBtu. (Note: It is likely that this price is representative of RIN pricing, rather than RNG pricing).
Oklahoma Natural Gas 2025	$12.15 *+ natural gas cost*	Oklahoma Natural Gas has a pilot voluntary RNG program, for which customers pay $3.038 per "block", and each block represents the environmental attributes of a quarter of a dekatherm. Oklahoma Natural Gas notes that they do not set the price and that they do not profit from the program and that customers pay what they pay.

Platforms like M-RETS do not provide RNG pricing information, and the amount of publicly available information on RNG pricing is limited. Furthermore, when information is presented, it is often presented as a range of estimates. Most RNG pricing is considered proprietary by the buyer and the seller, hence the use of ranges, estimates (e.g., "about $20/MMBtu"), and references to "multiple variables" (e.g., term length, feedstock, etc.).

ICF's literature review suggests that RNG pricing has generally increased since the initial estimates of $12-$23/MMBtu in 2019 provided by Energy Vision and $12-$18/MMBtu provided by Vinson & Elkins. This increase is to be expected given that D3 RIN pricing has generally increased from mid-2019 and has consistently traded in the range of $15-$35/MMBtu, and that new RNG projects have likely faced some inflationary price pressure, the same as other industries. That said, pricing reported by some utilities (e.g., FortisBC, Énergir, and Oklahoma Natural Gas) remain on the lower end of the publicly available reported range from the most recently available data sources (e.g., 2024-25).

Table 5 includes the links to the references from ICF's literature review on RNG pricing. All links were active as of the preparation of this report.

Table 5. References for ICF Literature Review of RNG Pricing

Source / Year	Weblink
Energy Vision, 2019	https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M311/K114/311114276.PDF
Vinson & Elkins, 2021	https://media.velaw.com/wp-content/uploads/2021/09/02100505/Renewable-Fuel-Presentation-CLE-Energy-Series-FINAL-10.13.2021.pdf

Source / Year	Weblink
EcoEngineers, 2022	https://www.spglobal.com/commodity-insights/en/news-research/latest-news/natural-gas/121622-rng-industry-expects-us-voluntary-customers-to-spur-demand-after-early-transport-boom
Kinder Morgan, 2022	https://www.spglobal.com/commodity-insights/en/news-research/latest-news/natural-gas/121622-rng-industry-expects-us-voluntary-customers-to-spur-demand-after-early-transport-boom
SusGlobalEnergy, 2023	https://www.newsfilecorp.com/release/182642/SusGlobal-Energy-Signs-Commercial-Terms-for-Renewable-Natural-Gas-Purchase-and-Sale-Agreement
Rabobank, 2024	https://www.rabobank.com/knowledge/d011421992-a-fork-in-the-road-for-renewable-natural-gas-exploring-policy-developments
FortisBC, 2025	https://www.fortisbc.com/services/sustainable-energy-options/renewable-natural-gas/how-much-does-renewable-natural-gas-cost https://justandreasonable.com/fortisbc-expands-its-renewable-natural-gas-program/
Energir, 2025	https://energir.com/en/business/renewable-natural-gas/steps-and-tariff
Southern California Gas, 2025	https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M555/K818/555818668.PDF
OPAL Fuels via Hart Energy, 2025	https://www.hartenergy.com/exclusives/hitting-gas-opal-fuels-accelerating-rng-growth-212482
Waste Management, 2025	https://investors.wm.com/node/29141/pdf
Oklahoma Natural Gas, 2025	https://www.oklahomanaturalgas.com/rng

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E.2 Alternative Fuels Study

E.2.1 Low Carbon Alternative Options

As discussed in Chapter 7, the Alternative Fuels Study provided 73 separate low carbon alternative options. These are listed in Table E-1. The full Alternative Fuels Study follows in this appendix.

Figure E-1: Alternative Fuels Study Resource Options

Category	Resource Name	Location	Count
RNG	LFG 1	National	1
RNG	LFG 2	National	2
RNG	LFG 3	National	3
RNG	LFG 4	National	4
RNG	LFG 5	National	5
RNG	LFG 1	NW	6
RNG	LFG 2	NW	7
RNG	LFG 3	NW	8
RNG	LFG 4	NW	9
RNG	LFG 5	NW	10
RNG	AM 1	National	11
RNG	AM 2	National	12
RNG	AM 3	National	13
RNG	AM 4	National	14
RNG	AM 5	National	15
RNG	AM 1	NW	16
RNG	AM 2	NW	17
RNG	AM 3	NW	18
RNG	AM 4	NW	19
RNG	AM 5	NW	20
RNG	WW 1	National	21
RNG	WW 2	National	22
RNG	WW 3	National	23
RNG	WW 4	National	24
RNG	WW 5	National	25
RNG	WW 1	NW	26
RNG	WW 2	NW	27
RNG	WW 3	NW	28
RNG	WW 4	NW	29
RNG	WW 5	NW	30
RNG	FW 1	National	31
RNG	FW 2	National	32
RNG	FW 3	National	33
RNG	FW 1	NW	34
RNG	FW 2	NW	35
RNG	FW 3	NW	36

Category	Resource Name	Location	Count
Hydrogen	GHW	National	37
Hydrogen	GHW	NW	38
Hydrogen	GHS	National	39
Hydrogen	GHS	NW	40
Hydrogen	BH	National	41
Hydrogen	BH	NW	42
Hydrogen	TH	National	43
Hydrogen	TH	NW	44
Synthetic Methane	Biomass-1	National	45
Synthetic Methane	Biomass-2	National	46
Synthetic Methane	Biomass-3	National	47
Synthetic Methane	Biomass-1	NW	48
Synthetic Methane	Biomass-2	NW	49
Synthetic Methane	Biomass-3	NW	50
Synthetic Methane	GHW-BiogenicCO2	National	51
Synthetic Methane	GHW-CCS1	National	52
Synthetic Methane	GHW-CCS2	National	53
Synthetic Methane	GHW-DAC	National	54
Synthetic Methane	GHS-BiogenicCO2	National	55
Synthetic Methane	GHS-CCS1	National	56
Synthetic Methane	GHS-CCS2	National	57
Synthetic Methane	GHS-DAC	National	58
Synthetic Methane	GHW-BiogenicCO2	NW	59
Synthetic Methane	GHW-CCS1	NW	60
Synthetic Methane	GHW-CCS2	NW	61
Synthetic Methane	GHW-DAC	NW	62
Synthetic Methane	GHS-BiogenicCO2	NW	63
Synthetic Methane	GHS-CCS1	NW	64
Synthetic Methane	GHS-CCS2	NW	65
Synthetic Methane	GHS-DAC	NW	66
CCUS	CCUS-1	NW	67
CCUS	CCUS-2	NW	68
CCUS	CCUS-3	NW	69
CCUS	CCUS-4	NW	70
CCUS	CCUS-5	NW	71
CCUS	CCUS-6	NW	72
CCUS	CCUS-11	NW	73

E.2.2 Complete Alternative Fuels Study

The complete study begins on the following page.

March 2025

Low Carbon Fuel Alternative Resources and Offsets for IRP Evaluation

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Executive Summary

Overview

This report, commissioned by NW Natural, Avista Utilities, and Cascade Natural Gas Corporation (collectively referred to as "the Utilities"), provides a detailed assessment of the levelized cost, resource potential, and carbon intensity of renewable natural gas (RNG), hydrogen, synthetic methane, and carbon capture and geologic storage (CCS) in Oregon and Washington. This analysis supports the Utilities' Integrated Resource Plan (IRP) filings and informs their decision-making processes.

Fuels Studied

- **Renewable Natural Gas (RNG)** is derived from biomass or other renewable resources and is a pipeline-quality gas interchangeable with conventional natural gas. The study evaluates the potential of RNG in contributing to a low-carbon energy future.
- **Hydrogen**, produced through various methods such as electrolysis, is assessed for its viability as a clean fuel. The analysis considers the technical advancements and cost implications of using hydrogen as a primary energy source.
- **Synthetic methane**, produced from two pathways: 1) via biomass gasification and 2) methanation of carbon dioxide and hydrogen produced via electrolysis and. These pathways offer another pathway to a sustainable energy system. The report evaluates the respective production processes and potential adoption.
- **Carbon Capture, Use, and Storage (CCUS)** technologies, essential for reducing emissions from current fossil fuel use, are analyzed for their effectiveness in capturing CO_2 and storing it underground. The report highlights the technical and economic feasibility of implementing CCS in the region.

Assessment Methodology

The assessment of carbon intensity for each low-carbon fuel and carbon capture/use/geologic storage involved a detailed analysis using the Greenhouse gases, Regulated Emissions, and Energy use in Technologies (GREET) model, developed by the Argonne National Laboratory (ANL).

The levelized cost of energy (LCOE) was also estimated for each resource to characterize lifetime costs relative to lifetime energy production.

ICF's study methodology included:

- Evaluating the technical potential of each fuel based on feedstock availability and technological advancements.
- Calculating the LCOE for each low-carbon fuel and the cost of carbon capture and storage.
- Conducting stochastic analysis to yield a distribution of probabilistic outcomes for supply potential and LCOE, aiding the integrated resource planning process.

Key Findings

1. **Renewable Natural Gas:** RNG shows significant potential due to its compatibility with existing natural gas infrastructure. However, its deployment is contingent on the availability of biomass feedstocks and advancements in production technologies. Its cost might be best considered compared to the cost of other decarbonization resources (i.e., on a $/ton$CO_2$e basis) than to conventional natural gas prices.
2. **Hydrogen:** Hydrogen emerges as a promising clean fuel, especially with advancements in electrolysis. Its scalability and integration into the energy system depend on cost reductions and infrastructure development.

3. **Synthetic Methane:** While synthetic methane offers a sustainable energy solution, its adoption is currently hindered by high production costs. Technological advancements and policy support are crucial for its future viability.

4. **Renewable Thermal Certificates:** A market-based mechanism that enables market actors to comply with state mandates and/or to fulfill their voluntary commitments, while preventing the risk of double counting environmental benefits. These will be an important mechanism to help build confidence in the import/export of gaseous low-carbon fuels like RNG, hydrogen, and synthetic methane.

5. **Carbon Capture and Geologic Storage:** CCS is a critical technology for mitigating emissions from fossil fuels. While the components of CCS systems (acid gas recovery units, compressors, pipeline, injection well) are mature technologies, the market for CCS services is just emerging. ICF's assessment is that the market for CCS is not mature. ICF’s assessment indicates that CCS can be effectively implemented in the region, provided there is adequate investment and regulatory support.

6. **Carbon Intensity (CI):** A common theme for the low-carbon fuels of interest, as well as geologic natural gas and the region’s electricity mix, is that CI was projected to decrease (improve) over time. This may be due to energy efficiency improvements in production processes, lower-carbon electricity portfolio trends, etc.

7. **Stochastic Analysis:** The stochastic modeling exercise demonstrated a range of probabilistic outcomes for the technical potential and LCOE of each low-carbon fuel. The results underscore the importance of considering variability and uncertainty in planning and decision-making.

This report ultimately provides a comprehensive analysis of low-carbon fuels and CCS, highlighting their potential to contribute to a sustainable energy future in Oregon and Washington. The findings support the Utilities' efforts to integrate these technologies into their IRP filings and advance their clean energy goals.

Introduction

NW Natural, Avista Utilities, and Cascade Natural Gas Corporation (collectively referred to as "the Utilities" throughout this report) contracted with ICF to develop forecasts for levelized cost, technical potential, resource life, and carbon intensity and characterize the renewable thermal credits (RTC) available for renewable natural gas (RNG), hydrogen, synthetic methane, carbon capture and geologic storage in Oregon and Washington. This report supports analyses that are performed by the Utilities as part of their respective Integrated Resource Plan (IRP) filings.

Overview of ICF's Approach

ICF's analysis focused on the technical potential and levelized cost of energy (LCOE) for the low-carbon fuels of interest. To do so, ICF assessed the carbon intensity of each fuel and utilized stochastic analysis to yield a distribution of probabilistic outcomes of supply potential and LCOE that can help inform the integrated resource planning process.

The methodology ICF used to calculate LCOE and technical potential for each low-carbon fuel of interest is detailed in the sections that follow. The general methodology for the LCOE calculation is provided in the Appendix. ICF's assessment of the technical potential of each low-carbon fuel is linked to factors such as feedstock availability and technological advancements. For each relevant section, ICF briefly discusses the status of Renewable Thermal Certificates or RTCs.

ICF also calculated the lifecycle carbon intensity of low-carbon fuels from the feedstocks and production methods of interest using the Greenhouse gases, Regulated Emissions, and Energy use in Technologies (GREET) model, developed by the Argonne National Laboratory (ANL).[1] GREET and GREET-based models like OR-GREET used for the Oregon Clean Fuels Program are the industry standard for analyzing the lifecycle carbon intensity of fuels in the United States.

The cost, resource, and carbon intensity analyses were combined into a stochastic modeling exercise. These were used as modeling variables yield a distribution of probabilistic outcomes for the study.

[1] Argonne GREET Fuel Cycle Model (anl.gov)

Renewable Natural Gas

Resource Type

RNG is derived from biomass or other renewable resources and is a pipeline-quality gas that is fully interchangeable with conventional natural gas. As a point of reference, the American Gas Association (AGA) uses the following definition for RNG:

> *Pipeline compatible gaseous fuel derived from biogenic or other renewable sources that has lower lifecycle carbon dioxide equivalent (CO_2e) emissions than geological natural gas.*[2]

The most common way to produce RNG today is via anaerobic digestion (AD), whereby microorganisms break down organic material in an environment without oxygen. The four key processes in anaerobic digestion are:

- *Hydrolysis* is the process whereby longer-chain organic polymers are broken down into shorter-chain molecules like sugars, amino acids, and fatty acids that are available to other bacteria.
- *Acidogenesis* is the biological fermentation of the remaining components by bacteria, yielding volatile fatty acids, ammonia, carbon dioxide, hydrogen sulfide, and other byproducts.
- *Acetogenesis* of the remaining simple molecules yields acetic acid, carbon dioxide, and hydrogen.
- Lastly, *methanogens* use the intermediate products from hydrolysis, acidogenesis, and acetogenesis to produce methane, carbon dioxide, and water, where the majority of the biogas is emitted from anaerobic digestion systems.

The process for RNG production generally takes place in a controlled environment, referred to as a digester or reactor, including landfill gas facilities. When organic waste, biosolids, or livestock manure is introduced to the digester, the material is broken down over time (e.g., days) by microorganisms, and the gaseous products of that process contain a large fraction of methane and carbon dioxide. The biogas requires capture and subsequent conditioning and upgrade before pipeline injection. The conditioning and upgrading helps to remove any contaminants and other trace constituents, including siloxanes, sulfides and nitrogen, which cannot be injected into common carrier pipelines, and increases the heating value of the gas for injection.

RNG can be produced from a variety of renewable feedstocks, as described in the table below.

Exhibit 1. List of RNG Feedstocks

Feedstock	Description
Animal manure	Manure produced by livestock, including dairy cows, beef cattle, swine, sheep, goats, poultry, and horses.
Food waste	Commercial, industrial and institutional food waste, including from food processors, grocery stores, cafeterias, and restaurants.
Landfill gas (LFG)	The anaerobic digestion of organic waste in landfills produces a mix of gases, including methane (40–60%).
Water resource recovery facilities (WRRF)	Wastewater consists of waste liquids and solids from household, commercial, and industrial water use; in the processing of wastewater, a sludge is produced, which serves as the feedstock for RNG.

[2] AGA, 2019. RNG: Opportunity for Innovation at Natural Gas Utilities, https://pubs.naruc.org/pub/73453B6B-A25A-6AC4-BDFC-C709B202C819

Resource Potential

ICF used a mix of existing studies, government data, and industry resources to estimate the current and future supply of the feedstocks. The table below summarizes some of the resources that ICF drew from to complete our resource assessment, broken down by RNG feedstock:

Exhibit 2. List of Data Sources for RNG Feedstock Inventory

Feedstock for RNG	Potential Resources for Assessment
Animal manure	• U.S. Environmental Protection Agency (EPA) AgStar Project Database • U.S. Department of Agriculture (USDA) Census of Agriculture
Food waste	• U.S. Department of Energy (DOE) Billion Ton Report • Bioenergy Knowledge Discovery Framework (KDF)
LFG	• U.S. EPA Landfill Methane Outreach Program • Environmental Research & Education Foundation (EREF)
WRRFs	• U.S. EPA Clean Watersheds Needs Survey (CWNS) • Water Environment Federation

The sub-sections below characterize the resources considered in the RNG analysis. ICF primarily drew from previous research conducted at the national and state levels[3] to characterize resource availability. ICF distinguished between two geographies for the analysis: a) Oregon and Washington and b) national. Note that the latter excludes the resources that are included in the former. ICF assumed that the Utilities would have near-full access to resources identified for RNG development in Oregon and Washington and a portion of the national-level resources considered.

More specifically, ICF assumed that the Utilities would have "first-mover access" to RNG from domestic resources. ICF reviewed states that have robust policy frameworks in place to advance RNG deployment in the state (but not necessarily exclusively within their state) and assumed that NW Natural, Avista Utilities, and Cascade Natural Gas Corporation would have a population-weighted share of first-mover access to national resources. ICF also included British Columbia and Quebec in our consideration of first movers because these two Canadian provinces have robust RNG policies in place and have already procured significant amounts of US-based RNG. ICF's assumption regarding first mover access yields a result whereby the Utilities will likely be able to access up to about 13% of the total domestic RNG production, which about 3.5-4 times greater than the simple population-weighted share that one might otherwise assume.

Animal Manure

Animal manure as an RNG feedstock is produced from the manure generated by livestock, including dairy cows, beef cattle, swine, sheep, goats, poultry, and horses.

The main components of anaerobic digestion of manure include manure collection, the digester, effluent storage (e.g., a tank or lagoon), and gas handling equipment. There are a variety of livestock manure processing systems that are employed at farms today, including plug-flow or mixed plug-flow digesters, complete-mixed digesters, covered lagoons, fixed-film digesters, sequencing-batch reactors, and induced-blanked digesters. Many dairy manure projects today use plug-flow or mixed plug-flow digesters.

[3] American Gas Foundation, Renewable Sources of Natural Gas, 2019. Available online at https://gasfoundation.org/2019/12/18/renewable-sources-of-natural-gas/

ICF considered animal manure from a variety of animal populations, including beef and dairy cows, broiler chickens, layer chickens, turkeys, and swine. Animal populations were derived from the United States Department of Agriculture's (USDA) National Agricultural Statistics Service. ICF used information provided from the most recent census year (2017) and extracted total animal populations on a county and state level.[4] ICF developed the maximum RNG potential using animal manure production and the energy content of dried manure taken from a California Energy Commission report prepared by the California Biomass Collaborative.[5] Concentrated animal feeding operations (CAFOs) – farms/ animal feeding operations with more than 1,000 animal "units" (defined as 1,000 pounds live weight[6]) – provide an indication of where RNG from animal manure could be produced at significant scale.

Food Waste

Food waste includes biomass sources from commercial, industrial and institutional facilities, including from food processors and manufacturers, grocery stores, cafeterias, and restaurants. Food waste from residential sources is not reflected in this analysis but could be an additional resource for food waste biomass with the implementation of effective waste diversion policies.

Food waste is a major component of municipal solid waste (MSW)—accounting for about 15% of MSW streams. More than 75% of food waste is landfilled. Food waste can be diverted from landfills to a composting or processing facility where it can be treated in an anaerobic digester. ICF limited our consideration to the potential to utilize the food waste that is currently landfilled as a feedstock for RNG production via AD, thereby excluding the 25% of food waste that is recycled or directed to waste-to-energy facilities. In addition, food waste that is potentially diverted from landfills in the future is not included in the landfill gas analysis (outlined in more detail below), thereby avoiding any issues around double counting of biomass from food waste.

As food waste is generated from population centers and typically diverted at waste transfer stations rather than delivered to landfills, it is challenging to identify specific facilities or projects that will generate RNG from food waste. However, food waste can potentially utilize existing or future AD systems at landfills and water resource recovery facilities.

Landfill Gas

The Resource Conservation and Recovery Act of 1976 (RCRA, 1976) sets criteria under which landfills can accept municipal solid waste and nonhazardous industrial solid waste. Furthermore, the RCRA prohibits open dumping of waste, and hazardous waste is managed from the time of its creation to the time of its disposal. Landfill gas (LFG) is captured from the anaerobic digestion of biogenic waste in landfills which produces a mix of gases, including methane, with a methane content generally ranging 45%–60%.[7] The landfill itself acts as the digester tank—a closed volume that becomes devoid of oxygen over time, leading to favorable conditions for certain micro-organisms to break down biogenic materials.

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[4] USDA, 2017. 2017 Census of Agriculture, https://www.nass.usda.gov/AgCensus/index.php

[5] Williams, R. B., B. M. Jenkins and S. Kaffka (California Biomass Collaborative). 2015. An Assessment of Biomass Resources in California, 2013 – DRAFT. Contractor Report to the California Energy Commission. PIER Contract 500-11-020. Available online here.

[6] This equates to "1000 head of beef cattle, 700 dairy cows, 2500 swine weighing more than 55 lbs, 125 thousand broiler chickens, or 82 thousand laying hens or pullets) confined on site for more than 45 days during the year." Via Natural Resources Conservation Service (U.S. Department of Agriculture), https://www.nrcs.usda.gov/wps/portal/nrcs/main/national/plantsanimals/livestock/afo/#:~:text=A%20CAFO%20is%20an%20AFO,confined%20on%20site%20for%20more

7 Biogas captured from dedicated anaerobic digesters tends to have a higher percent methane content (~60%), especially compared to landfill gas. That said, upgrading technology for other types of biogas is like that used for landfill gas.

The composition of the LFG is dependent on the materials in the landfill, among other factors, but is typically made up of methane, carbon dioxide (CO_2), nitrogen (N_2), hydrogen, CO, oxygen (O_2), sulfides (e.g., hydrogen sulfide or H_2S), ammonia, and trace elements like amines, sulfurous compounds, and siloxanes.[8] RNG production from LFG requires advanced treatment and upgrading of the biogas via removal of CO_2, H_2S, siloxanes, N_2, and O_2 to achieve a high-energy (Btu) content gas for pipeline injection. The table below summarizes landfill gas constituents, the typical concentration ranges in which they present in LFG, and commonly deployed upgrading technologies in use today.

Exhibit 3. Landfill Gas Constituents and Corresponding Upgrading Technologies

LFG Constituent	Typical Concentration Range	Upgrading Technology for Removal
Carbon dioxide, CO_2	40% – 60%	• High-selectivity membrane separation • Pressure swing adsorption (PSA) systems • Water scrubbing systems • Amine scrubbing systems
Hydrogen sulfide, H_2S	0 – 1%	• Solid chemical scavenging • Liquid chemical scavenging • Solvent adsorption • Chemical oxidation-reduction
Siloxanes	<0.1%	• Non-regenerative adsorption • Regenerative adsorption
Nitrogen, N_2 Oxygen, O_2	2% – 5% 0.1% – 1%	• PSA systems • Catalytic removal (O_2 only)

To estimate the feedstock potential of LFG, ICF used outputs from the LandGEM model, which is an automated tool with a Microsoft Excel interface developed by the U.S. EPA. ICF used LandGEM to estimate the emissions rates for landfill gas and methane based on user inputs including waste-in-place (WIP), facility location and climate conditions, and waste received per year. The LFG output was estimated on a facility-by-facility basis. About 1,150 facilities report methane content; for the facilities for which no data were reported, ICF assumed the median methane content of 49.6%. ICF also extracted data from the Landfill Methane Outreach Program (LMOP) administered by the U.S. EPA, which included more than 2,000 landfills.

Water Resource Recovery Facilities

Wastewater is created from residences and commercial or industrial facilities. It consists primarily of waste liquids and solids from household water usage, from commercial water usage, or from industrial processes. Depending on the architecture of the sewer system and local regulation, it may also contain storm water from roofs, streets, or other runoff areas. The contents of the wastewater may include anything which is expelled (legally or not) from a household and enters the drains. If storm water is included in the wastewater sewer flow, it may also contain components collected during runoff: soil, metals, organic compounds, animal waste, oils, and solid debris such as leaves and branches.

Wastewater is processed and treated at dedicated facilities, including sewerage treatment plants and wastewater treatment plants, covered by the umbrella term of "water resource recovery facilities" (WRRFs). Processing of wastewater influent to a WRRF is comprised typically of four stages: pre-treatment, primary, secondary, and tertiary treatments. These stages consist of mechanical, biological, and sometimes chemical processing.

8 Siloxane only exists in biogas from landfills and WRRF.

- Pre-treatment removes all the materials that can be easily collected from the raw wastewater that may otherwise damage or clog pumps or piping used in treatment processes.
- In the primary treatment stage, the wastewater flows into large tanks or settling bins, thereby allowing sludge to settle while fats, oils, or greases rise to the surface.
- The secondary treatment stage is designed to degrade the biological content of the wastewater and sludge and is typically done using water-borne micro-organisms in a managed system.
- The tertiary treatment stage prepares the treated effluent for discharge into another ecosystem, and often uses chemical or physical processes to disinfect the water.

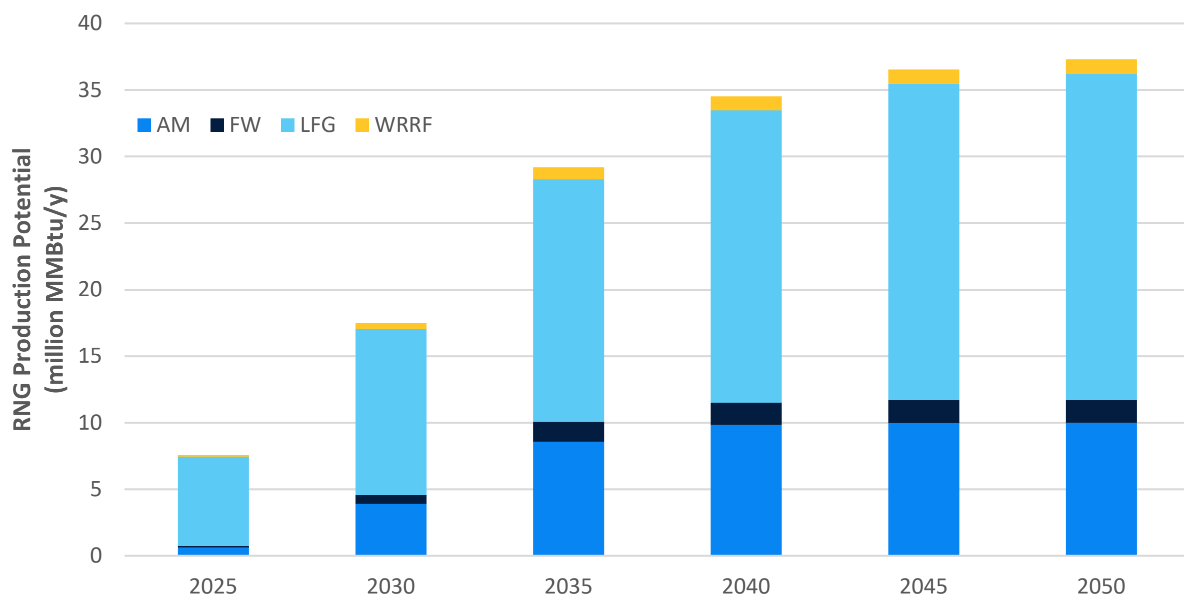
The treated sludge from the WRRF can be landfilled, and during processing it can be treated via anaerobic digestion, thereby producing methane which can be used for beneficial use with the appropriate capture and conditioning systems put in place.

To estimate the amount of RNG produced from wastewater at WRRFs, ICF used data reported by the U.S. EPA,[9] a study of WRRFs in New York State,[10] and previous work published by AGF.[11] ICF used an average energy yield of 7.003 MMBtu/million gallons per day of wastewater flow.

RNG Resource Potential Projection

The following figures summarize the maximum RNG potential for each feedstock and production technology in OR and WA and at the national level.

Exhibit 4. RNG Resource Potential Projection Base Case Results (million MMBtu/y) (OR & WA)

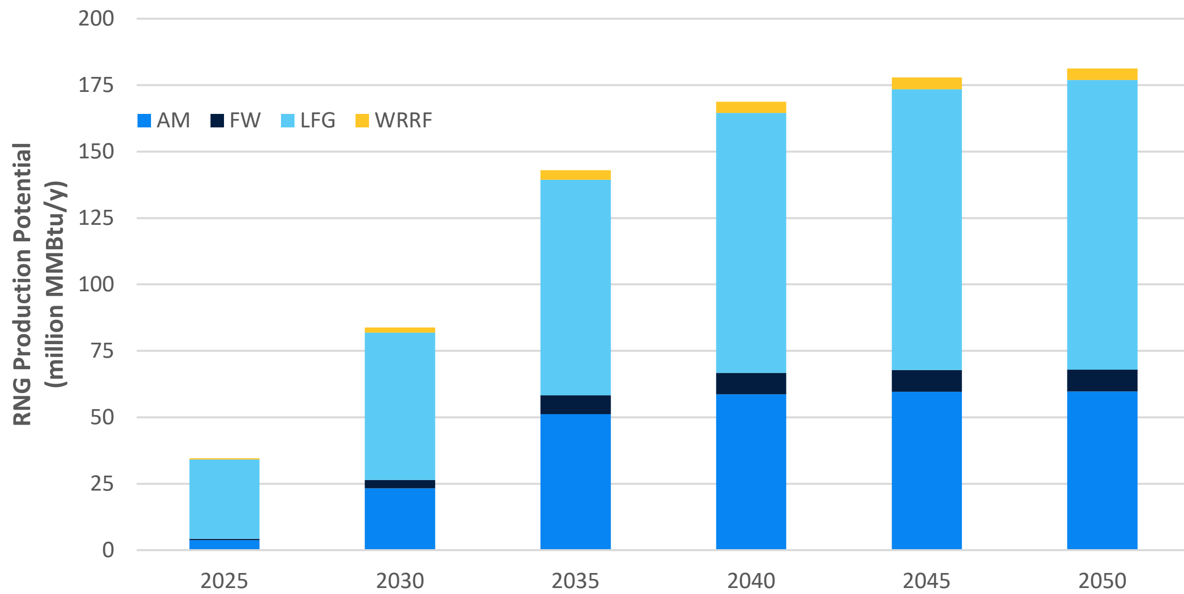


[9] US EPA, Opportunities for Combined Heat and Power at Wastewater Treatment Facilities, October 2011. Available online here.

[10] Wightman, J and Woodbury, P., Current and Potential Methane Production for Electricity and Heat from New York State Wastewater Treatment Plants, New York State Water Resources Institute at Cornell University. Available online here.

[11] AGF, The Potential for Renewable Gas: Biogas Derived from Biomass Feedstocks and Upgraded to Pipeline Quality, September 2011.

Exhibit 5. RNG Resource Potential Projection Base Case Results (million MMBtu/y) (National)[12]



RNG Levelized Cost

ICF developed assumptions for the capital expenditures and operational costs for RNG production from the various feedstock and technology pairings outlined previously. ICF characterized costs based on a series of assumptions regarding the production facility sizes (as measured by gas throughput in units of standard cubic feet per minute [SCFM]), gas upgrading and conditioning and upgrading costs (depending on the type of technology used, the contaminant loadings, etc.), compression, and interconnect for pipeline injection. We also include operational costs for each technology type. The table below outlines some of ICF's baseline assumptions that we employed in our production cost modeling.

Exhibit 6. Illustrative ICF RNG Cost Assumptions

Cost Parameter	ICF Cost Assumptions
Capital Costs	
Facility Sizing	• Differentiate by feedstock and technology type: anaerobic digestion and thermal gasification. • Prioritize larger facilities to the extent feasible but driven by resource estimate.
Gas Conditioning and Upgrade	• Vary by feedstock type and technology required.
Compression	• Capital costs for compressing the conditioned/upgraded gas for pipeline injection.
O&M Costs	

[12] Note that the volumes shown for the national resource are scaled. ICF's assumption regarding first mover access yields a result whereby the Utilities will likely be able to access up to about 13% of the total domestic RNG production.

Cost Parameter	ICF Cost Assumptions
Operational Costs	• Costs for each equipment type—digesters, conditioning equipment, collection equipment, and compressors—as well as utility charges for estimated electricity consumption.
Delivery	• The costs of delivering the same volumes of biogas that require pipeline construction greater than 1 mile will increase, depending on feedstock/technology type, with a typical range of $1–$5/MMBtu.
Levelized Cost of Gas	
Project Lifetimes	• Calculated based on the initial capital costs in Year 1, annual operational costs discounted, and RNG production discounted accordingly over a 20-year project lifetime.

ICF presents the costs used in our analysis as well as the levelized cost of energy (LCOE) for RNG in different end uses. The LCOE is a measure of the average net present cost of RNG production for a facility over its anticipated lifetime. The LCOE enables us to compare RNG feedstocks and other energy types on a consistent per unit energy basis. The LCOE can also be considered the average revenue per unit of RNG (or energy) produced that would be required to recover the costs of constructing and operating the facility during an assumed lifetime. The LCOE calculated as the discounted costs over the lifetime of an energy producing facility (e.g., RNG production) divided by a discounted sum of the actual energy amounts produced. The LCOE is calculated using the following formula:

$$LCOE = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

where I_t is the capital cost expenditures (or investment expenditures) in year t, M_t represents the operations and maintenance expenses in year t, F_t represents the feedstock costs in year t (where appropriate), E_t represents the energy (i.e., RNG) produced in year t, r is the discount rate, and n is the expected lifetime of the production facility.

ICF notes that our cost estimates are not intended to replicate a developer's estimate when deploying a project. For instance, ICF recognizes that the cost category "gas conditioning and upgrading" actually represents an array of decisions that a project developer would have to make with respect to CO_2 removal, H_2S removal, siloxane removal, N_2/O_2 rejection, deployment of a thermal oxidizer, among other elements.

In addition, the cost assumptions attempt to strike a balance between existing or near-term capital and operational expenditures, and the potential for project efficiencies and associated cost reductions that may eventuate over time as the RNG industry expands. For example, in general construction and engineering costs may decline from present levels driven by the development and implementation of modular technology systems or facilities.

These cost estimates also do not reflect the potential value of the environmental attributes associated with RNG, nor the current markets and policies that provide credit for these environmental attributes.

Furthermore, we understand that project developers have reported a wide range of interconnection costs, with numbers as low as $200,000 reported in some states, and as high as $9 million in other states. We appreciate the variance between projects, including those that use anaerobic digestion or thermal gasification technologies, and our supply-cost curves are meant to be illustrative, rather than deterministic. This is especially true of our outlook to 2050—we have not included significant cost reductions that might occur as a result of a rapidly growing RNG market or sought to capture potential technological breakthroughs. For anaerobic digestion systems we have focused on projects that have reasonable scale, representative capital expenditures, and reasonable operations and maintenance estimates.

To some extent, ICF's cost modeling does presume changes in the underlying structure of project financing, which is currently linked inextricably to revenue sharing associated with environmental commodities in the federal Renewable Fuel Standard (RFS) market and California's Low Carbon Fuel Standard (LCFS) market. Our project financing assumptions likely have a lower return than investors may be expecting in the market today; however, our cost assessment seeks to represent a more mature market to the extent feasible, whereby upward of 1,000-4,500 trillion Btu per year of RNG is being produced. In that regard, we implicitly assume that contractual arrangements are likely considerably different and local/regional challenges with respect to RNG pipeline injection have been overcome.

Animal Manure

ICF developed assumptions for the region by distinguishing between animal manure projects, based on a combination of the size of the farms and assumptions that certain areas would need to aggregate or cluster resources to achieve the economies of scale necessary to warrant an RNG project. There is some uncertainty associated with this approach because an explicit geospatial analysis was not conducted; however, ICF did account for considerable costs in the operational budget for each facility assuming that aggregating animal manure would potentially be expensive.

Exhibit 7 includes the main assumptions used to estimate the cost of producing RNG from animal manure, while Exhibit 8 that follows provides example cost inputs for low cost and high animal manure facilities.

Exhibit 7. Cost Consideration in LCOE Analysis for RNG from Animal Manure

Factor	Cost Elements Considered	Costs
Performance	• Capacity factor	• 92%
Installation Costs	• Construction / Engineering • Owner's cost	• 40% of installed equipment costs
Gas Upgrading	• CO_2 separation • H_2S removal • N_2/O_2 removal	• \$2.3 to \$7.0 million, depending on facility • \$0.3 to \$1.0 million, depending on facility • \$1.0 to \$2.5 million, depending on facility
Utility Costs	• Electricity: 35 kWh/MMBtu • Natural Gas: 35% of product	• State-based average OR national average
O&M	• 1 FTE for maintenance • Miscellaneous	• 20% of installed capital costs – conditioning/upgrade • 10% of installed capital costs – digester
For Injection	• Interconnect • Pipeline • Compressor	• \$1.5 million • \$2 million • \$0.1–\$0.5 million
Other	• Value of digestate • Tipping fee	• Valued for dairy at about \$100/cow/y • Excluded from analysis

Exhibit 8. Example Facility-Level Cost Inputs for RNG from Animal Manure

Factor	High LCOE	Low LCOE
Facility size (cows)	1,300	4,000
Biogas production (SCFM)	90	265
Capital: collection	\$2.2m	\$4.8m
Capital: conditioning (CO_2/O_2 removal)	\$1.0m	\$1.8m
Capital: sulfur treatment	\$0.1m	\$0.2m
Capital: nitrogen rejection	\$0.3m	\$0.5m
Capital: compressor	\$0.1m	\$0.2m
Capital: pipeline (on-site)	\$2.0m	\$2.0m

Factor	High LCOE	Low LCOE
Capital: utility interconnect	$1.5m	$1.5m
O&M: electricity and natural gas	$0.2m	$0.7m
Construction and engineering: installation	$0.9m	$1.1m
Construction and engineering: owner's cost	$0.4m	$0.5m

Food Waste

ICF made the simplifying assumption that food waste processing facilities would be purpose-built and be capable of processing 60,000 tons of waste per year. ICF estimates that these facilities would produce about 500 SCFM of biogas for conditioning and upgrading before pipeline injection.

In addition to the other costs included in other anaerobic digestion systems, we also included assumptions about the cost of collecting food waste and processing it accordingly (see Exhibit 9). Exhibit 10 that follows provides example cost inputs for low cost and high food waste facilities.

Exhibit 9. Cost Consideration in LCOE Analysis for RNG from Food Waste Digesters

Factor	Cost Elements Considered	Costs
Performance	• Capacity factor • Processing capability	• 92% • 30,000 to 120,000 tons per year
Dedicated Equipment	• Organics processing • Digester	• Varies by facility size • Varies by facility size
Installation Costs	• Construction / Engineering • Owner's cost	• 30% of installed equipment costs • 15% of installed equipment costs
Gas Upgrading	• CO_2 separation • H_2S removal • N_2/O_2 removal	• $2.3 to $7.0 million, depending on facility • $0.3 million • $1.0 million
Utility Costs	• Electricity: 35 kWh/MMBtu • Natural Gas: 20% of product	• State-based average or national average
Operations & Maintenance	• 1.5 FTE for maintenance • Miscellany	• 20% of installed capital costs – conditioning/upgrade • 10% of installed capital costs - digester
Other	• Tipping fees	• State based average ($71-$80/ton)
For Injection	• Interconnect • Pipeline • Compressor	• $1.5 million • $2 million • $0.1–$0.325 million

Exhibit 10. Example Facility-Level Cost Inputs for RNG from Food Waste

Factor	High LCOE	Low LCOE
Food waste processed (ton/y)	30,000	120,000
Biogas production (SCFM)	250	1,000
Capital: organics processing	$7.0m	$12.5m
Capital: digester	$7.2m	$19.2m
Capital: collection	$0.2m	$0.4m
Capital: conditioning (CO_2/O_2 removal)	$1.4m	$3.8m
Capital: sulfur treatment	$0.1m	$0.5m
Capital: nitrogen rejection	$0.3m	$2.5m
Capital: compressor	$0.1m	$0.3m

Factor	High LCOE	Low LCOE
Capital: pipeline (on-site)	$2.0m	$2.0m
Capital: utility interconnect	$1.5m	$1.5m
O&M: electricity and natural gas	$0.7m	$4.8m
Construction and engineering: installation	$1.2m	$2.7m
Construction and engineering: owner's cost	$0.6m	$1.4m

Landfill Gas

ICF developed assumptions by distinguishing between four types of landfills: candidate landfills[13] without collection systems in place, candidate landfills with collection systems in place, landfills[14] without collection systems in place, and landfills with collections systems in place.[15] ICF further characterized the number of landfills across these four types of landfills, distinguishing facilities by estimated biogas throughput (reported in units of SCFM of biogas).

For utility costs, ICF assumed 25 kWh per MMBtu of RNG injected and 6% of geological or fossil natural gas used in processing. Electricity costs and delivered natural gas costs were reflective of industrial rates reported at the state level by the EIA.

Exhibit 11 summarizes the key parameters that ICF employed in our cost analysis of LFG, while Exhibit 12 that follows provides example cost inputs for low-cost and high LFG facilities.

Exhibit 11. Cost Consideration in LCOE Analysis for RNG from Landfill Gas

Factor	Cost Elements Considered	Costs
Performance	• Capacity factor • Facility size	• 92% • Varies
Installation Costs	• Construction / Engineering • Owner's cost	• 30% of installed equipment costs • 15% of installed equipment costs
Gas Upgrading	• CO_2 separation • H_2S removal • N_2/O_2 removal	• $2.3 to $7.0 million, depending on facility • $0.3 to $1.0 million, depending on facility • $1.0 to $2.5 million, depending on facility
Utility Costs	• Electricity: 35 kWh/MMBtu • Natural Gas: 6% of product	• State-based average OR national average
Operations & Maintenance	• 1 FTE for maintenance • Miscellany	• 20% of installed capital costs – conditioning/upgrade • 10% of installed capital costs - digester
For Injection	• Interconnect • Pipeline • Compressor	• $1.5 million • $2 million • $0.1–$0.5 million

Exhibit 12. Example Facility-Level Cost Inputs for RNG from LFG

Factor	High LCOE	Low LCOE
Biogas production (SCFM)	786	11,766

[13] The EPA characterizes candidate landfills as one that is accepting waste or has been closed for five years or less, has at least one million tons of WIP, and does not have an operational, under-construction, or planned project. Candidate landfills can also be designated based on actual interest by the site.
[14] Excluding those that are designated as candidate landfills.
[15] Landfills that are currently producing RNG for pipeline injection are included here.

Factor	High LCOE	Low LCOE
Capital: collection	$0.6m	$3.3m
Capital: conditioning (CO_2/O_2 removal)	$2.3m	$7.0m
Capital: sulfur treatment	$0.2m	$1.0m
Capital: nitrogen rejection	$1.0m	$2.5m
Capital: compressor	$0.2m	$0.5m
Capital: pipeline (on-site)	$2.0m	$2.0m
Capital: utility interconnect	$1.5m	$1.5m
O&M: electricity and natural gas	$1.3m	$20.0m
Construction and engineering: installation	$1.7m	$3.9m
Construction and engineering: owner's cost	$0.9m	$1.9m

Water Resource Recovery Facilities

ICF developed assumptions by distinguishing between WRRFs based on the throughput of the facilities. The table below includes the main assumptions used to estimate the cost of producing RNG at WRRFs while the table that follows provides example cost inputs for low cost and high WRRF facilities.

Exhibit 13. Cost Consideration in LCOE Analysis for RNG from WRRFs

Factor	Cost Elements Considered	Costs
Performance	• Capacity factor • Facility size	• 92% • Varies
Installation Costs	• Construction / Engineering • Owner's cost	• 30% of installed equipment costs • 15% of installed equipment costs
Gas Upgrading	• CO_2 separation • H_2S removal • N_2/O_2 removal	• $2.3 to $7.0 million, depending on facility • $0.3 to $1.0 million, depending on facility • $1.0 to $2.5 million, depending on facility
Utility Costs	• Electricity: 26 kWh/MMBtu • Natural Gas: 6% of product	• State-based average OR national average
Operations & Maintenance	• 1 FTE for maintenance • Miscellany	• 20% of installed capital costs – conditioning/upgrade • 10% of installed capital costs - digester
For Injection	• Interconnect • Pipeline • Compressor	• $1.5 million • $2 million • $0.1–$0.5 million

Exhibit 14. Example Facility-Level Cost Inputs for RNG from WRRFs

Factor	High LCOE	Low LCOE
Biogas production (SCFM)	590	1,562
Capital: collection	$0.6m	$1.9m
Capital: conditioning (CO_2/O_2 removal)	$3.0m	$3.8m
Capital: sulfur treatment	$0.2m	$0.5m
Capital: nitrogen rejection	$1.0m	$2.5m
Capital: compressor	$0.2m	$0.3m
Capital: pipeline (on-site)	$2.0m	$2.0m
Capital: utility interconnect	$1.5m	$1.5m
O&M: electricity and natural gas	$1.0m	$2.6m
Construction and engineering: installation	$1.9m	$2.7m

Construction and engineering: owner's cost	$1.0m	$1.4m

RNG Levelized Cost Results

The following figures and tables summarize the maximum RNG LCOE for each feedstock and production technology in OR and WA and at the national level. ICF assumed the investment tax credit (ITC) for RNG production (via the Qualified Biogas Property provisions) is available and extended through 2030.

Exhibit 15. RNG Levelized Cost Projection Base Case Results (Oregon and Washington, $/MMBtu)

RNG Feedstock	2025	2050
Animal Manure	$35-$119	$50-$172
Food Waste	$42-$81	$61-$119
Landfill Gas	$7-$30	$10-$42
Water Resource Recovery Facilities	$10-$44	$12-$59

Exhibit 16. RNG Levelized Cost Projection Base Case Results (National, $/MMBtu)

RNG Feedstock	2025	2050
Animal Manure	$36-$120	$51-$172
Food Waste	$43-$83	$62-$120
Landfill Gas	$8-$31	$10-$43
Water Resource Recovery Facilities	$11-$45	$13-$60

The impact of the Monte Carlo process on costs for RNG in Oregon and Washington and nationally are shown in the figures below for 2030 and 2050, respectively. The histograms depict the number of the 1,000 Monte Carlo cases (y-axis) that fall within various cost ranges/technical potential ranges (x-axis) for RNG from each of the feedstocks considered for Oregon and Washington and the United States.

Exhibit 17. Summary of Monte Carlo Simulation Results for RNG in Oregon and Washington (2030)

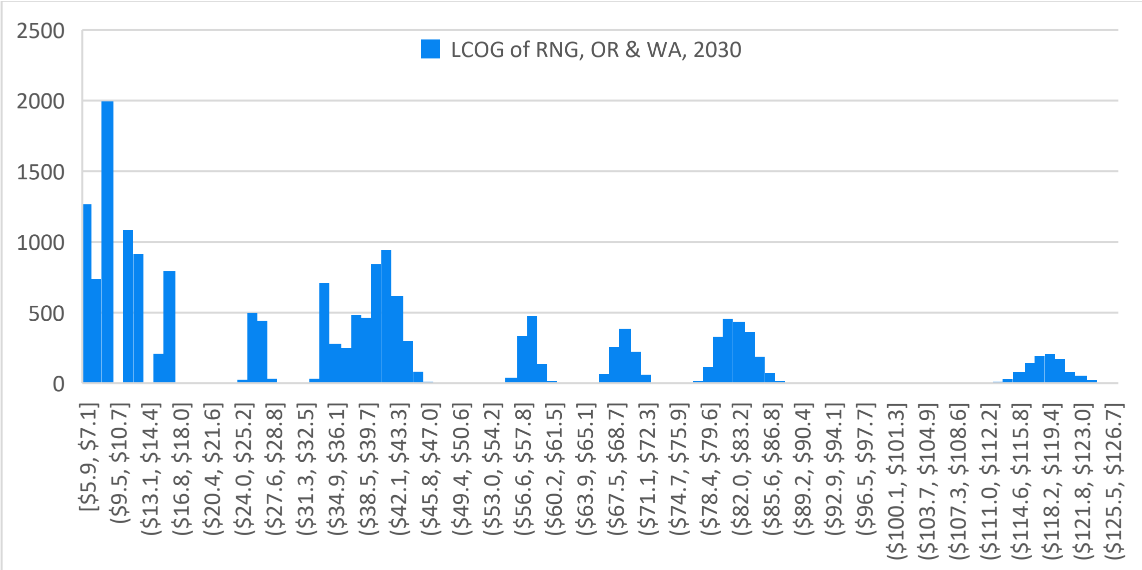


Exhibit 18. Summary of Monte Carlo Simulation Results for RNG in Oregon and Washington (2050)

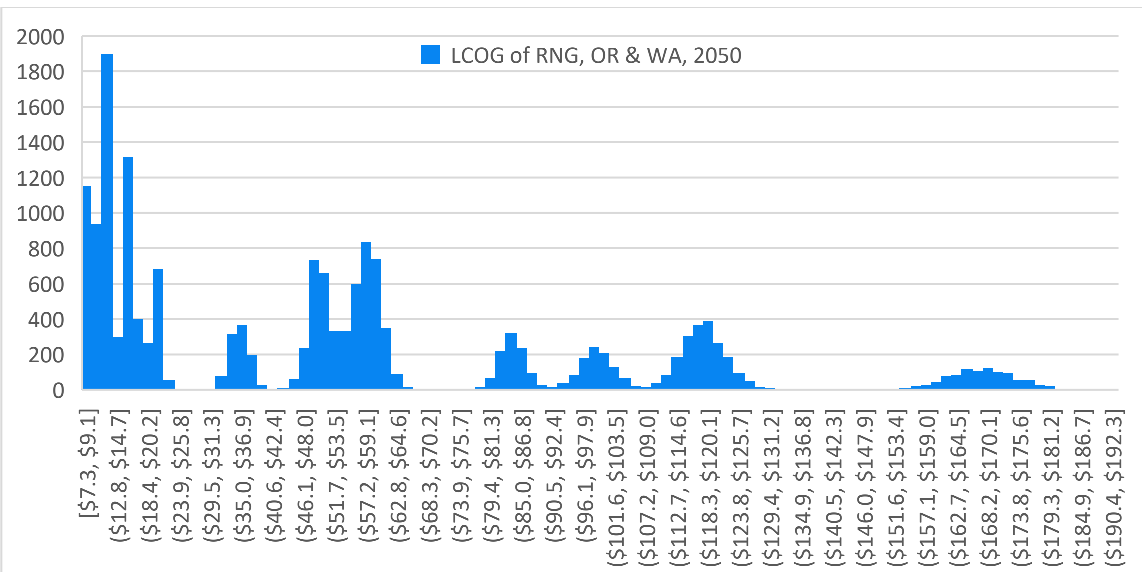


Exhibit 19. Summary of Monte Carlo Simulation Results for RNG domestically (2030)

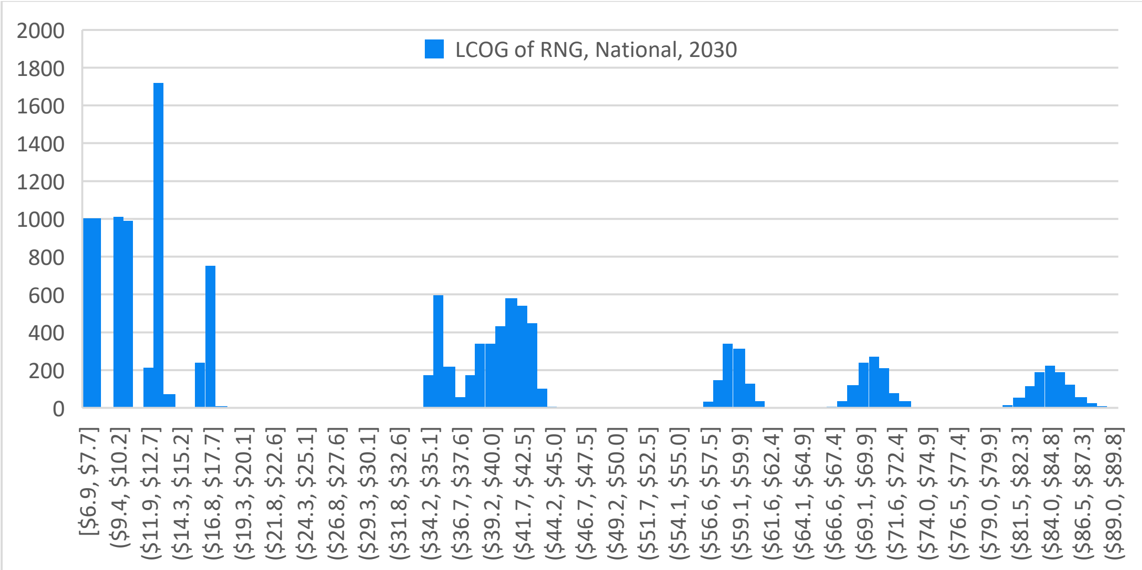
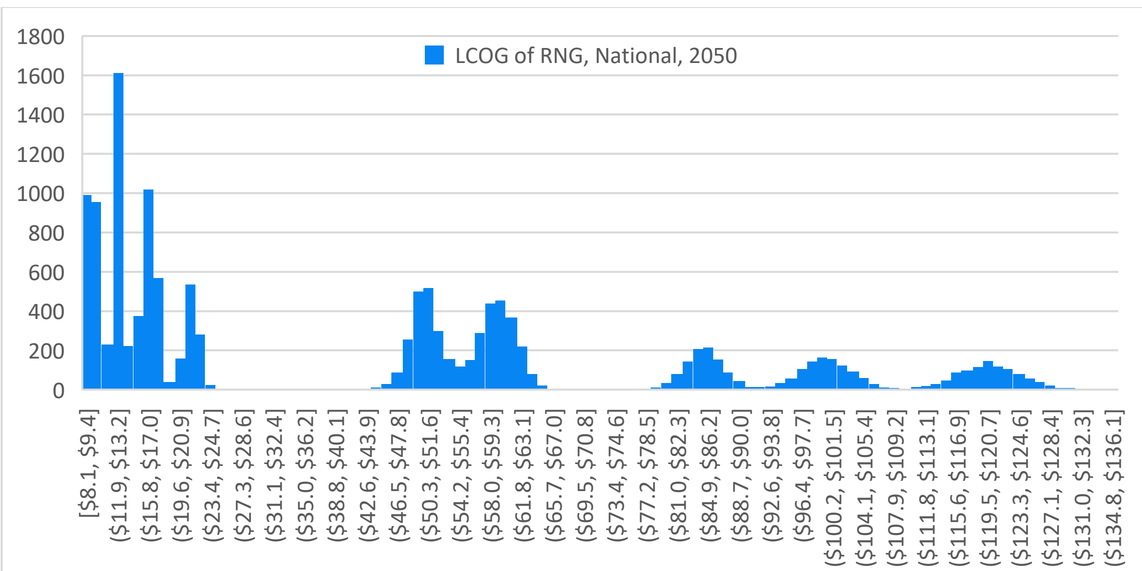


Exhibit 20. Summary of Monte Carlo Simulation Results for RNG domestically (2050)



RNG GHG Life Cycle Emissions

ICF evaluated life cycle carbon intensities (CIs) from the RNG feedstocks and production methods of interest identified in Section 0. Specifically, ICF used life cycle assessment (LCA) methodology to calculate the GHG emissions derived from all stages of the RNG production process up to the end use combustion of the final product. This is defined as a cradle-to-grave LCA. Carbon intensity is then quantified in terms of $kgCO_2e$/MMBtu of RNG. Cradle-to-grave differs in system boundary from other LCA methodologies such as the cradle-to-gate framework, in which accounting stops at the end of the production process and prior to end use. Further, it is worth noting that, in the context of this report, LCA refers only to the accounting of GHG emissions for within each stage of the RNG cradle-to-grave process, whereas in other contexts an environmental LCA may refer to complete accounting of all environmental impacts including, for example, water usage or impact assessment of pollutants, etc.

RNG production from biogenic sources requires a series of steps (see Exhibit 21): collection of a feedstock, delivery to a processing facility for biomass-to-gas conversion, gas conditioning, compression and injection into the pipeline and combustion at the end use.

Exhibit 21. LCA Boundary for RNG Supply Chain via Anaerobic Digestion

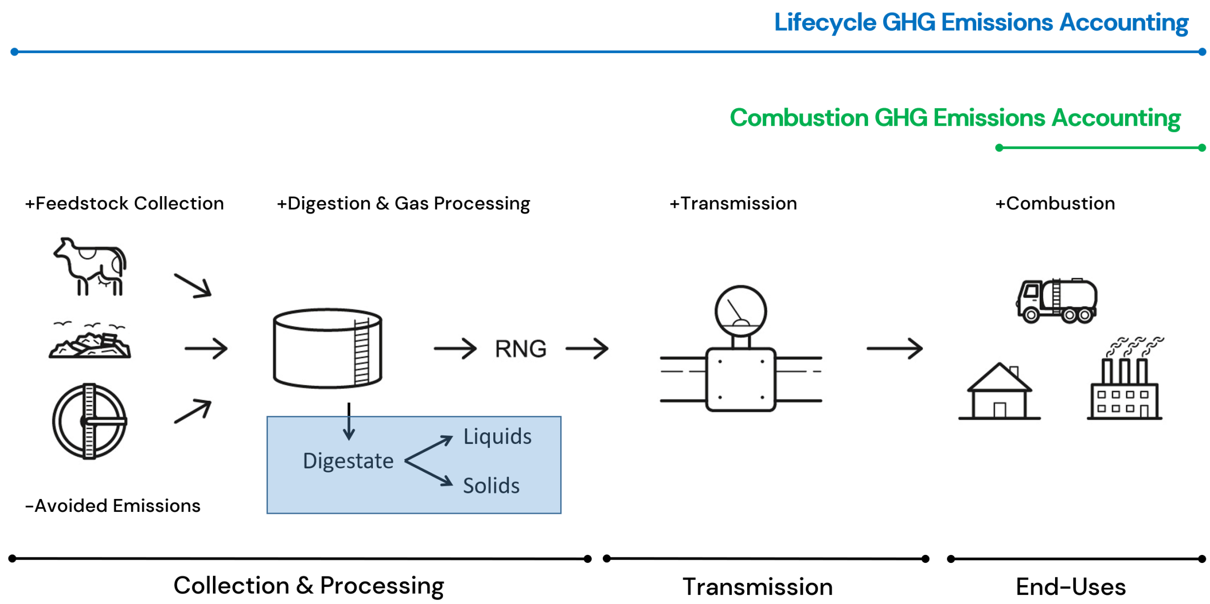


Exhibit 21 shows how life cycle GHG emissions from RNG are generated along the three key stages of the RNG supply chain.

- **Production:** Energy use required to collect feedstock material and then produce and process RNG by way of digestion and processing for anaerobic digesters and landfills, or synthetic gas (syngas) processing as it relates to thermal gasification. Sometimes, RNG production is also credited for avoiding emissions (like methane) that would otherwise have been released in the feedstock's business-as-usual management practices.
- **Pipeline transmission and distribution (T&D):** Methane leaks primarily during transmission. Methane leaks can occur at all stages in the supply chain from production through use but are generally focused on leakage during transmission.
    - ICF limits our explicit consideration to leaks of methane as those that occur during transmission through a natural gas pipeline, as other methane losses that occur during RNG production are captured as part of efficiency assumptions. The life cycle carbon intensity calculations generated for this study include assumptions for natural gas pipeline leaks synthesized by Argonne National Laboratory based on best available data from scholarly work and the U.S. EPA. One key area of criticism of the gas industry is that CH_4 leaks are underreported. That said, utilities are focusing their attention on driving down leaks on their systems. The potential for gas utilities and RNG project developers to reduce the T&D and other methane leaks assumed here could improve upon the estimated carbon emissions intensities estimated in this report.
- **End-use:** RNG combustion. The GHG emissions attributable to RNG combustion are straightforward: CO_2 emissions from the combustion of biogenic renewable fuels are considered zero, or carbon neutral. In

other words, the GHG emissions from combustion are limited to CH_4 and N_2O emissions because the CO_2 emissions are considered biogenic.[16]

For fuel users and providers trying to reduce combustion GHG emissions, RNG is an attractive prospect. Some entities report only on a combustion emissions accounting basis or report these downstream emissions separately (gas combustion is generally Scope 3 for gas utilities) from their other GHG tracking on Scope 1 and 2 GHGs. Depending on reporting protocol (voluntary or regulatory, and even between regulatory incentive structures and governing bodies), there are a variety of approaches taken to greenhouse gas emissions accounting. As policies develop federally and across the northwest, the Utilities will need to navigate these reporting protocols and can inform decision-making on the policy frameworks that will drive meaningful decarbonization in the energy sector.

Argonne National Laboratory's GREET Model

In this study, LCAs were conducted using R&D GREET1_2023, the latest GREET model version released by Argonne National Laboratory (ANL), to estimate the carbon intensity of RNG. Emission factors for different processes are obtained from GREET as well. The GREET model is widely recognized as a reliable tool for life cycle analysis – also known for transportation applications as well-to-wheels (WTW) analysis – of transportation fuels and has been used by several regulatory agencies (e.g., U.S. Environmental Protection Agency for the Renewable Fuel Standard and the LCFS) for evaluation of various fuels.

GREET RNG LCA Modeling Approach and Model Modifications

ICF largely relied on GREET default values with adjustments to RNG transmission and distribution distance, simulation year, Global Warming Potential (GWP) and grid electricity mix inputs to accommodate various sensitivity scenarios. Consumption rate of fossil NG and grid electricity for RNG pathways was adjusted to align with cost analysis values.

For WRRF, the baseline scenario ("Waste" tab) was adjusted to ensure the heating energy source for the existing AD is the same as under the RNG pathway.

RNG GHG Life Cycle Emission Projection

The table below summarize the RNG GHG life cycle emissions for each feedstock for RNG production in OR and WA and at the national level. ICF notes that the CI values change slightly over time in the analysis as a function of assumptions around decreases in a) the carbon intensity of electricity tied to deployment of renewable energy and b) slight reductions in the carbon intensity of gas extraction and distribution.

Exhibit 22. RNG Carbon Intensity Projection Base Case Results (kgCO_2e/ MMBtu)

RNG Feedstock	Carbon Intensity	
	OR & WA	National
Animal Manure	-212.24	-202.75
Food Waste	-71.94	-62.45
Landfill Gas	14.08	23.56
WRRFs	14.54	26.74

[16] Intergovernmental Panel on Climate Change (IPCC) guidelines state that CO_2 emissions from biogenic fuel sources (e.g., biogas or biomass based RNG) should not be included when accounting for emissions in combustion – only CH4 and N_2O are included. This is to avoid any upstream "double counting" of CO_2 emissions that occur in the agricultural or land use sectors per IPCC guidance.

Hydrogen

Types of Hydrogen

ICF notes that in the last number of years, hydrogen production technologies have been assigned colors to differentiate between various feedstock sources and production technologies like steam methane reforming (SMR) or autothermal reforming (ATR) or electrolysis, to name a few. The industry is moving away from these color descriptions in favor of carbon intensity metrics, the most popular of which is kilograms of CO_2 equivalent per kilogram of hydrogen (kg CO_2e/kg H_2). The different methods of hydrogen production are identified as different colors of hydrogen and are shown in the table below.

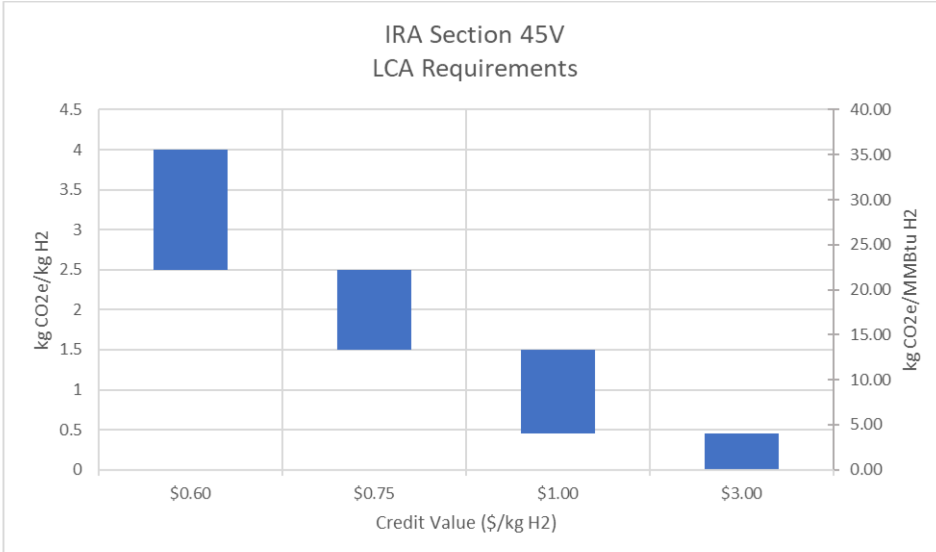
Exhibit 23. Different Hydrogen Production Methods

Hydrogen Feedstock	Production Technology	CI range kg CO_2e/kg H_2	Former Color
Natural Gas	Hydrogen produced from SMR, no carbon capture	10 – 14	Gray
Coal	Hydrogen produced from coal gasification	20 – 30	Brown
Natural Gas	Hydrogen produced from SMR/ATR with 97%+ CCS	1.8 – 2.6	Blue
Natural Gas & RNG	Hydrogen produced from SMR/ATR with 97%+ CCS	0 – 0.45	Blue
RNG	Hydrogen produced from methane pyrolysis	<0	Turquoise
Natural Gas	Hydrogen produced from methane pyrolysis	<2.5	Turquoise
Renewable Electricity	Hydrogen produced via electrolysis from renewable energy[17]	0 – 2.6[18]	Green
Nuclear Energy	Hydrogen produced via electrolysis from nuclear energy	<1	Pink

Several governing bodies have begun to define "Clean Hydrogen" according to its carbon intensity. In the US, the definition of Clean Hydrogen was established to be less than 4 kg CO_2e/kg H_2 under the Bipartisan Infrastructure Law, and further defined by categories under the Inflation Reduction Act (IRA) which created a new hydrogen production tax credit under Section 45V of the tax code. Only projects that can demonstrate life cycle GHG emissions of less than 4kg CO_2e/kg H_2 produced are to qualify, as demonstrated in the figure below. The emission ranges shown in the figure below are for Qualified facilities, which are to be required to meet certain wage and apprenticeship requirements as defined in the IRA.

[17] The Green Hydrogen Coalition also considers hydrogen produced from steam biomethane reforming and biomass gasification as green hydrogen. Source: https://www.ghcoalition.org/green-hydrogen
[18] May vary depending on energy attribute certificates for grid tied facilities and the temporal matching requirements.

Exhibit 24. IRA Section 45V Clean Hydrogen Production Tax Credit for Qualified Facilities



In this analysis, ICF primarily focused on supply from PEM Electrolysis using renewable energy for green and pink hydrogen, ATR with CCS for blue hydrogen, and both thermal and catalytic pyrolysis for turquoise hydrogen. For blue and turquoise models, ICF used a blend of renewable natural gas and conventional gas to optimize the tax credits.

Green and Pink Hydrogen (Electrolyzer)

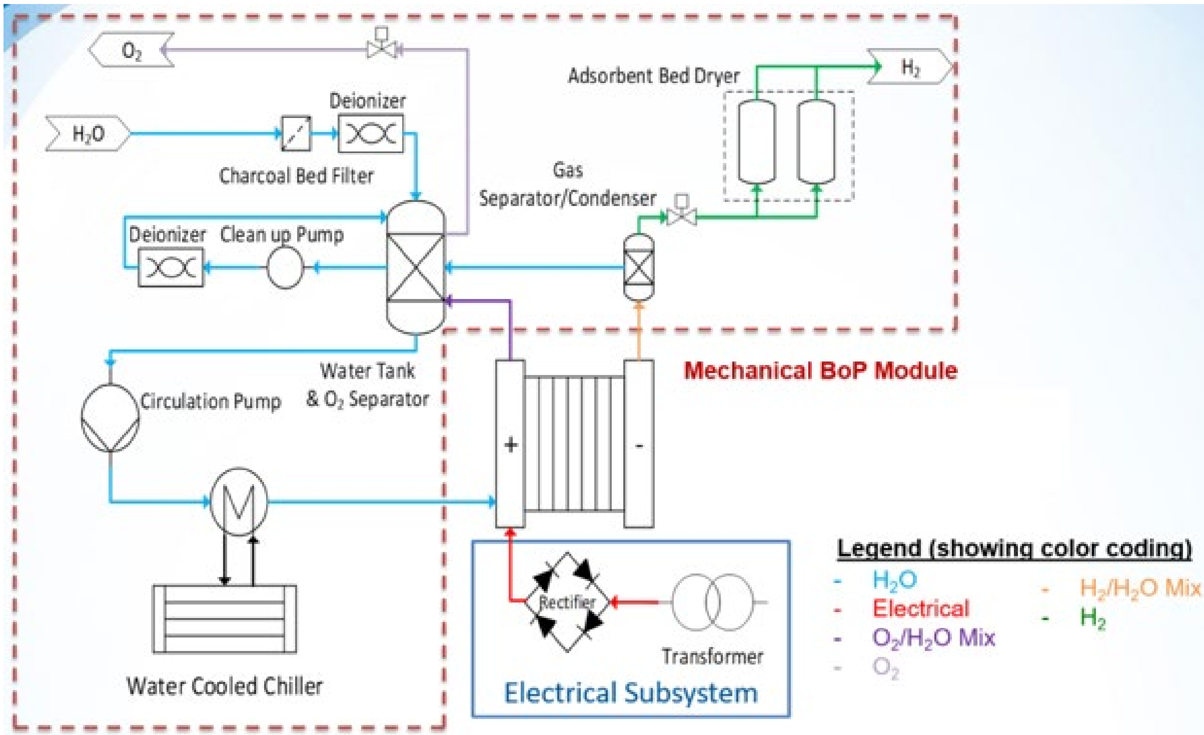
Levelized Cost of Hydrogen

ICF has developed hydrogen production cost models for hydrogen produced using renewable and nuclear energy and electrolyzer technology.

An electrolyzer facility includes the electrolyzer system along with the mechanical and electrical balance of plant (BoP). The electrolyzer requires deionized water and typical equipment manufacturers include a water treatment and recirculation system as part of the mechanical BoP. Once the deionized water feeds into the electrolyzer, the electrolyzer splits the water into hydrogen and oxygen. Oxygen and hydrogen are then treated to be separated from water. The oxygen could be captured and sold or vented out into the atmosphere. The hydrogen goes through dryers to remove moisture and is collected or compressed as a product. The electrical BoP consists of a transformer and rectifier used to convert AC to DC voltage. The figure below shows the typical electrolyzer and BoP equipment and the block flow diagram to produce hydrogen.[19]

[19] Analysis of Advanced Hydrogen Production and Delivery Pathways (energy.gov)

Exhibit 25. Sampled Proton Exchange Membrane (PEM) Electrolyzer Facility for Hydrogen Production[20]



The cost of renewable hydrogen produced via electrolysis is highly dependent on the cost of the electrolyzer units, the utilization of the electrolyzer units, and the price of electricity used in production. Currently, electrolysis is more expensive than renewable hydrogen from SMR/ATR units. Electrolysis for hydrogen production is a mature technology, but historical production to date has only been at small scale for specific applications such as to produce oxygen on submarines, with companies producing hydrogen for fuels such as Plug Power only emerging recently. Capacity deployment is estimated to increase from approximately 40 megawatts (MW) of PEM capacity in 2022 to over 3,000 gigawatts (GW) in 2050 by some estimates. The potential for "numbering up" architecture of including multiple electrolyzer stacks within a larger electrolyzer house is expected to drive significant per-unit cost reductions in the future. These cost reductions are typically modeled using "learning rates" which are calculated by determining the capital cost reduction for each doubling of capacity. It is also expected that economies of scale and learning efficiencies from the equipment manufactures as the technology develops could also decrease costs.

Production Cost Estimate Overview

ICF assumes that renewable costs are procured for hydrogen at the levelized cost of energy. The LCOE represents the minimum price a renewable resource must earn to recover all costs and provide the required rate of return to its investors. U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO) costs were used to develop LCOEs for wind and solar power and ICF developed costs for nuclear using NREL's technology data. [21] ICF used a Monte Carlo analysis for the renewable energy credit (RECs) pricing by assuming a varying premium percentage for the LCOE. The RECs pricing is dependent on the additional costs associated with Section 45V requirements for the Energy Attribute Credits (EAC) such as hourly matching of the renewable energy source to

[20] Analysis of Advanced Hydrogen Production and Delivery Pathways (energy.gov)
[21] Nuclear | Electricity | 2024 | ATB | NREL

every hour of hydrogen production, etc. ICF also assumed capacity factor (CF) on a regional and national basis using data from EIA[22] as shown in Exhibit 26.

Exhibit 26. Capacity Factor for Northwest U.S. and Average U.S.

Capacity Factor - EIA, 2022	Solar PV CF %	Wind CF %	Nuclear (SMR) CF%
Oregon	23.9%	23.7%	**92%**
Washington	14.8%	27.3%	
Average Regional	**19.4%**	**25.5%**	
Average National	**24.4%**	**35.9%**	

ICF analysis was prepared assuming 3% annual maintenance as a percentage of capex and uses an electrolyzer cost of $1050/kW based on average bid prices from recent projects which we are familiar and a total installed cost (TIC) factor range of 2X to 2.7X the electrolyzer cost for greenfield, grid connected electrolyzer plants with which we are familiar. The levelized cost of hydrogen projection is based on a 220 MW electrolyzer facility with a learning curve rate of 22% and a water cost of $5.63/kgal and is assumed with an annual escalation of approximately 1%.[23] The electrolyzer stack membranes are assumed to be replaced every 7-10 years; this is included in ICF's assumptions by accounting for as a major maintenance cost of 30% of the direct capex, the cost for which is allocated evenly as an annualized cost. The labor cost for this specific analysis was assumed to be approximately $2MM USD annually, however labor costs are subject to regional differences. Based on electrolyzer experience in other analog industries such as the chlor-alkali business, continuous deionization and reverse osmosis systems used to produce clean water, and academic studies[24] it is our expectation that industrial PEM electrolyzer maintenance will require between 3-5% of capex on an annual basis for preventative and corrective maintenance. Preventative and corrective maintenance components include but are not limited to cleaning of contamination or impurities within PEM system, and regular maintenance for the water treatment system, compressor, hydrogen dryer and other BoP components. The cost includes electrolyzer membrane stack replacement, which is funded as a major maintenance item.

Exhibit 27. Electrolyzer Facility Production Cost Inputs

Input	Value	Comments
Sample Facility Size		
Electrolyzer Size	220 MW	Based on projects with which ICF is familiar
Annual Production Target	20,000,000 kg	Based on projects with which ICF is familiar
Energy and Water Inputs		
Renewable Power Capacity Factor	Dependent on energy resource and location (national vs. regional averages)	Assuming energy from solar, wind and nuclear sources
Electrolyzer Energy Consumption Rate	53 kWh/kg	Based on projects with which ICF is familiar and ranges from original equipment manufacturers (OEMs)
BoP Energy Consumption Rate	8 kWh/kg	Based on projects with which ICF is familiar and ranges from OEMs

[22] https://www.eia.gov/state/seds/data.php?incfile=/state/seds/sep_fuel/html/fuel_cf.html&sid=WA
[23] https://www.osti.gov/servlets/purl/1975260
[24] Optimized electrolyzer operation: Employing forecasts of wind energy availability, hydrogen demand, and electricity prices - ScienceDirect

Input	Value	Comments
Electricity Cost	Dependent on resource type (solar, wind, nuclear or renewable energy certificates [RECs])	Based on AEO projections for solar and wind LCOEs and ICF estimates from NREL for nuclear LCOE; RECs assumed to come at a placeholder value of 5% premium to the LCOE which is varied in the Monte Carlo analysis due to the regulatory uncertainties
Water Intake Rate	2.64 gal/kg	Based on projects with which ICF is familiar and ranges from OEMs
Water Cost	$5.63/kgal	Industrial utility water with approximately 1% annual escalation from DOE's Office of Scientific and Technical Information (OSTI)
Operation Inputs		
Stack Membrane Life	10 years	Based on projects with which ICF is familiar
Life of Electrolyzer Equipment	80,000 hours	Based on projects with which ICF is familiar
Annual Degradation Rate	1%	Conservative estimate; levelized degradation factor was assumed to have minimal impact and not included in analysis
Operating year	333-353 days	Based on projects with which ICF is familiar
Annual Labor Costs	$2.95MM	ICF's estimate for standalone electrolyzer facility with ~25 staff
Membrane Replacement Cost as % of Direct Capex	30%	Based on projects with which ICF is familiar
Annual Maintenance as % of Capex	3%	Based on projects with which ICF is familiar
Project Finance and Capital Costs		
PEM Electrolyzer	$1050/kW	Based on projects with which ICF is familiar and bids from OEMs
Total Installed Cost Factor	2	Based on projects with which ICF is familiar; can range from 2 – 2.7 depending on BOP
Learning Curve Rate for Total System	22%	ICF's internal model
WACC	4%	Provided by utilities; varied in the Monte Carlo analysis
Loan Duration	20 years	Based on projects with which ICF is familiar

ICF assumes electrolyzer costs scale linearly as electrolyzer units are additive much like solar facilities where additional units are added to increase capacity rather than scaled up volumetrically by a factor similar to that of industrial plants such as combined cycle gas plants. Similar to solar where panels are added to increase the output, electrolyzer units can be added to increase the size of the hydrogen production facility. The BoP can be scaled up, which may result in some cost savings; however, we have included BoP costs in the total installed cost factor as a percentage of the electrolyzer capital cost in our assumptions.

ICF includes two sets of tax credits in the green and pink hydrogen model.

- The renewable electricity production tax credit is a per kilowatt-hour (kWh) federal tax credit included under Section 45 of the U.S. tax code for electricity generated by qualified renewable energy resources. ICF levelized the tax credit over 20 years and includes $20.86/MWh annual tax credit from 2025 to 2045.
- ICF levelized the Section 45V tax credit over 20 years. The tax credit by CI is summarized in the table below. Since hydrogen projects must be under construction by the end of 2032 to qualify for 45V credits, the 45V tax credits were modeled until 2035 as a conservative estimate assuming every new hydrogen facility beginning construction after 2032 may not qualify for the tax credit. ICF assumed EAC requirements and other requirements for 45V credits are met to minimize the CI which doesn't include embodied emissions and receive the maximum credit amount of $3/kg.

Exhibit 28. 45V Hydrogen Investment Tax Credit and Production Tax Credit

45V Hydrogen Investment Tax Credit and Production Tax Credit					
LIfe Cycle Emissions (kg CO2e/kg H2)		Value of Incentive			
Low	High	ITC%	PTC 2022$/kg	PTC 2022$/ MMBtu	Levelized PTC 2022$/ MMBtu
2.50	4.00	6.0%	$0.60	$4.45	$2.90
1.50	2.50	7.5%	$0.75	$5.57	$3.63
0.45	1.50	10.0%	$1.00	$7.42	$4.84
0.00	0.45	30.0%	$3.00	$22.26	$14.51

ITC and PTC apply to facilities whose construction begins by 2032. PTC continues for 10 years. Levelization is over 20-year operating life.

Technical Potential

ICF determined the technical potential by applying two main constraints:

1. **Resource Constraint**: ICF used annual forecasts for solar, wind, hydropower, and nuclear power from AEO Reference Case, assuming a placeholder percentage of 25% of these resources would be available for hydrogen production.
2. **Technology Readiness Constraint**: ICF estimated the annual installation of hydrogen plants using a database of announced hydrogen projects, categorized by technology and state, assuming no resource limitations.

For each year, the most conservative forecast from these two constraints was selected to create the technical potential forecast. Initially, the technology readiness constraint was the limiting factor, but over time, the resource constraint became more conservative.

ICF produced national and regional (Oregon and Washington) models for each hydrogen production type for differences in technical potential as well as some assumptions for the levelized cost modeling such as electricity cost and capacity factor. For regional modeling, ICF assumed the renewable resource potential of the states involved in the Pacific Northwest Hydrogen Hub which includes Oregon, Washington and Montana. ICF assumes approximately 60% of the AEO resource potential for the Northwest Power Pool (NWPP) represents Oregon, Washington and Montana. The 60% assumption is an estimate based on the population of Oregon, Washington and Montana relative to the regions mentioned in the NWPP. For the national modeling, ICF assumed there would be limitations to transporting hydrogen which will depend on future regulatory and infrastructure updates (e.g., transporting hydrogen by blending with natural gas in pipelines). ICF assumed California is active in hydrogen production projects based on project announcements and involvement in the Hydrogen Hub projects and closest in proximity to the Pacific Northwest Hydrogen Hub. Therefore, a placeholder assumption of 5% of projected renewable resource potential in California would be used as a constraint for the national technical potential for green and pink hydrogen for Oregon and Washington. The 5% placeholder is subject to change depending on hydrogen production and demand in California and the hydrogen to be transported to Oregon and Washington.

Technical Potential and Levelized Cost Results Overview

Exhibit 29 shows the hydrogen production from solar, wind and nuclear results for national and regional (OR and WA) basis and a summary of the range of regional and national results for 2050. ICF assumed the production tax credit (PTC) for both solar, wind and nuclear energy as well as the PTC for hydrogen production satisfies all requirements under Section 45Y and 45V, respectively.

Exhibit 29. Summary of Results for Hydrogen Produced from Solar, Wind and Nuclear

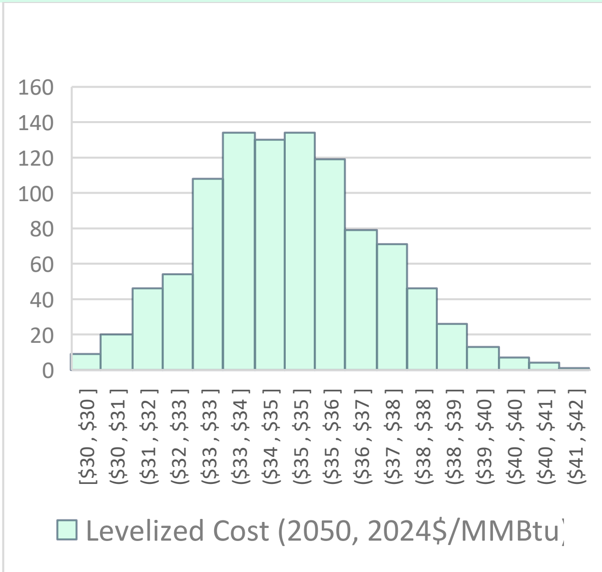
Year	Levelized Cost	Resource Potential	GHG Emissions	Levelized Cost	Resource Potential	GHG Emissions
Unit	\$2024 per MMBtu	BBtu (1000 MMBtu) per year	CO_2e kg/ MMBtu	\$2024 per MMBtu	BBtu (1000 MMBtu) per year	CO_2e kg/ MMBtu
	Green H_2 - Solar (NW)			**Green H_2 - Solar (National)**		
2025	\$29.11	197	0	\$24.32	970	0
2030	\$22.59	23,587	0	\$15.43	2,335	0
2035	\$20.07	62,223	0	\$13.70	3,951	0
2040	\$27.93	67,871	0	\$27.43	4,580	0
2045	\$25.47	68,897	0	\$26.96	5,399	0
2050	\$33.72	69,027	0	\$34.98	5,810	0
	Green H_2 - Wind (NW)			**Green H_2 - Wind (National)**		
2025	\$37.04	197	0	\$29.98	970	0
2030	\$27.59	23,587	0	\$25.32	2,335	0
2035	\$26.16	62,223	0	\$23.55	3,951	0
2040	\$40.36	67,871	0	\$38.34	4,580	0
2045	\$39.77	68,897	0	\$37.89	5,399	0
2050	\$49.05	69,027	0	\$47.34	5,810	0
	Pink H_2 (NW)			**Pink H_2 (National)**		
2025	\$30.51	22	1.09	\$30.88	108	1.09
2030	\$27.48	2,021	0.99	\$27.87	-	0.99
2035	\$26.07	2,021	0.97	\$26.41	-	0.97
2040	\$40.45	2,021	0.97	\$40.64	-	0.97
2045	\$40.15	2,021	0.96	\$40.16	-	0.96
2050	\$48.58	1,974	0.95	\$48.42	-	0.95

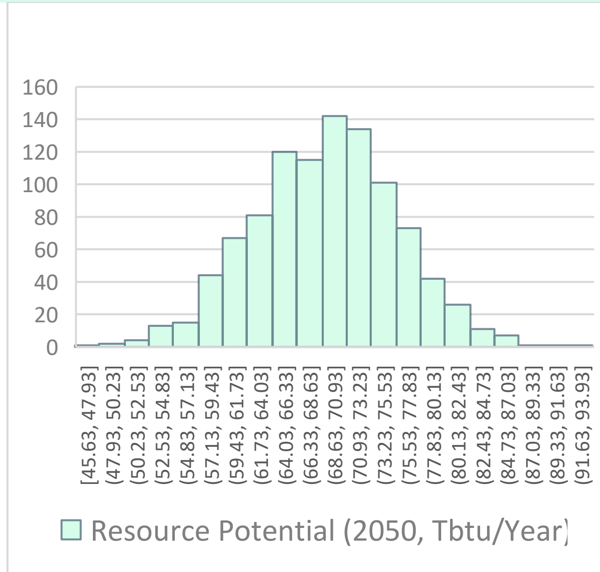
The impact of the Monte Carlo process on costs is illustrated in Exhibit 30. The histogram depicts the number of the 1,000 Monte Carlo cases (y-axis) that fall within various cost ranges/technical potential ranges (x-axis) for each type of green and pink hydrogen.[25]

[25] Note: 1 MMBtu = Million (10^6) Btu. 1 BBtu = Billion (10^9) Btu. 1 TBtu = Trillion (10^{12}) Btu.

Exhibit 30. Summary of Monte Carlo Simulation Results for Hydrogen Produced from Solar, Wind and Nuclear (Oregon and Washington, 2050)

Green Hydrogen - Solar

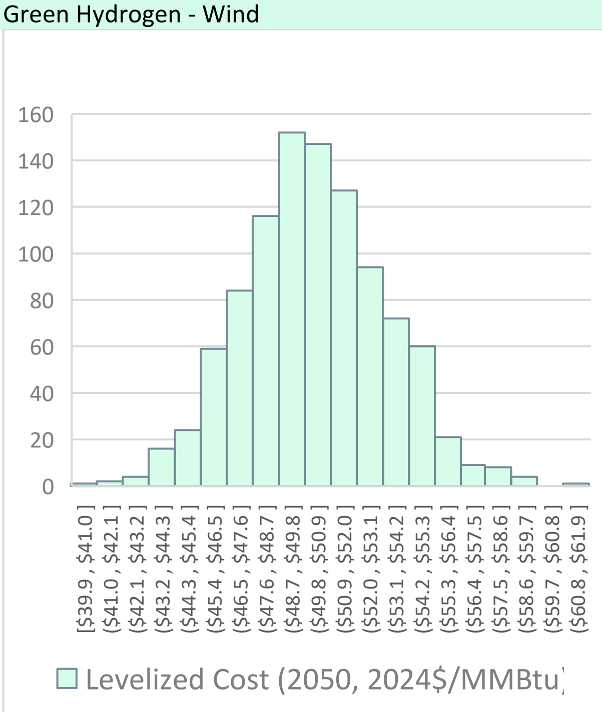


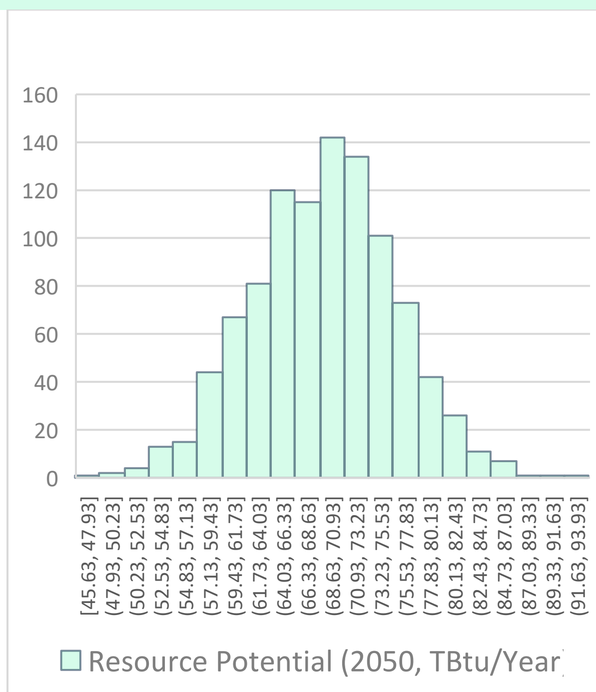


	Levelized Cost
Mean	$34.77
Max	$41.23
Min	$29.64
IQR	$2.78

	Resource Potential
Mean	69
Max	92
Min	46
IQR	9

Green Hydrogen - Wind

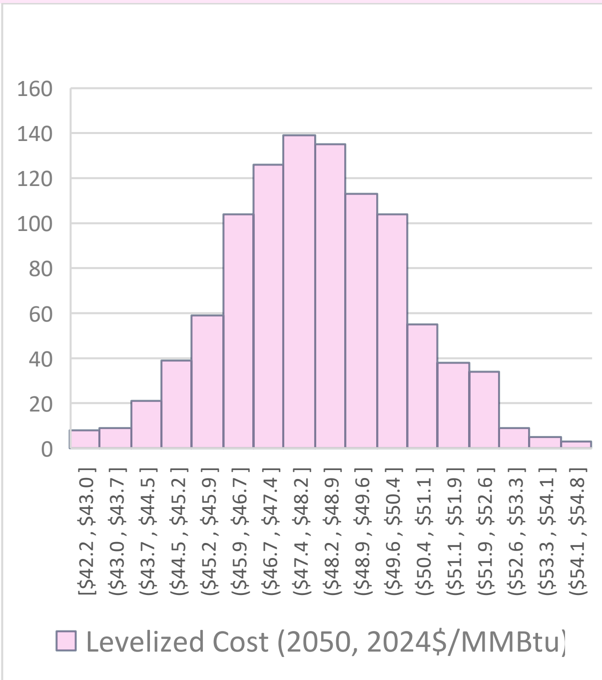


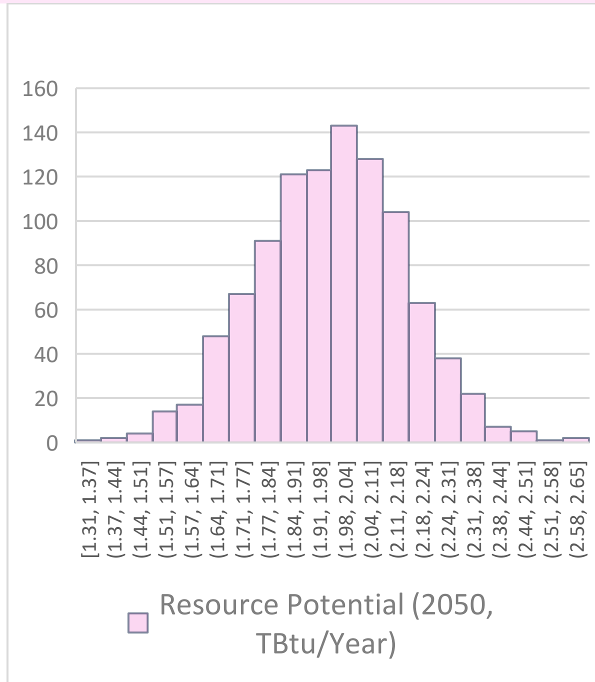


	Levelized Cost
Mean	$50.28
Max	$61.15
Min	$39.95
IQR	$4.02

	Resource Potential
Mean	69
Max	92
Min	46
IQR	9

Pink Hydrogen





	Levelized Cost
Mean	$48.18
Max	$54.77
Min	$42.24
IQR	$2.82

	Resource Potential
Mean	2.0
Max	2.6
Min	1.3
IQR	0.3

The levelized cost of hydrogen ranged from approximately $30/MMBtu to $61/MMBtu depending on the production method shown in Exhibit 30 for 2050. The costs increased after 2035 because of the removal of the 45V tax credit for new hydrogen facilities beginning construction after 2032. The largest cost contributor to the levelized cost of hydrogen is the cost of electricity which will vary depending on factors such as 45V tax credit amendments regarding EACs, future hydrogen demand, etc. Similarly, the technical potential may vary depending on the same factors, hydrogen infrastructure development, and the amount of renewable energy resources allocated to hydrogen production. For pink hydrogen, the national resource potential is based on AEO's nuclear energy generation forecast which is assumed to be zero after 2025.

Blue Hydrogen (Steam Methane Reforming)

Levelized Cost

Steam methane reforming (SMR) converts a hydrocarbon feedstock (such as natural gas) into a syngas by reacting the feedstock with steam in the presence of a catalyst, located inside multiple reformer tubes, to produce carbon monoxide, hydrogen and some carbon dioxide. The heat required for the reforming reactions is provided by external heating of the reformer tubes, by burners placed outside the tubes. Maximum hydrogen production is achieved by "shifting" as much of the carbon monoxide to hydrogen as feasible and hydrogen recovery from the syngas via a pressure swing adsorption (PSA) unit. Approximately 60% of the cost of a steam reformer is the cost of the reformer tubes, tube supports and catalysts and these items scale approximately linearly with capacity and therefore hydrogen production via SMR may not achieve efficient economies of scale at higher hydrogen capacities.

Autothermal Reforming (ATR) generates the heat required for the reforming reactions, internally in the process by oxygen in addition to the process burner, which partially oxidizes the syngas. The reforming reactions are carried out downstream of the burner in a catalyst bed, installed inside a refractory lined vessel, generally mounted below the burner. Like with SMR, hydrogen production is maximized by shifting any carbon monoxide to hydrogen in a CO shift unit and then using a PSA to recover a high purity hydrogen product. As the ATR reactor is a refractory lined vessel, partially filled with catalyst, higher capacities can be readily achieved by increasing the reactor diameter, up to a practical maximum vessel size. Hence, at high hydrogen capacities, the ATR tends to be more economic than similar capacity SMR-based plants.

With suitable CO_2 recovery technologies, both processes can produce relatively pure CO_2 streams which make them well situated to downstream compression, (pipeline) transportation and sequestration technologies. To reduce carbon intensity associated with the produced hydrogen further, these facilities can also replace natural gas with renewable natural gas.

Exhibit 31. ATR Facility Production Cost Inputs

Input	Value	Comments
Sample Facility Size		
Nameplate Capacity	8,929 kg/h	Based on projects with which ICF is familiar
Annual Production Target	78,218,040 kg	Based on projects with which ICF is familiar
Plant Utilization Rate	92%	Assume plant is offline for approximately 4 weeks for maintenance, etc.
Carbon Capture Percent	97%	Based on estimates for efficient carbon capture technology
Energy and Water Inputs		
Natural Gas Thermal Efficiency	84%	Based on projects with which ICF is familiar
Natural Gas Share of Feedstock	95%	Optimized to reduce carbon intensity to receive IRA tax credits
RNG Share of Feedstock	5%	Optimized to reduce carbon intensity to receive IRA tax credits

Input	Value	Comments
RNG and Natural Gas Cost	Dependent on varying natural gas values from Henry Hub or RNG cost model	Based on ICF's RNG model (including a 10% premium) and natural gas costs from Henry Hub
Electricity Consumption Rate	2.57 kWh/kg	Based on projects with which ICF is familiar and ranges from OEMs
Electricity Cost	Grid electricity forecast	Based on AEO projections
Water Intake Rate	20.78 gal/kg	Based on projects with which ICF is familiar and ranges from OEMs
Water Cost	$5.63/kgal	Industrial utility water with approximately 1% annual escalation from OSTI
Operation Inputs		
Annual Maintenance Share	5.5%	Based on projects with which ICF is familiar; includes labor costs
Plant Life	20 years	Based on projects with which ICF is familiar
Project Finance and Capital Costs		
Total Investment per Unit of Annual Capacity	$10.50/kg	Based on projects with which ICF is familiar and bids from OEMs
Total Capital Investment	$820 MM	Based on projects with which ICF is familiar
Technology Improvement	0.75%/year	ICF's estimate based on literature
WACC	4%	Provided by utilities; varied in the Monte Carlo analysis
Loan Duration	20 years	Based on projects with which ICF is familiar

Technical Potential

The technical potential for blue hydrogen follows a similar approach to Section 4.2.2; however, unlike the technical potential for electrolyzers, ICF did not impose resource constraints on blue hydrogen since natural gas and RNG are assumed to be accessible. Blue hydrogen can be produced solely from natural gas; however, this would increase emission intensity, potentially disqualifying it from the highest hydrogen production tax credit. For the NW regional model, ICF assumes the technical potential of hydrogen production in the region based on technical readiness constraints such as project announcements and estimate forecasts of hydrogen facilities in OR and WA. For the national model, ICF assumes a placeholder value of 5% of California's technical readiness potential which would be delivered to OR and WA. Similar to the green and pink hydrogen technical potential for the national modeling, the 5% placeholder is subject to change depending on hydrogen production and demand in California and the hydrogen to be transported to Oregon and Washington.

Technical Potential and Levelized Cost Results Overview

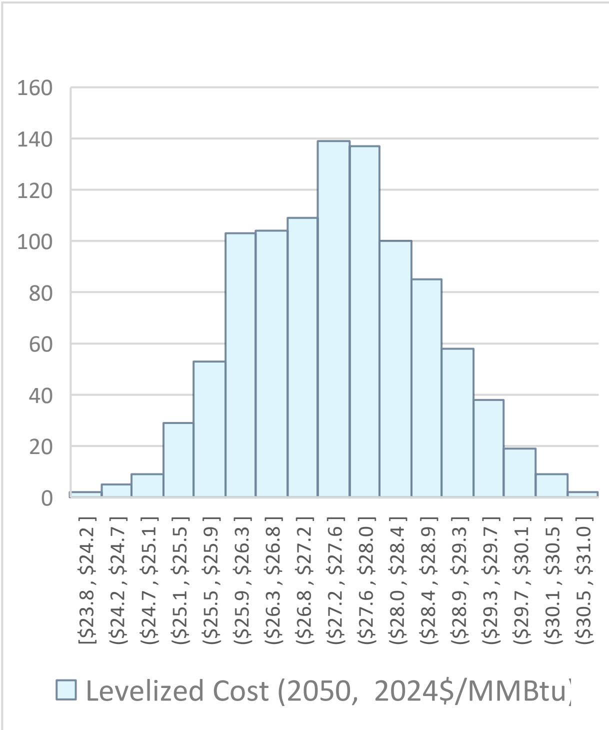
Exhibit 32 shows the hydrogen production results from natural gas and RNG used in an ATR facility for national and regional (OR and WA) basis and Exhibit 32 shows a summary of the range of regional and national results for 2050. ICF assumes the PTC for hydrogen production satisfies all requirements under Section 45Y and 45V, respectively.

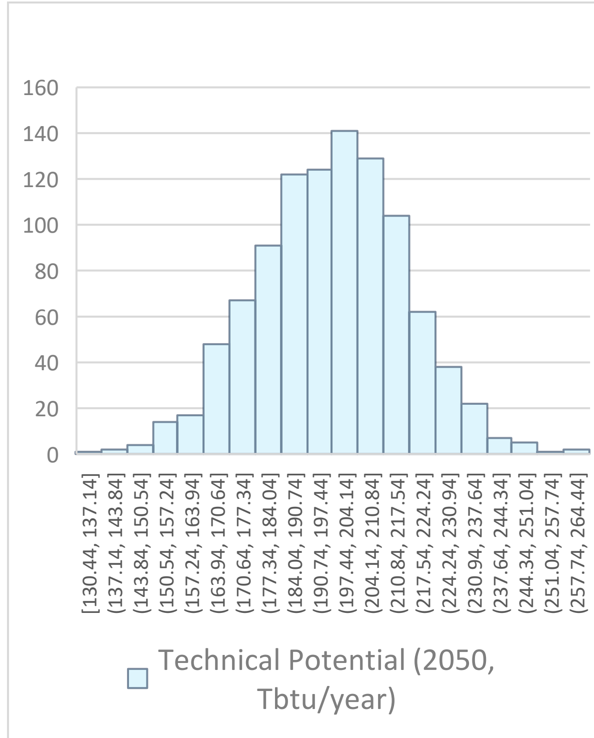
Exhibit 32. Summary of Results for Blue Hydrogen

Year	Levelized Cost	Resource Potential	GHG Emissions	Levelized Cost	Resource Potential	GHG Emissions
Unit	\$2024 per MMBtu	BBtu (1000 MMBtu) per year	CO_2e kg/ MMBtu	\$2024 per MMBtu	BBtu (1000 MMBtu) per year	CO_2e kg/ MMBtu
	Oregon and Washington			**National (Available to OR and WA)**		
2025	\$12.80	-	2.90	\$15.36	97	1.50
2030	\$12.91	16,845	2.88	\$14.51	3,359	2.89
2035	\$14.51	52,942	1.80	\$15.81	7,690	2.62
2040	\$26.59	101,071	18.20	\$27.21	13,466	20.99
2045	\$26.82	149,201	18.32	\$27.43	19,241	20.79
2050	\$26.94	197,330	18.37	\$27.42	25,017	20.49

The impact of the Monte Carlo process on costs is illustrated in Exhibit 33. The histogram depicts the number of the 1,000 Monte Carlo cases (y-axis) that fall within various cost ranges/technical potential ranges (x-axis) for blue hydrogen.

Exhibit 33. Summary of Monte Carlo Simulation Results for Blue Hydrogen (Oregon and Washington, the Year 2050)





	Levelized Cost
Mean	$27.45
Max	$30.93
Min	$23.82
IQR	$1.71

	Technical Potential
Mean	197
Max	264
Min	130
IQR	26

For blue hydrogen, a percentage of RNG was assumed to reduce the CI score for 45V tax credits by optimizing the ratio of RNG relative to natural gas as feed. The 45V tax credits were levelized over a 20-year period and applied to the model before 2035.

Turquoise Hydrogen (Methane Pyrolysis)

Levelized Cost

Turquoise hydrogen or methane pyrolysis is the process where methane is broken down into hydrogen gas and solid carbon through thermal energy. Natural gas or renewable natural gas could be used as feedstock to pyrolysis facilities. There are several pyrolysis methods: thermal, catalytic and plasma pyrolysis. Thermal pyrolysis involves the breakdown of methane from high temperatures. Catalytic pyrolysis involves the usage of catalysts such as iron, nickel, etc. and requires less temperature compared to thermal pyrolysis. Plasma pyrolysis uses plasma, a charged gas, which is used to break down methane molecules. Pyrolysis is typically considered to be low carbon technology as there are no combustion emissions in the main process. Carbon black is typically a co-product and can be sold to be used for pigments and reinforcement materials for rubber, asphalt, etc. ICF shows a conservative carbon black price range in the model ($0/kg to $0.50/kg); for example, the $0.50/kg price for carbon black could result in approximately in offsetting the cost of hydrogen production by $11/MMBtu hydrogen. The table below shows a representative levelized cost inputs for a microwave plasma pyrolysis unit.

Exhibit 34. Pyrolysis Facility Production Cost Inputs

Input	Value	Comments
Sample Facility Size		
Pyrolysis Nameplate Capacity	1,000 kg/d	Based on OEM estimates
Annual Production Target	339,500 kg	Based on OEM estimates
Margin for Annual Production	93%	Based on projects with which ICF is familiar
Carbon Black Yield	3 kg carbon black/kg hydrogen (for plasma)	Based on projects with which ICF is familiar
Energy and Water Inputs		
NG or RNG Consumption	1.8 MMBtu/MMBtu Hydrogen (for plasma)	Based on OEM estimates
Natural Gas Share of Feedstock	95%	Optimized to reduce carbon intensity to receive IRA tax credits
RNG Share of Feedstock	5%	Optimized to reduce carbon intensity to receive IRA tax credits
RNG and Natural Gas Cost		Based on ICF's RNG model (including an estimate 10% premium to the levelized cost) and natural gas costs from Henry Hub
Plasma Pyrolysis Electricity Consumption	12 kWh/kg	Based on OEM estimates
BOP Energy Consumption Rate	2.5 kWh/kg	Based on OEM estimates
Electricity Cost		Dependent on AEO costs for grid power
Operation Inputs		
Plant Life	20 years	Based on projects with which ICF is familiar
Annual Labor Costs as of Capex	2%	ICF's estimate
Annual Major Maintenance as % of Capex	1%	Based on projects with which ICF is familiar
Annual Maintenance as % of Capex	1.5%	Based on projects with which ICF is familiar

Input	Value	Comments
Project Finance and Capital Costs		
Total Capital Cost (Pyrolysis Unit + BOP)	$7 MM	Based on ICF assumptions and OEM estimates
Technology Improvement	5%/year	ICF's estimate using a percentage of global electrolyzer capacity projection as a placeholder for pyrolysis technology capacity
WACC	4%	Provided by utilities; varied in the Monte Carlo analysis
Loan Duration	20 years	Based on projects with which ICF is familiar

Technical Potential

ICF applied the same methodology as that used to assess the technical potential of blue hydrogen; therefore, no resource constraints were used. Since there is limited data for the technical readiness constraint based on project announcements, the technical readiness of the pyrolysis units was assumed to be based on a 10-year delayed project forecast for electrolyzer projects as a placeholder for the regional and national modeling. For the NW regional model, ICF assumes the technical potential of hydrogen production in the region based on technical readiness constraints such as project announcements and estimate forecasts of hydrogen facilities in OR and WA. For the national model, ICF assumes a placeholder value of 5% of California's technical readiness potential which would be delivered to OR and WA. Similar to the green and pink hydrogen technical potential for the national modeling, the 5% placeholder is subject to change depending on hydrogen production and demand in California and the hydrogen to be transported to Oregon and Washington.

Technical Potential and Levelized Cost Results Overview

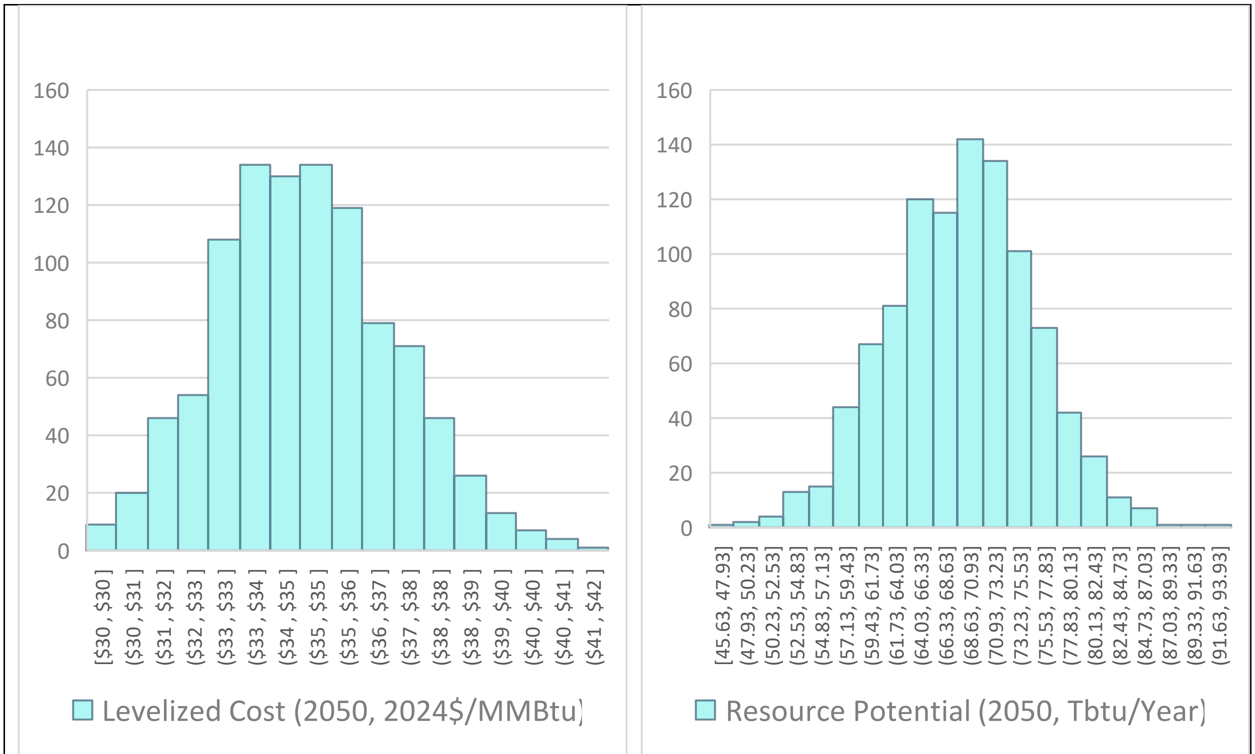
Exhibit 35 shows the turquoise results for national and regional (OR and WA) basis and Exhibit 35 shows a summary of the range of regional and national results for 2050. ICF assumes the PTC for both solar, wind and nuclear energy as well as the PTC for hydrogen production satisfies all requirements under Section 45Y and 45V, respectively.

Exhibit 35. Summary of Results for Turquoise Hydrogen

Year	Levelized Cost	Resource Potential	GHG Emissions	Levelized Cost	Resource Potential	GHG Emissions
Unit	$2024 per MMBtu	BBtu (1000 MMBtu) per year	CO_2e kg/ MMBtu	$2024 per MMBtu	BBtu (1000 MMBtu) per year	CO_2e kg/ MMBtu
	Turquoise H_2 - Plasma (NW)			**Turquoise H_2 - Plasma (National)**		
2025	$32.55	-	3.27	$36.71	-	32.42
2030	$32.31	62	3.27	$35.65	1	18.88
2035	$34.40	197	3.27	$37.73	970	16.36
2040	$44.03	23,587	31.35	$46.99	2,335	44.67
2045	$44.75	67,806	31.93	$47.66	6,480	43.73
2050	$45.95	143,609	32.18	$48.24	13,587	42.29

The impact of the Monte Carlo process on costs is illustrate in Exhibit 36. The histogram depicts the number of the 1,000 Monte Carlo cases (y-axis) that fall within various cost ranges/technical potential ranges (x-axis) for turquoise hydrogen.

Exhibit 36. Summary of Monte Carlo Simulation Results for Turquoise Hydrogen - Plasma Pyrolysis (Oregon and Washington, the Year 2050)



	Levelized Cost
Mean	$34.77
Max	$41.23
Min	$29.64
IQR	$2.78

	Resource Potential
Mean	69
Max	92
Min	46
IQR	9

Similar to blue hydrogen, a percentage of RNG was assumed to reduce the CI score for 45V tax credits by optimizing the ratio of RNG relative to natural gas as feed. The 45V tax credits were levelized over a 20-year period and applied to the model before 2035.

Transportation and Storage of Hydrogen

Transporting Hydrogen

Currently hydrogen is liquefied or compressed before being transported via on-road tube trailers. The tube trailer is a relatively mature technology that has been utilized for decades for the transportation of compressed and liquefied industrial gases such as carbon dioxide and nitrogen. Compressed trailers require pressures ranging from

200 – 500 bar, while liquefied hydrogen tube trailers require lower pressures, ranging from 6 – 12 bar. The lower density of the compressed hydrogen correlates to a higher transportation cost compared to liquefied hydrogen which is 2-3 times denser.

As a result of demand generally exceeding the supply available from compressed hydrogen, compressed hydrogen truck transport is only economically competitive for transporting short distances (< 200km) for customers with small hydrogen demands. As distribution distances increase past 200 km, the higher transportation capacities of liquefied hydrogen trailers become economically favorable. However, liquid hydrogen trailers suffer from boil-off rates (1-5%) that result in losses in delivered hydrogen capacity; some of the vaporized hydrogen may be returned to the liquefaction facility and re-entered into the delivery stream to fill the trailers.

As of 2024, there are 1,600 km of dedicated hydrogen pipelines in the United States, most of this infrastructure is repurposed natural gas pipelines. There is considerable interest in blending hydrogen into pipelines, however there are regulatory considerations involving the amount of hydrogen blend acceptable in a transmission or distribution line, and safety mitigation efforts for hydrogen leakage or pipeline embrittlement that would need to be addressed prior to blending hydrogen into natural gas pipelines For example, operating at lower pressures could reduce the risk of hydrogen pipeline embrittlement. Many utilities are testing small hydrogen blends through the distribution pipeline; Hawaii Gas contains up to 12-15% hydrogen[26] in their natural gas pipelines which is one of the highest hydrogen blends used by a utility company as of 2024. Depending on the end use, purification systems to remove the hydrogen from the blend may also be needed. Hydrogen separation technologies such as membrane separation or pressure swing adsorption could be used to extract a higher purity of hydrogen depending on the hydrogen offtake customer. ICF estimated the cost of a pure hydrogen pipeline in Exhibit 37 below assuming 1.66 kWh/MT-mi.

Exhibit 37. Hydrogen Pipeline Cost Summary

Outside Dia. Inches	Pipeline Cost in $/Inch-Mile	Flow Capacity in MMscf per day (60 deg. F and 14.73 psi)	Flow Capacity in metric tons/day	Flow Capacity in MMBtu/day	Pipeline Cost for 50 Miles ($mm)	Cost of Service for 50 Miles ($/MMBtu)
8.00	$161,543	40	102	13,720	$64.6	$1.71
10.00	$170,045	90	229	30,870	$85.0	$1.03
12.75	$188,939	182	464	62,552	$120.4	$0.74
16	$196,787	334	851	114,706	$157.4	$0.55
24	$211,911	946	2,407	324,403	$254.3	$0.34
30	$217,654	1,663	4,234	570,515	$326.5	$0.27
36	$223,397	2,638	6,715	904,890	$402.1	$0.22
42	$229,140	3,897	9,918	1,336,507	$481.2	$0.19

Storage and Liquefaction

Hydrogen is traditionally either stored as liquid, a compressed gas, or at low pressures in high-volume vessels. Storing hydrogen as a compressed gas requires high pressure vessels ranging from 350 to 700 bar, requiring between 1.05 and 1.36 kWh/kg respectively. Liquid hydrogen can be stored at lower pressures and higher

[26] More information available online here.

volumetric densities, albeit requiring cryogenic tanks to sustain low temperatures of approximately -423 degrees Fahrenheit. This storage method requires between 10-12 kWh/kg of energy for liquefaction with current technologies. When electrolyzer stacks are paired with an intermittent electricity source, compression and liquefaction systems must be designed to have the capacity to handle the maximum hydrogen production rates during peak energy production hours.

Due to the low temperatures required for liquefaction, many developers do try to reduce the number of times the systems get turned off to limit the thermal cycling of the equipment and time it takes to start up. Newer systems are being designed for better integration with intermittent power, so future systems may be more capable of rapid startup and shutdowns. Finally, transportation hydrogen value is impacted by the use of grid electricity to liquefy hydrogen, so future systems may be able to monetize the ability to shut down and start up quickly. The Section 45V credits are well to gate, so electricity for liquefaction is not included within the calculations for the tax credit.

In a recent analysis conducted by NREL[27], liquefaction costs were estimated to be in the range of $2.70-$5.20/kg for facilities ranging from 50,000/kg per day to 1 million/kg per day, and terminal storage costs in the range of $0.20-$1.00/kg.

Industry is also considering salt caverns as a potential long term storage medium that requires pressures of only 30 bar, which is already achieved in the production of hydrogen from industry typical PEM electrolyzers. Salt caverns can be both naturally occurring, or solution mined in salt formations. Historically salt caverns have been utilized for rapid cycling natural gas storage because of their low permeability to natural gas, so these facilities may be suitable for repurposing for hydrogen storage. The salt caverns typically require 30-40% cushion gas which is hydrogen used to maintain the pressure of cavern, however, other gases such as nitrogen are being studied as options for cushion gas[28]. According to the U.S. Department of Transportation, there are approximately 36 salt caverns in the U.S. used for natural gas and most are in the Gulf Coast[29]. There are also studies including ongoing research from Sandia National Laboratories[30] that show the potential of hydrogen to be used in depleted oil and natural gas reservoirs as additional gaseous storage methods.

Based on ICF's internal cost analysis, the annualized cost over a 20-year period with a 9% interest rate for storage in large cryogenic tanks is approximately $2 to $4/kg depending on electricity costs including liquefaction for liquid hydrogen and approximately less than $1/kg of additional levelized cost for salt cavern storage for large production facilities. The useful life of liquid storage tanks are estimated to be up to 30 years[31], assuming cycling or storing and releasing of hydrogen to be approximately weekly.

[27] https://www.nrel.gov/docs/fy24osti/88818.pdf
[28] https://www.sciencedirect.com/science/article/abs/pii/S2352152X21014560
[29] Fact Sheet: Underground Natural Gas Storage Caverns | PHMSA (dot.gov)
[30] https://newsreleases.sandia.gov/subterranean_hydrogen/
[31] DOE Technical Targets for Hydrogen Delivery | Department of Energy

Exhibit 38. Storage and Transport Assumptions for Hydrogen

Variable	Units	Values
2MM kg underground storage w/55 mi of pipeline & 1930 kW compressor		
Capacity	kg	2,000,000
Gas Storage Capex	$/kg	$50.13
Gas Storage w/ TIC	$	$100,251,543
Gas storage PMT (with withdrawal & injection cost)	$/MMBtu	$4.21
	$/kg	$0.48
Liquefaction		
Liquefaction levelized cost from NREL	$/kg	$3.76
	$/MMBtu	$33.17
300,000 kg cryogenic tank		
Capacity	kg	300000
Cryo tanks Capex	$	$9,464,306
Cryo tanks w/ TIC		$18,928,613
Cryo tank PMT	$/MMBtu	$0.78
	$/kg	$0.09
Liquid H2 Trucking		
Trucking Adder (Liq H2) for 100 mi	$/kg	$0.26
	$/MMBtu	$2.29

Synthetic Methane

Resource Type

ICF considered two pathways for synthetic methane production: a) biomass gasification and b) methanation of hydrogen combined with various carbon dioxide resources (we are referring to this here as power-to-gas).

Biomass Gasification

Biomass like agricultural residues, forestry and forest produce residues, and energy crops have high energy content and are ideal candidates for thermal gasification. The thermal gasification of biomass to produce RNG occurs over a series of steps. Thermal gasification typically requires some pre-processing of the feedstock. The gasification process first generates synthesis gas (or syngas), consisting of hydrogen and carbon monoxide. Biomass gasification technology has been commercialized for nearly a decade; however, the gasification process typically yields a residual tar, which can foul downstream equipment. Furthermore, the presence of tar effectively precludes the use of a commercialized methanation unit. The high cost of conditioning the syngas in the presence of these tars has limited the potential for thermal gasification of biomass. Over the last several years, however, several commercialized technologies have been deployed to increase syngas quantity and prevent the fouling of other equipment by removing the residual tar before methanation. There are a handful of technology providers in this space including Haldor Topsoe's tar reforming catalyst. Frontline Bioenergy takes a slightly different approach and has patented a process producing tar free syngas (referred to as TarFreeGas). The syngas is further upgraded via filtration (to remove remaining excess dust generated during gasification), and other purification processes to remove potential contaminants like hydrogen sulfide, and carbon dioxide. The upgraded syngas is then methanated and dried prior to pipeline injection.

ICF notes that biomass, particularly agricultural residues, are often added to anaerobic digesters to increase gas production (by improving carbon-to-nitrogen ratios, especially in animal manure digesters). It is conceivable that some of the feedstocks considered here could be used in anaerobic digesters. For the sake of simplicity, ICF did not consider any multi-feedstock applications in our assessment; however, it is important to recognize that the RNG production market will continue to include mixed feedstock processing in a manner that is cost-effective.

Exhibit 39. Biomass Resources Considered

Feedstock	Description
Agricultural Residue	Material left in the field, orchard, vineyard, or other agricultural setting after a crop has been harvested
Forestry Residue	Biomass generated from logging, forest and fire management activities, and milling. Inclusive of logging residues (e.g., bark, stems, leaves, branches), forest thinnings (e.g., removal of small trees to reduce fire danger), and mill residues (e.g., slabs, edgings, trimmings, sawdust)
Energy Crops	Inclusive of perennial grasses, trees, and some annual crops that can be grown specifically to supply large volumes of uniform, consistent quality feedstocks
MSW	The trash and various items that household, commercial, and industrial consumers throw away—including materials such as glass, construction and demolition (C&D) debris, food waste, paper and paperboard, plastics, rubber and leather, textiles, wood, and yard trimmings.

Methanated Hydrogen via P2G

Power-to-gas (P2G) is a form of energy technology that converts electricity to a gaseous fuel. Electricity is used to split water into hydrogen and oxygen, and the hydrogen can be further processed to produce methane when combined with a source of carbon dioxide. If the electricity is sourced from renewable resources, such as wind and solar, then the resulting fuels are carbon neutral. The key process in P2G is the production of hydrogen from renewably generated electricity by means of electrolysis. This is covered in More detail in Section 4.

ICF considers P2G as a synthetic methane production pathway whereby the combination of hydrogen and carbon dioxide (CO_2) yield methane. Methanation may be attractive because it avoids the cost and potential inefficiency associated with hydrogen storage and creates more flexibility in the end use through the natural gas system.

The table below summarizes the geography, hydrogen and CO_2 sources considered in the P2G analysis. ICF assumes that the hydrogen would be the limiting resources and restricted the hydrogen supply in line with constraints imposed and discussed previously in Section 4.

Exhibit 40. List of Data Sources for RNG Feedstock Inventory

Geography	Hydrogen	CO_2 source
Oregon & Washington National	Green hydrogen, solar Green hydrogen, wind Pink hydrogen	Biogenic CCS Direct air capture

Resource Potential

Biomass Gasification

ICF used a mix of existing studies, government data, and industry resources to estimate the current and future supply of the feedstocks. The table below summarizes some of the resources that ICF drew from to complete our resource assessment, broken down by feedstock.

Exhibit 41. List of Data Sources for RNG Feedstock Inventory

Feedstock for RNG	Potential Resources for Assessment
Agricultural residue	• U.S. DOE Billion Ton Report • Bioenergy Knowledge Discovery Framework
Energy crops	• U.S. DOE Billion Ton Report • Bioenergy Knowledge Discovery Framework
Forestry and forest product residue	• U.S. DOE Billion Ton Report • Bioenergy Knowledge Discovery Framework
MSW	• U.S. DOE Billion Ton Report • Waste Business Journal

This RNG feedstock inventory does not take into account resource availability—in a competitive market, resource availability is a function of factors, including but not limited to demand, feedstock costs, technological development, and the policies in place that might support RNG project development. ICF assessed the RNG resource potential of the different feedstocks that could be realized given the necessary market considerations.

Similar to feedstocks used to produce RNG (Section 3), ICF assumed that the Utilities would have "first-mover access" to synthetic methane produced via biomass gasification from domestic resources. ICF used the same approach here: we reviewed states that have robust policy frameworks in place to advance RNG (with the understanding that synthetic methane produced via biomass gasification would generally be defined as RNG) deployment in the state (but not necessarily exclusively within their state) and assumed that NW Natural, Avista Utilities, and Cascade Natural Gas Corporation would have a population-weighted share of first-mover access to national resources. ICF also included British Columbia and Quebec in our consideration of first movers because these two Canadian provinces have robust RNG policies in place and have already procured significant amounts of US-based RNG. ICF's assumption regarding first mover access yields a result whereby the Utilities will likely be able to access up to about 13% of the total domestic RNG production, which about 3.5-4 times greater than the simple population-weighted share that one might otherwise assume.

Agricultural Residue

Agricultural residues include the material left in the field, orchard, vineyard, or other agricultural setting after a crop has been harvested. More specifically, this resource is inclusive of the unusable portion of crop, stalks, stems, leaves, branches, and seed pods. Agricultural residues (and sometimes crops) are often added to anaerobic digesters

ICF extracted information from the U.S. DOE Bioenergy KDF including the following agricultural residues: wheat straw, corn stover, sorghum stubble, oats straw, barley straw, citrus residues, noncitrus residues, tree nut residues, sugarcane trash, cotton gin trash, cotton residue, rice hulls, sugarcane bagasse, and rice straw. The table below lists the energy content on a high heating value (HHV) basis for the various agricultural residues included in the analysis—these are based on values reported by the California Biomass Collaborative. To estimate the RNG production potential, ICF assumed a 65% efficiency for thermal gasification systems.

Exhibit 42. Heating Values for Agricultural Residues

Component	Btu/lb, dry	MMBtu/ton, dry
Wheat straw	7,527	15.054
Corn stover	7,587	15.174
Sorghum stubble	6,620	13.24
Oats straw	7,308	14.616
Barley straw	7,441	14.882
Citrus residues	8,597	17.194
Noncitrus residues	7,738	15.476
Tree nut residues	8,597	17.194
Sugarcane trash	7,738	15.476
Cotton gin trash	7,058	14.116
Cotton residue	7,849	15.698
Rice hulls	6,998	13.996
Sugarcane bagasse	7,738	15.476
Rice straw	6,998	13.996

Forestry and Forest Product Residues

Biomass generated from logging, forest and fire management activities, and milling. Inclusive of logging residues (e.g., bark, stems, leaves, branches), forest thinnings (e.g., removal of small trees to reduce fire danger), and mill residues (e.g., slabs, edgings, trimmings, sawdust) are considered in the analysis. This includes materials from public forestlands (e.g., state, federal), but not specially designated forests (e.g., roadless areas, national parks, wilderness areas) and includes sustainable harvesting criteria as described in the U.S. DOE Billion-Ton Study, including:

- Alterations to the biomass retention levels by slope class (e.g., slopes with between 40% and 80% grade included 40% biomass left on-site, compared to the standard 30%).
- Removal of reserved (e.g., wild and scenic rivers, wilderness areas, USFS special interest areas, national parks) and roadless designated forestlands, forests on steep slopes and in wet land areas (e.g., stream management zones), and sites requiring cable systems.

- The assumptions only include thinnings for over-stocked stands and didn't include removals greater than the anticipated forest growth in a state.
- No road building greater than 0.5 miles.

These sustainability criteria provide a robust assessment of available forestland. ICF extracted information from the U.S. DOE Bioenergy KDF, which includes information on forest residues such as thinnings, mill residues, and different residues from woods (e.g., mixedwood, hardwood, and softwood). The table below lists the energy content on a HHV basis for the various forest and forest product residue elements considered in the analysis. To estimate the RNG production potential, ICF assumed a 65% efficiency for thermal gasification systems.

Energy Crops

Energy crops are inclusive of perennial grasses, trees, and some annual crops that can be grown specifically to supply large volumes of uniform, consistent quality feedstocks for energy production. ICF extracted data from the Bioenergy KDF. The table below lists the energy content on a HHV basis for the various energy crops included in the analysis. To estimate the RNG production potential, ICF assumed a 65% efficiency for thermal gasification systems.

Exhibit 43. Heating Values for Energy Crops

Energy Crop	Btu/lb, dry	MMBtu/ton, dry
Willow	8,550	17.10
Poplar	7,775	15.55
Switchgrass	7,929	15.86
Miscanthus	7,900	15.80
Biomass sorghum	7,240	14.48
Pine	6,210	12.42
Eucalyptus	6,185	12.37
Energy cane	7,900	15.80

Municipal Solid Waste

Municipal solid waste (MSW) represents the trash and various items that household, commercial, and industrial consumers throw away—including materials such as glass, construction and demolition (C&D) debris, food waste, paper and paperboard, plastics, rubber and leather, textiles, wood, and yard trimmings. About 25% of MSW is currently recycled, 9% is composted, and 13% is combusted for energy recovery. And the roughly 50% balance of MSW is landfilled.

ICF limited our consideration to the potential for utilizing MSW that would otherwise be landfilled as a feedstock for thermal gasification; this excludes MSW that is recycled or directed to waste-to-energy facilities. ICF also excluded food waste from consideration, as that is covered separately as a feedstock for RNG production. ICF extracted information from the U.S. DOE Bioenergy KDF, which includes information collected as part of U.S. DOE's Billion-Ton Study. ICF only considered the waste residues that were biogenic in origin e.g., paper and paperboard, leather, textiles, wood, and yard trimmings.

Methanated Hydrogen via P2G

As noted previously, the resource potential for synthetic methane was assumed to be constrained based on the hydrogen availability for each geography (Oregon and Washington and the United States). These constraints are discussed in Section 4.2.2.

Synthetic Methane Resource Potential Projection

The following figures summarize the maximum synthetic methane potential for biomass gasification and via power-to-gas in OR and WA and at the national level. Note that the volumes shown for the national resource in both instances are scaled in the same manner as described previously as it relates to RNG: we assumed first mover access yielding a result whereby the Utilities will likely be able to access up to about 13% of the total domestic RNG production.

Exhibit 44. Synthetic Methane via Biomass Gasification Resource Potential Projection (OR & WA and National)

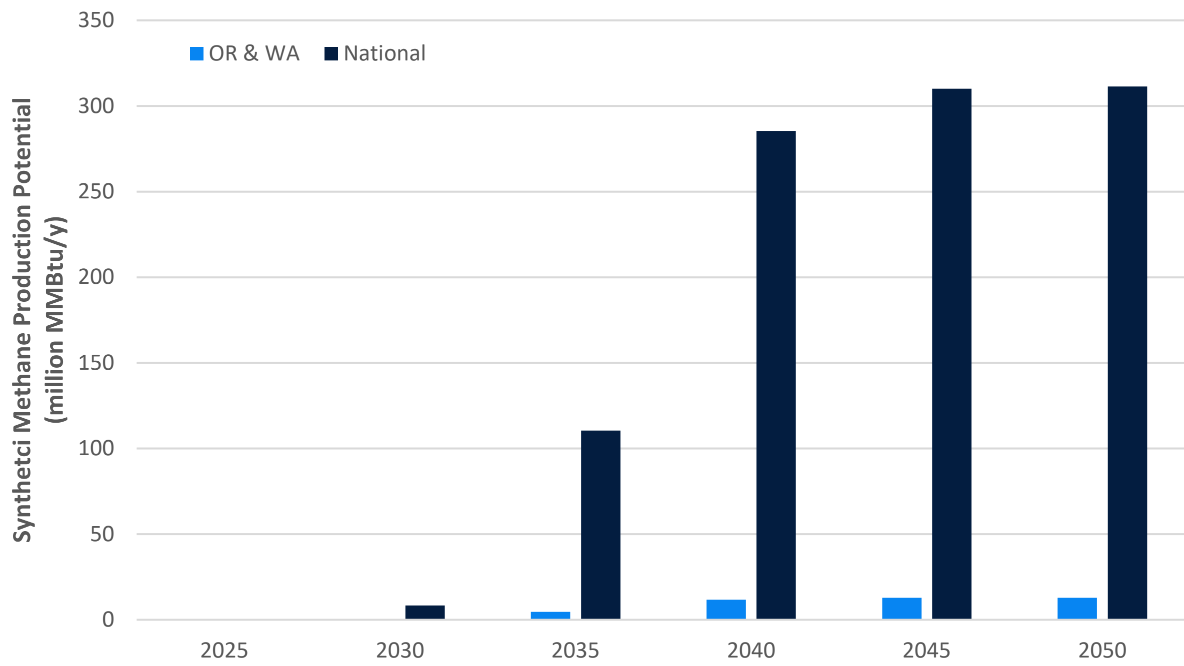


Exhibit 45. Synthetic Methane via P2G Resource Potential Projection (OR & WA, million MMBtu/y)

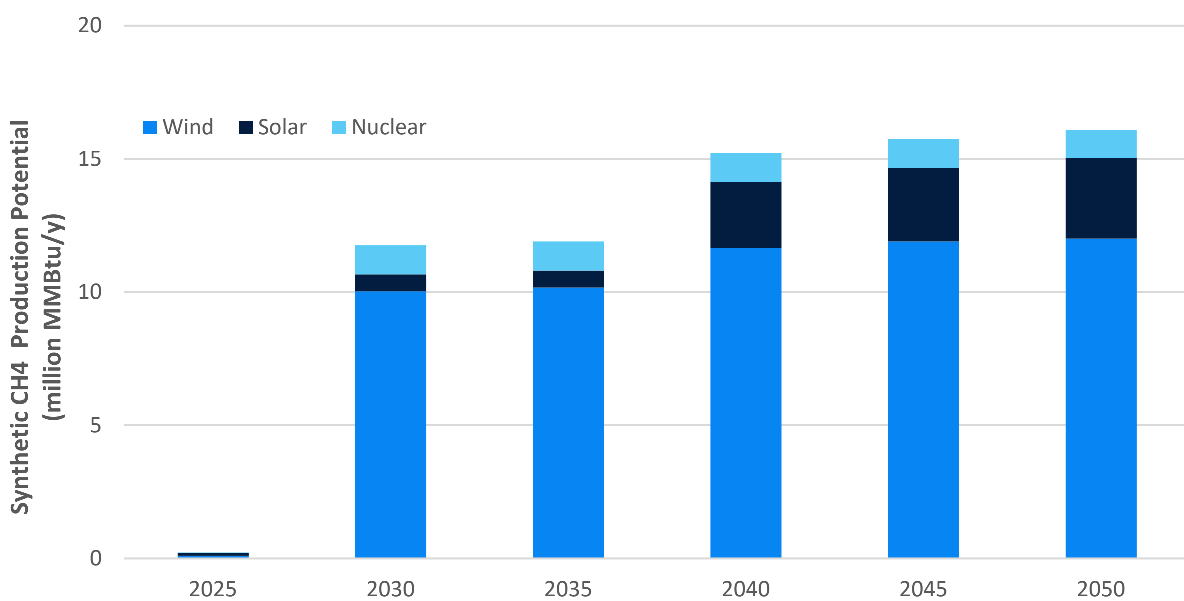
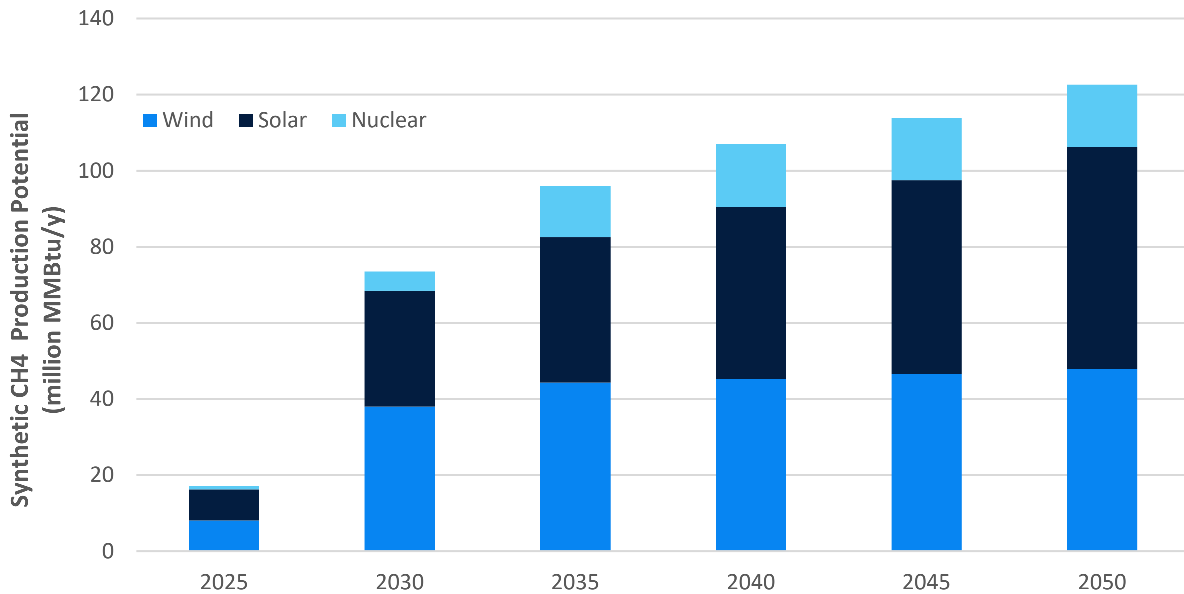


Exhibit 46. Synthetic Methane via P2G Resource Potential Projection (National, million MMBtu/y)



Synthetic Methane Levelized Cost

The LCOE for synthetic methane draws from similar data sources as those used in Section 3 and Section 4 for RNG and hydrogen, respectively. Exhibit 47 below outlines some of the incremental costs of synthetic methane production from either hydrogen produced via electrolysis or via biomass gasification. Note that the table excludes the baseline costs of hydrogen production via electrolysis (i.e., green and pink hydrogen) because that is discussed in Section 4.

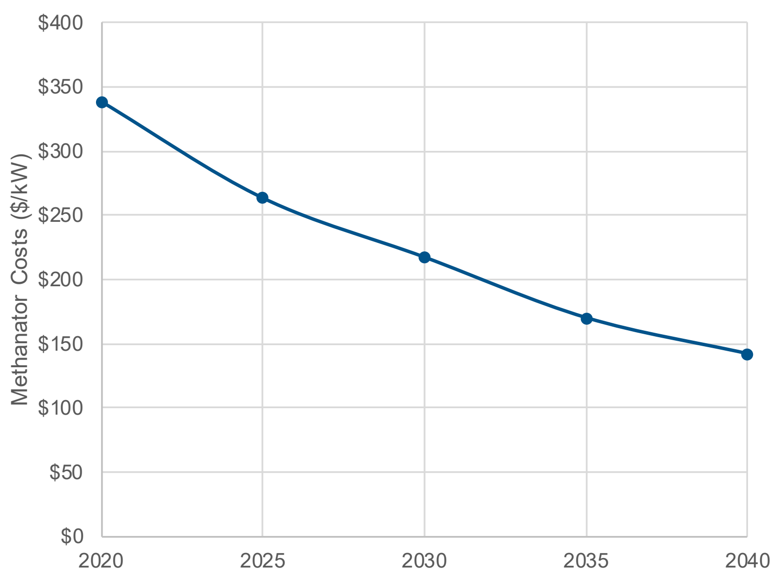
Exhibit 47. ICF Synthetic Methane Assumptions

Cost Parameter	ICF Cost Assumptions
Capital Costs	
Facility Sizing	• Differentiate by syngas feedstock e.g., hydrogen via electrolysis vs thermal gasification of biomass • Prioritize larger facilities to the extent feasible but driven by resource estimate.
Hydrogen storage	• Will vary depending on optimized configuration after considering CO_2 availability
CO_2 source	• Need a CO_2 source and may require a separation unit for purity
CO_2 storage	• Will vary depending on optimized configuration after considering H_2 availability
Compression	• Compression required for CO_2 prior to methanation
Methanation	• Capital costs for methanation equipment
Gas Conditioning and Upgrade	• As needed for syngas prior to methanation

Cost Parameter	ICF Cost Assumptions
O&M Costs	
Operational Costs	• Fixed opex costs: Costs for each equipment type for either methanation after electrolysis or biomass gasification to ensure operational readiness e.g., methanation, storage • Variable opex costs: Includes utility costs for electricity and gas purchases as necessary for electrolysis, methanation, and balance of plant
Feedstock	• Water costs • CO_2 costs for methanation after electrolysis • Feedstock costs for biomass gasification
Delivery	• Operating an interconnect or delivery to utility pipeline injection
Levelized Cost of Gas	
Project Lifetimes	• Calculated based on the initial capital costs in Year 1, annual operational costs discounted, and synthetic methane production discounted accordingly over a 20-year project lifetime, for example.

The potential for decreasing cost of methanation technology consistent with the figure below, presented in units of $/kW.

Exhibit 48. Projected Methanation Cost Reductions ($/kW)



Biomass Gasification

The following figures and tables summarize the LCOE for the thermal gasification of biomass in OR and WA and at the national level. ICF assumed the investment tax credit (ITC) for RNG production (via the Qualified Biogas Property provisions) is available and extended through 2030 for biomass gasification.

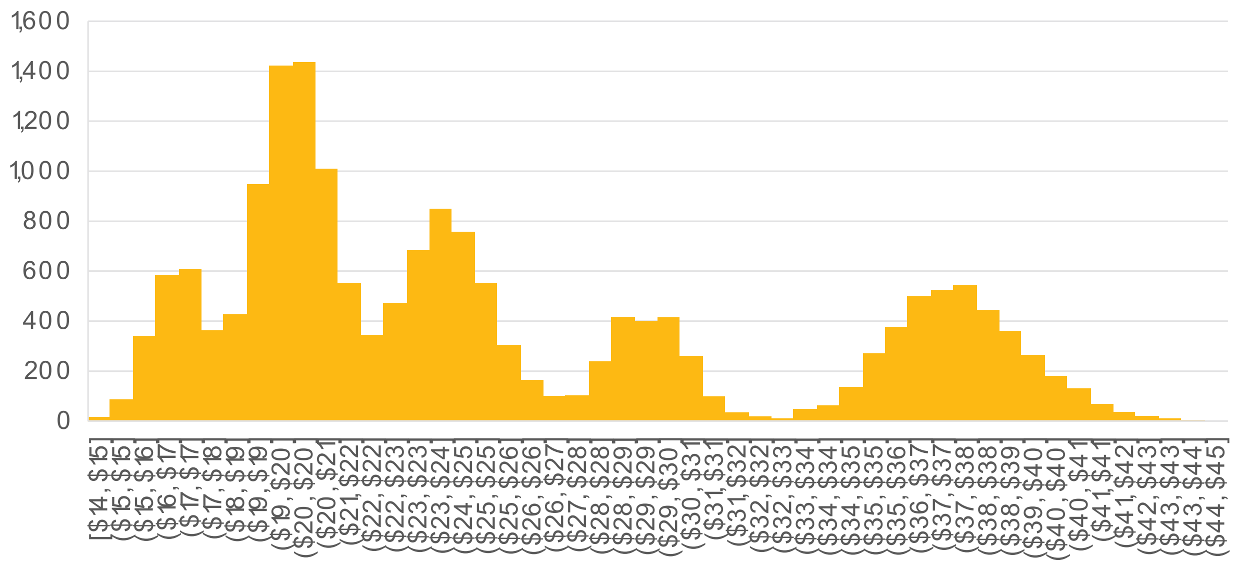
Exhibit 49. Synthetic CH4 from Biomass Levelized Cost Projection Base Case Results ($/MMBtu)

SynCH4 Feedstock	2030	2050
Biomass, NW and National	$17-$44	$22-$57

ICF notes that we observe a difference of less than 5% between the NW and National estimates for the levelized cost of synthetic methane via biomass gasification.

The impact of the Monte Carlo process on costs for synthetic methane from biomass gasification in Oregon and Washington and nationally are shown in the figures below for 2030 and 2050, respectively. The histograms depict the number of the 1,000 Monte Carlo cases (y-axis) that fall within various cost ranges/technical potential ranges (x-axis) for synthetic methane from biomass gasification for Oregon and Washington and the United States.

Exhibit 50. Summary of Monte Carlo Simulation Results for Synthetic CH_4 from Biomass (2030)



Methanated Hydrogen via P2G

The following figures and tables summarize the maximum RNG LCOE for each feedstock and production technology in OR and WA and at the national level. ICF assumed the investment tax credit (ITC) for RNG production (via the Qualified Biogas Property provisions) is available and extended through 2030.

Exhibit 51. Synthetic Methane paired with P2G Levelized Cost Projection Base Case Results (Oregon and Washington, $/MMBtu)

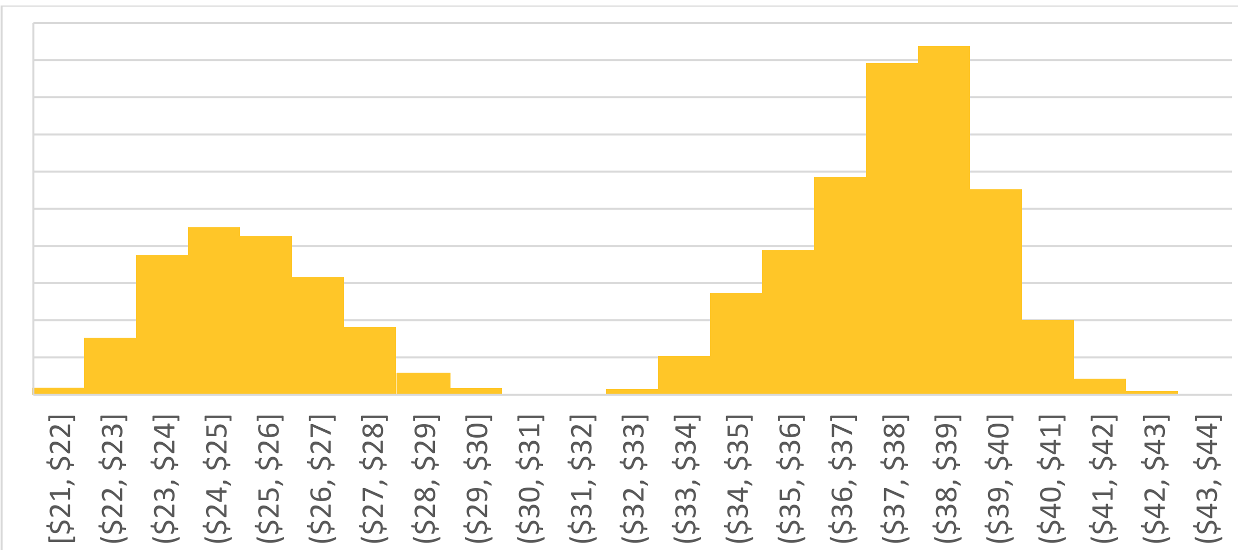
Electricity Source for P2G (NW)	2030	2050
Wind	$34-$46	$55-84
Solar	$29-$40	$44-61
Nuclear	$35-$42	$59-$77

Exhibit 52. Synthetic Methane paired with P2G Levelized Cost Projection Base Case Results (National, $/MMBtu)

Electricity Source for P2G (National)	2030	2050
Wind	$31-$43	$54-$81
Solar	$21-$30	$45-63
Nuclear	$35-$43	$58-$77

The impact of the Monte Carlo process on costs for synthetic methane produced from green and pink hydrogen and various CO_2 sources in Oregon and Washington and nationally are shown in the figures below for 2030 and 2050, respectively. The histograms depict the number of the 1,000 Monte Carlo cases (y-axis) that fall within various cost ranges/technical potential ranges (x-axis) for synthetic methane produced from green and pink hydrogen and various CO_2 sources from each of the feedstocks considered for Oregon and Washington and the United States.

Exhibit 53. Summary of Monte Carlo Simulation Results for Synthetic CH4 from Methanation of Hydrogen (2030)

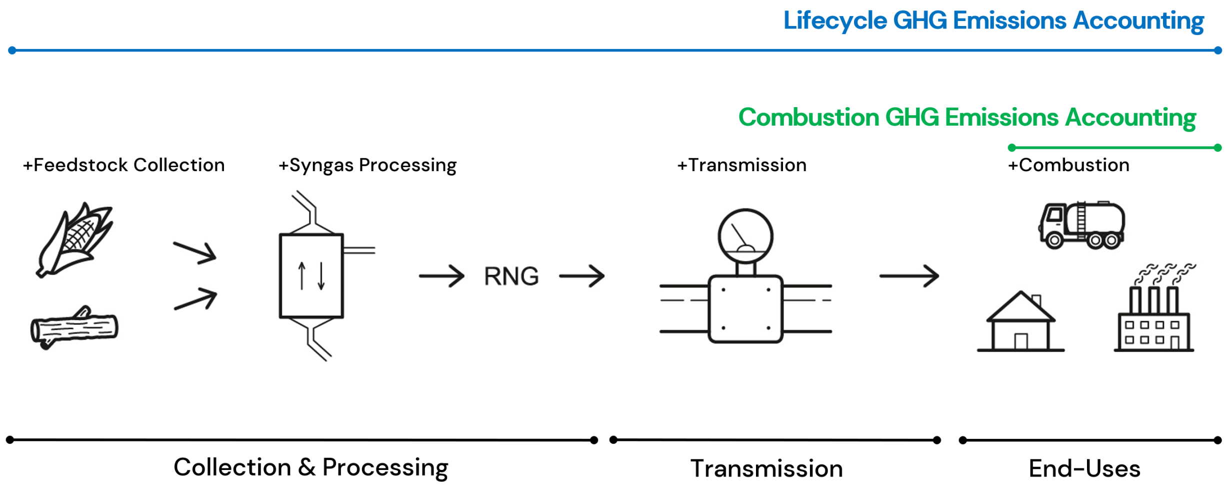


ICF found that the cost of CO_2 would be a marginal contributor to the overall cost of the system, and that it would be available at a low cost (e.g., less than $50 per ton).

Synthetic Methane GHG Life Cycle Emissions

ICF evaluated CIs from the synthetic methane feedstocks discussed in this section, using the same approach outlined previously in Section 3. Synthetic methane production from biogenic sources requires a series of steps (see figure below): collection of a feedstock, delivery to a processing facility for biomass-to-gas conversion, gas conditioning, compression and injection into the pipeline and combustion at the end use.

Exhibit 54. LCA Boundary for Synthetic Methane via Biomass Gasification



The table below summarizes the GHG life cycle emissions for synthetic methane production in OR and WA and at the national level for biomass gasification. ICF notes that the CI values for biomass differ slightly between the regional estimate and the national estimate based on changes in the carbon intensity of electricity. over time in the analysis as a function of assumptions around decreases in a) the carbon intensity of electricity tied to deployment of renewable energy and b) slight reductions in the carbon intensity of gas extraction and distribution.

Exhibit 55. RNG Carbon Intensity Projection Base Case Results (kgCO_2e/ MMBtu)

Synthetic Methane Pathway	OR & WA	National
Biomass Gasification	35-37	39-50
Methanated Hydrogen	3.4 – 7.7	

Renewable Thermal Certificates

The U.S. lacks a national certification program for the environmental attributes of low-carbon fuels considered in ICF's analysis. While some renewable fuel certification programs exist, such as the Green-e Renewable Fuels program, they are limited in scope and insufficient for broad market participation. M-RETS[32] offers a North American tracking system for renewable thermal credits or certificates (RTCs) that can—and does—support the work of certification schemes like Green-e Renewable Fuels Programs. Today there are about 75-80 RNG facilities registered as RTC generators with M-RETS, with most generators reporting from landfills; there is a single RTC generator listed that produces an RTC via hydrogen.

M-RETS facilitates RTC markets by issuing a unique, traceable digital certificate (i.e., one RTC) for every dekatherm ("dth") of verified renewable energy recorded on the platform. The M-RETS platform provides more than just the ability to track RNG volumes. M-RETS provides for—but does not require—the ability to track carbon pathways and CI values with documentation associated with each certificate. Once issued, M-RETS users can choose to transfer (buy/sell), retire, import, or export RECs or RTCs. M-RETS users can retire certificates either to comply with state mandates and/or to fulfill their voluntary commitments, while preventing the risk of double counting. M-RETS registers projects in all U.S. states and Canadian provinces and will support imports and exports with any registry in North America that meets its specific security and operational requirements specific to the risk of double counting.

M-RETS RTC platform launched January 1, 2020, and shortly thereafter issued the first certificates. This first-of-its-kind system saw the first ever public sale and claim by a Fortune 50 corporate client not too long after.[33] In 2020, Oregon established the first program that required the use of M-RETS through Senate Bill 98, under which the Oregon Public Utilities Commission adopted the M-RETS RTC platform as a compliance tool. California adopted M-RETS as the recognized compliance tool for implementing Senate Bill 1440 thereafter.[34] The California Public Utilities Commission now requires, "biomethane producers to track injections into the pipelines through the M-RETS platform" as part of Senate Bill 1440 compliance.[35] The applications for the M-RETS RTC registry continue to grow. In 2022, both Oregon and Washington adopted the use of M-RETS to track RNG under their respective state clean fuel programs.

Despite progress made by M-RETS and the increased acceptance of RTCs as a market-based mechanism to acquire the environmental attributes of low-carbon fuels like RNG, the market lacks liquidity, with lack of transparency on pricing and volumes. However, ICF conversations with stakeholders indicates that pricing to date has used environmental commodity pricing from the federal Renewable Fuel Standard (RFS) as a benchmark for contract pricing. Under the RFS, RNG from most feedstocks is designated as a Cellulosic Biofuel and is designated as a D3 RIN (where RIN is a Renewable Identification Number). RTC pricing has reportedly traded at a discount to the D3 RIN price—a price that is reported by various data sources such as OPIS, Argus, and is also reported publicly by the EPA (albeit with a lag).

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[32] M-RETs is a nonprofit organization governed by an independent and multi-jurisdictional board of directors.
[33] *U.S. Gain First to Provide RNG Through New M-RETS RTC Platform*, CSRWire, January 30, 2020, https://www.csrwire.com/press_releases/43478-u-s-gain-first-to-provide-rng-through-new-m-rets-rtc-platform, *ACT Commodities and Bluesource complete first renewable thermal transaction using state-of-the-art tracking tool*, M-RETS, February 8, 2021, https://www.mrets.org/act-commodities-and-bluesource-complete-first-renewable-thermal-transaction-using-state-of-the-art-tracking-tool/.
[34] CPUC Decisions No. 22-02-025 (*see* pg. 50 of the decision).
[35] Order Instituting Rulemaking to Adopt Biomethane Standards and Requirements, Pipeline Open Access Rules, and Related Enforcement Provisions, Decision Implementing Senate Bill 1440 Biomethane Procurement Program (2022), Cal. P.U.C. Dec. No. 22-02-025 (*see* pg. 50 of the decision).

Based on information available today, ICF used a forecasting approach for the federal RFS market in a Reference Case and Downside Case to provide a range of pricing that is indicative of RTC pricing over the term of the analysis (out to 2050). ICF did not explicitly characterize RTC volumes in the analysis; however, ICF has indicated that the upper limit of RTCs would be linked to the RNG (inclusive of the synthetic methane from biomass gasification and from methanated hydrogen via P2G) that was not incorporated into the supply stacks outlined in Section 3 and Section 5, respectively.

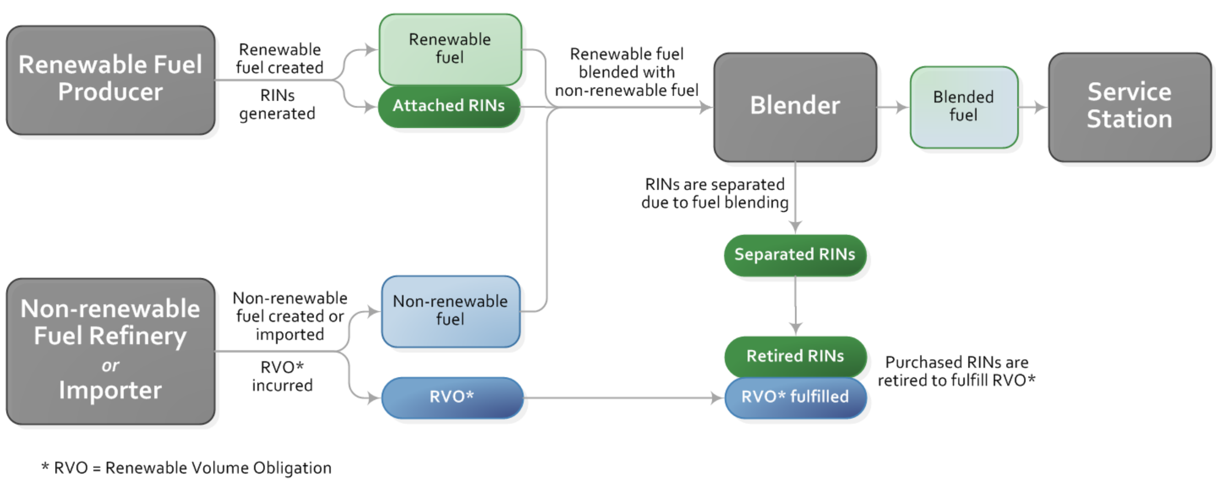
Overview of ICF Approach to RIN Forecasting

Introduction to the Federal RFS

The RFS mandates biofuel volumes that must be blended into transportation fuel each year. Specifically, the policy mandates that producers of petroleum fuel products and blenders add renewable fuels into their pool every year. The program was developed as part of the Energy Policy Act (EPAct) of 2005 and revised and updated by the Energy Independence and Security Act (EISA) in 2007. From 2006 to 2022, mandates were codified in legislation. Now the EPA, the program administrator, determines the volume targets.

Every eligible gallon of renewable fuel is given a Renewable Identification Number or RIN. Among other things, the RIN identifies who made the fuel, when it was made, and what type of fuel it is. The RINs can be sold along with the fuel or "separated" and sold to an obligated party (e.g., a petroleum refinery) separately. Typically, the RIN is sold with the volume of fuel to a blender who then sells the blended fuel to fuel outlets (e.g., retail gasoline stations). The blender then sells the "separated RIN" back to the refinery. A diagram is shown in the figure below.

Exhibit 56. Illustrative Flow of RIN Generation and Retirement



Changes to the program in the EISA created four nested categories, as shown in the table below: renewable biofuels, advanced biofuels, biomass-based diesel, and cellulosic biofuels. Each category has its own volume requirement and RIN type. RINs are the currency of the RFS program and are represented by a 38-digit code representing an ethanol gallon equivalent of fuel. Each category includes a threshold of life cycle GHG emission savings compared to petroleum products (i.e., gasoline and diesel).

Exhibit 57. Nested Categories of Renewable Fuels in the RFS Program

RIN Type	Description / Biofuel	Min GHG Reductions	RFS Qualifying Categories
D3	Cellulosic Biofuel	60% GHG savings	Cellulosic, Advanced or Renewable

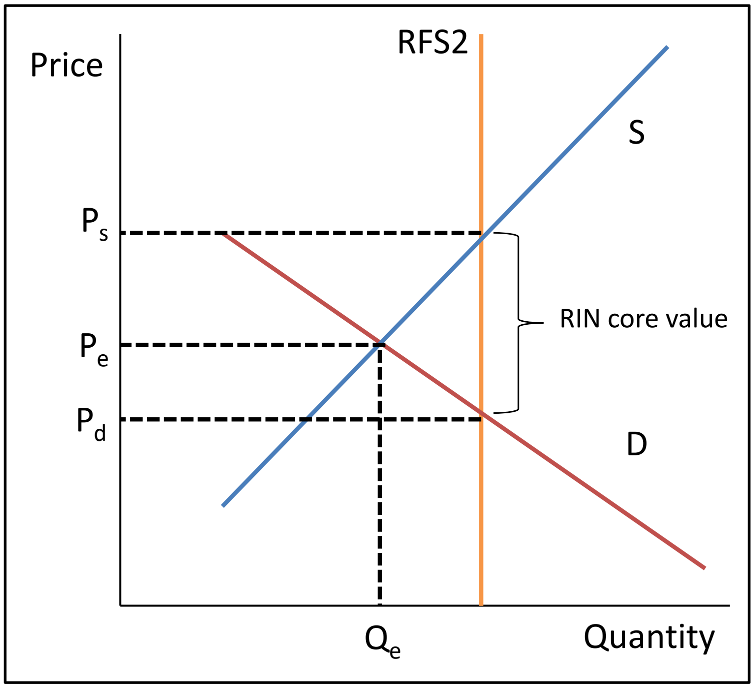
RIN Type	Description / Biofuel	Min GHG Reductions	RFS Qualifying Categories
D4	Biomass-Based Diesel	50% GHG savings	Biomass-Based Diesel, Advanced or Renewable Diesel
D5	Advanced Biofuel	50% GHG savings	Advanced or Renewable
D6	Renewable Fuel	20% GHG savings	Renewable (Corn-Based Ethanol)
D7	Cellulosic Diesel	60% GHG savings	Cellulosic or Advanced, Biomass-Based Diesel, or Renewable

The nested nature of the biofuel categories in RFS means that any renewable fuel that meets the requirement for cellulosic biofuels or biomass-based diesel is also valid to satisfy the advanced biofuels requirement. In other words, if any combination of cellulosic biofuels or biomass-based diesel exceeded the sub-mandates, the additional supply/volume would count towards the advanced biofuels mandate, thereby reducing the potential need for fuels (e.g., imported sugarcane ethanol) to meet the unspecified portion of the advanced biofuels mandate. Note that D3 RINs, however, are not eligible to satisfy D4 obligations.

RIN Price Modeling

The core value of a RIN is determined based on the price-supply relationship and price-demand relationship for each category of biofuel. Referring to the figure below, as you move along the supply curve (blue line), producers can charge a higher price, and supply increases. As we move along the demand curve (red line), higher prices lead to lower demand. At the point where the supply matches demand (P_e), the system is in balance and has achieved an equilibrium price with equilibrium volume (“Q_e”). The RFS mandate, however, assumes that the equilibrium price does not yield a sufficient volume of biofuels, and thereby artificially shifts demand to the right. As demand is shifted the supply price (“P_s”) and demand price (“P_d”) are no longer in equilibrium. The difference between these two prices, created as a result of the mandate, leads to the determination of the core or intrinsic RIN value.

Exhibit 58. Determining Intrinsic RIN Value

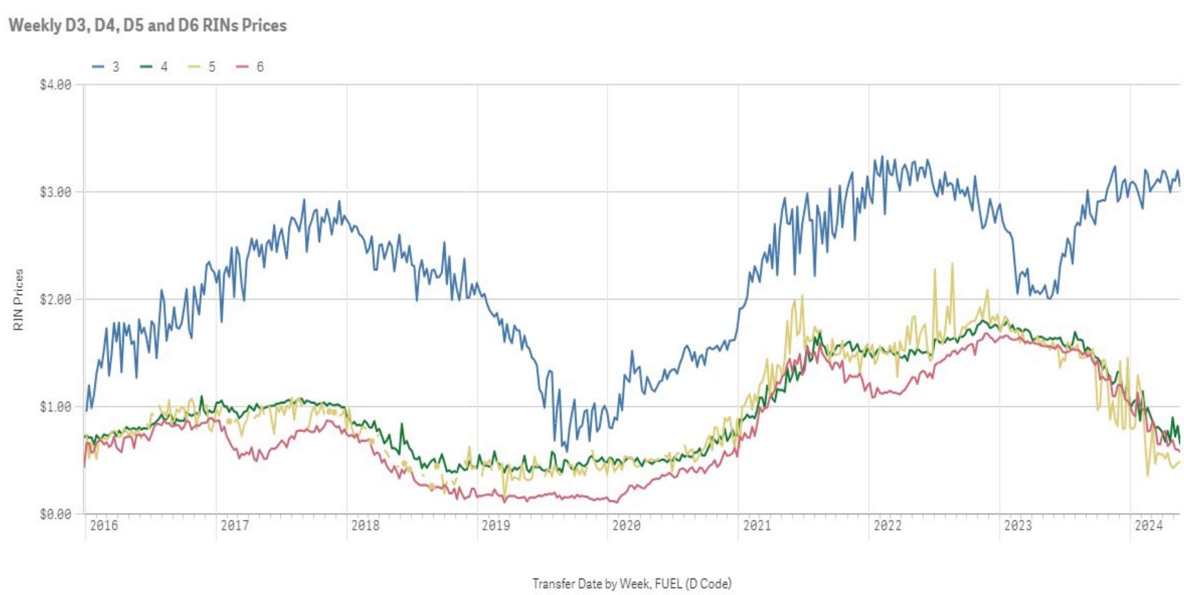


Source: Figured adjusted from McPhail, Westcott, & Lutman (2011)

This core valuation, however, does not capture market impacts like traders seeking arbitrage opportunities (e.g., importing sugarcane ethanol at a price advantage) or constraints like physical blend walls, which limit the quantity of fuel that can be taken up into the market. These types of phenomena lead to volatility and can run up the price in the RIN markets. Our modeling considers these phenomena to the extent feasible but predicting these types of spikes requires access to a large amount of privileged data/information.

The figure below shown below summarizes historical RIN prices across the different RIN types from 2016 to mid-2024.

Exhibit 59. Historical D3, D4, D5 and D6 RIN Pricing (nominal), 2016 to mid-2024



There are several components to ICF's RIN modeling. More specifically, we forecast wholesale gasoline and diesel pricing, we utilize third-party forecasts for feedstocks that are used to produce biomass-based diesel and then forecast D4 RIN and D5 RIN pricing based on different market assumptions. Lastly, we use these variables as inputs into our D3 RIN forecast.

***Wholesale petroleum product pricing*.** ICF uses an internal WTI forecast that reflects the long-term marginal cost of oil extraction, with short-term adjustments based on NYMEX futures and the Short-Term Energy Outlook ("STEO") published by the EIA. We use historical crack spreads for gasoline and diesel pricing forecasts, with near-term adjustments made based on market observations.

Soybean oil pricing. Soybean oil is the primary feedstock used for biomass-based diesel production—including biodiesel and renewable diesel. We use renewable oil feedstock (e.g., soybean oil) pricing provided by Euromoney Global Limited, d/b/a Fastmarkets, The Jacobsen ("Jacobsen"). The information provided by The Jacobsen is cross-referenced to other publicly available resources for consistency of market sentiment. Soybean oil is a primary input into the biodiesel and renewable diesel production process, and other fats and oils are often indexed to soybean oil pricing.

Corn Pricing*.* Corn is the primary feedstock used for ethanol production. We use corn pricing from the USDA for our ethanol production costs.

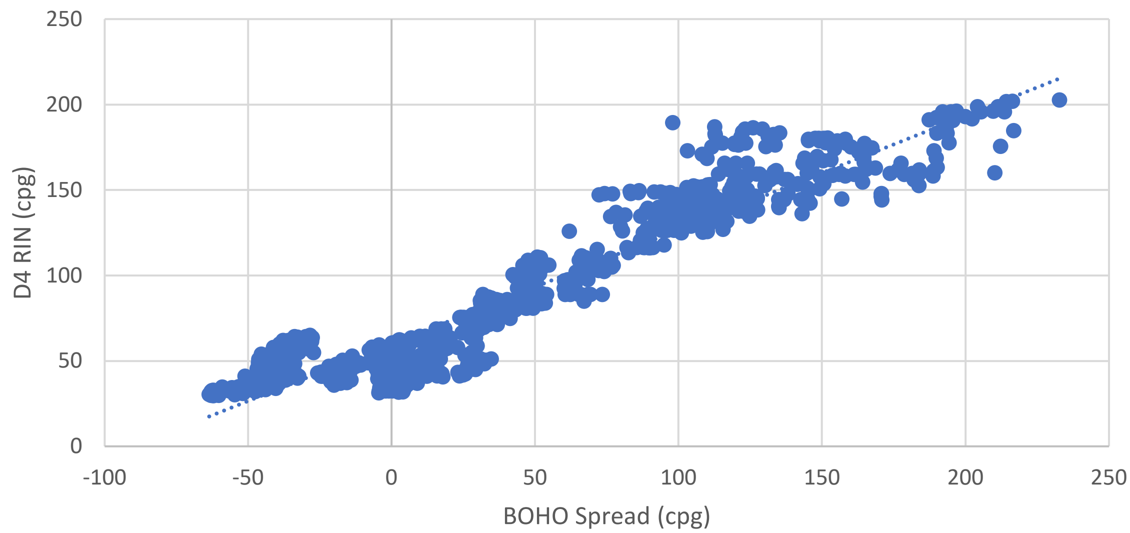
D6 RIN pricing. ICF models the D6 RIN price assuming the EPA sets the Renewable Fuels RVOs at 15 billion gallons. This volume is expected to remain well above the blend wall. We do not model increasing gasoline demand; rather, we model decreasing gasoline demand domestically due to increased efficiency (or improved fuel economy) for internal combustion engine vehicles and increased sales of electric vehicles. Decreasing gasoline demand yields a persistent gap (on the order of 1 billion gallons) between demand and required supply at the 15 billion gallon level. This modeled gap continues to keep D6 RINs tightly linked to D4-D5 RIN pricing, as the market looks to D4 RINs and/or D5 RINs to close the compliance gap at the margin and support D6 RIN pricing well above the perceived floor value of ethanol as an oxygenator (which is somewhere around 10 cpg).

Ethanol has inherent value as an oxygenator due to the Clean Air Act of 1990 which specified a certain amount of oxygen be added to gasoline. Because of this, we expect E10 blends to persist regardless of D6 RIN prices. If the EPA were to set RVOs at or below the E10 "blend wall", little or no incentive would be required to bring these fuels to market. However, in this case, we believe the D6 RIN would retain some value. Historically the value of ethanol as an oxygenator has been in the range of 10-15 cpg. During compliance years 2011-2012, this price dynamic persisted as ethanol blend rate growth outpaced the blend rates implied by the RVOs. We consider this to be a lower bound for the D6 RIN price.

***D4 RIN pricing*.** We model D4 RIN pricing by assuming that the marginal unit of compliance is achieved by blending biodiesel into the market. We consider biodiesel the marginal producer due to the amount of biodiesel sold into non-LCFS markets. This requires marginal biodiesel producers to recover more costs from the RFS program compared to other fuels (e.g., renewable diesel, which is almost entirely consumed in California), ultimately driving the RIN price.

D4 RIN prices generally find support from a historical market-based correlation with the bean oil-heating oil ("BOHO") spread. More specifically, elevated biodiesel production economics, as measured by the BOHO spread, drives the need for higher D4 RIN pricing to incentivize blending more expensive biomass-based biodiesel into conventional diesel. With respect to D4 RIN pricing, we assume that ULSD blended with biodiesel and unblended ULSD are effectively perfect substitutes, after adjusting for biodiesel's lower energy content (about 93% the energy content of ULSD). Because biodiesel is more expensive than ULSD, it would not enter the market were it not for D4 RIN prices (and other subsidies e.g., the BTC). We use the BOHO spread as a first-order approximation of the D4 RIN, after accounting for the "expectation" of the BTC subsidy. The graph below shows the base model of the D4 RIN weekly average price versus the BOHO spread.

Exhibit 60. D4 RIN Pricing vs. BOHO Spread



Our D4 RIN forecasting also includes current BTC and IRA considerations, including the retroactive extension of the BTC to eligible producers and the creation of the section 45Z Clean Fuels Production Tax Credit ("CFPC"). These tax credits contribute to the renewable fuel value stack and place downward pressure on RIN prices. Because the CFPC is carbon intensity dependent, we assume that marginal producers will have a CI of 35 $kgCO_2e$/MMBtu which results in about $0.30/gallon in value.

D5 RIN pricing. We assume that D5 RIN pricing is at parity with D4 RIN pricing. In other words, we assume that biodiesel from soybean oil is the marginal unit of compliance used to satisfy the D5 RIN obligations.

CWC Pricing. The CWC is calculated based on the formula in the regulation, which is the greater of $0.25 or $3.00 minus $P_{gasoline}$, where $P_{gasoline}$ is the average wholesale price of gasoline ("RBOB"). Both constants in the formula, $0.25 and $3.00, are adjusted for inflation from January 2009 (per the regulation) to June of the year in question.

D3 RIN pricing. Historically, D3 RIN pricing has tracked closely to the sum of the D5 RIN and the value of the Cellulosic Waiver Credit (CWC). However, EPA opted not to use its waiver authority during the promulgation of the Set Rule in 2023, which saw EPA set RVOs for 2023, 2024, and 2025. EPA posited that they could not use the waiver authority and set authority coincidentally. The EPA, however, explicitly noted that they retain their waiver authority.

In the absence of the CWC, we assume that the D3 RIN price will be set by market fundamentals i.e., that the D3 RIN price will be set by a marginal producer that looks to the D3 RIN value to cover production costs and make a rate of return.

The difficulty with using a supply and demand model to forecast the D3 RIN price is twofold:

- RNG supply to the transportation market (for RIN generation) is opaque because the fuel can be sold into multiple end use markets. It is possible that an RNG producer selling into the transportation market in year X may sell into a different market in year X+1. As a result, the RNG supply curve is more nuanced than in previous years and increases uncertainty in our modeling.
- Calculating production costs for specific RNG facilities is challenging. For fuels like ethanol and renewable diesel, feedstock costs represent such a large percentage of production costs that they are a good indicator of current and future production economics. RNG production costs, however, are tied to bespoke operating conditions and varying capital expenditures and their associated financing assumptions. This makes it difficult

to estimate the costs of RNG volumes coming into the transportation market, and the corresponding subsidy (e.g., the D3 RIN price) required for market clearance.

ICF currently uses the sum of our forecasted D5 RIN price and calculated CWC value as an indicator for D3 RIN price forecasts. We often use a market-based discount factor, represented in our modeling as alpha.

RIN Banking Dynamics. The regulation allows for a maximum 20% carryover of RINs from one year to the next, which means that a maximum of 20% of a regulated party's obligation in year X+1 can be met using RINs with vintage year X. We assumed that the 20% carryover of RINs is unchanged over the term of our modeling.

ICF RIN Price Outlook

ICF's RIN pricing outlook for D5 RINs (blue line) and D3 RINs (yellow line) is shown in the figures below for the Reference Case and Downside Case.

Exhibit 61. ICF's RIN Price Forecast, Reference Case (nominal dollars)

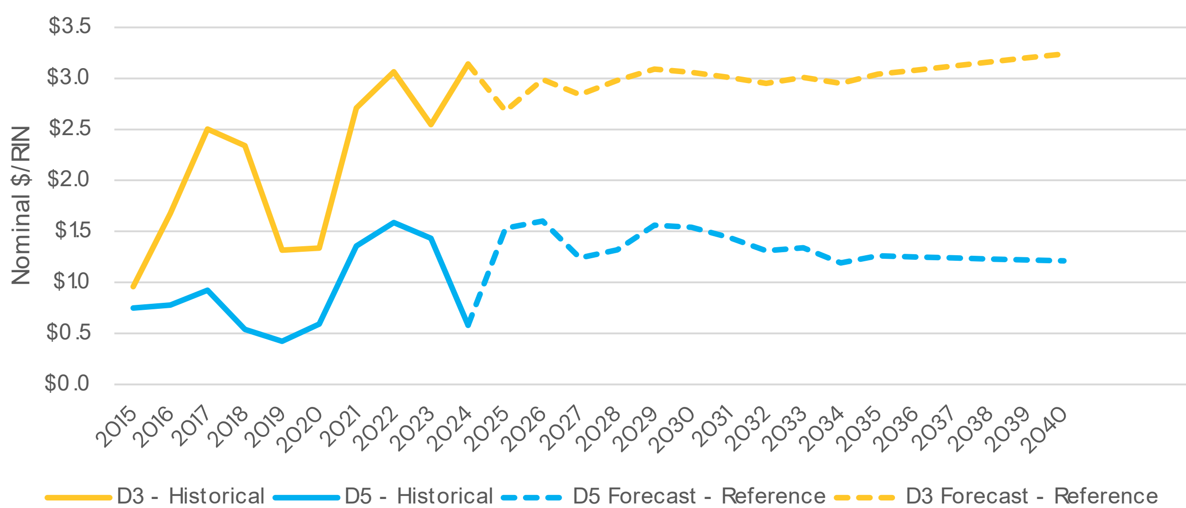
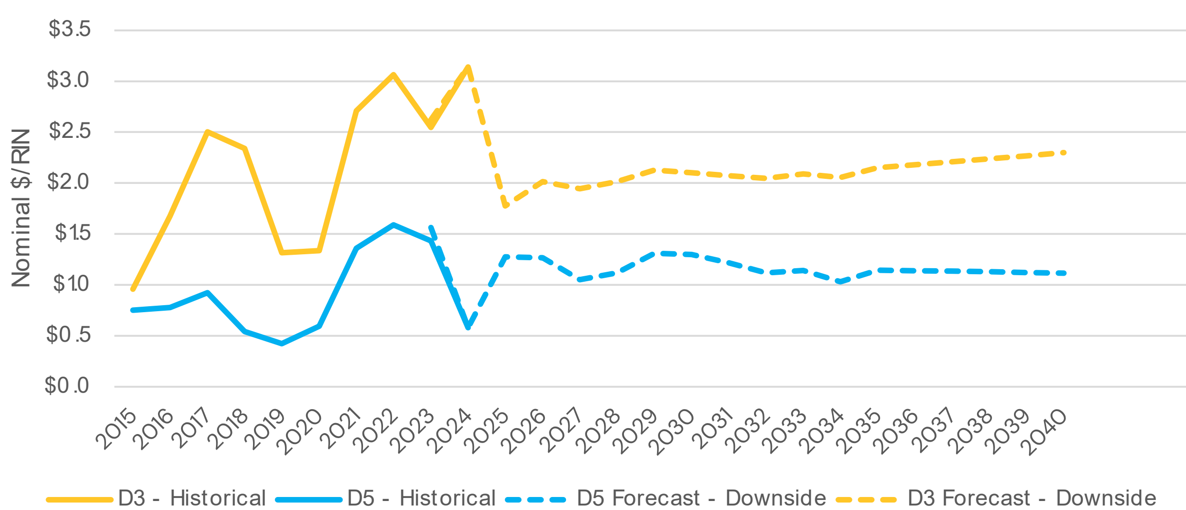


Exhibit 62. ICF's RIN Price Forecast, Downside Case (nominal dollars)



Note on D3 RIN Pricing

The announcement of the proposed partial waiver of the 2024 D3 RVO resulted in the first major shift in the D3 RIN market since the Set Rule in June 2023. In the proposed ruling, the EPA estimated that D3 RIN production in

2024 will be short of the 1.09 billion gallon RVO, suggesting the revised RVO will be 0.88 billion gallons. However, the EPA has indicated that it will ultimately set RVOs for 2024 at *actual* 2024 RIN generation, minus the 2023 carry-over deficits, meaning RIN supply and demand will be equal.

D3 RIN prices have been trading at an average of $2.30/RIN since the release of the proposed waiver, albeit likely at low trading volumes. With D4 RIN and D5 RIN spot prices at an average of $0.67/RIN in Q4 and a theoretical Cellulosic Waiver Credit value at roughly $1.63 in 2024, current pricing mirrors the CWC + D5 RIN pricing paradigm, which would be at $2.30 per RIN. While the EPA did not explicitly mention the use of the CWC, the EPA did note in their proposed ruling that they are seeking comment from market participants regarding the use of the cellulosic waiver as opposed to a general waiver. As such, it's a possibility the EPA administers the CWC for 2024.

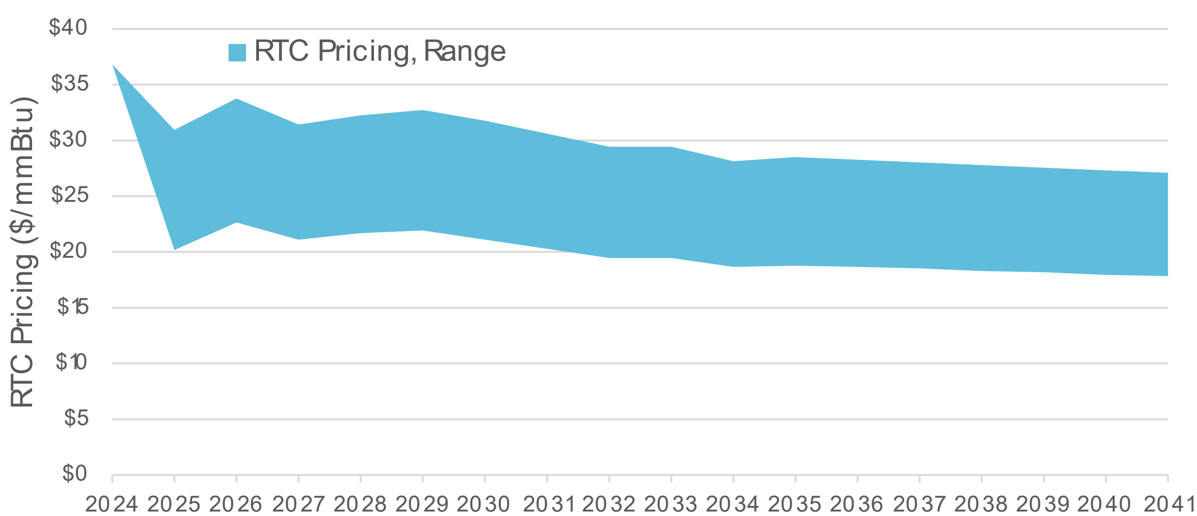
It is also possible a similar situation occurs in 2025. In the previous update ICF covered the gap between CNG dispensing demand and the 2025 RVOs. ICF's estimates suggest that to hit the 2025 RVO, CNG dispensing capacity would need to increase, implying an increase in the use of CNG as a transportation fuel, an uncertain outcome. Accordingly, ICF has adjusted its 2025 forecast to reflect the expectation that the market will produce insufficient D3 RINs and another volume waiver from the EPA will be issued. Previously we forecasted the D3 RIN pricing assuming that the undersupply continued without regulatory intervention, thus current forecasted D3 RIN prices for 2025 are down from the last update.

Beyond 2025, ICF's forecasts have risen from the previous update. Due to ICF's model methodology, the D3 RIN price is reacting to the upward change in D5 RIN economics, driven by long-term soybean oil outlooks. Given the potential limitations on dispensing in coming years and the significant demand pull from non-transportation markets, the forecasted prices in the range of $2.84-$3.42/RIN is justifiable.

RIN Prices as a Proxy for RTC Pricing

ICF used the forecasted D3 RIN pricing outlined previously to develop a range of pricing that will likely be used for RTC benchmarking for the foreseeable future. Presumably, as RNG demand in the non-transportation sector (e.g., for Utilities) increases significantly above RNG demand for on-road transportation, the D3 RIN will no longer serve as predictive benchmark. However, the D3 RIN pricing shown is consistent with moderate pricing observed in the RNG supply curves and may be reflective of where pricing will fall in the mid- to long-term future.

Exhibit 63. ICF Estimated Pricing Range for RTCs ($/mmBtu)



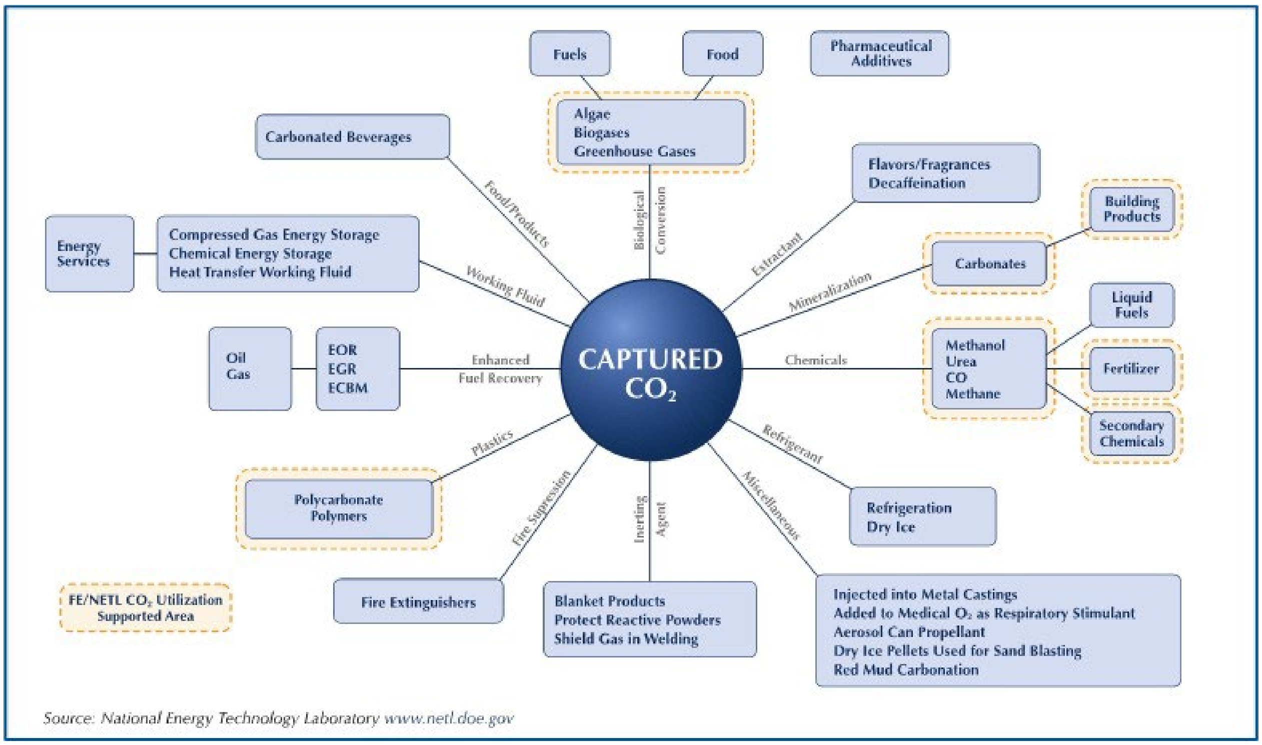
Carbon Capture, Use, and Storage

One of the carbon mitigation options included in the analysis is carbon capture, use, and storage (CCUS). The first step in this process is to capture the CO_2 from various possibles sources including:

- Flue gases of power plants and industrial facilities burning fossil fuels or biomass/biofuel,
- Process gas streams from industrial facilities (natural gas processing plants, ammonia plants, methanol plants, petroleum refineries, steel mills, cement plants, ethanol plants, etc.)
- Hydrogen plants using fossil fuels or biomass as feedstocks
- Air (through the application of direct air capture).

After capturing CO_2, the next steps typically are to purify and dehydrate the CO_2, compress it for transportation and then either (a) to inject it underground into an appropriate geological storage site, where it is trapped and permanently stored in porous rock or (b) utilize it in one or more of the ways shown in the chart below in Exhibit 64.

Exhibit 64. Options for CO_2 Utilization (via NETL)



Carbon Capture Costs

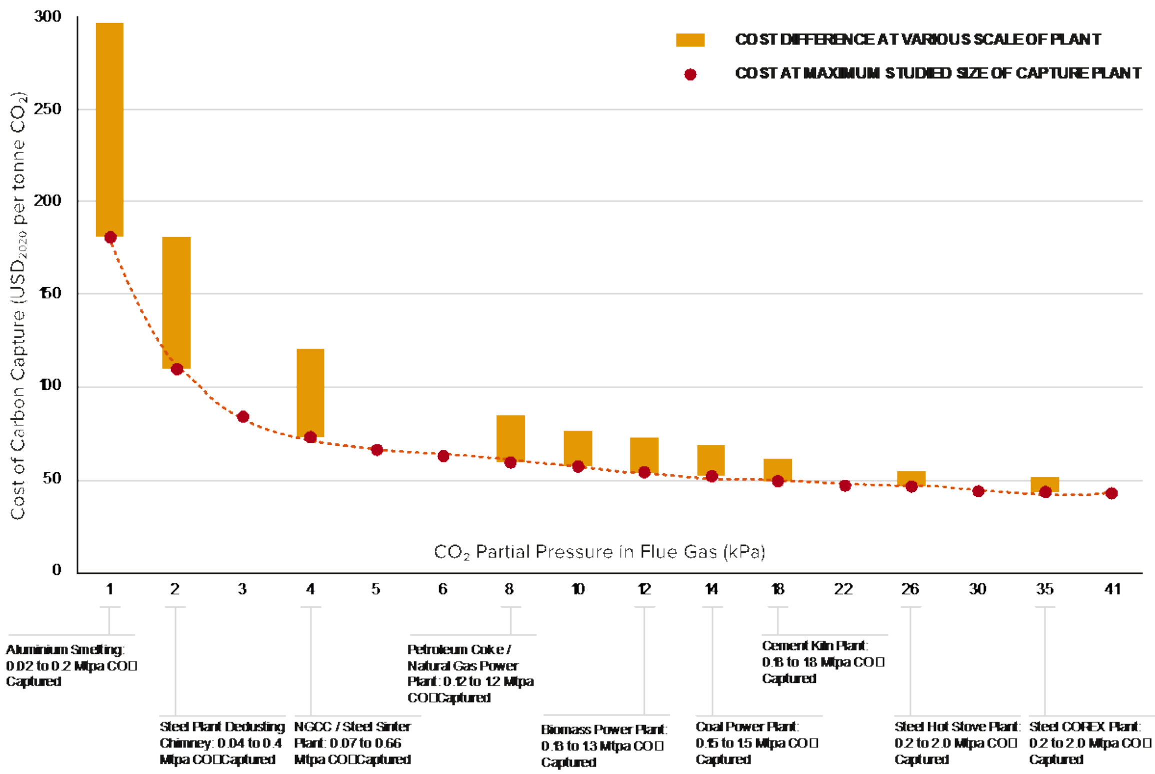
There are many technologies available to capture CO_2 from flue gas and process gas streams including several kinds of post-combustion capture (e.g., absorption by chemical solvents, adsorption by solid sorbents, membrane separation, cryogenic separation, and pressure swing adsorption). The major competitor to post-combustion technologies is oxy-fuel combustion in which pure oxygen combustion air is used to produce a nitrogen-free flue gas that can be transported and stored after relatively inexpensive dehydration and treatment steps. The main drawback to oxy-firing is the large amounts of energy use and high cost associated with separating oxygen from air.

The economic modeling of carbon capture costs for this analysis is based on post-combustion capture by absorption by chemical solvents. This is the most mature and widely used process. The basis is for the cost estimates is the Global CCS Institute's (GCCSI) March 2021 report entitled "Technology Readiness and Costs of CCS." Capture costs were modelled as largely a function of CO_2 partial pressure[36] and the volume of CO_2 being captured. The GCCSI cost estimate was based on an aqueous solution of 30% by weight of monoethanolamine (MEA). MEA is a chemical solvent that has wide commercial availability and performs well over a range of CO_2 partial pressures.

The cost of capturing CO_2 as calculated by GCCSI is shown in Exhibit 65 in units of dollars per metric ton of captured CO_2. These costs include annualized capital costs, operating and maintenance cost, costs for consumables, and energy costs. The exhibit indicates that high-volume gas streams with high CO_2 partial pressures can be captured at a cost of under $50/MT of CO_2, while gas stream gas with lower partial pressures and/or smaller stream volumes will have higher capture costs of $50 to $100/MT of CO_2 or more.

[36] Partial pressure is measured as the percent concentration of CO_2 (or any other gas) in a gas stream times the pressure of that gas stream. A gas stream with high partial pressure of CO_2 means that it will be easier and less expensive to capture the CO_2 because less external energy is required compared to streams with lower CO_2 concentrations and/or lower pressures.

Exhibit 65. CO_2 Capture Cost from Industrial and Power Plant Flue Gas and Process Gas Streams



Source: GCCSI. Costs are for capture only and exclude dehydration and compression, transportation, and geologic storage. The costs shown above are only to capture the CO_2 and do not include costs for dehydration, compression, transport, and storage. GCCSI also estimated these as shown below in Exhibit 66. Costs after the capture step will add an additional $16 to $69 per metric ton of stored carbon dioxide. This brings total CCS cost for large volume industrial and power combustion flue gas streams and industrial process gas streams to $60 to $150 per MT per GCCSI estimates.

Exhibit 66. CO_2 Compression, Dehydration, Transport, and Storage Costs as Estimated by GCCSI

CCS Costs to be Added to Capture Costs ($/metric ton)			
Step	Low	High	Middle
Compression & Dehydration	$10.00	$22.50	$16.25
Pipeline Transport 300km	$2.50	$24.00	$13.25
Injection & Geologic Storage	$2.00	$18.00	$10.00
Monitoring & Verification	$2.00	$4.00	$3.00
Sum	$16.50	$68.50	$42.50
Source: GCCSI			

Geologic Storage Capacity

Exhibit 67 shows that the estimated geologic storage capacity in the Lower 48 state sums to 8,215 billion metric tons of carbon dioxide. The capacity estimated for the state of Oregon 33.15 gigatons (that is 33.15 x 10^9 metric tons) and for the state of Washington, 176.18 gigatons.

These storage capacity estimates were derived by ICF from the most recent DOE analysis of the lower-48 states CO_2 sequestration capacities from the "Carbon Sequestration Atlas of the United States and Canada Version 5."[37] The analysis of storage volumes is conducted by regional carbon sequestration partnerships as overseen by NETL in Morgantown, West Virginia. State level onshore and offshore capacity volumes are reported for storage in oil and gas reservoirs and deep saline formations. The vast majority of storage volume is in deep saline formations, which are present in many states and in most states with oil and gas production. In the most recent version of the Atlas, offshore storage volumes have also been broken out by DOE into the Gulf of Mexico, Atlantic, and Pacific Outer Continental Shelf (OCS) regions. ICF conducted a separate analysis to break out CO_2 EOR storage potential from the total potential in oil and gas reservoirs reported in NATCARB.

Geologic Storage Costs

ICF has computed geologic storage costs in terms of levelized[38] dollars per metric ton of stored CO_2. These costs are largely a function of the geologic characteristics of each project and assumptions used in the costing algorithms for individual construction and operating components of geologic sequestration of CO_2. The largest economic drivers are the costs of well operation, injection and monitoring well construction costs, and the costs of site monitoring. Depending on the nature of each cost element, "unit costs" are specified as dollars per storage site, dollars per square mile, dollars per foot as a function of well depth, dollars per labor hour, or other kinds of specifications or algorithms. The unit cost specification module includes data and assumptions for about 105 cost elements falling within the following ten general cost categories:

- Geologic Site Characterization
- Area of Review (AoR) Study & Corrective Action
- Injection Well Construction
- Operation of Injection Wells & Pumps
- Water Management Capex & Opex
- Monitoring & Reporting Capex and Opex, includes mechanical integrity tests (MIT)
- Financial Responsibility
- Post-Injection Site Care & Site Closure
- General & Administrative Costs

The weighted average geologic storage cost for saline aquifers in the Lower 48 is $16.70 per metric ton, computed on a levelized basis.

[37] See https://www.netl.doe.gov/coal/carbon-storage/strategic-program-support/natcarb-atlas
[38] In mathematical terms, the levelized cost produces a net present value of cash inflows (discounted at the operator's weighted average cost of capital) that exactly equals the net present value of cash outflows (also discounted at the operator's weighted average cost of capital).

Exhibit 67. Geologic Storage Capacity by State

NATCARB US Geologic Storage Capacity Allocated to States (gigatons)					
	EOR CO2 Storage	Depleted Oil Fields	Unmineable Coal	Saline Aquifers - Non Basalt	Sum of All Types
Alabama	0.07	0.02	2.98	307.34	310.41
Arizona	-	-	-	0.42	0.42
Arkansas	0.08	0.10	2.46	21.20	23.84
Atlantic Offshore	-	-	-	202.00	202.00
California Onshore	1.24	3.61	-	147.55	152.40
Colorado	0.20	2.15	0.65	131.11	134.11
Delaware	-	-	-	0.04	0.04
Florida	0.13	0.03	1.95	246.45	248.56
Georgia	-	-	0.02	148.70	148.72
Idaho	-	-	-	0.15	0.15
Illinois	0.10	0.10	2.38	80.75	83.33
Indiana	0.02	0.02	0.14	66.67	66.85
Iowa	-	-	0.01	-	0.01
Kansas	0.41	0.84	-	34.40	35.65
Kentucky	0.01	1.74	0.18	46.43	48.36
LA Onshore	1.36	4.35	12.89	734.55	753.14
LA. Offshore	1.46	12.70	-	1,240.00	1,254.16
Maryland	-	-	-	1.88	1.88
Michigan	0.08	0.18	-	45.56	45.82
Minnesota	-	-	-	-	-
Mississippi	0.13	0.32	8.46	459.15	468.06
Missouri	-	-	0.01	0.10	0.11
Montana	0.25	0.13	0.33	335.74	336.45
North Carolina	-	-	-	6.51	6.51
North Dakota	0.32	0.59	0.54	136.50	137.95
Nebraska	0.02	0.01	-	54.47	54.50
Nevada	-	-	-	-	-
New England States	-	-	-	-	-
New Jersey	-	-	-	-	-
New Mexico	0.90	8.81	0.16	129.29	139.16
New York	-	0.08	-	4.37	4.45
Ohio	-	1.08	0.12	9.91	11.11
Oklahoma	1.41	2.99	0.01	76.87	81.28
Oregon	-	-	-	33.15	33.15
Pacific Offshore	-	0.05	2.63	37.00	39.68
Pennsylvania	-	1.34	0.27	17.34	18.95
South Carolina	-	-	-	31.07	31.07
South Dakota	-	-	-	7.04	7.04
Tennessee	-	-	-	1.85	1.85
Texas Onshore	7.55	130.05	21.80	1,505.79	1,665.19
Texas Offshore	-	2.97	-	798.00	800.97
Utah	0.28	2.11	0.07	88.65	91.11
Virginia	-	0.01	0.37	0.86	1.24
Washington	-	-	0.92	175.26	176.18
West Virginia	-	9.84	0.37	11.19	21.40
Wisconsin	-	-	-	-	-
Wyoming	0.42	0.17	6.64	570.92	578.15
Lower 48 US Sum	16.45	186.38	66.36	7,946.23	8,215.41

Source: Adapted from the U.S.DOE NATCARB database.

Treatment of Tax Credits

Under the Inflation Reduction Act (IRA), the 45Q tax credit was raised to $60/metric ton for carbon dioxide used in enhanced oil recovery or other industrial operations and to $85/metric for permanently stored CO_2 such as in saline aquifers or abandoned oil and gas fields. The CCUS credit is available for CCUS projects beginning construction before January 1, 2033, and is to be applied to CO_2 quantities stored in the first 12 years of a project's operation.

The output of the cost analysis is the before-tax-credit dollar per metric ton levelized cost for capture, transport and storage. Also provided in a second column is the levelized cost after the tax credit is applied (the tax credit is applied on a levelized basis). That is, the 12 years of credits is spread over the 20 operating years each CCUS project is expected to have. Under that calculation the $85/MT credit becomes $58.70/MT on a levelized basis.

The Difference between the Gross and Net GHGs from CCUS

Because the processes of capturing, dehydrating, compressing, transporting and storing carbon dioxide requires energy, the net effect of capturing and storing 1 metric ton of CO_2 is NOT -1 CO_2e metric ton. This is because their GHG emissions associated with additional energy (primarily natural gas and electricity) is needed to operate the CCUS facilities. The amount of net GHG benefit for each ton appears in the Output tables in the cells labeled "GHG Emissions". On average this the net benefit is about -0.93 CO_2e per metric ton captured and stored.

Estimating Potential Capture Volumes

The analysis of the potential capture volumes was conducted for each of the three utilities based on a list of the largest customers in their respective service territories. Data provided by the utilities included volume of gas sales and the classification of the customers by industry type. The potential CCUS customers were divided into the eight size classes shown below. The industry classification was used to develop approximate values for the average partial pressures (an important parameter in the cost estimation) for each grouping.

- under 25MMBtu/hour
- 25-50MMBtu/hour
- 50-100MMBtu/hour
- 100-200MMBtu/hour
- 200-400MMBtu/hour
- 400-800MMBtu/hour
- 800-1600MMBtu/hour
- 1600+MMBtu/hour

The potential volumes that could be captured are computed assuming a 90% capture rate. For modeling purposes, it is assumed that the facilities in the utility company customer databases (or other facilities with similar characteristics) will continue to operate throughout the forecast period to 2050.

CO_2 Transportation

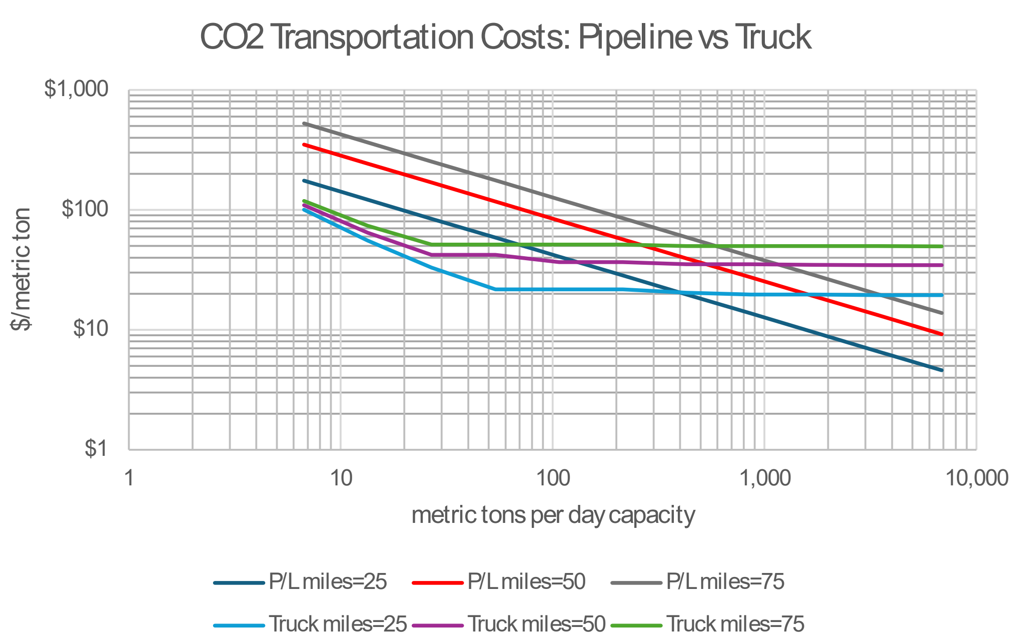
ICF's costs of pipeline transportation are based on standard engineering calculations for what diameter of pipeline is needed to transport a given volume of CO_2 and certain assumptions about how CO_2 volumes from individual power plants and other sources get aggregated into larger pipelines for long-distance, inter-regional transportation. The capital cost of the CO_2 pipelines is represented in the ICF cost model in terms of dollars per inch-mile as shown in the tariff rate is calculated using standard discounted cash flow techniques given these capital costs plus some assumptions about operating and maintenance costs for the CO_2 pipelines.

Exhibit 68. CO_2 Pipeline Costs

CARBON DIOXIDE PIPELINES (transported in dense phase at operating pressure of 1,600 to 2,200 psi)							
Outside Dia. Inches	Inside Dia. Inches	Wall Thickness Inches	Pipeline Cost in $/Inch-Mile	CO_2 Flow Capacity (metric tons/day @100% CU)	Pipeline Capex for 75 Miles ($mm)	Pump Capex for 75 Miles ($mm)	Cost of Service for 75 miles ($/metric ton)
4	3.2	0.4	$169,919	316	$51.0	$0.1	$58.37
6	5.2	0.4	$181,338	1,074	$81.6	$0.3	$27.71
8	7.2	0.4	$189,901	2,439	$113.9	$0.8	$17.17
10	9.2	0.4	$196,821	4,527	$147.6	$1.5	$12.08
12.75	12.0	0.4	$203,785	8,762	$194.9	$2.8	$8.35
16	15.0	0.5	$215,428	15,563	$258.5	$5.0	$6.32
24	22.5	0.7	$237,863	43,412	$428.2	$14.0	$3.89
30	28.2	0.9	$246,383	76,347	$554.4	$24.7	$2.96
36	33.8	1.1	$254,903	121,093	$688.2	$39.2	$2.39
42	39.4	1.3	$263,422	178,853	$829.8	$57.9	$2.01

For small volumes of CO_2, it might be more cost effective to transport the CO_2 by truck. As shown in Exhibit 69, trucking cost for 25 to 75 miles are $20 to $60 per metric ton for volumes above 50 metric tons per day.

Exhibit 69. CO_2 Transport Costs, Pipeline versus Truck



Use of Stochastic Variables for the CCUS Cost Analysis

There were no stochastic variables created specifically for CCUS. Instead, the cost analysis for CCUS employed several of the global stochastic variables used in the other techno-economic models. These include:

- The price of crude oil and diesel fuel (these affected the cost of drilling CO_2 storage wells and the cost of truck transportation of CO_2).
- Natural gas prices (these affected the cost of the amine capture process).
- Industrial electricity prices (these impacted the costs for capture, dehydration and compression, and pipeline transportation of CO_2)
- Various indices such as those for well drilling cost, industrial facility construction, cost of capital, etc.

Cost Results for Base Case

The cost results under base case assumptions are shown in Exhibit 70 for various sizes of facilities (e.g., industrial plants, powers plant or large commercial/educational facilities) for the year 2030. Similar information for the year 2050 is shown in Exhibit 71. All of these cases are for a 90% capture rate and geologic storage at $10/MT. The costs are before any consideration of 45Q tax credit which would reduce the levelized cost by $58.70 per metric ton.

Exhibit 70. CCUS Cost for Base Case Assumptions (2030)

CCUS Cost Results for Base Case Assumptions for Year: 2030													
Resource Subcategory or Step	Distance to Storage Site (miles)	Storage Type	CO2 Partial Pressure (psi)	Fraction CO2 Captured	Annual Capacity Utilization Rate	Capital Costs ($million)	Annual O&M + Energy Costs ($million)	Total Cost ($/MT of CO2 captured)	Dehydration & Compression ($/MT)	Trans Mode	Transport ($/MT)	Storage ($/MT)	Sum All CCS Costs ($/MT, before 45Q tax credit))
under 25MMBtu/hr	50	Geologic, Acquifer, Medium Injectivity	0.882	**90.0%**	**81.2%**	$2.49	$0.63	$117.97	$19.75	Truck	$64.55	$10.00	$212.26
25-50MMBtu/hr	50	Geologic, Acquifer, Medium Injectivity	0.882	**90.0%**	**62.7%**	$3.08	$0.67	$128.55	$21.72	Truck	$42.16	$10.00	$202.44
50-100MMBtu/hr	50	Geologic, Acquifer, Medium Injectivity	0.882	**90.0%**	**43.9%**	$3.66	$0.67	$155.75	$26.16	Truck	$42.16	$10.00	$234.07
100-200MMBtu/hr	50	Geologic, Acquifer, Medium Injectivity	0.882	**90.0%**	**53.6%**	$8.34	$1.40	$97.73	$20.27	Truck	$42.16	$10.00	$170.16
200-400MMBtu/hr	50	Geologic, Acquifer, Medium Injectivity	0.882	**90.0%**	**70.1%**	$14.31	$2.77	$72.19	$16.93	Truck	$36.57	$10.00	$135.69
400-800MMBtu/hr	50	Geologic, Acquifer, Medium Injectivity	0.882	**90.0%**	**85.0%**	$37.88	$9.33	$55.90	$15.12	Pipeline	$22.89	$10.00	$103.91
800-1600MMBtu/hr	50	Geologic, Acquifer, Medium Injectivity	0.882	**90.0%**	**75.0%**	$59.67	$14.41	$55.72	$15.93	Pipeline	$16.99	$10.00	$98.64
1600+MMBtu/hr	50	Geologic, Acquifer, Medium Injectivity	0.882	**90.0%**	**75.0%**	$103.90	$27.69	$52.34	$15.88	Pipeline	$11.80	$10.00	$90.03
Direct Air Capture	50	Geologic, Acquifer, Medium Injectivity			**85.0%**	$1,836.76	$116.97	$593.23		Pipeline	$16.07	$10.00	$619.30

Note: Cost are in 2022 dollars.

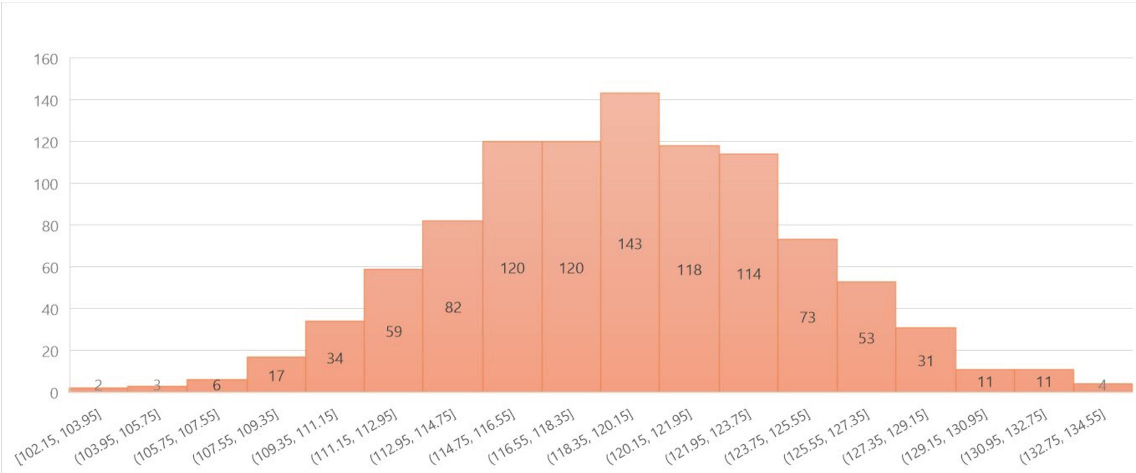
Exhibit 71. CCUS Cost for Base Case Assumptions (2050)

CCUS Cost Results for Base Case Assumptions for Year: 2050													
Resource Subcategory or Step	Distance to Storage Site (miles)	Storage Type	CO2 Partial Pressure (psi)	Fraction CO2 Captured	Annual Capacity Utilization Rate	Capital Costs ($million)	Annual O&M + Energy Costs ($million)	Total Cost ($/MT of CO2 captured)	Dehydration & Compression ($/MT)	Trans Mode	Transport ($/MT)	Storage ($/MT)	Sum All CCS Costs ($/MT, before 45Q tax credit))
under 25MMBtu/hr	50	Geologic, Acquifer, Medium Injectivity	0.882	**90.0%**	**81.2%**	$2.73	$0.67	$125.29	$23.31	Truck	$64.55	$10.00	$223.15
25-50MMBtu/hr	50	Geologic, Acquifer, Medium Injectivity	0.882	**90.0%**	**62.7%**	$3.37	$0.70	$136.88	$25.96	Truck	$42.16	$10.00	$215.01
50-100MMBtu/hr	50	Geologic, Acquifer, Medium Injectivity	0.882	**90.0%**	**43.9%**	$4.00	$0.71	$166.08	$31.66	Truck	$42.16	$10.00	$249.91
100-200MMBtu/hr	50	Geologic, Acquifer, Medium Injectivity	0.882	**90.0%**	**53.6%**	$9.12	$1.50	$105.59	$25.01	Truck	$42.16	$10.00	$182.77
200-400MMBtu/hr	50	Geologic, Acquifer, Medium Injectivity	0.882	**90.0%**	**70.1%**	$15.65	$3.00	$78.41	$20.86	Truck	$36.57	$10.00	$145.84
400-800MMBtu/hr	50	Geologic, Acquifer, Medium Injectivity	0.882	**90.0%**	**85.0%**	$41.44	$10.16	$60.95	$18.58	Pipeline	$27.70	$10.00	$117.23
800-1600MMBtu/hr	50	Geologic, Acquifer, Medium Injectivity	0.882	**90.0%**	**75.0%**	$65.27	$15.72	$60.80	$19.68	Pipeline	$20.52	$10.00	$111.01
1600+MMBtu/hr	50	Geologic, Acquifer, Medium Injectivity	0.882	**90.0%**	**75.0%**	$113.64	$30.21	$57.14	$19.64	Pipeline	$14.24	$10.00	$101.01
Direct Air Capture	50	Geologic, Acquifer, Medium Injectivity			**85.0%**	$1,360.71	$93.19	$454.87		Pipeline	$19.41	$10.00	$484.28

Note: Cost are in 2022 dollars.

The impact of the Monte Carlo process on costs is illustrate in Exhibit 72. The histogram depicts the number of the 1,000 Monte Carlo cases (y-axis) that fall within various cost ranges (x-axis) for capture and geologic storage of facilities in the 400-800 MMBtu/hr. size class. This distribution of cost has a mean of $119.10/MT of CO_2 and a standard deviation of $5.19/MT of CO_2.

Exhibit 72. Histogram on CCUS Costs Size 400-800MMBtu/hr. for 2050



Caveats and Uncertainties

The cost and volume estimate presented here are based on good-quality data and employ reasoned judgement. However, there are many uncertainties that should be considered in using these results:

- CCUS is not a mature industry so practices and costs can only be estimated based on current knowledge regarding similar products and services.
- There is a potential that technological advances for carbon captured could reduce cost below the amine process that forms the basis for the capture economics shown here.
- The economics of capture can be affected by a large number of site-specific factors such as the dispersion of sources of flue/process gas sources, contaminants in those gases and available space for capture equipment.
- Public opposition to CCUS may make it difficult and expensive to site geologic storage projects.
- The potential volumes for CCUS were estimated using databases of large customers as of 2023 and early 2024. The specific facilities contained in those databases might not continue to operate or use energy in the same manner over the full forecast period. Also, new facilities might begin operation in the forecast period.

Carbon Intensity Modelling

ICF evaluated representative carbon intensities of low carbon fuels using (1) the latest version of Greenhouse gases, Regulated Emissions, and Energy use in Technologies (GREET) model, developed by the Argonne National Laboratory (ANL)[39], R&D GREET 2023 (Rev1), and (2) Tier 1 simplified calculators for biomethane derived from the OR-GREET 3.0, which are used for Oregon's Clean Fuels Program (CFP).

While state version of GREET models (e.g. CA- or OR-GREET) are widely seen as a benchmark for RNG carbon intensity values, since Low Carbon Fuel Standards (LCFS) or similar programs in these states have driven much of the RNG development across the country, the current adopted versions were derived from an older version of GREET model and may not represent the up-to-date information. This project applied the simplified calculators of OR-GREET to reflect technical and policy decisions of RNG, particularly, about avoided methane emission credits. In addition, R&D GREET 2023 was used to estimate carbon intensities of electricity and fossil natural gas to include the latest updates in GREET[40] and estimate CO_2 equivalent emissions by using Global Warming Potential (GWP) over 100-year horizon under The Intergovernmental Panel on Climate Change's (IPCC) Fifth Assessment Report (AR5), as shown in Exhibit 73.

Exhibit 73. GWP over 100-year Horizon Under AR5

Greenhouse Gases	AR5/GWP
CO_2	1
CH_4	30
N_2O	265

Electricity

EIA's AEO was used to forecast electricity generation mixes for the Pacific region or Northwest Power Pool Area covered by Western Electricity Coordinating Council (WECC) and U.S. average from 2023 to 2050. EIA and DOE's power generation mixes in Washington and Oregon were used to estimate the electricity generation mixes in 2022. The electricity generation mix and shares of technologies for other power plants in the Pacific region are shown in Exhibit 74 and Exhibit 75, respectively. These mixes were used as inputs of R&D GREET 2023 to estimate electricity carbon intensities in this region, as summarized in Exhibit 76 with a breakdown of feedstock and combustion at power plants.

Exhibit 74. Electricity Generation Mix in the Pacific Region from 2022 to 2050

Year	Residual oil	Natural gas	Coal	Nuclear power	Biomass	Others
2022	0%	19%	2%	6%	1%	73%
2025	0%	18%	1%	4%	0%	76%
2030	0%	15%	0%	4%	0%	81%
2035	0%	14%	0%	4%	0%	81%
2040	0%	12%	0%	4%	1%	83%
2045	0%	13%	0%	4%	1%	82%
2050	0%	14%	0%	3%	1%	82%

[39] https://greet.anl.gov/greet_excel_model.models
[40] https://greet.anl.gov/publication-greet-2023-summary

Exhibit 75. Shares of Technologies for Other Power Plants in the Pacific Region from 2022 to 2050

Year	Hydroelectric	Geothermal	Wind	Solar PV	Others
2022	85%	0%	13%	1%	1%
2025	81%	0%	17%	2%	0%
2030	68%	0%	30%	2%	0%
2035	68%	0%	30%	2%	0%
2040	61%	1%	32%	7%	0%
2045	60%	1%	32%	7%	0%
2050	59%	1%	32%	8%	0%

Exhibit 76. Electricity Carbon Intensities (gCO_2e/kWh) in the Pacific Region from 2022 to 2050

Year	Feedstock	Combustion	Total
Unit	gCO_2e/kWh		
2022	17.7	106.6	124.4
2025	16.3	96.2	112.4
2030	13.0	69.0	82.0
2035	12.5	66.5	79.1
2040	10.9	57.8	68.7
2045	11.8	62.4	74.2
2050	12.1	64.5	76.6

Fossil Natural Gas

Defaults values within R&D GREET 2023 were used to estimate carbon intensities from the upstream emissions for fossil NG produced in North America, as well as from transmission and distribution from their production to end use facilities (e.g. boilers). A list of key default settings in R&D GREET 2023 is summarized below and in Exhibit 77, with details to be found in the model:

Methane venting and leakage: *Methane transmission and storage*: a venting and leakage emission factor of 64.1 grams of methane per million British thermal units ("$gCH_4/MMBtu$") of NG transported over 680 miles, alternatively 0.094 $gCH_4/MMBtu$-mile, was assumed to match default values, based on the hybrid top-down and bottom-up approach. This rate is usually updated based on the most recent EPA Green House Gas Inventory ("GHGI") CH_4 emissions data. *Methane Distribution*: 18.8 g $CH_4/MMBtu$ NG was used in the model.

Fossil NG production: Fossil NG supply was assumed to be composed of 25% conventional gas and 75% shale gas, with a total of 105.1 and 106.1 $gCH_4/MMBtu$ NG leakage and venting during recovery, respectively.

Pipeline transmission distance: the distance from NG fields to central end use facilities was assumed to be 680 miles.

Exhibit 77. CH_4 Leakage Rate for Each Stage in Conventional NG and Shale Gas Pathways

Item	Unit	Conventional NG	Shale gas
Recovery - CH_4 Leakage and Venting	g $CH_4/MMBtu$ NG	105.1	106.1
Recovery - Completion CH_4 Venting	g $CH_4/MMBtu$ NG	0.6	1.5

Recovery - Workover CH_4 *Venting*	g CH_4/MMBtu NG	0.0	0.1
Recovery - Liquid Unloading CH_4 *Venting*	g CH_4/MMBtu NG	4.3	4.3
Well Equipment - CH_4 *Venting and Leakage*	g CH_4/MMBtu NG	68.7	68.7
Gathering and Boosting - CH_4 *Venting and Leakage*	g CH_4/MMBtu NG	31.4	31.4
Processing - CH_4 Venting and Leakage	g CH_4/MMBtu NG	6.2	6.2
Transmission and Storage - CH_4 Venting and Leakage	g CH_4/MMBtu NG/680 miles	64.1	64.1
Distribution - CH_4 Venting and Leakage	g CH_4/MMBtu NG	18.8	18.8

As shown in Exhibit 78, the fossil NG carbon intensities would have a minor decrease over years, due to cleaner U.S. average grid. Approximately 82% of the total is from combustion of NG in boilers.

Exhibit 78. Fossil Natural Gas Carbon Intensities (gCO_2e/MMBtu, LHV) from 2022 to 2050

Year	Natural Gas Recovery & Processing	Methane Leakage at Recovery & Processing	T&D	Methane Leakage At T&D	Combustion	Total
Unit	gCO_2e/MMBtu					
2022	5,358	3,372	2,760	1,923	59,587	73,001
2025	5,344	3,372	2,751	1,923	59,587	72,977
2030	5,304	3,372	2,724	1,923	59,587	72,909
2035	5,297	3,372	2,719	1,923	59,587	72,898
2040	5,295	3,372	2,718	1,923	59,587	72,895
2045	5,292	3,372	2,716	1,923	59,587	72,891
2050	5,289	3,372	2,714	1,923	59,587	72,885

RNG

Carbon intensities of RNG with feedstocks from landfill gas (LFG), water resource recovery facilities (WRRF), animal waste, and food waste were estimated in this project. To align with OR CFP, the modeling concepts of avoided emission credits and methane loss from the simplified calculators of OR-GREET were applied, yet with the majority of emission factors derived from R&D GREET 2023, particularly considering about the carbon intensities of grid electricity and fossil natural gas from the above analysis. A list of assumptions was made, as shown in Exhibit 79. In addition, the avoided emissions credits for animal manure and food waste were estimated as:

Animal waste: 1,000 dairy cows with 21.8 MMBtu CH_4 per year per cow of biogas production at Portland, OR. The methane production was based on tables A.1 and A.2 under the Reference tab of the simplified calculator. No lagoon cleanout was considered as the manure management practice, and covered lagoon was assumed as the digester type. This resulted in -9.9 grams of avoided methane per MJ RNG, and -22.2 grams of diverted CO_2 emissions per MJ RNG.

Food waste: 1 ton of wet food waste, with 60 kg CH_4 per ton of wet food waste of biogas production, based on the FS Fate tab of the simplified calculator. This resulted in -136,044 gCO_2e/MMBtu RNG of avoided emission credits and 13,291 gCO_2e/MMBtu RNG credit adjustments.

The estimated RNG carbon intensities by feedstock are summarized in Exhibit 80.

Exhibit 79. Assumptions to estimate RNG carbon intensities

Energy	Unit	LFG	WRRF	Animal Manure	Food Waste
Electricity Use	kWh/MMBtu RNG	30	35	35	40
NG Use	MMBtu NG/MMBtu RNG	6%	5%	35%	35%
T&D Distance (Pipeline)	Miles	50	50	50	50
Methane Loss	%	1%	1%	2%	2%

Exhibit 80. RNG carbon intensities (gCO_2e/MMBtu, LHV) from 2022 to 2050

Year	LFG	WRRF	Animal Manure	Food Waste
Unit	gCO_2e/MMBtu			
2022	14,963	14,855	-235,036	-79,045
2025	14,603	14,436	-235,462	-79,532
2030	13,686	13,367	-236,551	-80,773
2035	13,599	13,265	-236,656	-80,893
2040	13,287	12,902	-237,020	-81,309
2045	13,450	13,092	-236,831	-81,092
2050	13,523	13,177	-236,748	-80,997

Stochastic Modeling for Simulated Values

The Monte Carlo simulation is a mathematical technique that generates a set of possible outcomes or “cases” of one or many uncertain event(s). The values of the Monte Carlo variables are then used to make (for each case) the main calculations needed in the analysis. For the low-carbon options evaluated here, the Monte Carlo variables are typically components of capital and operating costs or resource constraints and the main calculations are the per-unit cost of the resource and the amount of the resource that is expected to be available in each forecast year. The inputs of the Monte Carlo process are statistical descriptions of the distribution of each stochastic variable (e.g., factor prices and physical limits) and the outputs are the case results which depict the distribution of the main calculations (e.g. resource costs and quantities).

ICF used an Excel-based stochastic pathways simulation tool to create a range of possible values for input parameters that determine both levelized costs and technical potential for each year from 2025 to 2050 for each resource. This model contained ICF’s recommended statistical distribution (e.g., type of distribution, max, min, mean, standard deviation, etc.) for each input parameter and will generated 1,000 or more cases. Any correlations among input parameters as specified by the user were taken into account as samples were drawn from their respective distributions during the process by which the 1,000+ cases were generated.

For each variable and forecast year, ICF defined the type of statistical distribution (triangular, normal distribution, and uniform), and defined the mean/mode and shape of the distribution. Below are the description of the variables.

Global Variables (variables that are used across technology types)

- Brent crude oil price (Triangular distribution, Min = 0.870 of mode; Max = 1.900 of mode): Base Case is set to be AEO reference case forecast for each year. Min and Max are defined by the range of outcomes seen in AEO alternative cases (using the year 2050 data).
- Natural gas Henry Hub price (Triangular distribution, Min = 0.730 of mode; Max = 1.690 of mode): Base Case is set to be AEO reference case forecast. Min and Max are defined by the range of outcomes seen in AEO alternative cases (using the year 2050 data).
- NW regional and national electricity generation price (Triangular distribution, Min = 0.900 of mode; Max = 1.180 of mode): Base Case is set to be AEO reference case forecast. Min and Max is defined by AEO alternative cases (using the year 2050 data).
- NW regional and national electricity transportation and distribution price (Triangular distribution, Min = 0.900 of mode; Max = 1.070 of mode): Base Case is set to be AEO reference case forecast. Min and Max is defined by AEO alternative cases (using the year 2050 data).
- Construction cost index (Normal distribution, Min = 0.800 of mean; Max = 1.200 of mean): Base Case's annual growth rate is derived from historical data from the U.S. Bureau of Labor Statistics, new industrial building construction cost index. Min and Max are set to be +/- 20% of the mean by 2050, based on observed historical data standard deviation and ICF's estimation.
- Construction machinery cost index (Normal distribution, Min = 0.900 of mean; Max = 1.100 of mean): Base Case's annual growth rate is derived from historical data from the U.S. Bureau of Labor Statistics, construction machinery cost index. Min and Max are set to be +/- 10% of the mean by 2050, based on observed historical data standard deviation and ICF's estimation.
- Water commodity cost (Normal distribution, Min = 0.900 of mean; Max = 1.100 of mean): Base Case's annual growth rate is derived from the U.S. Department of Energy, office of Scientific and Technical Information's forecast on water and wastewater annual price escalation rates (2023 edition). Based on ICF's estimation, Min and Max are set to be +/- 10% of the mean.
- Weighted average cost of capital (Normal distribution, Min = 0.750 of mean; Max = 1.250 of mean): based on Utilities' data, the Base Case weighted average cost of capital in real terms is set to be 4%. Based on ICF estimation, the Min is set to be 3% and the max is set to be 5%.
- Technical Potential Index (Normal distribution, Min = 0.800 of mean; Max = 1.200 of mean): The Base Case reflects ICF's forecast on technical potential for each technology in terms or the maximum amounts of each resource type and category that could be available in each forecast year. To reflect the high uncertainty associated with technical potential, ICF conducted a stochastic modeling on the base case with the Min and Max set to be +/- 20% of the base case by 2050.

Technology-Specific Assumptions:

- Well D&C cost index (Normal distribution, Min = 0.900 of mean; Max = 1.100 of mean): Base Case's annual growth rate is derived from historical data from the U.S. Bureau of Labor Statistics, drilling costs for oil and gas cost index (which is applied also to CO_2 and H_2 wells). Min and Max are set to be +/- 10% of the mean by 2050, based on observed historical data standard deviation and ICF's estimation.
- Wind power levelized cost of electricity (LCOE) cost index (Normal distribution, Min = 0.900 of the mean; Max = 1.100 of mean): Base Case LCOE is developed using AEO's projections for wind power Capex, OPEX, and capacity factor. Based on ICF's estimation, Min and Max are set to be +/- 10% of the mean by 2050.
- Solar power LCOE cost index (Normal distribution, Min = 0.900 of the mean; Max = 1.100 of mean): Base Case LCOE is developed using AEO's projections for solar power Capex, OPEX, and capacity factors. Based on ICF's estimation, Min and Max are set to be +/- 10% of the mean by 2050.

- Nuclear power LCOE cost index (Normal distribution, Min = 0.900 of the mean; Max = 1.100 of mean): Base Case LCOE is developed using AEO's projections for nuclear power Capex, OPEX, and capacity factor. Based on ICF's estimation, Min and Max are set to be +/- 10% of the mean by 2050.
- REC price premium cost index (Triangular distribution, Mode = 5%， Min = 0% ; Max = 30%). The Base Case assumes a 5% REC price premium, indicating that REC prices are 5% higher than renewable electricity prices. Significant uncertainties surround REC prices due to the early stage of market development and the Hydrogen tax credit's hourly matching requirement. These uncertainties may make it difficult for utilities to procure enough RECs to keep the electrolyzer running near full capacity. The broad range of REC price premiums reflects these uncertainties and the risk of higher REC prices due to market supply-demand constraints.
- Electrolyzer learning rate (Triangular distribution, Min = 0.454 of mode; Max = 1.150 of mode): The Base Case learning rate is established at 22% according to ICF's projection. This means that capital costs decline for each doubling of worldwide installed capacity. The minimum and maximum rates are set at 5% and 25%, respectively. This broad distribution range, particularly below the mode, highlights the significant uncertainty linked to this assumption.
- Methane pyrolysis Learning rate (Triangular distribution, Min = 0.600 of mode; Max = 2.000 of mode): The Base Case learning rate is established at 5% according to ICF's projection. The minimum and maximum rates are set at 3% and 10%, respectively. This broad distribution range, particularly above the mode, highlights the significant uncertainty linked to this assumption.
- Hydrogen thermal efficiency (applicable for green, pink, and turquoise hydrogen, Triangular distribution, Min = 1 of mode; Max = 1.300 of mode): The Base Case assumes no annual improvement, which is also the minimum value. The maximum improvement is set at 0.3% per year. These assumptions account for potential technological advancements that could enhance the thermal efficiency of electrolyzers and pyrolysis. Since Blue Hydrogen (ATR) technology is relatively mature, its thermal efficiency improvement is set at 0 in all Monte Carlo cases.
- RNG/Syngas Capex (Normal distribution, Min = 0.900 of mean; Max = 1.100 of mean): The Base Case is set to decline by 5% by 2050 in real dollars, before adjustment of Construction cost index, which reflects expected technological advancement. Based on ICF's estimation, Min and Max are set to be +/- 10% of the mean by 2050.
- RNG/Syngas Equipment cost index (Triangular distribution, Min = 0.950 of mode; Max = 1.250 of mode): the Base Case is set to stay at the same level in real dollars, before adjustment of Construction machinery cost index. Based on ICF's estimation, the Min is set to be 5% below the mode and the Max is set to be 25% above the mode.
- Carbon Black Price (Triangular distribution, Min = 0.000 of mode; Max = 50.000 of mode): The Base Case carbon black price is set to 1 cent per Kg of carbon black (a number close to 0) as the Base Case is set to not include byproduct revenues. The Min is set to be 0 and the Max is set to be $ 0.50 per Kg of carbon black, which reflects the possible market price of carbon black according to studies such as Hydrogen Europe's Clean Hydrogen Production Pathways (2024 report).

The table below shows the applicable stochastic variables to each fuel type.

Exhibit 81. Applicable Stochastic Variables to Each Fuel Type

	RNG	Syngas	Blue H_2 (ATR)	Green & Pink H_2 (Electrolyzer)	Turquoise H_2 (CH_4 Pyrolysis)	CCS
Brent crude oil						Yes?

Natural gas Henry Hub			Yes		Yes	Yes?
Electricity generation	Yes	Yes	Yes	Yes	Yes	Yes
Electricity T&D	Yes	Yes	Yes	Yes	Yes	Yes
Construction cost index	Yes	Yes	Yes	Yes	Yes	Yes
Construction machinery cost index	Yes	Yes	Yes	Yes	Yes	Yes
Water commodity cost	Yes	Yes	Yes	Yes	Yes	Yes
Weighted average cost of capital	Yes	Yes	Yes	Yes	Yes	Yes
Technical Potential Index	Yes	Yes	Yes	Yes	Yes	Yes
Well D&C cost index						Yes?
Wind power LCOE cost index				Yes		
Solar power LCOE cost index				Yes		
Nuclear power LCOE cost index				Yes		
Electrolyzer learning rate				Yes		
Methane pyrolysis Learning rate					Yes	
Hydrogen thermal efficiency				Yes	Yes	
RNG/Syngas Capex	Yes	Yes				
RNG/Syngas Equipment cost index	Yes	Yes				
Carbon Black Price					Yes	

For the global variables, ICF performed regression tests on historical data and selected valid correlation coefficients for pairs with strong regression fits (t-stat > 2.064, 95% confidence level for 24 degrees of freedom). ICF also made assumptions about the correlation coefficients between global variables and technology-specific variables. For instance, since the construction of wind and solar power primarily involves construction and machinery costs, ICF assigned correlation coefficients of 0.4 and 0.2 with the construction cost index and construction machinery cost index, respectively. The graph below shows the correlation assumptions for each pair of variables.

Exhibit 82. Correlation Assumptions for Each Pair of Variables.

Correlation Coefficient Inputs	Brent Crude Oil ($/bbl)	Nat Gas HH ($/MMBtu)	Electricity Generation - Regional $/MWH	Electricity Trans & Dist- Regional $/MWH	Construction Cost Index 1=2022	Construction Machinery Cost Index 1=2022	Water Commodity - Annual Escalation	Wt'ed Avr Cost of Capital Index (Base Case =1)	Technical Potential Index	Well D&C Cost Index 1=2022	Wind LCOE 1=Base Case	Solar LCOE 1=Base Case	Nuclear LCOE 1=2022	Learning Rate Index - Electrolyzer (Base Case = 1)	Learning Rate Index - Pyrolysis (Base Case = 1)	Green, Pink and Turquoise Hydrogen Thermal Efficiency	RNG/Syngas Capex 1=2022	RNG/Syngas Equipment Index 1=2022	Carbon Black (in $2022, cent)
Brent Crude Oil ($/bbl)	1.00																		
Nat Gas HH ($/MMBtu)	0.10	1.00																	
Electricity Generation - Regional $/MWH		0.20	1.00																
Electricity Trans & Dist- Regional $/MWH				1.00															
Construction Cost Index 1=2022			0.10	0.20	1.00														
Construction Machinery Cost Index 1=2022			0.20	0.20	0.80	1.00													
Water Commodity - Annual Escalation							1.00												
Wt'ed Avr Cost of Capital Index (Base Case =1)			0.10	0.10	0.40			1.00											
Technical Potential Index									1.00										
Well D&C Cost Index 1=2022	0.80									1.00									
Wind LCOE 1=Base Case					0.40	0.20		0.10			1.00								
Solar LCOE 1=Base Case					0.40	0.20		0.10				1.00							
Nuclear LCOE 1=2022					0.40	0.20		0.10					1.00						
Learning Rate Index - Electrolyzer (Base Case = 1)														1.00					
Learning Rate Index - Pyrolysis (Base Case = 1)															1.00				
Green, Pink and Turquoise Hydrogen Thermal Efficiency																1.00			
RNG/Syngas Capex 1=2022																	1.00		
RNG/Syngas Equipment Index 1=2022					0.50	0.50												1.00	
Carbon Black (in $2022, cent)																			1.00

Using the predefined distribution curves and correlations, the model generated 1,000 random cases. These cases were applied to each technoeconomic model. In each case and year, all variables used the same set of random number multipliers to maintain consistency across global variables and minimize discrepancies between predefined and modeled correlations. All technoeconomic models used the same set of 1,000 draws to ensure uniformity in global variables across different fuel types.

Appendix

ICF's Approach to LCOE Calculation

The LCOE, a measure of the average net present cost of fuel production at a facility over its anticipated lifetime, enables comparison across low-carbon fuels and other energy types on a consistent per-unit energy basis. ICF employs a consistent method for modeling LCOE across different fuels: it is calculated as the discounted costs over the lifetime of energy production (e.g., RNG production) divided by a discounted sum of the actual energy amounts produced.[41] All capital and operating expenses are specified by year of occurrence and using specific financial assumptions are discounted back to year zero. Likewise, the volume of sales of the product or service (measured in, say, MMBtu or metric tons) is also specified by year and discounted back to year zero. The formula below shows the LCOE calculation.

$$LCOE = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

where I_t is the capital cost expenditures (or investment expenditures) in year t, M_t represents the operations and maintenance expenses in year t, F_t represents the feedstock costs in year t (where appropriate), E_t represents the energy produced in year t, r is the discount rate, and n is the expected lifetime of the production facility.

ICF usually first computes the levelized costs before any effects of federal tax credits such as those provided under the Inflation Reduction Act (IRA). Then a second levelized cost is computed including the effects of tax credits. This involves figuring out which credits apply and how large they will be given various emission criteria, labor requirements, domestic content limits, and other provisions. Since the tax credits are available only for projects beginning construction before certain dates and any qualified project can enjoy the credits only for a limited number of years, the credit value will change over time and might be different for different vintages (that is, start dates) of the project. The method used by ICF in dealing with these complexities is to compute the value of the credits (levelized over the project life) individually for projects that come online each year.

If there are coproducts (e.g., the sale of captured CO_2 for enhanced oil recovery), the revenues from coproducts need to be calculated by year and those revenues credited against annual expenditures before calculating the NPV of costs. This can be done by using a projected coproduct price. An alternative methodology that ICF has used for synthetic fuel technologies that produce multiple hydrocarbon products, is to add all products together and compute the average levelized cost in $/MMBtu for all outputs.

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[41] It is then adjusted for any severance taxes, royalties or fees that the provider might owe per unit of production.

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E.3 Current Renewable Natural Gas Projects

E.3.1 Renewable Natural Gas Offtakes

NW Natural has six currently active offtake agreements to purchase RNG from RNG projects. Most will be delivered to Oregon customers and will be a part of the Oregon PGA, however some RNG will be used for other programs, such as the Washington PGA and voluntary tariffs. The following are these offtake agreements:

- Offtake #1
  - Five-year term
  - About 200 Dth/day
  - Organic waste processing facility in southwestern U.S.
  - Fixed price per RTC; purchase what is delivered
- Offtake #2
  - Initial two-year term, with one year extension
  - About 1,000 Dth/day
  - Wastewater treatment plant in New York
  - Fixed price per RTC; purchase what is delivered
- Offtake #3
  - 21-year term
  - Volume ranges from 500,000-1,000,000 Dth/year
  - Landfill facilities (multiple)
  - Fixed price per RTC; purchase what is delivered; required minimums, damages for failure to deliver
- Offtake #4
  - One year term
  - 660,000 Dth
  - Landfill facility in Texas (subject to change)
  - Fixed price per RTC; purchase what is delivered; required minimums, damages for failure to deliver
- Offtake #5
  - Bundled resource where NW Natural retains the RTCs and the brown gas is sold
  - 15-year term, with option for five-year extension
  - About 1,500 Dth/day

  - Two landfills in North Carolina
  - Fixed price per RTC; purchase what is delivered; required minimums, damages for failure to deliver

- Offtake #6
  - Two-year term
  - About 20 Dth/day
  - Synthetic methane facility in New England. Some dairy manure RNG is also included.
    - Pilot-scale plant to assess the technical feasibility of coupling an electrolyzer system producing hydrogen and a biomethanation process to convert carbon dioxide to pipeline quality RNG
    - The project is groundbreaking; NW Natural is not aware of any other project in the US using microbes to upgrade hydrogen to RNG for pipeline injection
  - Fixed price per RTC; purchase what is delivered

Figure E-2: Biomethanation Reactor

E.3.2 Renewable Natural Gas Development

NW Natural has partnered on the development of RNG upgrading and conditioning facilities at the Tyson Fresh Meats plants in Lexington and Dakota City, Nebraska. These Tyson plants rank among the largest beef processing facilities in the United States, employing a total of 7,000 workers. The Lexington facility, established in 1990, and the Dakota City facility, built in 1966 and acquired by Tyson in 2001, are key contributors to the industry.

At both locations, NW Natural provided the capital for constructing the RNG facility and interconnect and manages the operation of the facilities. The Lexington facility was commissioned in January 2022, while the Dakota City facility followed in April 2023. Together, the two RNG facilities are projected to produce an average annual volume of 111,922 MMBtu, which accounts for 0.30 percent of Oregon's sales.

Scope of the Tyson RNG Projects:

- Implemented biogas flow balancing control systems
- Invested in upgrading technology (membrane/pressure-swing adsorption)
- Invested in interconnection to local gas pipelines
- Upgrade biogas from Tyson lagoons to RNG
- Purchase the RNG and sell brown gas locally
- Retire RTCs on behalf of NW Natural customers

Figure E-3: Tyson Lexington RNG Facility

Figure E-4: Tyson Dakota City RNG Facility

Appendix F – Supply-Side Resources

F.1 Gas Purchasing Common Practices

NW Natural also utilizes financial derivative hedges (mainly swaps) to manage cost risks. The physical baseload supply contracts mentioned in Chapter 8, which are priced at a variable index price, can be fixed using financial swaps. This is done for a large portion of our portfolio to lock in prices and decrease the volatility of costs in our gas supply portfolio for customers.

In addition to the long-term supply planning done in this IRP, NW Natural prepares a Gas Acquisition Plan (GAP) each year. The GAP is reviewed and approved by NW Natural's Gas Acquisition Strategy and Policies (GASP) Committee, but such plans are always subject to change based on market conditions. The primary objective of the GAP is to ensure gas supplies are sufficient to meet firm customer demand. To meet this objective, our primary goal is reliability, followed by lowest reasonable cost, rate stability, and cost recovery all while reducing the carbon content of the energy we deliver. The focus of the GAP is on the upcoming gas contracting year (November through October); however, this focus extends several years into the future for multi-year hedging considerations. Longer-term resource planning is the focus of the IRP and is not covered in the GAP, except of course to assure consistency in the transition from near-term to longer-term planning decisions.

F.2 Pipeline Charges

There are three primary costs components associated with pipeline contracts, one that is a fixed charge and two variable components. Table F-1 outlines these three components.

Table F-1: Three Cost Components for Pipeline Charges

Component	Description
Demand Charge	This is a fixed cost associated with holding the capacity rights to transport gas on a pipeline. Often specified in $/Dth/day, this price multiplied by the capacity amount held by the shipper and 365 would provide the annual payment to the interstate pipeline regardless of how much gas is transported over the course of that year. Also known as a reservation charge.
Variable Charge	This a variable charge associated with how much gas is scheduled on the pipeline each day. Some pipelines have postage-stamp variable charges that are independent of the receipt and delivery points, whereas other pipelines charge based not only the amount of gas scheduled but the distance that it is scheduled.
Fuel Charge	This is a secondary indirect variable charge that takes a percentage of the natural gas that is shipped on the pipeline.

F.3 Gas Supply Contracts

Table F-2: NW Natural Firm Off-System Gas Supply Contracts for the 2024/2025 Tracker Year

Supply Location	Duration	Baseload Qty (Dth/day)	Contract Termination Date
British Columbia:			
Canadian Natural Resources	Nov-Oct	15,000	10/31/2025
MacQuarie Energy Canada Ltd.	Nov-Oct	5,000	10/31/2025
ConocoPhillips Canada Marketing	Nov-Mar	10,000	3/31/2025
Direct Energy Marketing Limited	Nov-Mar	5,000	3/31/2025
IGI Resources	Nov-Mar	5,000	3/31/2025
J. Aron & Company	Nov-Mar	15,000	3/31/2025
MacQuarie Energy Canada Ltd.	Nov-Mar	5,000	3/31/2030
Powerex Corp	Nov-Mar	5,000	3/31/2030
Pacific Canbriam Energy Limited	Nov-Mar	10,000	3/31/2025
Uniper Trading Canada Ltd.	Nov-Mar	10,000	3/31/2025
MacQuarie Energy Canada Ltd.	Apr-May	5,000	5/31/2025
MacQuarie Energy Canada Ltd.	Apr-Jun	5,000	6/30/2025
MacQuarie Energy Canada Ltd.	Apr	5,000	4/30/2025
J. Aron & Company	Apr	10,000	4/30/2025
TD Energy Trading Inc	Oct	10,000	10/31/2025
Uniper Trading Canada Ltd.	Oct	10,000	10/31/2025
Alberta:			
Suncor Energy Marketing Inc	Nov-Oct	5,000	10/31/2025
Castleton Commodities	Nov-Oct	5,000	10/31/2025
Direct Energy Marketing Limited	Nov-Oct	5,000	10/31/2025
ConocoPhillips Canada Marketing	Nov-Mar	20,000	3/31/2025
MacQuarie Energy Canada Ltd.	Nov-Mar	5,000	3/31/2025
TD Energy Trading Inc	Nov-Mar	15,000	3/31/2025
J. Aron & Company	Nov-Mar	5,000	3/31/2025
Powerex Corp	Nov-Mar	5,000	3/31/2025
Suncor Energy Marketing Inc	Nov-Mar	5,000	3/31/2025
Castleton Commodities	Nov-Feb	5,000	2/28/2025
EDF Trading North America, LLC	Dec-Feb	5,000	2/28/2025
Suncor Energy Marketing Inc	Apr-Jun	5,000	6/30/2025
Castleton Commodities	Apr-May	10,000	5/31/2025
Suncor Energy Marketing Inc	Apr-May	5,000	5/31/2025
Suncor Energy Marketing Inc	Apr	10,000	4/30/2025
Uniper Trading Canada Ltd.	Apr	10,000	4/30/2025
Suncor Energy Marketing Inc	Sep-Oct	5,000	10/31/2025
J. Aron & Company	Oct	10,000	10/31/2025
Suncor Energy Marketing Inc	Oct	10,000	10/31/2025
Rockies:			
MacQuarie Energy, LLC	Nov-Oct	10,000	10/31/2025

ConocoPhillips Company	Nov-Oct	5,000	10/31/2025
CIMA Energy LTD	Nov-Oct	5,000	10/31/2025
Koch Energy Services, Inc	Nov-Oct	10,000	10/31/2025
MIECO LLC	Nov-Oct	5,000	10/31/2025
PureWest Resources, Inc.	Nov-Oct	5,000	10/31/2025
Vitol Inc.	Nov-Oct	5,000	10/31/2025
CIMA Energy LTD	Nov-Mar	10,000	3/31/2025
Concord Energy LLC	Nov-Mar	5,000	3/31/2025
MacQuarie Energy, LLC	Nov-Mar	5,000	3/31/2025
PureWest Resources, Inc.	Nov-Mar	5,000	3/31/2025
Concord Energy LLC	Dec-Mar	5,000	3/31/2025
Koch Energy Services, Inc	Dec-Mar	5,000	3/31/2025
MacQuarie Energy, LLC	Dec-Mar	15,000	3/31/2025
CIMA Energy LTD	Dec-Mar	10,000	3/31/2025
Citadel Energy Marketing, LLC	Dec-Mar	5,000	3/31/2025
Citadel Energy Marketing, LLC	Dec-Feb	5,000	2/28/2025
PureWest Resources, Inc.	Dec-Feb	5,000	2/28/2025
Vitol Inc.	Dec-Feb	5,000	2/28/2025
CIMA Energy LTD	Apr	15,000	4/30/2025
KM Gas Marketing LLC	Apr	10,000	4/30/2025
MacQuarie Energy, LLC	Apr	10,000	4/30/2025
ConocoPhillips Company	Oct	5,000	10/31/2025
MacQuarie Energy, LLC	Oct	5,000	10/31/2025

Month	Baseload Qty (Dth/day)
Nov-24	230,000
Dec-24	290,000
Jan-25	290,000
Feb-25	290,000
Mar-25	265,000
Apr-25	180,000
May-25	110,000
Jun-25	90,000
Jul-25	80,000
Aug-25	80,000
Sep-25	85,000
Oct-25	135,000

Notes: Contract quantities represent deliveries into upstream pipelines. Accordingly, quantities delivered into NW Natural's system are slightly less due to upstream pipeline fuel consumption.

Table F-3: NW Natural Firm Transportation Capacity for the 2024/2025 Tracker Year

Pipeline Contract	Contract Demand (Dth/day)	Termination Date
Northwest Pipeline:		
Sales Conversion (#100005)	214,889	10/31/2033
1993 Expansion (#100058)	35,155	9/30/2044
1995 Expansion (#100138)	102,000	10/31/2033
Occidental cap. acq. (#139153)	1,046	10/31/2033
Occidental cap. acq. (#139154)	4,000	10/31/2033
International Paper cap. acq. (#138065)	4,147	10/31/2033
March Point cap. acq. (#136455)	12,000	12/31/2046
Total NWP Capacity	373,237	
less recallable release to -		
Portland General Electric	(30,000)	10/31/2026
Net NWP Capacity	343,237	
TransCanada - GTN:		
Sales Conversion (#00180)	3,616	10/31/2030
1993 Expansion (#00164)	46,549	10/31/2030
1995 Rationalization (#11030)	56,000	10/31/2030
Total GTN Capacity	106,165	
TransCanada - Foothills:		
1993 Expansion	47,727	10/31/2025
1995 Rationalization	57,417	10/31/2025
Engage Capacity Acquisition	3,708	10/31/2025
2004 Capacity Acquisition	48,669	10/31/2030
Total Foothills Capacity	157,521	
less release to -		
Shell Energy North America (Canada) Inc	(48,669)	10/31/2030
Net Foothills Capacity	108,852	
TransCanada - NOVA:		
1993 Expansion	48,135	10/31/2025
1995 Rationalization	57,909	10/31/2025
Engage Capacity Acquisition	3,739	10/31/2025
2004 Capacity Acquisition	49,138	10/31/2030
Total NOVA Capacity	158,921	
less release to -		
Shell Energy North America (Canada) Inc	(49,138)	10/31/2030
Net NOVA Capacity	109,783	
T-South		
Capacity (through Tenaska)	19,000	3/31/2029
Capacity (through FortisBC)	28,435	10/31/2025
2021 Expansion	25,511	10/31/2061
Total T-South Capacity	72,946	

Notes:

1. All of the above agreements continue year-to-year after termination at NW Natural's sole option except for PGE, which requires mutual agreement to continue, and the T-South contracts with Tenaska and Fortis, which have no renewal rights.
2. The numbers shown for the 1993 Expansion contracts on GTN and Foothills are for the winter season (Oct-Mar) only. Both contracts decline during the summer season (Apr-Sep) to approximately 30,000 Dth/day.
3. Segmented capacity has not been included in this table.
4. The 2004 Capacity Acquisition on NOVA and Foothills totaling about 49,000 Dth/day has been released to a third party through 10/31/2030. The revenues related to this arrangement are being credited back to customers as outlined in Schedule P.

Table F-4: NW Natural Firm Storage Resources for the 2024/2025 Tracker Year

Facility	Max. Daily Rate (Dth/day)	Max. Seasonal Level (Dth)	Termination Date
Jackson Prairie:			
SGS-2F	46,030	1,120,288	10/31/2033
TF-2 (primary firm portion)	23,038	839,046	10/31/2033
TF-2 (primary firm portion)	9,467	281,242	10/31/2033
TF-1	13,525	n/a	10/31/2033
Firm On-System Storage Plants:			
Mist (reserved for core)	325,000	13,322,920	n/a
Portland LNG Plant	99,630	507,449	n/a
Newport LNG Plant	78,000	1,082,517	n/a
Total On-System Storage	502,630	14,912,886	
Total Firm Storage Resource	548,660	16,033,174	

Notes:
1. The SGS-2F and TF-2 contracts have a unilateral annual evergreen provision (continuation at NW Natural's sole option), while the TF-1 contract requires mutual consent with Northwest Pipeline to continue after the indicated termination date.
2. The TF-2 contracts also contain additional "subordinated" firm service of 9,586 Dth/day on the first agreement listed above and 3,939 Dth/day on the second agreement. The subordinated service is NOT included in NW Natural's peak day planning.
3. On-system storage peak deliverability is based on design criteria, for example, Mist is at least 50% full.
4. Mist numbers pertain to the portion reserved for core utility service per the Company's Integrated Resource Plan. Additional capacity and deliverability at Mist have been contracted under varying terms to Interstate storage customers.
5. The Dth numbers for Mist, Newport LNG and Portland LNG are approximate in that they are converted from Mcf volumes, and so depend on the heat content of the stored gas. The current heat content used for Mist is 1080 Btu/cf. The current heat content used for Newport LNG is 1095 Btu/cf and Portland LNG is 1107 Btu/cf. An engineering study was conducted for Newport LNG peak deliverability for the 2024-25 winter supporting 78,000 Dth/d as the maximum daily rate. An electrical project at PLNG will not be finalized for the 2024-25 PGA year thus limiting daily sendout to 90 MMSCFD instead of 120 MMSCFD.
6. Newport LNG tank rated to 98.86% of the tank capacity.
7. Due to an Engineering analysis of the Portland LNG tank, liquifaction will be limited to 76.4% of the tank's capacity.
8. NW Natural has no supply-basin storage contract for the coming year.

Table F-5: NW Natural Other Resources: Recall Agreements, Citygate Deliveries and Mist Production for the 2024/2025 Tracker Year

Type	Max. Daily Rate (Dth/day)	Max. Availability (days)	Termination Date
Recall Agreements:			
PGE	30,000	30	10/31/2026
Georgia Pacific-Halsey mill	1,000	15	Upon 1-year notice
Total Recall Resource	31,000		
Citygate Deliveries:			
Citygate Delivery	15,000	5	2/28/2025
On-System Supplies:			
Renewable Natural Gas	≈700	n/a	Varying Terms
Mist Production	≈500	n/a	Life of the wells
Total On System Supplies	1,200		

Notes:
1. There are a variety of terms and conditions surrounding the recall rights under each of the above agreements, but they all include delivery of the gas to NW Natural's system.
2. Citygate deal has been executed for 5 days peaking at 6,200 dth/day.
3. Mist production is expected to flow at roughly the figure shown above. Flows vary as new wells are added and older wells deplete. NW Natural's obligation is to buy gas from existing wells through the life of those wells.
4. Assumes three Renewable Natural Gas (RNG) projects are online this PGA year.

Table F-6: NW Natural Peak Day Resource Summary for the 2024/2025 Tracker Year

Resource Type	Max. Daily Rate (Dth/day)
Net Deliverability over Upstream Pipeline Capacity	343,237
Off-System Storage (Jackson Prairie only)	46,030
On-System Storage (Mist, Portland LNG and Newport LNG)	502,630
Recallable Capacity and Supply Agreements	31,000
Citygate Deliveries	15,000
On-System Supplies	1,200
Segmented Capacity (not primary firm)	60,700

Notes: Per the 2022 IRP, Segmented Capacity is included as a firm resource through the 2027-28 gas year. Reliance for a peak event reduces to zero dth/day beyond the 2027-28 gas year.

Appendix G - Simulation Inputs to PLEXOS®

G.1 Gas Price Simulation

Both the Reference Case gas price forecast and the Monte Carlo simulation use a blended price forecast for the first six years in the planning horizon. Forward prices are blended into the S&P Global forecast for the first six years at a decreasing rate. This blending allows for even more accurate forecasting, as NW Natural's Gas Supply team uses forward prices to develop their hedging strategy and represent prices that are currently available in the market. The prices are blended at the following percentages:

Table G-1: Gas Price Forecast Blend

Year	FWD Weight	S&P Global Weight
1	PGA Mix January/February FWD Prices	
2	75%	25%
3	75%	25%
4	50%	50%
5	50%	50%
6	25%	75%
7	0%	100%

The Monte Carlo gas price simulation produces 500 gas price paths (i.e., stochastic draws) for gas prices hubs across the U.S. and Canada based on historical price shocks. This IRP focuses on the four gas hubs where NW Natural purchases gas for customers (AECO, Sumas, Opal and Westcoast Station 2). These simulations are used in NW Natural's risk assessment.

1. Simulation results at a daily level for all four basins, and
2. The incorporation of weather correlation

Historically, the simulation yields annual average prices and monthly prices at each hub. In this IRP, annual averages were produced from the Monte Carlo simulation. Then, historical daily and annual prices were used to shape the forecasted annual average prices into forecasted daily prices. This change improves the effectiveness and accuracy of decision making as the resource optimization model, PLEXOS®, solves at a daily level.

In addition to simulating prices at a daily level, NW Natural included weather correlation. Before the gas price Monte Carlo is done, a Monte Carlo for weather is completed. The weather Monte Carlo assigns a historical representative year to shape each of the forecasted years. In order to include weather correlation, the same historical representative year that was assigned to each forecast year in the weather Monte Carlo is assigned to the same forecast year in the gas price Monte Carlo.

For gas prices at different locations there are three important correlations which must be considered when simulating stochastic draws:

1) Correlation across time – For example, gas prices today are likely to be correlated with previous gas prices both year-over-year and from day-to-day. These daily fluctuations in gas prices reflect the continuous shifts in natural gas supply, natural gas storage, and natural gas demand.

2) Correlation across basins or hubs – Interstate pipeline capacity limits the amount of gas able to be transported or “shipped” from one region. In addition to localized supply and demand, these shipping charges create different but highly correlated prices across different basins.

3) Weather Correlation – gas prices can be sensitive to weather. For example, a cold day, when there is high demand for natural gas, can drive up prices. By using this process outlined above any historical gas price volatility that was correlated with weather will be captured in the daily prices.

The Monte Carlo simulation is coded using RStudio and SAS software and uses historical and forecasted monthly gas prices from the S&P Global: North American Natural Gas Long-term Outlook – February 2025. The simulation first simulates annual gas prices for 500 draws for each basin based on historical annual prices shocks (i.e., changes from one year to the next). After an annual price simulation is complete for each hub, a secondary stochastic process is completed to apply daily shapes to each hub as well. The simulation is tied to the S&P Global forecast such that the median annual price of the 500 simulation is equal to the annual S&P Global price forecast in each year of the forecast for each basin. Detailed technical steps of the simulation are outlined below in two phases.

Phase 1: Simulate annual gas prices for each gas hub over the planning horizon

Step 1: Calculate an average historical and forecasted annual price from monthly prices for each hub.

Step 2: Calculate basis to AECO for each hub (i.e., hub price minus AECO gas prices).

Step 3: Use “auto.arima” package to define an ARIMA model for annual AECO prices and calculate residuals from the model based on historical training set.

Step 4: For each year in the planning horizon the AECO price ($AECO_t$) is equal to the previous annual price ($AECO_{t-1}$) plus a randomly selected residual from the ARIMA model (ε_y).

NOTE: A coding loop runs steps 5-7 to generate a value for each year, before looping over these steps again for the following year.

Step 5: For each of the other hubs and each year in the planning horizon apply the annual basis from the same year as the stochastic residual selected.

$$AECO_t = AECO_{t-1} + \varepsilon_y$$

$$Opal_t = AECO_t + (Opal_y - AECO_y)$$

$$Sumas_t = AECO_t + (Sumas_y - AECO_y)$$

$$WestCoastSt2_t = AECO_t + (WestCoastSt_y - AECO_y)$$

$$where:$$

$$t = forecast\ year$$

$$y = stocastic\ historical\ year\ selected$$

Step 6: Adjust gas price levels by adding a factor equal to the S&P Global forecast price minus median price of the draws. This creates the tie between the simulation and S&P Global forecast.

Step 7: Adjust any prices that exceed the lower bound parameter.

$$if: Hub_t < lb$$

$$then: Hub_t = Hub_{t-1} - \xi * (Hub_{t-1} - lb)$$

$$where:$$

$$lb = lower\ bound; [set\ to\ \$0.75]$$

$$\{\xi \in \mathbb{R} \mid 0 < \xi < 1\}\ ; [set\ to\ 0.5]$$

Phase 2: Simulate daily gas prices for each gas hub over the planning horizon

Step 1: Create daily shapes using annual and daily historical gas price data

Step 2: Create blank daily data set and assign a representative year to each forecast year based on the weather data simulation

Step 3: Merge on annual average forecast from gas price simulation and shape annual data to daily data based on the historical representative year

This process yields daily prices for each draw at 4 basins.

Additional technical notes:

- Historical and forecasted years in the simulation are defined as gas years (November-October).
- The monthly Sumas price is constrained to be greater than or equal to the minimum of AECO and WestCoastStation2.
- Even through daily prices can dip close to zero (even negative on occasion), the lower bound for monthly is set to $0.75.
- All prices are simulated as real 2024 $/MMBtu.
- The training set for the "auto.arima" uses data back to 2005.
- The stochastic shocks are pulled from post data back to 2010 (i.e., post shale gale when horizontal drilling became widespread drastically lowering prices and reduced year over year volatility.

Figure G-1: Monte Carlo Sumas Annual Average Gas Price Forecast

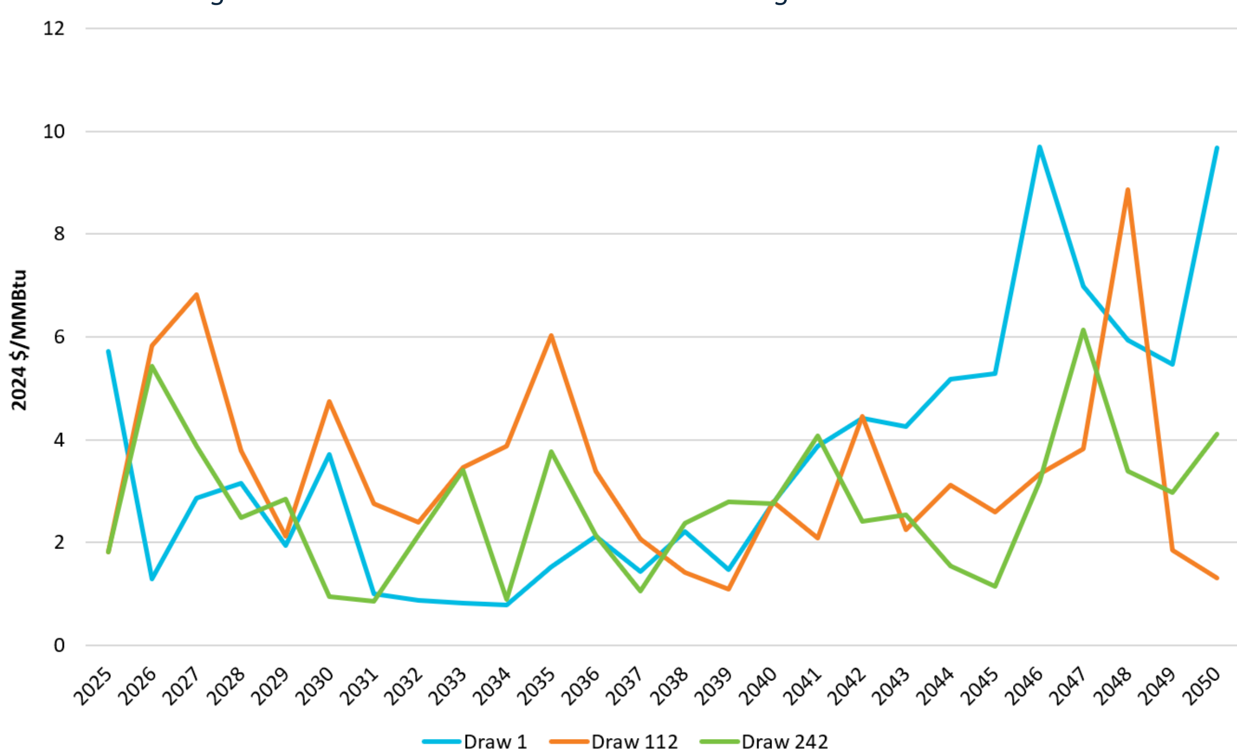
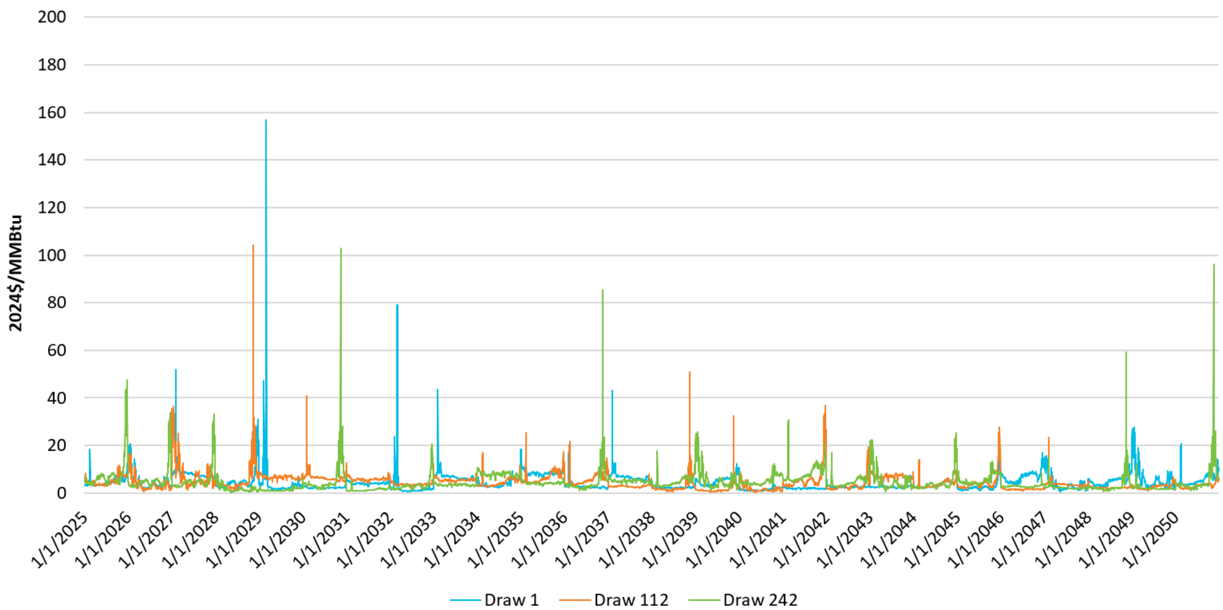


Figure G-2: Monte Carlo Sumas Daily Gas Price Forecast



G.2 Daily Temperature Weather Simulation

NW Natural's stochastic weather modeling across 11 separate locations for the IRP load forecast aims to achieve three key considerations:

1. Cross locational correlations in HDDs.
2. Incorporating climate change expectations into cumulative HDDs.
3. Correlating year-over-year correlations in HDDs captured by IPCC modeling.

To achieve these objectives, the modeling process combines four simulations (SIMs) to ultimately output simulated daily temperatures with reasonable variation in monthly HDDs.

- SIM #1: Using a normal distribution, with a mean and standard deviation of the ICF Reference Case, simulate monthly PORC HDDs from the 22 IPCC models for each forecast year and month.
    a. Monthly HDDs have an upper bound of the maximum value seen historically, or in found in the IPCC models.
    b. Monthly HDDs have a lower bound of the minimum value seen historically, or in found in the IPCC models.
    c. For months that have historically seen zero HDDs, a percentage of the draws are assigned zero based on historical probabilities.
- SIM #2: Randomly select one of the 22 IPCC models with equal probability across all models.

- SIM #3: Randomly select one of the forecast years.
- SIM #4: Randomly select a historical year.

After the SIMs are complete, they are combined in the following steps:

1. Calculate the difference in HDDs between the PORC load center and all other locations for each of the IPCC models.
2. Pair a simulation (i.e., SIM #2 and SIM #3) to select random IPCC models and a random set of HDD differences from PORC for each location, for each year in the planning horizon.
3. Apply those differences to SIM #1 to get a random HDD value for each location for each year in the planning horizon.
4. Use SIM #4 to shape HDD values into daily temperatures to input into the UPC model.

Figure G-3 shows ten randomly selected HDD draws for the Portland Central (PORC) load center relative to historical HDDs.

Figure G-3: PORC Load Center HDD Simulations of Ten Simulated Draws

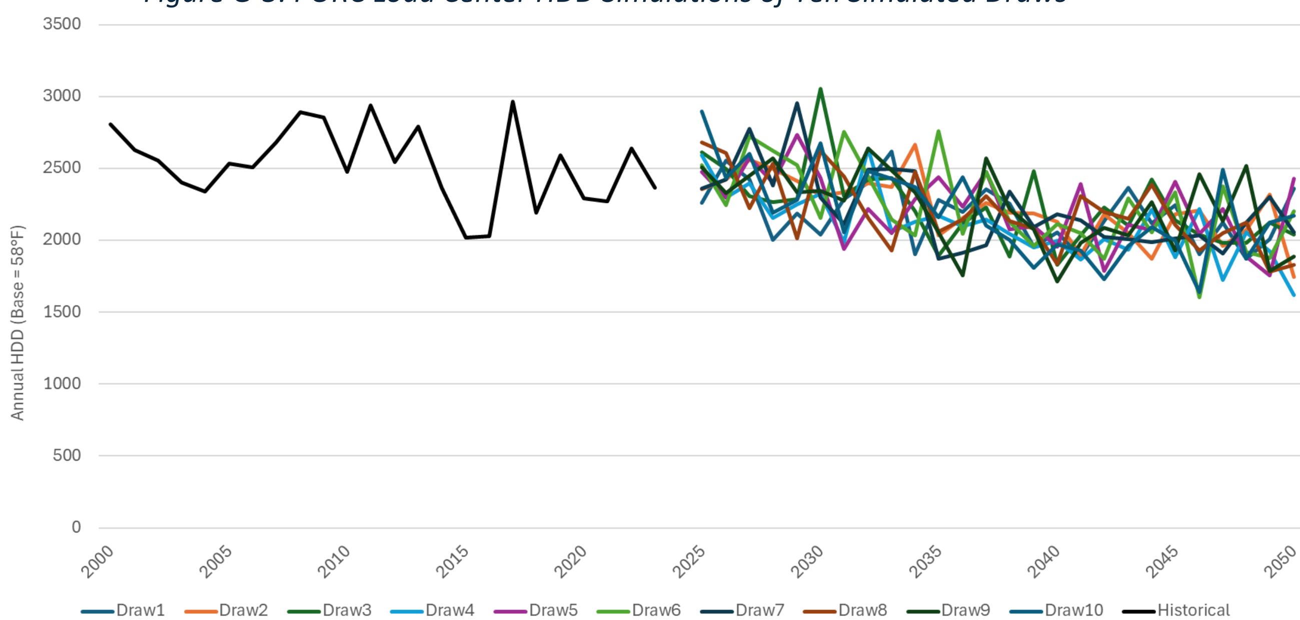
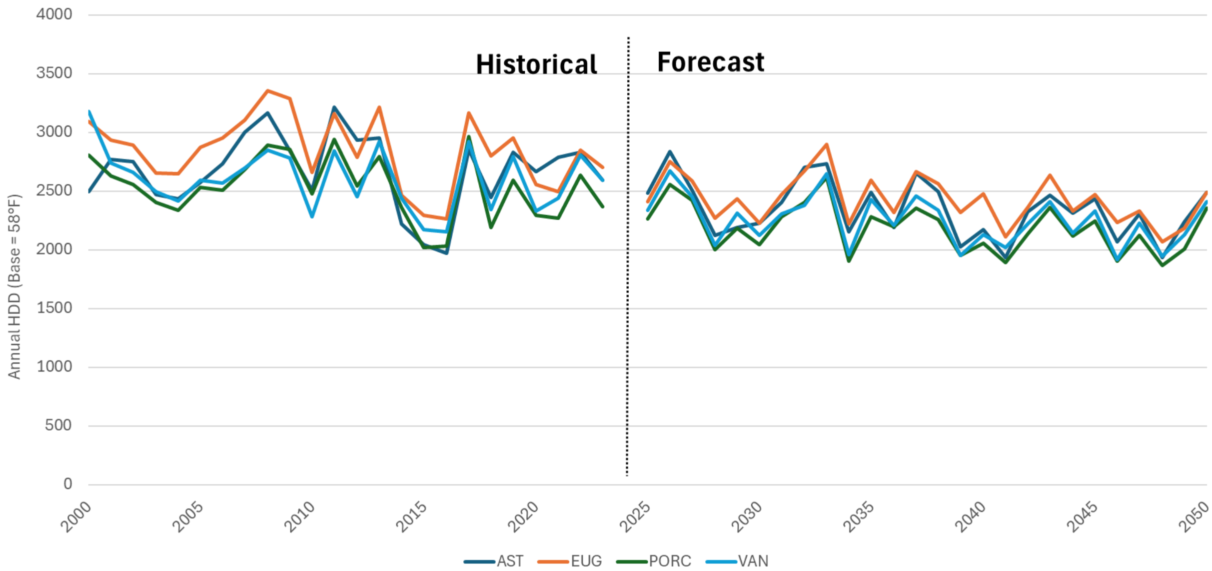


Figure G-4 illustrates the HDD correlations that occur for a sample of load centers for a given stochastic draw.

Figure G-4: HDD Correlation by Simulated Draw



G.3 Alternative Fuels Simulation

As a part of the Alternative Fuels study conducted by ICF, Monte Carlo simulations were run on the price and quantity for each resource. Results were provided in 5-year increments from 2025 to 2050. To use the results in the IRP, NW Natural did a step interpolation to fill all values. Below is an example. Values provided by ICF are highlighted in blue.

Table G-2: Alternative Fuels Step Interpolation Method

Year	Cost	Quantity	Year	Cost	Quantity
2025	$7.91	2,982.67	2040	$9.44	9,692.12
2026	$7.91	2,982.67	2041	$9.44	9,692.12
2027	$7.91	2,982.67	2042	$9.44	9,692.12
2028	$7.91	2,982.67	2043	$9.44	9,692.12
2029	$7.91	2,982.67	2044	$9.44	9,692.12
2030	$7.68	5,530.78	2045	$9.53	10,454.44
2031	$7.68	5,530.78	2046	$9.53	10,454.44
2032	$7.68	5,530.78	2047	$9.53	10,454.44
2033	$7.68	5,530.78	2048	$9.53	10,454.44
2034	$7.68	5,530.78	2049	$9.53	10,454.44
2035	$9.23	8,065.53	2050	$9.50	10,749.19
2036	$9.23	8,065.53	2051	$9.50	10,749.19
2037	$9.23	8,065.53			
2038	$9.23	8,065.53			
2039	$9.23	8,065.53			

NW Natural modified the costs to reflect increased cost uncertainty through time. The modified costs focus on a percentage difference between the cost for each draw and the Reference Case. The modified results are equal to:

$$\text{[Reference case cost]} * (1 + \{ \underbrace{\text{[2]} * \text{[\# of forecast years / total years in planning horizon]} * \text{[Percentage Difference]}}_{\text{Modifier}} \}$$

G.4 Renewable Thermal Credit Simulation

To develop a range of potential paths for RTC prices over the planning horizon, historical D3 RIN prices and ICF forecasts of D3 RIN prices were used to develop 500 Monte Carlo simulation draws.

Historical weekly D3 RIN prices were collected from the EPA *RIN Trades and Price Information* website, spanning the period January 2015 through March 2025.[7] In order to produce a simulation of average annual prices and compute price dispersion metrics, the historical price data was averaged by year.

ICF provided an annual D3 RIN price forecast real dollars (i.e., 2024 $/MMBtu). Specifically, they provide a base, upside, and downside annual price forecast over the 2025-2041 time frame. To extend the price forecast to match the 2025 IRP planning horizon, prices over the period 2042-2050 were calculated as follows, respectively:

$$P_t = P_{t-1} * (1 + RRI)$$

where, P_t is the annual forecasted price, P_{t-1} is the one-period lag of annual forecasted price, and RRI is the equivalent growth rate calculated over the period 2032-2040.

Each Monte Carlo simulation was calculated over the full IRP planning horizon as follows:

Step 1: For a given year in the IRP forecast horizon, a random variable is generated from a normal distribution with a mean equal to that year's ICF reference forecast and standard deviation equal to the historical variability of annual average prices.

Step 2: To avoid large, negatively autocorrelated price swings, the price generated in step 1 is smoothed out by calculating an equally weighted rolling average. The rolling average is composed of the price from step 1 and the one- and two-period price lags.[8]

[7] https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rin-trades-and-price-information
[8] To initialize this process for the first forecast year (2025), the 2023 historical average D3 RIN price and 2024 ICF base forecast price are used in each Monte Carlo simulation.

Step 3: To limit the potential of extreme outliers in the data generation process, if a price larger (smaller) than the corresponding ICF upside (downside) price forecast materializes in step 2, then the upside (downside) price is instead used and subsequently augmented by adding (subtracting) a random variable generated from a normal distribution which may take any continuous value between 0 and 2; otherwise, the price generated in step 2 is utilized.

Figure 7.22 in Chapter 7 provides a visual of this simulation.

G.5 Climate Commitment Act Allowance Price Simulation

The CCA price simulation relied on forecasts from a third-party consultant (cCarbon) and is bounded by the allowance price ceiling and price floor. The simulation is conducted in five steps and relies on the following inputs:

Table G-3: Parameters for CCA Allowance Price Simulation

Inputs:	*5% CI*	*Mean*	*SD*	*Chance of being below price ceiling:*
Year 1 Value Range	$25.62	$59.58	$20.65	40%
Percent Range	5.00%	6.94%	1.18%	

The fifth percentile (5% CI) of $25.62 per allowance is based on the low-case scenario provided by cCarbon. The mean is based on the Reference Case forecast and the standard deviation (SD) is calculated from these two numbers assuming a normal distribution. The *percent range* for the fifth percentile is the compound annual growth rate (CAGR) of the allowance prices in the low case from 2025 to 2050. Similarly, the percent range for the mean is the CAGR for the Reference Case forecast from 2025 to 2050. In order to reflect an expectation that there is a high likelihood of the allowance price being capped at the ceiling, the simulation incorporates a 40% chance that a draw is below the ceiling price.

Step 1: Simulate the first-year allowance price (i.e., 2025) based mean and standard deviation of specified in Table G-3 and assuming a normal distribution.

Step 2: Simulate an indicator variable with a 40 percent chance of being 1 and 60 percent chance of being zero.

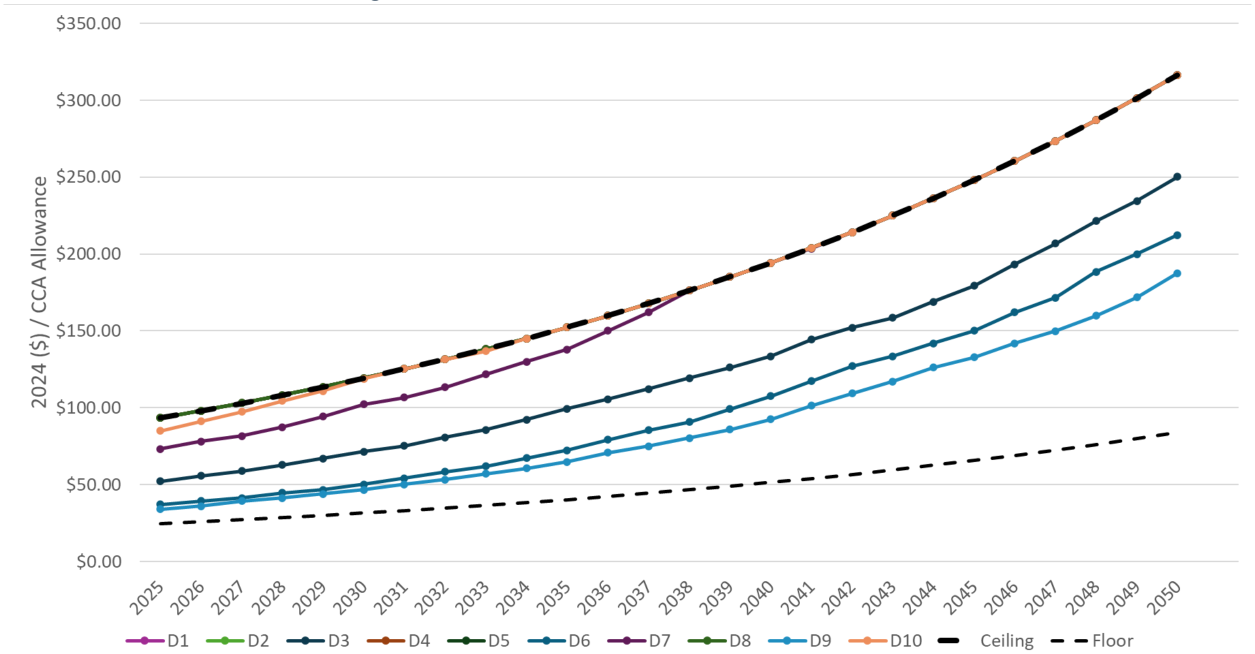
Step 3: Simulate annual growth rates using the mean and standard deviation for the *percent range* specified in Table G-3 and assuming a normal distribution for each draw and each year in the planning horizon.

Step 4: Combine step 1 and step 2 to create a first-year price (i.e., if indicator variable = 0 then first year price is equal to the ceiling price, otherwise it is equal to the simulated value).

Step 5: Combine step 2 and step 4 to create a price allowance path.

For any year in the planning horizon, allowance prices are bound by the price ceiling and price floor. Figure G-5 illustrates the different allowance price paths created through this simulation.

Figure G-5: CCA Allowance Price Simulation



Appendix H – Portfolio Results and Selection

H.1 Oregon – Climate Protection Program

H.1.1 Scenario 1 – CPP/CCA Compliance

S1.a – Low-cost Compliance

Figure H-1: S1.a Compliance Resources

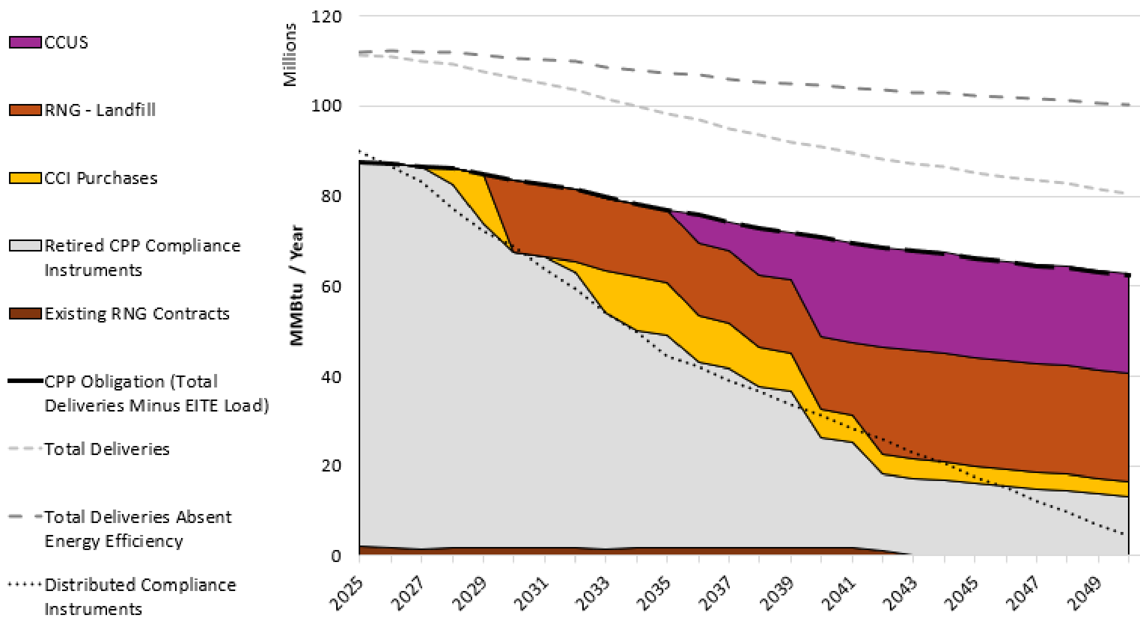
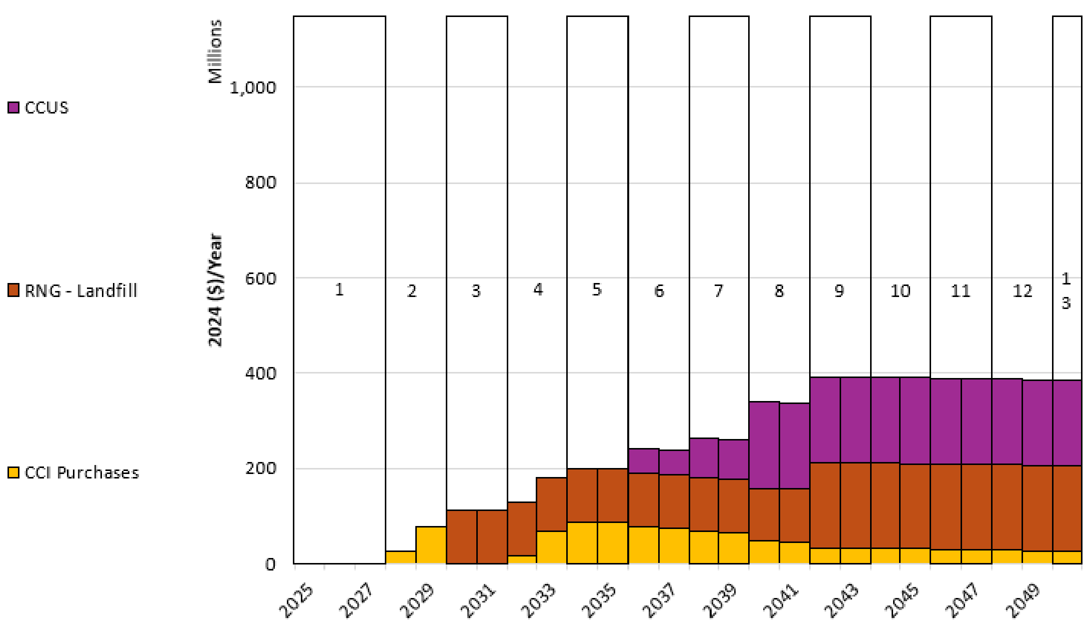


Figure H-2: S1.a Compliance Costs



S1.b – Mid-cost Compliance

Figure H-3: S1.b Compliance Resources

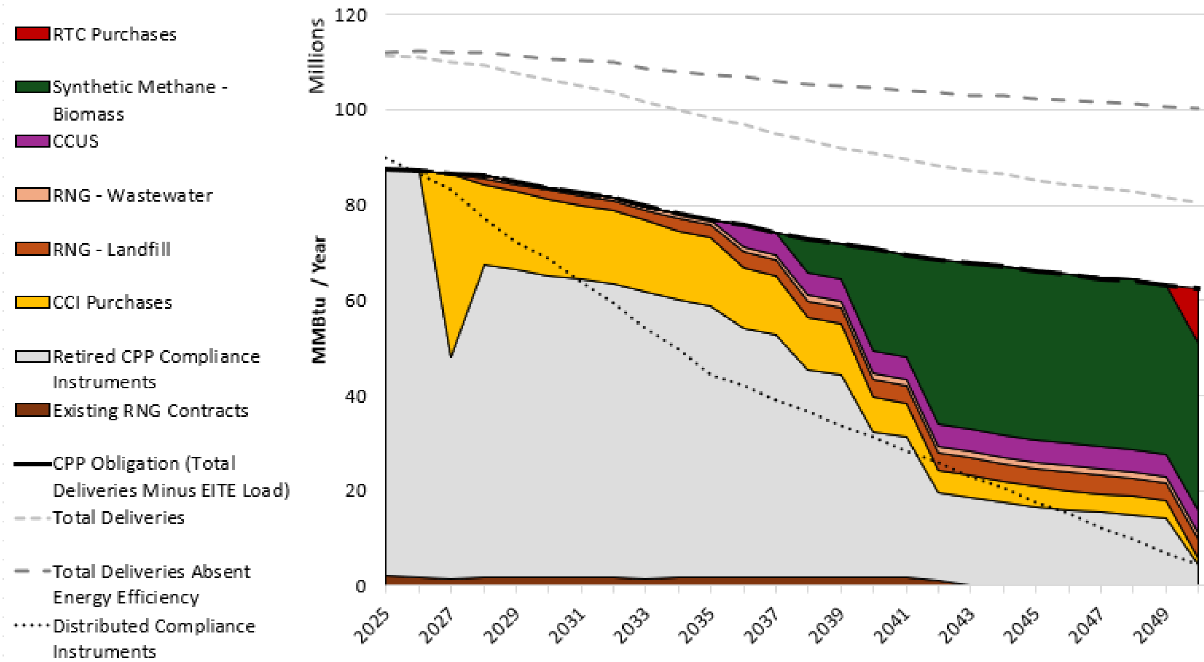
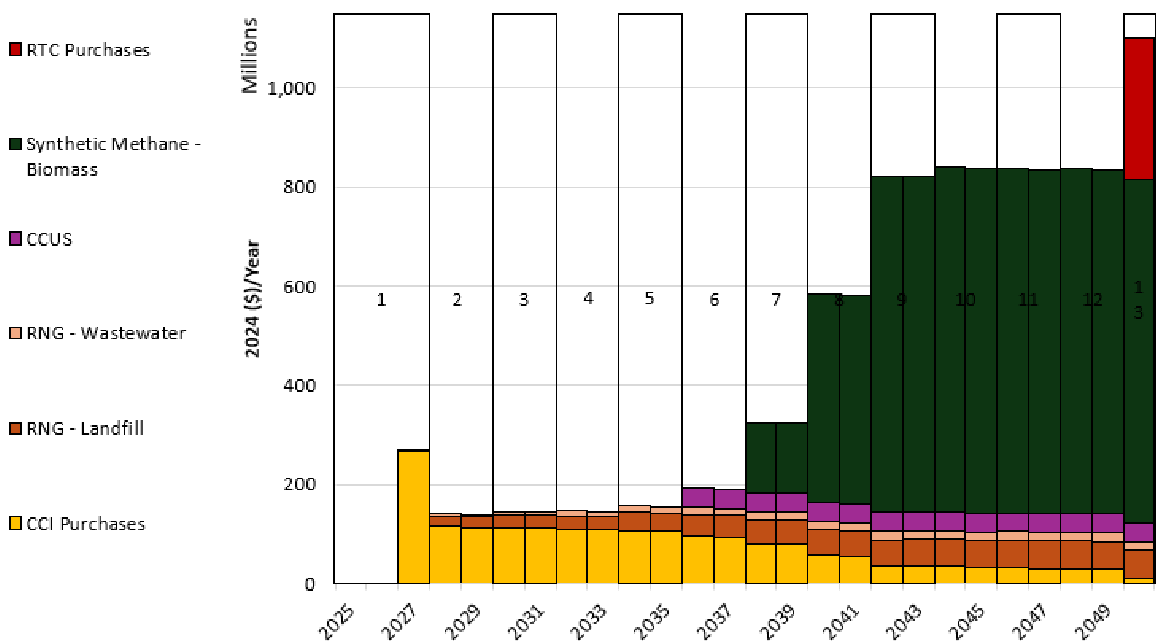


Figure H-4: S1.b Compliance Costs



S1.c – High-cost Compliance

Figure H-5: S1.c Compliance Resources

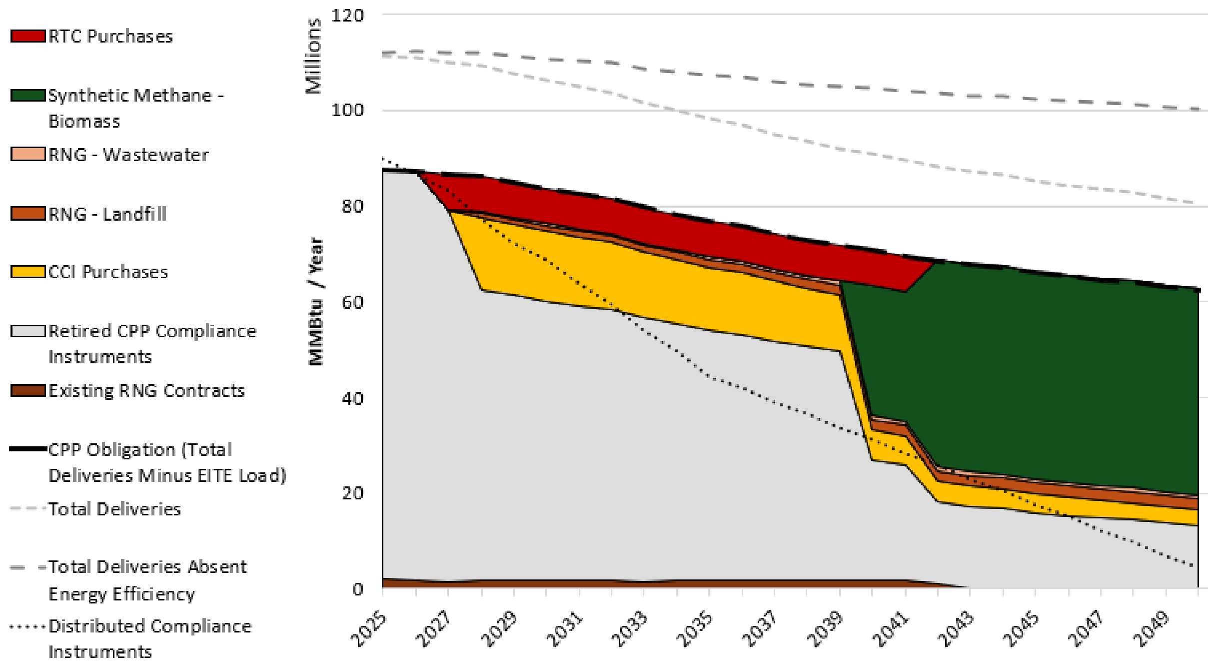
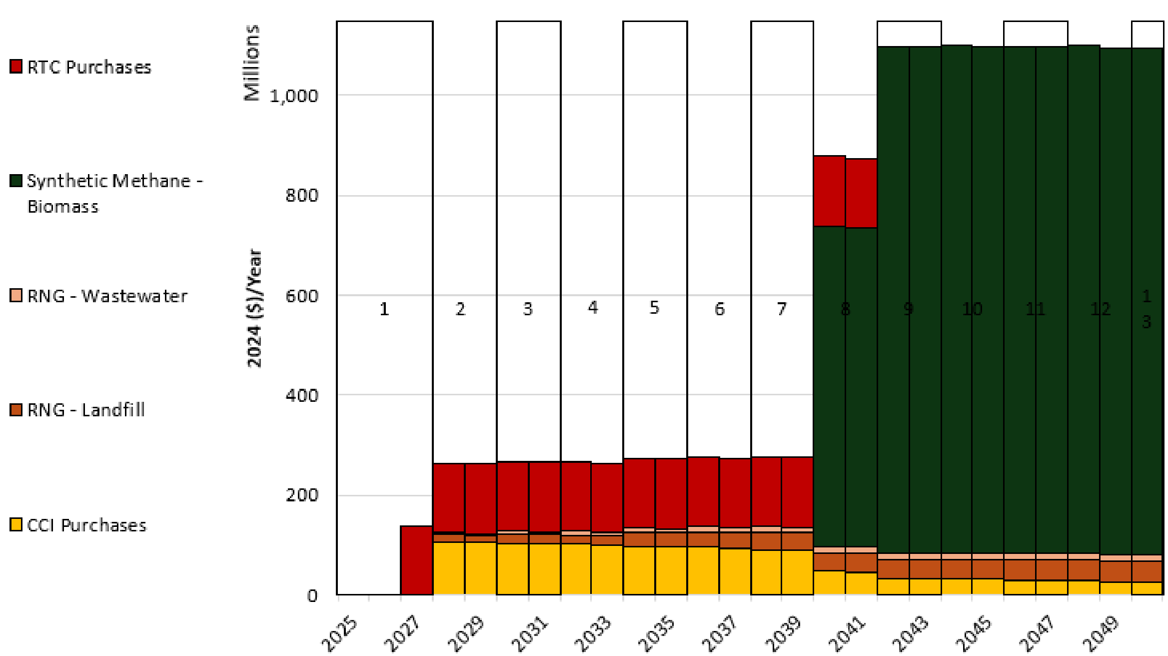


Figure H-6: S1.c Compliance Costs



S1.d – RTC Dependence

Figure H-7: S1.d Compliance Resources

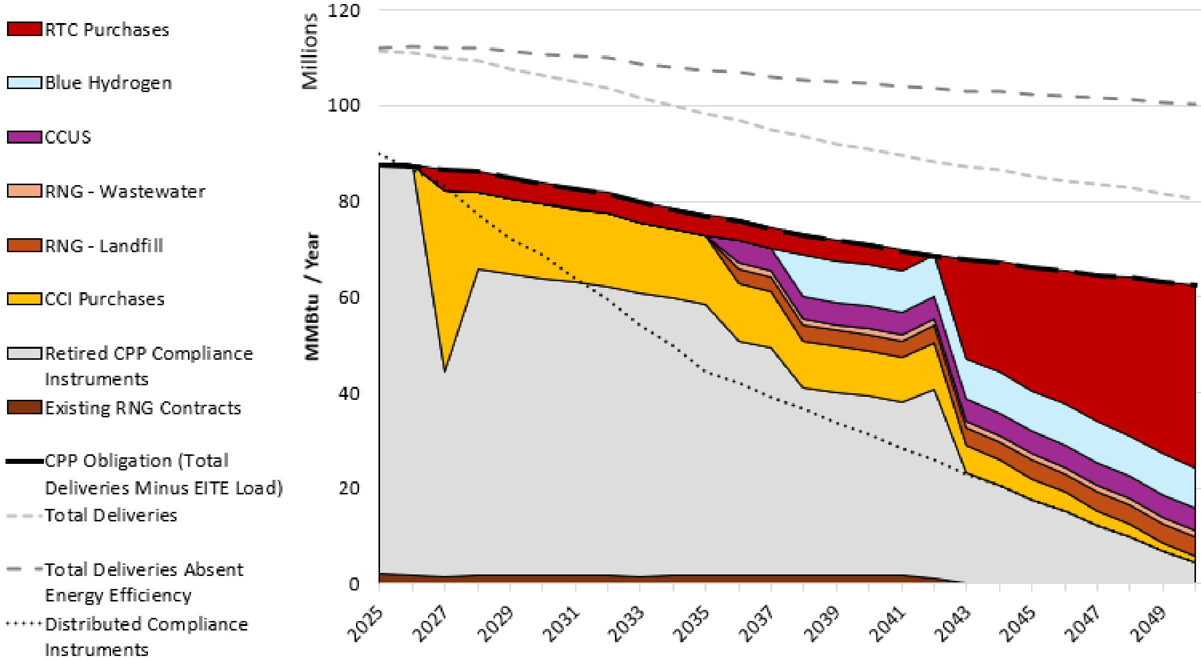
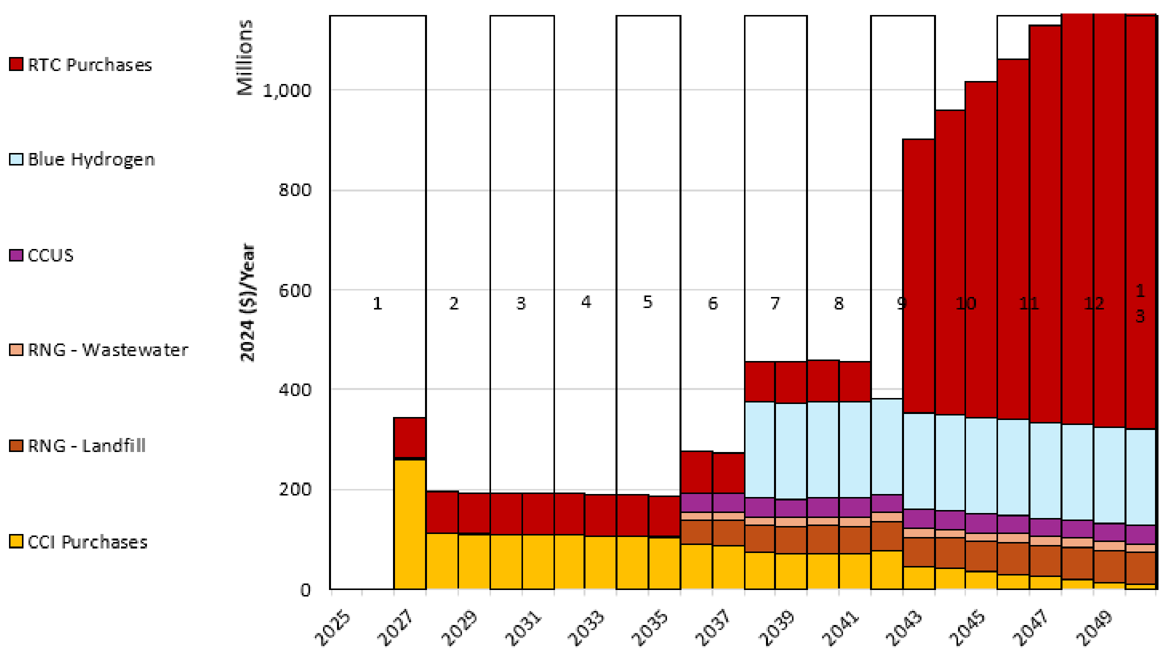


Figure H-8: S1.d Compliance Costs



S1.e – No CPP Instrument Banking

Figure H-9: S1.e Compliance Resources

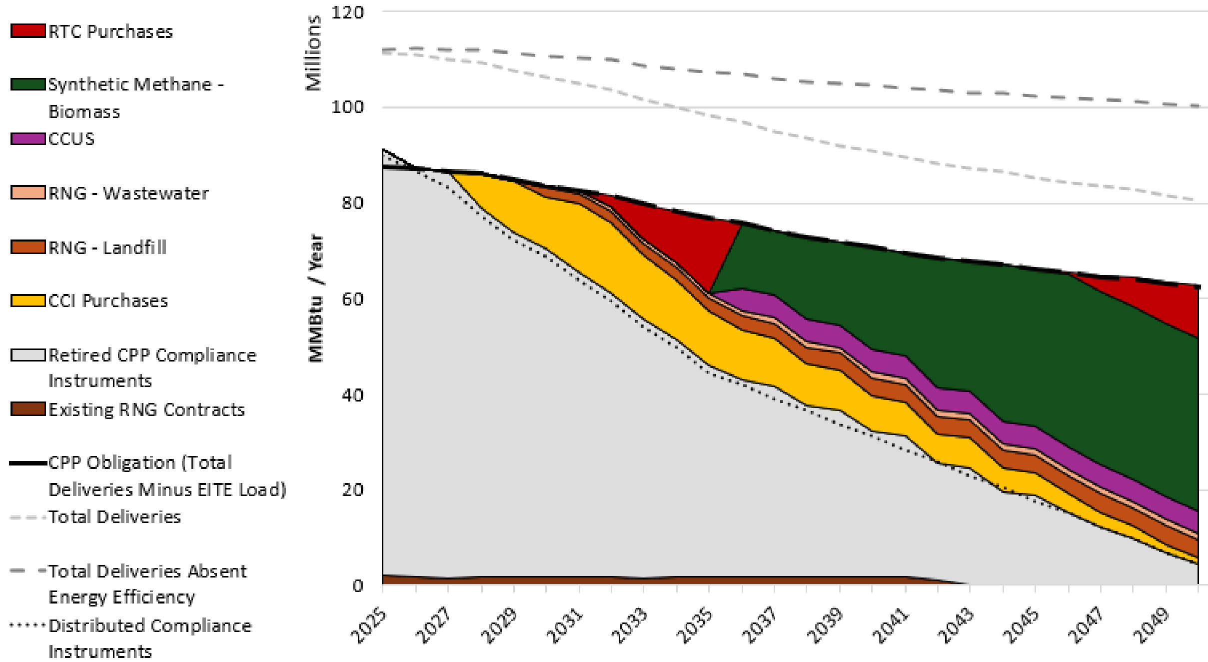
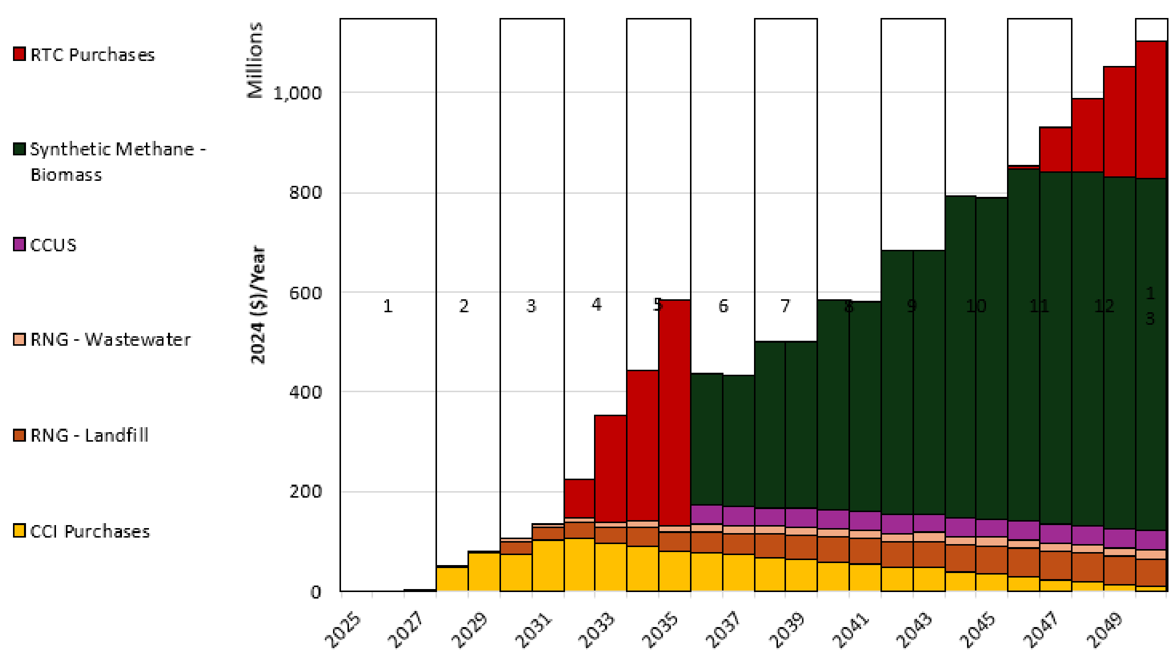


Figure H-10: S1.e Compliance Costs



H.1.2 Scenario 2 – Voluntary RNG Targets

S2.a – SB 98

Figure H-11: S2.a Compliance Resources

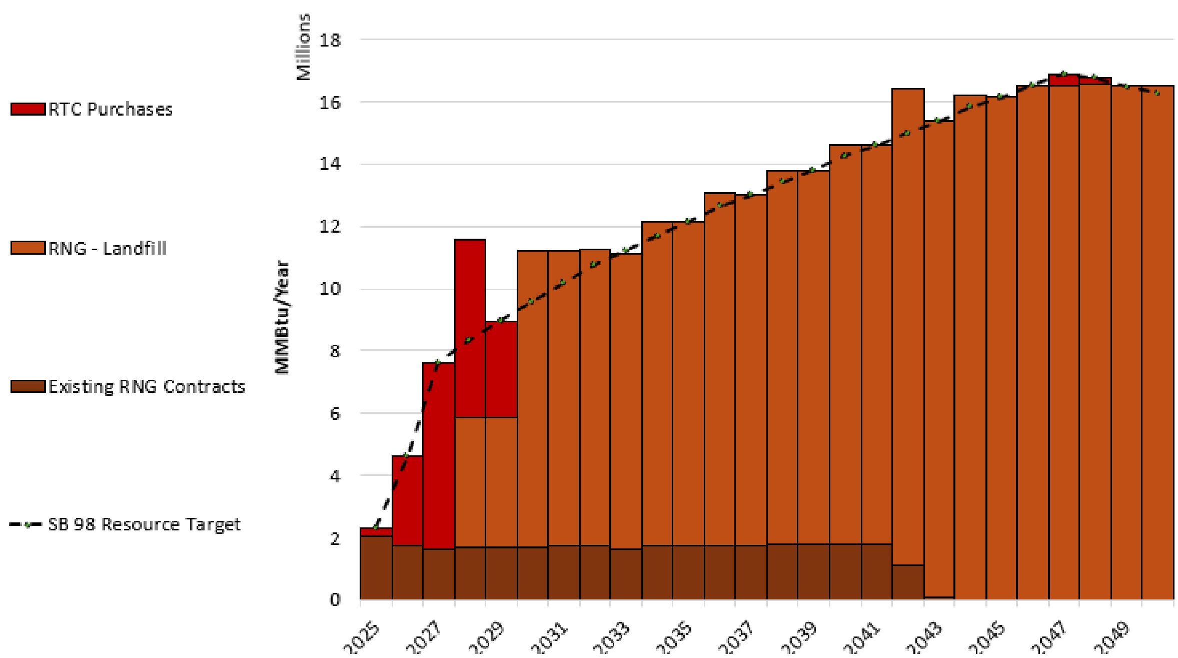
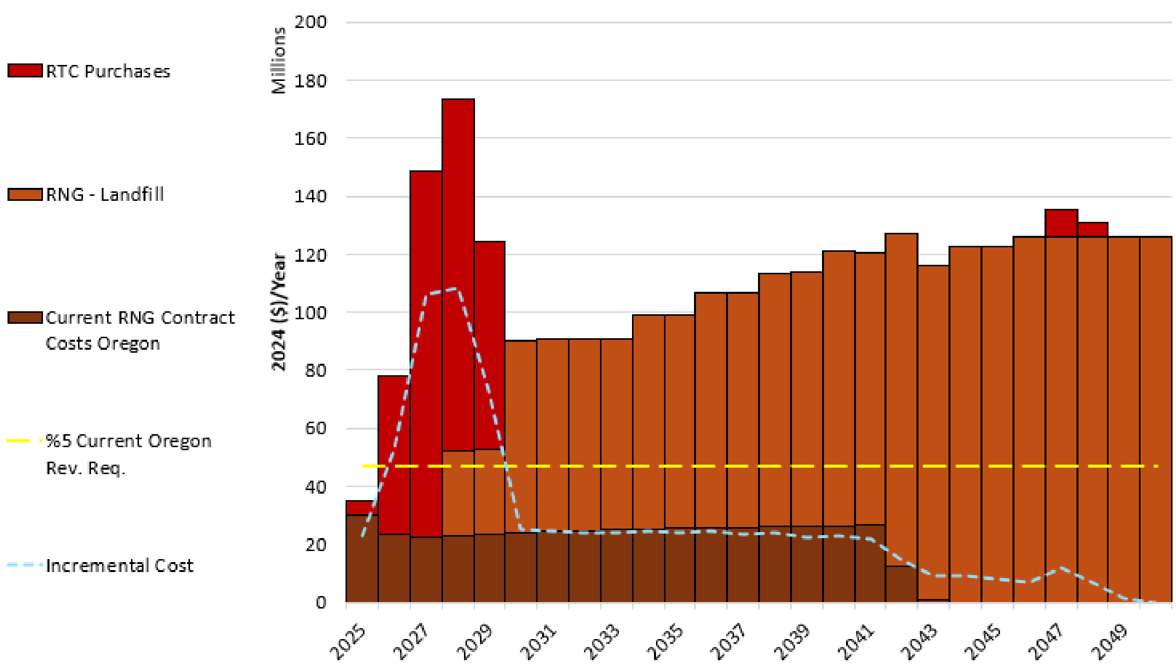


Figure H-12: S2.a Compliance Costs



S2.b – SB 98

Figure H-13: S2.b Compliance Resources

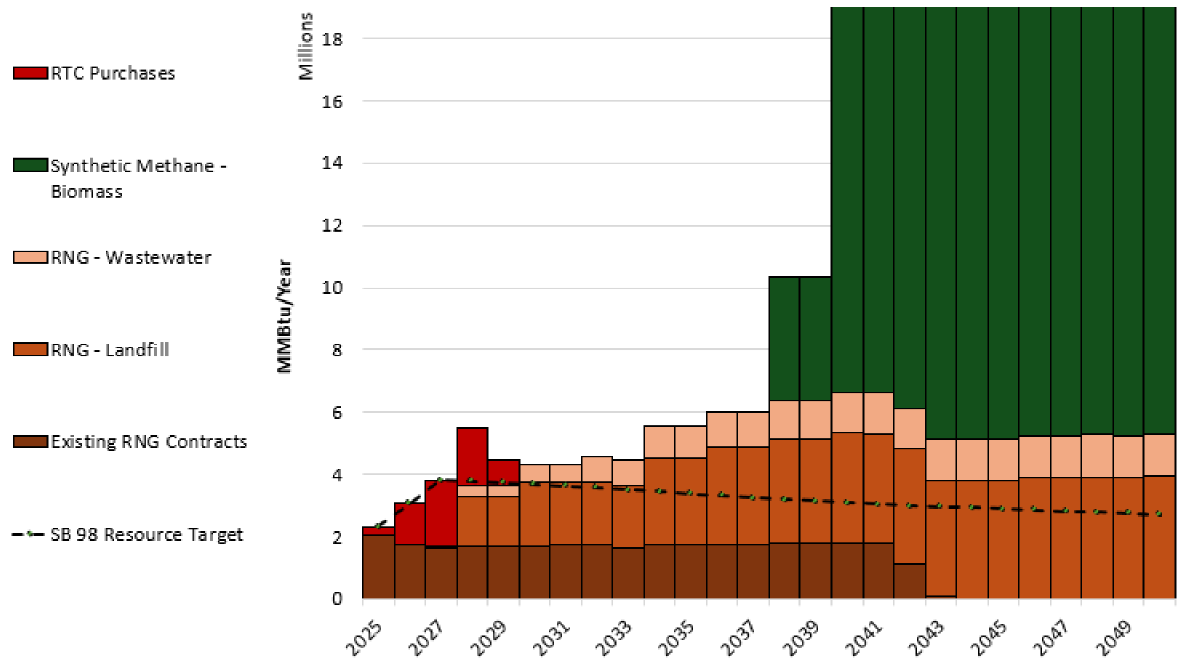
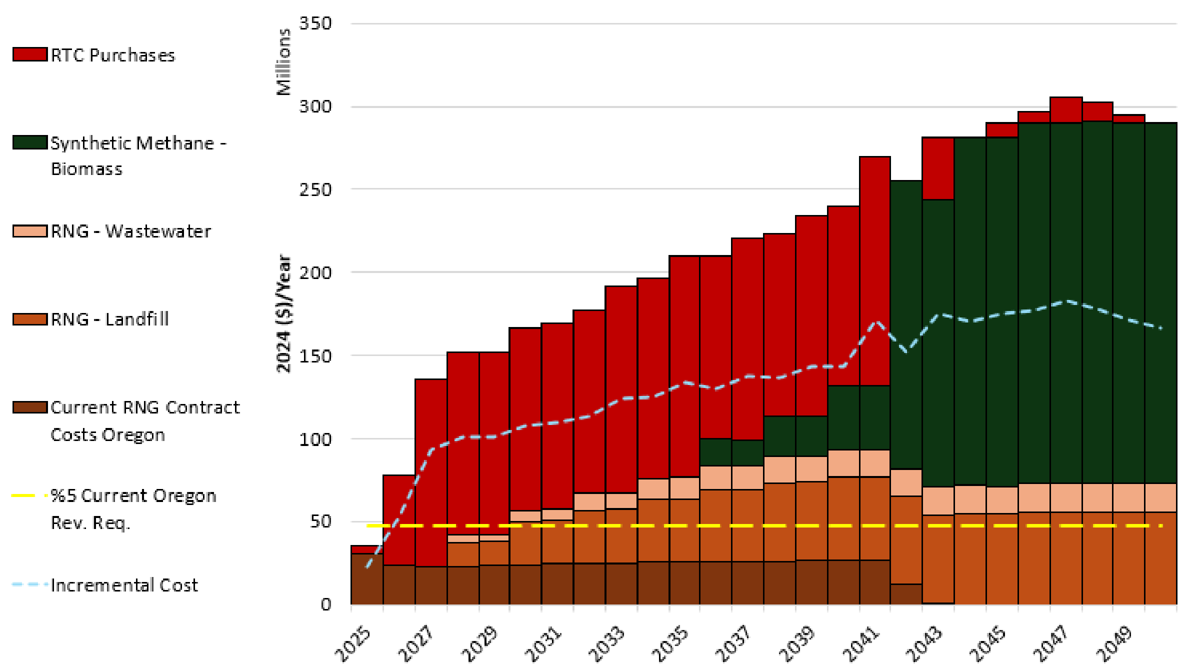


Figure H-14: S2.b Compliance Costs



H.1.3 Preferred Resource Strategy

PRS.a – Preferred Resource Portfolio

Figure H-15: PRS.a Compliance Resources

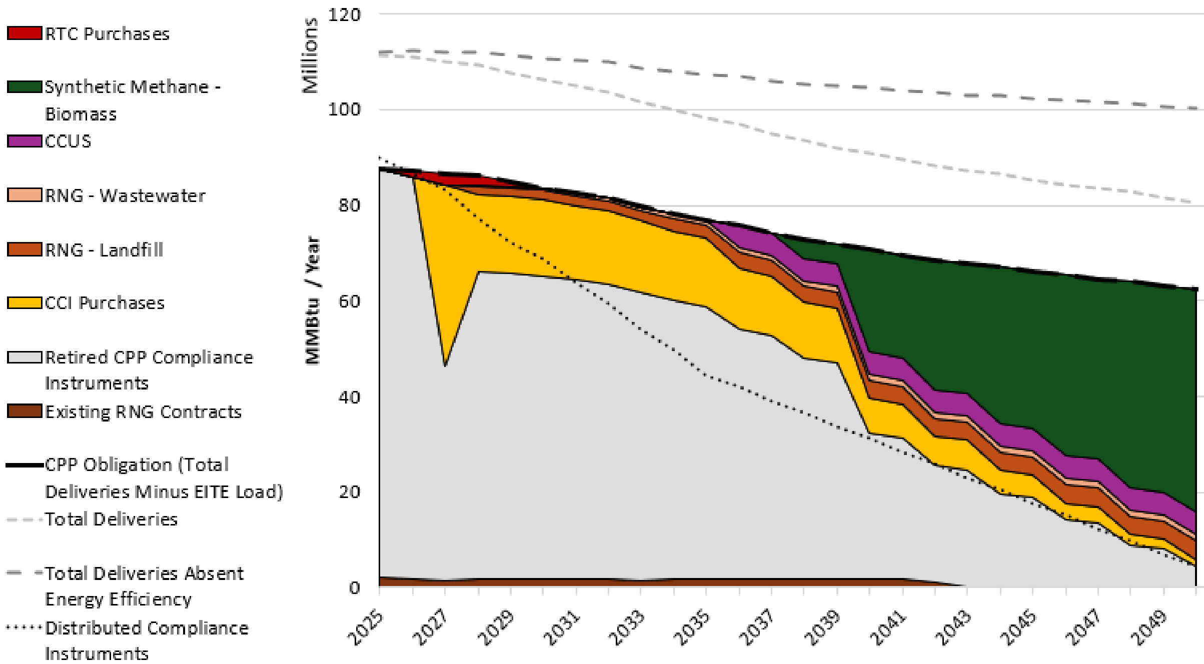
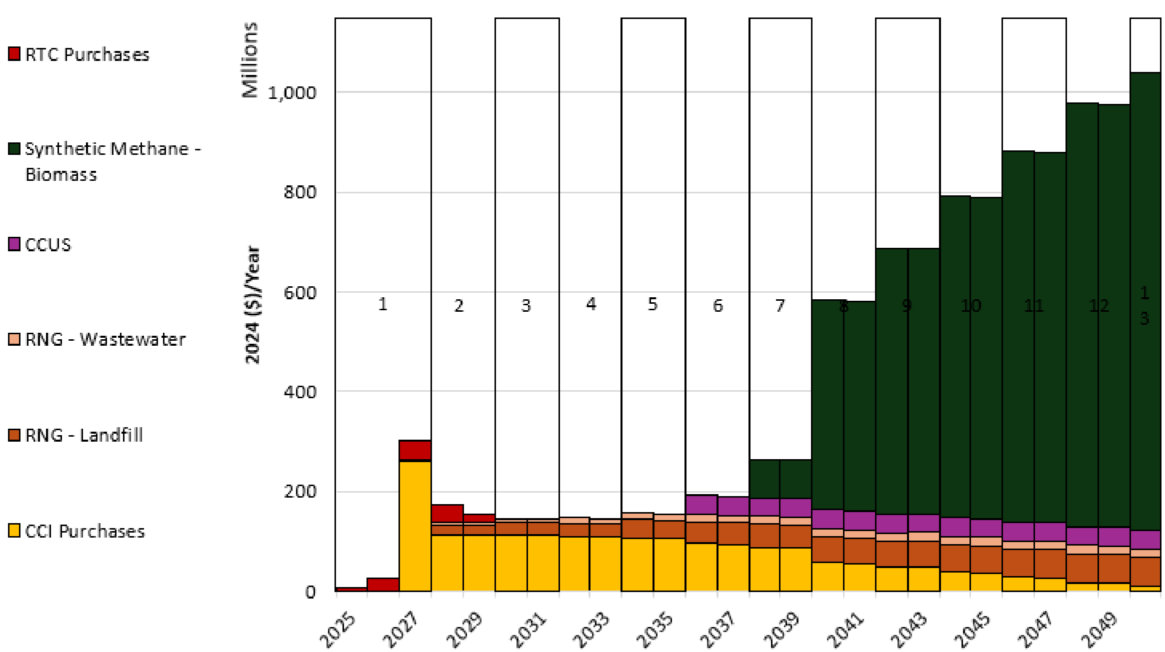


Figure H-16: PRS.a Compliance Costs



H.1.4 Scenario 3 – No GHG Compliance Policies

S3.a – No GHG Compliance

Compliance Resources

The are no compliance resources associated with this scenario.

Compliance Costs

There are no compliance costs associated with this scenario.

H.1.5 Scenario 4 – Growth Recovery

S4.a – Growth Recovery

Figure H-17: S4.a Compliance Resources

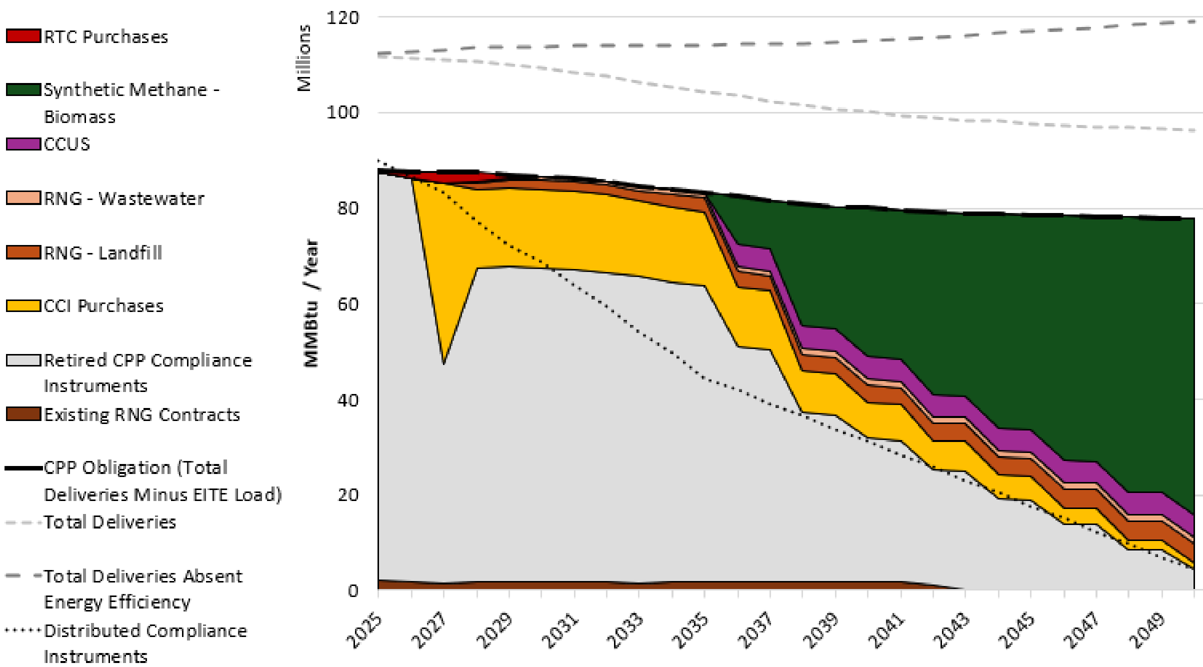
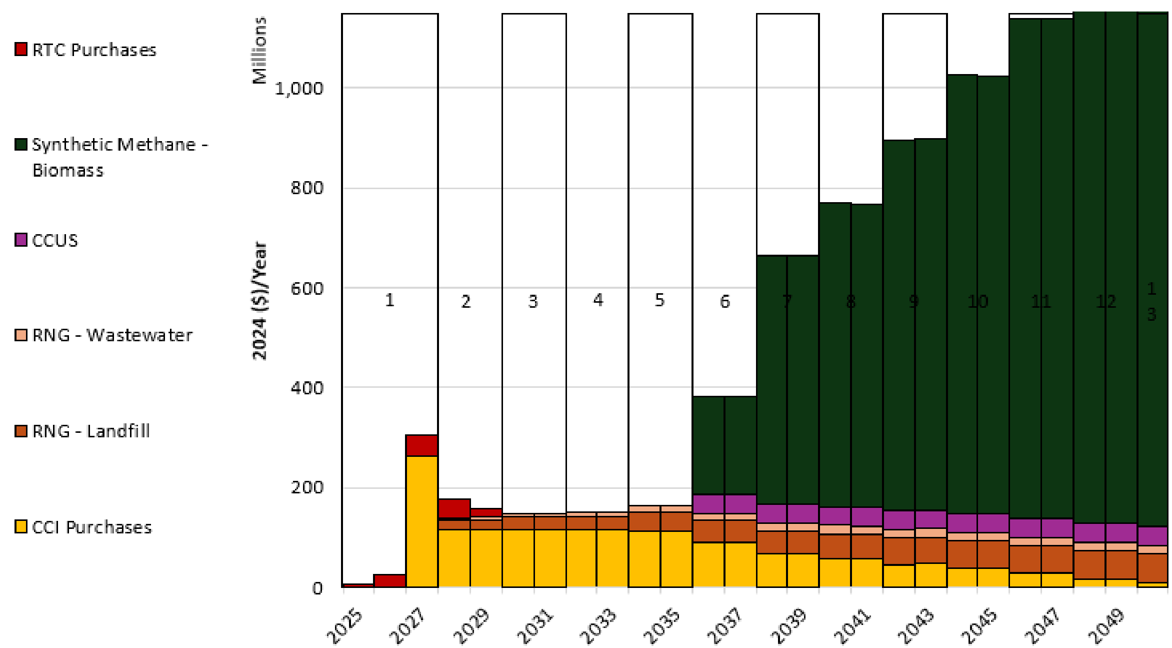


Figure H-18: S4.a Compliance Costs



H.1.6 Scenario 5 – Modest Customer Electrification

S5.a – Modest Customer Electrification

Figure H-19: S5.a Compliance Resources

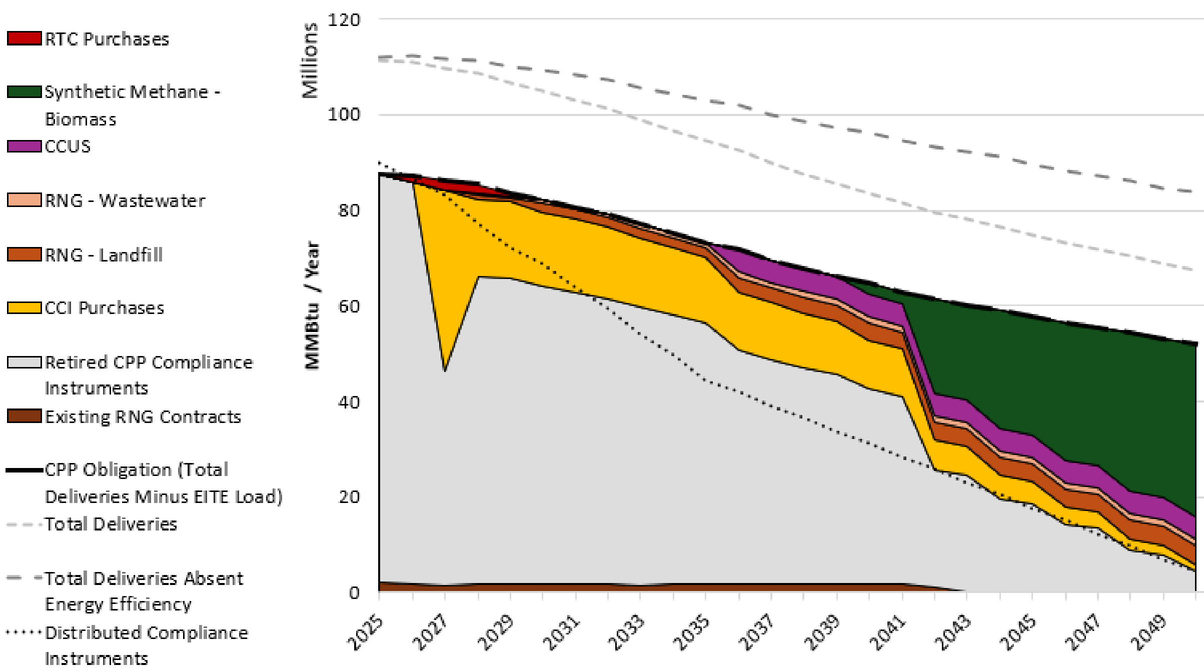
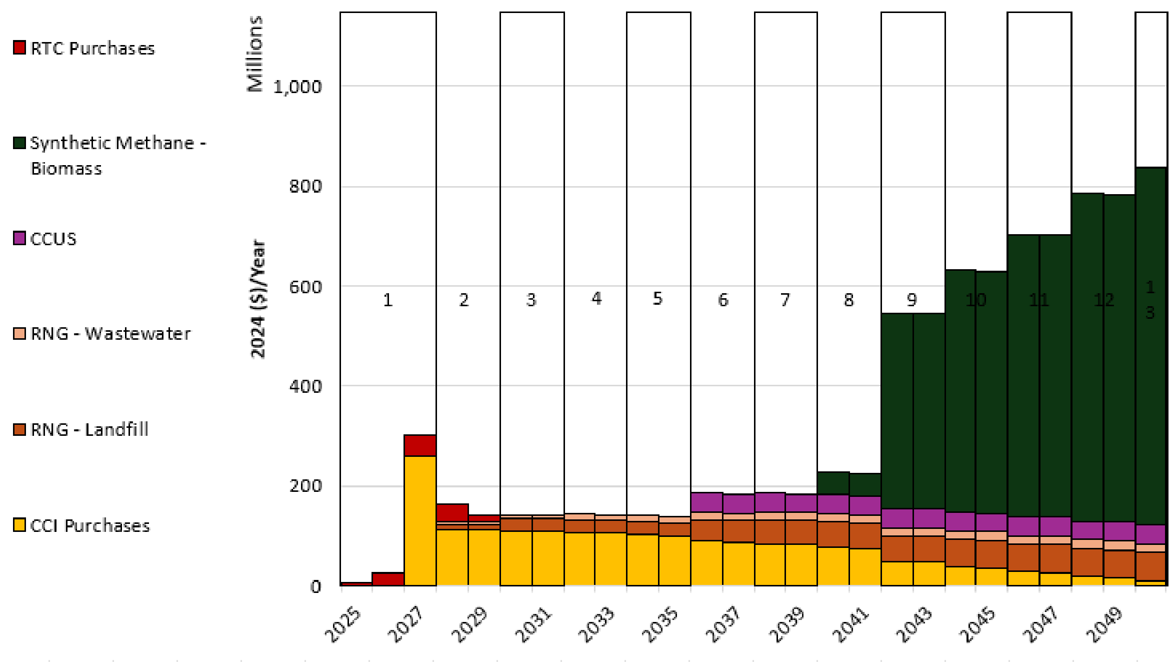


Figure H-20: S5.a Compliance Costs



H.1.7 Scenario 6 – Hybrid System Electrification

S6.a – Hybrid System Electrification

Figure H-21: S6.a Compliance Resources

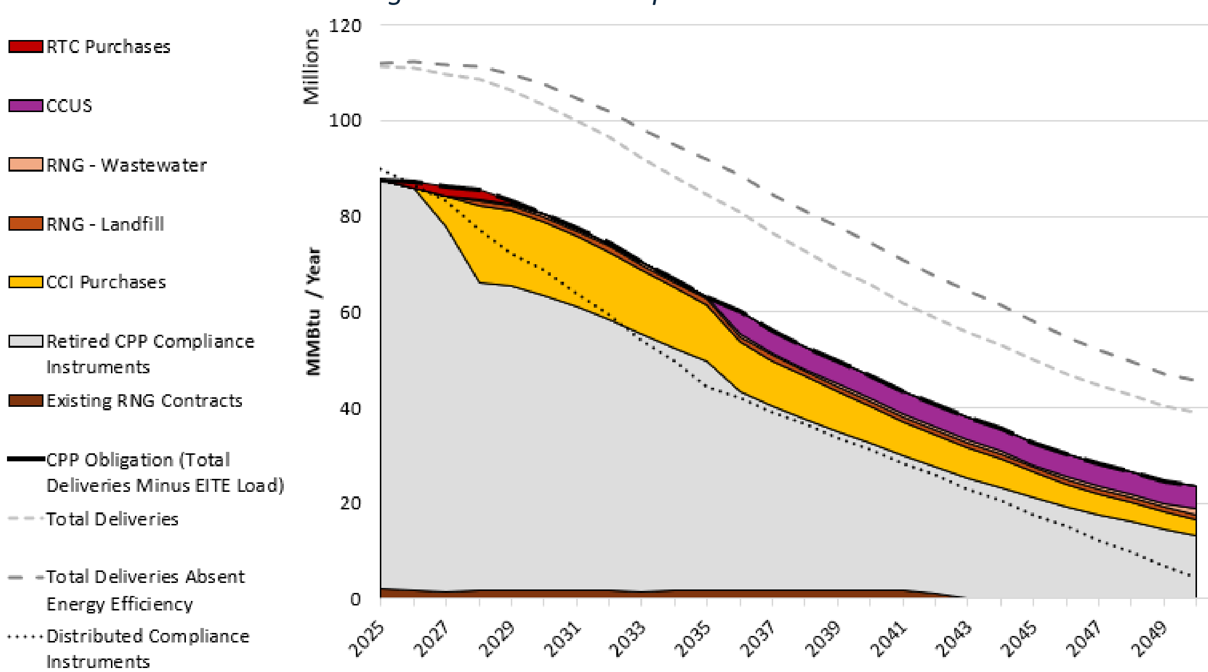
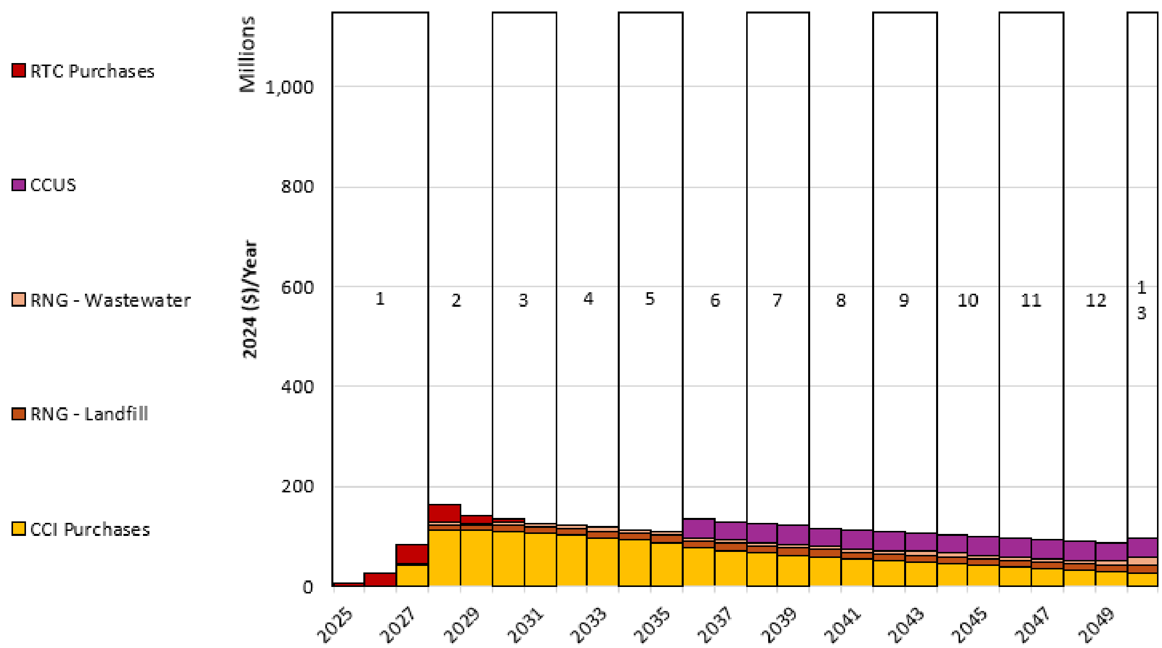


Figure H-22: S6.a Compliance Costs



H.1.8 Scenario 7 – All-Electric Buildings

S7.a – All-Electric Buildings

Figure H-23: S7.a Compliance Resources

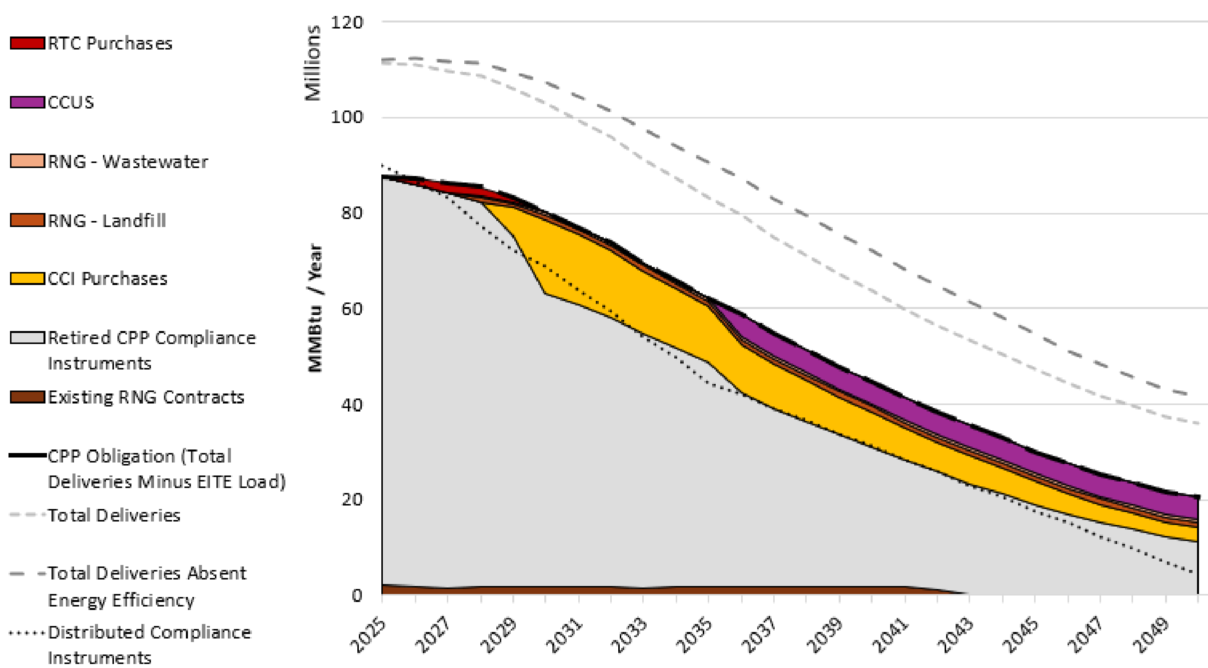
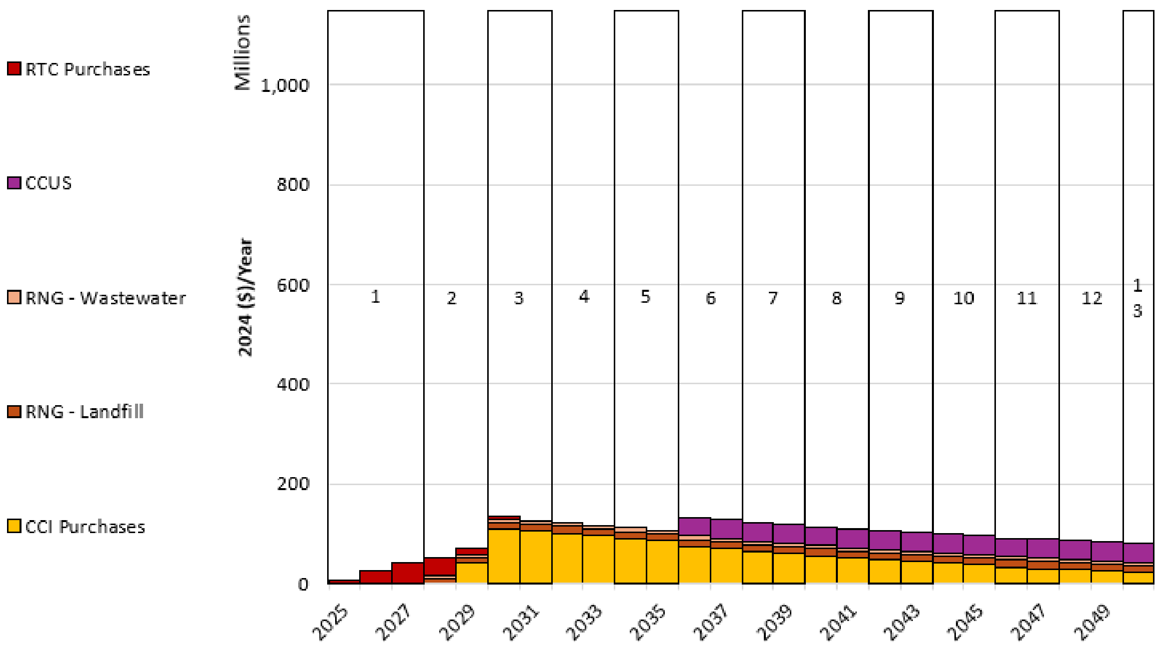


Figure H-24: S7.a Compliance Costs



H.2 Washington – Climate Commitment Act

H.2.1 Scenario 1 – CPP/CCA Compliance

S1.a – Low-cost Compliance

Figure H-25: S1.a Compliance Resources

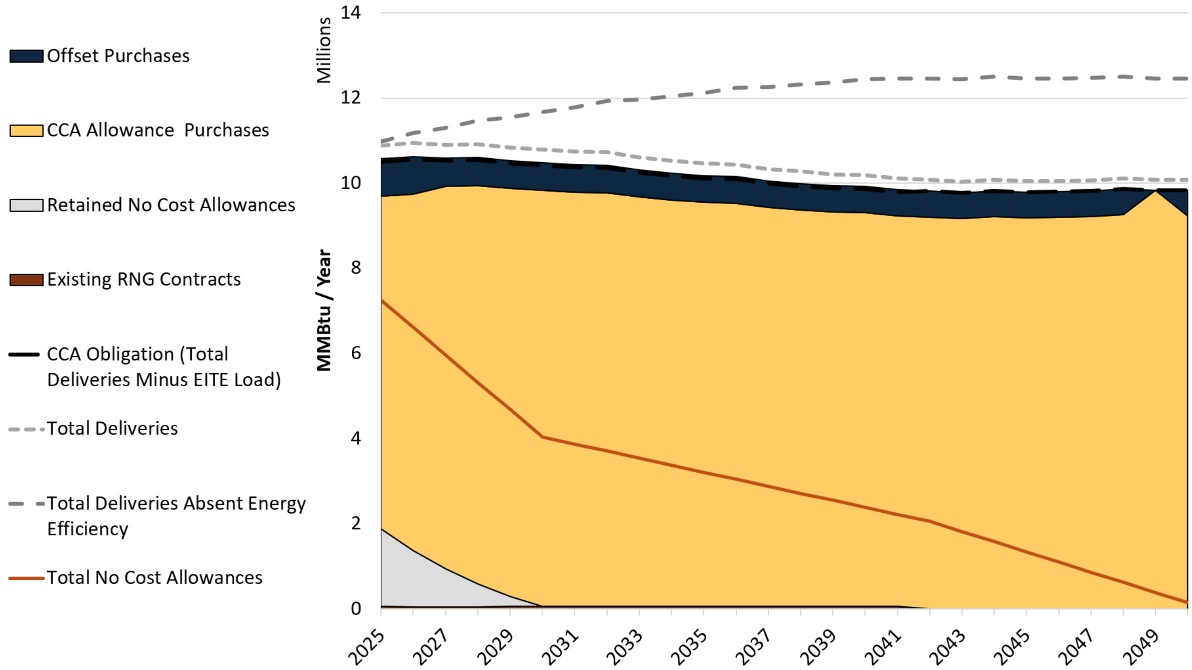
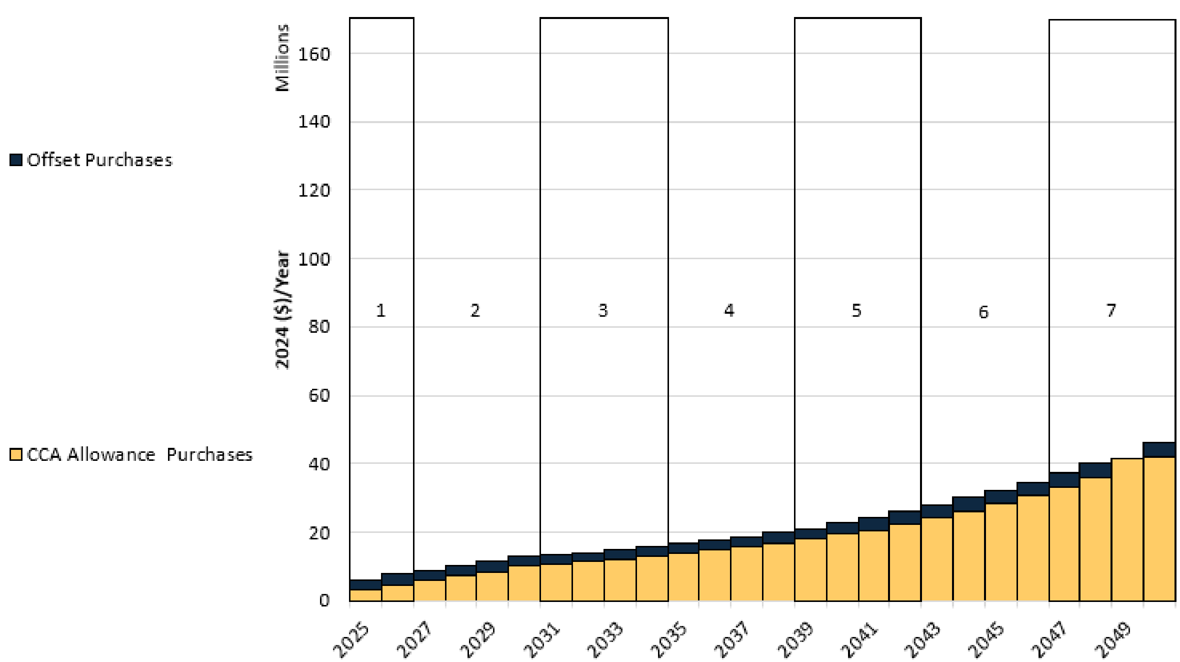


Figure H-26: S1.a Compliance Costs



S1.b – Mid-cost Compliance

Figure H-27: S1.b Compliance Resources

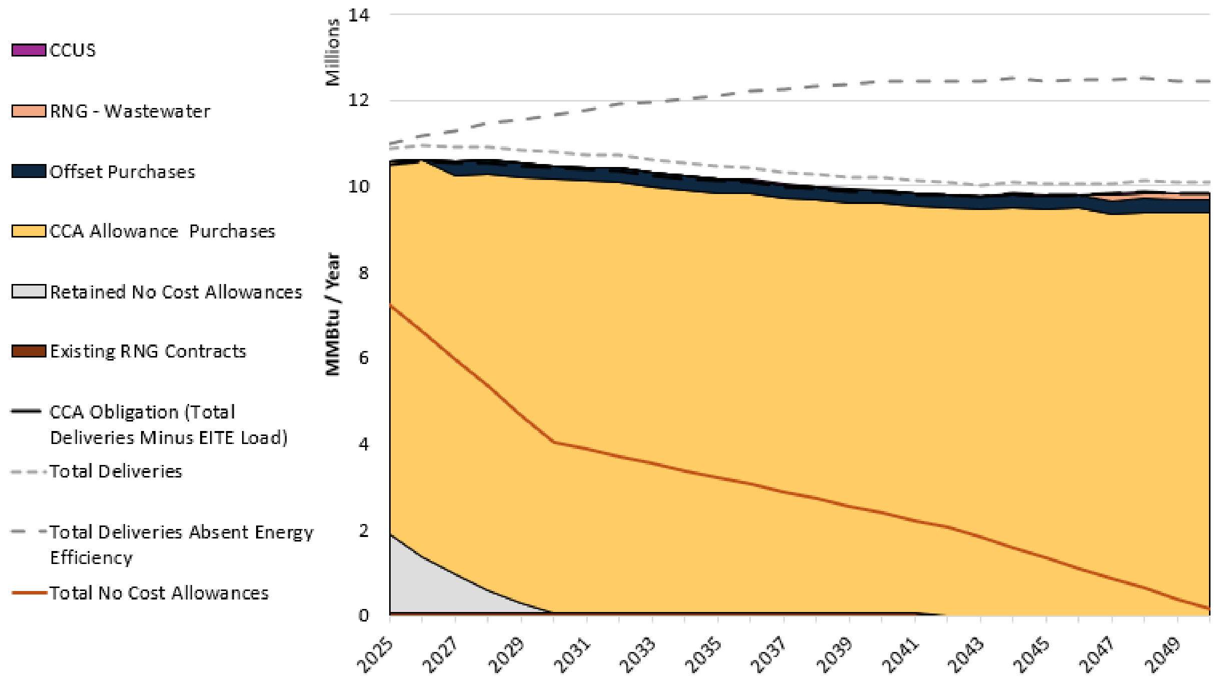
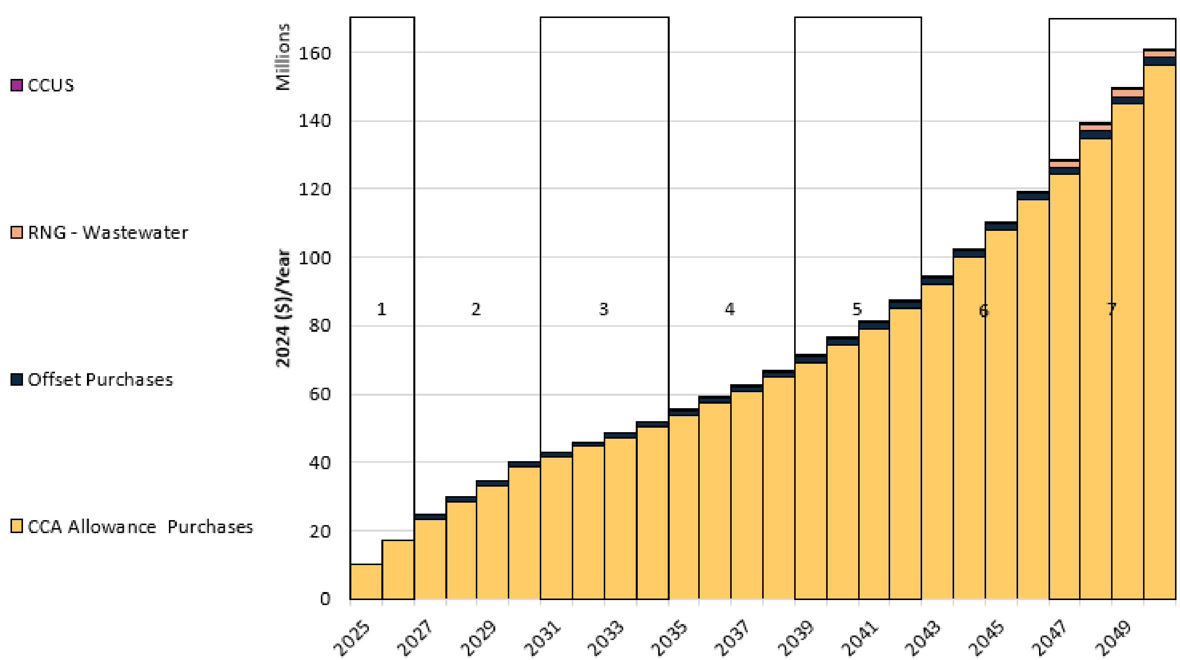


Figure H-28: S1.b Compliance Costs



S1.c – High-cost Compliance

Figure H-29: S1.c Compliance Resources

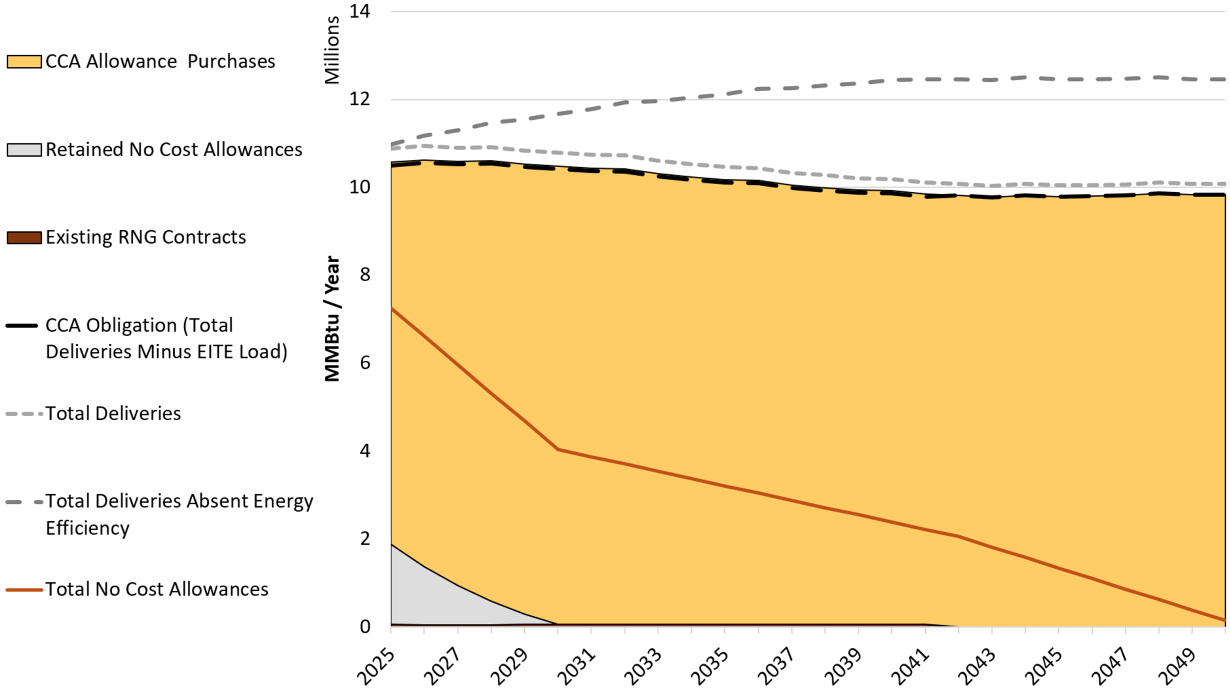
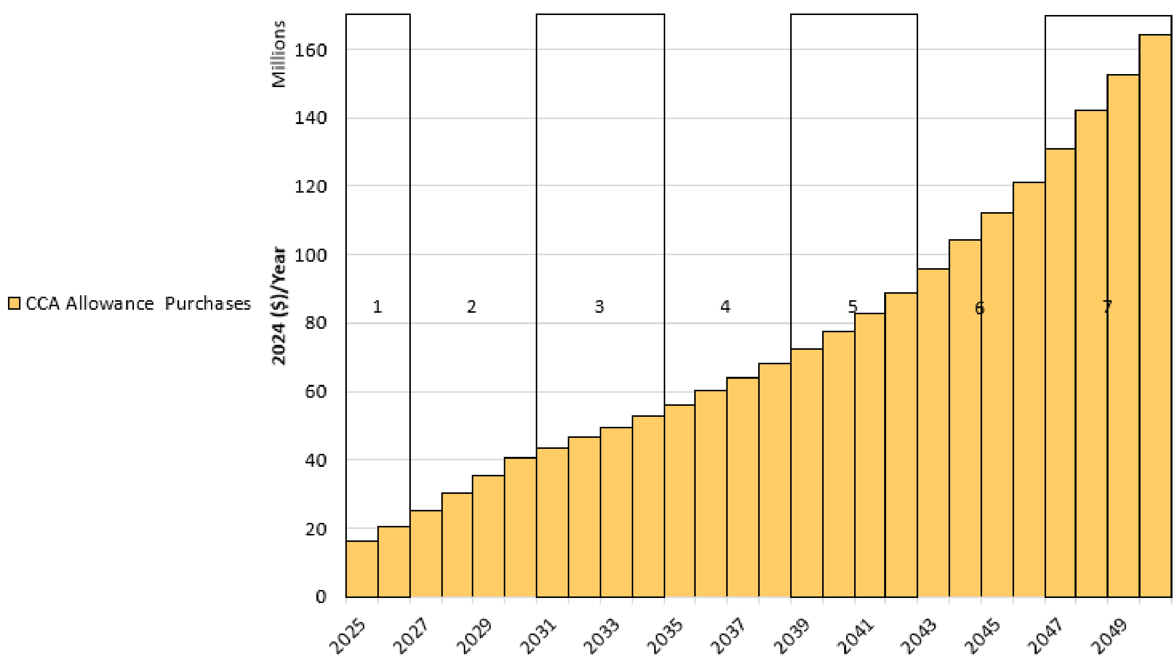


Figure H-30: S1.c Compliance Costs



S1.d – RTC Dependence

Figure H-31: S1.d Compliance Resources

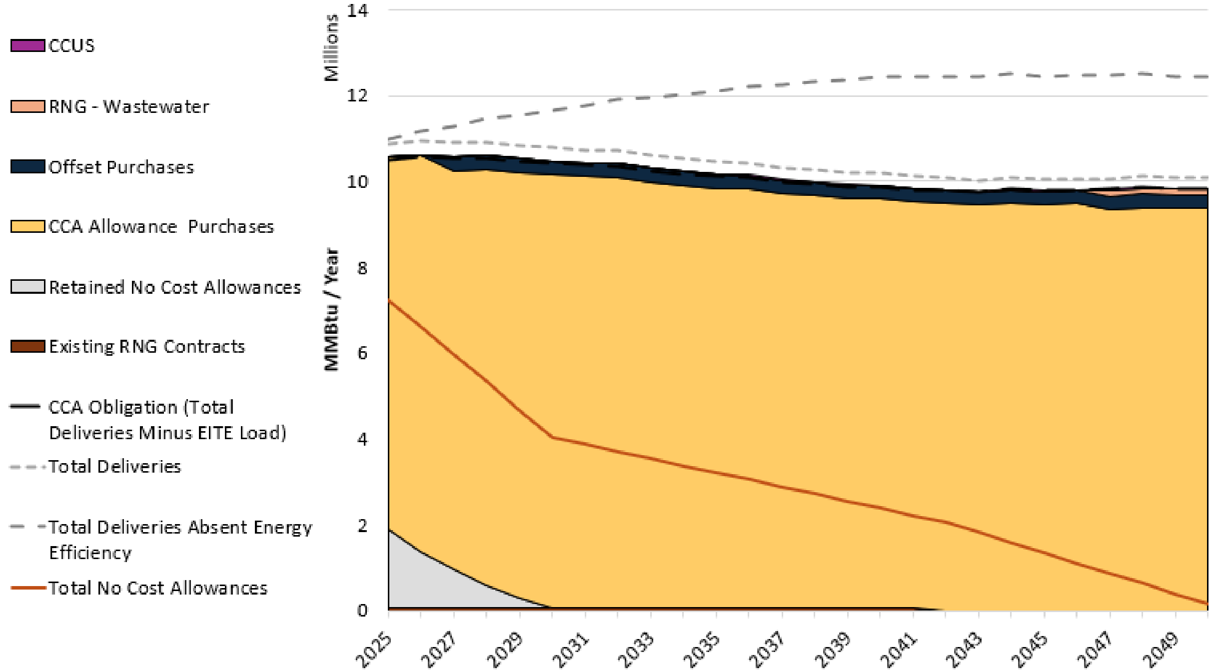
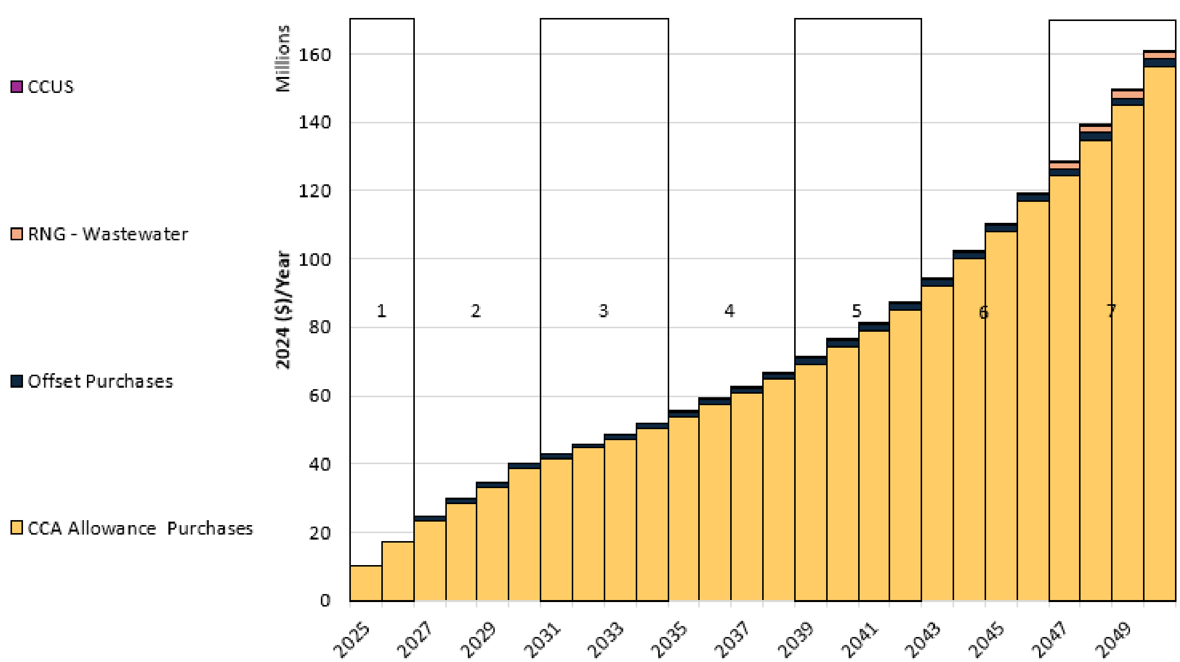


Figure H-32: S1.d Compliance Costs



S1.e – No CPP Instrument Banking

Figure H-33: S1.e Compliance Resources

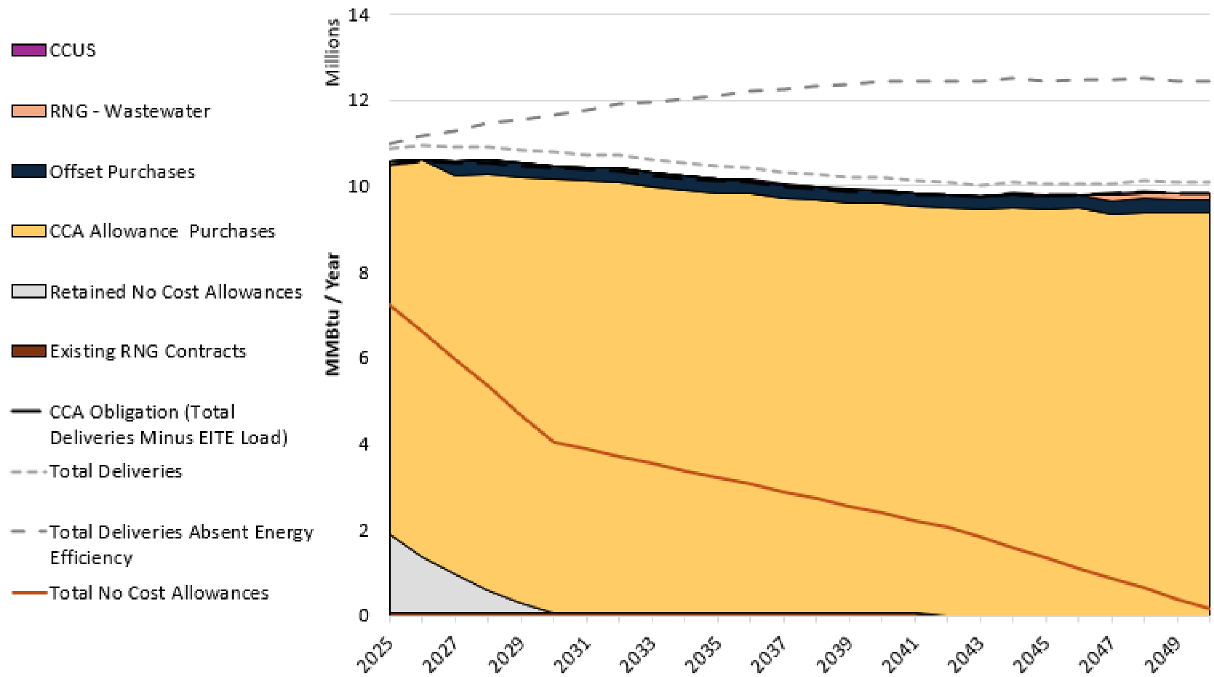
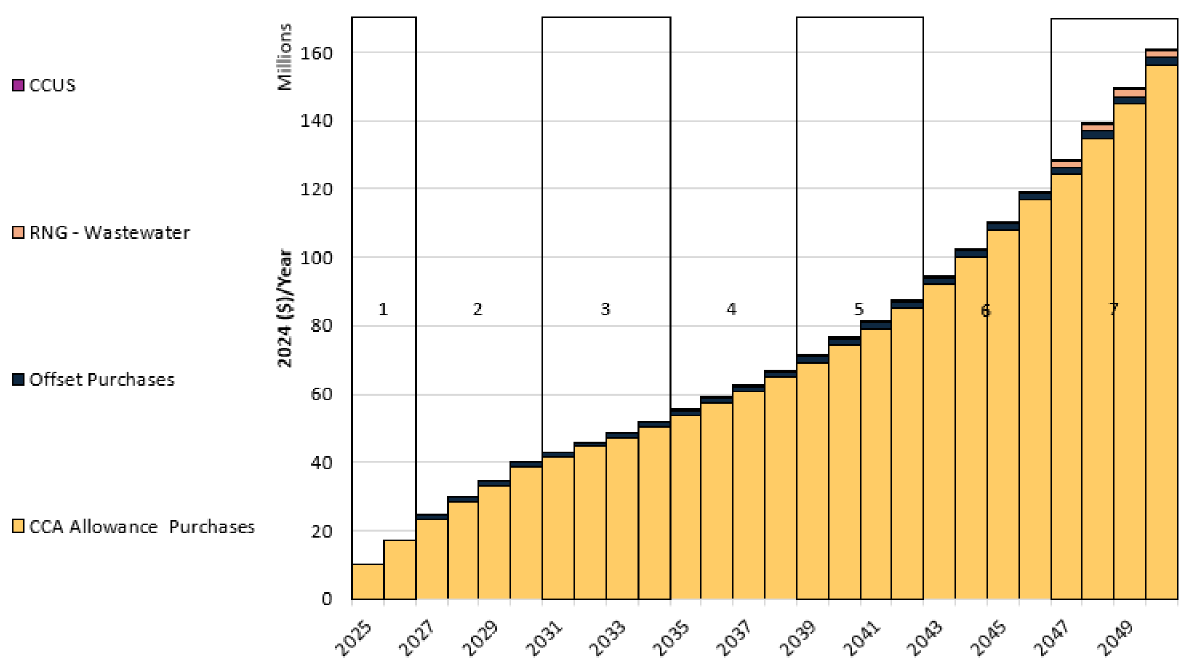


Figure H-34: S1.e Compliance Costs



H.2.2 Scenario 2 – Voluntary RNG Targets

S2.a – SB 98

Figure H-35: S2.a Compliance Resources

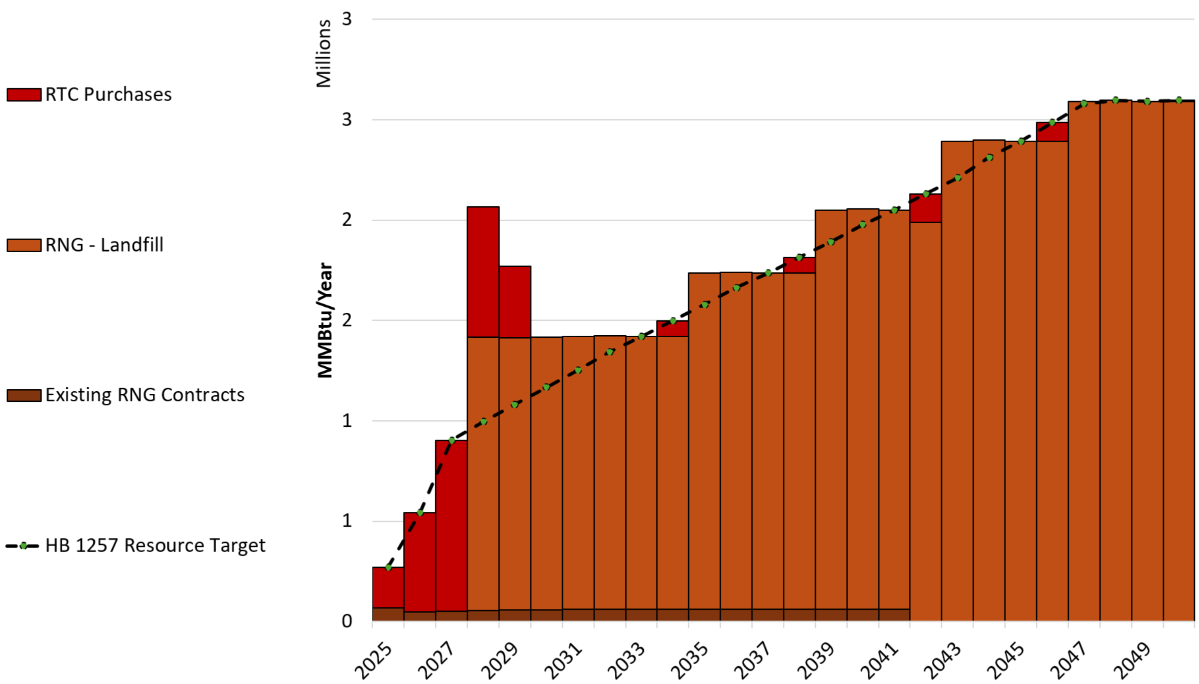
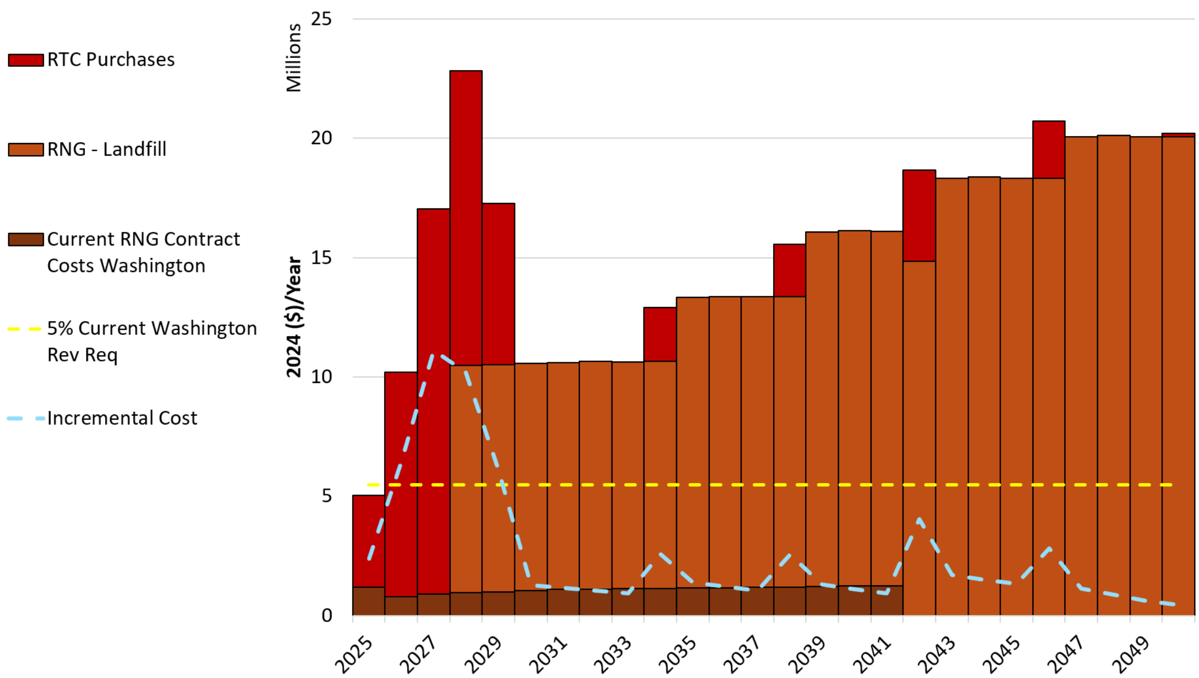


Figure H-36: S2.a Compliance Costs



S2.b – SB 98

Figure H-37: S2.b Compliance Resources

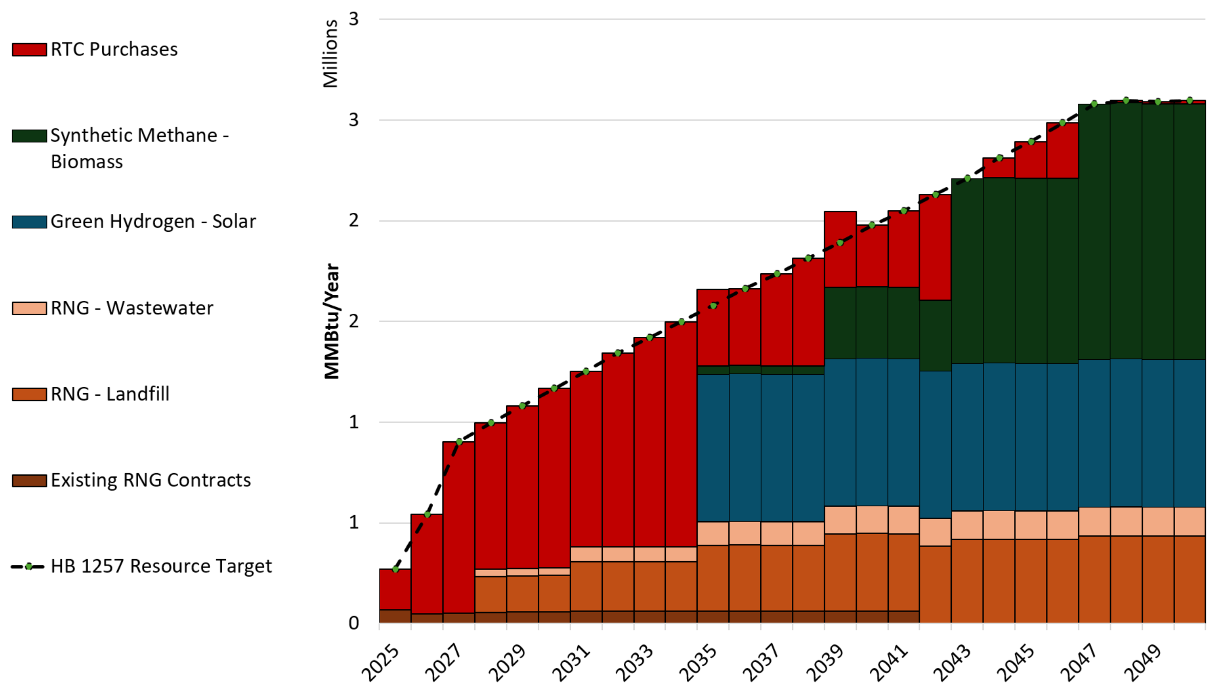
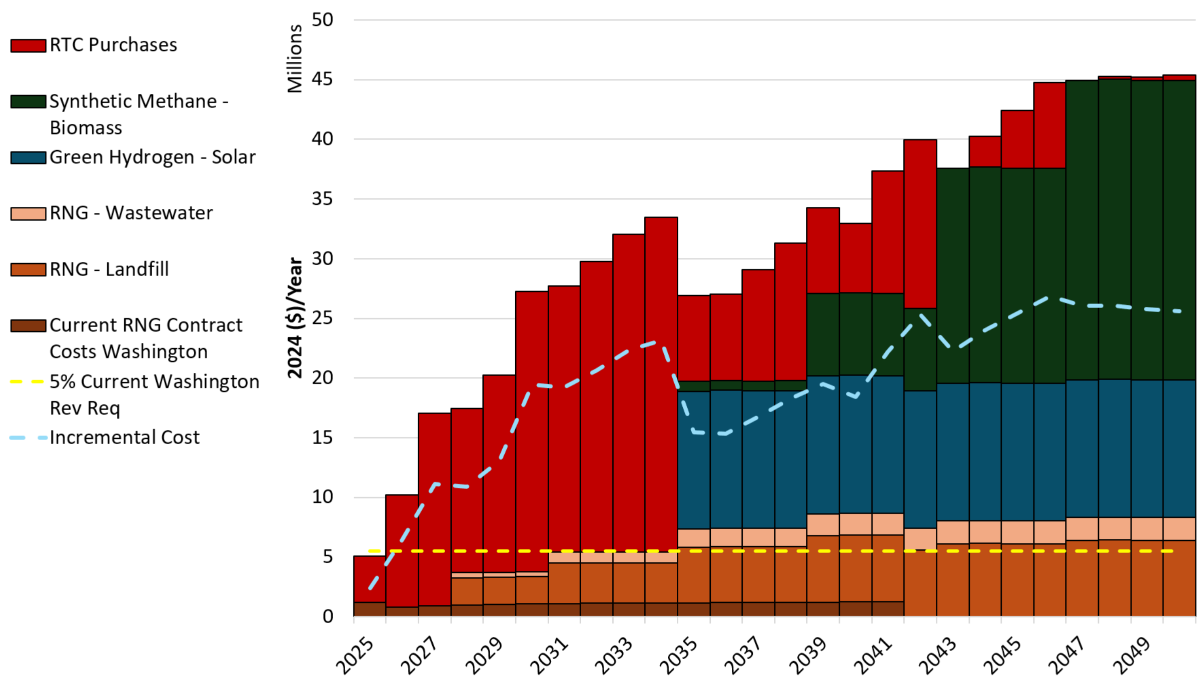


Figure H-38: S2.b Compliance Costs



H.2.3 Preferred Resource Strategy

PRS.a – Preferred Resource Portfolio

Figure H-39: PRS.a Compliance Resources

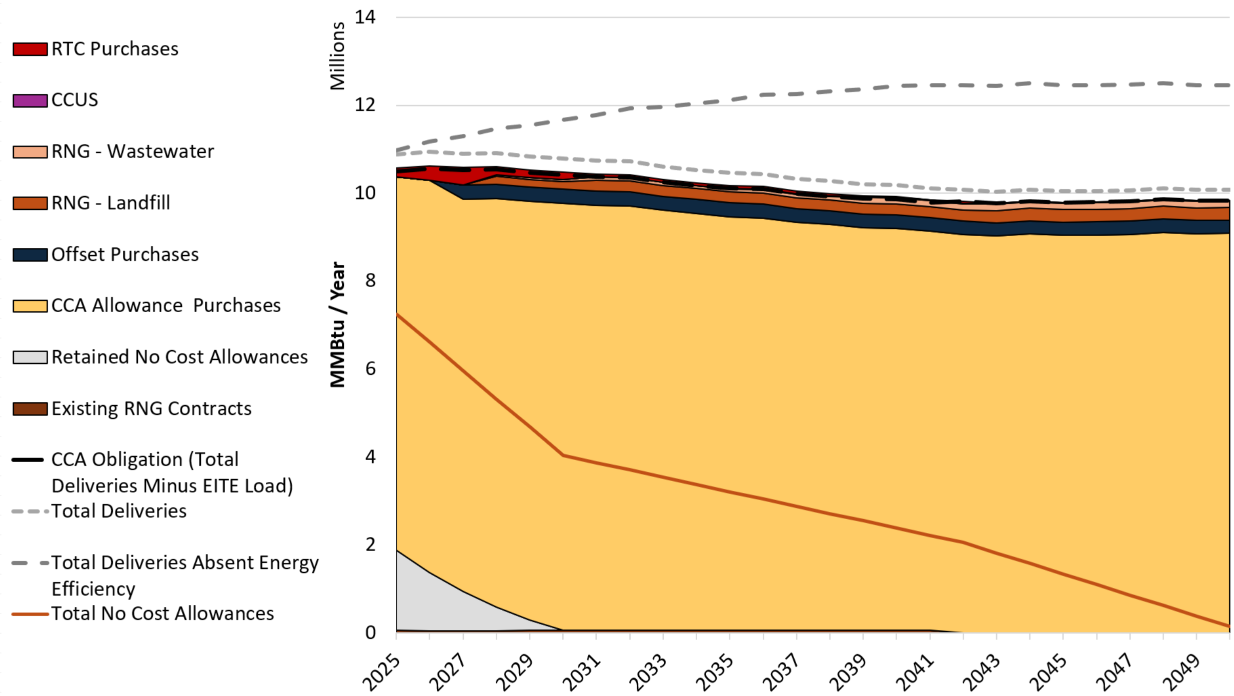
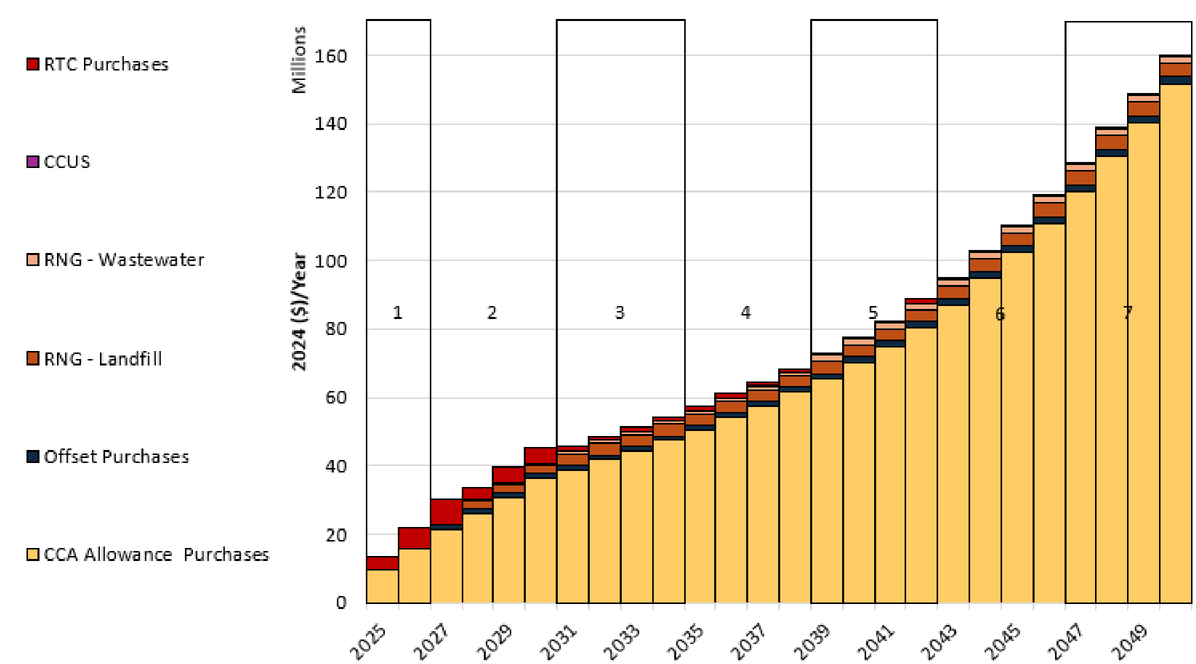


Figure H-40: PRS.a Compliance Costs



H.2.4 No GHG Compliance Policies

S3.a – No GHG Compliance

Compliance Resources

The are no compliance resources associated with this scenario.

Compliance Costs

There are no compliance costs associated with this scenario.

H.2.5 Scenario 4 – Growth Recovery

S4.a – Growth Recovery

Figure H-41: S4.a Compliance Resources

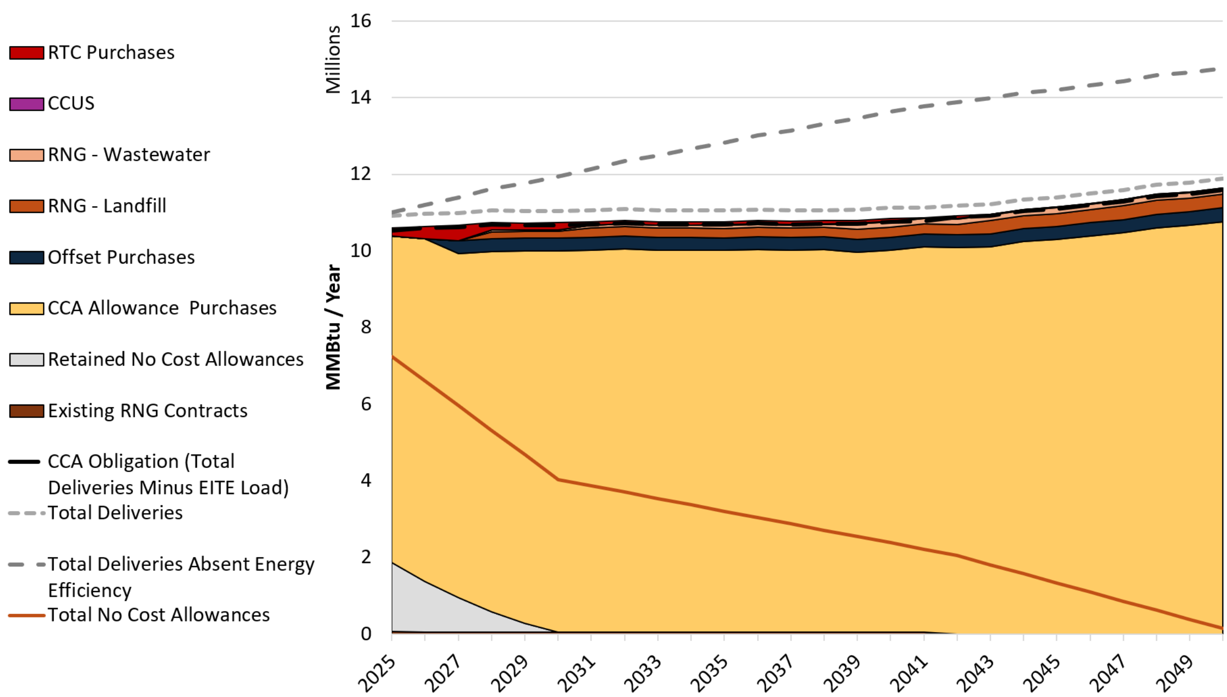
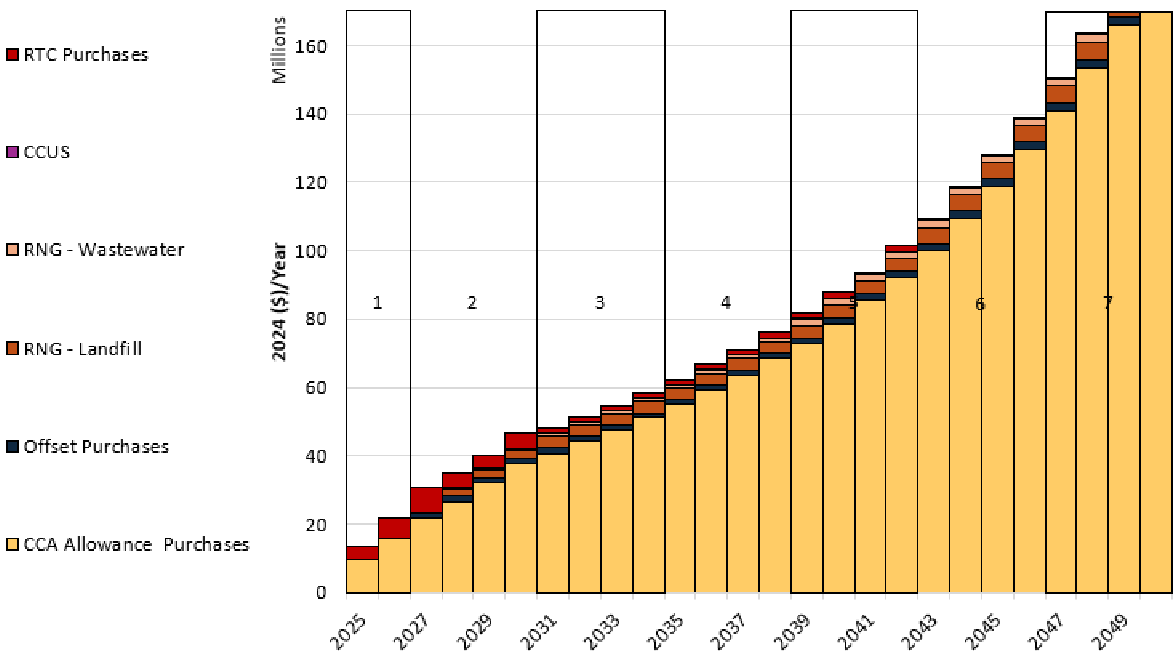


Figure H-42: S4.a Compliance Costs



H.2.6 Scenario 5 – Modest Customer Electrification

S5.a – Modest Customer Electrification

Figure H-43: S5.a Compliance Resources

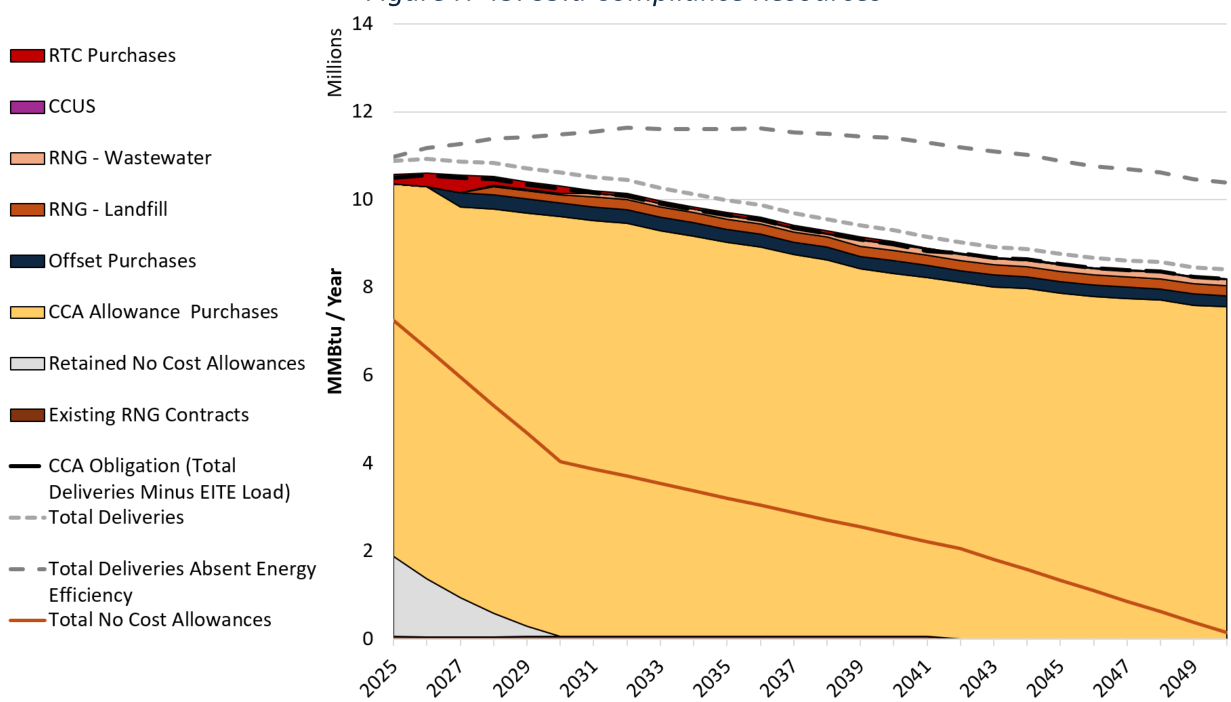
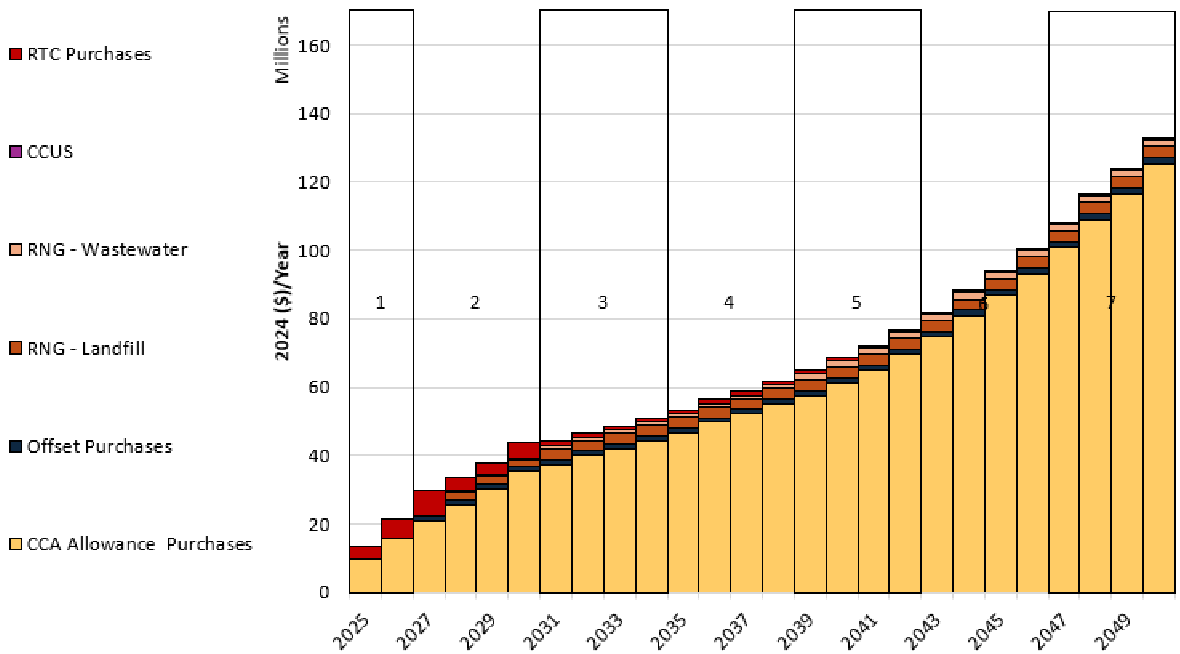


Figure H-44: S5.a Compliance Costs



H.2.7 Scenario 6 – Hybrid System Electrification

S6.a – Hybrid System Electrification

Figure H-45: S6.a Compliance Resources

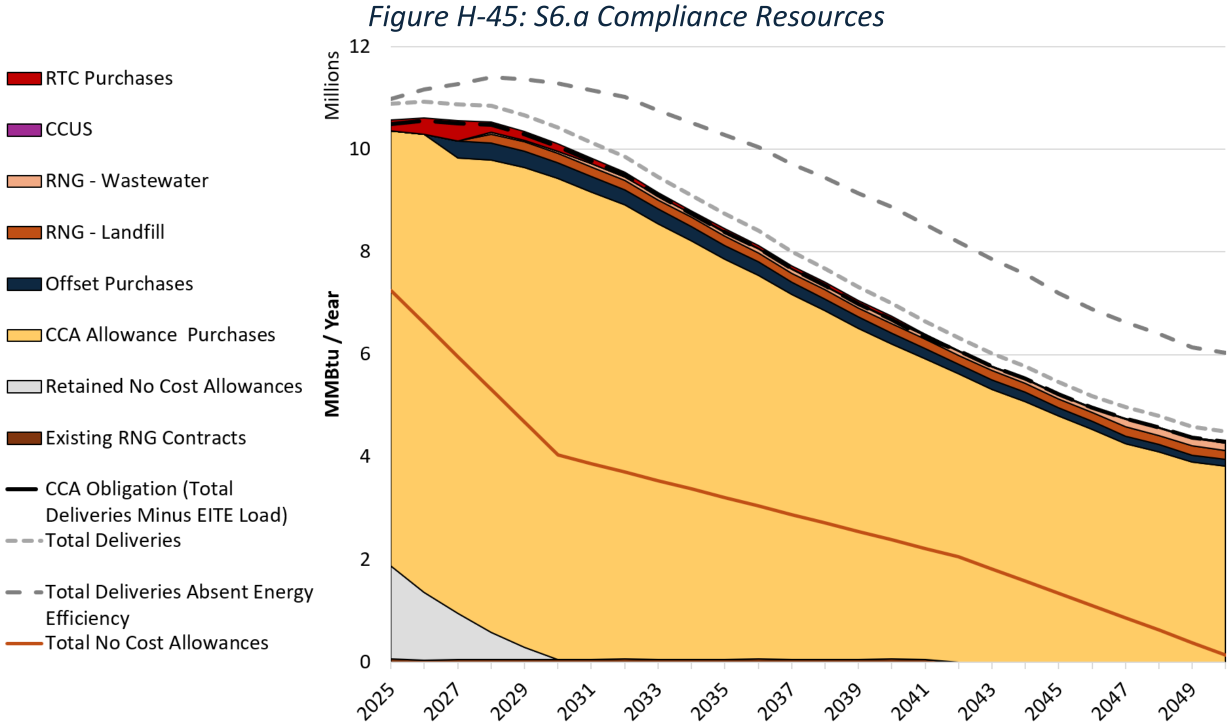
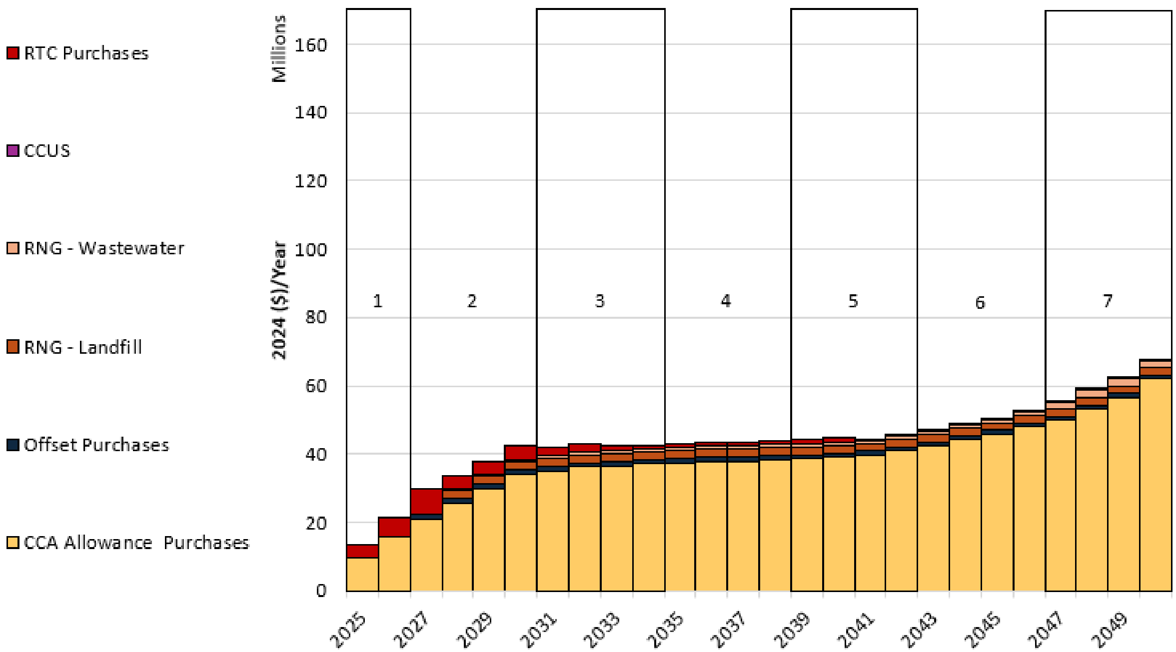


Figure H-46: S6.a Compliance Costs



H.2.8 Scenario 7 – All-Electric Buildings

S7.a – All-Electric Buildings

Figure H-47: S7.a Compliance Resources

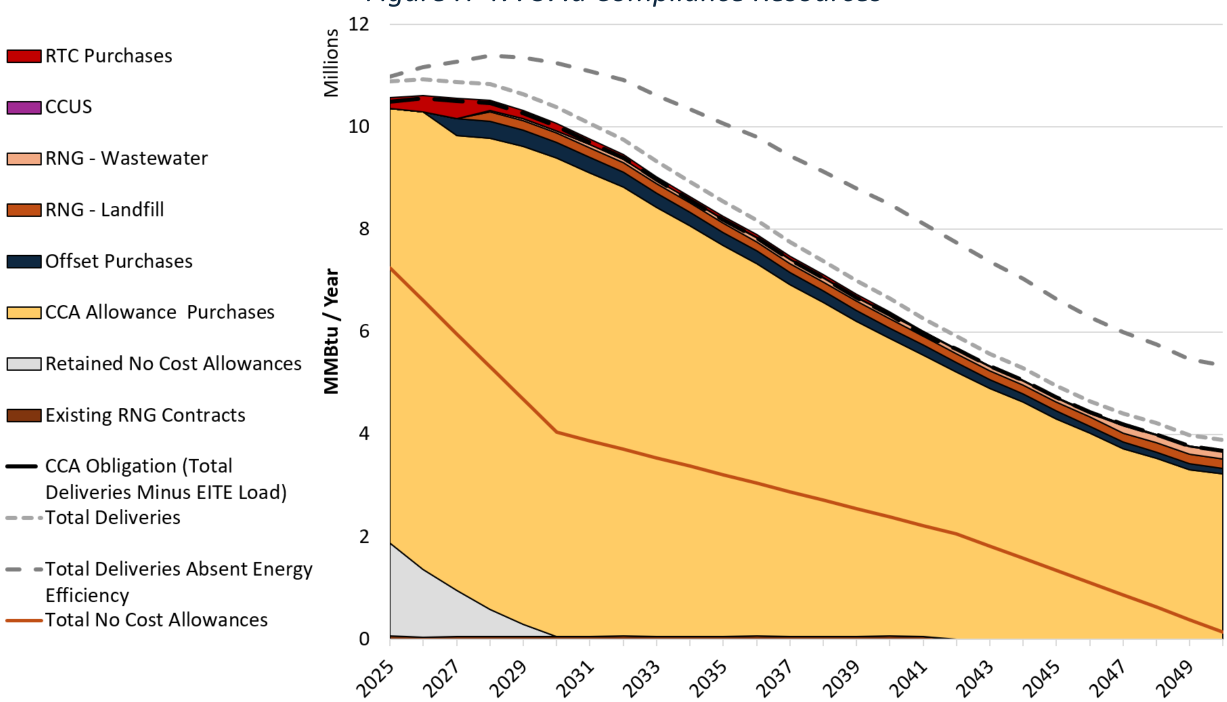
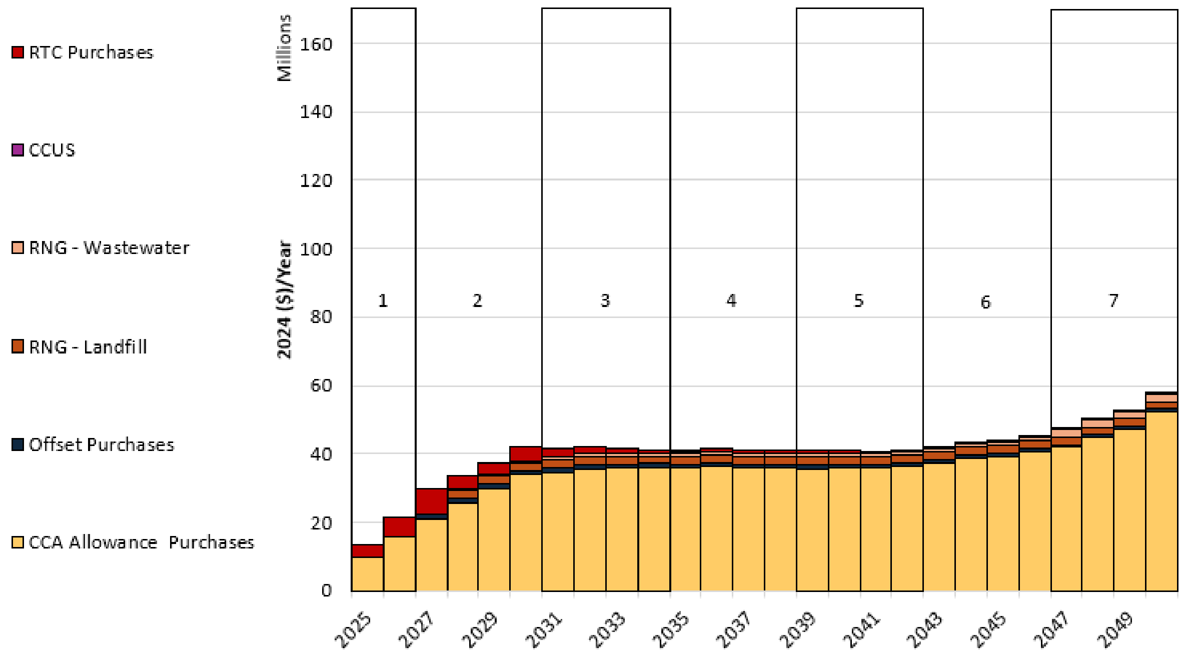


Figure H-48: S7.a Compliance Costs

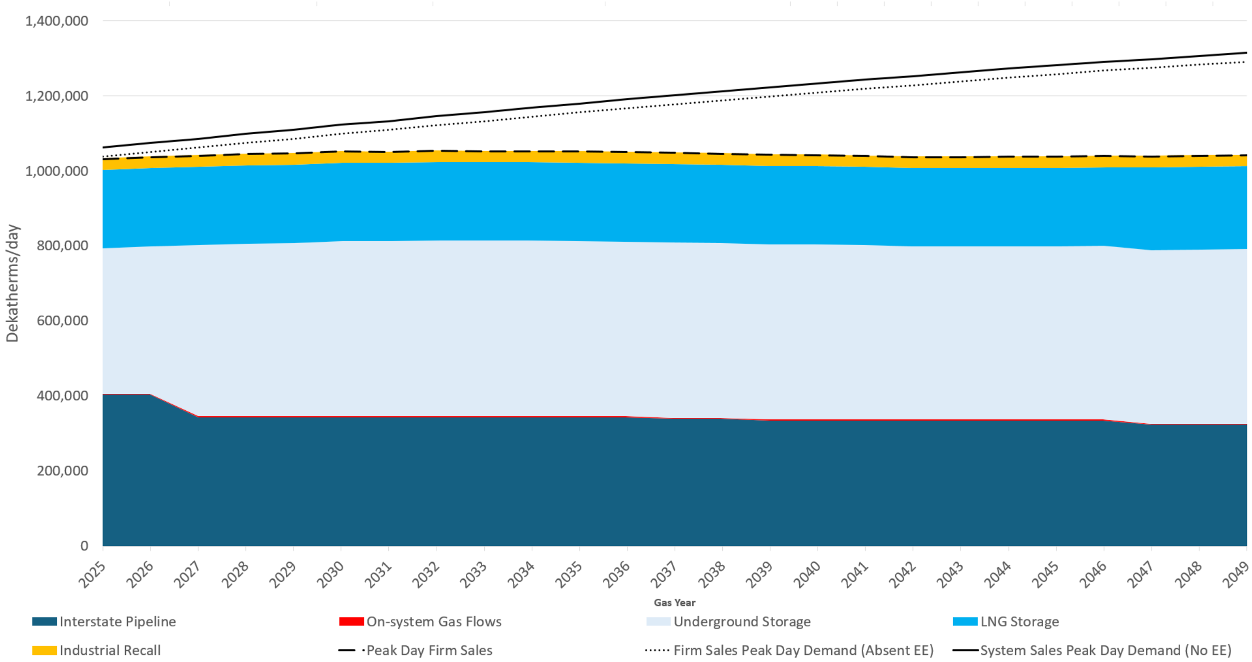


H.3 System Capacity Resource Stack

H.3.1 Scenario 1 – CPP/CCA Compliance, Scenario 2 – Voluntary RNG Targets, Preferred Resource Strategy, Scenario 3 – No GHG Compliance Policies

S1, S2, PRS and S3

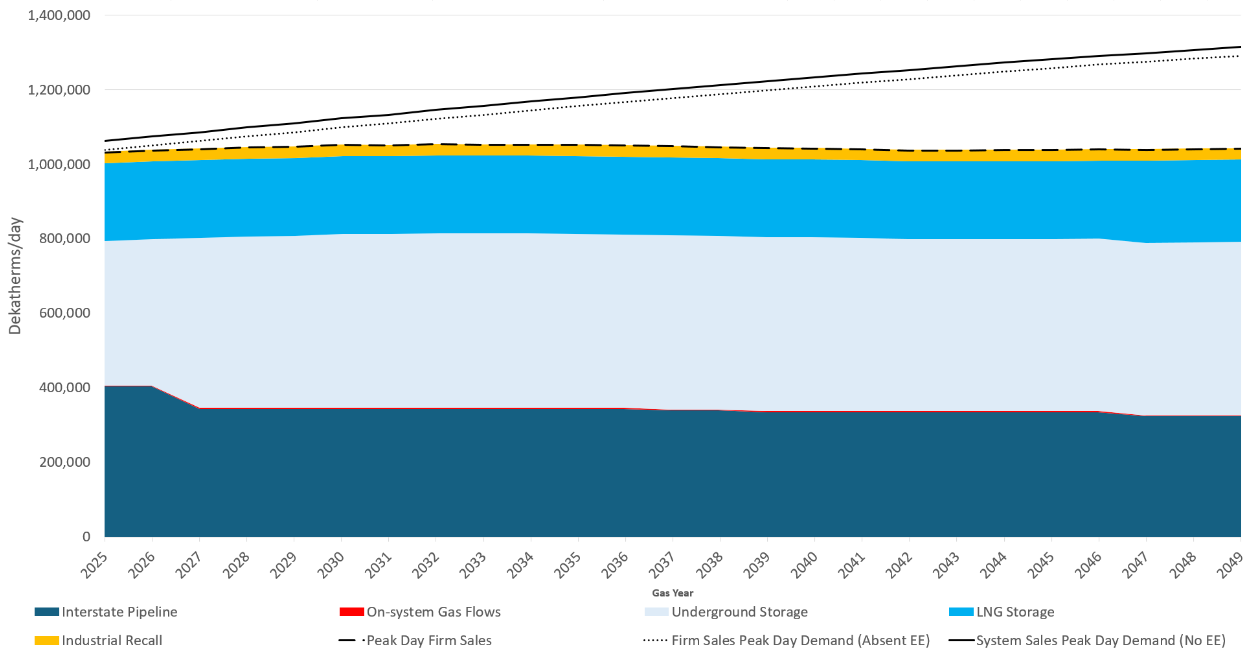
Figure H-49: PRS, S1, S2, and S3 Peak Day Capacity Resource Use



H.3.2 Scenario 4 – Growth Recovery

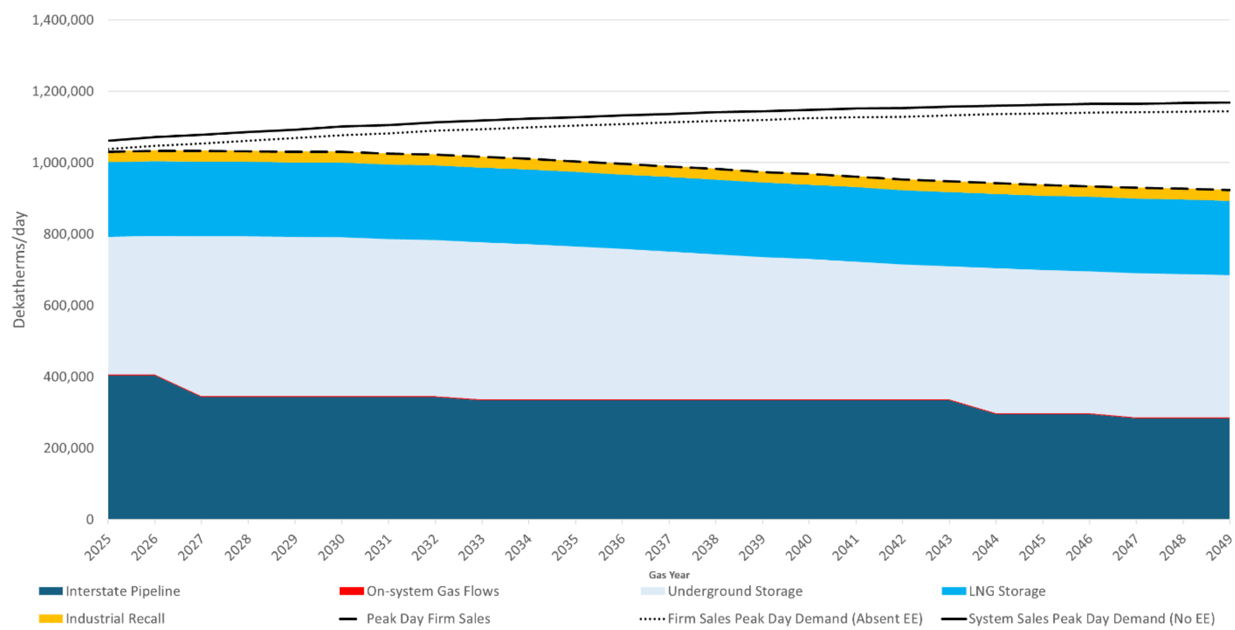
S4.a – Growth Recovery

Figure H-50: S4.a Peak Day Capacity Resource Use



H.3.3 Scenario 5 – Modest Customer Electrification

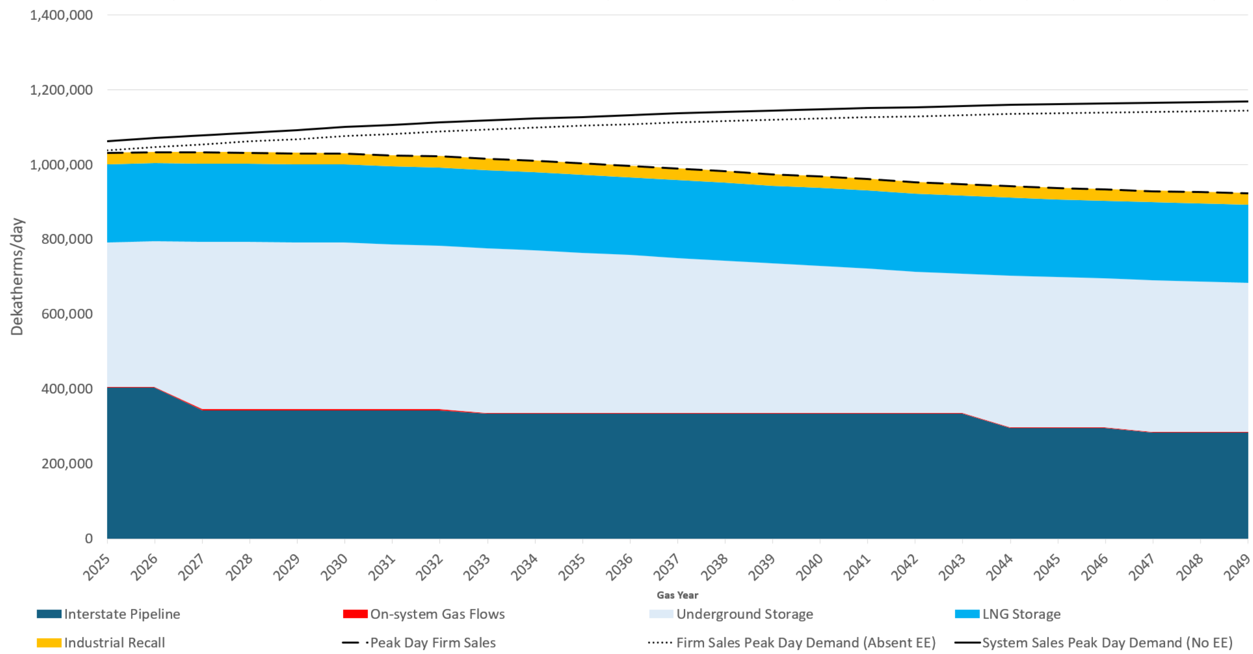
S5.a – Modest Customer Electrification



H.3.4 Scenario 6 – Hybrid System Electrification

S6.a – Hybrid System Electrification

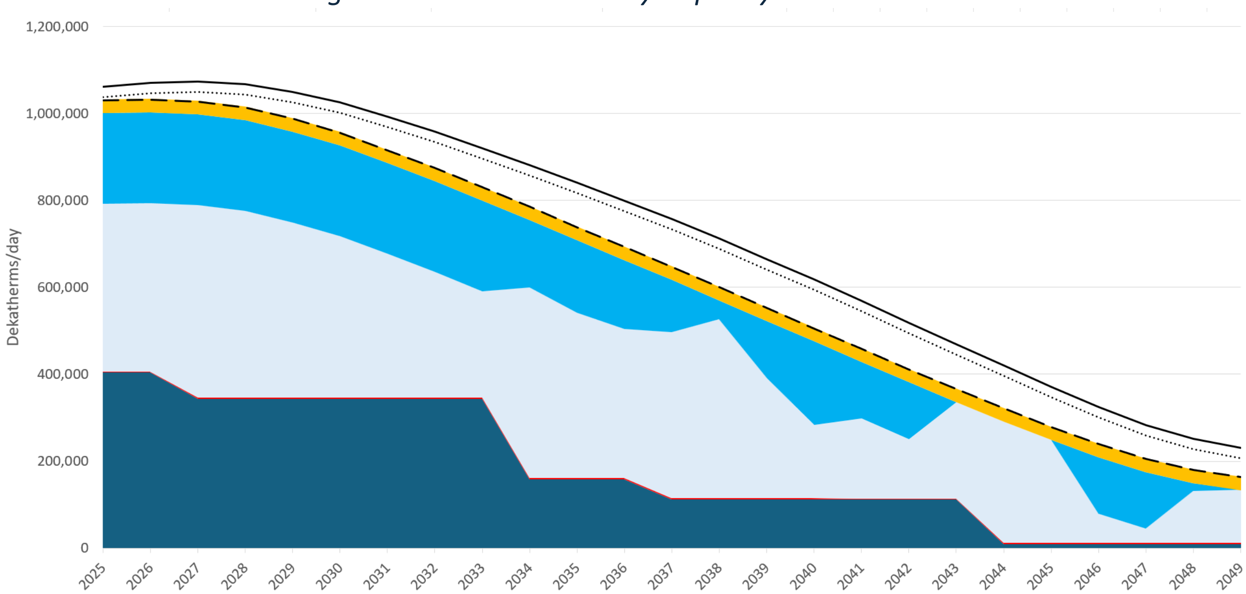
Figure H-51: S6.a Peak Day Capacity Resource Use



H.3.5 Scenario 7–All-Electric Buildings

S7.a – All-Electric Buildings

Figure H-52: S7.a Peak Day Capacity Resource Use



Appendix I – Equity Considerations and Public Participation

I.1 Equity Terms

The following terms and definitions are quoted from Washington Utilities and Transportation Commission's (WUTC) Equity Docket, A-230217.[9] As noted in Chapter 3 of this IRP, these quoted references are not intended to formalize specific definitions or frameworks; rather, they are included to acknowledge the Commissions' stated priorities—as well as to support shared language and understanding of concepts and definitions that are still emerging.

> ***Energy Justice:*** *ensuring that individuals have access to energy that is affordable, safe, sustainable, and affords them the ability to sustain a decent lifestyle.*
>
> ***Equality:*** *everyone receives the same treatment without accounting for differing needs or circumstances, which leads to or upholds inequitable outcomes.*
>
> ***Equity:*** *the act of developing, strengthening, and supporting procedural and outcome fairness in systems, procedures, and resource distribution mechanisms to create equitable (not equal) opportunity for all people. Equity focuses on eliminating barriers that have prevented the full participation of historically and currently oppressed groups.*

[9] WUTC docket A-230217, Communications Plan: 2023-2026, serviced on June 21, 2024, at page 3.

Table I-1: Tenets of Energy Justice

Energy Justice Tenet	Definition	Policy Expectation
Procedural justice	Focuses on inclusive decision-making processes and seeks to ensure that proceedings are fair, equitable, and inclusive for participants, recognizing that marginalized and vulnerable populations have been excluded from decision-making processes historically.	• Given a place to speak and empowered to speak. • • Participant Funding • Discuss how voices are considered and included in decision-making.
Distributional justice	Refers to the distribution of benefits and burdens across populations. This objective aims to ensure that marginalized and vulnerable populations do not receive an inordinate share of the burdens or are denied access to benefits.	• Increased benefits to named communities. • Reduced burdens for named communities. • Accounting for and measuring the impacts of company and Commission decisions on communities.
Recognition justice	Requires an understanding of historic and ongoing inequalities and inequities and prescribes efforts that seek to reconcile these inequalities and inequities.	• Recognizing past and present harms; where they occurred and who was harmed. • Being ready and willing to correct those harms.
Restorative justice	Uses regulation or other interventions to disrupt and address distributional, recognitional, or procedural injustices, and to correct them through laws, rules, policies, orders, and practices.	• Identify possible actions. • Take action to correct harms of injustices: *i.e.*, legislation, policies, orders, etc.

Source: WUTC docket A-230217, Equity Policy Statement – Notice of Opportunity to File Written Comments, at page 3, serviced on September 29, 2023.

I.2 Oregon and Washington Bill Discount Postcards

Figure I-1: Oregon Bill Discount Postcard

OREGON

NW Natural®

NW Natural can help lower your energy bills.

You may be able to get 15% to 85% off your monthly gas bill with NW Natural's Bill Discount Program

Usted podría obtener un descuento de 15 a 85 % en su factura mensual de gas con el Programa de Descuento en Factura de NW Natural.

您可能有机会通过 NW Natural 的账单折扣计划将每月的燃气账单减少 15% 到 85%。

Quý vị có thể được giảm giá từ 15% đến 85% hóa đơn tiền gas hàng tháng với Chương Trình Giảm Giá Hóa Đơn của NW Natural.

Вы можете получить скидку в размере от 15 до 85 % от вашего ежемесячного счета за природный газ благодаря программе скидок на оплату счетов от компании NW Natural.

We are here to help lower your energy bills with discounts. Scan the QR code to see qualifying incomes and apply. The application only takes minutes to complete online, by email, by traditional mail, or over the phone. You may be able to save more with free home energy improvements and flexible payment plans.

Estamos aquí para ayudarle a reducir sus facturas de energía con descuentos en la factura. Escanee el Código QR para ver los ingresos que califican y hacer la solicitud. Toma solo unos cuantos minutos completar la solicitud en línea, por correo electrónico o por correspondencia postal tradicional, o por teléfono. También podría ahorrar más con mejoras energéticas gratuitas en su hogar y con planes de pagos flexibles.

我们致力于帮助您降低能源费用，提供账单折扣。扫描二维码查看符合条件的收入并提出申请。申请只需几分钟即可在线、通过电子邮件、传统邮寄或电话完成。通过免费家庭节能改善和灵活的付款计划，您可能可以节省更多。

Chúng tôi ở đây để giúp quý vị giảm hóa đơn tiền điện bằng các khoản chiết khấu hóa đơn. Quét mã QR này để xem khả năng đủ điều kiện về thu nhập và nộp đơn. Chỉ mất vài phút để hoàn tất đơn trực tuyến, qua email hoặc thư truyền thống hoặc qua điện thoại. Quý vị có thể tiết kiệm nhiều hơn với các cải tiến năng lượng miễn phí tại nhà và các gói thanh toán linh hoạt.

Мы готовы помочь вам снизить стоимость счетов за электроэнергию с помощью скидок на оплату счетов. Отсканируйте QR-код, чтобы узнать о допустимых доходах и подать заявление. Заполнение заявления онлайн, по электронной или обычной почте или по телефону займет всего нескольких минут. Возможно, вы сможете сэкономить еще больше средств благодаря не требующему затрат повышению энергоэффективности дома и гибким планам оплаты.

nwnatural.com/BillDiscount
503-226-4211 or 800-422-4012

NW Natural®
NW Natural
250 SW Taylor Street
Portland OR 97204

Figure I-2: Washington Bill Discount Postcard

I.3 Integrated Resource Plan Engagement Activity Summaries

I.3.1 Summary of Open House

The Open House Workshop kicked off NW Natural's IRP engagement for the 2025 IRP. It was held in a hybrid fashion on October 10, 2024 from 9am- 10:30am, at the Company's headquarters in Portland, OR. In-person attendees were provided light refreshments. A total of 13 attendees participated remotely via Microsoft Teams while 12 attendees participated in-person. Participants included OPUC and WUTC Staff, peer utility representatives, NW Natural staff and facilitators, and other interested parties. An attendance list is provided in Table I-1.

The Company communicated this Open House Workshop to the public through the IRP distribution list, notice on NW Natural's website, and through outreach to CEAG member organizations and NW Natural partner organizations. The invitation included notes on accessibility and how to request further accommodation.

The content was structured as an introduction to resource planning with an intent to introduce the IRP team to stakeholders and cultivate relationships for the work ahead, as well as to provide stakeholders with a high-level review of the IRP process and outcomes. In-person attendees were then given a tour of the gas-control operations if they chose to proceed with that portion of the workshop. The Open House presentation and recording can be found on NW Natural's publicly available website[10].

[10] https://www.nwnatural.com/about-us/rates-and-regulations/integrated-resource-plan

Table I-2: 2025 IRP Open House Attendees

Setting	Name (last, first)	Organizational Affiliation
In-person	Baker, Seth	Maul Foster & Alongi
In-person	Childs, Erin	Renewable Hydrogen Alliance
In-person	DeLaquil, Pat	DecisionWare Group and MCAT (Mobilizing Climate Action Together)
In-person	Dennis, Joshua	WUTC
In-person	Franks, Wesley	WUTC
In-person	Herb, Kim	PUC
In-person	Kirschner, Dan	NWGA
In-person	Kort-Meade, Isaac	PUC
In-person	Moline, Heather	WUTC
In-person	Robbins, Chris	Cascade Natural Gas
In-person	Robertson, Brian	Cascade Natural Gas
In-person	Newell, Colleen	Maul Foster & Alongi
virtual	Sellers-Vaughn, Mark	Cascade Natural Gas
virtual	Shearer, Brett	WA Public Counsel
virtual	Harmon, Byron	WUTC
virtual	BATMALE, JP	OPUC
virtual	Regalado, Alondra	OPUC
virtual	Lin, Janice	Strategen / Green Hydrogen Coalition
virtual	Kennedy, Jake	ETO

I.3.2 Summary of Technical Working Groups and Office Hours

The Technical Working Group (TWG) is an integral part of developing NW Natural's resource plans and remained as the primary avenue for participation. During this planning cycle, NW Natural worked with representatives from the Public Utility Commission of Oregon (OPUC) Staff; Washington Utilities and Transportation Commission (WUTC) Staff; consumer advocates, environmental advocates, other utilities, and additional stakeholders.

NW Natural hosted 9 Technical Working Groups and one Office Hours session which was associated with two of the TWG sessions. Table I-3 shows TWG attendance; listed attendees were in attendance for at least a portion of one TWG session.

All TWGs and the Office Hours for the 2025 IRP were held virtually and facilitated by the Company's third-party facilitation consultant. Additionally, TWGs were recorded. Recordings, as well as associated meeting materials, were posted publicly on NW Natural's website[11]. Such materials and recordings remain on the Company's site until after the next IRP cycle begins.

TWG #1: Held via Microsoft Teams on October 22, 2024 from 1:00 – 4:00 p.m. There were 49 attendees in the meeting, which included NW Natural staff, facilitators, regulators, and other interested parties. The focus of this meeting was to introduce TWG participants to NW Natural and the IRP process, provide an overview of the planning environment, environmental policies/building codes, equity considerations, and gas supplies/alternative fuels.

TWG #2: Held via Microsoft Teams on November 1, 2024 from 9:00 a.m. – 12:00 p.m. There were 59 attendees in the meeting, which included NW Natural staff, facilitators, regulators, and other interested parties. The focus of this meeting was to provide an overview of the scenarios for the IRP, as well as an overview of NW Natural Electrification Study, presented by ICF.

TWG #3: Held via Microsoft Teams on November 21, 2024 from 9:00 a.m. – 12:00 p.m. There were 52 attendees at the meeting, which included NW Natural staff, facilitators, regulators, and other interested parties. The focus of this meeting was to continue the discussion around scenarios for the IRP, as well as provide an overview of the Power Sector Modeling, Climate Science Support, and Daily Temperature Modeling.

TWG #4: Held via Microsoft Teams on December 17, 2024, from 1:00 – 4:00 p.m. There were 44 attendees at the meeting, which included NW Natural staff, facilitators, regulators, and other interested parties. The focus of this meeting was to provide an overview on the topic of customer counts and load forecast.

TWG #5: Held via Microsoft Teams on January 21, 2025, from 1:00 – 4:00 p.m. There were 56 attendees in the meeting, which included NW Natural staff, facilitators, regulators, and other interested parties. The focus of this meeting was to provide an overview on the topic of avoided costs and demand side resources.

TWG #6: Held via Microsoft Teams on January 28, 2025, from 1:00 – 5:00 p.m. There were 74 attendees in the meeting, which included NW Natural staff, facilitators, regulators, and other

[11] https://www.nwnatural.com/about-us/rates-and-regulations/integrated-resource-plan

interested parties. The focus of this meeting was to provide an overview on the topic of supply and compliance resources.

TWG #7 / Office Hours: NW Natural replaced TWG #7 with an Office Hours session held via Microsoft Teams on April 1, 2025, from 1:00 - 2:00 p.m. There were 37 attendees, which included NW Natural staff, facilitators, regulators, and a couple attendees from other interested parties. This was held as a follow up to TWG #2 and TWG #3 on the topic of NW Natural's commissioned electrification study. The session allowed participants to ask questions directly of NW Natural's consultant, ICF. Questions received came from WUTC and OPUC only.

Unlike TWGs, the Company did not provide new materials or a presentation. Further, this session was not recorded.

TWG #8: NW Natural held Technical Working Group (TWG) meeting 8 for its Integrated Resource Plan (IRP) via Microsoft Teams on April 8, 2025, from 1:00 – 4:00 p.m. There were 43 attendees in the meeting, which included NW Natural staff, facilitators, regulators, and other interested parties. The focus of this meeting was to provide an overview of the topic of distribution system planning including the potential pipe and non-pipe solutions for potential future system needs.

TWG #9: NW Natural held Technical Working Group (TWG) meeting 9 for its Integrated Resource Plan (IRP) via Microsoft Teams on May 29, 2025, from 9:00 a.m. – 1:15 p.m. There were 50 attendees in the meeting, which included NW Natural staff, facilitators, regulators, and other interested parties. The focus of this meeting was the system resource planning model and pilot projects. Model results were shared for Scenarios 1-3 and the Preferred Resource Strategy (PRS).

TWG #10: NW Natural held Technical Working Group (TWG) meeting 10 for its Integrated Resource Plan (IRP) via Microsoft Teams on June 26, 2025, from 9:00 a.m. – 12:00 p.m. There were 47 attendees in the meeting, which included NW Natural staff, facilitators, regulators, and other interested parties. The focus of this meeting was on presenting the modeling results of the electrification study and the Action Plan.

Table I-3 lists attendees who attended at least a portion of one Technical Working Group during the development of the 2025 IRP, excluding NW Natural employees.

Table I-3: 2025 IRP Technical Working Group Attendees

Name (last, first)	Organizational Affiliation
Amrhein, Felix	ICF- Consultant to NW Natural
Art, Kristin	ECY
Astley, Greg	ORLA
Ayers, Kate	OPUC
Baker, Seth	Facilitator
Bolton, Madison	OPUC
Brett Shearer	WA Public Counsel
Brutocao, Michael	Avista Utilities
Call in by phone	Unknown
Call in by phone	Unknown
Cheung, Shelton	Fortis BC
Childs, Erin	Renewable Hydrogen Alliance
de la Torre, Alessandra	NWEC
de Villiers, Stefan	WA Public Counsel
DeBoer, Jennifer	Cascade Natural Gas
DeLaquil, Pat	MCAT
Dennis, Joshua	WUTC
Dimedio, Jillian	ODOE
Dloughy, Curtis	OPUC
Dodinval, Claire	ICF- Consultant to NW Natural
Doyle, Anita	Kinder Morgan
Drennan, Ted	OPUC
Dryer, Jean Marie	WA Public Counsel
Duncan, Angus	General Public
Dziedzic, Heather	American Biogas Council
Franks, Wesley	WUTC
Freels, Michael	ODOE
Fried, Mason	ICF- Consultant to NW Natural
Garrett, John	CUB
Gray, Roger	Consultant to NW Natural
Griffith, Andrew	ICF- Consultant to NW Natural
Hall, Genevieve	General Public
Harmon, Byron	WUTC
Hawkins, Paul	City of Portland
Herb, Kim	OPUC
Hertog, Cory	ETO
Heslam, David	Earth Advantage
Hinckley, Thor	Third Act OR
Jenks, Bob	CUB
John, Annu	Fortis BC

Kamermayer, Tim	Green Hydrogen Coalition
Kennedy, Jake	ETO
Kern, Ryan	OPUC
Kernan, Peter	OPUC
Kirschner, Dan	NWGA
Koenig, Paul	WUTC
Koepke, Elise	AWEC
Kort-Meade, Isaac	OPUC
Kotter, Xan	Williams
Light, Ted	General Public
Lin, Janice	Green Hydrogen Coalition
Lockwood, Charles	OPUC
Maltz, Elliot	General Public
Marineau, Makenzie	ORLA
McGreal, Devin	Cascade Natural Gas
Miller, Tim	Oregon Business for Climate
Morrill, Kyle	ETO
Muthiah, Shanthi	ICF- Consultant to NW Natural
Namukaya, Sandra	OPUC
Narbaitz, Peter	ICF- Consultant to NW Natural
Newell, Colleen	Facilitator
Nightingale, Joel	WUTC
Pardee, Tom	Avista Utilities
Pernick, Anne	General Public
Plaut, Melanie	OR- PSR
Prihoda, Claire	Climate Solutions
Pudleiner, David	ICF- Consultant to NW Natural
Regalado, Alondra	OPUC
Reilly, Joe	ICF- Consultant to NW Natural
Robertson, Brian	Cascade Natural Gas
Ross, Ken	Fortis BC
Sahler, Carra	GEI
Sellers-Vaughn, Mark	Cascade Natural Gas
Sheehy, Philip	ICF- Consultant to NW Natural
Shick, Adam	ETO
Simon, Nima	ICF- Consultant to NW Natural
Smith, Rebecca	Renewable Hydrogen Alliance
Snyder, Jennifer	WUTC
Steele, Matt	ODEQ
Stokes, Chad	AWEC
Wade, Sam	RNG Coalition

I.3.3 Summary of Public Engagement Webinars

The first Public Engagement Webinar (PEW) was held on March 5, 2025 via Zoom webinar. The Company made significant efforts to publicize this webinar, specifically to its customers. In addition to the traditional channels utilized for TWGs such as distribution lists, NW Natural sent out notice through customer e-newsletters (reaching over 182,000 customers), partner communications, and communicated with partners via direct outreach. Additionally, information was included through a tout on the Company's website homepage as well as the Company's energy/resource planning webpage. The PEW was recorded. This and associated materials were posted to the Company website for the public to view at any time. Similar to TWG materials and recordings, these will remain on the website for public consumption until after the start of the next IRP cycle.

Although the Company made significant outreach efforts, it received a total of 17 registrants for the first PEW. During the live webinar, NW Natural hosted 8 attendees outside of its own employees. Further, NW Natural found that of these attendees, many were already participating in the TWG process.

During the webinar, the Company received a single question related to the impacts of tariffs on the price of gas. This question was answered live during the webinar. Webinar polls were utilized for engagement on the subject and included the following questions:

- How far into the future does NW Natural plan its resources to serve customers?
- What is the largest customer group (sectors) NW Natural serves?
- By volume, what is the most common use of natural gas for residential customers?
- Have you ever participated in any of these programs? Choose all that apply.

Answers to poll questions were provided to attendees at the end of each poll and more detail was provided through the presentation. Additionally, the Company surveyed participants at the end of the webinar to understand how they heard about the engagement. Results showed that attendees were made aware of the webinar through direct outreach or topic specific email distribution lists. A meeting report including registration and attendance lists is included at the end of this section in Table I-4 and Table I-5.

Due to the lack of interest in the PEW, the Company chose to cancel the second scheduled webinar and focus its resources on in-person and partner-organizations community engagements.

Table I-4: March 5, 2025 Public Engagement Webinar Registrants and Attendees

Attended	Name (last, first)	Organizational Affiliation
Yes	Koenig, Paul	WUTC
Yes	Thompson, Charlee	NWEC
Yes	Dreyer, Jean Marie	Public Counsel
Yes	DeLaquil, Pat	MCAT
Yes	Piesik, Nichole	Clark PUD
Yes	Hinckley, Thor	Third Act OR
Yes	Mather, Korene	Clackamas County
Yes	Gray, Roger	Roger Gray Consulting
No	Davis, Nancy	Nancy Davis Consulting
No	Namukaya, Sandra	OPUC
No	Aguilar, Diana	Fortis BC
No	Hawkins, Paul	City of Portland
No	Dennis, Joshua	WUTC
No	Shepard, Andrew	ETO
No	Montero Chacon, Esteban	Homes for Good
No	Tanner, Silvia	Multnomah County
No	Campbell, Traia	MWVCAA
No	Youtsey, Amber	WAGAP
No	Cortes, Rogelio	MWVCCA
No	Plaut, Melanie	OR- PSR

Table I-5: March 5, 2025 PEW Survey Results

Survey: How did you learn about this webinar?	
Response	**Count**
Direct Outreach	2
NW Natural topic email list (IRP or other)	3
Other	2

I.3.4 Summary of Tabling Engagements

Winter Preparedness Fair

The Winter Preparedness Fair event (initially designed under the title of "IRP Fair") was held at Parkrose High School in Portland, OR on November 14, 2024 from 11am-2pm. The event was open to the public and was free of charge. NW Natural partnered with Community Services Network (CSN), an Oregon non-profit organization that convenes and supports direct service provider organizations. The City of Portland's Bureau of Planning and Sustainability additionally partnered on the event – broadening the funding and resourcing opportunities.

Prior to the Winter Preparedness Fair, the Company and its partners promoted the event widely. Promotion materials were provided in the top five languages spoken in NW Natural's service territory and in plain language. Both virtual and hard-copy announcements were utilized in addition to word-of-mouth and direct outreach.

Partnership was key to effective outreach, especially within hard-to-reach and underserved communities. The City of Portland introduced the Company and CSN to Community Engagement Liaison Services (CELs) who are either bi-cultural, and/or bi-lingual. These bridge-builders help to connect community members to services in a culturally-specific manner, allowing a level of comfort and familiarity in navigating processes and systems. CELs assisted in culturally specific outreach and were in attendance during the event to provide interpretation services.

As described in Chapter 3, the Winter Preparedness Fair was designed as an informal educational and resource rich event. Community members had opportunity to engage with NW Natural in addition to other utilities and direct service providers.

Features of the Winter Preparedness Fair included:

- Nonprofit and utility resources
- Lunch and family friendly activities
- Children's winter coat giveaway
- Weatherization Kits
- Food boxes
- Vaccinations
- Computer lab to facilitate bill discount sign ups
- Interpreters

The Winter Preparedness Fair turnout was much larger than the Company or its partners expected with over 850 attendees. An event 'passport' was utilized to encourage attendees to visit a variety of tables. Attendees could then turn their card in for a free home weatherization kit provided by NW Natural.

NW Natural had a group of tables which covered a range of topics including energy resource planning, energy efficiency and demand response, weatherization and home energy conservation, safety and winter preparedness, energy supply and networks, and importantly bill discounts and affordability programs. Although not specifically highlighted, the Company received questions on workforce development and provided information to both tabling partners and participants on how to get involved with the Company's apprenticeship and other workforce development programs.

NW Natural's team utilized their own lived experiences to connect with individuals, including providing additional interpretation. The team additionally engaged with participants through games and trivia – making the information provided more accessible. All materials were provided in plain language. Specific to the IRP, information was provided on what energy planning is and information on how to get involved during the planning process – including the processes led by utility commissions. This was done through both games as well as informational cards. The Company engaged with hundreds of attendees. It received three requests to join the IRP distribution list[12], assisted over 50 people with bill discount applications, shared over 50 safe meter turn off tutorials, and distributed over 250 weatherization kits.

Comments received from participants indicated a strong appreciation for NW Natural and its partners for sponsoring the event and providing resources in real time. Other feedback supported the notion that there is a deep need for free and low-cost home weatherization resources.

Clark County Fire District Open House/ Get Ready Community Event

NW Natural supports an annual community event in Clark County, WA through in-kind contributions and safety partnerships. For 2025, NW Natural additionally hosted a set of tables at the event which was held on June 7, 2025 from 12:00- 3:00 p.m. at the Clark County Fire District #6 Station. NW Natural's tables featured information on energy planning as well as safety, weatherization and bill discounts.

The team engaged with participants through games and trivia as well as through informational cards and conversations. All materials were provided in plain language, and many materials were provided in multiple languages (English, Spanish, Vietnamese, Russian, and Simplified Chinese).

Specific to the IRP, this event utilized the Company's 'IRP Toolkit' which was described in Chapter 3. Representatives from NW Natural engaged with attendees, bringing awareness to both Energy Planning – including what it is and how to get involved – and the public comment period for the draft IRP. The Company engaged with hundreds of attendees through this event (estimated at about 350 attendees), however, interest in further engagement with the IRP was quite limited.

[12] The IRP distribution list is an ongoing list of stakeholders who have requested to be included in NW Natural's IRP process. This distribution list is utilized to announce IRP related activities. Anyone can request to join the distribution list.

Beyond the IRP, the Company distributed over 63 custom home weatherization kits[13], informed many about the WA bill discount program through conversations and informational cards, and brought further awareness to gas and utility safety.

Comments received from participants continued to reflect the need for free and low-cost weatherization resources and an appreciation for ways to save money on household energy bills.

I.3.5 Summary of Draft Release

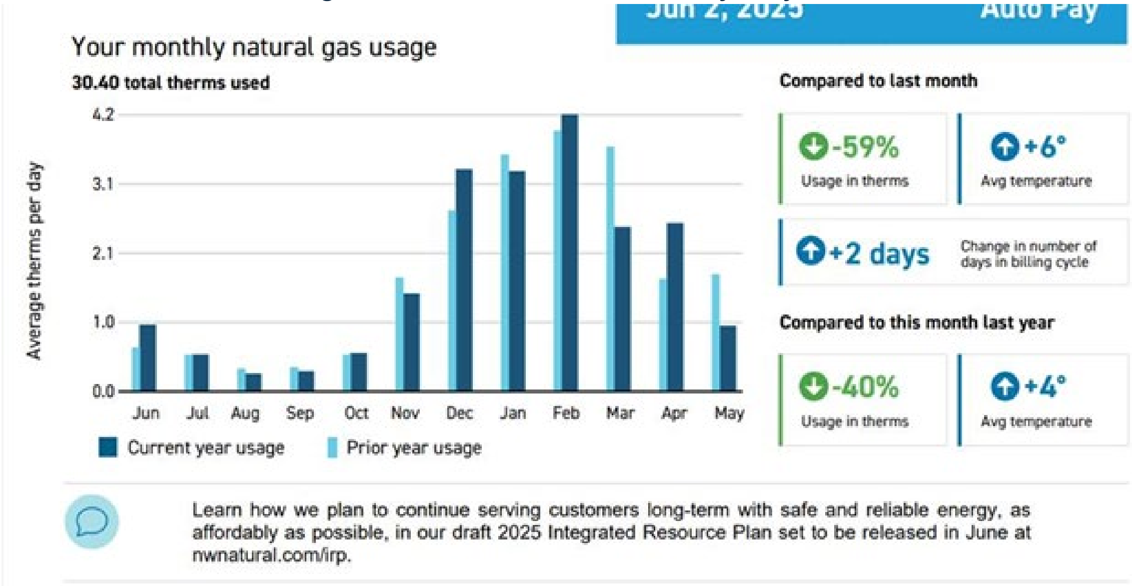
For the draft 2025 IRP, NW Natural notified all customers through a bill message beginning in May of 2025. All active customers received a notice[14] stating that the Company would be releasing the draft IRP in the near term and directed customers to the NW Natural website where more information was made available. An example of a customer bill with the draft release notice is shown in Figure I-3. Not only did this improved method of outreach help to reach more customers than previous methods; it also resulted in lower costs.

In addition to direct customer outreach, the Company notified stakeholders of the expected draft release and comment period timelines during each IRP public engagement. Further, a notice was sent directly to IRP stakeholders through the IRP email distribution list on June 2, 2025 with subsequent notices on June 13, 2025 and June 25, 2025.

The Company continued to bring awareness of the IRP to the Community and Equity Advisory Group during its second meeting of 2025. Here the Company reviewed resource planning at a high level and specifically discussed the draft release and how community members can be involved in the process. Finally, the Company sent direct outreach to partner organizations to announce the draft release and comment period.

[13] Rather than pre-building kits, attendees could customize their own kit based on household need. A Company representative provided information on each weatherization item to help participants inform their decisions.
[14] Notice was provided on all active customer electronic and paper bill statements. The Company utilized paper billing inserts in previous IRP cycles.

Figure I-3: Customer Bill Notice of Draft IRP



I.4 Stakeholder Comments During the Development of the 2025 Integrated Resource Plan

The following comments and feedback were provided to NW Natural by stakeholders during the development of the 2025 IRP through the Company's dedicated IRP feedback form. Feedback was requested by the NW Natural IRP team at the completion of each TWG. Due to the length and complexity of some feedback received, the Company has broken these down for ease of review.

Table I-6: Comments Received During IRP Development

#	Commentor	Comment/Feedback Detail	NW Natural Response
1	OPUC	The Company should seek to understand the competitiveness of RNG amongst other options, in the absence of regulatory influence.	NW Natural agrees that the Company should seek to understand the competitiveness of RNG amongst other options. The Company models RNG as such in this IRP.
2	OPUC	The SB 98 scenario should focus on how much and when the model selects RNG in a scenario without the Climate Protection Program (CPP); how much does that cost, rather than what the costs are of reaching SB 98 targets. By focusing on when and how much RNG is chosen, we gain insights on its competitive positioning and cost-effectiveness relative to other sources.	Given the higher market cost as compared to conventional natural gas, NW Natural does not anticipate any RNG would be selected by the model unless a) policies such as the CPP or SB 98 are considered or b) the Social Cost of Carbon is included as an adder to the cost of conventional natural gas. Scenario 2 optimizes a resource portfolio assuming SB 98 compliance absent of CPP and CCA policy. Even under the low cost scenario, NW Natural does not believe it will be able to reach SB 98 targets due to SB 98's 5% revenue limitation. NW Natural agrees that there is insight to be gained from comparing RNG with other compliance resources.
3	OPUC	Staff supports the modeling of this [SB 98] scenario, it can provide valuable context for making informed decisions, ensuring procurement strategies are adaptable to different regulatory/policy environments.	NW Natural thanks Staff for their support.
4	OPUC	Staff is interested in the temperature an electric heat pump is assumed to transition to resistance heat, and is concerned that too high a switchover temperature would overstate energy consumption of the heat pump. Staff asks the	As discussed in Chapter 10, ICF leveraged analysis conducted by the National Renewable Energy Laboratory (NREL) in their ResStock tool which analyzed a series of electrification measures with customized building modelling for each county in the country. ICF

		Company to confirm the switchover temperature used, the sources behind the assumption, and whether it differs for Air Source and Cold Climate Heat Pumps.	extracted the electrification impacts that NREL had modelled for the relevant counties and measures for this study. It was not ICF or NW Natural that made specific assumptions on the parameters that you are requesting, but it was NREL's pre-existing work that established those values for the results included in this analysis. NREL's documentation on assumptions used in their ResStock datasets can be found at the following URL: https://oedi-data-lake.s3.amazonaws.com/nrel-pds-building-stock/end-use-load-profiles-for-us-building-stock/2024/resstock_tmy3_release_2/resstock_documentation_2024_release_2.pdf Based on NREL's documentation, our understanding is the following. The assumed switchover temperature at which an electric heat pump transitions to resistance heat is generally not fixed but rather is determined by load. The heat pump meets whatever capacity that it is able to at each temperature, and then the remaining heating needs are met through supplemental heat. There is no lock-out of the heat pump. This applies to all air source heat pump options that include electric back-up, but not to the air source heat pump measures that include natural gas back-up heating (which does include explicit temperature-based lockout controls). NREL documentation indicates that for the ENERGY STAR Air-to-Air Heat Pump with Electric Backup, the heat pump retains 50% of its heating capacity at 5°F. For the High Efficiency Cold-Climate Air-to-Air Heat Pump with Electric Backup, the system retains 90% of its capacity at 5°F. This higher retention allows the system to meet the load in colder conditions and results in a lower effective switchover temperature, reducing reliance on resistance heating.

			As noted, the exception in NREL's analysis is for the ENERGY STAR Air-to-Air Heat Pump with Existing System as Backup, which includes explicit temperature-based lockout controls. In this measure, the compressor locks out at 5°F, below which the heat pump is disabled. The backup fossil fuel system is locked out above 40°F, meaning it only activates when temperatures fall below that threshold. Between 40°F and 5°F, the system relies primarily on the heat pump, but the backup fossil heat is allowed to turn on, but only if the heat pump cannot meet the load. The full switchover from the heat pump to fossil fuel backup occurs at 5°F.
5	OPUC	Staff is interested in assumptions of heat pump attributes and penetration levels and the sources driving those assumptions. Staff asks that the Company compare how its attribute and sales assumptions align with recent NEEA sales data on equipment types and trajectories out to 2030.	As pointed out in Section 10.4, Chapter 10, the level of electric equipment adoption used by ICF for existing NW Natural customers in both the Hybrid System Electrification and the All-Electric Buildings scenarios was chosen to align with some of the high-level assumptions available in the fall of 2024 from the Oregon Department of Energy's (ODOE) Oregon Energy Strategy Reference Case assumptions. This was a "what if" analysis, showing what the impacts of these assumed adoption levels would be, not an endorsement from ICF or NW Natural that the adoption levels in either of these scenarios were likely or realistic. The electrification scenarios also do not attempt to estimate what policies and/or incentive levels would be required to drive adoption to these levels. As such, neither of these hypothetical scenarios intended to align with NEEA forecasts to 2030.
6	OPUC	Staff is interested in assumptions of hybrid system attributes and penetration levels and the sources driving those assumptions. Staff asks that the company compare how its hybrid system adoption assumptions align with recent	As with the previous question, in order to illustrate the potential impacts of hybrid electrification, the Company intentionally did not limit adoption assumptions to current practices that might have been captured in recent NEEA assessments. Other practices or

		NEEA's 2022 Residential Building Stock Assessment and with Energy Trust of Oregon's Energy Performance Score data.	approaches would likely be possible, with the right policies or incentives.
7	OPUC	Staff is mindful of how enabling costs (e.g. equipment costs, electrical panel upgrades, building shell and weatherization) are accounted for given that there is considerable financial and policy support for energy efficiency adoption. Staff asks the Company to describe which enabling costs are denoted as customer out-of-pocket costs and which are incurred by the Company.	Section 10.5 in Chapter 10 provides an overview of the key assumptions about the enabling equipment costs for residential and commercial customers. Our understanding of the costs for gas to electric conversions referenced from the Puget Sound Energy (PSE) decarbonization analysis is that in addition to heat pump cost they also factor in some additional gas-to-electric conversion costs for panel upgrades, wiring, and duct/pad costs. For the customer equipment conversion costs that are considered, including any enabling costs, most of the IRP analysis is agnostic as to whether these are customer out-of-pocket costs or are supported by the Company (or an electric utility) through incentives. The analysis focuses on overall cost impacts in Oregon and Washington. For example, the total system costs in Section 11.1.1 would be the same if customers had to pay the full incremental costs of their equipment themselves or if the utilities in Oregon and Washington needed to provide incentives covering those costs (and in turn charge their customers more to cover the incentive costs). This section does reduce total costs based on an estimate of Inflation Reduction Act (IRA) incentive funding, ignoring that Oregon and Washington taxpayers will also need to contribute to funding IRA incentives. Ultimately, the adoption levels for electrification technologies were an input assumption to establish the potential impacts from each scenario – the customer share of the incremental costs was not a factor used to adjust the level of equipment adoption assumed in any of the scenarios. Another thing to note is that the costs shown in the electrification scenario analysis are all incremental to the NW Natural IRP

			Reference Case. The IRP Reference Case includes significant expectations for customer energy efficiency improvements (based on forecasts provided to the Company by the Energy Trust of Oregon) and so the costs for all of this energy efficiency are not captured in the electrification scenarios (but assumed to be incurred in the Reference Case and all other scenarios).
8	OPUC	Staff asks the Company to explain how it will treat a program design that uses CPP compliance to fund electrification of an end-use.	The Company does not specifically examine the possibility of the use of CCI funds for electrification. However, NW Natural believes that the impact of such a program is captured within the range of electrification scenarios included in the IRP.
9	OPUC	Staff asks the Company to explain how it will treat the Department of Energy's Home Electrification and Appliance Rebate (HEAR) and Portland Clean Energy Fund (PCEF) electrification programs.	The Company does not specifically estimate the effects of incremental electrification driven by the HEAR or PCEF Programs. However, NW Natural believes that the impacts of these policy scenarios are captured within the range of electrification scenarios included in the IRP.
10	OPUC	Staff asks the Company how it will include specific HEAR and PCEF end-use electrification targets in its base-case scenario.	The Company does not specifically include the end-use targets from HEAR or PCEF in its base case. However, the Company believes that the impacts of these policies are captured within the range of electrification scenarios included in the IRP.
11	OPUC	Staff explains that a combined effect of different variables (e.g. high price trend for natural gas, scarcity of non-conventional gasses, customers being more responsive to price signaling, colder climate futures compared to warmer climate futures, declining customer growth) increases risk to ratepayers. Staff asks that the Company perform a risk analysis to better accommodate these changing variables and looks forwards to discussions between the Company and Staff.	NW Natural designed its scenarios and sensitivities in this IRP to evaluate a wide range of risks, including many of the variables cited as examples by the commenter. The Company also notes that the combined effect of different variables applies to both gas and electric systems. Thus, in this IRP, the Company explores a broad set of scenarios ranging from a gas growth scenario to a full electrification scenario. The results of these analysis have guided the Company's strategy of centering on optionality as there is material uncertainty related to costs of an energy transition related to both the gas and electric system.

12	CUB	CUB questions the value of the Company's cost analysis of load growth from electrification above PGE's IRP, which CUB notes is based on PGE's internal customer data and company-specific information.	NW Natural's electrification study leverages data from PGE's IRP when it is available. Further, the Company is being responsive to the Commission requesting that the Company look at electrification as a compliance alternative. Thus, analyzing costs associated to a largely electrified system is appropriate.
13	CUB	CUB notes that NW Natural does not have a scenario examining low-availability/high cost of alternative fuels, and suggests the Company examine the considerable cost and risk-factors associated with alternative fuels.	The Company is running Monte Carlo simulations across multiple scenarios that examine the impact of high cost and low availability of alternative fuels.
14	CUB	CUB suggests an energy efficiency-focused pathway such as building weatherization, which they note could decarbonize without committing customers to, and risking long-term utility investments in, one distribution system (gas or electric) over another.	Based on this feedback, the Company worked with Energy Trust to identify what measure could potentially be accelerated. NW Natural ran a supplemental load forecast which captured these accelerated measures. The results showed a small decrease in load and in turn a decrease in NPV costs of about $134 Million less in NPV over the planning horizon relative to the PRS.a results, about 1% of the total costs modeling in PRS.a. NW Natural recognizes the importance of achieving cost effective energy efficiency. The forecasted energy efficiency in the Reference Case demand forecast is aggressive as first year therm savings ramps roughly 5 million therms saved today to about 9 million therms, a 70 percent increase, over the next ten years. NW Natural will continue to work with Energy Trust to achieve these ambitious goals.
15	NW Pipeline	NW Pipeline is concerned that supply options ICF presented at the Technical Working Group [TWG #2] eliminate new natural gas-fired generation (with or without CCS) as a viable option for electric supply.	NW Natural appreciates the feedback from NW Pipeline.
16	NW Pipeline	NW Pipeline notes that while HB 2021 stipulates the Oregon Energy Facility Siting Council cannot issue site certificates for any new generation facility powered by fossil fuels, it seems	NW Natural appreciates the feedback from NW Pipeline.

		unlikely to them that non-fossil fuel sources alone will be able to meet the regional load growth, particularly from data centers. NW Pipeline suggests that Oregon legislators may need to recognize the value of new natural gas-fired generation as a near- to intermediate-term solution.	
17	Green Hydrogen Coalition	Green Hydrogen Coalition (GHC) thanks NW Natural. They suggest that ICF's analysis on alternative fuels should incorporate opportunities for converting biomass to hydrogen and its derivative fuels, in addition to synthetic renewable methane, utilizing environmentally responsible commercially available Non-Combustion Thermal Conversion (NCTC) technologies.	NW Natural appreciates the feedback from Green Hydrogen Coalition. The Company has included a discussion of the production of hydrogen and its derivative fuels from biomass in Chapter 7. The Company is additionally proposing to develop Biomass Derived Synthetic Methane Feasibility Study as Action Item B-7.
18	Green Hydrogen Coalition	GHC describes multiple benefits of NCTC, including: NCTC technology enables environmentally responsible conversion of biomass, including municipal biomass and sewage biosolids. NCTC can also utilize ample forest biomass to be converted to syngas and hydrogen in a closed loop system that prevents harmful emissions. NCTC's can produce pure renewable hydrogen while reducing the biomass sent to landfills, including the near total destruction of PFAS (aka 'forever chemicals') because of the high temperature of the NCTC process. Because the process also produces biogenic CO2, NCTC technologies are ideally suited for the production of alternative fuels such as renewable methanol or sustainable aviation fuel which require biogenic CO2 as an input.	NW Natural appreciates the feedback from Green Hydrogen Coalition.
19	Green Hydrogen Coalition	The GHC is currently finalizing an analysis of Organic Waste to Clean H2 Opportunity Assessment for the LA Area. The study looks at the concept of biomass to hydrogen from an economic standpoint and focuses specifically on dry woody feedstocks and municipal biosolids from the Los Angeles	NW Natural appreciates the feedback from Green Hydrogen Coalition. As noted above, the Company is additionally proposing to develop Biomass Derived Synthetic Methane Feasibility Study as Action Item B-7.

		area. The findings are very promising (~$2.3-$5/kg LCOH post tax credit, depending on the assumptions for electricity cost used for H2 production in the NCTC process). They note this hydrogen production pathway can be scaled to leverage the abundant amounts of forest biomass in the Pacific NW.	
20	Green Hydrogen Coalition	GHC requests that ICF update its findings based on 45v Final Rule changes. This includes changes to how the tax credit is applied depending on the lifecycle of the emissions produced, additional pathways for demonstrating incrementality, and delays to the time-matching provision.	NW Natural appreciates the feedback from Green Hydrogen Coalition. Chapter 7 discusses how the 45V tax credit was applied within the Alternative Fuels Study. The study was completed prior to the final ruling, however, the Company has updated costs to reflect the significant decrease in tax incentives for Blue and Turquoise Hydrogen.
21	Green Hydrogen Coalition	GHC supports investigation into H2 Pipeline Blending, as it is being successfully implemented in Hawaii. They note that states like Hawaii demonstrate how hydrogen blending is viable and safe for existing commercially used pipeline infrastructure and end uses. With up to 15% of hydrogen content in Hawaii's existing synthetic methane infrastructure today, the state is smartly pursuing opportunities to incorporate more clean hydrogen into their energy supply. GHC cites the Hydrogen Impact Study by UC Riverside, and commissioned by the California Public Utilities Commission, which found "concentration of hydrogen blended in natural gas in the range of 5%- 20% as acceptable, without significant impact on safety and operation of end-use appliances."	NW Natural appreciates the feedback and study citation from Green Hydrogen Coalition.
22	Coalition for Renewable Natural Gas	RNG Coalition appreciates that the IRP TWG process is examining how renewable gas can be used in tandem with technologies that involve the turnover of long-lived capital stock (e.g., electrification of building space and water heating). Renewable gas resources can be shifted between end uses, and it will take time to determine which end-uses are best served using renewable gaseous fuels.	NW Natural appreciates the feedback from the Coalition for Renewable Natural Gas.

23	Coalition for Renewable Natural Gas	Biomethane is an important near-term "drop in" fuel that can be used to decarbonize any (and all) applications currently utilizing conventional natural gas. Incorporating the use of renewable gases within a gas system has a variety of compound benefits, including: the displacement of anthropogenic carbon dioxide emissions from the combustion of fossil fuels; achieving critical near-term non-CO2 greenhouse gas (GHG) benefits due to increased methane capture and destruction; increased energy security; additional environmental benefits that result from the improved management of organic waste; enhancing resource value and income for rural areas; and avoiding conventional fertilizer demand.	NW Natural appreciates the feedback from the Coalition for Renewable Natural Gas. The Company has provided a discussion of the benefits of RNG in Chapter 7.
24	Coalition for Renewable Natural Gas	As of December 2024, RNG Coalition notes that their project database shows 442 operational RNG projects in North America, with another 170 under construction and 286 in planning. This ~330 million MMBtu/year value for North America is in between the national (US only) values for 2025 assessed in ICF's low and high cases in their 2019 study (see figures 5 and 6 from that study). It also compares well to the ~100 million MMBtu/year national (US only, currently operational) value presented by ICF on slide 45 of the TWG #6 deck.	NW Natural appreciates the feedback from the Coalition for Renewable Natural Gas. The Company has provided the most recent statistics provided by the RNG coalition (June 2025) in its discussion of RNG Markets in Chapter 2.
25	Coalition for Renewable Natural Gas	In the TWG #6 deck, ICF estimates that supply available from national sources to OR/WA could increase to slightly over 175 million MMBtu/year value by 2050. That growth rate is reasonable. Prorating this national supply to Oregon and Washington based on population is an appropriate way to determine the region's "fair share" of the total resource.	NW Natural appreciates the feedback from the Coalition for Renewable Natural Gas.

26	Coalition for Renewable Natural Gas	The levelized cost projection for biomethane assets shared by ICF on slide 49 of the TWG deck presents an appropriate range by feedstock. Costs for RNG projects have increased recently due to macro drivers, including general inflationary pressures. While we hope this trend does not continue, we feel that the increased production cost range presented by ICF at the TWG (relative to their 2019 study) correctly reflects this trend.	NW Natural appreciates the feedback from the Coalition for Renewable Natural Gas.
27	Coalition for Renewable Natural Gas	Economic analysis of RNG (and other GHG abatement technologies) should always evaluate both costs and benefits. For example, the RNG industry supported over 55,000 jobs and generated $7.2B in GDP in 2024.	NW Natural appreciates the feedback from the Coalition for Renewable Natural Gas.
28	Coalition for Renewable Natural Gas	In the longer-term, pathways involving additional renewable gases—including renewable hydrogen, e-fuels (e.g., synthetic methane), and captured carbon dioxide (CO_2)—will be necessary in applications that are not well-suited to electrification. For example, many heavy industries may be difficult to electrify and renewable molecules derived from non-fossil sources have many potential benefits. In the mid- to long-term, hydrogen produced from renewable feedstocks such as clean electricity and waste biomass should also be viewed as an essential part of NWN renewable gas mix.	NW Natural appreciates the feedback from the Coalition for Renewable Natural Gas.
29	Coalition for Renewable Natural Gas	Furthermore, the use of carbon capture and sequestration (CCS) technologies such as geologic storage or biochar will produce negative-GHG outcomes when paired with RNG and hydrogen derived from waste biomass. These technologies will provide a necessary pathway to remove emissions from	NW Natural appreciates the feedback from the Coalition for Renewable Natural Gas.

		the atmosphere, creating an important pathway to carbon neutrality and, ultimately, carbon negativity.	
30	OPUC	Staff supports the Company's efforts to implement a forward-looking distribution system planning process, to identify areas that may need future reinforcements through pipeline and non-pipeline solutions and is confident that this will be beneficial to system design and ratepayers. Staff appreciates that the Company has provided information on both pipeline and non-pipeline alternatives for the three areas identified. In understanding that more information will be provided once a full NPA analysis is complete, Staff would like to see the results include: (a) Cost benefit analysis which reflects an avoided GHG compliance cost element consistent with a high-cost estimate of future alternative fuels prices. (b) Addressing whether identified areas require intervention due to A) safety and general system reliability or B) customer growth and reliability related to growth. (c) Timeline for the proposed projects and if they will be a part of this year's action plan.	NW Natural thanks staff for their support on the forward-looking distribution system planning process. The benefits of the GeoDSM efforts consist of the standard avoided costs for a DSM program as described in Chapter 5 and the time value of delayed pipeline investments. These areas were selected for safety and reliability of the system due to forecasted load growth could cause the distribution system to operate above design capacity at some time in the future between 2028 and 2050. Please see Chapter 12 for more details. Please see the Action Plan in Chapter 13 for the proposed NPA timelines.
31	OPUC	To coordinate with Staff involved in the UG 520 rate case, Staff restates our expectation for the Company to include alternatives analysis for at least five years ahead, and to either have its GeoTEE program ready to implement or have an RFP ready to issue to the market for feeder-based load reduction in its forthcoming 2025 IRP filing. [Docket No. UG 520 Exhibit 1000]	The Company's new CMM modeling and its forward looking plan should meet that expectation as evidenced by the Company's Near-Term Action plan which includes GeoTEE programs and other non-pipeline alternatives. The exception for GEOTEE is the Creswell non-pipeline alternative, but the Company will attempt other non-pipeline alternatives in Creswell; please also see ETO's GeoTEE Memorandum in Appendix J for information on GeoTEE implementation and RFP.
32	OPUC	The intent of the IRP guidelines is to compare all alternative resources and associated costs. Accordingly, Staff requests that electrification be holistically modeled in load and resource selection.	Please see the Executive Summary, Section 1.10, for more information about these challenges as well as what the Company has done to significantly advance the conversation.

		Staff acknowledges the Company's efforts to model electrification within their various demand scenarios and appreciates the range of futures. The Company is not considering an incremental effect on gas system demand that could result from moratoriums on gas system expansion or customer-wide electrification. While modeling lower gas load due to electrification within scenarios is important, it doesn't fully address Staff's concerns about how electrification is treated, as communicated in Order 23-281. All scenarios examined and subject to optimization should allow for incremental reduction of gas load through electrification as a selectable gas-load-reducing option. Staff understands that the Electric Supply Study is the Company's attempt to give context and characterize costs associated with electrifying customers and that it is seeking to use this as an input to avoided costs for further use in selection. Staff recognizes the Company's efforts but requests that more to be done. Staff is working with a consulting company to inform its recommendations surrounding electrification and looks forward to coordinating with the Company on this topic. We hope to provide actionable information that can be implemented in the near term.	
33	OPUC	Staff supports the Company's addition of a risk reduction value for GHG compliance. Currently, Staff supports, and the Company calculates a commodity cost risk reduction value, which puts an additional avoided cost value on the potential for high future costs. Staff finds it reasonable to quantify and account for this risk by calculating a compliance risk reduction value.	NW Natural thanks Staff for their support and comments on the proposed risk reduction value for GHG compliance.

34	OPUC	This GHG compliance risk reduction value could be used in avoided costs and other resource valuation to determine appropriate investment levels. The GHG compliance risk reduction value would be used in addition to GHG compliance avoided costs which are currently set at Oregon Department of Environmental Quality's Community Climate Investment credit cost.	Staff's understanding about the GHG compliance risk reduction value is correct. Please see Chapter 5 and Appendix C for details on how GHG compliance risk reduction value is integrated into the avoided costs.
35	WUTC	Staff asks if there has been internal or Advisory Group conversation on how NW Natural intends to align its portfolio and procurement strategies with the interim emissions reduction targets set forth under the CCA. How is the Company incorporating the statutory milestones outlined in RCW 70A.45.020—specifically, the 2030, 2040, and 2050 greenhouse gas limits—into its planning framework?	The Company plans to meet its requirements as set forth in the Climate Commitment Act. The program cap of Climate Commitment Act aligns with the State's greenhouse gas emissions reduction targets. While the program cap aligns with the statewide 2030, 2040, and 2050 limits, the program does not dictate specific reduction trajectories for each covered entity. The CCA provides flexibility for entities to comply in the most cost effective manner. As such, the Company believes that by aligning its planning to comply with the CCA it also aligns with the milestones set forth in the targets.
36	WUTC	Staff believes it is important to proactively assess system attrition risks and customer self-electrification. They note factors such as CCA compliance costs, high gas price trajectories, fixed-cost recovery challenges, and state building code constraints may converge in ways that accelerate cost pressures, especially for low-income customers. Slide 97 of TWG 9 seems to acknowledge this risk dynamic.	The Company's electrification analysis assesses this risk. The Company also believes (and assumes Staff also recognizes) that there are also costs and risks relative to electrification as well both in terms of the impact to low income customers and the potential reliability and safety risks.
37	WUTC	Given the potential for a feedback loop—where rising costs drive attrition, which in turn amplifies those very costs—has NW Natural considered modeling a portfolio that both fulfills its statutory obligation to serve and aligns its emissions profile proportionally with statewide reduction targets?	In all scenarios the Company meets its statutory obligation to serve and its emissions reductions targets under the CCA. CCA program cap aligns with the statewide reduction target, but does not include requirements for specific covered entities to reduce emissions according to a specific trajectory. Cap and trade programs drive statewide emission reductions but allow flexibility

		If current CCA implementation is not expected to achieve that alignment, would the Company be open to modeling an alternative scenario that does?	for covered entities to comply in the most cost effective way, which may drive some entities to reduce emissions faster than the statewide targets and other entities to reduce more slowly.
38	WUTC	Would NW Natural consider assessing the role of elevated avoided costs and targeted energy efficiency as a potential tool for stabilizing rates and mitigating self-electrification trends in overburdened communities?	During TWG 5, Avoided Costs and Demand Side Resources, the Company discussed the avoided costs process and methodologies. Indeed, the Company proposed increasing avoided costs to recognize the Compliance cost risk reduction value. These are laid out in Chapter 5. Further, during the TWG process, the question of increasing avoided costs was asked and ETO described working with NW Natural to evaluate the impacts of increased avoided costs. The results showed no significant impact on the projected cost-effectively achievable EE savings. Geographically targeted energy efficiency (GeoTEE) is one of the non-pipe alternatives the Company evaluates. Other targeted demand-side solutions are also being evaluated. The Company believes this analysis should be reviewed for distribution system projects regardless of whether they are for an overburdened community or not.
39	WUTC	On Slide 57 of TWG 9, the yellow dotted line appears to represent 5% of the current Washington revenue requirement. Could you clarify what that means and how it influences the sensitivity costs shown in this scenario?	WUTC Staff is correct in that the yellow line on Slide 57 of TWG #9 represents approximately 5% of Washington's *current* revenue requirement. This line is illustrative to provide context for the cost containment provision in HB 1257 regarding voluntary RNG. It does not influence the costs or resource selection in this scenario (S2b). More detail on how this scenario was developed and how it influenced the development of the Preferred Resource Strategy can be found in the recording of TWG 9.
40	WUTC	Regarding BC Allocation/ Access Constraint, was there any discussion during the modeling process about the 15% loss attributed to British Columbia's allocation or access constraints?	While the Woodfibre project is expected to take about 15% of the supply from the Sumas market, NW Natural has contracting mechanisms in place which will ensure that the Company continues

			to fill winter take-away capacity from Sumas, therefore no changes to the modeling process is required.
41	WUTC	Staff noted that each scenario projects customer growth beyond 2031, which appears to be inconsistent with current state building codes under RCW 19.27A.020(2)(a). Given that this statute restricts gas availability in new construction, any assumptions of post-2031 customer growth should be accompanied by strong supporting evidence or clearly stated exemptions. Staff would appreciate further explanation of how these projections were developed and whether alternative modeling approaches were considered.	RCW 19.27A.020(2)(a) requires the state building code council to follow the legislature's standards for adopting the Washington state energy code, which is designed to "Construct increasingly energy efficient homes and buildings by the year 2031". RCW 19.27A.020 further states in RCW 19.27A.020(3), "The Washington state energy code may not in any way prohibit, penalize, or discourage the use of gas for any form of heating, or for uses related to any appliance or equipment, in any building." NW Natural's customer count forecasts of Washington customers in its 2025 IRP Reference Case show slowing customer count growth after 2031, which is not inconsistent with RCW 19.27A.020. The Company notes that RCW 19.27A.020(2)(a) and RCW 19.27A.020(3) are part of Washington Ballot Initiative I-2066, which impacts state building codes, was passed, subsequently found unconstitutional, and is currently in litigation (to be reviewed by the Washington State Supreme Court). While the appeal plays out, a separate lawsuit arguing that the codes are invalid under I-2066 is on hold.
42	WUTC	Staff believes there is the possibility that rising gas service costs under the CCA could lead to increased rates of self-electrification. Has the Company explored or modeled the extent to which customers might choose to electrify in response to anticipated CCA-related price signals?	Please see Section 11.1.3.
43	WUTC	Scenario 5 (S5) appears to treat limitations on gas in new construction as a hypothetical. However, Staff respectfully notes that such limitations are codified in law and therefore should be integrated into the Preferred Resource Strategy as	RCW 19.27A.020(2)(a) requires the state building code council to follow the standards of the Washington state energy code, which is designed to "Construct increasingly energy efficient homes and buildings by the year 2031". RCW 19.27A.020 further states in RCW

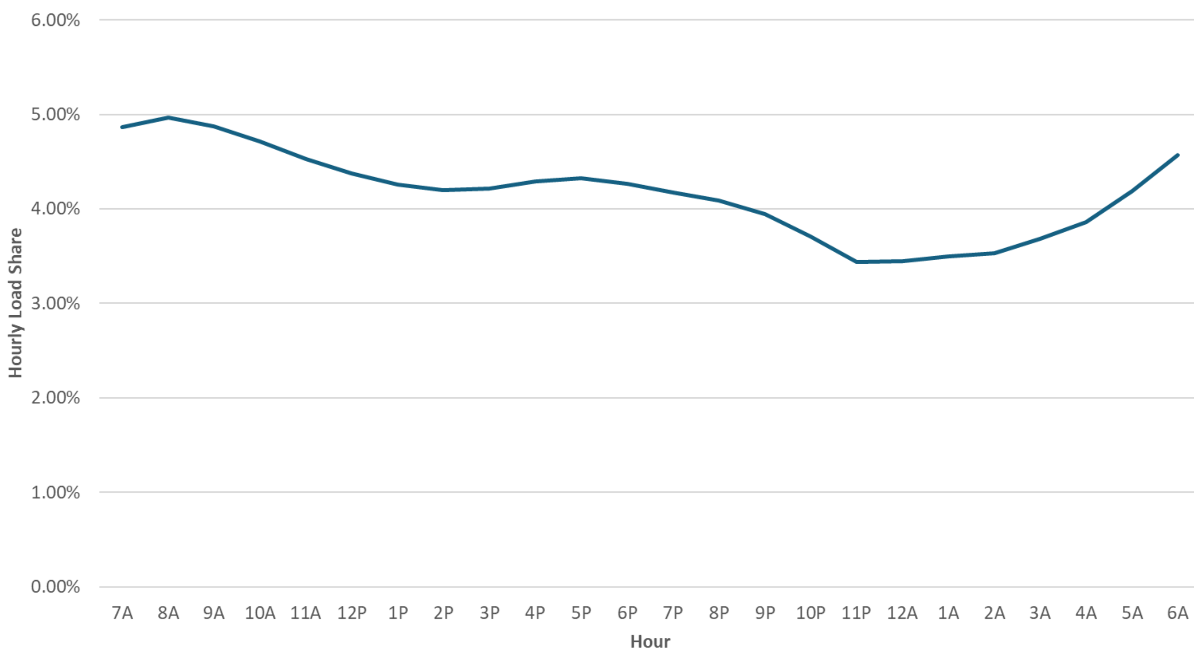
		a planning constraint—not merely tested as a scenario. Absent a legal reversal, these statutory provisions should guide baseline planning.	19.27A.020(3), "The Washington state energy code may not in any way prohibit, penalize, or discourage the use of gas for any form of heating, or for uses related to any appliance or equipment, in any building." The Company notes that RCW 19.27A.020(2)(a) and RCW 19.27A.020(3) are part of Washington Ballot Initiative I-2066, which impacts state building codes, was passed, subsequently found unconstitutional, and is currently in litigation (to be reviewed by the Washington State Supreme Court). While the appeal plays out, a separate lawsuit arguing that the codes are invalid under I-2066 is on hold.
44	WUTC	Staff appreciate the Company's efforts to manage a complex planning landscape and thank you for your continued engagement with Staff and other participants.	NW Natural appreciates the feedback and is making best efforts to engage with a variety of stakeholders in a rapidly changing and complex planning environment.

Appendix J – Distribution System Planning

J.1 Peak Hour Modeling

Design peak hour is modeled using hourly firm system data where the average daily temperature is less than, or equal to, 45˚F.[15] The estimated model is then applied to the out-of-sample coldest days on record from 1985, 1989, and 1990 to predict firm system dekatherms, on an hourly basis. These hourly predictions are then divided by their respective aggregated gas day predictions to produce hourly load shares. Finally, the hourly load shares from the three out-of-sample peak days are averaged together, by hour, to yield the design hourly peak day load shares.

Figure J-1: Design Peak Hour Average Load Shares



J.2 2025 System Reinforcement Forward Looking Plan

The following pages provide NW Natural's 2025 System Reinforcement Forward Looking Plan.

[15] Contiguous hourly data spans Jan. 2009 – Mar. 2024.

2025 Forward Looking Distribution System Plan

Planning Documentation
Date Updated: July 17, 2025

Contents

Scope

NW Natural completes a comprehensive review of the distribution system to identify areas for further investigation during a peak Heating Degree Day (HDD). Heating Degree days are the difference between 65°F and the mean daily temperature, (high temperature plus low temperature divided by two). Peak design HDD values are different for each geographic area within our service territory, as shown in the table below:

Weather Zone	HDD
Clark County	57.4
Columbia River Gorge	66.8
Portland	57.0
Astoria	49.4
Salem	54.8
Lincoln City	45.7
Albany	54.5
Eugene	56.2
Coos County	41.9

This Forward Looking Distribution System Plan identifies areas for investigation and monitoring on NW Natural's system that may require a large system reinforcement or non-pipeline alternative effort to provide reliable service to firm sales and transportation customers. Areas for investigation do not currently violate system reinforcement criteria but are areas where the gas distribution system is approaching these thresholds and/or is showing evidence of growth in demand that could reach system monitoring thresholds. NW Natural updates and reviews the Forward Looking Distribution System Plan annually.[1]

The areas identified for investigation in the Forward Looking Distribution System Plan are continuously being evaluated by a mixed-method approach using a combination of modeling results and actual field recorded pressure data to verify system modeling behavior. Peak day modeling is accomplished using the DNV Synergi Gas™ software with the following configurations[2]:

1. Interruptible Customers Disabled
2. Peak HDD Customer Demands Based on CMM Data & Peak HDD's for Zone
3. Williams Gas Energy Content – 1040 BTU/SCF
4. Mist Gas Energy Content – 1040 BTU/SCF
5. LNG Gas Energy Content – 1075 BTU/SCF

Field recorded pressure data may be observed and documented by:

[1] In previous years, these were often referred to as 10-year plans but have been renamed *forward looking plans*.
2 See Section 12.4 Distribution System Planning Tools and Standards in Chapter 12 for a detailed description of the modeling tools and approaches that have been used in the 2025 IRP.

1. SCADA Data pressure logs
2. Electronic Portable Pressure Recorders (EPPR's) temporarily sited in the field
3. Cold Weather Survey Points that are manually read by NW Natural Technicians

Distribution System Evaluations

NW Natural's system reinforcement criteria establish thresholds in which traditional supply-side investments are required to maintain reliable service to customers. Non-pipeline alternatives can be implemented in advance to avoid or delay reaching these thresholds. NW Natural also sets guideline criteria for system modeling to identify areas to be considered under investigation.

System Reinforcement Criteria:

- Exceeds system design capacity.
- For systems with nominal diameters less than six inches, or have a Maximum Allowable Operating Pressure (MAOP) of 300 psig or less:
  - Experiencing or modeling a greater than 40 percent pressure drop from a source to the lowest pressure indicates that reinforcing the facility is critical, as a 40 percent pressure drop equates to an 80 percent level of capacity utilization.
- For systems with nominal diameters of six inches or greater or have a Maximum Allowable Operating Pressure (MAOP) greater than 300 psig:
  - Experiencing or modeling a pressure below 180 psig on the system indicates that reinforcing the facility is critical.
- High pressure or transmission systems that do not maintain the required regulator inlet pressure for proper operation.
- Class B pipeline systems (60 MAOP or less) experience or are modeled to have pressures of 10 psig or less.

System Areas for Investigation Criteria:

- Approaching System Design Capacity.
- For systems with nominal diameters less than six inches, or have a Maximum Allowable Operating Pressure (MAOP) of 300 psig or less:
  - Experiencing or modeling a greater than 30 percent pressure drop from a source to the lowest pressure indicates that an investigation will be initiated.
- For systems with nominal diameters of six inches or greater or have a Maximum Allowable Operating Pressure (MAOP) greater than 300 psig:
  - Experiencing or modeling a pressure below 210 psig on the system indicates that an investigation will be initiated.
- Experience, and / or model, minimum Class B distribution pressures of 15 psig or less, or where incremental consumption may cause the distribution pressures to drop to 10 psig or less.

System Areas for Investigation

The proposed solutions in this section address areas of the gas distribution system that may reach design capacity because of demand growth. This plan and any future forward looking plan may include further validation of pressure data to confirm system modeling, conceptual design of system reinforcement projects, evaluation of any on-going or potential non-pipeline solutions, and any other alternatives required to maintain reliable service for the areas as specified by design criteria. The distribution systems provided in this section are identified because they would violate our system reinforcement criteria if there were increased consumption as projected in the areas over time. Both traditional pipeline projects and non-pipeline alternatives are evaluated for these areas.

Dallas

Feeder Uprate

- The 15 mile Dallas Feeder is a 175 MAOP 6"(W) and 4"(W) High Pressure pipeline that serves the town of Dallas, OR. This pipeline is fed from two sources, one from Perrydale from the Central Coast Feeder and another from Rickreall which is fed by the Mid-Willamette Valley Feeder.
- Industrial load interest along with incremental growth can lead to capacity constraints on the 175 MAOP system.
    - Lowest modeling pressure: 115.6 psig at 54.8 HDD (30.0% Pressure Drop)
    - Recorded System Low Pressures
        - An EPPR was sited at Dallas during the 24/25 Heating Season.
        - 2024/25 – 135.2 psig at 31 HDD (Tue. 2/11/2025)
    - Refer to Figure 1 for impact area image.
- Pipeline solution
    - Refer to Figure 2 for project area image.
    - Pipeline Replacement and Uprate system from 175 MAOP to 300 MAOP.
        - Replace approximately 1,100' of 4"(W) High Pressure with 6"(W) High Pressure.
        - Uprate the 15 miles of 6"(W) from an MAOP of 175 to an MAOP of 300 psig.
- Estimated available capacity on system: 335 Th/hr

Non-pipeline Alternatives (NPAs)

- **GeoTEE**: In partnership with Energy Trust of Oregon, plan and develop a 3-year (2027-2029) GeoTEE project starting in 2027 in the Dallas area with the goal of achieving 20 Th/hr savings incremental to baseline energy efficiency efforts.
- **BYOT DR**: Coordinating with ETO's thermostat energy efficiency program to enhance the marketing effort for the BYOT program by raising incentives for customers in the Dallas area for the next 3-years (2026-2028) aimed at achieving 10 Th/hr savings at a cost not to exceed an incremental $8,800 to baseline.

- **Behavior DR:** Pursue a 3-year (2026-2028) Geo Behavioral DR program with large commercial customers and industrial customers in the Dallas area to achieve 39 Th/hr at a cost not to exceed $98,900.

Preferred Option

The Company's preferred option for this area is to implement NPAs as described above, beginning in 2026 since the NPAs take time to implement. In the meantime, the Company will continue monitoring pressures and update Synergi Gas™ modeling annually. Therefore, both the pipeline solution and the NPA efforts will be adjusted accordingly based on the outcome of updated annual forecasts and system pressure monitoring in an effort to provide safe, reliable and affordable services to the customers in this area.

Creswell

Feeder Uprate

- The Creswell Feeder is a 1.9 mile-long 3-1/2"(W) 150 MAOP High Pressure pipeline servicing the city of Creswell.
- An increase in consumption can lead to capacity constraints on the Creswell Feeder.
  - Lowest modeling pressure: 88.6 psig at 56.2 HDD (30.6% Pressure Drop)
  - Recorded Low Pressures (Without Emerald Forest Product Consumption)
    - 2020/21 – 116.3 psig at 34 HDD (Sun. 12/27/2020)
    - 2021/22 – 113.2 psig at 35 HDD (Sun. 12/26/2021)
    - 2022/23 – 111.5 psig at 38 HDD (Thu. 12/22/2022)
    - 2023/24 – 107.0 psig at 33 HDD (Sun. 1/14/2024)
    - 2024/25 – 107.5 psig at 33 HDD (Sun. 1/26/2025)
  - Refer to Figure 3 for impact area image.
- Pipeline solution
  - Refer to Figure 4 for project area image.
  - Uprate High Pressure main from 150 MAOP to 300 MAOP.
    - Uprate approximately 1.9 miles of 3"(W) from Creswell Gate Station to the end of High Pressure main adjacent to Emerald Forest Products.
- Estimated available capacity on current system: 80 Th/hr

Non-pipeline Alternatives

- **Historical EE**: No GeoTEE effort is recommended by ETO given the time and resource constraints in this area; but the historical level of EE effort will be pursued.[3]
- **BYOT DR**: Coordinating with ETO's thermostat energy efficiency program to enhance the marketing effort for the BYOT program by raising incentives for customers in the Creswell area for the next 3-years (2026-2028) aimed at

[3] See ETO's Memorandum in Appendix J.4 for more details.

achieving 4 Th/hr savings at a cost not to exceed an incremental $2,000 to baseline.

- **Behavior DR:** Pursue a 3-year Geo Behavioral DR programs with large commercial customers and industrial customers in the Creswell area to achieve 13 Th/hr at a cost not to exceed $24,400.

Preferred Option

The Company's preferred option in this area is to deploy the NPAs and make all necessary preparations for the pipeline solution as described above starting from 2026 since both the NPAs and the pipeline solution take time to implement. In the meantime, the Company will continue monitoring pressures and update Synergi Gas^{TM} modeling annually. Therefore, both the pipeline solution and the NPA efforts will be adjusted accordingly based on the outcome of updated annual forecasts and system pressure monitoring in an effort to provide safe, reliable and affordable services to the customers in this area.

Lebanon

- Upon current analysis, Lebanon has sufficient capacity over the planning horizon. However, the area will continue to be investigated annually. No further actions are needed at this time.

McMinnville

Feeder Reinforcement

- The McMinnville Feeder is a 400 MAOP 6"(W), 17.2 mile-long pipeline, with two laterals of 4" (W) that have a combined length of roughly 3.9 miles, servicing Amity, McMinnville and Lafayette.
- Increased flows on the system can exhaust available capacity. It is estimated that on a peak day the system can support approximately 650 Th/hr of additional firm load before the lowest pressure on the system reaches 180 psig, thereby forcing some improvement or reduction in load. The exact amount of additional load that can be supported would depend on where the load is placed.
    - Lowest modeling pressure: 240.7 psig at 54.8 HDD (24.7% Pressure Drop, starting pressure 319.8 psig due to distance from sources, and regulating equipment) with interruptible customers offline.
    - Recorded Low Pressures (with interruptible customers on)
        - 2020/21 – 283.0 psig at 26 HDD (Tue. 2/9/2021)
        - 2021/22 – 267.4 psig at 30 HDD (Tue. 2/22/2022)
        - 2022/23 – 257.3 psig at 41 HDD (Thu. 12/22/2022)
        - 2023/24 – 278.2 psig at 25 HDD (Thu. 11/27/2023)
        - 2024/25 – 250.6 psig at 28 HDD (Sun. 2/7/2025)
    - Refer to Figure 5 for impact area image.
- Pipeline solution
    - Refer to Figure 6 for project area image
    - As the pressure on the CCF on a peak day, where the McMinnville feeder takes off from the CCF, is below the MAOP of the McMinnville Feeder, a

pressure uprate provides no benefit by itself. Consequently, the options to improve deliverability are:

  - looping or replacing portions of the pipe with a larger diameter pipe, at least 8” in diameter with length and diameter to be determined based on need and whether the new pipe is a replacement or a loop. The minimum amount of new 8” pipe looping the existing main, in order for the minimum pressure to be 180 psig, with the 2050 projected load of 5384 Th/hr would be 5.2 miles. Additionally, the regulation equipment that feeds McMinnville feeder will need to be redesigned and rebuilt to minimize unintended pressure loss. As load is generally added incrementally, the addition of the main can also be done in lengths appropriate to the load addition over time. Or
  - Adding compression either:
    - West of Grand Ronde, which would improve the pressure on the CCF while enabling 100 MMscfd of sendout from Newport LNG. This would require about 6,700 hp. Or
    - Compression on the McMinnville Line. Note that uprating the pipe could improve deliverability in conjunction with compression in this option. It is anticipated that the initial likely horsepower requirements would be roughly 300 to 700 hp, depending on many variables such as MAOP, location of compressor, suction and discharge pressures, desired flow rate capability. If the existing MAOP were retained, then the horsepower requirements would likely be between 400 and 500, with the likely technology being rotary screw compression and reciprocating compression being a less desirable secondary choice. Compression is more suited to larger step increases in capacity than pipe additions. Additionally, the regulation equipment that feeds McMinnville feeder will need to be redesigned and rebuilt to minimize unintended pressure loss.
- Estimated available capacity on current system: 730 Th/hr.

Non-pipeline Alternatives

- **GeoTEE**: In partnership with Energy Trust of Oregon, plan and develop a 3-year (2027-2029) GeoTEE project starting in 2027 in the McMinnville area with the goal of achieving 35 Th/hr savings incremental to baseline energy efficiency efforts.
- **BYOT DR**: Coordinating with ETO’s thermostat energy efficiency program to enhance the marketing effort for the BYOT program by raising incentives for customer in the McMinnville area for the next 3-years (2026-2028) aimed at achieving 16 Th/hr at a cost not to exceed an incremental $18,800 to the baseline.

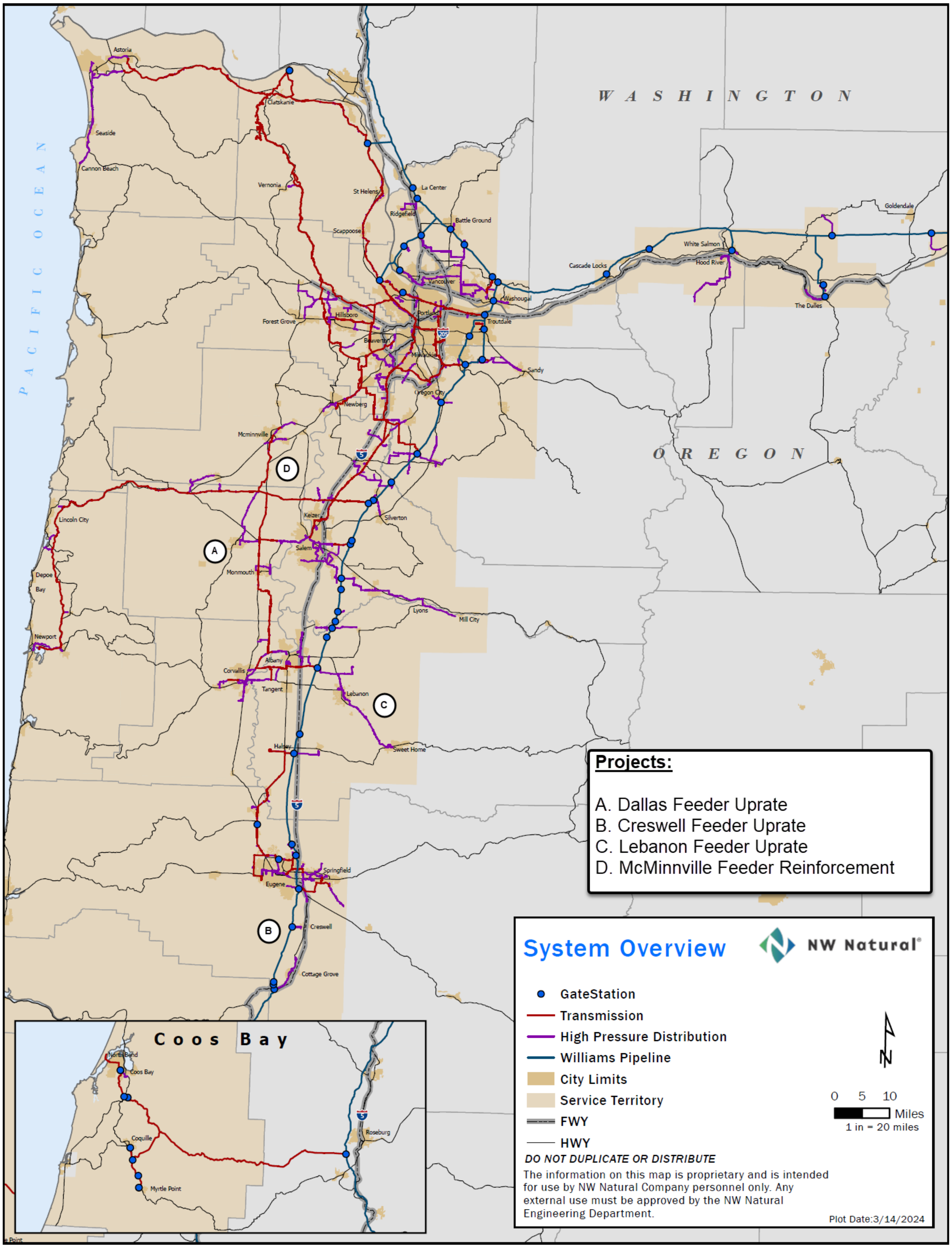
- **Behavior DR:** Pursue a 3-year Geo Behavioral DR programs with large commercial customers and industrial customers in the McMinnville area to achieve 105 Th/hr at a cost not to exceed $331,500.

Preferred Option

The Company's preferred option for this area is to implement NPAs as described above, beginning in 2026 since the NPAs take time to implement. In the meantime, the Company will continue monitoring pressures and update Synergi Gas™ modeling annually. Therefore, both the pipeline solution and the NPA efforts will be adjusted accordingly based on the outcome of updated annual forecasts and system pressure monitoring in an effort to provide safe, reliable and affordable services to the customers in this area.

System Investigation Locations

The following map shows the system investigation areas identified in this plan.



System Distribution Supply Projects

Supply projects discussed in this section are intended to increase supply side resources by increasing deliverability from NW Natural's existing system storage assets.

Central Coast Feeder Reinforcement

There are two options to provide additional takeaway capacity from the Newport LNG facility to the Albany and Salem load centers. Each option allows for different additional incremental gas supplies to reach the Valley load centers on a design day.

- Option 1: Uprate (increase the Operating Pressure) the existing 12-inch Central Coast Feeder transmission main to an MAOP of 720 psig between the North Lincoln Primary (regional station) and Blowdown 6 (pipe bridal), a distance of approximately 15 miles. Pressure regulation, valve automation, instrumentation and controls will be needed where the new 720 MAOP ends, and the existing 600 MAOP begins, at Blowdown 6. The new station will need a full port ball valve with automation to open the valve when the pressure is below MAOP, and begin regulating pressure before the pressure reaches MAOP. This will allow Newport LNG to vaporize at a maximum rate of about 97 MDTh/d at 860 psig with a 24-hour sendout capability of roughly 91 MDTh instead of the existing 78 MDTh at 844 psig.
- Option 2: The capability to vaporize 100 MMscfd (107+ MDTH/d) requires the installation of a single compressor station west of Grand Ronde to boost the pressure for a flow rate of roughly 84.8 MMscfd from 170 psig (179 psig arrival pressure) to 600 psig (595 psig outlet pressure to CCF) using a compressor of approximately ~6700 hp. Note that Option 2, does not require option 1, nor the uprate of any pipe, as the pressure at Lincoln city primary is below 500 psig when flowing roughly 85 MMscfd east towards the Willamette River Valley.
- Refer to Figure 7 for project area image.

Project Images

Two images are provided for each system investigation area within our gas distribution system. The impact area shows areas of the system where customers could experience low pressure during cold weather events. The project image provides a general area of the proposed pipeline solution provided in this plan.

Figure 1

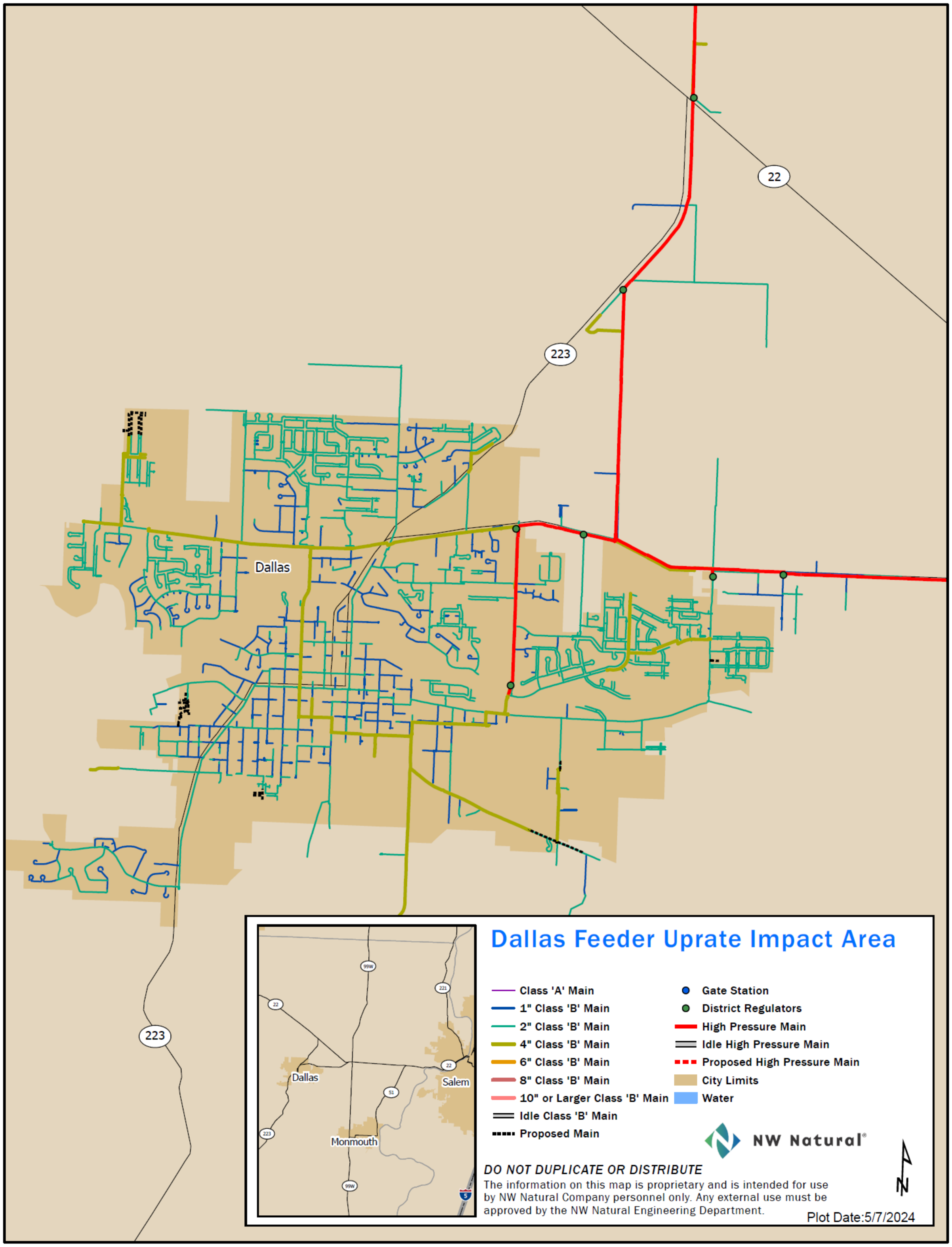
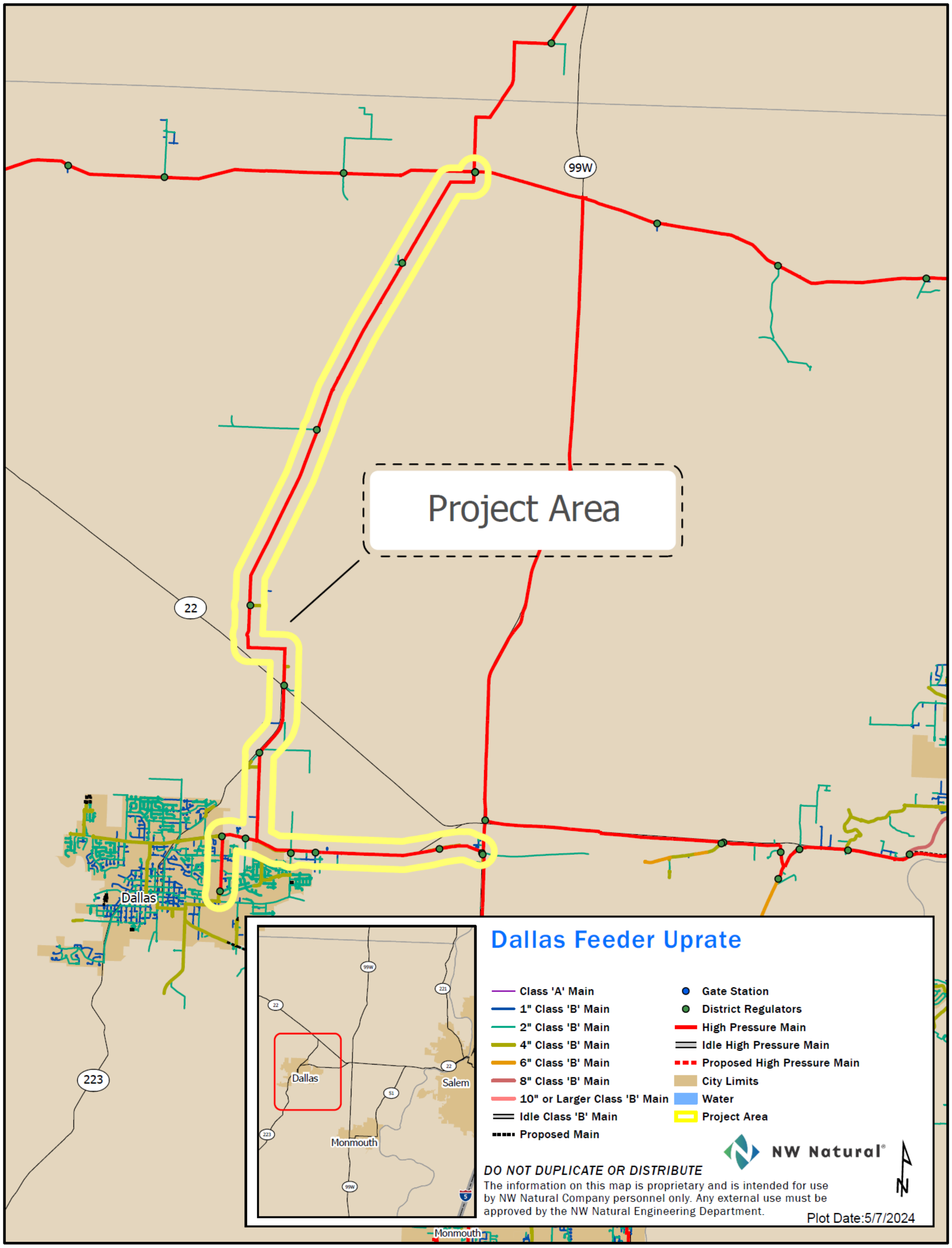

22
223
Dallas
223
Dallas
Salem
Monmouth
Dallas Feeder Uprate Impact Area
Class 'A' Main
1" Class 'B' Main
2" Class 'B' Main
4" Class 'B' Main
6" Class 'B' Main
8" Class 'B' Main
10" or Larger Class 'B' Main
Idle Class 'B' Main
Proposed Main
Gate Station
District Regulators
High Pressure Main
Idle High Pressure Main
Proposed High Pressure Main
City Limits
Water
NW Natural
N
DO NOT DUPLICATE OR DISTRIBUTE
The information on this map is proprietary and is intended for use by NW Natural Company personnel only. Any external use must be approved by the NW Natural Engineering Department.
Plot Date:5/7/2024

Figure 2


99W
Project Area
22
Dallas
223
Salem
Monmouth
221
51
Dallas Feeder Uprate
Class 'A' Main
1" Class 'B' Main
2" Class 'B' Main
4" Class 'B' Main
6" Class 'B' Main
8" Class 'B' Main
10" or Larger Class 'B' Main
Idle Class 'B' Main
Proposed Main
Gate Station
District Regulators
High Pressure Main
Idle High Pressure Main
Proposed High Pressure Main
City Limits
Water
Project Area
NW Natural
DO NOT DUPLICATE OR DISTRIBUTE
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Plot Date:5/7/2024
N

Figure 3

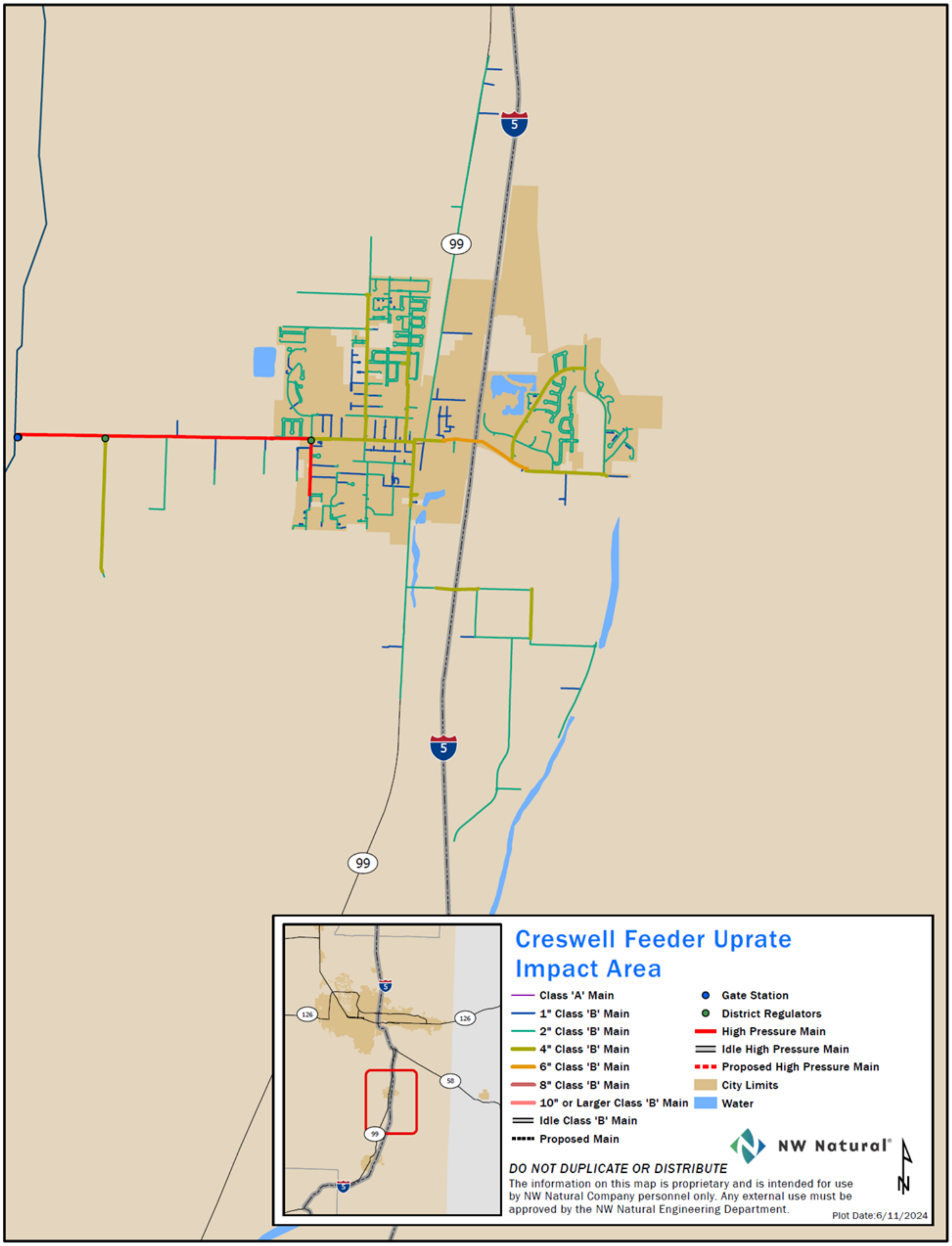
99
5
5
99
126
126
58
99
5
Creswell Feeder Uprate
Impact Area
Class 'A' Main
1" Class 'B' Main
2" Class 'B' Main
4" Class 'B' Main
6" Class 'B' Main
8" Class 'B' Main
10" or Larger Class 'B' Main
Idle Class 'B' Main
Proposed Main
Gate Station
District Regulators
High Pressure Main
Idle High Pressure Main
Proposed High Pressure Main
City Limits
Water
NW Natural®
N
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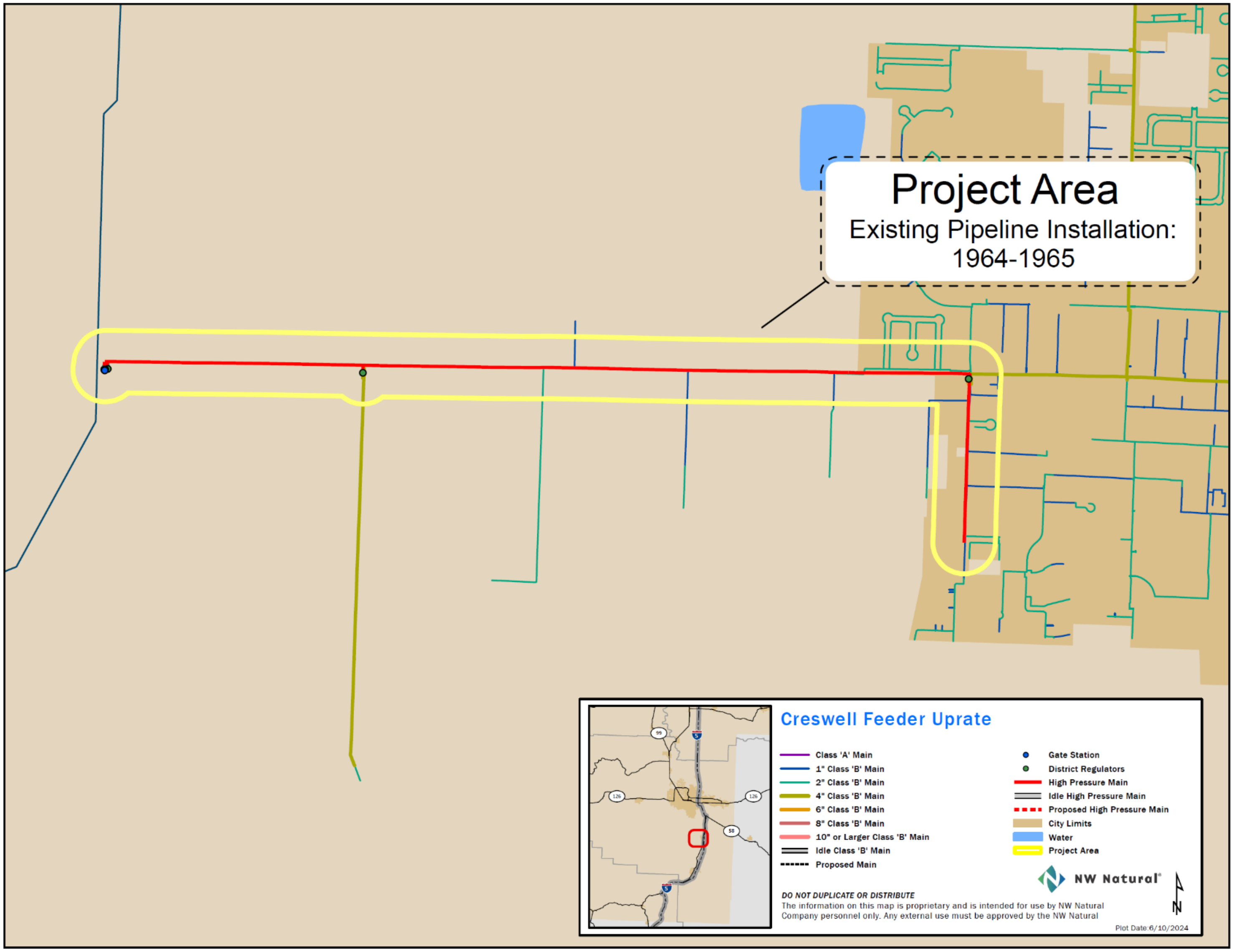
Figure 4



Project Area
Existing Pipeline Installation:
1964-1965
Creswell Feeder Uprate
Class 'A' Main
1" Class 'B' Main
2" Class 'B' Main
4" Class 'B' Main
6" Class 'B' Main
8" Class 'B' Main
10" or Larger Class 'B' Main
Idle Class 'B' Main
Proposed Main
Gate Station
District Regulators
High Pressure Main
Idle High Pressure Main
Proposed High Pressure Main
City Limits
Water
Project Area
NW Natural
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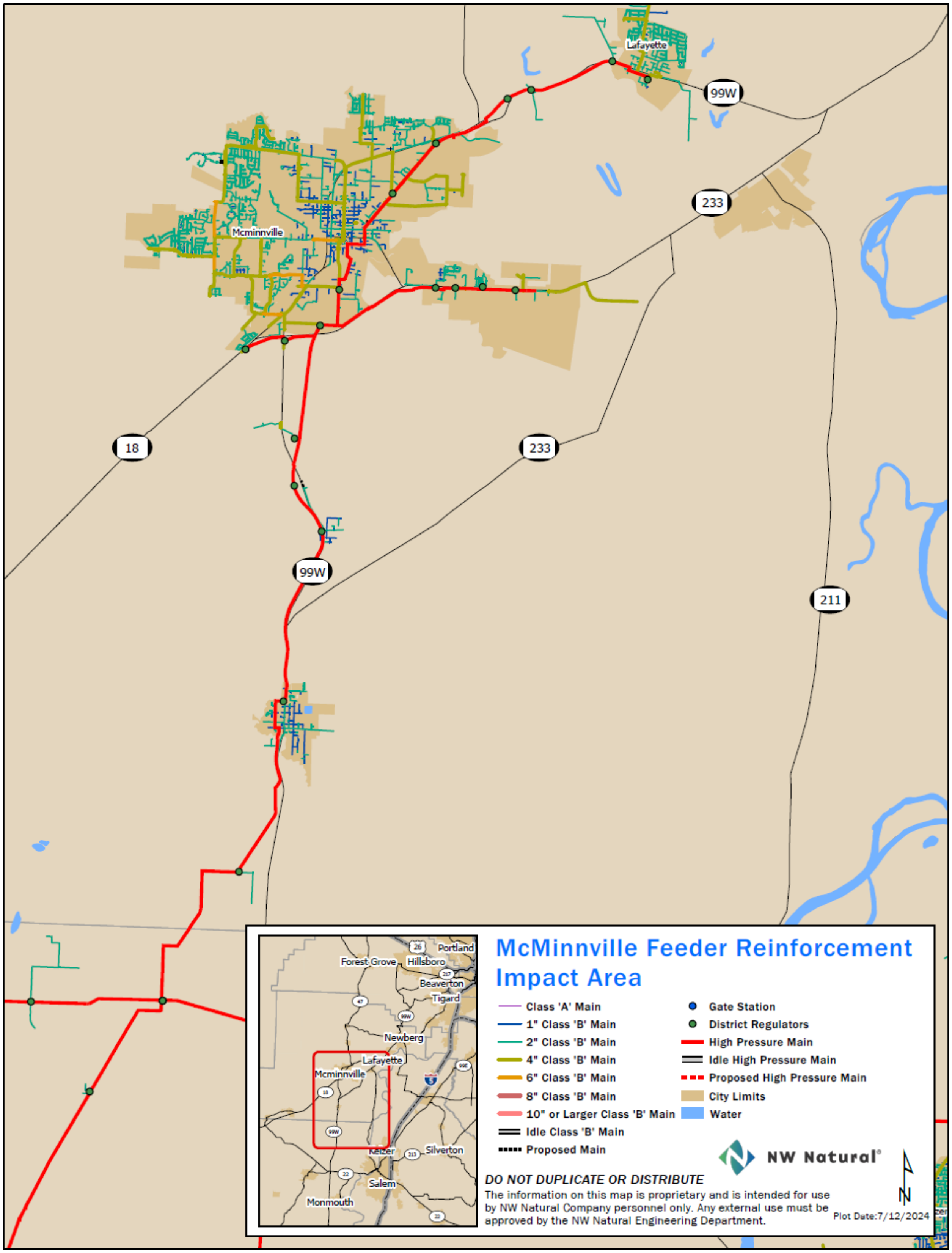
N
Plot Date:6/10/2024

Figure 5



Lafayette
99W
Mcminnville
233
18
233
99W
211
McMinnville Feeder Reinforcement Impact Area
Portland
Forest Grove
Hillsboro
Beaverton
Tigard
Newberg
Lafayette
Mcminnville
Keizer
Silverton
Salem
Monmouth
Class 'A' Main
1" Class 'B' Main
2" Class 'B' Main
4" Class 'B' Main
6" Class 'B' Main
8" Class 'B' Main
10" or Larger Class 'B' Main
Idle Class 'B' Main
Proposed Main
Gate Station
District Regulators
High Pressure Main
Idle High Pressure Main
Proposed High Pressure Main
City Limits
Water
NW Natural®
N
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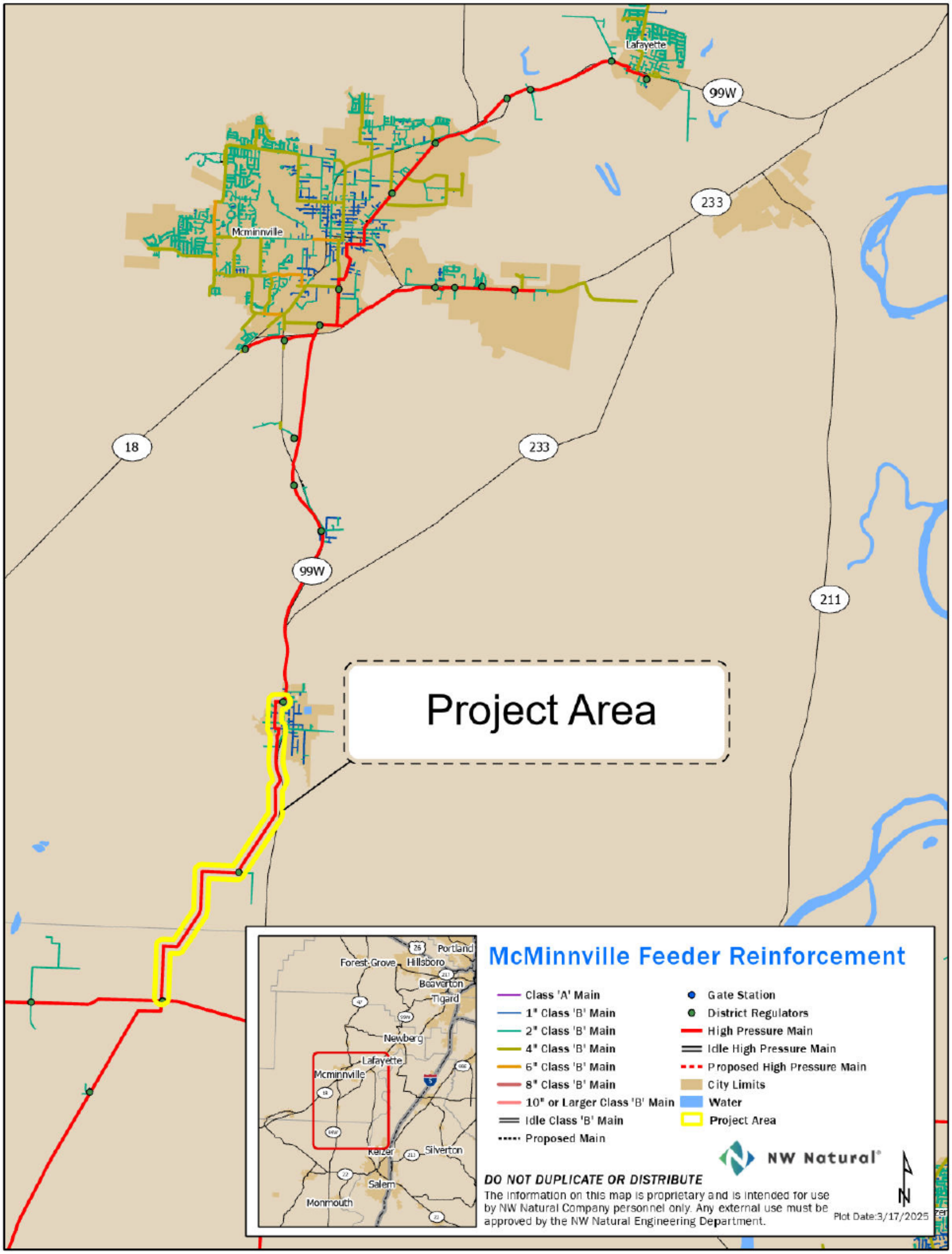
Plot Date:7/12/2024

Figure 6


Lafayette
99W
Mcminnville
233
18
233
99W
211
Project Area
McMinnville Feeder Reinforcement
Portland
Forest Grove
Hillsboro
Beaverton
Tigard
Newberg
Lafayette
Mcminnville
Keizer
Silverton
Salem
Monmouth
Class 'A' Main
1" Class 'B' Main
2" Class 'B' Main
4" Class 'B' Main
6" Class 'B' Main
8" Class 'B' Main
10" or Larger Class 'B' Main
Idle Class 'B' Main
Proposed Main
Gate Station
District Regulators
High Pressure Main
Idle High Pressure Main
Proposed High Pressure Main
City Limits
Water
Project Area
NW Natural®
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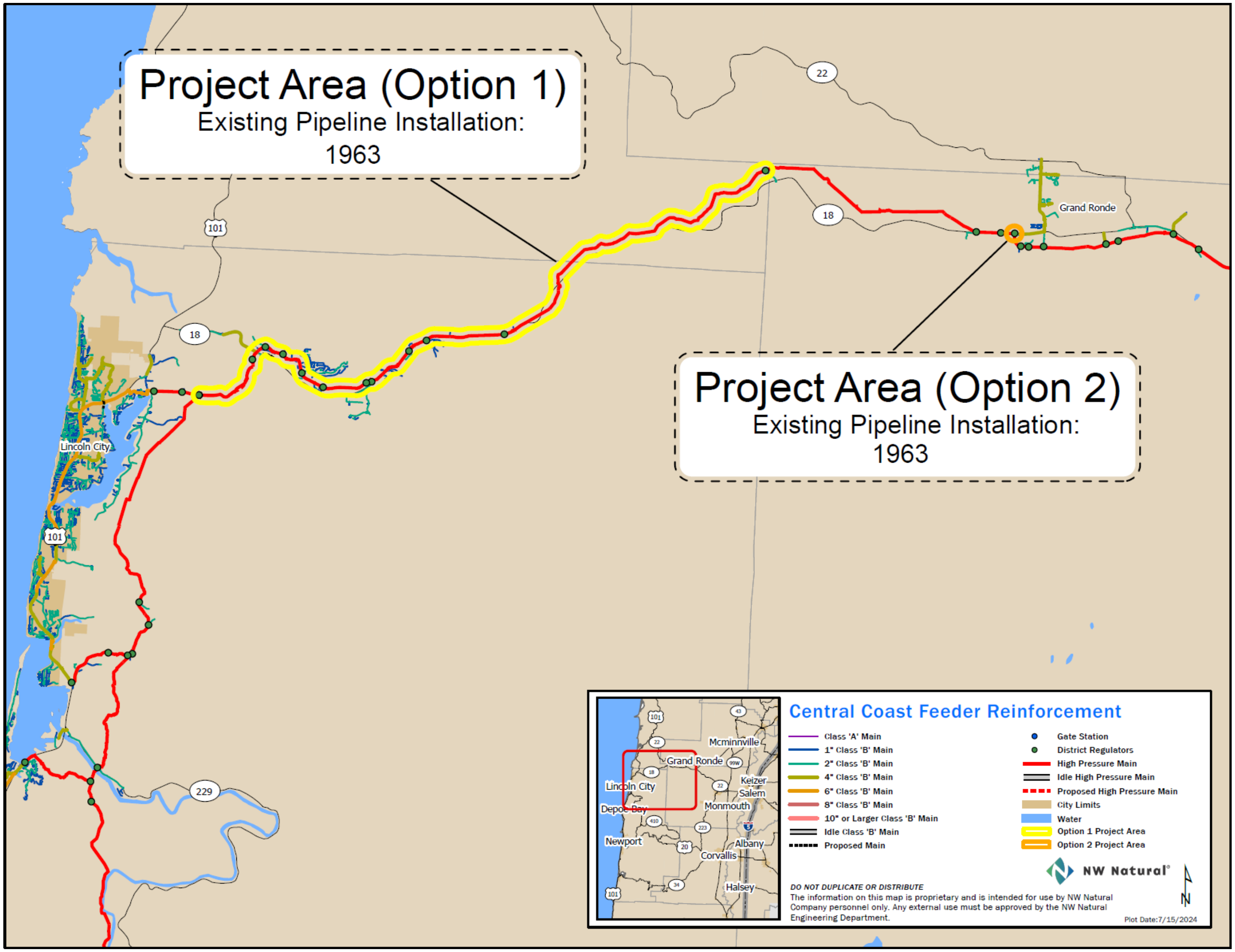
Plot Date:3/17/2025
N

Figure 7


Project Area (Option 1)
Existing Pipeline Installation:
1963
Project Area (Option 2)
Existing Pipeline Installation:
1963
Grand Ronde
Lincoln City
22
18
101
229
Central Coast Feeder Reinforcement
Class 'A' Main
1" Class 'B' Main
2" Class 'B' Main
4" Class 'B' Main
6" Class 'B' Main
8" Class 'B' Main
10" or Larger Class 'B' Main
Idle Class 'B' Main
Proposed Main
Gate Station
District Regulators
High Pressure Main
Idle High Pressure Main
Proposed High Pressure Main
City Limits
Water
Option 1 Project Area
Option 2 Project Area
Mcminnville
Grand Ronde
Lincoln City
Depoe Bay
Keizer
Salem
Monmouth
Newport
Albany
Corvallis
Halsey
NW Natural
N
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J.3 Compressed Natural Gas and Liquid Natural Gas Trucking

NPAs were presented and discussed with stakeholders during TWG 8, held on April 8, 2025. The following risks and benefits were shared during this meeting on slide 50 of the presentation.[16]

Table J-1: Risks and Benefits of CNG and LNG Trucking

Risks	Benefits
• NW Natural reliant upon third party vendor for LNG supply • CNG and LNG trucking vendor market is limited • Pricing unknown beyond year 1 • Pricing for CNG & LNG trucking subject to market conditions for LNG availability, fuel source location and diesel fuel prices • LNG not locally sourced • Requires advanced vendor coordination and planning ○ Payment to vendor required to secure vendor's commitment to service • Cold weather demand could potentially exceed the volume of LNG fuel supply • Weather conditions could make delivery conditions challenging • NW Natural field staff required to coordinate connection to system	• Provides temporary fuel supply when areas of low pressure require reinforcement • LNG trucking is a viable resource for serving isolated communities that cannot be economically reached by pipeline (Tillamook, for example.)

J.3.1 Trucking Study Overview- **[BEGIN CONF]** [redacted]

[16] As noted throughout the IRP, all TWG presentations, including recordings are posted to NW Natural's website at the following URL: https://www.nwnatural.com/about-us/rates-and-regulations/integrated-resource-plan

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] **[END CONF]**

J.3.2 Complete NW Natural Trucking Study

The following pages provide the completed study.

[BEGIN CONF]

NW Natural's Trucking Study (pages J23-J139) is confidential in its entirety under General Protective Order No. 23-132 and has been redacted.

J.4 ETO Geographically Targeted Energy Efficiency IRP Memorandum

The following pages are provided by ETO regarding geographically targeted energy efficiency.

Memo

EnergyTrust of Oregon

To: NW Natural
Matt Doyle, Director of Integrated Resource Planning;
Laney Ralph, Energy Efficiency Program Manager;
Haixiao Huang, Senior Economist;
Hastings Marek, Peak Load Analyst

From: Energy Trust of Oregon
Cory Hertog, Sr. Project Manager – Communities and New Initiatives;
cc: Alex Novie, Sector Lead – Communities and New Initiatives;
Spencer Moersfelder, Director of Planning and Evaluation;
Adam Shick, Planning Manager;
Elaine Prause, Sr. Advisor – Regulatory Policy and Utility Relations;
Natalie Hathaway, Assistant Director – Energy Programs

Date: July 8, 2025

Re: Scoping and Viability Analysis for GeoTEE Project Implementation in the Dallas, McMinnville, and Creswell areas

This memo summarizes the criteria Energy Trust uses to determine the viability of Geographically Targeted Energy Efficiency (GeoTEE)[1] projects, as well as the results from a scoping and viability analysis for proposed GeoTEE projects in the Dallas, McMinnville, and Creswell area, as defined in NW Natural's 2022 Integrated Resource Plan (IRP) Update filed in 2024. This memo also includes an explanation from Energy Trust's perspective for not recommending that NW Natural contract with another third-party for GeoTEE projects in these three areas, including the Creswell area, which was determined to not be a viable area for Energy Trust to conduct a GeoTEE project.

Criteria for GeoTEE site selection

Energy Trust uses the following criteria to determine if a proposed area is a viable candidate for a GeoTEE project:

1. The amount of time needed to implement a demand side option meets the timing of the utility system need to successfully alleviate or defer local capacity constraints
2. The magnitude of achievable savings potential within the area is enough to cost effectively defer supply side resource investments
3. The overall avoided cost value, including the time value of delaying utility investment in local distribution upgrades, exceeds the cost to invest in a demand side option

Results of GeoTEE Scoping and Viability Analysis for the Dallas, McMinnville, and Creswell areas

In August 2024, NW Natural shared information with Energy Trust regarding potential future capacity constraints in the Dallas, McMinnville, and Creswell areas and requested that Energy Trust conduct a scoping

[1] This memo refers to Geographically Targeted Energy Efficiency or GeoTEE. In other materials, Energy Trust uses Targeted Load Management (or TLM) when describing non-pipe or non-wires solutions.

and viability analysis for implementing GeoTEE projects in these three areas. Energy Trust conducted this analysis and had subsequent discussions with NW Natural throughout Q4 2024 and Q1 2025. Because of this analysis and these discussions, it was determined that the Dallas and McMinnville areas were potentially viable candidates for GeoTEE projects as both areas met Energy Trust's criteria for site selection. Pending IRP acknowledgement, Energy Trust and NW Natural will collaborate on GeoTEE program planning for these two areas in 2026, with implementation starting in 2027 and continuing for three years. However, because of this analysis and the subsequent discussions with NW Natural, Energy Trust determined that the Creswell area was not a viable candidate for a GeoTEE project for the following reasons:

> Timing: NW Natural's capacity constraint analysis shows that without increased demand side energy management efforts, the Creswell area will likely become capacity constrained in 2028. However, if a GeoTEE project were to be implemented in 2026, in conjunction with other demand-side management efforts, and all stated energy savings goals were achieved, it could defer the capacity constraint until 2030, a mere two years after the original projected capacity constraint. Energy Trust would not be able to implement a GeoTEE project in the Creswell area until 2027, which threatens the ability to meet the necessary energy savings goal by 2028. This limited window of time to generate enough energy savings to defer system investments to address the constraint, and the fact that a successful effort would only defer the capacity constraint for two years, is not enough time for GeoTEE project planning and implementation.
>
> Magnitude: It takes a certain fixed amount of resources for Energy Trust to plan and implement a GeoTEE project regardless of the project size, and therefore the magnitude of a project affects if a project will be a cost-effective investment. NW Natural is requesting two peak-hour therm savings per year through a GeoTEE project in this area, which is a comparatively small amount. For comparison NW Natural is requesting a minimum of 13 and 23 peak hour therm savings per year for the Dallas and McMinnville areas, respectively. Even though the necessary energy savings in the Creswell area are relatively small, it would still require a certain fixed amount of Energy Trust's resources for planning and implementation, which reduces the prospect that a GeoTEE project in the Creswell area would be a cost-effective investment.
>
> Finally, Energy Trust had previously conducted a GeoTEE project in the Creswell Area. Because of this, Energy Trust is concerned about the remaining energy efficiency potential in the Creswell area, as well as limited contractor infrastructure in such a geographically specific area, to achieve the stated GeoTEE goals.

Energy Trust does not recommend NW Natural create an RFP for a third-party to pursue a GeoTEE project in any of these three areas.

The Oregon Public Utility Commission provided this recommendation to NW Natural in their 2022 Integrated Resource Plan (document page 27), "*Recommendation 18: In the near-term, if NW Natural's geographical load reduction programs are not available to alleviate forward-looking distribution system constraints, then a peak load reduction RFP should be issued to third-parties."*

Since Energy Trust and NW Natural plan to collaborate on developing GeoTEE projects in the McMinnville and Dallas areas, it is not necessary, nor is it recommended by Energy Trust, for NW Natural to create an RFP for a third-party to pursue GeoTEE projects in these two areas. Based on the results of Energy Trust's analysis of remaining energy efficiency potential in the Creswell area compared to the timing and magnitude of the system need, Energy Trust also does not recommend that NW Natural conduct a competitive RFP process for a third-party to pursue a GeoTEE project in the Creswell area, even though Energy Trust will not be pursuing a GeoTEE project in this area. The small amount of peak hour therm savings would require significant additional ratepayer expense to acquire, particularly for an entity new to the area where Energy Trust is already actively marketing and conducting outreach for energy efficiency products and services.

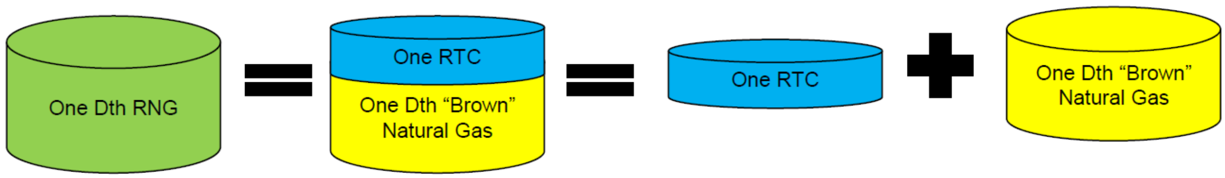
Appendix K - Low Emissions Gas Resource Evaluation Methodology

K.1 Terminology

Acquisition: In this policy, any RNG or RTC procurement contract, investment in RNG project development, or acquisition of an RNG project is referred to collectively as an "acquisition" of an RNG resource.

Brown gas: When RNG is purchased as a bundled commodity it can be separated into RTCs and "brown" gas. Once the RTC is separated from the underlying gas, the brown gas does not carry any environmental benefits. It can be separately accounted for distinct from the transactions associated with the RTCs. In most cases the brown gas will be sold locally to a buyer able to take delivery of physical gas near the point of RNG production. The costs or revenues associated with transacting any brown gas related to an RNG transaction are taken into account when determining a resource's total incremental cost.

Figure K-1: RTC Illustration



Cost of Service model: An Excel-based financial model that calculates the overall cost to customers of an RNG or RTC resource, considering the utility costs of debt and equity if any capital investments are required, utility tax burden, anticipated cost recovery activity and timing, and other relevant and salient aspects of a procurement, project development, or investment (collectively "Transaction").

Development Project: An RNG resource that requires some amount of capital investment and legal agreements associated with ownership of assets.

Incremental Cost: The levelized incremental cost of projects contributing to NW Natural's RNG portfolio over the remaining expected life of the project. This metric is the expected incremental cost of an RNG resource to NW Natural customers and is not risk-adjusted. The incremental cost of each resource in the RNG portfolio is included in the annual RNG compliance report detailed in OAR 860-150-0600, where the summation of the total incremental cost of each resource in the portfolio is the total incremental revenue requirement of the RNG portfolio.

Incremental Cost Workbook: An Excel-based model that evaluates the value of RNG resources for NW Natural customers. It calculates the incremental cost of RNG based upon "all-in costs," where the difference in the cost of service of an RNG resource and the costs avoided from not needing to procure an equivalent amount of conventional natural gas is the incremental cost.

Using the most recent methodology approved by the OPUC to calculate incremental costs[17] and the direction of OAR 860-150, this model produces a levelized incremental cost, both in expectation and on a risk-adjusted basis. The model yields the cost of delivering the RTC and brown gas, bundled together, to NW Natural customers. Thus, when evaluating RNG resources, this policy stipulates the incremental cost of an RNG resource is the incremental cost of delivering that RNG as a bundled resource, inclusive of the underlying gas. When a transaction is for RTCs only, the model attributes a brown gas purchase to the deal in order to compare deals on an apples-to-apples basis.

Offtake: an RNG resource that is purely a contract for the purchase of RTCs or bundled RNG (environmental attributes plus "brown gas.") An offtake requires no capital investment and is a pure pass-through cost that, per the final OPUC rules related to SB 98, is to be recovered via the Purchased Gas Adjustment (PGA).

Renewable Natural Gas (RNG): Per Oregon ORS 757.392[18], means any of the following products processed to meet pipeline quality standards or transportation fuel grade requirements:

(a)Biogas that is upgraded to meet natural gas pipeline quality standards such that it may blend with, or substitute for, geologic natural gas;

(b)Hydrogen gas derived from renewable energy sources; or

(c)Methane gas derived from any combination of: (A)Biogas; (B)Hydrogen gas or carbon oxides derived from renewable energy sources; or (C)Waste carbon dioxide.

Per Washington RCW 54.04.190[19](6), means a gas consisting largely of methane and other hydrocarbons derived from the decomposition of organic material in landfills, wastewater treatment facilities, and anaerobic digesters.

"Renewable hydrogen" means hydrogen produced using renewable resources both as the source for the hydrogen and the source for the energy input into the production process.

Renewable Thermal Certificate (RTC): The unique environmental attributes from the production, transportation, and use of one dekatherm of RNG.

RNG Portfolio: The collection of RNG resources delivering, or contractually committed to deliver in the future, RTCs to NW Natural customers.

[17] See OPUC Order No. 20-403 at https://apps.puc.state.or.us/orders/2020ords/20-403.pdf
[18] ORS 757.392
[19] RCW 54.04.190

RNG Resource Pipeline: A list of all RNG resources known to the Renewable Resources team that could become part of NW Natural's RNG portfolio. This pipeline includes information gathered during origination activities including issuance of RFPs for RNG resources.

FYRALIC (First Year Risk-Adjusted Levelized Incremental Cost): The levelized risk-adjusted incremental cost as calculated as an output of the Incremental Cost model for the first year a prospective project is expected to deliver RTCs to NW Natural customers. This cost, in levelized $/Dth over the expected life of the project, is deemed to be the incremental cost of RNG for evaluation of prospective RNG resources based upon OAR 860-150-0200 and the calculation methodology approved by the OPUC in Order No. 20-403.

Renewable Thermal Certificate (RTC): The unique environmental attributes from the production, transportation, and use of one dekatherm of RNG.

RNG Acquisition Target: A year-by-year state specific target of RNG for delivery to NW Natural customers in each state based upon complying with OR SB 98 and the Oregon Department of Environmental Quality's (ODEQ's) Climate Protection Program (CPP) in Oregon; and WA HB 1257 and Washington's Cap-and-Invest program under the Climate Commitment Act (CCA) in Washington.

Senate Bill 98 (SB 98)/ OAR 860-150: A bill passed by the Oregon Legislature and signed into law in 2019[20]. The law establishes targets for Oregon's natural gas utilities to procure renewable natural gas for its sales customers and recover costs prudently incurred to meet those targets. The rules to implement SB 98 are Division 150 of Chapter 860 of Oregon's Administrative Rules (OAR 860-150), which were ordered into rule by the Oregon Public Utility Commission (OPUC)[21].

K.2 Purpose and Overview

As part of its 2018 Integrated Resource Plan (IRP), NW Natural proposed a methodology to evaluate prospective low emissions gas resources based upon risk-adjusted "all-in" costs. This methodology went through a regulatory investigative process and resulted in an order by the OPUC (Order 20-403) where the methodology was approved by the Commission. While there are low emission gas resources that are not renewable natural gas (RNG), this appendix will colloquially refer to low emissions gas as RNG.

The purpose of this methodology is to calculate the levelized incremental cost of each resource in NW Natural's RNG portfolio for the compliance reports detailed in OAR 860-150-0200 and 0600 and to calculate the risk-adjusted levelized incremental cost to compare prospective RNG

[20] https://olis.leg.state.or.us/liz/2019R1/Measures/Overview/SB98

[21] See OPUC Order No. 20-227 and https://secure.sos.state.or.us/oard/viewSingleRule.action?ruleVrsnRsn=271677

resources using the stochastic Monte Carlo simulation analysis outlined in the 2025 IRP. This methodology is an application of numerous resource planning and rate-making concepts and accounting, including:

- Comparing resources on a fair and consistent basis
- Least cost/least risk planning standard
- Incremental costs
- Avoided costs
- Cost of service
- Levelized costs
- Accounting for risk/risk-adjustment

The methodology was also developed to be able to be flexible enough to appropriately assess all potential RNG resource types, of which there are many. While there are many sub-types, Table K-1 shows the types of resources that allow NW Natural to obtain the renewable thermal credits that prove RNG ownership for its customers:

Table K-1: Low Emissions (RNG) Resource Types

	RTC Acquired	Attach physical gas to bundled RNG for Incremental Cost	Sale of "Brown Gas"	Avoided Commodity Costs	Avoided Capacity Costs
Unbundled Environmental Attribute (RTC) Purchase	✓	✓			
Bundled RNG Delivered to NW Natural's System	✓			✓	
Bundled RNG with Brown Gas Sales	✓	✓	✓	✓	
On-System Bundled RNG	✓		✓	✓	✓

In addition to being able to account for different resource types, the evaluation methodology needs to consider the RNG acquisition process which the evaluation methodology folds into accounts for market conditions for RNG opportunities. As a practical matter, NW Natural will need to make decisions at the pace that the RNG market dictates, which is usually faster than IRP acknowledgement allows. The Incremental Cost Workbook that implements this methodology was developed by taking into account RNG market conditions which requires the ability to make frequent updates to the terms of prospective RNG resources while maintaining the ability to compare all prospective resources on an equal footing.

K.3 Evaluation Methodology

The RNG Incremental Cost Workbook implements the following calculations of the risk-adjusted levelized incremental "all-in" cost (see Table K-2 for descriptions of the evaluation components):

Annual all-in cost of RNG (R) =

Cost of methane (M) + Emissions compliance costs (E) – Avoided infrastructure costs (I)

Or: $$R_T = M_T + E_T - I_T$$

Where:

$$M_T = X_T + \sum_{t=1}^{365} [P_{T,t} + Y_{T,t}^{RNG}] Q_{T,t}$$

$$E_T = \sum_{t=1}^{365} N^{RNG} G_T Q_{T,t}$$

$$I_T = S_T A_T + DH_T$$

Substituting leaves the annual all-in cost of RNG as:

$$R_T = X_T - S_T A_T - DH_T + \sum_{t=1}^{365} [P_{T,t} + Y_{T,t}^{RNG} + N^{RNG} G_T] Q_{T,t}$$

Where the annual all-in cost of the conventional natural gas alternative (C) is:

$$C_T = \sum_{t=1}^{365} [V_{T,t} + Y_{T,t}^{CONV} + N^{CONV} G_T] Q_{T,t}$$

The levelized incremental cost (IC) for each prospective resource is used for evaluation where IC is:

$$IC = \sum_{T=k}^{T=k+z} \frac{R_T - C_T}{[1+d]^T}$$

This is risk-adjusted to account for uncertainty where the metric used for evaluating prospective projects is the first-year risk-adjusted levelized incremental cost (FYRALIC):

$$FYRALIC_{T=k} = 0.75 * \text{deterministic } LIC_{T=k} + 0.25 * \text{95th Percentile Stochastic } LIC_{T=k}$$

Table K-2: Project Evaluation Component Descriptions

Term	Units	Description	Source	Project Specific?	Input or Output of IC Workbook?	Treated as Uncertain?
R	$/Year	Annual all-in cost of prospective renewable natural gas (RNG) project	Output of RNG evaluation process	Yes	Output	Yes
C	$/Year	Annual all-in cost of conventional natural gas alternative	Output of RNG evaluation process	Yes	Output	Yes
M	$/Year	Annual costs of natural gas and the associated facilities and operations to access it	Output of RNG evaluation process	Yes	Output	Yes
E	$/Year	Annual greenhouse gas emissions compliance costs	Output of RNG evaluation process	Yes	Output	Yes
I	$/Year	Annual infrastructure costs avoided with on-system supply	Output of RNG evaluation process	Yes	Output	Yes
Q	Dth	Expected or contracted daily quantity of RNG supplied by project	Project evaluation or RNG supplier counterparty	Yes	Input	If no contractual obligation
P	$/Dth	Contracted or expected volumetric price of RNG	Project evaluation or RNG supplier counterparty	Yes	Input	If no contractual obligation
T	Year	Year relative to current year, where the current year T = 0, next year T = 1, etc.	Project evaluation or RNG supplier counterparty	Yes	Input	If no contractual obligation
k	Year	When the RNG purchase starts in # of years in the future; k = RNG start year - current year	Project evaluation or RNG supplier counterparty	Yes	Input	If no contractual obligation
z	Years	Duration of RNG purchase in years	Project evaluation or RNG supplier counterparty	Yes	Input	If no contractual obligation
t	Days	Day number in year ***T*** from 1 to 365	N/A	No	Input	No
V	$/Dth	Price of conventional gas that would be displaced by RNG project	Marginal price of conventional gas dispatched in PLEXOS® in run without RNG project	Yes	Input	Yes
Y	$/Dth	Variable transport costs to deliver gas to NWN's system	*For off-system RNG* - based upon geographic location of project; *For conventional gas* - determined from marginal gas dispatched in PLEXOS®	Yes	Input	No
X	$/Year	Annual revenue requirement of capital costs to access resource	Engineering project evaluation or RNG supplier counterparty	Yes	Input	If no contractual obligation
N	TonsCO_2e /Dth	Greenhouse gas intensity of natural gas being considered	From actual project certification if available, from California Air & Resources Board by biogas type if no certification has been completed	Yes	Input	No
G	$ /TonCO_2e	Volumetric Greenhouse gas emissions compliance costs/price	Expected greenhouse gas compliance costs from the most recently acknowledged IRP	No	Input	Yes
S	$/Dth	System supply capacity cost to serve one Dth of peak DAY load	Based upon marginal supply capacity resource cost by year as determined from PLEXOS® modeling in most recent IRP	No	Input	Yes
A	Dth	Minimum natural gas supplied on a peak DAY by project	Project evaluation or contractual obligation from RNG supplier counterparty	Yes	Input	If no contractual obligation
D	$/Dth	Distribution system capacity cost to serve one DTH of peak HOUR load	Distribution system cost to serve peak hour load from avoided costs in most recently acknowledged IRP	No	Input	No
H	Dth	Minimum natural gas supplied on a peak HOUR by project	Project evaluation or contractual obligation from RNG supplier counterparty	Yes	Input	If no contractual obligation
d	% rate	Discount Rate	Discount rate derived from most recently concluded general rate case outcome	No	Input	No

Table K-3 below details the update frequency of the various inputs and forecasts into the RNG Incremental Cost Workbook.

Table K-3: Input Update Frequency

Inputs and Forecasts	Frequency of Update	Additional Explanation
Resource Under Evaluation	Most Current Estimate	For example, if an RNG project requires any capital costs, the most current estimate of those costs will be run through the cost-of- service model and used for the evaluation.
Gas Prices (Deterministic and Stochastic)	Once a year	Stochastic gas prices are updated once a year using the Monte Carlo process detailed in the most recent IRP and the most recent gas price forecast from a third-party consultant
Peak Day & Annual Load Forecast	Once a year	These forecasts are updated spring/summer to include data from the most recent heating season.
GHG Compliance Cost Expectations (Deterministic and Stochastic)	Once a year	The GHG compliance cost assumptions will be updated each year after the legislation sessions in each state or when legislation is signed into law.
Design, Normal, and Stochastic Weather	Each IRP	Resources are planned based on design weather but are evaluated on cost using normal and stochastic weather.
Gas Supply Capacity Costs (Deterministic and Stochastic)	Each IRP	The cost of the marginal system capacity resource by year, based upon the results in the most recent IRP. Consistent with value used for energy efficiency and demand response.
Distribution System Capacity Costs	Each IRP	NW Natural will calculate and present the avoided distribution avoided costs through the IRP process. Consistent with value used for energy efficiency and demand response.

K.3.1 Incremental Cost Workbook

The RNG evaluation methodology described in this document is implemented within the Company’s RNG Incremental Cost Workbook. Each prospective project has its own incremental cost workbook that calculates FYRALIC and can be updated at any time so that resources can be compared on equal footing and the levelized incremental cost of existing projects can be calculated for portfolio management and compliance reporting.

K.4 Evaluation Methodology as Part of Acquisition Process

NW Natural's Decarbonization Services team continually collects information about the RNG market and specific opportunities for the procurement of RNG. This information is collected through research and communication with RNG project developers, marketers, investment funds, feedstock owners, and others involved in the RNG market. Additionally, the Renewable Resources team issues an RFP for new RNG resources once per year. Prospective resources are analyzed for their eligibility to be used for compliance with the policies under which NW Natural is a covered party (OR-SB 98, OR-CPP, WA-HB 1257, and WA-CCA). Resources deemed eligible are incorporated into the full list of RNG resources assessed for feasibility within the RNG Resource Pipeline.

The RNG Resource Pipeline is updated continually as new information is collected on potential RNG resources. Once the Renewable Resources team has sufficient information about a resource, it conducts an initial feasibility assessment. The assessment will vary based on whether the opportunity is a development project or an offtake project. A high-level overview of the assessment process for each type of project is provided below.

K.4.1 Initial Feasibility Assessment

K.4.1.1 Offtake Projects

Key information is gathered for the potential project including vendor, project status, price, volume, term and if relevant, price escalator and sale of brown gas. These values are entered into the Incremental Cost Workbook along with an assessment of risk in the following categories: finance, constructability, counterparty, marketability, commercial terms, bidder experience and gas/interconnect/feedstock rights.

The workbook produces a First Year Risk-Adjusted Levelized Incremental Cost (FYRALIC) value that is used to compare the project to other opportunities.

K.4.1.2 Development Projects

An assessment of a development project is broader than an offtake project. Inputs to this activity typically include the financial information shared by the counterparty as well as the team's own analysis of the gas production, equipment costs, and other relevant information. The Decarbonization Services team uses the Cost-of-Service model and the Incremental Cost model to determine whether the RNG Resource could potentially yield a FYRALIC that would be competitive with other RNG resources in the RNG Pipeline. If relevant, the Decarbonization

Services team works with Gas Supply to estimate the impact of any sale of brown gas or any requirements to transport the commodity associated with the RNG resource.

A risk assessment is also performed, and in addition to the risk evaluated for offtakes, also encompasses risk items such as production, feedstock and cost variability. As with offtakes, the Incremental Cost workbook produces a FYRALIC value that is used to compare the project to other opportunities.

K.4.2 RFP Evaluation Process

Since 2020, NW Natural has released an annual RFP for RNG procurement. Initially, these RFPs targeted both development and offtake projects, but more recent ones have concentrated solely on offtake projects. Over time, the evaluation process has been refined to ensure a fair comparison of proposals. The following steps reflect the evaluation process for the 2024 RFP.

1. Verify general qualifications
2. Calculate FYRALIC for each accepted proposal
3. Determine Short List by selecting those accepted proposals with the lowest 33% of incremental cost
4. Score the short-listed proposals (items b and c are considered when comparing proposals of similar cost)
    a. 90% Cost
    b. 5% Local Economic Benefit
    c. 5% Contract Equity
5. FYRALIC values for the short-listed proposals are compared to the FYRALIC of other opportunities in the RNG Resource Pipeline. Those proposals that compare favorably to these other pipeline opportunities are pursued further while those that do not are rejected.

NW Natural does not have an obligation to award the proposals with the highest desirability score; NW Natural will pursue opportunities that are prudent and advance NW Natural's procurement strategy.

K.5 Project Recommendations

Regardless of the source of an opportunity or the type, the feasibility assessment produces an estimated FYRALIC in the form of $/Dth of delivered RNG. The FYRALIC reflects the Decarbonization Services team's current assessment of cost and risks of the potential RNG resource.

If the initial feasibility assessment yields an estimated FYRALIC that appears favorable compared to other opportunities in the RNG Resource Pipeline, the assessed risk appears to be reasonable, and the project helps fulfill the RNG Acquisition Target, the prospective resource will progress to further due diligence and a potential recommendation for acquisition. Further due diligence may engage other NW Natural work groups or external consultants for targeted evaluations. Based on the FYRALIC, assessed risk, and the volumes needed, opportunities are prioritized and pursued for the benefit of NW Natural's customers. As new information is gathered about a project throughout its evaluation, the risk inputs may be updated, and the recommended portfolio of projects may be updated accordingly.

As NW Natural has gained experience in the RNG industry, the approach to risk mitigation has evolved. A risk mitigation strategy for each resource is negotiated with vendors prior to the execution of an agreement and may include items such as guaranteed minimums or Price Gas Adjustment (PGA) approval. This allows NW Natural to secure the least-cost and least-risk resources for their customers.

Appendix L - Electrification

L.1 ICF Electrification Report

To be filed as a supplement to the final 2025 IRP.

L.2 Statement of the Independent Advisory Group

The following pages are provided by an independent Advisory Group convened by NW Natural regarding NW Natural's Integrated Resource Plan and evaluation of electrification of current gas loads.

Statement of the Independent Advisory Group Regarding NW Natural's Integrated Resource Plan and Evaluation of Electrification of Current Gas Loads (IRP)

Independent Advisory Group Members:

Mr. Lee Beyer (1)

Mr. Stefan Bird (2)

Ms. Debra Smith (3)

Mr. Stephen Wright (4)

February 2025

<u>Executive Summary:</u>

The four-member independent Advisory Group (AG) provides this statement on the elements of NW Natural's IRP (IRP) we were asked to review. This IRP examines different scenarios related to electrification of natural gas loads currently served by the local distribution company, NW Natural. Our engagement was to focus on key assumptions that would affect cost, reliability and carbon emissions on the electric system of the Pacific Northwest (PNW) and particularly those electric systems that overlap with NW Natural's service territory.

The AG was presented an initial set of three supply-side scenarios and four demand-side scenarios. The AG focused on the supply-side scenarios. These initial scenarios had different assumptions about the future development costs, location, timing and availability of different supply-side generation resources and transmission expansion throughout the PNW region. These kinds of resources would be needed for normal electric load growth and these three supply-side resource scenarios also are used in the IRP to meet the varying degrees of load growth assumed in the four demand-side scenarios. We understand that these four demand-side scenarios are driven by different assumptions about electrification of loads currently served by natural gas and not fundamental differences in "base load" electric demand growth. Although we did not review the demand-side scenarios in detail, this statement does express a concern about the "base load" forecast possibly underrepresenting electric load growth based on current trends.

We found the initial three supply-side scenarios presented to the AG to be overly optimistic by assuming base assumptions that would result in electrification of current gas loads being easier, faster and cheaper than our own experience and judgment. Even the least optimistic scenario was not consistent with our view of current reality facing the PNW energy system. Our collective feedback was that the electric future transition will be harder, slower and more expensive than the scenarios we were presented even without electrifying current natural gas use.

NW Natural then developed a revised set of supply-side scenarios with one scenario called "Current Trends" that reflected the most change from the original three scenarios. The other two scenarios moved somewhat, but our judgment is they remain too reliant on overly favorable assumptions. It is the AG's view that the electric system will be greatly challenged to meet the existing policy prescriptions and planned load growth even without taking into account electrification of the natural gas system.

As an overall observation, we think the electric systems are already being pressed against the edges of their capabilities and electric systems are experiencing more "close call" events such as in January 2024 in the PNW. The electric systems of the region are also relying heavily on the gas systems for electric generation for peak load service. For example, the PNW electric system was in severe emergency conditions last January. Without record electric imports from the Southwest and Rocky Mountain states, the Pacific Northwest could have experienced rolling blackouts of a magnitude that would be unprecedented in our region.

The AG expressed views about future supply side additions, load forecasts, and electric system planning for uncertainty. The AG also added thoughts about the need for better gas-electric integrated system planning in the future although not achievable in this study.

The AG noted the following about future supply side additions:

1. The biggest unknown about the cost of future supply is estimating the availability and cost of zero emission load following resources. There are substantial federal research and development dollars currently authorized, but it is unknown how effectively these will be deployed. The current very high cost of maintaining reliability under stress conditions without carbon-emitting load following resources (the status quo) should be a scenario that is analyzed. The AG recommends maintaining the availability of natural gas-fueled generation capability, which will increasingly operate at lower dispatch factors as more zero fuel cost renewable energy becomes available, until cost-effective, longer duration, zero emitting load following resources can make more advances.
2. Battery costs have been decreasing and are increasingly being adopted in the market. Currently cost-effective batteries, however, are limited to four hour duration. Longer duration batteries such as 100 hour iron-air batteries are on the horizon, but it is unclear how long they will take before they achieve widespread commercialization. Other proven technologies such as pumped hydro storage may be available in limited geographical locations but are historically higher cost and face more challenging permitting timelines. Longer term storage is necessary to maintain reliability in a system with increased reliance on variable resources and even more so without carbon-emitting dispatchable generation.
3. New standardized modular nuclear reactors are an option for both energy and peaking capability, but the technology currently carries an extraordinary array of risk in terms of cost and timeframe to be in place.
4. Demand side options hold tremendous potential but there are limits to the amounts of firm energy and capacity that can be assumed to be available in the most difficult circumstances due to consumers willingness to sustain demand reductions under stress temperature conditions.
5. The transmission assumptions we were presented are based on current planned schedules. For transmission upgrades that do not require new right of way the assumptions are likely reasonable. The increasing resistance to new transmission nationwide suggests caution

with respect to schedules for new transmission that requires new right-of-way. The ability to meet Western states' emission reduction targets with current load forecasts, let alone under more aggressive data center expansion and or more aggressive natural gas-based electrification assumptions, will require expansion of the transmission grid to access and deliver energy reliably from new remote renewable resources and new load following resources. Historically long timelines to permit new transmission lines, particularly across federal lands, as well as concerns about customer rate pressure, suggest caution with respect to the assumed speed of development of new transmission lines.

6. The accredited capacity for wind appears high relative to the capacity attributed to wind in regions using an established ELCC methodology. Offshore wind, which has received opposition by the new federal administration, is also limited by available transmission on the coast, which is generally weak due to small coastal loads. More sizable offshore wind resources will require new network transmission to be permitted and constructed to intertie to bulk transmission that can access large load centers, which adds to the timing risk and uncertainty.
7. There has also been a trend across the country to derate accredited capacity for thermal resources due to operational challenges occurring during extreme temperature conditions. There are a variety of reasons including inadequate weatherization of equipment and fuel supply disruptions. We recommend consideration as to whether the capacity factors for thermal units should be modified. The Western Power Pool may be able to help with this assessment.

8. There is substantial evidence that the cost of the clean electricity transition increases steadily over time, with rapid increases after 80% renewables is achieved, if there are not adequate cost-effective zero-emitting load following resources available.[1] Today, we are likely still on the upward slope prior to achieving 80%. This projected increase in costs translates into rate impacts. Utilities are increasingly seeing push back from customers on rate increases, mostly related to new resource capital expense. Oregon's House Bill 2021 – 100% Clean Energy for All - that was passed into law includes consumer protections for both affordability and reliability in the form of regulatory off-ramps. In addition, the physical siting of these resources is experiencing strong opposition from many customers. This raises concerns about the industry's ability to bring new resources online in a timely manner. A feedback loop is needed to recognize that if rates increase dramatically and quickly, or if permitting processes do not evolve to address siting concerns, there will be consequences for the rate at which the clean electricity transition can occur.

It is also important to understand that current and long-term concerns about product affordability are based on resource adequacy, as well as a myriad of other factors also putting pressure on forward rate trajectories. Although this work only deals with the rate impacts of acquiring sufficient resources within the regulatory framework established by each state, rate impacts are cumulative and customers generally do not look at individual drivers such as wildfire mitigation, system resiliency, grid modernization or general capital

[1] 2019 Resource Adequacy Study in the Pacific Northwest on the Public Generating Pool website.

> investment. Instead, rate actions associated with resource adequacy must be examined in the context of all other rate pressures.

As a result, we have concerns about the achievability of the supply side assumptions even in the "Current Trends" scenario.

For the demand side, the "base load" demand forecast was standardized across the demand scenarios using current load forecasts. Like locking down other variables so that the policies and rates of electrification could be examined as the changing variable, we understand the purpose of a single "base load" forecast. However, we remain concerned that this forecast likely underrepresents the potential electric load increases being driven by factors other than electrification of gas load. Regional electric load forecasts have increased in an unprecedented fashion in the last two years, and we expect the forecasts to continue to increase. Specifically, data centers and AI have become large swing short-term variables and vehicle electrification is a long-term driver.

Planning Reserve Margin (PRM) is a key assumption in this analysis that addresses uncertainty in electric utility planning. We have already seen upward pressure on PRMs around the country due to the increased use of energy and dispatchability limited resources, load growth uncertainty and the capability of resources to deliver capacity during temperature related stress events, a challenge which has been exacerbated by extreme weather events. We also expect there will be an increasing effort to address the duration and magnitude of reliability risk (through tools like expected unserved energy or EUE) in addition to the standard probabilistic assessment of the frequency of electric outages. The emerging long duration, high magnitude outages during extreme weather events, as experienced in Texas and California, present high level human health and safety issues. In addition, the PNW is in the midst of a transition from being an energy constrained to a capacity constrained system and systems need to evolve as well. Electrification of natural gas uses will have the biggest impact at the times which are becoming the most challenging for the electric system. All these factors point toward the use of higher than historical levels of planning reserve margin to maintain the level of reliability PNW consumers have come to expect from their electric power system.

Moreover, the AG thinks the study should also consider the reality of periodic severe ice or windstorm events as we have experienced in recent years. Such events have resulted in multi-day electric distribution grid outages disrupting electricity supply to thousands of customers until electric distribution grid damage is repaired and power is restored. If natural gas winter heating capability is fully displaced by electric heating without auxiliary/hybrid natural gas heat pump capability, or without extraordinary levels of storage at the local retail user level, there will be substantial public safety and economic impacts. It is possible to underground electric distribution but only at significant expense, over a lengthy time period and requiring increased maintenance. The AG encourages that this risk receive attention in discussion of electrification.

Finally, we note that the AG believes there is potential for consumer value to be generated through increasing coordinated/joint planning and/or coordinated operations between gas and electric systems where there are overlapping service territories. Building on recent efforts to build collaboration in the PNW, it is recommended that synergies be unlocked that can reduce cost, improve reliability and decrease carbon emissions through consideration of coordinated and/or joint integrated resource planning, investment and operations for options from supply source to consumer use of the gas and electric systems.

Our specific recommendations regarding assumptions are included in the "Detailed Recommendations" section that follows below.

<u>Detailed Recommendations:</u>

The AG recognizes there is never a perfectly accurate single point forecast for the future. The IRP's goal of evaluating the impacts of possible future scenarios to help inform policy and strategy is reasonable, as long as the probability is not evenly weighted between the various scenarios currently being utilized. Our collective view is that, of the scenarios NW Natural is studying, the "Current Trends" supply side scenario most accurately reflects current reality now and for the foreseeable future. However, we continue to have residual concerns that the reasonable risk to electric system reliability is outside the range of the scenarios to be studied. This is due to supply, demand and uncertainty assumptions embedded in the study. We recommend addressing these concerns through sensitivity analysis to better understand load and resource uncertainty.

- The Current Trends scenario includes near-term increase in costs for wind, solar and batteries that best reflects current reality for the supply side in electricity markets. The causes for these increases would best be described as driven by high demand, supply chain challenges, import tariffs and permitting issues, driving costs up in the near term while technological improvements are driving costs down over the longer term. The other two scenarios follow more traditional NREL cost forecasting. The AG also noted there is an interaction between load and costs for supply. Higher loads lead to more stress on generation and transmission supply chains lead to higher costs. A scenario that assumes costs of all resources are higher when load growth is high is within the realm of reason and should be considered for scenario analysis purposes.
- The AG has suggested use of a sensitivity analysis approach that would vary the base load forecast using a higher growth rate. Although we do not have a specific numerical recommendation, we have suggested using the trends from the last two years as a basis for assuming a corresponding increase for at least one additional year at the beginning of the forecast period.
- The single planning reserve margin (PRM) that is based on PNUCC's short-term PRM of 16% is reasonable in the short term. However, consistent with comments above, the AG believes this PRM is likely understated in long-term studies that assume increasingly higher percentages of variable generation resources over time. Electric system planning in this new long-term environment will require more sophisticated modeling techniques to ensure reliable service in all 8,760 hours of the year and not just the peak hour. In-lieu of deployment of these more sophisticated modeling techniques, the AG recommends consideration of an approach that would increase the PRM in relationship to increasingly higher percentage reliance on zero-emitting variable generation resources that is supported

by review of other expert sources, or alternatively consider a sensitivity scenario with a gradually increasing PRM to provide an indicator of potential cost and risk impact. Potential sources of this PRM insight are information emerging in the work performed by the Electric Systems Integration Group (ESIG), Pacific Power's current 2025 IRP process, and PRM analysis performed by RTO/ISOs across the nation. In the future, the AG's recommendation to pursue coordinated joint planning between the electric and gas utilities would support a more informed set of assumptions including PRM and improved quality of analysis.

- There has been a trend across the country to derate accredited capacity for thermal resources due to operational challenges occurring during extreme temperature conditions. There are a variety of reasons including inadequate weatherization of equipment and fuel supply disruptions. We recommend consideration as to whether the capacity factors for thermal units should be modified. The Western Power Pool may be able to help with this assessment.
- With respect to reliability and the issues of moving from a "dual fuel" (electric and gas) system to a "single fuel" (electric system) we have raised numerous concerns about assuring that the IRP analysis carefully assess issues around resulting system reliability and the potentially profound public health and safety issues of relying on a single fuel (electric) system. NW Natural's IRP process examines its own gas system but is also attempting to evaluate the electric systems of the PNW which is a reason we were asked to serve on the AG. What is lacking, not just in this study but in all current integrated resource plans across the country, is an integrated systems perspective incorporating the gas and electric systems. The risk of reliance on one fuel is increased due to the exposure of the electric distribution system to ice and wind events. Recent storms in Oregon have displayed that multi-day electric outages while distribution systems are repaired would create a substantially greater human health and safety risk following electrification of the natural gas system. While this risk is difficult to address in this study, we recommend at least addressing qualitatively. Ultimately, these critical issues should be addressed through regional joint system planning (gas and electric).

Independent Advisory Group Members Bios:

(1) **Lee Beyer:** Lee Beyer was a member of the Oregon Legislature for 22 years serving in both the House and State Senate. From 2001 until 2010 he served as a member and Chair of the Oregon Public Utility Commission. He also served for many years as a board member of the Western Electric Coordinating Council, as a member of the EPRI Advisory Council and member and Vice-Chair of the NARUC Electricity Committee. During his time in the Legislature, Beyer chaired the committees with oversight of energy policy and was directly involved in the drafting and sponsorship of much of Oregon's recent energy legislation.

(2) **Stefan Bird:** Stefan Bird previously served as CEO of Pacific Power, a division of PacifiCorp, senior vice president, commercial and trading, PacifiCorp Energy, CEO of CalEnergy, an independent power producer, and vice president of acquisitions and project development for Berkshire Hathaway Energy. During his 17-year tenure at PacifiCorp, among other activities, Bird led the dramatic expansion of PacifiCorp's renewable energy portfolio and interstate transmission grid, western electricity market transformation and engagement in Oregon energy legislation.

(3) **Debra Smith:** Deborah (Debra) Smith served as CEO of Seattle City Light, General Manager of Central Lincoln PUD (serving the Oregon coast), and various roles at the Eugene Water & Electric Board. During her 30 years in the electric utility industry, Deborah prioritized customer responsiveness, collaboration across the region, and electrification/decarbonization. Deborah also served as the first female chair of the Public Power Council, as well as on the boards of the Smart Energy Provider's Alliance, the Electric Power Research Institute EPRI, and the American Public Power Association. She remains active on the Pacific Northwest National Lab advisory committee, as well as the Western Transmission Consortium.

(4) **Stephen Wright:** Steve Wright began his career developing energy efficiency supply curves and integrated resource plans. He served as Administrator/CEO of the Bonneville Power Administration from 2000-2013, CEO of Chelan Public Utility District from 2013-2021 and is now a member of the Southwest Power Pool Board of Directors as well as the Interim Markets+ Independent Panel. He has served on the boards of the Alliance to Save Energy, Electric Power Research Institute and American Public Power Association.

Appendix M – Enabling Strategies

M.1 Commercial Gas Heat Pump Pilot

M.1.1 Purpose of the Research

This proposal aims to justify the initiation of pilot projects for gas heat pumps (GHPs) in various commercial installations. The primary objectives are to evaluate the performance of GHPs under different scenarios, inform a broader strategy to reduce gas use as well as greenhouse gas (GHG) emissions, and demonstrate cost-effectiveness and proof of concept to the commercial market.

M.1.2 Objectives and Research Questions

These five subjects will be informed by the project:

1. **Performance Evaluation**:

- Assess the efficiency and reliability of GHPs in diverse commercial settings, including but not limited to office buildings, laundry, retail spaces, and healthcare facilities.
- Monitor performance metrics such as energy consumption, heating capacity, and maintenance requirements.

2. **Scenario Analysis**:

- Implement GHPs in various climatic conditions and building types to understand their adaptability and effectiveness.
- Compare GHP performance with traditional heating systems in terms of energy savings and operational costs.

3. **GHG Emissions Reduction**:

- Quantify the reduction in GHG emissions achieved by using GHPs compared to conventional gas heating systems.
- Evaluate the environmental benefits of GHPs, including their impact on carbon footprint.

4. **Cost-Effectiveness:**

- Analyze the economic viability of GHPs by comparing installation, operational, and maintenance costs with those of traditional systems.
- Provide a detailed cost-benefit analysis to demonstrate the financial advantages of adopting GHP technology.
    - Data from pilots can be used to validate Energy Trust incentive measures.

5. **Proof of Concept**:

- Showcase successful pilot projects to the commercial market, highlighting the practical benefits and scalability of GHPs.

- Gather feedback from stakeholders to refine and optimize GHP deployment strategies.

M.1.3 Methodology – Pilot design

1. **Site Selection**:
- Identify and select diverse commercial sites for pilot installations, ensuring a representative sample of different building types and climatic conditions.
- Identify at least ten potential target sites for selection of three to five preliminary installation candidates with final selection of three qualified sites.

2. **Installation and Monitoring**:
- Install GHP systems at selected sites and establish monitoring protocols to track performance metrics.
- Use advanced data analytics to evaluate system efficiency, energy savings, and emission reductions.

3. **Data Collection and Analysis**:
- Collect data on energy consumption, operational costs, and maintenance requirements over a specified period.
- Utilize data collection devices to determine gas usage, temperature ranges.
- Survey building operators and possibly occupants to determine satisfaction levels. Additionally, survey mechanical contractors involved in the installation to obtain feedback.
- Analyze the data to identify trends, challenges, and opportunities for improvement.

4. **Reporting and Dissemination**:
- Prepare comprehensive reports detailing the findings of the pilot projects.
- Share results with stakeholders, including commercial property owners, policymakers, and industry experts, through workshops, webinars, and publications.

5. **Timeline:**

   With approval, this project will follow this timeline:

a)	Prospecting and qualifying potential sites	3 months
b)	Planning phase- equipment and materials orders	3 months
c)	Installations	2 – 4 months
d)	Evaluation period	6 – 10 months
e)	Analysis and reporting	2 months

6. **Cost:**

   Utilized actual pilot installation cost from 2020 NEEA project as a basis for the pilot cost estimates. Applied Consumer Price Index to determine cost increase from 2020 to 2025.[22]

Table M-1: Project Costs[23]

Description	2025 Project Cost	2020 Actual Pilot Cost
(2) Robur GAHP Gas Heat Pumps	$30,019	$15,845
Contractor Markup 35%	$10,507	$5,546
Mechanical/Plumbing Installation	$31,828	$16,800
Circulator Pump	$4,025	$2,125
Controls (building controls integration)	$7,100	$3,749
Crane	$1,000	$500
Electrical	$1,420	$750
Structural Analysis and Drawings	$1,700	$896
Building Permits	$1,000	$500
TOTAL per project installed	**$88,599**	**$46,711**

The estimated cost per project site is $88,599. This proposal seeks approval for three (3) sites with total pilot project cost of $265,800.

Some conclusions from that pilot:

> "In summary, the Robur gas absorption heat pumps have a positive outlook. Its reasonable first cost, ease of installation, efficient operation, reliability, and low maintenance operation result in a viable solution for achieving natural gas savings."

Challenges in this pilot included:

- Finding a suitable site
- Lack of modulation capability

M.1.4 Expected Outcomes – Potential benefits to ratepayers

1. **Portfolio consideration:**

- The pilot will complement related research being conducted elsewhere in North America.

[22] Tierney, Jennifer, P.E., et al, Robur Heat Pump Field Trial, NEEA report #E20-309, March 11, 2020. Page 19.
[23] CPI Inflation Calculator (www.bls.gov/data/inflation_calculator.htm?pubDate=20250323)

- Additionally, it will add to the research findings from the 2020 NEEA pilot conducted in Salem Oregon.

2. **Enhanced Understanding**:

- Gain insights into the performance and adaptability of GHPs in various commercial settings.
- Identify best practices for optimizing GHP installations and operations.

3. **Strategic Recommendations**:

- Develop a broader strategy for reducing gas use and GHG emissions in the commercial sector.
- Provide actionable recommendations for policymakers and industry leaders to support the adoption of GHP technology.

4. **Market Adoption and overcoming barriers to acceptance**:

- Demonstrate the cost-effectiveness and environmental benefits of GHPs to the commercial market.
- Encourage widespread adoption of GHPs, contributing to a sustainable and energy-efficient future.
- Leverage the results of this pilot in a whitepaper and other collateral to inform the regional commercial HVAC trade about gas heat pumps.

M.1.5 Existing Reports

- Robur Heat Pump Field Trial
  neea.org/img/documents/Robur-Heat-Pump-Field-Trial.pdf
- What are gas heat pumps and how can they help save money and energy?
  www.fortisbc.com/news-events/stories/what-are-gas-heat-pumps-and-how-can-they-save-money-and-energy
- Commercial HVAC Gas Heat Pump- Considerations for Installation
  gasheatpumpcollab.org/wp-content/uploads/2023_NAGHP_COMHVACGHP_Installation_Considerations.pdf
- ACEEE Hot Air-Hot Water Presentation, Randy Opdyke, NAGHPC
  drive.google.com/file/d/1OaTrmqavLQSaNbLxGlRmb0YLD5-JHv3v/view
- Energy Solutions Center- Efficient & Affordable Natural Gas Heat Pumps
  consortia.myescenter.com/GHP/ESC-GHP_Guide.pdf
- California Energy Commission - Demonstrating Natural Gas Heat Pumps for Integrated Water Heating and Air Conditioning in Restaurants
  www.energy.ca.gov/sites/default/files/2024-06/CEC-500-2024-058.pdf
- Gas Absorption Heat Pumps Best Practices Guide, Clear Result, Robur, Fortis BC
  www.robur.com/en-us/media/gas-absorption-heat-pumps-best-practices-guide

M.1.6 Need for More Pilot Projects in this Market

More GHP Pilot installations are needed to gather measurement and verification data to help develop incentive programs for our customers in partnership of Energy Trust of Oregon. Additionally, new manufacturers are emerging in the North American Market that offer a broader range of equipment options aimed at addressing the specific heating and cooling needs of a building. These Pilot installs are also critical to engage with the local trades, designers and building owners to showcase successful installations and build confidence and familiarity of this technology within this community.

Fortis BC (Vancouver, British Columbia) has completed several successful pilots, and they are moving forward with commercial heat pump rebates to drive the adoption of this energy saving technology.[24]

M.1.7 Conclusion

Initiating pilot projects for gas heat pumps in commercial installations is a crucial step towards understanding their performance, reducing gas use as well as GHG emissions, and proving their cost-effectiveness. By achieving these objectives, we can pave the way for broader adoption of GHP technology and contribute to a cleaner, more sustainable commercial sector.

More GHP Pilot installations are needed to influence Market Transformation toward this high efficiency technology. The impact of widespread adoption of this technology will reduce demand on the gas and electric grids, reduce greenhouse gas emissions and maintain the performance and reliability expectations our customers demand from fuel-fired equipment. Additionally, the validation of gas heat pumps in the market will lead the way toward consideration of commercial hybrid (electric plus gas) solutions. Approval of this pilot project proposal will enable the advancement in understanding this technology.

M.2 Carbon Capture Utilization and Storage/ Sequestration Pilot

M.2.1 Project Overview

NW Natural aims to develop a pilot project to test post-combustion carbon capture technology as a cost-effective solution for reducing CO2 emissions from natural gas building heating systems. By capturing emissions directly from boiler flue gas, this pilot will evaluate capture efficiency, operational feasibility, costs, and potential challenges in determining whether to scale up the deployment across institutional and commercial buildings.

[24] Gas absorption heat pump rebates, www.fortisbc.com/rebates/business/gas-absorption-heat-pump-rebates

Buildings are a major source of greenhouse gas (GHG) emissions in Oregon and Washington– 34 percent and 25 percent respectively –primarily due to electricity use (air conditioning, lighting, heating, cooking, etc.), as well as natural gas used for space and water heating.

Carbon capture provides a viable option by reducing emissions from existing gas-based heating systems without major retrofits. It enables buildings to lower upfront costs with a continued and reliable energy supply while still achieving deep decarbonization. Additionally, it can induce lower emissions in non-energy products such as concrete and industrial CO_2 and avoids creating further grid stress.

By integrating carbon capture with energy efficiency upgrades and renewable energy, Oregon and Washington can accelerate building decarbonization while maintaining energy reliability and affordability, especially in the commercial and industrial sectors.

The following provides information about the project using guidance provided to utilities from OPUC Energy Resources and Planning.

M.2.2 Purpose of the Research

This pilot project aligns with NW Natural's commitment to environmental stewardship and compliance with state and local climate policies. The purpose of this research is to explore a post-combustion carbon capture system as a viable solution for reducing GHG emissions from natural gas-fueled heating systems in buildings. The findings of this pilot will support several legislative directives:

- Oregon's Climate Protection Program (CPP): establishes a declining cap on GHG emissions from fossil fuels requiring a 50 percent reduction by 2035 and 90% by 2050. The pilot will advance the CPP's goals by capturing and permanently removing on site emissions.
- City of Portland's Climate Emergency Workplan (2022-2025): Prioritizes emissions reductions in buildings. This project will directly contribute by decarbonizing a major heating system in an institutional building within city limits.
- Oregon Climate Action Roadmap to 2030: Supports further study and analysis to continue to guide effective climate action over time. This pilot will provide critical data to shape future decarbonization strategies and policies.
- Washington Climate Commitment Act: Implements a cap-and-invest program requiring large emitters to reduce emissions 95 percent below 1990 levels by 2050. While this pilot is in Oregon, it will serve as a model for future carbon capture deployment in Washington.

M.2.3 Research Question

Can post-combustion carbon capture provide a reliable, scalable, and cost-effective solution for reducing emissions from heating systems while maintaining operational feasibility and economic viability?

To answer this, the pilot will focus on five key objectives:

- Assess Technology Performance: Conduct evaluations to determine CO_2 capture efficiency, reliability, and operational feasibility.
- Ensure Seamless Integration: Validate compatibility with existing heating and surrounding infrastructure to minimize disruption.
- Optimize Costs: Identify opportunities to reduce both capital expenditures and operational expenses, improving economic viability in future scale-up.
- Develop a Scalable Deployment Strategy: Use pilot findings to create a roadmap for broader adoption across building and equipment types.
- Support Regulatory Development: Provide data-driven insights to inform policy and compliance frameworks for emissions reduction.

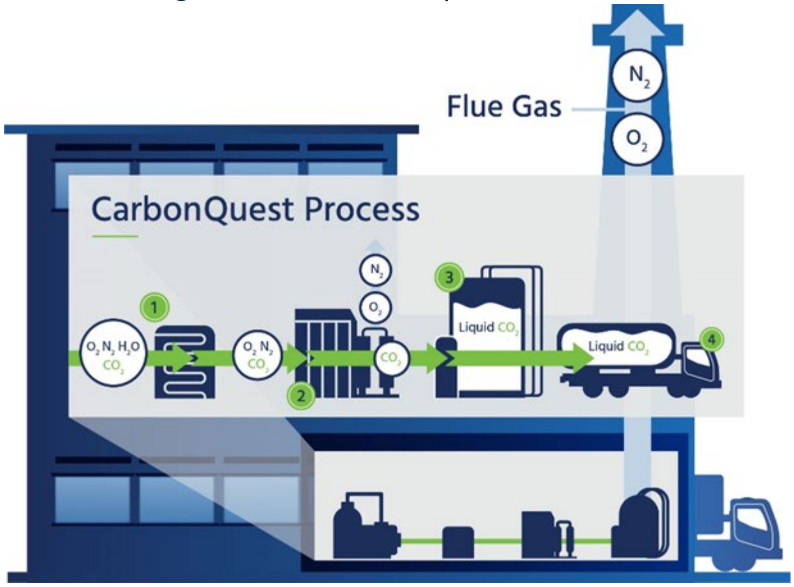
M.2.4 Overall Pilot Design Strategy

The following answers the question “*What is the theory behind this strategy?”* and addresses the research question detailed in the above section.

Decarbonizing buildings is a complex challenge, especially in space-constrained urban environments. While large-scale carbon capture technologies exist, they are designed for industrial applications and often impractical for building-level deployment.

The proposed technology to be tested, poses significant advantages. It is engineered specifically for buildings, offering a scalable, space-efficient, and highly adaptable solution. It can capture up to 95 percent of CO_2 emissions from boilers and CHP systems, without requiring major infrastructure changes. A schematic of the proposed system’s operation is shown in Figure M-1.

Figure M-1: Carbon Capture Process[25]



1. **Extraction:** Flue gases containing O2, N2, CO2, and water vapor are diverted from the exhaust stream. The stream passes through a heat exchanger, compressor, and dryer to remove moisture before entering the separation phase.
2. **Separation:** The gas stream moves through a pressure swing adsorption (PSA) system, which selectively removes N2 and O2, returning them to the exhaust while directing the concentrated CO2 stream to the next stage.
3. **Conversion:** The CO2 stream undergoes liquefaction, converting it into liquid CO2, which is stored in onsite tanks for transportation.
4. **Sequestration**: The liquid CO2 is delivered to industrial partners such as concrete manufacturers or sequestration sites, where it undergoes mineralization or storage, thereby permanently preventing it from entering the atmosphere as a greenhouse gas.

For this pilot, a post-combustion carbon capture system would be installed at Oregon Health & Science University (OHSU). The technology provider would deliver a turnkey solution and managing all aspects of system design, construction, operation, and performance monitoring. NW Natural would act as the primary liaison between the host site and the technology provider, oversee project administration, ensure alignment with site-specific requirements, and receive performance data to support regulatory compliance, reporting, and long-term planning.

The pilot aims to capture up to 70 percent of the facility's current CO2 emissions and permanently prevent them from being emitted to the atmosphere. The technology provider

[25] https://carbonquest.com/building-carbon-capture/how-it-works

would coordinate CO2 transportation twice per day in pressurized tanks and its injection into available permitted sequestration sites. Potential destinations include basalt formations and deep saline sequestrations sites being explored and developed in Oregon and Wyoming. Both facilities are expected to start operations in 2027-2028, aligning with the proposed schedule.

Alternatively, the captured CO2 may be supplied to regional cement and concrete manufacturers for use in carbon-cured building materials, aligning with circular economy principles while still achieving permanent prevention of CO2 emitted to the atmosphere. As the adoption of this technology grows nationwide, underground sequestration and developing a carbon market may play a major role to ensure the permanent removal of emissions.

The pilot would be executed in the following phases, ensuring structured development and evaluation.

M.2.4.1 Phase I: Design and Permitting

A preliminary feasibility analysis would be used to confirm that the site is suitable for integrating the carbon capture system. In this phase, a detailed site assessment would be conducted to finalize system configuration, analyze flue gas composition, and determine utility interconnection requirements. Engineering teams would collaborate with the university to develop a tailored system design that ensures seamless integration with campus operations. Simultaneously, regulatory and permitting requirements would be reviewed to ensure full compliance with local, state, and federal guidelines. Engagement with key stakeholders can help refine operational parameters. Baseline emissions data would also be collected, establishing a benchmark for measuring CO2 reductions once the system is operational.

M.2.4.2 Phase II: Installation

With the design finalized and regulatory pathways confirmed, the project would transition to the installation on site. The technology provider would source and deliver its modular system components, including the flue gas extraction unit, pressure swing adsorption (PSA) separator, liquefaction module, and storage tanks.

Installation would involve constructing any necessary infrastructure, integrating the carbon capture system into the existing heating systems. A startup sequence would follow, including safety verifications, calibration of key components, and testing of the gas separation and liquefaction processes. The phase would conclude with operational checks to ensure the system is functional and ready for continuous operation.

M.2.4.3 Phase III: Monitoring and Data Collection

Once operational, the system would enter a continuous monitoring phase to evaluate CO2 capture efficiency, energy consumption, and reliability. A real time measurement system would track performance metrics, including system adaptability to varying seasonal heating loads.

Facility operators would receive hands-on training for system maintenance and operation for safety and emergency troubleshooting and notification and escalation procedures, ensuring smooth day-to-day operations. Regular feedback sessions with university stakeholders will provide insights into system usability and inform any necessary adjustments.

M.2.4.4 Phase IV: Data Analysis and Evaluation

The final phase would focus on synthesizing key findings and evaluating the potential for broader deployment. Technical and economic data would be analyzed to determine whether the system meets performance and cost-effectiveness benchmarks. The captured emissions would be quantified and compared to initial projections, assessing the overall impact on the university's carbon footprint. A cost-benefit analysis would be performed to help compare carbon capture with other decarbonization strategies. Insights from the pilot would inform a scalability roadmap, outlining the conditions for replicating similar systems in other institutional and commercial buildings.

The findings of the pilot would be shared with regulators, policymakers, and users to help inform future programs, regulatory pathways, and investment decisions. If successful, this project could serve as a blueprint for replicating carbon capture technology across campuses, hospitals, and commercial facilities, thereby contributing to broader decarbonization efforts in the region.

M.2.5 Potential Benefits to the Ratepayer if the Pilot Succeeds

M.2.5.1 Portfolio Consideration

The following provides a *"description of how this pilot complements or adds to related utility activities and addresses a market gap/opportunity not currently addressed by current operations or ongoing research, and how overlap with existing work is minimized."*

This pilot builds upon NW Natural's ongoing carbon capture initiatives aimed at decarbonizing institutional buildings. Previous pilots have deployed CarbinX™ carbon capture systems, which have and emission reduction design of up to eight metric tons of CO2 annually, with additional benefits including heat recovery. However, to achieve deeper decarbonization and meet state climate goals, it is necessary to explore additional technologies that may have a greater impact such as the proposed technology.

The proposed system represents a step forward, offering significantly higher CO2 capture potential—up to 70 percent in this application—while integrating seamlessly with existing natural gas infrastructure and customer equipment. Unlike current research and pilot projects, which focus on smaller-scale reductions, this pilot tests a more advanced and scalable solution that can be replicated across similar commercial facilities throughout the region. This pilot will fill a critical market gap, providing data on performance, cost-effectiveness, and operational feasibility, which would minimize overlap with existing efforts and accelerate the deployment of modular carbon capture in hard-to-electrify buildings.

M.2.5.2 Support of Executive Order 20-04

The following answers the question *"Will there be any positive or negative impact in reducing GHG emissions as a direct result of this Pilot, or if applied to wider adoption?"*

This pilot would have a direct and measurable impact on reducing GHG emissions supporting Oregon's decarbonization goals outlined in Executive Order (EO) 20-04. The carbon capture system would extract CO2 directly from flue gas emissions and permanently prevent its release into the atmosphere.

According to The State of Oregon Greenhouse Gas Emissions Data from Air Quality Permitted Sources[26], the emissions from stationary sources of OHSU over the past 5 years (2019-2023) averages 26,000 metric TCO2e per year. This technology could be designed for up to 95 percent CO2 removal; however, the available space and power supply enables a configuration of 65 to 75 percent capture, decarbonizing of up to **17,400 metric TCO2e per year**.

Beyond direct emissions reductions, the pilot would analyze the broader impact of carbon capture and management adoption, including potential GHG reductions at scale if the technology is widely implemented in other facilities.

The following answers the question *"Will there be any positive or negative impact on any "vulnerable populations or impacted communities" as a direct result of this Pilot, or if applied to wider adoption?"*

The pilot would analyze any potential impacts to vulnerable populations or impacted communities, particularly in relation to air quality improvements and equitable access to decarbonization technologies.

M.2.6 Context

The following provides prior research and relevant market research supporting this pilot strategy. It also answers the questions; "*What are the major barriers that stand between this concept and wider adoption? What is the technical/conceptual viability of what is being tested, i.e. how market-ready is it? Has this been implemented elsewhere?"*

This technology is in an advanced stage of market readiness, having been successfully deployed in a commercial building in Broadway, Manhattan, where it achieved a 60-70 percent CO2

[26] Department of Environmental Quality : Greenhouse Gas Emissions Reported to DEQ : Action on Climate Change : State of Oregon

reduction. The captured CO_2 was permanently sequestered through concrete mineralization, demonstrating both effectiveness and long-term viability.

Despite the advanced market readiness of this carbon capture technology, data on its use in commercial settings remains limited, especially in terms of integration feasibility across diverse building types and under varying operational conditions. This pilot aims to address these gaps by testing the technology in a large-scale environment, generating critical insights to inform broader adoption.

Widespread deployment still faces several challenges, including high upfront costs, regulatory uncertainties, limited market mechanisms, and a lack of accessible sequestration sites to support extensive implementation. Current building codes do not yet recognize carbon capture as a compliance pathway, and further efforts are needed to improve public perception and ensure workforce readiness.

By generating real-world performance data, this pilot would enable more accurate cost-benefit analyses, support regulatory development, validate safety protocols, and identify the infrastructure and workforce training needed to scale carbon capture effectively. Ultimately, it seeks to bridge the gap between technical feasibility and practical market implementation, aligning carbon capture with long-term decarbonization goals.

M.2.7 Study Scope and Key Focus Areas

1. Feedstock Assessment:

- Quantify volumes of woody biomass within economically viable haul radii (50–75 miles).
- Analyze seasonal availability and harvest logistics.
- Integrate fire-prone regions and stewardship forestry practices to balance ecological health with resource supply.
- Update and expand upon ODOE's 2018 RNG Inventory and feedstock modeling.

2. Technology and Lifecycle Analysis:

- Examine proven and emerging gasification and methanation systems, including fixed-bed, fluidized-bed, and entrained-flow configurations.
- Evaluate syngas cleanup, methane synthesis reactors, and required balance-of-plant components.
- Assess CO_2 capture from biomass combustion and anaerobic digestion, and methanation with green hydrogen produced via electrolysis.
- Model lifecycle greenhouse gas (GHG) reductions and net carbon intensity (CI) values.

3. Economic and Infrastructure Feasibility:

- Develop cost curves for synthetic methane production based on scale and technology.

- Estimate capital expenditures (CAPEX), operations and maintenance (O&M), and levelized costs of gas per MMBtu.
- Analyze infrastructure compatibility and injection logistics into Oregon's gas distribution network.

4. Forest Health and Wildfire Mitigation:

- Conduct modeling of fire risk reductions under proposed biomass removal scenarios.
- Quantify avoided carbon and particulate emissions from large-scale wildfire events.
- Assess long-term ecological outcomes and resilience enhancements from thinning and biomass harvesting.
- Coordinate with state forestry experts and leverage data from the Oregon Department of Forestry.

5. Policy and Regulatory Evaluation:

- Review existing permitting, siting, and environmental regulations that affect biomass-to-gas projects.
- Identify gaps and opportunities in state and federal incentive frameworks, including the Inflation Reduction Act (IRA), 45Q and 45V tax credits, the Oregon Climate Protection Program.
- Recommend legislative and rulemaking actions needed to enable project development.

6. Roadmap for Implementation:

- Identify pilot-ready regions and deployment pathways.
- Forecast scale potential based on feedstock availability and gas demand.
- Create a phased investment roadmap aligned with IRP targets and CPP targets.
- Engage stakeholders across forestry, environmental, industrial, and community organizations.

M.2.8 Research Plan

M.2.8.1 Learning Objectives and How Objectives will be Achieved

The learning objectives and research questions are detailed in Sections M.2.3 and M.2.4.

M.2.8.2 Target of the Pilot

The pilot will be conducted in collaboration with Oregon Health and Science University (OHSU) where natural gas is used for steam heat in a centralized system supplying multiple buildings which serves as both an educational facility and a hospital.

Figure M-2: OHSU Campus

Table M-2: Target of the Pilot

Item	Detail
Site	Oregon Health and Science University
Location	3181 SW Sam Jackson Park Rd, Portland, OR 97239
Natural Gas Use	Natural gas usage is to produce steam heat in a central system that is piped to different buildings on campus.

M.2.8.3 Potential Scale

The following answers the question *"what is the ultimate potential?"*

This pilot would assess the broader potential of carbon capture technology with the opportunity to scale to a wider range of commercial and potentially industrial customers—segments that currently represent 23 percent and 15 percent of the company's gas sales, respectively. The ultimate viability of this solution will depend on several factors: the CO2 concentration in exhaust streams meeting the minimum thresholds required by capture technology, operating hours, physical space availability for the installation of capture and storage equipment, and overall economic feasibility.

M.2.8.4 Number of Participants or Test Subjects – Including Statistical Rationale

The pilot will include one facility, which was preliminary identified as a suitable candidate based on the following criteria:

- High natural gas consumption and representative use patterns, making it a strong candidate for impactful carbon reduction, allowing for stable CO2 capture data across different seasons, and conditions ensuring that insights can be applied to similar commercial buildings
- Centralized steam heating, a common system in universities, hospitals, and large-scale commercial buildings, improving scalability of findings

- Customer interest and alignment with sustainability goals, ensuring engagement from facility decision-makers and commitment to long-term decarbonization strategies
- Available space and facilities team support, providing the necessary infrastructure for equipment installation and seamless integration with existing operations

This selection ensures the pilot generates scalable data, supporting future deployments across a wide range of buildings and other large energy users such as industrial sites.

M.2.8.5 Evaluation Strategy

The following answers the question *"How will we know if it worked?"*

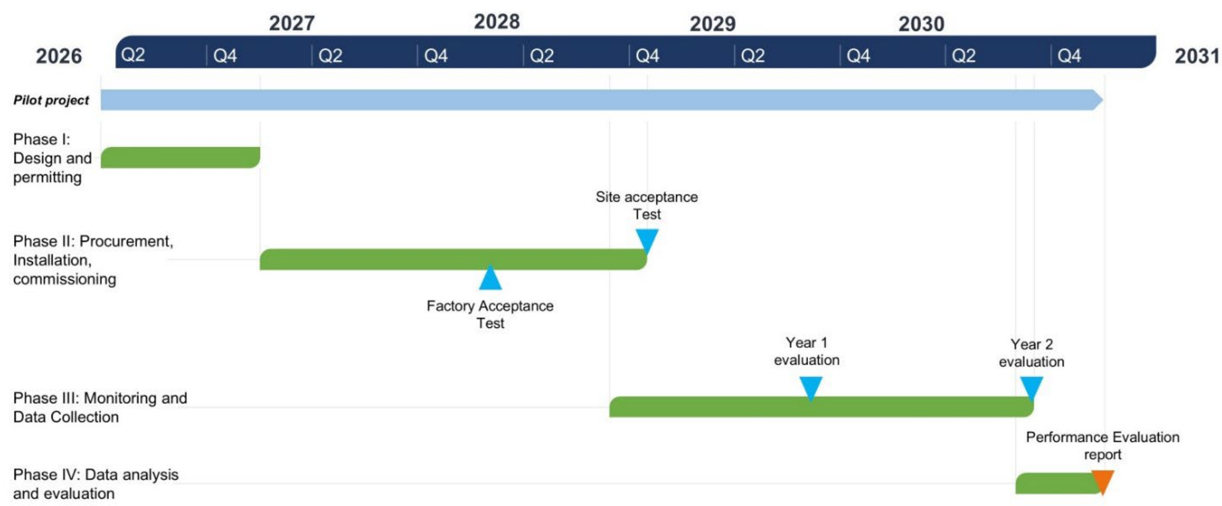
The pilot project evaluation and success would be determined by assessing key performance metrics across capture efficiency, reliability, cost, and environmental impact, as follows:

- **Carbon Capture Performance:** Measured as the CO2 removal efficiency (%) and capture rate (tonnes per day) from the exhaust stream under various operating conditions as well as energy consumption (kWh per ton of CO2 captured)
- **Carbon Reduction Impact:** Total CO2 emissions reductions (tonnes per year) achieved through deployment of the technology and mineralization or sequestration. This will help determine the scalability of the solution and its potential contribution to broader decarbonization goals.
- **Operational Stability & System Integration:** Evaluated through system uptime (% of operational time vs. availability). Operator feedback will be gathered to assess ease of integration with existing boiler operations and any impacts on overall system performance.
- **Economic Viability:** The economic feasibility of the technology will be analyzed by comparing the cost of CO2 capture ($/tonne of CO2) vs. alternative decarbonization strategies.

M.2.9 Schedule

The pilot would run from April 1, 2026, through December 30, 2030. Given the intent to keep the equipment installed at the selected site beyond the pilot period, no decommissioning or dismantling activities are planned. Instead, the focus would be on long-term operational insights and continued performance monitoring. Schedule of pilot and its phases is shown in Figure M-3.

Figure M-3: CCUS Pilot Schedule



M.2.10 Budget

This project follows a third party-owned and financed model that minimizes capital risk for NW Natural and its ratepayers. All design, equipment procurement, installation, operations, and maintenance will be managed by the technology provider. NW Natural would not own the infrastructure and would instead pay a performance-based fee per tonne of CO2 captured.

Although NW Natural would not fund the system, the estimated total cost of the solution the carbon removal service provider is as follows:

- Capital Expenditure (CAPEX)—$25 million. Including design, permitting, mechanical and electrical upgrades, carbon capture equipment, and on-site CO2 storage.
- Operational Expenditure (OPEX)— $2.8 million per year. Covering electricity, maintenance, carbon transport and permanent sequestration.

For NW Natural, the cost of the pilot would be based solely on the amount of CO2 removed, which is estimated at $4.8 million per year, with a two percent annual escalator for the duration of the pilot and continued operation. This fee-for-service structure offers predictable costs based on fuel consumption, reduces financial risk, and provides a clear decarbonization cost benchmark to evaluate broader adoption.

The estimated incremental cost of decarbonization through this model is $315/tonne of CO2, which is significantly more cost-effective, nearly three times less, than electrification costs for natural gas heating systems reported by other educational institutions[27].

[27] WA Priority Climate action Plan, https://deptofcommerce.app.box.com/s/hhk4l9mszf6vgzb7hvg11xbiu6il7ula

As the technology matures and deployments scales, the decarbonization cost is expected to decline (target price $150-$200/tonne of CO_2). Operational efficiencies, economies of scale, and experience will help drive down the per-tonne cost. Additionally, the development of regional carbon capture networks and closer sequestration sites—such as potential hubs in Oregon's geologic formations—could significantly reduce transportation and sequestration costs, which currently represent a major share of the operational expenses. Shared infrastructure could enable multiple facilities to benefit from economies of scale, further lowering the long-term cost of decarbonization through this model.

NW Natural intends to pursue a cost recovery approach of the pilot that aligns with regulatory guidance and limits ratepayer risk.

M.2.11 Decision Points

The pilot includes several key milestones to assess alignment with project objectives. The carbon capture system is expected to continue operating beyond the formal pilot period, extending data collection and reporting if conditions warrant.

The first evaluation milestone occurs upon completion of the Factory Acceptance Test, which would verify that the system performs according to specifications prior to shipment. If major deficiencies are identified, equipment modifications or scope adjustments may be considered.

The next milestone would be achieved after the Installation and Site Acceptance Test marking the transition to the operational phase. The system must demonstrate readiness for long-term operation. The last milestones would be achieved after one and two years of continuous operation, and performance data would be analyzed to evaluate capture efficiency, reliability, integration, and cost effectiveness. These reviews would inform a comprehensive assessment of system performance, economic viability, and scalability for broader deployment.

M.2.12 Reporting Requirements

NW Natural would implement reporting to provide transparency on pilot progress and outcomes. Annual technical reports would include the analysis of system performance, including captured carbon by the system and operational efficiency, insights into operation with varying conditions, and carbon management and sequestration.

The Final Pilot Report would include comprehensive findings on technical feasibility, economic viability, and scalability, lessons learned and recommendations for potential future deployments. assessment of ratepayer cost implications and regulatory considerations.

This reporting framework would ensure stakeholder visibility, data-driven decision-making, and accountability throughout the pilot's lifecycle.

M.3 Local Water Resource Recovery Facility RNG Projects

NW Natural modeled only a single on-system local water resource recovery facility in the resource optimization model but is currently working with two potential water resource recovery facility partners that could provide on-system RNG. Both projects are very similar in size, volumes and costs. Negotiations with both partners are still ongoing.

M.3.1 RNG Facility 1 **[BEGIN CONF]** [redacted] **[END CONFIDENTIAL]**

M.3.1.1 Project overview

In alignment with NW Natural's decarbonization goals, NW Natural plans to collaborate with **[BEGIN CONF]** [redacted] **[END CONFIDENTIAL]** to develop a Renewable Natural Gas (RNG) facility at **[BEGIN CONF]** [redacted] **[END CONFIDENTIAL]**.

The **[BEGIN CONF]** [redacted] **[END CONFIDENTIAL]**, provides critical wastewater treatment services to **[BEGIN CONF]** [redacted] **[END CONFIDENTIAL]**. The facility treats an average of 39 million gallons of wastewater daily and recycles over 18 dry tons of biosolids into soil amendments.

M.3.1.2 Rate Recovery

NW Natural seeks acknowledgment of its investment in the **[BEGIN CONF]** [redacted] **[END CONFIDENTIAL]** RNG Facility, which would generate RNG more cost-effectively than other decarbonized resources in its portfolio. This project would also deliver the added benefits of supporting local infrastructure and upcycling waste. NW Natural would retire the environmental attributes on behalf of customers, using RNG to decarbonize the local gas distribution system by replacing fossil natural gas with biogenic RNG.

The proposed facility aligns with the Oregon Climate Protection Program and is designed to provide low-cost, low-risk decarbonization. To meet projected compliance needs once CCI allowances are maximized—anticipated by 2030 under normal weather or earlier during colder conditions—NW Natural is initiating investments now. Given the 3–5 year timeline required to originate, construct, and commission such projects, early development is crucial. The ICF report and NW Natural pipeline validate that development projects, like the **[BEGIN CONF]** [redacted] **[END CONFIDENTIAL]** project, represent the lowest cost and lowest rate impact to customers.

M.3.1.3 Project Schedule

The anticipated project schedule is outlined below:

Table M-3: RNG Facility 1 Project Schedule

Pilot Phase	Task Name	Estimated Duration	Estimated Start	Estimated Finish
Due Diligence	Due Diligence and contracting	9 months	Q3 2025	Q2 2026
	Pre-design Design	3 months	Q2 2026	Q3 2026
Design	Engineering Design	6 months	Q3 2026	Q4 2026
Construction	Construction	12 months	Q4 2026	Q4 2027
	Commissioning	1 month	Q4 2027	Q4 2027

M.3.1.4 Project Budget

[BEGIN CONF] [redacted] **[END CONFIDENTIAL]**. The incremental, risk-adjusted cost in the first year is estimated at $4/MMBtu.

M.3.2 RNG Facility 2 **[BEGIN CONF]** [redacted] **[END CONFIDENTIAL]**

M.3.2.1 Project overview

In alignment with NW Natural's decarbonization goals, NW Natural plans to collaborate with **[BEGIN CONF]** [redacted] **[END CONFIDENTIAL]** to develop a Renewable Natural Gas (RNG) facility at **[BEGIN CONF]** [redacted] **[END CONFIDENTIAL]**.

The **[BEGIN CONF]** [redacted] **[END CONFIDENTIAL]**, provides critical wastewater treatment services. The facility treats an average of 12 million gallons of wastewater daily.

M.3.2.2 Rate Recovery

NW Natural seeks acknowledgment of its investment in the **[BEGIN CONF]** [redacted] **[END CONFIDENTIAL]** RNG Facility, which would generate RNG more cost-effectively than other decarbonized resources in its portfolio. This project would also deliver the added benefits of supporting local infrastructure and upcycling waste. NW Natural would retire the environmental attributes on behalf of customers, using RNG to decarbonize the local gas distribution system by replacing fossil natural gas with biogenic RNG.

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M.3.2.3 Project Schedule

The anticipated project schedule is outlined below:

Table M-4: RNG Facility 2 Project Schedule

Pilot Phase	Task Name	Estimated Duration	Estimated Start	Estimated Finish
Due Diligence	Due Diligence and contracting	9 months	Q3 2025	Q2 2026
	Pre-design Design	3 months	Q2 2026	Q3 2026
Design	Engineering Design	6 months	Q3 2026	Q4 2026
Construction	Construction	12 months	Q4 2026	Q4 2027
	Commissioning	1 month	Q4 2027	Q4 2027

M.3.2.4 Project Budget

[BEGIN CONF] [redacted] **[END CONFIDENTIAL]**. The incremental, risk-adjusted cost in the first year is estimated at $9/MMBtu.

M.4 Initiate Geological Screening Study for CO2 Sequestration in Northwest Oregon

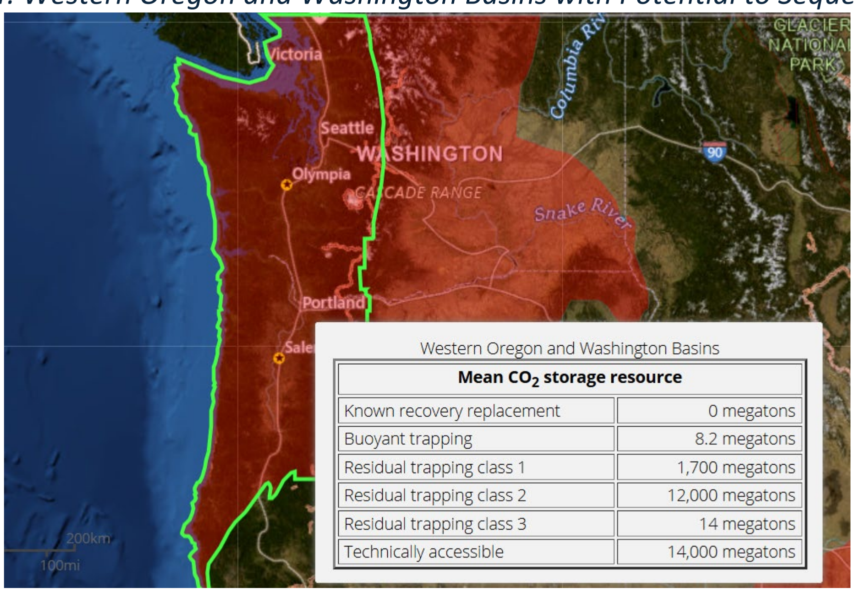
M.4.1 Background

As seen in many of the scenarios and sensitivities, including the preferred portfolio (i.e., resources selected in PRS.a), carbon capture, utilization, and storage (CCUS) has been identified as a likely least-cost pathway for achieving deep emissions reductions for the utility. In alignment with this finding, the utility seeks to evaluate in-state geologic formations for their potential to serve as long-term CO2 storage reservoirs.

According to the Oregon Department of Geology and Mineral Industries (DOGAMI), two areas show significant potential for future Geologic Carbon Sequestration in the Pacific Northwest:

1. Western Oregon and Washington Basins (Figure M-4)
2. Columbia Basin of eastern Oregon and Washington.

Figure M-4: Western Oregon and Washington Basins with Potential to Sequester CO2[28]



Mean CO_2 storage resource	
Known recovery replacement	0 megatons
Buoyant trapping	8.2 megatons
Residual trapping class 1	1,700 megatons
Residual trapping class 2	12,000 megatons
Residual trapping class 3	14 megatons
Technically accessible	14,000 megatons

For reference, Oregon's Geologic carbon sequestration can take place in different types of formations and involve different mechanisms:

- Sedimentary formations, such as porous sandstones, store CO2 in supercritical form beneath impermeable caprock.
- Volcanic formations, such as basalt, can mineralize CO2 over time—converting it to solid carbonate minerals for permanent storage.

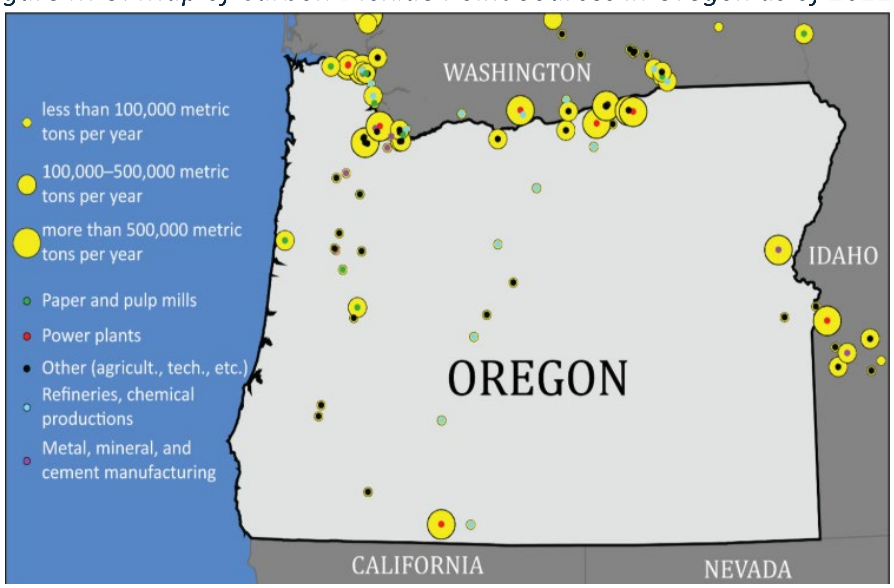
[28] https://energy.usgs.gov/co2public/

This proposed action would complement ongoing state efforts. In its 2025–2027 Agency Request Budget, DOGAMI prioritizes expanding subsurface data collection and building a centralized carbon sequestration data portal to support CCUS development. A major focus of their effort is the Columbia River Basalt Group (CRBG) in eastern Oregon, where they will assess the potential for permanent mineralization-based CO2 storage in volcanic formations.

While DOGAMI is advancing the understanding and development of eastern Oregon's basalt formations for mineralization, the utility's proposed project explores western Oregon, where CO2 could be stored in porous rock layers or mineralized. By implementing this project NW Natural could expand the state's portfolio of sequestration options—both geographically and geologically.

The Western Oregon Basin includes the Mist Underground Natural Gas Storage Facility, which NW Natural has successfully operated for over four decades. This area is particularly promising due to its proximity—within 10 to 25 miles—to several large carbon dioxide Point Sources, including power plants, chemical manufacturers, paper and pulp mills, and other industrial facilities, see Figure M-5.

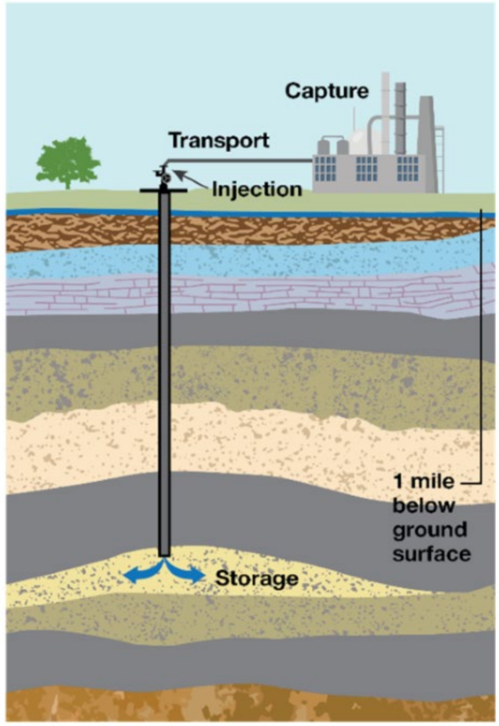
Figure M-5: Map of Carbon Dioxide Point Sources in Oregon as of 2021[29]



The formations would be accessed via Class VI sequestration wells, which would be used to permanently store CO2 produced and captured from natural gas combustion sources (e.g., industrial boilers) and transported by truck or pipeline. Figure M-6 graphically shows a Class VI well.

[29] DOGAMI, Carbon Sequestration: Geologic Carbon sequestration. https://www.oregon.gov/dogami/geology/pages/carbon_seq.aspx

Figure M-6: Class VI Injection Well (Traditional Sedimentary Storage)[30]



Source: https://www.epa.gov/uic/class-vi-wells-used-geologic-sequestration-carbon-dioxide

M.4.2 Opportunity

The *Sunset Highway Sandstone*, located in Columbia County, Oregon, was preliminarily assessed in 2022 by the NW Natural Underground Gas Storage team using proprietary data from gas storage and production activities in the Mist, Oregon area over the last few decades.

The formation is positioned below the Clark and Wilson Sandstone formation, which is where NW Natural's existing gas storage reservoirs are located. The formation exhibit presents favorable characteristics for CO2 sequestration, including:

- High porosity (~27 percent) and permeability
- Adequate depth for supercritical CO2 storage (2,900–5,500 ft)
- Thick, regionally extensive claystone caprock proven through four decades of underground gas storage service
- Structurally isolated fault blocks that may provide lateral containment

Beyond the sandstone formation, additional opportunities exist for carbon sequestration in the basalt formations of the Mist area, where CO2 could also be sequestered and mineralized.

[30] Figure is not to scale.

Mineralization consists on the injection of carbonated water into basaltic rock providing additional benefits compared to supercritical CO2 storage, specifically:

- Injected fluid has a density greater than saline water, reducing migration risk
- Injected CO2 quickly mineralizes within the basalt, reducing surveillance requirements
- Shallower depths of basalt formation in the Mist area, allow for lower operating pressures with simple, cost-efficient well designs.

Pursuing CO2 sequestration in the Sunset Highway Sandstone and exploring the potential of the underlying basalt formations, builds on decades of successful underground operations in the Mist area. Advancing this opportunity would contribute meaningfully to the company's and the region's long-term decarbonization goals by expanding its capacity for safe, permanent CO2 storage.

M.4.3 Proposed Action

Advance technical and geological screening studies to evaluate different CO2 sequestration methods leveraging existing geologic and geophysical data and other initial assessments. The proposed studies will:

- Validate the suitability of the Sunset Highway Sandstone for CO2 storage.
- Develop the feasibility assessment of basalt formations in Mist and NW Natural's service territory for CO2 storage via mineralization.
- Estimate potential storage capacity and containment risks
- Prioritize areas for further site characterization and piloting
- Recommend the next steps, including permitting needs, cost estimations and pilot testing options.

The proposed studies include activities such as data retrieval and analysis, reservoir modelling, legislation, licenses and permits assessment, techno-economic assessment, and pilot planning for future implementation if it is determined to be feasible.

M.4.4 Deliverables

- Geological screening report with maps, volumetric estimates, and risk assessment.
- Preliminary costs estimation and preliminary engineering, availability and requirements for infrastructures and resources.
- Feasibility reports with modeling results, permitting roadmap and cost estimates.
- Recommendations for advancing site characterization and pilot planning of CO_2 storage infrastructure.

M.4.5 Timeline

Estimated to be complete within 12 months of IRP Action Item acknowledgment.

M.4.6 Budget Estimate

To be determined based on scope refinement; initial estimate is: $720,000-$1,000,000.

M.4.7 Strategic Alignment

This screening study supports the utility's long-term decarbonization goals and regulatory compliance under Oregon state climate policy. The study would also position the utility to pursue federal and state funding opportunities for CCUS infrastructure and contributes to Oregon's broader geologic carbon management strategy by exploring a complementary storage formation to DOGAMI's CRBG focus.

M.5 Synthetic Methane from Woody Biomass Study

M.5.1 Objective

Conduct a detailed 12-month study assessing woody biomass feedstocks in Oregon for synthetic methane production via gasification plus syngas methanation and CO2 plus green hydrogen methanation to support the near-term, least-cost decarbonization of the state's gas system. The action follows the importance of woody biomass derived synthetic gas as a potential least cost compliance resource in the PRS.

M.5.2 Background and Rationale

The Oregon Department of Energy's (ODOE) 2018 *Biogas and Renewable Natural Gas Inventory* identified over 40 billion cubic feet (BCF) of theoretical renewable gas potential statewide, with more than 75 percent attributable to woody biomass and other thermochemical feedstocks. The report noted the critical importance of coupling these resources with appropriate conversion technologies such as gasification and methanation. Since that time, forest health, wildfire severity, and decarbonization urgency have all intensified.

Oregon's forests, particularly in fire-prone regions of the Cascade foothills and Klamath Basin, have accumulated hazardous fuels due to decades of fire suppression and disease. The strategic removal of low-value forest biomass not only reduces wildfire intensity and frequency but also generates a valuable renewable energy feedstock.

Synthetic methane (also called synthetic natural gas or SNG) created through biomass gasification or CO2 methanation with electrolytic hydrogen enables a drop-in substitute for fossil natural gas. Synthetic methane is fully compatible with existing pipelines, appliances, and end-use infrastructure. This reduces transition friction while leveraging the state's existing energy delivery system.

This study is a critical next step in exploring the value, scale, and readiness of woody biomass-based synthetic methane as a foundational decarbonization resource in Oregon's integrated energy system.

M.5.3 Comparable Studies and Precedents

- **ODOE Renewable Gas Inventory (2018):** Identified extensive theoretical supply of RNG, including woody biomass, municipal solid waste, and agricultural residues. Provided early estimates of gasification system costs and siting barriers.
- **Green Hydrogen Coalition (GHC), California (2022–2025):** Published white papers and provided regulatory comments to CPUC and CARB promoting power-to-gas projects. Highlighted the compatibility of methanation using green hydrogen and CO2 with existing gas infrastructure.
- **California Forest Biomass Working Group (2023):** Assessed pathways for wildfire mitigation through biomass utilization, including thermal conversion to gas.
- **NREL & EPRI Studies (2021–2023):** Modeled techno-economic performance of synthetic methane via biomass and electrofuels; emphasized regional adaptation of conversion pathways.

M.5.4 Deliverables

- Updated feedstock supply curves with geospatial overlays of fire-prone zones.
- Technology readiness level (TRL) for technologies and cost benchmark matrices with a focus on cost of carbon.
- Lifecycle emissions and carbon intensity calculations for multiple conversion routes.
- Ecological and wildfire risk co-benefit analysis.
- Regulatory and policy landscape gap assessment.
- Implementation roadmap with phased infrastructure integration options.
- Stakeholder and public engagement plan.

M.5.5 Estimated Budget

The total cost for the study is estimated at **$1.25 million**, allocated as follows:

- Feedstock and ecological modeling: $320,000
- Technology and lifecycle cost analysis: $300,000
- Policy and regulatory review: $250,000
- Fire mitigation and land use modeling: $200,000
- Stakeholder engagement and final reporting: $100,000

- Contingency (8%): $80,000

M.5.6 Timeline and Milestones

The study will be launched within 60 days following IRP acknowledgment and completed within **12 months**, with key milestones as follows:

- Month 0–2: RFP release and contractor selection and project scoping
- Month 3–6: Feedstock and technology modeling, stakeholder engagement launch
- Month 6–9: Economic analysis and environmental co-benefits modeling
- Month 10–11: Draft report circulation and feedback
- Month 12: Final report delivery and presentation to OPUC, WUTC, and other stakeholders

M.5.7 Conclusion

Woody biomass-derived synthetic methane presents a rare convergence of climate, ecological, and economic value. Oregon is uniquely positioned to leverage its abundant low-value woody biomass to produce renewable gas, mitigate forest fire risk, and meet its CPP targets. The IRP action item enables a rigorous and actionable exploration of this resource with relevance not only for Oregon's gas utility, but also for regional and national energy strategy.

Appendix N - Comments on NW Natural's Draft 2025 IRP

The following comments were received via NW Natural's dedicated IRP feedback form during the Company's draft IRP comment period from June 13, 2025 through July 11, 2025. Due to the length of some comments, NW Natural has broken them out to individual comments.

#	Commentor	Feedback	Response
1	OPUC	The following Recommendations from Staff's Final Report in LC 79 have been flagged by the NWN team as items to be discussed in the IRP:	NA/ See below
2	OPUC	a. Recommendation 20: In future IRPs, NWN should provide an RNG procurement scoring methodology and associated modeling details, including up to date and accurate table(s) that list all sources of data inputs to the RNG acquisition model, as well as a narrative description of all updates and changes. *Status as of Draft IRP:* This is not included in the Draft IRP.	To assist in evaluating which RNG projects to pursue, NW Natural uses its risk adjusted incremental cost methodology established in UM 2030. This methodology is used to assess the ratepayer costs and benefits of NW Natural-owned RNG projects and third-party RNG contracts. A risk-adjusted incremental cost model is completed for each opportunity and is based on data such as volume, term, price, and assessed risk. Details on NW Natural's RNG evaluation methodology, incremental cost workbook, and evaluation process are detailed in Appendix K. Table K-3 describes the inputs to the incremental cost model along with the update frequency.

3	OPUC	b. Recommendation 22: In its next IRP, NW Natural shall provide a table of its existing RNG projects, including the type of project and the deal structure, similar to the table that PacifiCorp provides in its filings. i. *Status as of Draft IRP:* This is not included in the Draft IRP	In response to Recommendation 22, the Company had included Table 7.6 which is a table of its existing RNG projects. It includes the type of project and the deal structure, similar to the table that PacifiCorp provides in its filings (Order No. 23-281 at 12, Table 6.16). Previously and upon receipt of this comment, the Company has reached out to Staff to try to identify what is missing.
4	OPUC	c. Recommendation 26: The next IRP should include modeling of all relevant distribution system costs and capacity costs, including additional projects that would be needed in high load scenarios as well as costs that would not be incurred in lower load scenarios. i. *Status as of Draft IRP:* Staff notes that the ICF Electrification Study includes Oregon Annualized System Costs for the Reference Case (Figure 10.27) and for the other scenarios (Figure 10.28), the graphs differentiate between capital costs, FO&M, VO&M, Fuel and Distribution.	In this IRP, the Company included incremental commodity, capacity, and compliance costs. As well as using a Cost of Service analysis where applicable. However, and as discussed in the Executive Summary, when trying to include all relevant distribution cost, it became evident that more analysis is needed to understand what additional savings may accrue relative to NW Natural specific gas infrastructure for varying levels of natural gas customers. The Executive Summary discusses the challenges and provides some additional context.
5	OPUC	d. Recommendation 27: The Company should provide NPVRR for each portfolio in the next IRP and a breakdown of portfolio NPVRR into cost categories in workpapers filed with the IRP. i. *Status as of Draft IRP:* The Draft IRP does not include NPVRR for each portfolio. 1. Question: Does the Company expect to provide this through workpapers?	NPVRR for compliance costs by each sensitivity are provided in Figure 9.7. These costs are broken out by compliance resource. Section 11.1.1 show box-and-whisker plots of NPVRR cost for varying components (fixed and variable costs, electrification costs, and compliance costs) across the 50 draws for the PRS, S6 – Hybrid, and S7 – All Electric scenarios. These costs are aggregated in Figure 11.11. Specific values for these figures are also provided in the workpapers.
6	OPUC	e. Recommendation 30: To explore the potential benefits of dual fuel heat pumps, the Company's next IRP should include an in-depth study of dual fuel heat pump potential	Please see Chapters 10, 11, and 13 for detailed information on Dual Fuel Heat Pumps. Additionally, NW Natural dedicated a full scenario (S6) to dual fuel heat

		and the effects of dual fuel technology on peak and average load on the gas system. i. *Status as of Draft IRP:* Staff notes that Chapter 6 provides an overview of heat pumps. Chapter 10, the ICF Electrification Study, includes a thorough review of dual fuel technology on the gas system. Chapter 11 includes a review of the Company's Hybrid Systems On-Going Pilots.	pumps as a counterfactual to an All-Electric scenario. Figure 11.1 illustrates the potential benefits over an All-Electric buildings scenario. As a result, NW Natural is requesting acknowledgement of two hybrid heating system action items in this 2025 Action Plan.
7	OPUC	f. Recommendation 38: For the next IRP, the Company should provide an analysis that would examine high-cost RNG, hydrogen, and synthetic gas as a sensitivity. The cost estimates should be on the higher end of recent, relevant publicly available forecasts, and the Company should provide the sources used for each cost forecast. i. *Status as of Draft IRP:* Staff notes that a literature review on forecasts of RNG availability and price will be available in Appendix E.1.	Please see Scenario **S1.c** in section 9.4.1.1. Please also see Appendix E for the alternative fuels study.
8	OPUC	g. Recommendation 39: For the next IRP, the Company should provide a literature review of RNG price and availability forecasts. i. *Status as of Draft IRP*: Chapter 7 includes a review of RNG supply and procurement. Staff notes that a literature review on forecasts of RNG availability and price will be available in Appendix E.1.	Please see Appendix E.1.
9	OPUC	Regarding NWN's current RNG resources: a. As part of addressing Recommendation 22 (from the LC 79 Staff Report), can NWN provide information on its current RNG resources and procurement efforts? What do costs and emissions factors look like? b. What were the costs of the Lexington and Dakota City Facilities?	Please see RG 99 NW Natural 2024 SB 98 Annual Renewable Natural Gas Compliance report.

		c. How much RNG is NWN procuring from the Lexington and Dakota City Facilities?	
10	OPUC	1. Policy Variation Scenarios: CPP/CCA compliance, SB 98 compliance, No GHG Compliance Policies scenarios: a. How are these three scenarios used to inform the demand variation scenarios? b. For the No GHG Compliance Policies scenario, does 'lowest cost' analysis take gas and electric costs into account?	As shown, Figures 9.2, S1, S2, and S3, and their corresponding sensitivities, are used to inform the preferred resource strategy (PRS), which is a set of constraints (i.e., not specific resources) imposed on PLEXOS®. These constraints are discussed in Section 9.4.2. The PRS constraints defined in this section are used in all demand variation scenarios, which include (PRS.a, S4.a, S5.a, S6.a, and S7.a). The load forecasts for each of the demand variation scenarios determine the resource requirement for the scenario and are independent of the constraints defined in the PRS. The demand scenarios are driven by macro-economic conditions in the case of the Growth Recovery, the modest electrification is driven primarily by the electric IRPs, and the other demand variations are driven primarily by ODOE's Oregon Energy Strategy Reference Case. The ICF electrification study did not conduct a scenario for the No GHG Compliance Policy scenario (S3). In other words, this IRP did not analyze what it would mean for electric utilities if HB 2021 requirements no longer existed. S3 is conducted from NW Natural's perspective only. 'Lowest cost' in table 9.2 simply refers to utilizing the resource optimization model (PLEXOS®) to acquire the least cost resources to meet energy and capacity requirements (e.g., optimizing gas purchases, storage operations, and Mist Recall).

11	OPUC	2. Regarding the demand variation scenario assumptions and results: a. What are NWN's fuel price assumptions (including natural gas, RNG, hydrogen, etc.) used when modeling each scenario? b. How much of the distribution pipeline system is maintained in each of these scenarios? What capacity expansion projects are required in each scenario?	Figure 1.4 illustrates the forecasted weighted cost of gas (WACOG) as an output of the PRS.a model run. Please see Figure 2.7 that illustrates the natural gas prices for each of the hubs where NW Natural purchases gas. These gas prices do not vary across scenarios. Please see Chapters 7, 9, 10, and Appendix E, Appendix G, and Appendix L for alternative fuel price assumptions in each scenario. Except for S1.c, these prices do not vary across scenarios. Availability of some compliance resources varies across scenarios. These limitations are described throughout Chapter 9 for the different scenarios and sensitivities. Compliance resource costs are described for each state in Chapter 9. Section 9.5 discusses capacity expansion selection; however, it is simply varying levels of Mist Recall required to meet peak day requirements. Varying levels of upstream pipeline capacity are released across scenarios as well. As discussed above, no assumptions regarding distribution system costs were made in these in these scenarios.
12	OPUC	3. Regarding the Hybrid System Electrification scenario: a. Why does NWN assume such a high hybrid heating penetration rate for the Hybrid System Electrification scenario (higher than the current penetration rate for gas heating)?	The Company intentionally has the Hybrid Scenario mirror the electrification scenario to answer the question of: what would the same scenario look like if rather than full electrification, hybrid heating was deployed? For additional information please refer to

		b. What are the current shares of heat pumps with electric backup and with gas backup? c. How does NWN calculate the size of backup (gas) equipment and primary (heat pump) heating equipment?	the ICF report for detailed information as well as the responses found in Appendix I, Section I.4.
13	OPUC	4. All-Electric Buildings: a. Can NWN articulate the impacts of gas system demand being downsized by 90% of existing customers as they convert to ASHPs with electric backup by 2040? b. Would the revenue requirement metric for this case reflect any changes in depreciation rates?	Please see Chapter 10 which discusses how the reduction in gas load is calculated. There are no assumed changes in depreciation rates.
14	OPUC	1. What are the challenges and opportunities to model or otherwise consider electrification as a possible compliance resource option on the supply side as well as the demand side.	In the Executive Summary, Figure 1.8 has been added that diagrams that electrification cannot be a supply-side resource. As it only decreases demand on NW Natural's system it is a demand-side resource. Demand-side resources can also be compliance resources. Staff may be asking about the challenges and opportunities for electrification to be modeled as a compliance resource in PLEXOS® alongside other compliance resources. At a minimum, cost and quantity potential estimates are required to develop an option as selectable in PLEXOS®. Please also see the Executive Summary which also sets forth some of the challenges.
15	OPUC	2. NWN considers geographically targeted EE and DR as distribution system planning alternatives. Why not also consider geographically targeted electrification?	This question is currently being litigated in NW Natural's general rate case in UG 520. In addition to the legal arguments that will be made in briefing, a high-level summary of the policy positions are included here. More detail can be found in UG 520 testimonies: NWN/1700, NWN/3400. NW Natural's core business is the provision of natural gas to end-use customers. NW Natural has an obligation to serve its customers – not to seek to remove service from its customers.

			Geographically targeted electrification will result in NW Natural incurring costs on behalf of its natural gas customers that are not associated with the provision of natural gas service, including the removal of gas appliances from customers' homes and replacing those appliances with the purchase and installation of electric appliances. As a gas-only utility, geographically targeted electrification would have the unjust effect of causing NW Natural's customers to increase their own costs by first funding efforts to move other NW Natural customers off the system and then increase their own costs again by absorbing the fixed system-wide costs of previously serving the departing customer. Additionally, geographically targeted electrification could create stranded assets on the gas system. Further, the costs to heat a home with natural gas at NW Natural's residential rates are lower than the costs to heat a home with electricity at Portland General Electric's and PacifiCorp's residential rates. With respect to the electric system, NW Natural cannot model the geographically specific transmission and distribution system impact of adding winter peak load to the electric system. It is also known that there are currently serious resource adequacy concerns in the region based, in part, on PGE's 2023 CEP/IRP Update, concluding that there are "winter adequacy challenges requiring substantial storage resources"[31] and that "short-duration storage [four-hour batteries] has

[31] PGE 2023 CEP/IRP Update, Chapter 6, page 132 (available at: https://portlandgeneral.com/about/who-we-are/resource-planning/combined-cep-and-irp)ttps://portlandgeneral.com/about/who-we-are/resource-planning/combined-cep-and-irp

			limited effectiveness in winter capacity needs."[32] Although as a gas utility, NW Natural cannot evaluate the precise nature of these challenges, it appears that there are already significant winter resource adequacy issues even without any geographically targeted electrification. Additionally, to the extent the Company is modeling avoiding GHG compliance costs in distribution system planning, the associated GHG compliance costs would need to be captured on the electric system, which is not something in NW Natural's possession. Recent changes in federal tax law would also have to be factored into the electric system's GHG compliance cost calculation as well. NW Natural also notes that PGE's 2023 CEP/IRP Update concludes that "non-emitting energy is scarce"[33] in the winter, strongly indicating that geographically targeted electrification would only shift emissions from the gas system to the electric system.
16	OPUC	3. How could electrification be modeled on the supply side as a compliance resource?	As discussed above, electrification is not a supply side option. It is a demand side option. Please see the Executive Summary (Chapter 1) for more information about the challenges and what the Company has done to significantly advance the conversation.
17	OPUC	The incremental costs/NPV used to compare the different demand scenarios seems to include electric system costs,	Staff is correct and, as discussed above, in this IRP during the electrification study, it was recognized that

[32] PGE 2023 CEP/IRP Update, Chapter 6, page 133 (available at: https://portlandgeneral.com/about/who-we-are/resource-planning/combined-cep-and-irp)ttps://portlandgeneral.com/about/who-we-are/resource-planning/combined-cep-and-irp
[33] PGE 2023 CEP/IRP Update, Chapter 6, page 132 (available at: https://portlandgeneral.com/about/who-we-are/resource-planning/combined-cep-and-irp)

		customer capital costs, gas supply costs/savings, but from Staff's understanding is that it does not include any corresponding costs (or avoided costs) related to the gas distribution system. Can you please confirm this?	additional investigation would need to be done. More analysis needs to be done to understand what additional savings may accrue relative to NW Natural specific gas infrastructure for varying levels of natural gas customers. In a scenario where 90 percent of the residential customer base is electrified, further investigation is necessary to identify what infrastructure and company operations would still be required to serve the remaining ten percent of customers. The Company talks about this in the Electrification section of the Executive Summary and includes some additional information to provide some context.
18	OPUC	1. How does NWN consider the implications of electrification (such as decreasing number of customers or the early retirement of assets) as part of gas-side distribution system costs or future revenue requirement metrics when comparing scenarios?	As mentioned above, this IRP does include the implications on the gas side relative to avoided commodity costs, capacity costs, and compliance costs. Please see previous responses relative to the treatment of distribution system costs in this IRP.
19	OPUC	2. Design day assumptions and calculations: a. Explain the rationale for using the 1st percentile daily temperatures. i. Is this threshold different from ASHRAE's heating design temperature at 99%? b. What historical load and temperature data was used to determine hourly load shares? c. What balance temperature was used to estimate degree days? d. Is using two years of historical data sufficient to develop reliable linear regressions?	a. The temperatures correspond to a 1-in-100 year event. The company has established this risk threshold to ensure reliability for customers. i. Yes, the Company's threshold is different from ASHRAE's 99% design day temperature. The Company's reliability standard likely varies from the residential energy code design day standard. b. The model parameters were developed using firm load data with temperatures less than, or equal to, 45 degrees Fahrenheit. The average hourly load shares were subsequently determined using the

			inputs of the three coldest out-of-sample days on record. c. What does this mean? If it refers to the base temperature value of HDDs, it is of no consequence. d. The Company uses two to three years of historical billing and weather data to generate CMM demands based on the developer's recommendation. Using two to three years of billing data is sufficient to generate linear regressions in CMM. This timeframe captures recent consumption trends and avoids older data that may no longer reflect current usage behavior.
20	RNGC	Our comments focus on the role of renewable natural gas (RNG) as a clean energy resource and how NWN's long-term planning can better reflect procurement of RNG as a key tool for meeting state-level climate goals in Oregon and Washington. We agree with the Draft Plan's statement that, "NW Natural is a leader in RNG procurement and project development among gas utilities in the United States and Canada."	Thank you for your comment.
21	RNGC	There are over 43,000 existing waste sites in North America with the potential to support expanded biogas/RNG development. The existing natural gas infrastructure enables immediate deployment of renewable gas with minimal additional investment, providing a cost-effective decarbonization and gas transition pathway for hard-to-electrify sectors. The International Energy Agency (IEA) recently highlighted the potential of biogases as a hidden solution to many of today's energy security and sustainability challenges. The	Thank you for your comment.

		IEA finds that **today's sustainable production potential for biogases is nearly 1,000 billion cubic meters (equivalent to a quarter of current global natural gas demand)**; that RNG/biogas turns waste into sustainable, low emissions fuel; and that RNG allows for integration and optimization of energy, environment, waste and emissions policies and targets.[2] [2] *IEA (2025), Outlook for Biogas and Biomethane, IEA, Paris hGps://www.iea.org/reports/outlook-for-biogas-and-biomethane* The RNG Potential work conducted by ICF in support of the Draft IRP is reasonable. Specifically, we support ICF's assumption that NWN would have access to a population-weighted share of first-mover access to national resources—roughly 13 percent of the total domestic RNG production, or just over 175 million MMBtu/y by 2045. [3,4] [3] *Draft Plan Flight 2 - pg. 7-40* [4] *Draft Plan Flight 2, Figure 7.16*	
22	RNGC	We appreciate the Draft Plan's acknowledgment that RNG is a critical component of a diversified strategy to decarbonize the gas system. As shown in Figure 7.5 of the Draft IRP, incorporating the use of renewable gases within a gas system has a variety of compound benefits, including: the displacement of anthropogenic carbon dioxide emissions from both the combustion of fossil fuels and achieving critical near-term greenhouse gas benefits due to increased methane capture and destruction; increased energy security; additional environmental benefits that result from the improved management of organic waste;	Thank you for your comment.

		enhancing resource value and income for rural areas; and avoiding conventional fertilizer demand.	
23	RNGC	RNG should be given significant attention in the near-term, based on both the well-proven technology readiness level of various methods of making RNG today—such as anaerobic digestion (AD)—and the flexibility provided by RNG's fungibility with all conventional gas applications. Additionally, the fungibility of RNG and renewable gases provides the opportunity to leverage existing gas infrastructure, which has already been paid for by ratepayers.	Thank you for your comment. NW Natural is committed to sourcing least-cost least-risk resources, including resources used for decarbonization.
24	RNGC	The Draft IRP is clear that hydrogen and/or synthetic gas produced from renewable feedstocks such as clean electricity and waste biomass could be a helpful medium- to long-run[1] component of NWN's renewable gas mix. Chapter 7.4 of the Draft IRP provides an appropriate and holistic overview of these technologies. Waste-biomass-derived hydrogen is poised to contribute to the circular bioeconomy as a pathway for recycling resources which are not suitable for AD. …the use of carbon capture and sequestration (CCS) technologies such as geologic storage or biochar will produce negative-GHG outcomes[2] when paired with RNG and hydrogen derived from waste biomass (including pyrolysis of biomethane). These technologies will provide a necessary pathway to remove emissions from the atmosphere, creating an important pathway to carbon neutrality and, ultimately, carbon negativity. *[1] Post-2035, see Draft IRP Flight 2 - pg. 9-9.* *[2] Better than 'carbon neutral'*	Thank you for your comment. NW Natural is committed to sourcing least-cost least-risk resources, including resources used for decarbonization.

25	RNGC	Renewable gas has a clear role within any reasonable gas decarbonization strategy. However, there is often diversity of opinion about the best targeted long-term uses of RNG. The RNG industry does not claim to be able to solve the daunting challenge of eliminating all organic waste methane emissions and decarbonizing the entire gas system. However, we believe that deciding on the best long-run end use for RNG (e.g., guessing what current gas load cannot be electrified) is less important in the near term than ensuring that renewable gas is a key component of Oregon and Washington's GHG strategy. Waste methane exists throughout the economy. Encouraging the capture and utilization of it now is one of the most effective tools to immediately reduce near-term warming. As well stated by the World Resources Institute: *"The viability of RNG as a decarboniza9on strategy will vary depending on regional context, and ultimately the role that it plays in decarbonization and how it complements other key strategies may shift over time. However, through careful consideration of the factors included in the preceding discussion, policymakers can explore and identify opportunities for targeted RNG production and use that can meaningfully contribute to GHG reduction goals. Overall, the flexibility of RNG, along with the methane emissions reductions associated with its production, mean that it can play a dynamic and complementary role in decarbonization in the long term."*[1] Therefore, NWN should continue to focus on deploying RNG quickly. Doing so does not require *a priori* selection of	Thank you for your comment. NW Natural is committed to sourcing least-cost least-risk resources, including resources used for decarbonization.

		RNG's ultimate best end use as the gas system transition takes place. As described in Chapter 10 of the Draft IRP, electrification will take significant time (even for the residential sector) and require thoughtful infrastructure planning. Therefore, it remains to be determined which long-run applications will best be served by clean gaseous fuels. Our industry remains openminded to those varying possibilities, and we look forward to working with all stakeholders as the long-term vision for RNG use evolves. [1] *World Resources InsTtute, Renewable Natural Gas as a Climate Strategy: Guidance for State Policymakers. (See page 37). https://www.wri.org/publicaTon/renewable-natural-gas-guidance*	
26	RNGC	We commend NW Natural for undertaking system resource and procurement scenario planning that examines the potential role of all renewable gases. The scenarios described in Chapter 9 of the Draft Plan provide a helpful foundation for understanding how renewable gas use is incented for NWN across Oregon's Climate Protection Program (CPP) and Washington's Climate Commitment Act (CCA).	Thank you for your comment.
27	RNGC	With respect to the costs of RNG supply, in our 2024 Economic Impact Assessment, we noted that RNG production costs can vary significantly depending on feedstock and project type. The range of RNG supply cost estimates discussed during the Technical Working Group process for the Draft IRP, and those found in Tables 7.7-9, generally align with the range from RNG COALITION's Economic Impact Assessment. We also generally agree with the Draft IRP's finding that, "Capital costs do increase with production volume; however, they do so at a slower pace,	Thank you for your comment. The Company appreciates the confirmation of the accuracy of the RNG cost estimates.

		meaning the per-unit cost of RNG decreases as production capacity expands."[2] [2] *Draft IRP Flight 2- pg. 7-14*	
28	RNGC	With respect to the results of the scenario analysis, we are pleased to see that NWN's Oregon portfolio will likely include a significant amount of renewable gas in the long run. It is encouraging to see a flexible mix of RTC purchases, development projects from Landfill RNG, Wastewater RNG, and Synthetic Methane from Biomass as preferred compliance strategies. We agree that if Synthetic Methane from biomass is not available, NWN will likely be able to comply with CPP through hydrogen development and RTC purchases.	Thank you for your comment.
29	RNGC	It is unfortunate that the WA CCA compliance does not yet appear to drive much renewable gas use. However, we understand why the optimal CCA strategy currently would rely primarily on allowance purchases and any available offsets (until the allowance prices exceed the costs of renewable gases). That said, we certainly support the Preferred Resource Strategy that includes limited RNG use in Washington as a hedge against uncertainty in CCA compliance requirements changing over time. Meeting five percent of sales demand voluntarily with RNG will mitigate risk from changes to WA environmental policies.	Thank you for your comment.
30	RNGC	We appreciate the Draft IRP's transparency around how RNG procurement continues to support Oregon and Washington's GHG goals, and even the clear acknowledgement of the challenges associated with NWN's leadership on RNG…it is disappointing to see the Preferred Resource Strategy include RNG usage that is below the SB	Thank you for your comment. NW Natural believes customers would prefer direct decarbonization through renewable natural gas purchases and other decarbonization mechanisms that reduce their greenhouse gas emissions in tangible ways over local offsets.

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		98 voluntary targets, we understand why Community Climate Investment (CCI) use might (at this time) be preferred by Oregon Public Utilities Commission (OPUC) and other Oregon decisionmakers.[1] The OPUC, the Department of Environmental Quality, and other OR leaders have been clear about the desire to see the CCI framework successfully launch, which may unintentionally deprioritize RNG use, especially in the short run. …we believe this view may change over time as the ability of the CCI framework to motivate true global GHG reductions in a cost-effective way is tested…Oregon will continue to learn from other jurisdictions who also take serious approaches to gas system decarbonization. We remain confident RNG will be proven as a critical tool that can complement other strategies. Today, many RNG projects in WA and OR are selling their RNG outside of those states, into programs that clearly value the many benefits of RNG. If Oregon and Washington regulations prioritized RNG, we expect the industry would see more RNG flowing to customers in WA and OR. [1] *As implied by the Draft IRP Flight 2- pg. 9-21 and 9-22*	
31	RNGC	Achieving 3% RNG blend for 2025, 4% for 2026 and 5% by 2027 is still progress. We support NWN meeting these modest RNG targets slightly ahead of CPP compliance needs and believe that RNG use will, in the long run, demonstrate superior environmental benefits when compared to other forms of allowable CPP compliance.	Thank you for your comment.
32	RNGC	With respect to how improvements to the net framework could be implemented, RNG COALITION has long	Thank you for your comment. NW Natural continues to work with its regulators on best practices for carbon

		recommend the use of lifecycle carbon intensity (CI) accounting for reporting the greenhouse gas (GHG) benefits of SB 98 implementation.[2] Incenting the utility to procure the best performing RNG projects on a GHG basis is better aligned with the United Nations Intergovernmental Panel on Climate Change's direction around the importance of methane. For example, the UN Environment Program states that: [1] *"Cutting methane is the strongest lever we have to slow climate change over the next 25 years and complements necessary efforts to reduce carbon dioxide. The benefits to society, economies, and the environment are numerous and far outweigh the cost. We need international cooperation to urgently reduce methane emissions as much as possible this decade."* The fact that the current framework in both Oregon and Washington does not properly recognize and motivate methane reduction from RNG projects is still a concern to our industry. Further, synthetic methane sources incented outside of a framework based on proper lifecycle accounting may not create the desired GHG benefits. At a minimum, NWN should continue to share CI information on existing RNG procurement. This allows all stakeholders to see net GHG performance of projects that are being incentivized. [2] *For example, see our January 13, 2020, comments in OPUC Docket No. AR 632* [1] *https://www.unep.org/news-and-stories/press-release/global-assessment-urgent-steps-must-be-taken-reduce-methane*	accounting and how that information is presented in GHG reporting.
33	RNGC	We commend NWN's consideration of RNG and its commitment to exploring diversified decarbonization	Thank you for your comment.

		pathways. RNG Coalition has participated in processes related to evaluating gas decarbonization in 13 states. In general, these dialogs have been constructive, but slow moving, discussions related to the tradeoffs between (1) the critical need to decarbonize the energy services currently provided by conventional gas and (2) the reality that the gas system is integral to many aspects of our everyday lives. The Draft IRP is one of the few cases in North America where serious planning is being undertaken to achieve true gas system decarbonization. We applaud that effort and look forward to continued engagement as this work progresses.	
34	WUTC	In staff comments for the 2022 IRP, Staff commended "*NW Natural for evaluating transportation customer conservation potential during its most recent conservation potential assessment conducted in 2021, well before the CCA established gas companies as the point of regulation for transportation customer emissions*."[1] NW Natural kept that practice in the current IRP and uses this information to develop incentive programs for Washington customers. [1] *In re NW Natural's 2022 Integrated Resource Plan (IRP), Docket UG-2100094, 2022 IRP Staff Comments at [page 7] (January 19, 2023) (2023 IRP Order 01).*	NW Natural thanks Staff for this commendation.
35	WUTC	NW Natural's reference to gas-powered heat pumps for performance at lower ambient temperatures in the Columbia River Valley presents an intriguing opportunity. Staff seeks clarification on the distinction between gas heat pumps and hybrid heat pump systems as referenced in the	Gas heat pumps (GHP), like electric heat pumps (ELP), use an energy source to move heat from the ambient air to inside a building. In this case the energy source is gas combustion. The most prominent type is an "absorption cycle" based on refrigerant with zero global warming potential (GWP). GHPs can operate at

		IRP. A clear explanation of the technological differences, use cases, and expected emissions or efficiency outcomes would help participating party members better evaluate the role these systems may play in decarbonization strategies and energy affordability.	very low temperatures without back up heat, many down to – 40° F/C. They provide a nominal efficiency of 140% AFUE – about 50% better than federal minimum efficiency furnaces – so they can reduce gas use and emissions up to 50%. They can also be configured to provide both space and water heating. Because the bulk of the heat comes from the air and combustion, the electrical load is very small compared to an ELP. GHPs can be used for residential and commercial space and water heating. They can be particularly useful for existing buildings that already have or don't need cooling, have a constraint on their electrical service capacity, can benefit from lower heating costs, and have space for outdoor equipment. Hybrid (or dual fuel) heat pumps couple an electric heat pump (HP) with a gas furnace or boiler for space heating. The HP is the primary source of heat – in warmer temperatures it is the sole source. When the ambient temperature drops below the 'changeover' point, the system switches from HP heating to furnace heating. The changeover temperature depends on the HP's capabilities and the heating load. Some boiler-based systems allow the HP and boiler to operate together (integrated), expanding the HP's range. Systems with a boiler can also provide water heating. Hybrid systems provide cooling as well. When connected to external utility emissions and cost inputs, these systems can be controlled to minimize heating cost for the owner, heating source emissions for society, or load demand for an electric utility – by

			choosing which heat source makes sense in the moment (a process being piloted now through NEEA). These systems can be applied to residential and commercial buildings. The Washington State Energy Code requires hybrid or all-electric heat pump systems for space and water heating for commercial buildings. Hybrid HPs can reduce source emissions – depending on the source of electrical generation – but our analysis shows that with the current generation mix, avoided source emissions are about the same during the heating season. Where electric rates are low, hybrids can lower heating costs; where rates are not low, hybrids can raise heating costs – unless they are controlled to minimize cost (currently being piloted).
36	WUTC	Staff acknowledges that the Draft IRP includes a placeholder section that is expected to be completed by the final filing. Staff appreciates the Company's effort to incorporate this information and recommends that in future IRPs, NW Natural continue this practice of flagging forthcoming content to enhance transparency and planning continuity.	NW Natural thanks Staff for this comment.
37	WUTC	While Staff acknowledges that a macroeconomic outlook can provide context for fuel cost assumptions or demand risk, Staff questions whether such sections can be narrowly tailored and explicitly tied to NW Natural's Washington-specific planning decisions, modeling assumptions, and compliance obligations. Staff has serious concerns about the framing, tone, and relevance of the content presented. Staff considers it necessary for NW Natural to address the following issues in the final 2025 Natural Gas IRP to ensure	As staff acknowledges, the macroeconomic outlook does provide context for fuel cost assumptions and demand risk, as well as context for discussions of affordability and other issues. The macroeconomic outlook is very relevant to understanding changes in demand across the service territory, including Southwest Washington. It includes macroeconomic trends and analysis for Clark County and the Portland metro area (which includes Clark and Skamania counties) that provide valuable context for the

		consistency with Washington's statutory energy equity goals and community engagement expectations:	development of Washington customer count forecasts, which are distinct from the Oregon customer count forecasts.
38	WUTC	Pg 2-1 1. Stigmatizing and unsupported narratives: The attribution of population declines to "increased homelessness along with associated drug use, mental health, and public safety issues" is presented without supporting data or citation. If NW Natural conducted no independent analysis or relied on sources not grounded in credible demographic research, this assertion appears speculative and unsupported. Additionally, this framing risks reinforcing harmful stereotypes and fails to acknowledge broader systemic or structural factors. As written, the statement lacks relevance to the IRP's core energy planning objectives and may be inconsistent with the intent of Washington's equity statutes, which emphasize the importance of respectful and inclusive engagement with overburdened communities. Staff recommends the Company either substantiate this claim with appropriate evidence or remove the reference altogether in the final IRP.	Footnotes added to IRP for reference. There are many potential reasons to explain population decline in the region, including affordability (higher house prices and taxes), which was omitted in the partial quote referenced in the comment, and those mentioned in the partial quote, which are supported by statistical evidence and comparative analysis. Understanding the socioeconomics behind changes in population is relevant to the Company's long-term planning, which is materially impacted by recent changes in these trends, in particular, changes in forecasted customer counts.
39	WUTC	Pg 2-1 2. Misalignment with Washington's regulatory environment: Washington has explicitly prioritized environmental justice through the Climate Commitment Act (CCA) and agency-level equity frameworks such as the Washington Utilities and Transportation Commission orders.[2] Staff questions whether, rather than presenting generalized socioeconomic decline, the Company missed an	Macroeconomic trends are relevant and valuable to resource planning and help provide context for some of the considerations mentioned in the comment. Higher costs of living and affordability concerns in the region highlight the need for programs and planning to assist low-income and disadvantaged customers. The equity planning consideration of this need is discussed at length in Chapter 3 and includes NW Natural's actions in this IRP cycle to highlight low-income programs,

		opportunity to connect macroeconomic trends to relevant planning considerations—such as customer energy burden, arrearages, localized infrastructure needs, or targeted energy assistance strategies. Absent these linkages, the section contributes little to resource planning and may alienate vulnerable customers from participating in the IRP process. [2] *Wash. Utils. & Transp. Comm'n v. Cascade Natural Gas Corp., Docket UG-210755, Final Order 09, 16-17, ¶ 52; 19, ¶ 58; (Aug. 23, 2022) (2021 Cascade GRC Order).*	reduction of energy burden and expanded opportunities for customers to participate in the IRP process.
40	WUTC	Pg 2-2 "Economic and demographic trends since the COVID-19 pandemic have changed in the region, especially in Oregon, which makes up nearly 90 percent of NW Natural's service territory." While NW Natural's Washington service territory represents a smaller portion of its customer base, the Company remains fully subject to Washington-specific statutes, emissions mandates, and equity planning requirements.[3] Staff is concerned that the IRP heavily centers Oregon-specific assumptions and framing - particularly in the Regional Macroeconomic Outlook and early chapters - while deferring or omitting discussion of Washington customers and conditions until much later in the document. [3] *NW Natural, Technical Working Group #1 Presentation, Slide 12, 2024.*	Macroeconomic trends in NW Natural's Washington service territory are discussed in Section 2.1.3 NW Natural System Area Macroeconomic Outlook, including population, building permits, and employment (as part of the Portland metro area). From a larger regional or state perspective, macroeconomic trends in the entire state of Washington are less impactful to the Company's long-range planning than those in Oregon since NW Natural's Washington service territory represents a small percentage of the state, and trends in Southwest Washington are more closely aligned with the Portland metro area and Oregon, rather than the Seattle-Tacoma-Bellevue metro area and Washington.
41	WUTC	Pg 2-2 "Consumer spending…" While macroeconomic context can support utility planning, the current framing includes speculative attributions (e.g.,	Chapter 2, titled "Planning Environment," provides a high-level overview of macroeconomic conditions that shape long-term utility planning. Chapter 2 does not attempt to provide a granular accounting of federal expenditures. Rather, it situates macroeconomic trends

		deficit spending and inflation) that are not supported by cited source. Staff expects NW Natural's final 2025 IRP to include clear citations when referencing macroeconomic projections or attributing causal relationships between policy and economic outcomes. These sections may also be strengthened by narrowing their focus to planning-relevant variables such as demand growth, fuel price expectations, and interest rates.	as relevant context for resource planning and, specifically, how these shifts may impact affordability, energy burden, and access to resources. The reference to structural limitations is not an abdication of responsibility, but a contextual framing that recognizes the broader landscape in which utility planning occurs—one shaped by housing insecurity, inflation, and regulatory constraints. The IRP's macroeconomic analysis is supported by multiple sources, with additional footnotes added to the IRP for reference as requested.
42	WUTC	Pg 2-2 "State and local governments will also be impacted by reduced federal spending…" The IRP attributes anticipated changes in economic growth to the winding down of "massive deficit spending in the wake of COVID-19,". However, the scale and composition of federal COVID-related spending are misstated in this section. NW Natural's final, filed 2025 IRP should provide sourced and verifiable economic data when referencing federal fiscal policy to support transparency and planning credibility.	It appears this comment has taken part of a sentence in the macroeconomic outlook out of context and misinterprets the information provided. The full sentence is, *"Consumer spending remains strong and, together with government spending, fueled GDP growth in 2024, but that is expected to change in 2025 as the boost to the economy provided by massive deficit spending in the wake of COVID-19 and expansionary monetary policy (which helped fuel high inflation), is coming to an end."* The context here is that government spending was a driver of GDP growth in 2024 (and 2023) along with consumer spending, and that recent tailwind for growth is now forecasted to be a headwind in the coming years. The IRP does not attribute all changes in economic growth in 2025 and subsequent years to reductions in federal spending. To be clear, the level of deficit spending is not intended to be a value statement, as to whether the spending

			was "good" or "bad". Between six COVID-19 relief laws passed from 2020 to 2021, the federal government has provided nearly $4.6 trillion for pandemic response and recovery. All that spending was deficit spending. In particular, 2020 saw the deficit jump to $3.1 trillion from $984 billion the year before. This was the largest increase in deficit spending since World War II, as the deficit reached 15 percent of GDP. Additional large deficits run from 2021 to 2024 ($2.8 trillion, $1.4 trillion, $1.7 trillion, and $1.8 trillion) injected a historic amount of money into the economy and boosted aggregate demand. Between the expiration of pandemic funding and a new administration that is projected to reduce spending, forecasts call for federal spending to decrease over the next three years. The increase in aggregate demand provided by the spending, and now the decrease in aggregate demand left in the wake of that spending, are pertinent to U.S. economic outlooks in 2025 and beyond. Footnotes added in the IRP as requested.
43	WUTC	Pg 2-5 "Federal spending is expected to decrease…" NW Natural's final, filed 2025 and future IRPs should contain only reliable and supported claims about federal fiscal policy, and instead provide verifiable, cited data from credible sources such as the Congressional Budget Office, U.S. Treasury, or Office of Management and Budget. If the Company expects federal spending trends to influence planning assumptions – such as capital markets, inflation,	The assertion that "federal spending is expected to decrease" is not speculative. S&P Global's *Economic Outlook U.S. Q2 2025* forecasts weaker spending by the federal government in 2025, 2026, and 2027. Footnote added in the IRP. The connection here between the macroeconomic outlook and the IRP is that a slowing economy, all things equal, may impact the rate at which the Company can grow and add customers.

		or infrastructure co-funding – the IRP should clearly explain the connection and cite authoritative data.	
44	WUTC	Pg 2-6 "Looking forward, gas from RNG sources…will become a larger share of the Company's supply purchases." Staff found this statement to be vague and lacking sufficient detail to assess the Company's RNG planning assumptions. Staff encourages NW Natural to either integrate its RNG planning considerations directly into this section or expand the accompanying narrative to clearly explain those assumptions	The Company tries to balance accessibility of the IRP with providing the appropriate level of information in each chapter. The Planning Environment Chapter is intended to provide an overview of the environmental policies that will impact future resources with more specificity in the chapters that talk about renewable resources. Chapters 7, 9, as well as Appendices E, G, and K provide detailed information related to RNG. Additionally, in response to Staff's comment, the Company has removed this statement.
45	WUTC	Pg 3-4 "The Company recognizes that certain factors lie beyond its direct influence. Broader economic policies…" Staff appreciates NW Natural's stated intent to promote inclusion and customer awareness. However, intent alone is not sufficient. The Company's equity framing focuses on structural limitations outside its control, without demonstrating how equity is substantively embedded in scenario development, resource selection, or analytical modeling. Washington's Climate Commitment Act (RCW 70A.65.020), together with the UTC's Equity Docket, underscores that climate-related planning must deliver meaningful benefits to overburdened communities.[4] These expectations apply across all energy sectors, including natural gas. Staff encourages NW Natural to strengthen the final IRP by clearly showing how equity considerations inform planning logic - such as scenario	NW Natural is surprised and disappointed by Staff's assertion that "the Company's equity framing focuses on structural limitations outside its control." This comment undermines the Company's engagement described in the Equity Considerations Chapter and the Company believes it is based on a misunderstanding of its intent. The sentence in question did not deflect responsibility or accountability - it was an acknowledgement of the broader structural conditions and realities that shape the planning environment. The Company's position here is that planning must be responsive to real-world conditions. NW Natural is taking actions to strengthen equity considerations in the IRP and beyond. NW Natural looks forward to more engagement on this topic with WUTC Staff. With respect to the Staff's comment on outreach and engagement—the Company discussed these topics in

		weighting, investment prioritization, geographic targeting, and benefit-cost analysis. Including examples of public outreach materials (e.g., mailers, social media, community meeting announcements) would also improve transparency and demonstrate how the Company is engaging Washington communities in the IRP process. [4] Washington…, *Interim Policy Statement*	detail in the draft IRP, as well as throughout the TWG process. Examples include: - Multiple outreach channels to announce IRP related activities - A publicly available, dedicated IRP webpage, including a plain language review, enhanced accessibility features, and less technical, more accessible language to enhance clarity for the general public - The November 2024 Winter Preparedness Fair ("IRP Fair") borne out of conversations with the CEAG on ways to improve procedural equity practices and public engagement opportunities in the development of the IRP - Tabling at a June Clark County community event which utilized an informational toolkit on the IRP for use at in-person events The Company's outreach includes physical mailers, digital platforms, in-person events, and facilitated advisory groups. In an effort to balance the length of this document and include all relevant details, the Company has chosen to highlight specific examples of mailers and other outreach efforts. Appendix I provides further details to supplement Chapter 3.
46	WUTC	Pg 3-9 "By concentrating on these [including enhancing public participation, integrating diverse perspectives into planning	The sentence in question articulates NW Natural's approach to its consideration of equity in the IRP as a

		processes, and expanding access to energy assistance programs] areas, the Company can ensure that its actions are impactful and achievable, and that the IRP remains a practical and effective tool for resource planning, rather than an aspiration document with unattainable goals." Staff have concerns about the framing of this statement. While feasibility is an essential consideration, Washington law - via the CCA, and RCW 19.285 - clearly establishes that long-term equity and decarbonization goals must be part of utility planning.	resource tool, and did not intend to limit the applicability of Washington law in that statement.
47	WUTC	Pg 3-5 Table 3.1, Community Equity Advisory Group (CEAG) - "Strengthen Procedural Equity practices; broaden engagement and participation in energy planning" Staff appreciates the formation of the CEAG and NW Natural's recognition of procedural equity as a planning priority. However, the Company's description remains broad and lacks sufficient detail on how CEAG input has been operationalized or meaningfully informed the IRP's scenarios, resource selections, or program design.	The Community Equity Advisory Group (CEAG) is noted in Table 3.1 and then is described in more detail in the following section. How the CEAG informed the 2025 IRP was provided further in the chapter (see Section 3.5.2) which reiterates that the focus of equity considerations for the 2025 IRP focus on procedural equity. A footnote has been added to reference information supplied in the 2025 IRP Workplan filed in Washington where the Company supplied the February 2024 CEAG meeting summary, survey results, and in-meeting activities. Clarification has been added. Additionally, Appendix I provides details on the enhanced public engagement activities including the recent tabling activities in Clark County. In the introduction of the Equity Considerations chapter, the Company states that the 2025 IRP represents early efforts to incorporate equity principles into resource planning. Section 3.4 further emphasizes

			that the IRP should not be considered the Company's primary effort to progress equity work, rather it is a part of a constellation of programs, resources, services, and analysis. The CEAG is distinctly different from similarly named advisory groups which are required for electric utility peers. As the company has shared in prior communications, the impetus for the formation of this advisory group was not limited to increasing engagement in resource planning processes, but rather to increase dialogue and advisement across programs which impact and serve customers. While the CEAG has greatly informed NW Natural programs (such as Bill Discount, workforce development, RNG projects, and Low-income Energy Efficiency), it has not yet been engaged on more technical topics of the IRP such as scenarios and resource selections.
48	WUTC	Pg 3-5 Framing CEAG activities within an energy justice framework - as outlined in Commission orders and Washington statutes - would enhance transparency and demonstrate alignment with regulatory expectations. In Cascade's 2021 GRC Order, the Commission affirmed the importance of the four energy justice tenets: distributional, recognition, procedural, and restorative justice.[5] Check it: *So that the Commission's decisions do not continue to contribute to ongoing systemic harms, we must apply an equity lens in all public interest considerations going*	The Company seeks clarity on Staff's conclusion that the activities and practices of the CEAG are not framed within an energy justice framework, and looks forward to more dialogue on this topic. The Company has shared many details of the CEAG with IRP stakeholders, Staff, and other external parties, and believes that the CEAG is in alignment with regulatory expectations. During TWG 1, WUTC Staff asked, and the Company responded to, questions relating the CEAG. Footnote 36 in Chapter 3 further directs to where more information

		forward. Recognizing that no action is equity-neutral, regulated companies should inquire whether each proposed modification to their rates, practices, or operations corrects or perpetuates inequities. Companies likewise should be prepared to provide testimony and evidence to support their position. Meeting this expectation will require a comprehensive understanding of the ways in which systemic racism and other inequities are self-perpetuating in the existing regulatory framework absent corrective intervention. It is incumbent upon regulated companies to educate themselves on topics related to equity just as it is incumbent upon the Commission to do the same.[6] These principles offer a consistent lens for evaluating equity-centered engagement and should guide the Company's process design and documentation. Multi-year rate plan statute (RCW 80.28.405) further reinforce the state's expectation that utilities prioritize overburdened communities and integrate equity into public interest determinations. As Staff has noted in other proceedings, participant compensation - such as that used in general rate cases - can reduce barriers to participation and help ensure diverse and sustained engagement. Clarifying how CEAG members are selected, supported, and compensated could help distinguish the Company's procedural equity practices from performative engagement. To support transparency, the IRP would benefit from: 1. A timeline of CEAG activities;	can be found on the NW Natural website regarding the CEAG, including the current Charter (which states the annual compensation, objectives, roles, etc.), participating organizations, and schedule of meeting topics. Section 3.5.2 of the IRP details how CEAG feedback shaped the IRP's procedural equity framework, including the development of multilingual outreach materials, the concept for and design of in-person events like the Winter Preparedness Fair, and updates to the Company's website. Additional details are included in Appendix I. Initial and subsequent recruitment of CEAG members focused on community-based organizations that serve an identity, community and underrepresented/underserved population present within the NW Natural Service territory in Oregon and Washington---prioritizing organizations that have not historically engaged in energy planning and Company program planning opportunities in the past. Through the CEAG the Company has most notably been able to take member feedback to refine programs to better reach and serve people of different abilities, ages and linguistic/cultural communication styles. As noted in Section 3.4.1, NW Natural holds quarterly CEAG discussions with its members on specific topics related to company programs, offerings and communication tools through the lens of equity, energy

		2. A summary of how CEAG input shaped planning decisions; 3. A discussion of compensation approaches; and 4. Development of metrics to evaluate procedural equity over time.	justice, or other relevant topics. CEAG member feedback heavily inform meeting topics. Meetings center on concrete, actionable asks of the advisory group—an approach that demands clear expectations, thoughtful planning and ongoing dialogue. At each CEAG meeting, NW Natural provides a detailed report to the CEAG on topics such as the concrete actions, deliverables, and milestones achieved that were undertaken or achieved since the last meeting and under the recommendations from CEAG membership. Compensation is a critical equity practice. It acknowledges the value of community expertise, especially from organizations that may not have the resources to participate in unpaid advisory roles. By offering compensation to the CEAG member organizations, NW Natural removes a key barrier to participation and affirms that community insight is as valuable as technical or regulatory expertise. As noted in the CEAG Charter which is publicly available, the $5,000 annual compensation was calculated based on an estimated 30-hour annual commitment per CEAG member, at a rate of $160 per hour. This rate reflects standard consulting fees for similar professional services.
49	WUTC	Pg 4-3, Table 4.1 Staff appreciates the Company's use of ARIMA models and associated statistical criteria (AIC and MAPE) to project customer counts across four segments. However, Staff continues to observe the use of Oregon-based housing data as a proxy for Washington residential forecasts, which may	NW Natural is not aware of governmental or third-party forecasts of Clark County or Southwest Washington building permits or housing starts. Without these forecasts, the company cannot create forecast models incorporating this data. From historical data of Clark County or Southwest Washington building permits from

		not reflect the distinct housing and growth patterns in Washington communities. Staff repeatedly shared Washington-specific housing and permitting data sources throughout the planning period and continues to encourage their integration. For example: 1. The Washington State Office of Financial Management (OFM) provides jurisdiction level building permit and completion data updated annually.[7] 2. For larger jurisdictions (pop. >10,000), University of Washington's Center for Real Estate Research (WCRER) also publishes relevant permit and completion data.[8] Staff acknowledges that the OFM data excludes manufactured housing and group quarters but believes it still offers a valuable and geographically appropriate indicator. Staff expects that the Company either incorporate these sources directly or explain why they were not used, particularly given their continued availability and Staff's multiple references to them throughout the IRP planning process. [7] *Washington State Office of Financial Management. Historical Population and Housing Estimates.https://ofm.wa.gov/washington-data-research/population-demographics/population-estimates/historical-estimates* [8] *Washington Center for Real Estate Research. Permitting Data. https://realestate.washington.edu/research/wcrer/permitting-data/*	the U.S. Census Bureau, NW Natural could produce its own forecast, but the company prefers to use forecasts from governmental, or reputable, third-party experts to maintain objectivity and integrity in the modeling. For each IRP, Washington residential customer count forecast models are tested using Clark County population and U.S. housing starts (along with Oregon housing starts) as independent variables since forecasts are available for each from the Washington Office of Financial Management and Oregon Office of Economic Analysis. In the end, models using Oregon housing starts outperformed those using U.S. housing starts or Clark County population for the 2025 IRP Washington residential customer count forecast. While growth patterns in the company's Washington service territory are distinct from the rest of the Portland metro area, they still follow a pattern more closely related to the Portland metro area and Oregon than to Washington or the U.S. If staff are aware of timely sources of forecasts for building permits, housing starts, or employment in Clark County or Southwest Washington, please share this information with the company and our economists will evaluate customer count forecast models for Washington residential and commercial customers in the service territory with this new data.
50	WUTC	Pg 4-4 "Outside of these changes…"	The customer count forecast for Washington residential customers in the 2025 IRP includes the use of SME

		Staff notes that despite prior input and discussions during the planning period, the IRP does not appear to incorporate or respond to Staff's earlier comments regarding the effects of Washington State building code updates and the Climate Commitment Act's long-term price signaling.[9] [9] *While NW Natural discusses allowance purchasing strategies and CCA-related compliance costs, these considerations are treated as financial planning inputs rather than as behavioral price signals. The IRP does not demonstrate how the carbon price - central to the CCA's policy design - is expected to influence long-term customer demand, fuel-switching behavior, or scenario design assumptions. This distinction is critical, as state policy intends for the carbon price to drive decarbonization through both market and consumption-side responses.*	near-term customer count forecast data as a forward-looking time series in the model (see 4.1.3 Near-term Customer Count Forecast for information on how near-term forecasts are created). The near-term forecast used in the IRP was completed in December 2024 and was done under the assumption of current laws and policies, including Washington State Building Codes, so effects of Washington State Building Code updates are captured in the modeling for the Washington residential customer count forecast. The Company notes that Washington Ballot Initiative I-2066, which impacts state building codes, was passed, subsequently found unconstitutional, and is currently in litigation (to be reviewed by the Washington State Supreme Court). While the appeal plays out, a separate lawsuit arguing that the codes are invalid under I-2066 is on hold.
51	WUTC	Pg 4-5 to 4-6 (4.1.8) Staff acknowledges the Company's methodological updates and appreciates the incorporation of updated econometric models for forecasting systemwide customer growth. The reduced compound annual growth rates (CAGRs) relative to the 2022 IRP reflect a meaningful shift in long-term planning assumptions and signal responsiveness to evolving policy and economic conditions. However, Staff notes that the IRP does not provide sufficient detail on Washington-specific customer count trends or how these projections reflect the state's distinct policy landscape,	NW Natural appreciates the request for Washington-specific customer count forecast charts and tables in the main body of the 2025 IRP. For accessibility and brevity reasons, the company includes Washington-specific customer count forecast charts and tables in Appendix B. The Washington customer count forecast charts include CAGRs for 2025 IRP reference cases and 2022 IRP reference cases for comparison, which clearly show changes in growth trajectories for both forecasts.

		including building code changes, decarbonization policies, and the anticipated impacts of the CCA. NW Natural should include breakout graphs or summary tables in the main body - not just in an Appendix - that clearly disaggregate residential and commercial customer growth by state. This would allow stakeholders to assess whether Washington-specific drivers (e.g., electrification pressure, code constraints on new gas connections) are meaningfully incorporated into the forecast. Additionally, given the lower growth trajectories in the 2025 IRP, Staff encourages the Company to provide narrative context for how those changes relate to state-level customer trends, particularly in Washington service territories where future growth may diverge more significantly from historical patterns.	The Company notes that Washington Ballot Initiative I-2066, which impacts state building codes, was passed, subsequently found unconstitutional, and is currently in litigation (to be reviewed by the Washington State Supreme Court). While the appeal plays out, a separate lawsuit arguing that the codes are invalid under I-2066 is on hold.
52	WUTC	Pg 6-3 “AEG also applied benefits…” Staff appreciates AEG’s inclusion of non-gas energy savings - such as electric HVAC and lighting - when assessing DSM measures like weatherization and retro-commissioning. This cross-fuel approach appropriately reflects the full system value of efficiency, particularly in mixed-fuel homes. To support transparency, Staff encourages the Company and AEG to clearly document the methodology and assumptions behind the Council’s calibration credit applied to space heating savings. Providing this detail in the IRP	To address this comment, in Section 6.3 of Chapter 6, the Company has included more details provided by AEG to describe the specific ways and data sources used by AEG to estimate non-energy impacts on TRC calculations.

		appendices or technical materials would allow stakeholders to better evaluate its impact on TRC calculations	
53	WUTC	Pg 6-43 "For this study, work from the 2021 CPA measure development was retained…" Staff acknowledges the Company's statement that the CPA retains most measure development from the 2021 analysis, with selective updates made based on changes in technology or assumptions. However, the IRP provides limited detail on the scope and substance of those updates. Given the pace of change in energy efficiency technologies, policy, and equity considerations in Washington, a more transparent and thorough refresh of conservation measures would strengthen confidence in the CPA's relevance. High-level references without supporting documentation make it difficult to assess how well the CPA reflects current conditions. Staff encourages NW Natural to include, in its final 2025 IRP, an appendix or supplemental filing outlining which measures were updated, what assumptions changed, and how these adjustments affect achievable potential. Greater clarity in future CPA updates would improve alignment with Washington's decarbonization and equity goals.	Thanks for the comments and suggestions. The deliverables of the 2023 CPA study by AEG include a lengthy CPA summary report and Excel-based results workbooks by customer sector detailing the outputs from its assessment model. These documents would be too much to be included in an IRP appendix, but they'll be available upon request.
54	WUTC	6-40 "In late 2024…" Staff is concerned by the lack of clear differentiation between Oregon and Washington program information—particularly in the low-income and program evaluation sections. While jurisdictional distinctions are noted early on, later sections often merge findings, outcomes, and	When possible, the Company reports the performance and results in the IRP Chapters for the low-income EE programs, OLIEE and WALIEE. Due to the number of participating homes in WALIEE being so small (only 175 homes in total over the past 15 years), data availability limits the feasibility of conducting separate analysis such as the average annual arrearage reduction value

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		strategies into a single narrative, making it difficult to determine what applies specifically to Washington.[10][11] This issue recurs across the IRP, with Oregon-specific data frequently dominating or serving as proxy for Washington analysis. Even in Washington-labeled sections, references to Oregon programs are often used in place of direct, Washington-specific insights. This limits the ability of Washington stakeholders to evaluate whether programs effectively address local needs, especially in overburdened communities. Staff encourages NW Natural to more clearly disaggregate Oregon and Washington content in future IRPs, and, to the degree possible, in the final 2025 IRP. Doing so would strengthen regulatory oversight and enhance trust and accountability for Washington customers. *[10]RCW 80.28.010(2) Every gas company... shall furnish and supply such service instrumentalies and facilities as shall be safe, adequate and efficient, and in all respects just and reasonable.* *[11] RCW 80.01.040(3) The utilities and transportation commission shall: ... Regulate in the public interest, as provided by the public service laws, all person engaging in the transportation of persons or property within this state in the business of supplying any utility service or commodity to the public for compensation.*	of the program at the individual state level. It is worth noting that the evaluation, measurement, and verification report for the program produced by an independent third party does provide more detailed and separate analysis and reporting of the program by state. As mentioned above, there is a natural tension between making the IRP accessible and including all relevant information. The Company has tried to address this balance for both Washington as well as Oregon by including key content in the body of the IRP and more granular information in Appendices. For example, in Appendix B.1.2 State Results, customer count forecasts for Washington residential and commercial customers are included. Prior to filing the next IRP, the Company recommends that it meet with Staff to discuss this balance.
55	WUTC	Pg 6-41 "The evaluation also revealed…" Staff appreciates the inclusion of the reported $213 average annual arrearage reduction for OLIEE participants. To improve relevance for Washington, Staff encourages the Company to provide a similar analysis for Washington customers or clarify if such data is unavailable.	The Company has clarified why the Washington value was unavailable (see response to 52) and will continue address the inclusion of a Washington arrearage reduction metric in future impact evaluations.

		Disaggregated metrics are essential given Washington's distinct regulatory and economic context.	
56	WUTC	Pg 6-43 "In NW Natural's 2022 IRP…" The IRP discusses Oregon's BYOT program but provides no comparable detail for Washington. Staff requests clarification on whether any residential or small commercial DR scoping occurred in Washington. If not, a brief explanation and timeline would support transparency and consistency with prior multi-jurisdictional planning commitments.	The BYOT program has been offered to residential and small commercial customers in both Oregon and Washington since its inception. The discussion on the BYOT program in the draft IRP was at the system-wide program level (i.e., including customers/devices enrolled in both Oregon and Washington), based on the post-season preliminary summary analysis provided by the implementation vendor. In the final version of the IRP, the discussion has been updated by state whenever possible with the results of the evaluation, measurement, and verification analysis conducted by an independent third party.
57	WUTC	Pg 7-3 "These allowances are acquired through a variety of pathways…" Chapter 7 states it covers resources to meet emissions compliance but does not present Washington's specific strategy - such as efficiency targets, RNG goals, or offset plans - which appear later in Chapter 13.2.3. This may create confusion about where to find key CCA compliance details. Staff suggests either summarizing Washington's compliance approach in Chapter 7 with a cross-reference to Chapter 13 or revising the title and introduction of Chapter 7 to more accurately reflect its focus on compliance instruments and market tools.	Table 7.1 lists the resources that are available for compliance under Washington's CCA. These resources (with the exception of energy efficiency which is discussed in section 6.3), are discussed further in sections 7.2, 7.3, and 7.4. The parameters on the preferred resource strategy are outlined in section 9.4.2. Figure 9.13 shows the resource selections, including energy efficiency, to meet CCA compliance and achieve a specified amount of the HB 1257 targets. A very high level summary of the Washington Action Plan is outlined in section 1.12.
58	WUTC	7-10 "Both Oregon and Washington's laws…"	While carbon intensity does vary between RNG based on feedstock and production methodology, overall the

		Staff has concerns with the broad characterization of RNG as inherently carbon neutral. While biogenic sources differ from fossil fuels in lifecycle terms, RNG carbon intensity varies significantly depending on feedstock, collection, upgrading, leakage, and combustion. Frameworks such as Washington's Clean Fuel Standard (WAC 173-424) and Climate Commitment Act (RCW 70A.65) do not presume RNG is carbon neutral; rather, they require lifecycle carbon intensity reporting and emissions accounting across all fuel pathways. Agencies such as Ecology and EPA increasingly emphasize full fuel-cycle analysis. RNG emissions - particularly upstream methane leakage and embodied carbon - remain central to assessing compliance value in Washington's regulatory context. While organizations like the IPCC, U.S. EPA, and IEA distinguish biogenic CO_2 in inventories, none treat it as irrelevant.[13,14] The IPCC requires separate accounting of biogenic CO_2, and the EPA's Greenhouse Gas Reporting Program (Subparts HH and FF) mandates reporting of methane and CO_2 from sources such as landfills and digesters. [13] *Intergovernmental Panel on Climate Change. (2023). Climate change 2023: Synthesis report. Contribution of Working Groups I, II and III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [Core Writing Team, H. Lee & J. Romero (Eds.)]. IPCC.*	use of the fuel at the point of combustion is typically considered carbon neutral. In EPA's guidance document on RNG titled "An Overview Of Renewable Natural Gas From Biogas"[34]. The agency states "tailpipe emissions of CO2 from RNG fuels are considered carbon neutral because the carbon is biogenic." This is consistent with how NW Natural describes RNG in this IRP. As a local distribution company, NW Natural is not subject to the requirements of Washington's Clean Fuel Standards program. Additionally, under the Washington GHG Reporting program and Washington CCA, RNG combustion CO2 emissions are considered biogenic and not subject to CCA compliance. RNG carbon intensity does not factor into CCA emissions compliance obligations.

[34] An Overview of Renewable Natural Gas from Biogas, January 2024: https://www.epa.gov/system/files/documents/2024-01/lmop_rng_document.pdf

		https://www.ipcc.ch/report/ar6/syr/ Climate Change 2022: Mitigation of Climate Change *[14] U.S. Environmental Protection Agency. (2024, April 25). Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule. Federal Register, 89(81), 31270–31356.*	
59	WUTC	7-33 "Oregon has favorable geology…" Staff finds the Oregon-focused discussion incomplete. As this IRP is filed in Washington, the Company should clarify whether similar geologic opportunities for carbon sequestration exist in Washington and assess how state-specific policies - such as the Climate Commitment Act, Clean Fuel Standard, and HB 1257 - affect decarbonization options like RNG, hydrogen, and CCUS. Clearer differentiation between Oregon and Washington is needed to ensure Washington's decarbonization potential is analyzed with appropriate rigor and visibility.	Unfortunately, the Company does not have the same data set from similar storage formations in Washington for conventional CO2 storage as it does for the Mist Oregon region due to the Company's natural gas storage development work there. That said, the basalt formations mentioned in the scoping study apply to significant portions of Washington. The Grande Ronde Basalt of the Columbia River Basalt Group in eastern Washinton and Oregon holds an estimated 40 gigatons of CO2 storage (https://www.osti.gov/pages/biblio/2484726). The DOE also estimates traditional CO2 saline storage at up to 495 billion metric tons (https://www.netl.doe.gov/sites/default/files/2018-10/ATLAS-V-2015.pdf), which is over five times the estimate for Oregon. Development of a sequestration resource in Oregon would most likely be quicker than developing one in Washington given the head start through available data. This resource could be used to efficiently decarbonize SW Washington point sources. The Washington Clean Fuel Standard, like the Oregon and California programs increase competition and therefore increase prices for RNG and other low-carbon resources. HB 1257 enables procurement of these

			resources and is a market driver similar to SB 98 in Oregon. Washington and Oregon share many of the same policy drivers, geology, and decarbonized resource potentials, which influences the analyses and information presentation in the IRP.
60	WUTC	7-35 “Using the downscaled national and regional quantities…” Staff appreciates the refinement of low-carbon resource estimates for planning relevance but seeks clarification on the methodology behind the 33 percent “customer-weighted” allocation to NW Natural. Customer share alone may not reflect factors like siting, infrastructure, or market access. Staff encourages the Company to disaggregate Washington-specific resource access and describe how practical constraints were considered in the allocation.	The Alt Fuels Study provided 74 separate low carbon alternative options (see Appendix E for full list). This includes both downscaled national and regional quantities that could be available to the Pacific NW and their corresponding prices (i.e., levelized costs). Using the downscaled national and regional quantities, NW Natural further reduced those values as the Company applied a customer weighted value between Avista, Northwest Natural, Puget Sound Energy, and Cascade. This value is calculated to be approximately 33 percent. This customer weighted allocation is also discussed in depth in TWG #9 at minute 28:40. In PLEXOS, 90% of the downscaled resources are available for selection in Oregon and 10% are available for selection in Washington, with the exception of CCUS from Industrial customers, where the split (approximately 97%/3%) is based on actual customer make-up.
61	WUTC	Pg 8-6 “It will have significant adverse implications…” Staff acknowledge the Company’s recognition of Sumas supply constraints and related market risks. Clarification is requested on whether the gas load forecast accounts for price elasticity, supply disruptions, or fuel-switching	Please see section 11.1.3 of the 2025 IRP for a detailed discussion on the limitations around incorporating price elasticity into the load forecast. Potential supply disruptions are exogenous to the demand forecast. They are modeled in the gas price forecast, which is an input to the PLEXOS modeling.

		behavior. If so, Staff would appreciate references to the relevant assumptions or modeling. Looking ahead, Staff encourages the Company to incorporate these dynamics into future planning, given their implications for system resilience and cross-sector interactions.	Any kind of fuel-switching behavior would be reflected within customer losses in the most recent customer count forecast which is an input into the load forecast.
62	WUTC	Pg 8-12 “These are fixed costs that are incurred…” Staff request clarification on the decision to model emissions obligations and offset limits on an annual basis rather than across the full CCA compliance period. While this may simplify modeling, it may not reflect the regulatory flexibility the CCA affords - such as banking, borrowing, and trading allowances across years. Additionally, the Company appears to use per-customer counts as a proxy for gas system emissions, assuming relatively uniform usage. While this proxy may streamline allocation, it risks overlooking variations in actual Therm usage that drive emissions obligations. Staff encourage further explanation of the rationale behind these assumptions and how they may influence cost, resource selection, and compliance outcomes under real-world regulatory conditions.	The decision to model obligations and offset limits on an annual basis was not done for simplicity. Conversely, as described in Section 9.4.1.1, “[t]he initial versions of the optimization model reflected meeting obligations by compliance period, but since the model minimizes the NPV of future costs, compliance resources were being purchased on the last possible day of the compliance period for each compliance period. Operationally, intra-compliance period compliance resource procurement will be driven by many factors, such as weather, changes in customer growth, or the availability of compliance resource opportunities. IRP modeling provides guidance to achieving CPP and CCA compliance, not necessarily specifics on what compliance resources are acquired on any specific day in the forecast.” Annual constraints is an intentional decision is more reflective of how NW Natural would operate to acquire compliance resources. Staff is correct that banking, borrowing, and trading allowances will provide more flexibility, which NW Natural will utilize to these strategies to navigate variation in compliance obligations, for example from weather impacts, and take advantage of opportunities,

			such as offset purchases, that may or may not become available. This flexibility will help mitigate risks and limit compliance costs for customers relative to the modeled results that represent a road map for CCA compliance. The IRP does not dictate the exact compliance resources procurements the Company will take. The Company is unclear about Staff's concern with regards to how the Company is forecasting emission obligations and what Staff is referring to by "use-per customer count". Please see Section 4.1 that discusses the customer count forecast, Section 4.3 that discusses the use-per-customer (UPC) model and TWG #4 that discusses these models in detail. As discussed in these sections, and in the TWG, the UPC model and the customer count forecast are combined to develop the residential and small commercial load forecast. Industrial and large commercial demand is estimated at the state level. Uniform usage is not assumed across gas customers but estimated for various customer segments and developed using historical usage data for those specific customers segments. Correspondingly, emission obligation calculations use the average emissions factor for conventional natural gas. The Company's emissions obligations are set at the state level, and the Company subtracts out the contributions of any existing compliance resources already acquired. Both demand estimates and emissions estimates are validated against reported data for accuracy. Therm usage, as

			staff points out, drives emissions obligations and variation in those obligations is analyzed through stochastic weather modeling (i.e., stochastic demand) and scenario analysis. The Company conducts this analysis to take into consideration the potential year-over-year variation in emission obligations and potential variation in emissions obligations from one compliance period to the next. These considerations are reflected in the Company's action plan to comply with the CCA. Supporting details and figures can be found in Chapter 4 of the 2025 IRP. Moreover, Appendix B displays the estimated UPC coefficients, by load center and market segment, used to calculate demand.
63	WUTC	Pg 9-9 and 9-13 "Offsets available at full quantity…" Staff notes that Scenario S1.a assumes full use of offsets at the statutory maximum through 2050, yet the IRP lacks narrative addressing whether this reflects a cost containment strategy, long-term reliance on offsets, or a placeholder for future emissions abatement. The assumption that offsets will remain fully available and affordable over the entire planning horizon deserves further clarification, especially given market uncertainties and policy emphasis on direct in-state reductions under the CCA. Additionally, Staff notes that in Scenario S1.b, Washington's compliance path relies heavily on allowance purchases, while Oregon's includes physical decarbonization investments such as RNG and hydrogen.	NW Natural evaluated several different sensitives where varying levels of offsets are available in order to compare costs and resource selection. In S1a, offsets are available at full quantity; 8% of the obligation in each year for the first compliance period, and 6% starting in 2027 for the rest of the planning horizon. If offsets are the least-cost resource, they will be selected. S1a is not meant to represent NW Natural's expectations, but rather, what could be a low-cost compliance pathway. All other scenarios, sensitivities (with the exception of S1c), and stochastic analysis, limit offsets twofold; first, they are not available until 2027 and, secondly, they are limited to 3% of the compliance obligation per year. In S1c, offsets are not available for selection.

		When normalized by customer count, Washington's modeled compliance costs appear roughly 40% higher per customer—raising equity concerns about long-term affordability and the distribution of compliance benefits. Staff encourage the Company to clarify the strategic role of offsets in each scenario and to evaluate how compliance strategies affect customer equity and long-term resilience. Incorporating tools such as equity-weighted cost metrics, scenario comparisons, or distributional analysis could help inform more balanced and transparent planning in NW Natural 2025 IRP.	The limitation of offsets being available below their full amount in the PRS is an intentional change from the 2022 IRP, where offsets were modeled at the full amount in every scenario. A description in 9.4.2 was added describing the reason for limiting offsets to three percent in the PRS. Because offsets are limited to a relatively small percentage of the compliance obligation, they make up a relatively small percentage of the net present value of CCA compliance costs, as seen in Figure 9.8. In scenario S1b, allowances are selected as the least cost resource. CCUS and RNG from waste water are also selected as they become cheaper than allowances. Additionally, with ongoing conversations of risk sharing at the UTC under docket U – 230161, there is more risk to the company and shareholders to pursue other means of compliance for the WA CCA. *Note: There was an error in the costs for CCA compliance costs presented in the draft due to a formula error not accounting for retained no cost allowances and revenue from the consignment allowances. This number is updated.*
64	WUTC	9-15 "The resource acquisition graphs and annual cost graphs..." While the IRP models sensitivities such as S1B and S1D, it does not appear to evaluate or optimize compliance portfolios centered on physical decarbonization (e.g., RNG, hydrogen, or energy efficiency). All scenarios rely heavily on allowance purchases through 2045, without assessing	Natural gas local distribution companies are not subject to the requirements of CETA, however NW Natural remains committed to exploring decarbonization mechanisms and they were modeled as CCA compliance options in this IRP. Due to the lower price of allowances in WA vs. OR CCI's (and CCI limits), the

		how this approach supports long-term compliance with Washington laws or mitigates market and cost risks. Staff encourages the Company to clarify whether alternative decarbonization-focused portfolios were considered and to provide future analysis explaining how sustained allowance reliance aligns with CETA goals and protects Washington customers from regulatory and affordability risks.	model selects allowances over other decarbonization technology and fuels.
65	WUTC	Pg 10-2 "As building decarbonization and electrification accelerate…" As electrification advances, NW Natural may face increasing difficulty recovering fixed gas system costs from a shrinking customer base. This poses long-term affordability and equity risks, particularly for low-income customers who may be least able to transition off gas. While the IRP acknowledges this dynamic, it lacks modeling of cost recovery pressures under high-electrification scenarios. Staff encourages the Company to assess at what point fixed costs may become unsustainable, and to explore potential mitigation strategies - such as accelerated depreciation or coordinated infrastructure planning - to reduce equity and stranded asset risks.	The Company has discussed this several times in meetings with Staff, and looks forward to further discussion on this topic. In particular, as electrification advances, it too could pose long-term affordability and equity risks to electric customers. Rather than attempt to Identify a specific point in time to determine when a cost becomes unsustainable (for either energy system), NW Natural is supportive of joint system planning with electric utilities to comprehensively plan and leverage the strengths of both energy systems to best optimize the systems and mitigate harms to customers. Please see the Executive Summary, Chapters 11 and 13 for additional information in terms of the Company's approach.
66	WUTC	Pg 10-4 "Many have noted the "close call" events…" The IRP attributes rising electric rates and reliability concerns to electrification, referencing the January 2024 cold weather event. However, this framing omits key context. Recent electric rate increases reflect multiple	In response to Staff's comment, the Company has added a critical assumption section to Chapter 11 which includes assumptions to both electrification approaches, as well as modest electrification and gas decarbonization via CCAs and alternative fuels or CCUS.

		drivers—wildfire mitigation, T&D upgrades, and market volatility—not electrification alone. Similar volatility has affected gas rates. The January event was weather driven, and regional grid reliability was maintained through existing contingency planning. The analysis also omits Washington policies - such as CETA, HB 1257, and the State Energy Strategy - which establish electrification as central to long-term decarbonization. Absent are discussions of public health, emissions, or long-term cost benefits. Staff encourages NW Natural to present electrification in a more balanced, policy-aligned manner, with clearer comparisons of fuel costs, reliability planning, and emissions impacts	Following this section is a discussion of how this all fits together to inform the Company's action plan.
67	WUTC	Pg 12-3 "The planning process is continuous…" Given that the 2025 IRP relies on a 2023 CPA, Staff request clarification regarding how customer growth assumptions are incorporated into the load forecast - and whether these assumptions reflect Washington-specific trends. As the CPA should use customer counts from the IRP's load forecast, transparency regarding how those counts were developed and how frequently they are updated is critical. Staff anticipate that the final IRP include either a reference to the most recent Washington-specific customer growth study used to inform the load forecast, or a clear	The 2023 CPA conducted by AEG used the latest customer count forecast available in the Company's service territory in Washington at that time. The savings associated with residential new construction homes for this IRP were set to zero as the new homes program in Washington has ceased. The Company updates its customer count forecast regularly and the 2025 CPA uses the most recent customer count forecast.

		description of the Company's process and frequency for updating growth assumptions.	
68	WUTC	Pg 13-8 "Increase community awareness of/involvement…" Staff notes that equity is represented as a placeholder in the Draft IRP's 5-year Action Plan, pending further development prior to the final filing. While Staff appreciates NW Natural plan to include equity in future actions, the absence of specific near-term commitments may raise concerns about how equity is operationalized within NW Natural's resource planning. Staff encourages NW Natural to include, in the final IRP and future filings, specific equity-centered actions - such as targeted stakeholder engagement, equity-informed program design, and the development of relevant metrics - to more clearly demonstrate alignment with Washington's clean energy goals.	Action item B-32 is not intended to be a placeholder in the Draft IRP's 5-year Action Plan. Action item B-32 reads: *Increase community awareness of/involvement in energy planning and utility programs by partnering with trusted community partners and service providers (including peer/local utilities) to bring forward an annual resource fair centered on energy planning topics and resources.* Language on action item B-32 has been added to Chapter 3 for continuity. Including a specific near-term action related to energy planning outreach and engagement was intended to enhance procedural equity and does not replace the suite efforts that the Company has built upon over the last IRP cycle or efforts the Company undertakes to reach energy burdened customers in its territory, rather it supplements them.
69	WUTC	The placement of a 15-page glossary and abbreviation section ahead of the executive summary reduces accessibility of the plan's key findings. To enhance usability and support stakeholder engagement, Staff suggest the Company consider relocating this material to after the executive summary	In response to Staff's suggestion, the Glossary and Abbreviations section has been moved. A note at the front of the Executive Summary has been to indicate where the Glossary and Abbreviations can be found. The Company continues to work to make a very large, dense, and complex document accessible to multiple audiences. Bookmarks supplied within the PDF as well as navigable/cross linked Table of Contents, Table of Tables, and Table of Figures are meant to support usability of the document. Additionally, page numbers and headers are set up to help guide a reader.

70	WUTC	While the IRP briefly references equity, a more comprehensive and upfront analysis is needed to support a clear understanding of its implications. The resource planning decisions outlined in the IRP will result in material outcomes for customers, and without equity as a guiding framework, the plan risks overlooking the needs of historically underserved and overburdened ratepayers in NW Natural's Washington service territory. As the state continues to advance equity-centered energy policy, Staff emphasizes that integrating equity as a core component of utility planning is necessary to align with Washington's regulatory expectations and to ensure that resource decisions account for the needs of historically underserved and overburdened communities. Staff anticipates seeing these integrations in future IRP filings.	Chapter 3 discusses equity beginning from a high level discussion of concepts and regulatory frameworks to help set the context for the reader. The chapter acknowledges the work ahead (with language added for clarity in the final IRP) while also noting the array of work underway to support the needs of energy burdened and historically underserved communities in NW Natural's service territory. As noted in Section 3.4.1, the Energy Burden Assessment is one tool which the Company has utilized to inform its energy affordability programming. Additionally, the section provides a summary of the Gas Residential Energy Assistance Tariff (GREAT) Advisory Group which is a Washington specific advisory group. NW Natural looks forward to working with Staff as it develops its next and future IRPs. The Company is interested to understand the details of Staff's expectations as well as to learn more from those involved in the Washington Equity Docket, A-230217, as the docket progresses into its next phases over the next couple of years.
71	WUTC	Pg 3-1 "This chapter signals NW Natural's intent…" The IRP mentions that it lines up with major Washington policies like the Clean Energy Transformation Act (CETA), the Climate Commitment Act (CCA), and House Bill 1257. But Staff doesn't see much evidence that equity goals from these laws are actually shaping NW Natural's core planning decisions.	The Company looks forward to more engagement on this topic. Chapter 3 details the actions NW Natural took to strengthen inclusive, informed, and meaningful public engagement specific to the 2025 IRP—core elements of procedural equity and justice. Section 3.5.2 of the IRP details how CEAG feedback shaped the IRP's procedural equity framework, including the development of multilingual outreach

		The plan would be stronger if it clearly showed how equity is built into: 1. Key planning assumptions (like how affordability or access to programs is considered), 2. Decision-making (such as how equity factors into picking resources or weighing scenarios), 3. Community engagement (especially with overburdened or historically underserved groups), and 4. Comparing different options (looking at trade-offs with an equity lens). Staff would appreciate an explanation of how NW Natural defines and identifies overburdened or energy-insecure communities in Washington, and how those communities' needs are reflected in the plan. This would help show that NW Natural isn't just talking about equity—it's acting on it in a way that meets Washington's policy and regulatory goals	materials, in-person events like the Winter Preparedness Fair, and updates to the Company's IRP webpage. Clarifications have been included in Chapter 3. Appendix I and Appendix D further share community engagement efforts. NW Natural refers to the Department of Energy[35] and other[36] resources, such as Commission Orders,[37] to define its working energy justice terms and concepts. These have been included in Chapter 3 and Appendix I. Chapter 3, additionally discusses energy burden and how burden is calculated per the Energy Burden Assessment. The Company would like to meet with Staff to continue discussions on this important topic.

[35] Definitions were previously available under the Biden Administration through the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy website. See also U.S. Department of Energy. "How Energy Justice, Presidential Initiatives, and Executive Orders Shape Equity at DOE." Office of Energy Justice Policy and Analysis, 2023: https://www.energy.gov/sites/default/files/2024-02/Energy%20Justice%20at%20DOE_untagged_0.pdf.; U.S. Department of Energy Policy DOE P120.1: https://www.directives.doe.gov/directives-documents/200-series/0120-1-apolicy/@@images/file; https://www.energy.gov/sites/default/files/2024-02/Energy%20Justice%20at%20DOE_untagged_0.pdf.; U.S. Department of Energy https://www.directives.doe.gov/directives-documents/200-series/0120-1-apolicy/@@images/file

[36] "The Energy Justice Workbook" Initiative for Energy Justice, 2024: https://iejusa.org/section-1-defining-energy-justice/1, National Conference of State Legislatures, "Energy Justice and the Energy Transition" NCSL, 2022.; "Incorporating energy justice throughout clean-energy R&D5 in the United States: A review of outcomes and opportunities", Arkhurst, Bettina K. et al. Cell Reports Sustainability, Volume 1, Issue 2, 100018

[37] See WUTC docket No. UG-210755, Final Order 09.