2025

Natural Gas Integrated Resource Plan




Appendix

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APPENDIX 1.1: TAC MEMBER LIST

Organization	Representatives	
Applied Energy Group	Kenneth Walter	Andy Hudson
Avista	Shawn Bonfield	Catherine Mair
	Kim Boynton	Scott Kinney
	Annette Brandon	John Lyons
	Terrence Browne	Jaime Majure
	Michael Brutocao	Lisa McGarity
	Josie Cummings	Joey Nguyen
	Kelly Dengel	Austin Oglesby
	Justin Dorr	Tom Pardee
	Grant Forsyth	Heather Rosentrater
	James Gall	John Rothlin
	Amanda Ghering	Erik Soreng
	John Gross	Jason Thackston
	Lori Hermanson	Jeff Webb
	Mike Hermanson	Jared Webley
	Clint Kalich	Michael Whitby
Biomethane, LLC	Kathlyn Kinney	
Cascade Natural Gas Company	Brian Robertson	Mark Sellers-Vaughn
	Bailey Steeves	
Citizens Utility Board of Oregon	General Email for CUB	
City of Spokane	Logan Callen	
Eastern Washington University	Erik Budsberg	
Energy Trust of Oregon	Ben Cartwright	Spencer Moersfelder
	Hannah Cruz	Adam Shick
	Kyle Morrill	Willa Pearlman
Oregon Department of Energy	Michael Freels	
Oregon DEQ	Nicole Singh	Matt Steele

Energy Strategies	Jeff Burks	
Fortis	Ken Ross	Jesse Scharf
Idaho Public Utility Commission	Donn English	Mike Louis
	Michael Eldred	Victoria Stephens
	Terri Carlock	Jason Talford
	Rick Keller	Joseph Terry
	Kimberly Loskot	Taylor Thomas
Intermountain Gas	Raycee Thompson	Lori Blattner
	Dave Swenson	
Lewis and Clark Law School	Carra Sahler	
Metro Climate Action Team	Pat Delaquil	
Northwest Energy Coalition	Charlee Thompson	
Northwest Gas Association	Dan Kirschner	
Northwest Natural Gas	Michael Meyers	
Northwest Power and Conservation Council	Steve Simmons	
Oregon Public Utility Commission	JP Batmale	Kim Herb
	Ted Drennan	Sudeshna Pal
Puget Sound Energy	Jennifer Coulson	Hannah Wahl
	Gurvinder Singh	
RNG Coalition	Vincent Morales	
Sierra Club	Jim Dennison	
Washington State Office of the Attorney General	Jean Marie Dreyer	Stefan de Villers
Washington Utilities and Transportation Commission	Sofya Attitsogbe	Byron Harmon
	Emily Gilroy	Heather Moline

Appendix 1.2: OPUC Draft Feedback

<u>Chapter 2: Preferred Resource Strategy</u>	<u>Avista's Response</u>
1. Per Recommendation 3, Staff appreciates Avista's efforts to develop alternative resource portfolios. The 5 presented scenarios, as well as 12 sensitivities applied to the PRS, provide desired insight as to how the selection of resources varies across different futures.	
2. While expressed as a recommendation (Recommendation 5) for future Avista IRPs, Staff appreciates Avista's modeling the comparative costs for a high-growth scenario as well as a high-electrification scenario, which begin to address Recommendation 5 urging Avista to model all relevant distribution system costs and capacity costs as well as describe the associated projects-needed-, and costs-incurred-, from high and low load scenarios. Staff requests that Avista's filed IRP specify any differences in anticipated near-term procurement (including specific projects which Avista might already be considering) between the high load scenario and the PRS.	Distribution is not expected to exceed forecasted projects currently found in Chapter 10 in any case modeled in the 2025 IRP. However, if new large customers request service in a specific area not forseen in these distribution upgrades it may require additional distribution needs other than those projects included. It is unknown how Avista would estimate the location and upgrades needed, if any, unless specifics around volumes and location are provided by these large customers.
3. In the filed IRP, please include a narrative description about the drivers of alternative fuels resources selection in the high and low-cost alternative fuel cost sensitivities.	Updated in the document in Chapter 6.
<u>Chapter 3: Demand Forecast</u>	
1. Staff appreciates Avista basing its load forecast upon the RCP 4.5 GHG mitigation scenario, its description of the implications of the varying RCP scenarios, and its estimation of future temperatures and modeled HDD's.	

a. Additionally, Staff recognizes Avista's inclusion of a scenario of future weather informed by the RCP 6.0 model, per Expectation 5.	
2. Staff recognizes, per Expectation 3, that Avista modeled a load forecast reflecting GCM trends and appreciates the Company's responsiveness in its downscaling of the Multivariate Adaptive Constructed Analogs (MACA) methodology to its Oregon service territory regions of Medford, Roseburg, and Klamath Falls.	
3. Per Expectation 9, Staff appreciates Avista's application of IRA credits to the specified electrification resources including space heating, water heating, and other appliances across residential and commercial customers. Staff asks that Avista, in its IRP, describe whether and how policy uncertainties surrounding the IRA have an impact on Avista's modeling for electrification.	Updated in the document in Chapter 7. In short, in the absence of the IRA all resource costs would be expected to increase
4. Per Expectation 8, in the filed IRP, please describe how the line extension allowance decision from Docket No. UG 461 is reflected in the load forecast modeling.	This can be found specifically in the "No Growth" case in Chapter 8. Oregon and Washington line allowances go away in 2026 and 2025 respectively. The building code requirements in Washington are expected to drastically reduce new customers to the LDC, but in Oregon similar building codes have yet to include the requirements for heat pump related space and water heating. Avista will continue to monitor new customers added to the system to provide updates on how the line extension policy may change customer hookups to the LDC.

5. Per Expectation 6, Staff requests that Avista include in its 2025 IRP Update, a scenario of no future customer growth beyond 2027.	This can be found specifically in the "No Growth" case in Chapter 8. Oregon and Washington line allowances go away in 2026 and 2025 respectively.
<u>Chapter 4: Demand Side Resources</u>	
1. Per Recommendation 7, in the filed IRP, please describe whether the Company used advanced metering infrastructure (AMI) data and Form 10Q data to capture customer behavior, as expected through Expectation 7 (originally Staff Recommendation 7) from Order No. 24-156.	Avista does not have AMI located in it's Oregon territory so this is not an available avenue for this IRP. Instead of the options in recommendation 7 Avista contracted with AEG to develop an end use forecast to estimate the number of customers that may choose to naturally convert to electric end uses.
a. If AMI and Form 10Q data weren't used in inform the rate of electrification occurring naturally among Avista customers, in the filed IRP, please describe Avista's reasoning for not deploying such methodology and any feasibility challenges faced by the Company in doing so and what steps might need to be taken to consider inclusion of this data in the Company's 2027 IRP.	With the lack of detailed information in a 10Q and no AMI infrasturcture in Oregon, Avista
<u>Chapter 6: Supply-Side Resource Options</u>	

1. Per Expectation 2 from Order No. 24-156, Staff requests that Avista include in its 2025 IRP Update-, an RNG procurement update including a comparison of projected and actual procurement; RNG prices secured; a description of how the Company has leveraged other carbon markets to reduce RNG costs; and how the Company is applying the environmental attributes of the RNG procured to CPP compliance.	Avista has provided this update in Chapters 5 & 6. An annual alternative fuels RFP was released in 2024. With the CPP rules not yet finalized, costs were not available to compare program offsets (CCIs) to these alternative fuels. An RFP will be released in 2025 to help measure resource options to secure the least cost resource for CPP compliance.
2. Staff request that Avista provide to Staff all of the details, data and assumptions associated with ICF's study for modeling available-, and technical potential-, volumes and prices of alternative fuels [See Figure 6.4]	A full resport is available in Appendix 6
3. Hydrogen, CCUs and synthetic methane projects seem to be planned to take effect after 2030 and 2037. In the filed IRP, please explain how is modelling addresses Staff's concerns in the previous IRP about procurement and readiness of adoption of emerging alternative fuel options.	Neither Hydrogen nor Synthetic Methane is selected in the PRS. CCUS is selected, but due to uncertainty around costs and practicality, further time is needed before considering this resource in an action plan.
Chapter 7: Policy Considerations	
1. Concerning Request No. 10 from Staff's report included in Order No. 24-156, Staff appreciates Avista's demonstration of costs associated with CCIs. Staff further requests that Avista include price forecasting for the nominal per metric ton of carbon dioxide equivalent (MTCO2e), parallel to Figure 7.4, for renewable thermal credits (RTCs).	Updated in the Chapter
Chapter 9: Customer Equity and Metrics	
1. Please provide any information and workpapers associated with the NEI study conducted by ICF.	Implan NEI summaries are available in Appendix 9.
Chapter 10: Distribution Planning	

2. Staff recognizes and appreciates Avista's presentation and detail of the updates to the Company's methodology for analyzing NPAs, as previously detailed in Expectation 23 from Order No. 24-156.	
3. Staff appreciates Avista's update regarding the latest information on possible distribution projects, including any proposed traditional investments or proposed NPA, as requested by Staff Request 4 in Order No. 24-156.	
<u>Chapter 11: Action Plan</u>	
1. The Draft IRP does not mention or include the assumptions of pipeline project Aldyl A in 2037, which is in the process of being replaced, nor its implications on supply side projections. Staff requests that Avista describe any relevant assumptions and impacts to supply side projections, of the Aldyl A project, within its 2025 IRP.	Updated to include these details

<u>Chapter 8: Alternative Scenarios and Sensitivities and Risks</u>		
Topic	**Staff Feedback**	**Avista Response**
Responsiveness to Order 23-156		
Recommendation 3: Regardless of the analytical approach taken to create the PRS, future IRPs should include alternative resource portfolios that represent different utility decisions.	Staff reiterates its appreciation for Avista's modeling of 5 scenarios including the PRS (or base case), and 12 sensitivities. Staff looks forward to reviewing all forthcoming workpapers and additional information regarding the refined set of scenarios and sensitivities provided by Avista.	

	Staff notes that while chapter 8 incorporates several scenarios, the sensitivities seem to focus on the baseline PRS with less exploration of other scenarios. Staff requests that summary descriptions figures, and associated analysis are provided for the resiliency and diversified portfolio selection scenarios, which parallel those included for the PRS, social cost of greenhouse gas, and no climate programs scenarios (pages 8-4 through 8-6 of the draft 2025 IRP).	The PRS is the expected case with load growth and future characteristics we primarily plan for furture resources and costs. Other scenarios, while important, are not directly comparable to the PRS because of different futures. If one were to compare them, inaccurate outcomes would occur as the future has changed. These alternative growth/demand futures are to estimate costs and risks in the event they occur. For example, choosing a set of resource for the "high electrification" scenario is not comparable to the PRS as the expectations vastly differ from one another. Comparisons are made available throughout chapter 8 showing how resource selections and costs differ.
	Staff requests that Avista further clarify whether:	
	• The resiliency and diversified portfolio selection scenarios should be included under the section for sensitivity forecasts.	Resiliency and Diversified portfolios are considered a scenario as shown in Table 8.1. They have numerous changes like weather, peak demand or resources that are forced in (Diversified Portfolio) to consider reliabillity and costs of these resources.
	• The presented high electrification sensitivity is indeed a sensitivity or rather a scenario, given the introductory language on page 8-11, "This scenario considers a loss of demand due to building electrification…".	adjusted language in the high electrification case from "scenario" to "sensitivity". It is a sensitivity as the load reduction begins with expected loads in the PRS and drives downward each year by an average of 4%. In this case, only the served load changes with resources selected around this new load.
	• The removal of the high load growth scenario, between what was presented during Avista's TAC meeting number 2 (April 4, 2024) and the draft 2025 IRP, was the result of feedback provided by TAC members. If so, Staff requests that Avista cite any feedback used its decision-making process.	The High growth sensitivity is an alternate case to show a higher than expected demand from increased customer growth. Although Avista considers this unlikely, it does help to show risk bands for plausible future outcomes. This case can be found in Chapter 8.

Recommendation 4: Future IRPs should include stress testing of the PRS and alternative resource portfolios and provide metrics comparing the severity and variability of risk in alternative portfolios.	Staff appreciates Avista's responsiveness to the application of stress testing to the presented scenarios, as discussed on page 8-3 and Figure 8.34. In Avista's 2025 IRP, Staff requests that a similar analysis is provided for the alternative scenarios and their selected portfolios, as is provided for the PRS in steps 1-4 outlined on page 8-33.	Avista has provided this illustration in Figures 8.32 to 8.38 to show the risks of these scenarios through 500 Monte Carlo draws to estimate alternative fuels volumetric risk, price risk of resource and demand risks from varying weather. Additionally, these costs and risks are shown in Figures 8.24 to 8.26.
	As mentioned earlier, the current focus of the alternative scenario analysis is based on the baseline PRS, Staff believes that the value of the stress testing would be greater if it were also conducted on alternative resource portfolios, with PRS results presented alongside alternative portfolios results. Doing so would help assess decisions the Company may make, and the risks associated with those decisions, resulting in an even more useful planning process.	Monte Carlo runs are helpful to understand risks for the selected resources based on the specific changes. When comparing scenarios and sensitivities, a deterministic model is useful to help show cost variability based on different assumptions. If Avista were to compare all scenarios and sensitivities, based on statistics, the costs would average out to roughly those costs as depicted in the deterministic scenarios. For this reason, using Monte Carlo on all cases evaluated is not helpful as they use the same values. The PRS is the most reasonable to run a Monte Carlo for risk of differing prices, loads and volumes available as it is the expected future.
Recommendation 6: Avista work with the TAC to develop additional scenarios and sensitivities for the next IRP, including for example: greater price variation for low carbon resources, high-cost for low carbon resources, omission of any highly uncertain resource, or utilization of only existing resources.	Staff appreciates Avista's efforts to work with the TAC to develop sensitivities according to high-, and low-, costs for low carbon resources, as demonstrated in Figures 8.7 and 8.14 respectively. Staff further observes that Avista provided a scenario that considers current resources used for the 2025–2045-time horizon through its No Climate Programs scenario. Additionally, Staff recognizes Avista's efforts to explore alternative fuels like hydrogen, RNG and synthetic methane, and modeling the uncertainty surrounding their adoption. While Staff's feedback here does not represent its final findings, Staff understands Avista's efforts listed above as the Company being responsive to Recommendation 6 from Order No. 24-154.	

Request 1: Future IRPs should include a clearer explanation of the PRS, and a more transparent presentation of the assumptions and processes used in creating the PRS, including examples noted by Staff.	Staff appreciates the additional detail regarding the development of Avista's PRS and associated stress testing on page 8-33, as well as the detailed information regarding modeled supply and demand side resources in chapter 2.	
Expectation 6: For the next IRP, include a scenario of no future customer growth beyond 2027.	Staff recognizes that Avista models a demand forecast of 0.68% lower than previous submissions in acknowledgement of the actual anticipated low demand projection in Oregon and Washington going forward. However, Avista doesn't appear to model a no customer growth scenario. Staff reiterates its request that Avista include in its 2025 IRP a scenario of no future demand / customer growth beyond 2027 to fully understand the implications of a flat customer base on the system demand and long-term cost structures.	Based on feedback and for transparency a no growth case is included in Chapter 8. In the draft version, Avista did not show a no growth case as many other scenarios show the same demand trajectory including the Low Natural Gas Use Case.

Expectation 10: Scenarios and sensitivities developed for the next IRP should include complex possible futures that capture plausible sources of risk due to uncertainty; Avista should explore its resource portfolios against these scenarios. Avista should run stochastic analysis for price and demand assumptions consistent within scenarios and report risk severity metrics for each scenario.	Staff appreciates the efforts that Avista has made in the employment of stochastic modeling and Monte Carlo simulations to assess the variability across multiple portfolios and scenarios providing some level of analysis to evaluate risk.	Uncertainties include expected weather by planning region impacting demand, volumetric availability of alternative fuels, peak day planning with increasing or decreasing loads, natural gas price volatility, and alternative price volatility. Avista modeled 9 cases where demand specifically is varied from the PRS and impacts to the resources required and timing of those resources. The weather stochastics can be found in Figures 3.27 to 3.31. Additionally, price risks for natural gas can be found in Figures 5.4 and 5.6 for the 500 stochastic prices used in the IRP. Alternative fuels risk is shown in Figures 6.16 to 6.21 by resource type. The combination of these risks is evaluated in Chapter 8 under the Monte Carlo Risk Analysis section. All identified scenarios are run through a 500 draw monte carlo risk analysis and the PRS, and it's expected case attributes, are further run through a set of 5 - 500 draw Monte Carlo analyis by portfolio % to help determin the lowest risk and cost set of resources in our expected future. As mentioned previously, running stochastics on alternative sensitivities would all average out to what is being shown in the deterministic runs as the same data sets are used for all scenarios and don't differ as this would not be comparable or help find a solution to the expected load. Efforts will be made continually to address these scenarios to provide as

	Page 8-3 explains that the scenarios "consider plausible futures with critical uncertainties...". In the filed IRP, Staff asks that Avista provide a description of uncertainties considered in their modeling, how they are reflected in that modeling, and explain whether and how uncertainties resulted in changes in the scenarios, and how they would influence the utility's decisions.	accurate of growth and cost expectations as possible. Avista continually estimates short term demand and reflections in actual variations compared to future expectations will be included in future IRPs. In the event these expectations begin to drastically differ from expectations Avista will include the savarity of these changes in demand growth and load expectations.
Expectation 16: The next IRP include electrification modeling assumptions that decrease capacity costs, distribution system costs, and other appropriate expenses corresponding with reduced demand from electrification	Staff appreciates that Avista has included high electrification as part of its sensitivity analysis. In the filed IRP, Staff asks that Avista clearly describe and support all electrification modeling assumptions, and explain how those assumptions reflect decreased capacity costs, distribution system costs, and any other appropriate expenses corresponding with reduced demand from electrification. Staff requests that Avista specifies any differences in assumptions used for the modeling of electrification in its 2025 IRP PRS relative to its 2023 IRP PRS.	Additional description has been added to the High Electrification case. In short, costs may go down once decommissioned, but if a single customer were to remain on the line, Avista would be required to maintain the safety and reliability of any individual lines. The methodology to identify these specific lines is not available in CROME as it is a resource optimization model intending to solve least cost/risk for demand and available resources. The planned distribution upgrades in Chapter 10 would still be required as these upgrades are necessary in the short term. No distribution projects are expected outside of the 5 year action plan.

Expectation 17: Future IRPs should include a scenario with significantly increased residential heat pump adoption and the corresponding shift in winter load from the gas system to the electric system.	Staff seeks clarification regarding whether Avista's electrification sensitivity is how the Company is being responsive to Expectation 17. In the filed IRP, for the high electrification sensitivity, Staff requests that Avista attempt to distinguish between the impacts to forecasted load of electrification through increased heat pump adoption as opposed to the electrification of other equipment.	All scenarios include increased residential heat pump adoption as described in Chapter 3. Naturally occurring heat pump adoption, among other end uses, are shown in Figures 3.9-3.14. Additionally, the demand by state in Figures 3.5 to 3.9 show the amounts of demand by end use remaining in the PRS. Similar percentages can be derived based on these percentages for the high electrification case. The hybrid case is also useful in this expectation.
Expectation 18: Avista should work with the TAC to more fully explore and model the potential of dual fuel heat pumps in the next IRP, for example by ensuring that the use of some dual fuel heat pumps is represented in Monte Carlo risk analysis	Staff appreciates Avista's inclusion of Hybrid Heating sensitivity which allows for the impact of electric heat pumps alongside natural gas furnaces. However, Staff cannot determine whether a Monte Carlo analysis was conducted in which historical dual fuel heat pump data is used to construct a probability distribution; for which a specified percentile of hybrid heating load-impact over the 2025-2045 time horizon is applied to the PRS's load forecast. However, Staff cannot determine whether a Monte Carlo analysis was conducted to capture the probability and range of potential adoption rates for dual fuel heat pumps over the 2025-2045 horizon. Staff requests that Avista provides a description of the hybrid heating assumptions including the sources of data used and how the data informed load forecast. In the filed IRP, please describe how the stochastic analysis was used to represent uncertainty around dual fuel heating uptake and ultimately through PRS.	A monte carlo analysis was not run for the same reasons as mentioned above (recommendation 4). Avista did further modeling on the heat pump and COP curve to allow for additional uptake in heat pumps outside of naturally occurring electrification as discussed in expectation 17. updates and descriptions have been made to this case and can be found in chapter 8.

Expectation 20: Staff expects Avista to work with the TAC to identify a PAC IRP scenario reflecting electrification that Avista might use to generate a load forecast for its next IRP. Before the next IRP, Avista should work with PAC to collect the load forecasts used in planning that most closely reflects a building electrification scenario for the overlapping territories. With these load forecast results, Avista should discuss with PAC supporting commentary regarding supply-side and demand-side resource impacts, rate impacts, and associated GHG emissions with each scenario/ portfolio. Avista should discuss with the TAC the extent to which the Company might be able to model the equivalent in its next IRP.	Staff recognizes Avista's efforts to model electrification scenarios and sensitivity analysis and appreciates its work in attempting to capture electrification costs in overlapping electric territories. It is Staff's understanding that Avista has not included other PacifiCorp's load forecasting in its electrification scenario modeling to date. In its filed IRP Staff asks that Avista describe its efforts to be responsive to this expectation and provide any outcomes of this effort to date.	Avista did not consider this for the following reasons: -in order to get a scenario from PAC and sufficient data to accurately depict in an electrification scenario, Avista would need to work with all IOU, PUD, and CO-Ops to get their costs and estimates as well for an accurate comparison of electrification growth by area. Otherwise it's taking only a piece of growth expectations into consideration. For example: If we were to only get this information from PAC and apply it to La Grande with Oregon Trail Electric or the City of Ashland, these growths may not be comparable due to climate and economic factors. Another concern is which forecast we use for these efforts? Is the most recently filed IRP appropriate or should it be based on the last acknowledged IRP for PAC? Finally, in these service areas outside of PACs service territory what is a reasonable recent forecast in terms of time frame to use in these cases with the understanding they may not provide growth projections as they may not submit a bi-yearly filing? Avista will look for possible methodologies to consider this in the 2027 IRP and may reach out to the OPUC to help guide this effort.
Other Feedback		
Miscellaneous	Staff notes that chapter 8, page 33, addresses Figures up to 8.40 and that Figures 8.37-8.40 appear to be missing. Please include Figures 8.37-8.40 within Avista's 2025 IRP.	All figures will be corrected in the final IRP filing
CROME Modeling & Workpapers	Staff requests that Avista provide to the Commission at the time of filing all supporting workpapers for Avista's CROME modeling of its PRS as well as alternative scenarios and sensitivities modeling	Avista will have all available non-confidential workpapers posted to the IRP website by the filing date. Any confidential workbooks such as CROME can be made available through a confidential filing with the commissions

Monte Carlo Risk Analysis and Workpapers	At the time of filing, please provide any workbooks detailing the historical data used in Avista's Monte Carlo risk analysis, particularly concerning natural and renewable gas prices, allowance prices, and weather forecasts as noted on page 29 (of chapter 8) of Avista's 2025 Draft IRP.	These will be provided at the time of filing

Appendix 1.3: WUTC Draft Feedback

Feedback	Response
1. Accessibility and Equity Considerations	
• Consider revising the Introduction (p.1) for accessibility by using plain language to enhance comprehension.	Added language for clarification
• It may be helpful to ensure that procedural equity is considered throughout the document, making it more accessible for interested parties with varying levels of technical expertise (e.g., p. 1-9: "Trended coldest on record to the % of overall weather future reduction in heating degree days by 2045", and p. 20-5: "Carbon Policy Resource Utilization Summary").	Avista has clarified this sentence and has tried to do the same for the entire document.
• Consider assigning the same color to the resource on all figures (e.g., Figures 2.21-2.25).	Updated in document
2. Data Transparency and Clarity	
• Figures 2.7-2.10	
○ These figures might benefit from showing change over time in a different format.	Avista will work to provide an updated format for these figures in the 2027 IRP
○ Improving the placement of these figures so they are closer to their relevant discussions would enhance readability and comprehension.	Updated within the document.
○ Does average case demand mean year-around daily average or the average on a peak day?	Average case demand uses a 3 year base and heat coefficients by area, combined with expected EE and excludes peak days
○ Consider disaggregating these figures for each service area.	Updated document for all cases
• Clarifications on customer classification:	
○ Further elaboration on how future policy changes might affect different customer segments would strengthen this section.	Updated in the document
○ Consider providing rate impacts analysis here.	Updated in chapter 8 to compare to all cases
3. Modeling and Methodology Considerations	
• CROME Model:	
○ Would it be possible to provide us with training or resources to help us better understand and utilize this model?	Avista staff is available for questions or training on this model at any time
○ Are there any available plugins or extensions that Staff might need for recreation of the results?	A "What's Best" license from Lindo Systems would be required to recreate these results

○ Figures 2.1-2.3: in Resource Integration, you state that you forecast 11 service areas. Consider adjusting the figures to reflect that.	These service areas are based on physical deliverability of pipelines and are grouped to provide results for demand regions to provide an understanding of what is needed to serve these specific areas.
• Electrification Assumptions (p.13, p.35, p.50):	
○ Some stakeholders might benefit from additional clarity on whether assumptions regarding voluntary electrification and gas demand decline are too conservative or need adjustment.	No stakeholder feedback has been provided to Avista during the TAC process or in the meeting, to date. If feedback is provided, we will consider altering these expectations in the 2027 IRP.
4. Greenhouse Gas (GHG) Compliance	
○ Figure 2.5: consider reflecting the auction ceiling and floor prices on the graph.	For clarity purposes, it may confuse the general reader. This is available in Figure 7.8.
○ Would transport customers have access to the same compliance mechanisms? Clarifying this could be useful.	Updated in the document
5. Resource Planning and Future Demand	
• Figure 2.6: this x-axis might be clearer if you use month names.	Avista tried to find a format but was unsuccessful. We'll work on this for the 2027 IRP.
• "This IRP assumes pipelines will file to recover costs at rates equal to increases in GDP." - What would be the implications of this assumption? (p. 2-5)	If rates come in higher or lower based on customers and the tariff design, costs of transporting this gas may change the least cost resource selections.
• How would the portfolio behave in the case of Canadian tariffs on gas imports, particularly from AECO?	Avista currently obtains 83% of its total natural gas from Canada and 17% from the Rockies region. Historically, AECO is the lowest cost basin and while adding 10% tariffs to this gas, the overall resource selection is unlikely to change due to this gas being least cost along with our interstate transportation rights deliver from Canada.
• Figure 2.3: WA territory is larger than OR, but the figure shows similar load served by EE. What is the reason behind it?	The analysis is completed by two separate entities, AEG (ID/WA) & ETO (OR). Methodology differences between models may account for some of the changes. Avoided costs will also differ between OR and WA based on resource selections and climate programs. The CPAs for both entities can be found in Appendix 4.

• Figure 2.18: is it possible to see a stacked graph that accounts for the causes of the decline in demand? How much of this is attributable to customer losses?	There are slight additions to customers in the PRS across the 20 year planning horizon. This means all demand is attributed to energy intensity of end products gain in efficiency from building codes and energy efficiency program savings. Fewer HDDs add to the declining demand.
• Table 2.5: RNG in 2038 and 2039 – how would this be implemented?	The CROME model purchases alternative fuels resources based on system needs and least cost. The model decides how to serve these objectives including the energy needs and emissions goals. Overall, OR takes the vast majority of RNG.
• Figure 2.21: Who pays for these allowances? Avista who passes them on to transport customers? Or the transport customers? How do these allowances factor into the lowest reasonable cost analysis? Is this data Avista received from its transport customers? Is it a suggested compliance strategy for transport customers on which Avista has no influence?	Avista has the obligation to comply with the CCA for all customers under 25k MTCO2e. This analysis considers all customers meeting this criteria, but pulls out transport customers specifically to show the overall impact needed to comply with the CCA. Any transport customers above this 25k MTCO2e need to comply to the CCA considering their own options and selections. Avista does not model these suppliers.
• Figures 3.1-3.3: The rationale for projected gas demand growth might need further explanation, especially considering policies encouraging electrification and decarbonization.	Updated charts in section. In Washington, little to no growth is expected for residential, commercial or industrial customers. Energy intensity per customer pulls demand down through the forecast horizon.
• Figure 3.4: the 2013 customer survey data might be too old and benefit from updated data. Consider using NEEA 2022 residential stock assessment in place of 2016 one. Consider using 2018 MECS (released in 2021) in place of the 2015 study.	Avista agrees and has this updated data consideration in its current statement of work for conservation potential assessments for future analysis and IRP documents.
• Figure 3.7: the data doesn't appear congruent with Figure 2.23. What is the reason for it? Why does demand in 3.7 go down without DSM?	Figure 3.7 includes building codes reducing the energy intensity per customer and a declining number of HDDs throughout the forecast horizon.
• "The demand forecast only includes customer driven electrification decisions, where a customer has the option to replace the existing gas space or water heating equipment with electric alternatives, includes purchase decision logic copied from the	This is intended to state the higher efficient products will be switched out at the end of life with a more efficient product. At a system level this means more and more customers will naturally

U.S. DOE's National Energy Modeling System." – What is the change in customers due to this? If residential customer counts appear steady but demand trends downward w/out DSM does that mean Avista is losing more energy intensive customers and gaining less intensive customers?	drive down demand due to a lower energy intensity per customer.
• What are the drivers behind commercial customers growth in WA?	The primary driver for the WA commercial customers is the building code requirements
• Table 3.2: How much of the decline is attributable to climate change, end-use technology, building codes, building shells, and electrification each?	Some of these demands are attributable to climate change and less HDDs, but the primary decline is from building code requirements that drive electrification of WA commercial customers.
• Figure 3.15: what is the standard deviation here? Is it possible to see box and whisker plot?	The standard deviation of space heating is 53 therms, water heating is 2 therms, secondary heating is 1.1 therms, appliances is 0.7 therms.
• Weather stochastics: Additionally to comparing a 30-year period to a 20-year period, is it possible to divide them into 15 year chunks and compare into year-by-year?	Avista likes this idea and will implement this in future IRPs
• Figures 3.22-3.26: could you share with us the datasets for these figures?	We will post on Avista's IRP website
• Could you clarify this sentence: "Historic temperatures are used as the standard deviation of these values as there is more data to draw information from with actual temperature variation to measure these mean HDD expectations variability."	The data sets provided in the weather futures have a large difference in standard deviations. To normalize the weather and not create exceedingly high HDDs a historic dataset was utilized.
• Consider presenting the datawith the planning horizon of 2050 - in line with the deadline for greenhouse gas emissions limits in accordance with Climate Commitment Act and RCW 70A.45.020.	Unfortunately, our data does not go out to 2050. In the 2027 IRP we will provide all data to go to this timeframe.
6. Public Engagement	
• Differentiating between who was invited vs. who attended TAC meetings might provide a clearer picture of stakeholder engagement.	Updated in document
General Comments on Data and Figures	
○ Mitigation of CPA Data Staleness: Could you provide more detail on how Avista is addressing the potential impact of outdated CPA data on planning results? This would offer stakeholders more confidence in the robustness of the analysis.	Avista agrees and has this updated data consideration in its current statement of work for conservation potential assessments for future analysis and IRP documents.

o	Real vs. Nominal Dollars: Please indicate whether figures present nominal or real dollars. Our preference would be for real dollars to ensure consistency and comparability.	All figures are in Nominal dollars. For the 2027 IRP we would be open to reporting results in real $.
o	Comparative Metrics Across Jurisdictions: Including comparisons among Washington, Oregon, and Idaho—such as EE Dth per customer and EE dollars per customer—would provide useful regional insights.	Avista will consider this in the 2027 IRP
	Chapter 4: Demand-Side Resources	
o	Figure 4.1: Oregon's avoided cost appears significantly lower than Washington's. How does this difference impact conservation acquisition?	The avoided costs are the beginning of the analysis performed by the ETO. Further considerations are implemented as described in Appendix 4. Due to the CPP covering emissions in the first compliance period the avoided costs are lower than in WA where the cap decline is much higher with 7% in the first 2 compliance periods, requiring additional allowances to meet program requirements.
o	Figure 4.2: Consider adding a narrative explanation or modifying the data presentation for Total Utility Cost. The sharp bend in 2035 raises questions—why is Avista anticipating a reduction in total utility costs after 2035? Additionally, aligning the graphs' timelines (either both cumulative or both yearly) would improve clarity.	The costs shown in these figures represent incremental costs by year with cumulative therms savings. Each year has individual costs for implementation of the savings, but the savings are carried forward where no additional costs are involved and that is why we show this as depicted in these figures.
o	Table 4.1: What is driving the conservation target to double between 2026 and 2027? Additional context would be helpful.	Please see Appendix 4, for the full description of costs and savings in these timeframes.
o	Demand Response Program: Consider adding a discussion on the expediency of DR implementation and how Avista plans to scale participation.	Demand response was not selected and due to the overall small savings and high costs Avista does not plan on implementing a DR program at this time.
o	Building Electrification: We couldn't find further discussion of electrification in Chapter 7. Could you provide a page reference for easier navigation?	Updated in Document
o	Page 4-18: The first sentence could be rewritten for better clarity.	Sentence has been updated to provide more clarity.
o	Figures 4.16 & 4.17: Consider aligning the x-axis direction to flow from negative to positive, as this is the expected format for most readers.	Figures have been updated

○ Figure 4.17: An overlay histogram showing the distribution of temperatures in a representative region would improve visualization.	Avista will consider this in the 2027 IRP. It's a great idea!
○ Figure 4.19: Could you confirm whether these figures are in real or nominal dollars? Also, does this graph reflect the cost of electric business expansion?	Nominal $ and added language to clarify that they do include estimated generation, transmission and distribution from 2025 Avista electric IRP.
○ Electrification & Heat Pump Modeling: Will the modeling workpapers be included in the final IRP filing?	The workbook will be available on the Avista IRP website along with many other inputs and considerations for data within this IRP.
○ Figure 4.20: How do these electric cost projections compare to gas costs?	See Figures 4.21 – 4.24 for a comparison in dekatherms and Figure 5.5 for natural gas pricing
○ Figure 4.21: Consider adding gas heating costs as a baseline for comparison.	Estimated heating costs can be found in Figure 5.2-5.5
○ Figure 4.23: The orange line does not have a corresponding key, could you clarify?	Figure has been updated (thanks)
○ Electrification Assumptions: The IRP states that 81% of natural gas customers in Washington are expected to transition to Avista for electricity, while 19% would switch to public power providers (e.g., Inland Power & Light, Modern Electric, VERA). At what point in the analysis does this assumption get applied?	These costs are averaged based on # of meters estimate by service area with the costs being included within the electrification analysis for the cost per kWh
Chapter 5: Gas Markets and Current Resources	
• Page 5-1: Consider expanding on the diminishing need for gas in the East and the primary factors driving this trend.	Avista considered this, but the eastern US and it's gas basins have limited impact on the Western US as most of the gas purchases are from Western Canada. Reduced demand in the Eastern US would likely lead to reduced drilling or diversion of natural gas from the East coast. If supply becomes constrained due to limited demand, production would be shut in and reduce supply to the market while driving costs downward until a supply/demand balance is achieved.
• Figures 5.2 & 5.3: Could you replace or supplement these figures with real dollars per dekatherm?	All figures are in Nominal dollars. For the 2027 IRP we would be open to reporting results in real $.
• Figure 5.4: Additional explanation would be helpful.	Additional explanation has been added to Figure 5.4.

• Gas Storage Options: For future IRPs, consider analyzing the elevated risk of coincident infrastructure failure during peak demand events.	Please refer to the Resiliency scenario in the “Alternative Scenarios and Sensitivities and Risks” chapter of the IRP.
• Figure 5.11: What is driving the shape of the voluntary RNG program participation curve? Additionally, how does Avista procure these low volumes of RNG for participants?	The figure appears to show a saturation for voluntary RNG based on current program prices, customer desire to participate, and marketing efforts for the program. These volumes were historically procured from PSE for the quantities and volumes needed. Future volumes will be procured from contracts secured from Pine Creek.
Chapter 6: Supply-Side Resources	
• Figure 6.6: Consider adding Avista’s total demand line for reference.	To keep the resources clear we chose not to update in document.
• Figure 6.12: It would be helpful to include gas prices plus CCA compliance costs for clarity. Consider overlaying the total demand curve to contextualize supply costs.	Because this figure applies to all States Avista believes it best to not include this CCA plus gas line within the supply costs.
• Figures 6.16–6.21: Adding a narrative discussion on Avista’s acquisition strategy in light of the significant price spread would provide useful insights.	Added to the paragraph to describe the valuation of these resources in comparison to other available resources and options over time.
Chapter 7: Policy Considerations	
• Page 7-7: Consider expanding the discussion of Washington state policy to include information on the initial 2008 law that established the state's carbon reduction targets.	Updated in document
• Figure 7.8: Great graph!	
• Figure 7.9: Consider adding a sentence explaining the key takeaway from this graph.	Updated in document
• Chapter 7: Consider adding a discussion of ESHB 2131 (*public policies regarding resource preference adopted by Washington state*, per WAC 480-90-238(2)(b)).	Updated in document
Chapter 8: Alternate Scenarios	
• Presentation of Scenarios: Consider reviewing Northwest Natural’s and Cascade’s presentation of scenarios—their formatting appears clearer and more intuitive.	Updated these figures by breaking out by state to provide clarity of resource selections
• Addressed by Tom’s email (3/3/2025): Please consider adopting at least one scenario where Avista meets demand per its statutory obligation while also ensuring compliance with the Climate Commitment Act in the broader context of statewide emissions reductions.	Updated to include in Chapter 8

• Figure 8.1: In the high electrification scenario, as opposed to the hybrid heating scenario, Staff anticipates a demand collapse following a 30% decline in the customer base, primarily due to a 40-50% increase in fixed costs. Consider providing an explanation or adjusting the projection to account for customer responses to rising prices.	See Table 8.9 for price impacts estimate
• Scenario Forecasts: Will the final version include figures for the Diversified Portfolio and Resiliency scenarios?	Figures and descriptions for these scenarios are included in Chapter 8
• Figure 8.2: At least for the PRS, it would be useful to have similar graphs broken out by state.	Updated these figures by breaking out by state to provide clarity of resource selections
• Figure 8.2 (Future IRP Consideration): Consider modeling price trends for a fuel that experienced a historical decline in use (e.g., coal or wood between the 1940s and 1970s or fuel oil between the 1960s and 2000s) to compare against projected gas price trends.	Thanks for the comment, Avista will take that into consideration for future IRPs
• Figure 8.2: Does the space between the bars and the line represent Idaho consumption? Consider clarifying this and differentiating CCUS and Alternative Fuels with distinct colors.	Updated in document to clarify results
• Figures 8.X: Consider changing the way System Emissions is displayed—currently, the line format is unintuitive as it does not visually stack with the other elements.	Updated in document to clarify results
• Figures 8.X: It would be helpful to overlay scenarios and sensitivities onto the PRS for greater clarity.	Avista will consider this in the 2027 IRP
• Figure 8.9: Does this scenario include high electrification in Idaho as well? Consider adding a note to clarify.	Updated to include in Chapter 8. All states are included.
• Page 8-16: Could you elaborate on why there are no changes in residential usage in the I-2066 analysis?	Avista assumed state and federal incentives may help with WA residential switchover costs and customers would continue down the path of continuing with current building codes.
• Page 8-18: The IRP describes this as a near worst-case scenario. Could you elaborate on the reasoning? Staff believes a near worst-case would include high natural gas and alternative fuel prices, no I-2066, cold weather, and high CCA allowance prices.	This scenario includes high natural gas, alternative fuel prices and high CCA allowance prices. Weather is considered warmer than expected to represent less throughput and higher costs per therm of use with RCP 8.5. This is in contrast to the RCP 4.5 where weather is colder and spreads costs through more demand resulting in a

	lower cost per therm on a total billing rate. Less HDDs may prove to be a edge where electrification becomes more cost effective thus resulting in less demand on the gas system.
• Page 8-22: For completeness, consider including information on the total projected/assumed number of allowances per year and the maximum allowances projected to be available for Avista per year.	Avista agrees this would be beneficial. With the possibility of linkage with the California/Quebec market showing this will be considered in the 2027 IRP.
• Figure 8.21: Appears to reflect incorrectly.	
• Figures 8.25–8.28: Please specify whether these values are in real or nominal dollars. If nominal, consider converting to real dollars for consistency.	Avista is open to replacing nominal $ with real $ in the 2027 IRP
• Figures 8.25–8.28: Consider adding a discussion in Chapter 9 about how bill impacts will vary across usage levels and income groups, particularly in hybrid heating and electrification scenarios, per *WAC 480-90-238(2)(b) ("risks imposed on ratepayers")*. Consider referencing potential increased burdens on the electric side.	Energy burden has been added for Oregon and Washington. The full rate burden estimate has been added to Chapter 8 as well.
• Figure 8.34: Great graph!	
Chapter 9: Customer Equity & Planning Metrics	
• Page 9-2: How does Avista see the named foundation translating into future planning efforts?	Will clarify question and respond to staff appropriately
• Page 9-3: Have customer advocates engaged with the Technical Advisory Committees (TACs) as invited?	Yes and the full list of advocates can be found in Chapter 1 – Table 1.1
• Figures 9.3–9.5: Consider replacing these with real-dollar values for consistency and accuracy.	Avista is open to replacing nominal $ with real $ in the 2027 IRP
• Figure 9.14: Does this reflect the number of jobs created per year? If so, how does this align with the slowdown in energy efficiency growth after 2037?	This figure represents the number of jo creations based on annual energy efficiency spend as used directly in the model and aligns directly with figures in Chapter 3.

Work Plan for Avista's

2025 Gas Integrated Resource Plan

For the
Technical Advisory Committee,
Washington Utilities and Transportation Commission,
&
Idaho Public Utility Commission

Updated on March 25, 2024

2025 Gas Integrated Resource Planning (IRP) Work Plan

This work plan, as required in Washington pursuant to Washington Administrative Code (WAC) 480-90-238(4), outlines the process Avista will follow to develop its 2025 Gas IRP, which will be filed by April 1, 2025. Avista uses a transparent public process to solicit technical expertise and stakeholder feedback throughout the development of the IRP through a series of Technical Advisory Committee (TAC) meetings and public outreach to ensure its planning process considers input from all interested parties prior to Avista's decisions on how to meet future customer gas needs. All meeting announcements, meeting minutes, meeting recordings, and IRP related documents and data will be posted on the Company's website at https://www.myavista.com/about-us/integrated-resource-planning. Avista will communicate with its TAC members through email and/or Microsoft Teams for any meeting information and data shared outside of TAC meetings, and all information related to TAC presentations will be provided prior to each TAC meeting.

The 2025 IRP process will use the new modeling techniques referred to as CROME[1]. Avista is making this change due to the steadily increasing costs of 3rd party models, which necessitated the evaluation of alternative modeling options to help contain costs while providing the same level of analysis and considerations necessary in an IRP. Avista may also use the PRiSM[2] model for certain resource selection options as an alternative to CROME.

Avista contracted with Applied Energy Group (AEG) to assist with key activities including the energy efficiency and demand response potential studies. AEG will also provide the IRP with a long-term energy forecast using end use techniques to improve estimates for building and transportation electrification scenarios. Avista also intends to align the IRP's load forecast and resource options with this study. The Energy Trust of Oregon (ETO) will continue to provide results for the Avista Oregon territories and will be directly input into the model as a cost and load savings.

Avista intends to use both detailed site-specific and generic resource assumptions in the development of the 2025 IRP. The assumptions will utilize Avista's research of similar gas producing technologies, engineering studies, vendor estimates and market studies. Avista will rely on publicly available data to the maximum extent possible and provide its cost and operating characteristic assumptions and model for review and input by stakeholders. The IRP may model certain resources as purchase agreements in lieu of Company ownership if it is a lower cost. Future Requests for Proposals (RFP) will ultimately decide final resource selection and ownership type based on third party resource options and potential self-build resources specific to Avista's service territory.

Avista intends to create a Preferred Resource Strategy (PRS) using market and policy assumptions based on final rules from the Climate Commitment Act (CCA) for Washington. In Oregon, the Climate Protection Program (CPP) will be included as a scenario as the Department of

[1] CROME is Avista's proprietary model it uses to select new resources and was developed to replace PLEXOS at a daily level. CROME is the Comprehensive Resource Optimization Model based in Excel paired with optimization software.

[2] PRiSM is Avista's proprietary model it uses to select new resources in the Electric IRP process. Avista first developed this tool for use in the 2003 IRP.

Environmental Quality moves to re-establish the CPP through rulemaking beginning in Q1 2024. Because the timing and outcome of the CPP rulemaking is unknown, a scenario is the most appropriate way to consider Oregon's potential future climate policies in the IRP. Conversations with the TAC as to methods and logic to include in scenarios will be discussed including beginning the program in 2025 for the PRS. Final CPP rules, that may or may not be the same, will not be known until after the modeling and process of the 2025 IRP is completed. A similar outcome is possible with the CCA due to a public initiative to repeal the CCA being submitted to the Legislature where it can be repealed, altered, or sent to the ballot in the November 2024 election. In the 2024 legislative session, a bill is being considered to link Washington's program with California and Quebec's programs, where the CCA program rules would be altered to conform to the other programs. Finally, a least cost planning methodology will be used in Idaho. For Washington resource selection, Avista will solve its PRS to include least reasonable cost for meeting state building codes and energy policies including energy costs, societal externalities such as Social Cost of Greenhouse Gas, and the non-energy impacts of resource on public health (air emissions), safety, and economic development. Resource selection will solve for state clean energy requirements and Avista's energy and capacity planning standards. Avista will track certain customer metrics the PRS creates to assist in measuring customer equity.

The plan will also include a chapter outlining the key components of the PRS, with a description of which state policy is driving each resource need. The IRP will include a limited number of scenarios to address alternative futures in the gas market and public policy, such as limited RNG and building electrification. TAC meetings help determine the underlying assumptions used in the IRP, including market scenarios and portfolio studies. Although, Avista will also engage customers using a public outreach and an informational event, as well as provide transparent information on the IRP website. The IRP process is technical and data intensive; public comments are encouraged as timely input and participation ensures inclusion in the process resulting in a resource plan submitted according to the proposed schedule in this Work Plan. Avista will make all data available to the public *except* where it contains market intelligence or proprietary information. The planned schedule for this data is shown in Exhibit 1. Avista intends to release slides and data five days prior to its discussion at TAC meetings and expects any comments within two weeks after the meeting.

The following topics and meeting times may change depending on the availability of presenters and requests for additional topics from TAC members. The timeline and proposed agenda items for TAC meetings follows:

- **TAC 1: Wed. February 14, 2024: 9:00 am to 12:00 pm (PTZ)**
    - January Peak Event
    - Work Plan
    - RNG Acquisition
    - Customer Impacts
    - Modeling Update
    - State Policy Update

- Planned Scenarios for Feedback

- **TAC 2: Wed. April 24, 2024: 10:30 am to 12:00 pm (PTZ)**
  - Feedback from prior TAC
  - Action Items from 2023 IRP
  - Chosen Model Methodology and modeling overview
- **TAC 3: Wed. 15 May 2024: 10:30 am to 12:00 pm (PTZ)**
  - Feedback from prior TAC
  - Distribution System Modeling
  - Non-Pipe Alternatives (NPA) in Distribution Planning
  - Oregon Staff Recommendation on NPA
- **TAC 4: Wed. 5 June 2024: 10:30 am to 12:00 pm (PTZ)**
  - Feedback from prior TAC
  - Future Climate Analysis Update
  - Historic weather comparison
  - Peak Day Methodology
- **TAC 5: Wed. 26 June 2024: 10:30 am to 12:00 pm (PTZ)**
  - Feedback from prior TAC
  - GHG assumptions and Climate pricing
  - Current natural gas resources
- **TAC 6: Wed. 17 July 2024: 10:30 am to 12:00 pm (PTZ)**
  - Feedback from prior TAC
  - Load Forecast – AEG
- **TAC 7: Wed. 7 Aug. 2024: 10:30 am to 12:00 pm (PTZ)**
  - Feedback from prior TAC
  - Natural Gas Market Overview and Price Forecast
  - Avoided Costs Methodology
- **TAC 8: Wed. 28 Aug. 2024: 10:30 am to 12:00 pm (PTZ)**
  - Feedback from prior TAC
  - Conservation Potential Assessment (AEG)
  - Demand Response Potential Assessment (AEG)
  - Conservation Potential Assessment (ETO)

- **TAC 9: Wed. 18 Sep. 2024: 10:30 am to 12:00 pm (PTZ)**
    - Feedback from prior TAC
    - NEI Study
    - New Resource Options Costs and Assumptions
    - All assumptions review
- **TAC 10: Wed. 6 Nov. 2024: 9:00 am to 12:00 pm (PTZ)**
    - Scenario Results
    - Scenario Risks
    - PRS Overview of selections and risk
    - Per Customer Costs by Scenario
    - Cost per MTCO2e by Scenario
    - Open Questions
- **Sep. 2024**
    - Virtual Public Meeting- Natural Gas & Electric IRP
        - Recorded presentation
        - Daytime comment and question session (12pm to 1pm- PTZ)
        - Evening comment and question session (6pm to 7pm- PTZ)

2025 Gas IRP Report Outline

This section provides a draft outline of the expected major sections in the 2025 Gas IRP.

Executive Summary

1. **Introduction and Planning Environment**
    a. Customers
    b. Integrated Resource Planning
    c. Planning Model
    d. Planning Environment
2. **Demand Forecasts**
    a. Demand Areas
    b. Customer Forecasts
    c. Electrification of Natural Gas Customers
    d. Use-per-Customer Forecast
    e. Weather Forecast
    f. Peak Day Design Temperature
    g. Load Forecast
    h. Scenario Analysis
    i. Alternative Forecasting Methodologies
    j. Key Issues
3. **Demand Side Resources**
    a. Avoided Cost
    b. Idaho and Washington Conservation Potential Assessment
    c. Pursuing Cost-Effective Energy Efficiency
    d. Washington and Idaho Energy Efficiency Potential
    e. Demand Response
    f. Building Electrification
4. **Current Resources and New Resource Options**
    a. Natural Gas Commodity Resources
    b. Transportation Resources
    c. Storage Resources
    d. Incremental Supply-Side Resource Options
    e. Alternative Fuel Supply Options
    f. Project Evaluation - Build or Buy
    g. Avista's Natural Gas Procurement Plan
    h. Market-Related Risks and Risk Management
5. **Policy Issues**
    a. Avista's Environmental Objective
    b. Natural Gas Greenhouse Gas System Emissions
    c. Local Distribution Pipeline Emissions - Methane Study
    d. State and Regional Level Policy Considerations
    e. Idaho
    f. Oregon
    g. Washington
    h. Federal Legislation
    i. Key Takeaways
6. **Preferred Resource Strategy**
    a. Planning Model Overview
    b. Stochastic Analysis

c. Resource Integration
d. Carbon Policy Resource Utilization Summary
e. Resource Utilization
f. Demand and Deliverability Balance
g. New Resource Options and Considerations
h. Energy Efficiency Resources
i. Preferred Resource Strategy (PRS)
j. Monte Carlo Risk Analysis
k. Estimated Price Impacts

7. Alternate Scenarios

a. Alternate Demand Scenarios
b. Deterministic – Portfolio Evaluation and Scenario Results
c. Demand
d. PRS Scenarios
e. Electrification Scenarios
f. Supply Scenarios
g. Other Scenarios
h. Washington Climate Commitment Act Allowances
i. Oregon Community Climate Investments
j. Natural Gas Use
k. Methanation
l. Renewable Natural Gas
m. Emissions
n. Cost Comparison
o. Regulatory Requirements

8. Distribution Planning

a. Distribution System Planning
b. Network Design Fundamentals
c. Computer Modeling
d. Determining Peak Demand
e. Distribution System Enhancements
f. Conservation Resources
g. Distribution Scenario Decision-Making Process
h. Planning Results
i. Non-Pipe Alternatives

9. Equity Considerations

a. Overview
b. Equity Metrics

10. Action Plan

a. Avista's 2025 IRP Action Items
b. 2025-2026 Action Plan

Draft IRP will be available to the public on Friday, January 10, 2025, and the final draft filed with Idaho, Oregon, and Washington Commissions on April 1, 2025. Comments from TAC members are expected back to Avista by Friday, February 7, 2025, or through each states public comment timeline. Avista's IRP team will be available for conference calls or by email to address comments with individual TAC members or with the entire group if needed.

Exhibit 1: Major 2025 Gas IRP Assumption Timeline	
Task	Target Date
CCA/Other GHG Pricing Assumptions	June 2024
Due date for study requests from TAC members	July 30, 2024
Demand Side Management Deliverables	
Final Energy Forecast (AEG)	July 2024
Energy Efficiency (AEG & ETO)	August 2024
Demand Response (AEG)	August 2024
Natural Gas price forecast	August 2024
New Resource Options Cost & Availability	September 2024
Finalize resource selection model assumptions	September 2024

APPENDIX 1.5: WASHINGTON PUBLIC UTILITY COMMISSION IRP POLICIES AND GUIDELINES – WAC 480-90-238

Rule	Requirement	Plan Citation
WAC 480-90-238(4)	Work plan filed no later than 12 months before next IRP due date.	Work plan submitted to the WUTC on March 26, 2024.
WAC 480-90-238(4)	Work plan outlines content of IRP.	See Appendix 1.1.
WAC 480-90-238(4)	Work plan outlines method for assessing potential resources. (See LRC analysis below)	See Appendix 1.1.
WAC 480-90-238(5)	Work plan outlines timing and extent of public participation.	See Appendix 1.1.
WAC 480-90-238(4)	Integrated resource plan submitted within two years of previous plan.	Last Integrated Resource Plan was submitted on March 31, 2023
WAC 480-90-238(5)	Commission issues notice of public hearing after company files plan for review.	TBD
WAC 480-90-238(5)	Commission holds public hearing.	TBD
WAC 480-90-238(2)(a)	Plan describes mix of natural gas supply resources.	See Chapters 5 and 6 on New and Existing Resources
WAC 480-90-238(2)(a)	Plan describes conservation supply.	See Chapter 4 on Demand Side Resources
WAC 480-90-238(2)(a)	Plan addresses supply in terms of current and future needs of utility and ratepayers.	See Chapter 5 and 6 on New and Chapter 2 for the Preferred Resource Selection
WAC 480-90-238(2)(a)&(b)	Plan uses lowest reasonable cost (LRC) analysis to select mix of resources.	See Chapters 3, 5, and 6 for Demand and New and Existing Resources. Chapters 2 and 8 details how Demand and Supply come together to select the least cost/best risk portfolio for ratepayers.
WAC 480-90-238(2)(b)	LRC analysis considers resource costs.	See Chapters 3, 5, and 6 for Demand and New and Existing Resources. Chapters 2 and 8 details how Demand and Supply come together to select the least cost/best risk portfolio for ratepayers.
WAC 480-90-238(2)(b)	LRC analysis considers market-volatility risks.	See Chapters 5 and 6 on New and Existing Resources
WAC 480-90-238(2)(b)	LRC analysis considers demand side uncertainties.	See Chapter 3 Demand Forecasting
WAC 480-90-238(2)(b)	LRC analysis considers resource effect on system operation.	See Chapters 3, 5, and 6 for Demand and New and Existing Resources. Chapters 2 and 8 details how Demand and Supply come together to select the least cost/best risk portfolio for ratepayers.
WAC 480-90-238(2)(b)	LRC analysis considers risks imposed on ratepayers.	See Chapter 5 procurement plan section and chapter 8 for risks to ratepayers and Chapter 2 for the

		preferred resource selection. Chapter 7 considers customer equity and metrics. We seek to minimize but cannot eliminate price risk for our customers.
WAC 480-90-238(2)(b)	LRC analysis considers public policies regarding resource preference adopted by Washington state or federal government.	See Chapter 7 for policies and chapter 8 for demand scenarios
WAC 480-90-238(2)(b)	LRC analysis considers cost of risks associated with environmental effects including emissions of carbon dioxide.	See Chapters 2, 3 and 9 on preferred resource selection, demand scenarios and customer equity and metrics
WAC 480-90-238(2)(b)	LRC analysis considers need for security of supply.	See Chapters 5 and 6 on Gas Markets and Existing Resources and Supply Side Resource Options. Chapter 8 includes scenarios needs for security of supply
Rule	**Requirement**	**Plan Citation**
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.	See Chapter 4 on Demand Side Resources
WAC 480-90-238(3)(a)	Plan includes a range of forecasts of future demand.	See Chapter 3 on Demand Forecast
WAC 480-90-238(3)(a)	Plan develops forecasts using methods that examine the effect of economic forces on the consumption of natural gas.	See Chapter 3 on Demand Forecast and chapter 8 for alternative scenarios and sensitivities and risks
WAC 480-90-238(3)(a)	Plan develops forecasts using methods that address changes in the number, type and efficiency of natural gas end-uses.	See Chapters 3 and 4 on Demand Forecast and Demand Side Resources
WAC 480-90-238(3)(b)	Plan includes an assessment of commercially available conservation, including load management.	See Chapter 4 on Demand Side Management including demand response section.
WAC 480-90-238(3)(b)	Plan includes an assessment of currently employed and new policies and programs needed to obtain the conservation improvements.	See Chapters 4 and 5 on Demand Side Resources and Policy Considerations and Appendix 4
WAC 480-90-238(3)(c)	Plan includes an assessment of conventional and commercially available nonconventional gas supplies.	See Chapter 5 and 6 on New and Chapter 2 for the Preferred Resource Selection
WAC 480-90-238(3)(d)	Plan includes an assessment of opportunities for using company-owned or contracted storage.	See Chapter 5 and 6 on New and Chapter 2 for the Preferred Resource Selection.
WAC 480-90-238(3)(e)	Plan includes an assessment of pipeline transmission capability and reliability and opportunities for additional pipeline transmission resources.	See Chapters 3, 5, and 6 for Demand and New and Existing Resources. Chapters 2 and 8 details how Demand and Supply come together to select the least cost/best risk portfolio for ratepayers.

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.	See Chapter 4 on Demand Side Resources and Chapters 3, 5, and 6 for Demand and New and Existing Resources. Chapters 2 and 8 details how Demand and Supply come together to select the least cost/best risk portfolio for ratepayers.
WAC 480-90-238(3)(g)	Plan includes at least a 10 year long-range planning horizon.	Our plan is a comprehensive 20 year plan. (2026-2045)
WAC 480-90-238(3)(g)	Demand forecasts and resource evaluations are integrated into the long range plan for resource acquisition.	See Chapter 4 on Demand Side Resources and Chapters 3, 5, and 6 for Demand and New and Existing Resources. Chapters 2 and 8 details how Demand and Supply come together to select the least cost/best risk portfolio for ratepayers.
WAC 480-90-238(3)(h)	Plan includes a two-year action plan that implements the long range plan.	See Section 11 Action Plan
WAC 480-90-238(3)(i)	Plan includes a progress report on the implementation of the previously filed plan.	See Section 11 Action Plan
WAC 480-90-238(5)	Plan includes description of consultation with commission staff. (Description not required)	See Appendix 1.1
WAC 480-90-238(5)	Plan includes description of completion of work plan. (Description not required)	See Appendix 1.1.

APPENDIX 1.2: IDAHO PUBLIC UTILITY COMMISSION IRP POLICIES AND GUIDELINES – ORDER NO. 2534

	DESCRIPTION OF REQUIREMENT	FULLFILLMENT OF REQUIREMENT
1	Purpose and Process. Each gas utility regulated by the Idaho Public Utilities Commission with retail sales of more than 10,000,000,000 cubic feet in a calendar year (except gas utilities doing business in Idaho that are regulated by contract with a regulatory commission of another State) has the responsibility to meet system demand at least cost to the utility and its ratepayers. Therefore, an ‘‘integrated resource plan’’ shall be developed by each gas utility subject to this rule.	Avista prepares a comprehensive 20 year Integrated Resource Plan every two years. Avista will be filing its 2025 IRP on or before April 1, 2025.
2	Definition. Integrated resource planning. ‘‘Integrated resource planning’’ means planning by the use of any standard, regulation, practice, or policy to undertake a systematic comparison between demand-side management measures and the supply of gas by a gas utility to minimize life-cycle costs of adequate and reliable utility services to gas customers. Integrated resource planning shall take into account necessary features for system operation such as diversity, reliability, dispatchability, and other factors of risk and shall treat demand and supply to gas consumers on a consistent and integrated basis.	See Chapter 4 on Demand Side Resources and Chapters 3, 5, and 6 for Demand and New and Existing Resources. Chapters 2 and 8 details how Demand and Supply come together to select the least cost/best risk portfolio for ratepayers.
3	Elements of Plan. Each gas utility shall submit to the Commission on a biennial basis an integrated resource plan that shall include:	The last IRP was filed on March 31, 2023.
	A range of forecasts of future gas demand in firm and interruptible markets for each customer class for one, five, and twenty years using methods that examine the effect of economic forces on the consumption of gas and that address changes in the number, type and efficiency of gas end-uses.	See Chapter 4 on Demand Side Resources and Chapters 3, 5, and 6 for Demand and New and Existing Resources. Chapters 2 and 8 details how Demand and Supply come together to select the least cost/best risk portfolio for ratepayers.
	An assessment for each customer class of the technically feasible improvements in the efficient use of gas, including load management, as well as the policies and programs needed to obtain the efficiency improvements.	See **Chapter 4 - Demand Side Management** and **DSM Appendices 4 et.al.** for detailed information on the DSM potential evaluated and selected for this IRP and the operational implementation process.

	An analysis for each customer class of gas supply options, including: (1) a projection of spot market versus long-term purchases for both firm and interruptible markets; (2) an evaluation of the opportunities for using company-owned or contracted storage or production; (3) an analysis of prospects for company participation in a gas futures market; and (4) an assessment of opportunities for access to multiple pipeline suppliers or direct purchases from producers.	See **Chapters 5 and 6** for details about the market, storage, and pipeline transportation as well as other resource options considered in this IRP. See also the procurement plan section in chapter 5 for supply procurement strategies.
	A comparative evaluation of gas purchasing options and improvements in the efficient use of gas based on a consistent method for calculating cost-effectiveness.	See Methodology section of **Chapter 3 - Demand-Side Resources** where we describe our process on how demand-side and New and Existing Resources are compared on par with each other in the CROME model. Chapter 4 also includes how results from the IRP are then utilized to create operational business plans. Operational implementation may differ from IRP results due to modeling assumptions.
	The integration of the demand forecast and resource evaluations into a long-range (e.g., twenty-year) integrated resource plan describing the strategies designed to meet current and future needs at the lowest cost to the utility and its ratepayers.	See **Chapter 2 – Preferred Resource Selection and Chapter 8 Alternative Scenarios and Sensitivities and Risks** for details on how we model demand and supply coming together to provide the least cost/best risk portfolio of resources in comparison to alternative futures and resource options.
	A short-term (e.g., two-year) plan outlining the specific actions to be taken by the utility in implementing the integrated resource plan.	See **Chapter 11 - Action Plan** for actions to be taken in implementing the IRP.
4	Relationship Between Plans. All plans following the initial integrated resource plan shall include a progress report that relates the new plan to the previously filed plan.	See **Chapter 11 - Action Plan**
5	Plans to Be Considered in Rate Cases. The integrated resource plan will be considered with other available information to evaluate the performance of the utility in rate proceedings before the Commission.	We prepare and file our plan in part to establish a public record of our plan.
6	Public Participation. In formulating its plan, the gas utility must provide an opportunity for public participation and comment and must provide methods that will be available to the public of validating predicted performance.	Avista held 11 Technical Advisory Committee meetings beginning in February and ending in December. A public focused meeting occurred on March 5, 2025. See **Chapter 1 - Introduction** for more detail about public participation in the IRP process.

7	Legal Effect of Plan. The plan constitutes the base line against which the utility's performance will ordinarily be measured. The requirement for implementation of a plan does not mean that the plan must be followed without deviation. The requirement of implementation of a plan means that a gas utility, having made an integrated resource plan to provide adequate and reliable service to its gas customers at the lowest system cost, may and should deviate from that plan when presented with responsible, reliable opportunities to further lower its planned system cost not anticipated or identified in existing or earlier plans and not undermining the utility's reliability.	See section titled "Avista's Natural Gas Procurement Plan" in **Chapter 5 – Gas Markets and Existing Resources**. Among other details we discuss plan revisions in response to changing market conditions.
8	In order to encourage prudent planning and prudent deviation from past planning when presented with opportunities for improving upon a plan, a gas utility's plan must be on file with the Commission and available for public inspection. But the filing of a plan does not constitute approval or disapproval of the plan having the force and effect of law, and deviation from the plan would not constitute violation of the Commission's Orders or rules. The prudence of a utility's plan and the utility's prudence in following or not following a plan are matters that may be considered in a general rate proceeding or other proceedings in which those issues have been noticed.	See also section titled "Alternate Scenarios and Sensitivities and Risks" in **Chapter 8 for a comparison to all future scenarios considered in the 2025 IRP.**

APPENDIX 1.2: OREGON PUBLIC UTILITY COMMISSION IRP STANDARD AND GUIDELINES – ORDER 07- 002

Guideline 1: Substantive Requirements		
1.a.1	All resources must be evaluated on a consistent and comparable basis.	All resource options considered, including demand-side and supply-side are modeled in CROME utilizing the same common general assumptions, approach, and methodology.
1.a.2	All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.	Avista considered a range of resources including demand-side management, distribution system enhancements, capacity release recalls, interstate pipeline transportation, interruptible customer supply, renewable natural gas by source, hydrogen, electrification by end source and synthetic methane. Chapter 4 and Appendix 4.1 documents Avista's demand-side management resources considered. Chapters 5 and 6 show New and Existing Resources. Chapter 2 and 8 documents how Avista developed and assessed each of these resources.
1.a.3	Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.	Avista considered various combinations of technologies, lead times, in-service dates, durations, and locations. Chapter 2 provides details about the modeling methodology and results. Chapter 5 describes current resource options and Chapter 6 describes new resource options and lead times.
1.a.4	Consistent assumptions and methods should be used for evaluation of all resources.	Appendix 6.2 documents general assumptions used in Avista's CROME modeling software. All portfolio resources both demand and supply-side were evaluated within CROME using the same sets of inputs.
1.a.5	The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.	See Appendix 0
1.b.1	Risk and uncertainty must be considered. Electric utilities only	Risk and uncertainty can be found in Chapter 6 and Chapter 8.

1.b.2	Risk and uncertainty must be considered. Natural gas utilities should consider demand (peak, swing and base-load), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas (GHG) emissions.	See Chapter 4 on Demand Side Resources and Chapters 3, 5, and 6 for Demand and New and Existing Resources. Chapters 2 and 8 details how Demand and Supply come together to select the least cost/best risk portfolio for ratepayers.
	Utilities should identify in their plans any additional sources of risk and uncertainty.	See Chapter 4 on Demand Side Resources and Chapters 3, 5, and 6 for Demand and New and Existing Resources. Chapters 2 and 8 details how Demand and Supply come together to select the least cost/best risk portfolio for ratepayers.
1c	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.	Avista evaluated cost/risk tradeoffs for each of the risk analysis portfolios considered. See Chapter 2 and 8 plus supporting information in the Appendix.
	The planning horizon for analyzing resource choices should be at least 20 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.	Avista used a 20-year study period for portfolio modeling. Avista contemplated possible costs beyond the planning period that could affect rates including end effects such as infrastructure decommission costs and concluded there were no significant costs reasonably likely to impact rates under different resource selection scenarios.
	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 of 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.	Avista's CROME modeling software utilizes a PVRR cost metric methodology applied to both long and short-lived resources.
	To address risk, the plan should include at a minimum: 1) Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes. 2) Discussion of the proposed use and impact on costs and risks of physical and financial hedging.	Avista, through its stochastic analysis, modeled 500 twenty year futures via Monte Carlo iterations developing a distribution of total 20 year cost estimates utilizing CROME PVRR methodology. Chapter 5 discusses Avista's physical and financial hedging methodology. Chapter 8 discusses risk and severity of bad outcomes.
	The utility should explain in its plan how its resource choices appropriately balance cost and risk.	Chapter 2 to 10 describe various specific resource considerations and related risks.

1d	The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	Avista considered state and federal energy policies and impacts as described in Chapter 7.
Guideline 2: Procedural Requirements		
2a	The public, including 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.	Chapter 1 provides an overview of the public process and documents the details on public meetings held for the 2025 IRP. Avista encourages participation in the development of the plan, as each party brings a unique perspective and the ability to exchange information and ideas makes for a more robust plan.
	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.	The entire IRP, as well as the TAC process, and website includes all of the non-confidential information the company used for portfolio evaluation and selection. Avista also provided stakeholders with non-confidential information to support public meeting discussions via email. The document and appendices will be available on the company website for viewing.
	The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.	Avista distributed a draft IRP document for external review to all TAC members from January 31, 2025 to February 21, 2025 and requested comments by March 7, 2025. All comments and responses are included in Appendix 1
Guideline 3: Plan Filing, Review and Updates		
3a	Utility must file an IRP within two years of its previous IRP acknowledgement order.	The 2023 IRP was filed March 31, 2023 with short term acknowledgement in May of 2024. The 2025 IRP will be filed on or before March 31, 2025.
3b	Utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.	Avista will work with Staff to fulfill this guideline following filing of the IRP.
3c	Commission staff and parties should complete their comments and recommendations within six months of IRP filing	Pending
3d	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 plan before issuing an acknowledgment order	Pending

3e	The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.	Pending
3f	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	The 2025 IRP will be filed in full with the OPUC as an extension was granted to issue an extension from May 2026 to April 1, 2027 due to the RAC process for developing new rules for the CPP.
3g	Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that: • Describes what actions the utility has taken to implement the plan; • Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and • Justifies any deviations from the acknowledged action plan.	Avista will utilized the updated IRP template to discuss changes with the Commission at our annual update around May 2025.
Guideline 4: Plan Components		
	At a minimum, the plan must include the following elements:	
4a	An explanation of how the utility met each of the substantive and procedural requirements.	This table summarizes guideline compliance by providing an overview of how Avista met each of the substantive and procedural requirements for a natural gas IRP.
4b	Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions.	Chapter 3 describes the demand forecast data and risk analysis of demand. Chapter 5 and 6 describes price risk. Chapter 8 provides the scenario and sensitivities and risk analysis results.
4c	For electric utilities only	Not Applicable
4d	A determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources.	Chapter 2 describes peak demand expectations and preferred resource selection.
4e	Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology	Chapter 4 and Appendix 4.1 identify the demand-side potential included in this IRP. Chapter 4, 5 & 6 and Appendix 6.3 identify the New and Existing Resources.
4f	Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs.	Chapter 2 discusses analysis of the preferred resource selection.

		Chapter 8 shows the distribution or city gate upgrades that may need to occur to provide reliability and cost-risk tradeoffs. Chapter 9 shows the energy burden expected from these choices for residential customers.
4g	Identification of key assumptions about the future (e.g. fuel prices and environmental compliance costs) and alternative scenarios considered.	Chapter 5,6, and 7 identifies assumptions about future costs or prices and the polices driving these costs while chapter 8 considers alternative scenarios and future cost variability.
4h	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.	This Plan documents the development and results for portfolios evaluated in chapters 2 and 8.
4i	Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties.	We evaluated our candidate portfolio by performing stochastic analysis using CROME varying price, volumetric availability of alternative fuels and weather under 500 different scenarios. Additionally, we test the portfolio of options with the use of CROME under deterministic scenarios where demand and price vary.
4j	Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results.	Chapter 8 illustrates cost and risk variability of the 19 modeled scenarios in the 2025 IRP.
4k	Analysis of the uncertainties associated with each portfolio evaluated	See the responses to 1.b above.
4l	Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers	Avista evaluated cost/risk tradeoffs for each of the risk analysis in Chapter 8.
4m	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	This IRP is presumed to have no inconsistencies.
4n	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.	The action plan and resource needs and selection can be found in Chapter 11.
Guideline 5: Transmission		
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	Chapters 5, 6 and 8 consider all resource options available and their selections in each scenario/sensitivity.

	sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.	
Guideline 6: Conservation		
6a	Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.	ETO and AEG both performed a conservation potential assessment study for our 2025 IRP. A discussion of the study is included in Chapter 4. Each full study document is in Appendix 4.1. Avista incorporates a comprehensive assessment of the potential for utility acquisition of energy-efficiency resources into the regularly-scheduled Integrated Resource Planning process.
6b	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.	Chapter 11 contains the requested information.
6c	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 outside party's projection of conservation acquisition.	See the response for 6.b above. ETO administers all programs in Oregon other than low-income residential. These conservation resources are discussed in depth in Chapter 4, pairing these results with the preferred resource selection in Chapter 2. These CPAs can be found in Appendix 4 by potential study.
Guideline 7: Demand Response		
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).	Avista has periodically evaluated conceptual approaches to meeting capacity constraints using demand-response and similar voluntary programs. Technology, customer characteristics and cost issues are hurdles for developing effective programs.
Guideline 8: Environmental Costs		
8	Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for CO_2, NO_x, SO_2, and Hg emissions. Utilities should analyze the range of potential CO_2 regulatory costs in Order No. 93-695, from \$0 - \$40 (1990\$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for NO_x, SO_2, and Hg, if applicable.	These costs can be found in Chapter 9 and are also discussed in Chapter 7. The Environmental Externalities discussion in Appendix 9.2 describes our analysis performed. Sensitivities to these costs can be found in Chapter 8.
Guideline 9: Direct Access Loads		

9	An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.	Not applicable to Avista's gas utility operations.
Guideline 10: Multi-state utilities		
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.	The 2025 IRP conforms to the multi-state planning approach with a specific cost of compliance to Oregon and Washington for their respective climate compliance programs as discussed throughout the IRP.
Guideline 11: Reliability		
11	Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with 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.	This demonstration of these guidelines can be found in Chapters 2, 4, 5, 6, 7 and 8 where all resources and policies considered in chapters 4 to 7 are modeled for a optimal solution in chapter 2 and risk in 8.
Guideline 12: Distributed Generation		
12	Electric utilities should evaluate distributed generation technologies on par with other New and Existing Resources and should consider, and quantify where possible, the additional benefits of distributed generation.	Not applicable to Avista's gas utility operations.
Guideline 13: Resource Acquisition		
13a	An electric utility should: identify its proposed acquisition strategy for each resource in its action plan; Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party; identify any Benchmark Resources it plans to consider in competitive bidding.	Avista will release an annual RFP to determine least cost solutions and continually monitor loads for possible shifts in expected demand. Chapter 11 shows the resources selected in the PRS scenario for the 2025 IRP.
13b	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.	A discussion of Avista's procurement practices is detailed in Chapter 5.
Guideline 8: Environmental Costs		
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 scenarios ranging from the present CO_2 regulatory level to the upper reaches of credible proposals by governing	Chapter 2 is considered the base case with the preferred resource selections of options modeled within the 2025 IRP. Chapter 8 considers alternatives using a variety of compliance methods for weather futures, upstream emissions and SCC.

	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.	
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 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.	Chapter 2 contains the PRS, Chapter 8 contains alternative scenarios and portfolio analysis for the PRS and cost implications. Chapter 9 considers energy burden from these selections in the PRS to income levels and induced benefits to the state economy with resources selected and emissions.

WINTER AVOIDED COST PER DEKATHERM (NOMINAL $)

2025/2026 and 2045/2046 values reflect only the first three and last two months of the year, respectively.

Residential Customers

Winter	Average Case			Diversified Portfolio			High Alternative Fuel Costs		
	WA	ID	OR	WA	ID	OR	WA	ID	OR
2025/2026	4.27	3.35	5.00	4.31	3.38	4.62	4.31	3.38	4.63
2026/2027	4.57	3.73	6.07	4.64	3.94	5.65	4.65	3.94	5.65
2027/2028	4.98	3.86	6.42	5.02	4.08	5.80	5.03	4.08	5.81
2028/2029	5.19	3.94	6.86	5.20	4.16	5.99	5.21	4.16	6.12
2029/2030	5.38	4.01	7.03	5.35	4.03	9.38	5.37	4.03	6.55
2030/2031	5.73	3.99	7.72	9.47	4.00	7.49	5.66	4.00	7.12
2031/2032	6.38	4.14	8.09	10.61	4.15	9.07	6.35	4.15	7.64
2032/2033	6.59	4.44	8.92	10.11	4.45	10.81	6.44	4.45	8.41
2033/2034	6.99	4.62	9.34	10.33	4.64	12.32	6.90	4.64	9.08
2034/2035	7.24	4.78	9.72	10.85	4.79	12.41	7.03	4.79	9.63
2035/2036	7.55	4.87	10.07	10.20	4.90	13.91	7.46	4.89	9.91
2036/2037	7.77	5.05	10.49	11.14	5.08	13.85	7.56	5.08	10.00
2037/2038	7.77	5.21	10.69	11.84	5.23	14.49	7.52	5.23	10.42
2038/2039	8.08	5.40	10.92	10.64	5.43	16.31	7.86	5.43	10.86
2039/2040	8.35	5.61	11.29	11.12	5.65	15.09	7.90	5.64	11.04
2040/2041	8.64	5.86	11.82	11.18	5.91	16.13	8.08	5.91	11.55
2041/2042	8.94	6.05	12.14	11.15	6.09	15.90	8.54	6.09	11.84
2042/2043	9.26	6.20	12.55	10.86	6.25	16.82	8.86	6.24	12.26
2043/2044	9.62	6.41	12.97	10.64	6.44	16.90	9.15	6.44	12.66
2044/2045	10.13	6.65	13.32	11.57	6.68	16.88	9.43	6.68	12.54
2045/2046	11.24	7.03	13.63	12.56	6.83	16.86	10.35	6.83	12.57

Winter	High CCA Allowance Pricing			High Electrification			High Growth on the Gas System		
	WA	ID	OR	WA	ID	OR	WA	ID	OR
2025/2026	4.50	3.38	4.63	4.35	3.43	4.63	4.31	3.36	4.47
2026/2027	4.86	3.94	5.65	4.71	4.03	5.65	4.68	3.92	5.57
2027/2028	5.30	4.08	5.81	7.35	5.57	5.83	5.08	4.06	5.86
2028/2029	5.51	4.16	6.12	9.71	7.00	6.06	5.27	4.14	6.30
2029/2030	5.70	4.03	6.49	10.75	8.46	6.44	5.45	4.02	6.48
2030/2031	6.06	4.00	7.00	12.79	9.57	6.28	5.75	3.99	7.10
2031/2032	6.88	4.15	7.51	16.13	11.20	6.64	6.34	4.14	7.68
2032/2033	7.01	4.45	8.37	18.69	13.21	7.61	6.56	4.44	8.55
2033/2034	7.42	4.64	8.85	22.24	15.11	7.80	6.93	4.62	9.16
2034/2035	7.56	4.79	9.28	24.87	17.21	8.65	7.19	4.78	9.62

2035/2036	8.11	4.90	9.68	31.05	23.66	8.78	7.48	4.88	9.95
2036/2037	8.35	5.08	9.82	37.56	29.44	9.03	7.70	5.06	10.32
2037/2038	8.12	5.23	10.27	45.19	33.55	9.35	7.61	5.22	10.55
2038/2039	8.41	5.43	10.62	55.55	41.89	9.61	7.89	5.41	10.92
2039/2040	9.09	5.65	10.61	69.69	53.62	9.22	8.20	5.62	11.30
2040/2041	9.44	5.91	11.08	86.93	73.42	9.30	8.32	5.88	11.85
2041/2042	9.25	6.10	11.34	149.63	99.67	9.85	8.68	6.07	12.29
2042/2043	9.61	6.24	11.43	227.42	133.24	9.65	8.98	6.21	12.37
2043/2044	10.07	6.45	11.89	291.63	174.65	10.43	9.33	6.42	12.93
2044/2045	10.36	6.68	11.96	389.56	220.80	9.24	9.63	6.66	13.41
2045/2046	11.92	6.83	11.82	445.25	242.91	8.83	10.88	6.83	13.66

Winter	High Natural Gas Prices			Hybrid Heating			I-2066		
	WA	ID	OR	WA	ID	OR	WA	ID	OR
2025/2026	4.60	3.57	4.83	4.31	3.38	4.63	4.31	3.38	4.63
2026/2027	5.61	4.76	6.64	4.65	3.94	5.65	4.68	3.94	5.65
2027/2028	6.60	5.35	7.25	5.70	6.85	5.81	5.07	4.08	5.81
2028/2029	7.20	5.83	8.00	7.41	7.53	6.08	5.28	4.16	6.12
2029/2030	7.68	6.15	8.47	8.58	6.84	6.39	5.46	4.03	6.49
2030/2031	8.18	6.18	9.06	9.29	7.49	6.79	5.77	4.00	7.06
2031/2032	9.63	6.58	9.13	10.26	8.57	7.55	6.36	4.15	7.39
2032/2033	9.79	7.54	11.12	10.88	9.54	7.72	6.58	4.45	8.21
2033/2034	10.76	7.84	11.60	11.98	10.31	8.28	6.97	4.64	8.61
2034/2035	11.17	8.61	11.98	12.55	11.30	8.77	7.26	4.79	9.10
2035/2036	11.63	8.79	12.51	14.80	12.93	9.04	7.53	4.90	9.35
2036/2037	11.99	9.21	12.52	16.35	14.77	9.25	7.76	5.08	9.58
2037/2038	12.37	9.65	13.35	16.48	17.74	9.60	7.70	5.23	9.92
2038/2039	13.89	10.08	13.39	18.35	19.48	9.96	8.02	5.43	10.33
2039/2040	13.68	11.12	13.99	21.55	18.29	10.05	8.30	5.64	10.47
2040/2041	14.38	11.63	14.55	23.86	18.63	10.35	8.63	5.91	10.87
2041/2042	14.18	11.51	14.38	26.76	19.98	10.71	8.81	6.09	11.10
2042/2043	15.11	11.70	14.62	29.81	21.33	10.69	9.11	6.24	11.21
2043/2044	16.27	12.63	15.39	31.29	24.75	11.13	9.46	6.44	11.58
2044/2045	15.66	13.44	14.89	37.01	25.06	11.69	9.76	6.68	12.09
2045/2046	17.02	13.45	15.18	41.07	24.21	11.62	11.03	6.83	12.11

Winter	Low Alternative Fuel Costs			Low Natural Gas Use			No Purchased Allowances After 2030		
	WA	ID	OR	WA	ID	OR	WA	ID	OR
2025/2026	4.31	3.38	4.63	4.80	3.60	4.86	4.32	3.38	4.63
2026/2027	4.65	3.94	5.65	5.84	4.75	6.67	4.65	3.94	5.65

2027/2028	5.03	4.08	5.81	6.91	5.36	7.26	5.03	4.08	5.81
2028/2029	5.21	4.16	6.12	7.54	5.84	7.94	5.22	4.16	6.12
2029/2030	5.37	4.03	6.45	8.02	6.17	8.65	5.39	4.03	7.77
2030/2031	5.66	4.00	6.87	8.98	6.20	9.17	8.06	4.00	8.25
2031/2032	6.35	4.15	7.07	10.43	6.60	9.59	11.90	4.15	7.09
2032/2033	6.44	4.45	7.90	10.62	7.57	11.27	13.98	4.45	8.45
2033/2034	6.91	4.64	8.30	11.47	7.87	11.41	13.09	4.64	9.14
2034/2035	7.03	4.79	8.67	11.83	8.65	12.53	14.56	4.79	10.55
2035/2036	7.46	4.89	8.95	12.40	8.84	13.12	13.69	4.89	12.77
2036/2037	7.60	5.08	9.29	13.21	9.27	13.15	14.30	5.08	12.85
2037/2038	7.52	5.23	9.54	13.16	9.68	13.79	14.15	5.23	13.66
2038/2039	7.78	5.43	9.99	14.78	10.16	14.00	14.75	5.43	13.45
2039/2040	8.03	5.64	10.20	14.69	11.10	14.90	14.34	5.65	15.16
2040/2041	8.28	5.91	10.42	15.46	11.70	15.24	14.13	5.91	15.92
2041/2042	8.55	6.09	10.83	15.12	11.57	15.12	14.74	6.09	15.69
2042/2043	8.87	6.24	10.78	16.35	11.73	15.56	15.31	6.24	16.24
2043/2044	9.15	6.45	11.29	17.43	12.61	16.60	16.36	6.44	15.86
2044/2045	9.43	6.68	11.64	16.51	13.07	15.81	15.32	6.68	16.88
2045/2046	10.35	6.83	11.87	18.45	13.36	16.04	14.01	6.83	14.22

Winter	No Climate Programs			No Growth			Preferred Resource Strategy		
	WA	ID	OR	WA	ID	OR	WA	ID	OR
2025/2026	3.68	3.38	4.63	4.31	3.38	4.63	4.32	3.38	4.63
2026/2027	3.94	3.94	5.54	4.62	3.94	5.66	4.64	3.94	5.65
2027/2028	4.15	4.08	5.67	4.98	4.08	5.83	5.03	4.08	5.81
2028/2029	4.25	4.16	5.80	5.15	4.16	6.07	5.21	4.16	6.12
2029/2030	4.34	4.03	5.87	5.30	4.03	6.39	5.37	4.03	6.50
2030/2031	4.37	4.00	5.86	5.65	4.00	6.66	5.66	4.00	7.02
2031/2032	4.60	4.15	6.09	6.33	4.15	7.01	6.35	4.15	7.37
2032/2033	4.92	4.45	6.51	6.32	4.45	7.91	6.44	4.45	8.05
2033/2034	5.15	4.64	6.71	6.79	4.64	8.49	6.91	4.64	8.47
2034/2035	5.34	4.80	6.85	6.82	4.79	8.93	7.03	4.79	9.04
2035/2036	5.43	4.89	6.96	7.11	4.89	9.20	7.41	4.89	9.28
2036/2037	5.66	5.08	7.13	7.23	5.08	9.53	7.58	5.08	9.59
2037/2038	5.79	5.24	7.26	7.34	5.23	9.74	7.52	5.23	9.87
2038/2039	5.93	5.43	7.46	7.55	5.43	10.24	7.81	5.43	10.28
2039/2040	6.08	5.64	7.66	7.78	5.64	9.89	8.05	5.65	10.55
2040/2041	6.40	5.91	7.91	8.09	5.91	10.49	8.22	5.91	10.85
2041/2042	6.55	6.09	8.10	8.24	6.10	10.68	8.55	6.10	11.13
2042/2043	6.73	6.24	8.22	8.86	6.24	10.90	8.85	6.24	11.33
2043/2044	6.89	6.44	8.39	8.81	6.44	11.28	9.15	6.44	11.55
2044/2045	7.12	6.67	8.59	9.14	6.67	11.25	9.42	6.68	12.03

2045/2046	7.20	6.83	8.39	9.65	6.83	10.10	10.35	6.84	12.31

Winter	RCP 6.5 Weather			RCP 8.5 Weather			Resiliency		
	WA	ID	OR	WA	ID	OR	WA	ID	OR
2025/2026	4.32	3.38	4.63	4.31	3.38	4.63	5.26	4.24	4.63
2026/2027	4.64	3.94	5.66	4.65	3.94	5.66	5.53	4.73	5.66
2027/2028	5.02	4.08	5.81	5.02	4.08	5.81	5.90	4.87	5.81
2028/2029	5.21	4.16	6.11	5.21	4.16	6.10	6.09	4.96	6.12
2029/2030	5.37	4.03	6.39	5.37	4.03	6.36	6.26	4.88	6.51
2030/2031	5.66	4.00	7.09	5.66	4.00	6.94	6.57	4.86	6.95
2031/2032	6.35	4.15	7.39	6.34	4.15	7.31	7.24	5.03	7.32
2032/2033	6.45	4.45	8.02	6.43	4.45	8.07	7.48	5.34	8.24
2033/2034	6.91	4.64	8.45	6.91	4.64	8.54	7.82	5.54	8.50
2034/2035	7.03	4.80	9.02	7.02	4.79	8.97	7.98	5.70	9.02
2035/2036	7.42	4.89	9.33	7.36	4.89	9.27	8.29	5.82	9.29
2036/2037	7.56	5.08	9.56	7.63	5.08	9.61	8.56	6.00	9.72
2037/2038	7.52	5.23	9.91	7.51	5.23	9.96	8.49	6.16	9.95
2038/2039	7.79	5.43	10.26	7.84	5.43	10.36	8.81	6.38	10.38
2039/2040	7.90	5.65	10.49	7.93	5.65	10.43	9.04	6.60	10.45
2040/2041	8.23	5.91	10.72	8.18	5.91	10.79	9.17	6.87	10.87
2041/2042	8.45	6.10	11.07	8.48	6.10	11.22	9.59	7.07	11.24
2042/2043	8.87	6.24	11.17	8.79	6.24	11.13	9.83	7.22	11.34
2043/2044	9.15	6.44	11.70	9.15	6.44	11.60	10.17	7.43	11.85
2044/2045	9.42	6.67	11.89	9.48	6.68	12.00	10.43	7.66	12.22
2045/2046	10.35	6.84	12.02	10.34	6.83	11.67	9.45	7.78	12.27

Winter	Social Cost of Greenhouse Gas		
	WA	ID	OR
2025/2026	4.32	3.38	4.62
2026/2027	4.64	3.94	5.65
2027/2028	5.03	4.08	5.83
2028/2029	5.22	4.17	6.05
2029/2030	5.36	4.04	7.37
2030/2031	7.23	4.01	7.34
2031/2032	9.16	4.16	7.73
2032/2033	9.44	4.45	10.13
2033/2034	9.94	4.65	11.73
2034/2035	10.53	4.80	13.11
2035/2036	12.56	4.91	11.31
2036/2037	12.62	5.10	12.23
2037/2038	12.19	5.25	14.13
2038/2039	12.54	5.45	14.64

2039/2040	13.06	5.67	13.66
2040/2041	13.04	5.93	15.03
2041/2042	14.03	6.12	13.82
2042/2043	13.24	6.27	15.12
2043/2044	14.13	6.47	15.32
2044/2045	13.70	6.69	16.13
2045/2046	10.99	6.76	15.00

Commercial Customers

Winter	Average Case			Diversified Portfolio			High Alternative Fuel Costs		
	WA	ID	OR	WA	ID	OR	WA	ID	OR
2025/2026	4.34	3.33	4.42	4.39	3.37	3.98	4.38	3.37	3.98
2026/2027	4.63	3.70	5.49	4.72	3.91	4.99	4.72	3.91	5.00
2027/2028	5.03	3.81	5.86	5.08	4.03	5.15	5.09	4.03	5.16
2028/2029	5.23	3.89	6.28	5.26	4.11	5.31	5.27	4.11	5.44
2029/2030	5.41	3.98	6.38	5.41	3.99	8.50	5.43	3.99	5.83
2030/2031	5.75	3.95	7.05	9.48	3.95	6.64	5.71	3.95	6.34
2031/2032	6.37	4.09	7.40	10.53	4.09	8.20	6.38	4.09	6.74
2032/2033	6.58	4.39	8.17	10.09	4.39	9.68	6.47	4.39	7.39
2033/2034	6.97	4.57	8.60	10.25	4.58	11.23	6.93	4.57	8.07
2034/2035	7.25	4.73	9.06	10.81	4.73	11.45	7.09	4.73	8.67
2035/2036	7.57	4.83	9.36	10.21	4.84	13.11	7.54	4.84	9.03
2036/2037	7.81	5.02	9.77	11.14	5.04	13.01	7.68	5.04	9.19
2037/2038	7.84	5.19	10.03	11.85	5.20	13.57	7.67	5.20	9.54
2038/2039	8.17	5.38	10.32	10.74	5.40	15.52	8.04	5.40	10.02
2039/2040	8.45	5.60	10.71	11.22	5.62	14.30	8.10	5.62	10.28
2040/2041	8.74	5.85	11.21	11.31	5.88	15.31	8.28	5.88	10.75
2041/2042	9.03	6.04	11.52	11.27	6.06	15.06	8.72	6.06	11.06
2042/2043	9.35	6.19	11.93	10.99	6.21	15.89	9.04	6.20	11.47
2043/2044	9.71	6.40	12.32	10.80	6.41	15.99	9.34	6.41	11.78
2044/2045	10.23	6.63	12.40	11.70	6.63	15.75	9.62	6.63	11.33
2045/2046	11.31	7.01	12.56	12.68	6.79	15.42	10.49	6.79	11.21

Winter	High CCA Allowance Pricing			High Electrification			High Growth on the Gas System		
	WA	ID	OR	WA	ID	OR	WA	ID	OR
2025/2026	4.58	3.37	3.99	4.43	3.42	3.98	4.38	3.35	3.84
2026/2027	4.93	3.91	5.00	4.79	4.00	5.00	4.74	3.89	4.95
2027/2028	5.37	4.03	5.16	7.41	5.54	5.18	5.13	4.01	5.28
2028/2029	5.58	4.11	5.44	9.78	6.96	5.35	5.32	4.09	5.70
2029/2030	5.76	3.99	5.78	10.81	8.45	5.63	5.49	3.98	5.84
2030/2031	6.12	3.95	6.23	12.85	9.53	5.38	5.78	3.95	6.41

2031/2032	6.92	4.09	6.61	16.15	11.16	5.62	6.36	4.09	6.91
2032/2033	7.05	4.39	7.37	18.72	13.16	6.44	6.58	4.38	7.75
2033/2034	7.46	4.57	7.83	22.26	15.05	6.51	6.95	4.57	8.33
2034/2035	7.64	4.73	8.32	24.94	17.15	7.41	7.23	4.73	8.88
2035/2036	8.21	4.84	8.80	31.16	23.68	7.52	7.55	4.83	9.26
2036/2037	8.47	5.04	9.00	37.73	29.42	7.70	7.79	5.02	9.66
2037/2038	8.28	5.20	9.44	45.43	33.56	7.90	7.74	5.19	9.90
2038/2039	8.60	5.40	9.81	55.84	41.97	8.09	8.06	5.38	10.31
2039/2040	9.29	5.62	9.82	70.04	53.71	7.67	8.39	5.60	10.72
2040/2041	9.64	5.88	10.35	87.29	73.65	7.62	8.51	5.86	11.28
2041/2042	9.45	6.06	10.59	150.20	99.93	7.93	8.86	6.04	11.73
2042/2043	9.82	6.20	10.61	227.92	133.60	7.29	9.14	6.18	11.85
2043/2044	10.29	6.41	10.97	292.15	175.00	7.44	9.51	6.39	12.34
2044/2045	10.59	6.63	10.82	390.28	221.18	4.15	9.82	6.62	12.60
2045/2046	12.06	6.79	10.40	445.83	242.65	2.02	11.01	6.79	12.71

Winter	High Natural Gas Prices			Hybrid Heating			I-2066		
	WA	ID	OR	WA	ID	OR	WA	ID	OR
2025/2026	4.68	3.56	4.18	4.38	3.37	3.98	4.38	3.37	3.98
2026/2027	5.70	4.73	5.98	4.72	3.91	5.00	4.75	3.91	5.00
2027/2028	6.67	5.30	6.60	5.76	6.85	5.17	5.13	4.03	5.16
2028/2029	7.26	5.80	7.32	7.48	7.47	5.40	5.31	4.11	5.44
2029/2030	7.73	6.11	7.73	8.65	6.83	5.67	5.49	3.99	5.77
2030/2031	8.22	6.13	8.25	9.37	7.49	6.01	5.79	3.95	6.26
2031/2032	9.65	6.54	8.28	10.33	8.60	6.69	6.35	4.09	6.46
2032/2033	9.84	7.50	10.17	10.96	9.58	6.79	6.56	4.39	7.20
2033/2034	10.78	7.78	10.60	12.09	10.39	7.30	6.94	4.58	7.57
2034/2035	11.23	8.55	11.09	12.72	11.43	7.83	7.25	4.73	8.13
2035/2036	11.72	8.74	11.63	15.05	13.14	8.15	7.54	4.84	8.46
2036/2037	12.11	9.17	11.63	16.70	15.08	8.37	7.79	5.04	8.79
2037/2038	12.51	9.62	12.49	16.90	18.24	8.73	7.75	5.20	9.10
2038/2039	14.03	10.06	12.58	18.92	20.06	9.16	8.10	5.40	9.53
2039/2040	13.89	11.12	13.18	22.32	18.84	9.28	8.39	5.62	9.67
2040/2041	14.54	11.60	13.76	24.82	19.30	9.57	8.74	5.88	10.11
2041/2042	14.36	11.47	13.58	27.95	20.77	9.90	8.90	6.06	10.35
2042/2043	15.28	11.67	13.79	31.28	22.27	9.85	9.20	6.20	10.46
2043/2044	16.44	12.60	14.50	33.05	26.02	10.22	9.57	6.41	10.76
2044/2045	15.86	13.40	13.71	39.43	26.33	10.43	9.87	6.63	10.95
2045/2046	17.15	13.41	13.79	43.79	25.48	10.16	11.09	6.79	10.78

Winter	Low Alternative Fuel Costs			Low Natural Gas Use			No Purchased Allowances After 2030		
	WA	ID	OR	WA	ID	OR	WA	ID	OR
2025/2026	4.39	3.37	3.98	4.88	3.59	4.20	4.39	3.37	3.98
2026/2027	4.72	3.91	5.00	5.92	4.73	6.01	4.72	3.91	5.00
2027/2028	5.09	4.03	5.16	6.97	5.32	6.63	5.10	4.03	5.16
2028/2029	5.27	4.11	5.44	7.60	5.81	7.28	5.27	4.11	5.44
2029/2030	5.43	3.99	5.72	8.07	6.14	7.88	5.45	3.99	6.93
2030/2031	5.71	3.95	6.09	9.02	6.15	8.39	8.14	3.95	7.44
2031/2032	6.38	4.09	6.21	10.43	6.57	8.70	11.92	4.09	6.24
2032/2033	6.48	4.39	6.92	10.64	7.53	10.26	13.98	4.39	7.50
2033/2034	6.94	4.58	7.32	11.49	7.82	10.39	13.12	4.58	8.20
2034/2035	7.09	4.73	7.80	11.88	8.61	11.64	14.61	4.73	9.59
2035/2036	7.54	4.84	8.12	12.47	8.80	12.25	13.65	4.84	11.70
2036/2037	7.71	5.04	8.42	13.30	9.25	12.31	14.29	5.04	11.98
2037/2038	7.66	5.20	8.76	13.30	9.67	12.96	14.21	5.20	12.73
2038/2039	7.95	5.40	9.18	14.92	10.15	13.22	14.79	5.40	12.51
2039/2040	8.22	5.62	9.43	14.90	11.12	14.16	14.38	5.62	14.19
2040/2041	8.47	5.88	9.60	15.63	11.69	14.50	14.22	5.88	15.08
2041/2042	8.73	6.06	10.04	15.31	11.55	14.40	14.81	6.06	14.78
2042/2043	9.04	6.20	9.95	16.52	11.72	14.82	15.43	6.20	15.29
2043/2044	9.34	6.41	10.44	17.60	12.59	15.76	16.48	6.41	14.97
2044/2045	9.62	6.63	10.50	16.73	13.04	14.62	15.38	6.63	15.58
2045/2046	10.49	6.79	10.54	18.58	13.33	14.60	14.14	6.79	12.83

Winter	No Climate Programs			No Growth			Preferred Resource Strategy		
	WA	ID	OR	WA	ID	OR	WA	ID	OR
2025/2026	3.74	3.37	3.98	4.38	3.37	3.98	4.39	3.37	3.98
2026/2027	4.00	3.91	4.88	4.70	3.91	5.01	4.72	3.91	5.00
2027/2028	4.20	4.03	5.02	5.06	4.03	5.19	5.09	4.03	5.16
2028/2029	4.29	4.11	5.13	5.23	4.11	5.40	5.27	4.11	5.44
2029/2030	4.38	3.99	5.15	5.38	3.99	5.64	5.43	3.99	5.75
2030/2031	4.38	3.95	5.08	5.74	3.95	5.87	5.71	3.95	6.19
2031/2032	4.60	4.09	5.24	6.41	4.09	6.15	6.38	4.09	6.47
2032/2033	4.92	4.39	5.58	6.42	4.39	7.03	6.47	4.39	7.06
2033/2034	5.15	4.57	5.76	6.90	4.58	7.54	6.94	4.58	7.52
2034/2035	5.36	4.73	5.96	6.98	4.73	8.03	7.09	4.73	8.21
2035/2036	5.48	4.84	6.10	7.31	4.84	8.38	7.49	4.84	8.41
2036/2037	5.73	5.04	6.27	7.48	5.04	8.72	7.69	5.04	8.73
2037/2038	5.89	5.20	6.41	7.62	5.20	8.94	7.66	5.20	9.02

2038/2039	6.05	5.40	6.63	7.88	5.40	9.50	7.98	5.40	9.45
2039/2040	6.23	5.62	6.86	8.14	5.62	9.15	8.25	5.62	9.77
2040/2041	6.53	5.88	7.11	8.45	5.88	9.74	8.42	5.88	10.10
2041/2042	6.68	6.06	7.31	8.59	6.06	9.97	8.73	6.06	10.37
2042/2043	6.84	6.20	7.37	9.18	6.20	10.18	9.03	6.20	10.50
2043/2044	7.01	6.41	7.51	9.15	6.41	10.52	9.34	6.41	10.73
2044/2045	7.25	6.63	7.42	9.49	6.63	10.10	9.62	6.63	10.88
2045/2046	7.32	6.79	7.01	9.92	6.79	8.56	10.49	6.79	10.85

Winter	RCP 6.5 Weather			RCP 8.5 Weather			Resiliency		
	WA	ID	OR	WA	ID	OR	WA	ID	OR
2025/2026	4.39	3.37	3.98	4.39	3.37	3.98	5.34	4.23	3.98
2026/2027	4.72	3.91	5.01	4.72	3.91	5.00	5.61	4.70	5.01
2027/2028	5.09	4.03	5.16	5.09	4.03	5.17	5.97	4.82	5.16
2028/2029	5.27	4.11	5.43	5.27	4.11	5.42	6.15	4.91	5.44
2029/2030	5.43	3.99	5.63	5.43	3.99	5.64	6.31	4.84	5.77
2030/2031	5.71	3.95	6.27	5.71	3.95	6.18	6.62	4.81	6.13
2031/2032	6.38	4.09	6.51	6.37	4.09	6.45	7.27	4.97	6.43
2032/2033	6.48	4.39	7.17	6.47	4.39	7.17	7.51	5.28	7.31
2033/2034	6.94	4.58	7.55	6.94	4.58	7.63	7.85	5.48	7.53
2034/2035	7.09	4.73	8.10	7.08	4.73	8.12	8.04	5.64	8.12
2035/2036	7.50	4.84	8.40	7.45	4.84	8.39	8.38	5.76	8.41
2036/2037	7.67	5.04	8.68	7.73	5.04	8.69	8.67	5.96	8.83
2037/2038	7.66	5.20	9.07	7.66	5.20	9.12	8.63	6.13	9.08
2038/2039	7.96	5.40	9.38	8.02	5.40	9.50	8.99	6.35	9.55
2039/2040	8.10	5.62	9.64	8.13	5.62	9.64	9.24	6.58	9.64
2040/2041	8.43	5.88	9.94	8.37	5.88	9.95	9.37	6.84	10.09
2041/2042	8.64	6.06	10.25	8.67	6.07	10.41	9.77	7.03	10.47
2042/2043	9.05	6.20	10.34	8.97	6.21	10.31	10.00	7.18	10.49
2043/2044	9.34	6.41	10.80	9.33	6.41	10.70	10.36	7.39	10.97
2044/2045	9.62	6.63	10.71	9.67	6.63	10.82	10.63	7.62	11.04
2045/2046	10.48	6.79	10.64	10.48	6.79	10.31	9.59	7.73	10.90

Winter	Social Cost of Greenhouse Gas		
	WA	ID	OR
2025/2026	4.40	3.37	3.97
2026/2027	4.72	3.91	5.00
2027/2028	5.10	4.03	5.18
2028/2029	5.28	4.12	5.37
2029/2030	5.41	4.00	6.60
2030/2031	7.28	3.96	6.45
2031/2032	9.15	4.10	6.87

2032/2033	9.42	4.39	9.16
2033/2034	9.87	4.59	10.71
2034/2035	10.49	4.74	12.18
2035/2036	12.54	4.86	10.35
2036/2037	12.64	5.06	11.28
2037/2038	12.18	5.22	13.18
2038/2039	12.56	5.42	13.68
2039/2040	13.10	5.64	12.76
2040/2041	13.07	5.90	14.08
2041/2042	14.05	6.09	12.89
2042/2043	13.28	6.23	14.22
2043/2044	14.15	6.44	14.34
2044/2045	13.77	6.65	14.89
2045/2046	11.11	6.71	13.61

Industrial Customers

Winter	Average Case			Diversified Portfolio			High Alternative Fuel Costs		
	WA	ID	OR	WA	ID	OR	WA	ID	OR
2025/2026	4.42	3.31	5.48	4.45	3.35	6.20	4.45	3.35	6.23
2026/2027	4.72	3.66	6.66	4.80	3.88	7.33	4.80	3.88	7.34
2027/2028	5.10	3.77	7.05	5.15	4.00	7.57	5.16	4.00	7.58
2028/2029	5.30	3.85	7.52	5.32	4.08	7.80	5.33	4.08	7.92
2029/2030	5.49	3.99	7.85	5.46	4.01	11.72	5.48	4.01	8.69
2030/2031	5.84	3.97	8.37	9.44	4.00	9.61	5.77	4.00	9.35
2031/2032	6.42	4.10	8.94	10.31	4.13	10.93	6.39	4.13	9.20
2032/2033	6.64	4.39	9.35	9.84	4.42	13.15	6.50	4.42	9.67
2033/2034	7.02	4.57	9.70	10.05	4.60	14.62	6.93	4.60	10.12
2034/2035	7.30	4.72	9.86	10.44	4.75	14.28	7.08	4.75	10.63
2035/2036	7.61	4.82	10.39	9.89	4.86	14.58	7.51	4.86	10.85
2036/2037	7.85	5.01	10.64	10.82	5.05	15.15	7.64	5.05	10.85
2037/2038	7.88	5.18	10.74	11.54	5.21	14.78	7.63	5.21	10.77
2038/2039	8.24	5.37	10.72	10.47	5.42	15.73	8.00	5.42	10.73
2039/2040	8.54	5.60	10.55	10.98	5.64	14.77	8.11	5.64	10.17
2040/2041	8.83	5.84	11.24	11.00	5.89	15.00	8.31	5.89	10.54
2041/2042	9.16	6.03	11.62	10.99	6.08	14.81	8.77	6.08	11.02
2042/2043	9.51	6.18	12.13	10.84	6.23	16.07	9.14	6.22	11.05
2043/2044	9.90	6.39	12.22	10.78	6.43	15.54	9.47	6.43	11.86
2044/2045	10.41	6.62	12.99	11.71	6.65	14.63	9.77	6.65	11.51
2045/2046	11.46	7.00	13.70	12.56	6.81	16.60	10.60	6.81	11.86

Winter	High CCA Allowance Pricing	High Electrification	High Growth on the Gas System

	WA	ID	OR	WA	ID	OR	WA	ID	OR
2025/2026	4.65	3.35	6.20	4.49	3.40	6.23	4.45	3.33	5.89
2026/2027	5.03	3.88	7.33	4.87	3.97	7.33	4.83	3.86	7.15
2027/2028	5.45	4.00	7.57	7.48	5.51	7.61	5.21	3.98	7.52
2028/2029	5.65	4.08	7.91	9.54	6.83	7.82	5.39	4.06	8.01
2029/2030	5.83	4.01	8.48	10.24	8.12	8.21	5.55	3.99	8.69
2030/2031	6.20	4.00	8.95	11.79	8.91	8.06	5.85	3.97	9.01
2031/2032	6.95	4.13	9.11	14.22	10.08	7.99	6.39	4.10	9.31
2032/2033	7.10	4.42	9.98	15.71	11.45	8.67	6.61	4.40	10.17
2033/2034	7.49	4.60	10.24	17.83	12.55	8.56	6.95	4.57	10.36
2034/2035	7.65	4.75	10.38	18.89	13.66	8.89	7.23	4.72	10.70
2035/2036	8.21	4.86	10.07	22.25	17.68	8.69	7.53	4.83	10.86
2036/2037	8.47	5.05	10.06	25.08	20.66	8.76	7.76	5.01	11.02
2037/2038	8.28	5.21	10.35	27.87	22.02	8.66	7.71	5.18	11.01
2038/2039	8.62	5.42	10.66	31.49	25.33	8.50	8.04	5.38	10.94
2039/2040	9.32	5.64	10.17	35.65	29.45	7.26	8.39	5.60	11.07
2040/2041	9.67	5.90	9.96	39.86	36.01	6.57	8.53	5.85	11.38
2041/2042	9.56	6.08	10.38	58.81	42.87	6.71	8.90	6.04	11.79
2042/2043	9.98	6.22	10.50	75.44	49.33	5.59	9.22	6.18	11.81
2043/2044	10.48	6.43	11.17	80.65	54.56	5.53	9.62	6.39	12.55
2044/2045	10.81	6.65	10.74	87.97	55.65	2.55	9.95	6.61	12.79
2045/2046	12.20	6.81	11.30	90.61	55.14	1.03	11.09	6.79	13.43

Winter	High Natural Gas Prices			Hybrid Heating			I-2066		
	WA	ID	OR	WA	ID	OR	WA	ID	OR
2025/2026	4.75	3.55	6.43	4.45	3.34	6.28	4.45	3.35	6.28
2026/2027	5.81	4.72	8.30	4.80	3.88	7.35	4.84	3.88	7.33
2027/2028	6.75	5.27	9.01	5.85	6.82	7.59	5.21	4.00	7.60
2028/2029	7.34	5.77	9.78	7.55	7.40	7.88	5.40	4.08	7.93
2029/2030	7.79	6.14	10.47	8.67	6.79	8.43	5.57	4.01	8.89
2030/2031	8.27	6.17	10.89	9.35	7.44	8.98	5.88	3.99	9.11
2031/2032	9.63	6.59	10.85	10.25	8.46	8.99	6.41	4.13	8.91
2032/2033	9.89	7.54	12.72	10.85	9.37	8.80	6.63	4.42	9.63
2033/2034	10.75	7.81	12.89	11.88	10.08	9.17	6.99	4.60	9.71
2034/2035	11.24	8.58	12.96	12.45	11.00	9.61	7.30	4.75	9.91
2035/2036	11.69	8.76	13.15	14.64	12.53	9.46	7.58	4.86	9.72
2036/2037	12.07	9.20	13.22	16.09	14.23	9.39	7.83	5.05	9.77
2037/2038	12.49	9.64	13.34	16.18	16.99	9.60	7.80	5.22	10.11
2038/2039	13.95	10.09	13.18	18.01	18.51	9.49	8.17	5.41	10.08
2039/2040	13.90	11.14	13.45	21.01	17.31	9.00	8.48	5.64	9.91
2040/2041	14.44	11.63	13.37	23.08	17.56	9.13	8.82	5.90	9.84
2041/2042	14.41	11.47	13.39	25.70	18.70	9.57	9.03	6.08	10.08

2042/2043	15.35	11.70	13.31	28.38	19.81	9.53	9.37	6.22	9.58
2043/2044	16.57	12.63	14.16	29.59	22.77	9.85	9.76	6.43	10.66
2044/2045	15.97	13.42	13.52	34.69	22.88	10.18	10.09	6.65	10.64
2045/2046	17.24	13.38	13.65	38.08	22.09	9.87	11.25	6.81	10.62

Winter	Low Alternative Fuel Costs			Low Natural Gas Use			No Purchased Allowances After 2030		
	WA	ID	OR	WA	ID	OR	WA	ID	OR
2025/2026	4.45	3.35	6.35	4.96	3.57	6.39	4.46	3.35	6.23
2026/2027	4.80	3.88	7.34	6.06	4.72	8.31	4.80	3.88	7.35
2027/2028	5.16	4.00	7.59	7.08	5.28	8.98	5.16	4.00	7.58
2028/2029	5.33	4.08	7.91	7.71	5.78	9.72	5.33	4.08	7.92
2029/2030	5.48	4.01	8.36	8.16	6.16	11.04	5.51	4.01	10.49
2030/2031	5.77	4.00	8.76	9.10	6.19	11.26	8.27	3.99	10.84
2031/2032	6.39	4.13	8.73	10.45	6.60	11.70	11.82	4.13	8.58
2032/2033	6.50	4.42	9.33	10.73	7.57	13.22	13.91	4.42	9.84
2033/2034	6.93	4.60	9.26	11.49	7.83	13.28	13.08	4.60	10.16
2034/2035	7.08	4.75	9.44	11.94	8.62	13.56	14.51	4.75	10.90
2035/2036	7.51	4.86	9.49	12.50	8.80	13.95	13.34	4.86	13.61
2036/2037	7.68	5.05	9.55	13.29	9.24	14.01	13.90	5.05	12.83
2037/2038	7.63	5.21	9.27	13.32	9.67	14.42	13.90	5.21	13.45
2038/2039	7.93	5.42	9.54	14.89	10.16	14.41	14.43	5.42	12.71
2039/2040	8.23	5.64	9.42	14.96	11.13	14.65	14.11	5.64	14.88
2040/2041	8.48	5.89	9.39	15.64	11.69	14.58	13.92	5.89	14.24
2041/2042	8.78	6.08	9.95	15.42	11.52	14.41	14.55	6.08	14.07
2042/2043	9.14	6.22	9.70	16.63	11.72	14.49	15.42	6.22	13.98
2043/2044	9.47	6.43	10.12	17.81	12.60	15.55	16.50	6.43	13.36
2044/2045	9.78	6.65	10.18	16.93	13.03	14.44	15.16	6.65	15.13
2045/2046	10.61	6.81	10.47	18.72	13.27	14.66	14.14	6.81	12.36

Winter	No Climate Programs			No Growth			Preferred Resource Strategy		
	WA	ID	OR	WA	ID	OR	WA	ID	OR
2025/2026	3.78	3.34	6.28	4.45	3.35	6.35	4.46	3.35	6.24
2026/2027	4.04	3.88	7.23	4.77	3.88	7.35	4.80	3.88	7.34
2027/2028	4.21	3.99	7.41	5.11	4.00	7.61	5.16	4.00	7.58
2028/2029	4.30	4.08	7.61	5.27	4.08	7.89	5.33	4.08	7.92
2029/2030	4.37	4.01	7.68	5.41	4.01	8.32	5.48	4.01	8.67
2030/2031	4.35	3.99	7.56	5.74	4.00	8.58	5.77	3.99	8.78
2031/2032	4.53	4.13	7.55	6.36	4.13	8.62	6.39	4.13	9.03
2032/2033	4.85	4.42	7.76	6.37	4.42	8.94	6.49	4.42	9.42
2033/2034	5.06	4.60	7.71	6.81	4.60	9.30	6.93	4.60	9.69

2034/2035	5.24	4.75	7.60	6.88	4.75	9.49	7.08	4.75	9.50
2035/2036	5.35	4.86	7.41	7.17	4.86	9.45	7.46	4.86	9.80
2036/2037	5.58	5.05	7.32	7.31	5.05	9.58	7.65	5.05	9.71
2037/2038	5.74	5.22	7.21	7.44	5.21	9.52	7.63	5.21	9.89
2038/2039	5.90	5.42	7.06	7.70	5.42	9.71	7.96	5.42	10.05
2039/2040	6.10	5.64	6.76	7.98	5.64	9.19	8.25	5.64	9.78
2040/2041	6.41	5.89	6.80	8.30	5.89	9.32	8.43	5.90	9.85
2041/2042	6.58	6.08	6.93	8.48	6.08	9.54	8.78	6.08	10.05
2042/2043	6.78	6.22	7.02	9.12	6.22	9.63	9.12	6.22	10.46
2043/2044	6.97	6.42	7.19	9.13	6.43	9.80	9.47	6.43	10.22
2044/2045	7.22	6.64	7.30	9.50	6.65	9.53	9.77	6.65	11.23
2045/2046	7.30	6.81	7.05	9.91	6.81	9.67	10.61	6.81	12.31

Winter	RCP 6.5 Weather			RCP 8.5 Weather			Resiliency		
	WA	ID	OR	WA	ID	OR	WA	ID	OR
2025/2026	4.46	3.34	6.27	4.45	3.35	6.26	5.42	4.22	6.41
2026/2027	4.80	3.88	7.32	4.80	3.88	7.35	5.69	4.67	7.35
2027/2028	5.16	4.00	7.57	5.16	4.00	7.59	6.04	4.79	7.59
2028/2029	5.33	4.08	7.92	5.33	4.08	7.92	6.21	4.89	7.93
2029/2030	5.48	4.01	8.40	5.48	4.01	8.33	6.37	4.86	8.50
2030/2031	5.77	3.99	9.08	5.77	3.99	8.80	6.67	4.86	8.87
2031/2032	6.39	4.13	8.90	6.39	4.13	8.83	7.28	5.01	8.96
2032/2033	6.51	4.42	9.28	6.49	4.42	9.34	7.53	5.31	9.94
2033/2034	6.93	4.60	9.35	6.93	4.60	9.39	7.85	5.50	9.81
2034/2035	7.08	4.75	9.71	7.08	4.75	9.43	8.03	5.66	10.06
2035/2036	7.47	4.86	9.91	7.42	4.86	9.96	8.36	5.78	9.91
2036/2037	7.64	5.05	10.09	7.69	5.05	9.96	8.63	5.97	10.29
2037/2038	7.63	5.22	9.95	7.62	5.21	9.98	8.60	6.15	10.39
2038/2039	7.94	5.42	10.00	8.00	5.42	9.90	8.96	6.36	10.20
2039/2040	8.10	5.64	9.77	8.14	5.64	9.83	9.24	6.60	9.87
2040/2041	8.45	5.90	9.69	8.39	5.90	10.12	9.39	6.86	9.86
2041/2042	8.69	6.08	10.10	8.72	6.09	10.39	9.82	7.05	10.43
2042/2043	9.15	6.22	10.02	9.06	6.22	10.14	10.09	7.20	10.45
2043/2044	9.46	6.43	10.57	9.46	6.43	10.47	10.49	7.41	10.98
2044/2045	9.77	6.65	10.65	9.82	6.65	10.70	10.78	7.63	11.20
2045/2046	10.59	6.81	10.97	10.58	6.81	10.49	9.86	7.75	10.94

Winter	Social Cost of Greenhouse Gas		
	WA	ID	OR
2025/2026	4.46	3.35	6.24
2026/2027	4.79	3.88	7.32
2027/2028	5.16	4.00	7.61

2028/2029	5.34	4.09	7.87
2029/2030	5.46	4.02	9.87
2030/2031	7.34	4.00	9.78
2031/2032	8.97	4.13	9.68
2032/2033	9.20	4.42	11.65
2033/2034	9.60	4.61	12.84
2034/2035	10.13	4.76	13.90
2035/2036	12.20	4.88	11.86
2036/2037	12.35	5.07	12.25
2037/2038	11.79	5.23	14.30
2038/2039	12.15	5.43	14.81
2039/2040	12.76	5.66	12.50
2040/2041	12.70	5.92	14.02
2041/2042	13.67	6.11	12.81
2042/2043	12.95	6.25	13.84
2043/2044	13.92	6.46	14.28
2044/2045	13.54	6.66	14.52
2045/2046	11.09	6.73	12.38

Transport Customers

Winter	Average Case			Diversified Portfolio			High Alternative Fuel Costs		
	WA	ID	OR	WA	ID	OR	WA	ID	OR
2025/2026	3.87	N/A	3.55	3.89	N/A	2.89	3.89	N/A	2.89
2026/2027	4.42	N/A	4.19	4.43	N/A	3.38	4.43	N/A	3.38
2027/2028	4.91	N/A	4.57	4.89	N/A	3.47	4.91	N/A	3.47
2028/2029	5.23	N/A	5.03	5.21	N/A	3.81	5.23	N/A	3.81
2029/2030	5.34	N/A	5.42	5.32	N/A	5.11	5.34	N/A	4.11
2030/2031	5.86	N/A	5.75	7.46	N/A	5.09	5.85	N/A	4.61
2031/2032	6.58	N/A	6.39	6.49	N/A	8.48	6.57	N/A	5.27
2032/2033	6.86	N/A	7.20	6.88	N/A	8.17	6.86	N/A	5.96
2033/2034	6.99	N/A	7.75	7.01	N/A	7.28	6.99	N/A	6.51
2034/2035	7.33	N/A	8.35	7.35	N/A	10.00	7.33	N/A	7.15
2035/2036	7.68	N/A	8.51	7.68	N/A	6.26	7.68	N/A	7.17
2036/2037	7.95	N/A	8.80	7.96	N/A	6.92	7.95	N/A	7.38
2037/2038	8.24	N/A	9.22	8.25	N/A	7.70	8.24	N/A	7.89
2038/2039	8.59	N/A	9.57	8.59	N/A	7.72	8.59	N/A	8.27
2039/2040	9.07	N/A	10.12	9.07	N/A	10.28	9.07	N/A	8.80
2040/2041	9.38	N/A	10.58	9.38	N/A	8.78	9.38	N/A	9.26
2041/2042	9.59	N/A	11.14	9.60	N/A	10.98	9.59	N/A	9.81
2042/2043	9.66	N/A	11.38	9.67	N/A	9.76	9.66	N/A	10.05
2043/2044	10.19	N/A	11.97	10.19	N/A	10.42	10.19	N/A	10.65
2044/2045	10.65	N/A	12.62	10.65	N/A	10.83	10.65	N/A	11.31

2045/2046	11.06	N/A	13.07	11.11	N/A	9.54	11.06	N/A	11.80

Winter	High CCA Allowance Pricing			High Electrification			High Growth on the Gas System		
	WA	ID	OR	WA	ID	OR	WA	ID	OR
2025/2026	4.15	N/A	2.89	3.89	N/A	2.89	3.87	N/A	2.68
2026/2027	4.76	N/A	3.38	4.43	N/A	3.38	4.42	N/A	3.35
2027/2028	5.37	N/A	3.47	4.90	N/A	3.37	4.90	N/A	3.76
2028/2029	5.74	N/A	3.81	5.22	N/A	3.54	5.22	N/A	4.26
2029/2030	5.91	N/A	4.13	5.34	N/A	3.66	5.34	N/A	4.67
2030/2031	6.56	N/A	4.48	5.85	N/A	3.75	5.85	N/A	5.02
2031/2032	7.45	N/A	5.43	6.56	N/A	4.21	6.57	N/A	5.71
2032/2033	7.74	N/A	5.75	6.85	N/A	4.71	6.86	N/A	6.59
2033/2034	7.89	N/A	6.31	6.98	N/A	4.86	6.99	N/A	7.20
2034/2035	8.34	N/A	7.00	7.32	N/A	5.29	7.33	N/A	7.87
2035/2036	8.85	N/A	6.99	7.67	N/A	5.48	7.68	N/A	8.01
2036/2037	9.15	N/A	7.13	7.94	N/A	5.75	7.95	N/A	8.31
2037/2038	9.46	N/A	7.75	8.23	N/A	5.97	8.24	N/A	8.80
2038/2039	9.92	N/A	8.19	8.58	N/A	6.12	8.59	N/A	9.19
2039/2040	10.57	N/A	8.73	9.05	N/A	6.70	9.07	N/A	9.83
2040/2041	10.91	N/A	9.20	9.38	N/A	6.63	9.38	N/A	10.36
2041/2042	11.16	N/A	9.63	9.46	N/A	7.76	9.59	N/A	10.97
2042/2043	11.38	N/A	9.79	10.02	N/A	8.01	9.66	N/A	11.25
2043/2044	12.14	N/A	10.26	11.37	N/A	4.48	10.19	N/A	11.95
2044/2045	12.65	N/A	10.84	11.96	N/A	3.74	10.65	N/A	12.67
2045/2046	13.09	N/A	11.33	12.90	N/A	4.98	11.06	N/A	13.14

Winter	High Natural Gas Prices			Hybrid Heating			I-2066		
	WA	ID	OR	WA	ID	OR	WA	ID	OR
2025/2026	4.12	N/A	3.13	3.89	N/A	2.89	3.89	N/A	2.89
2026/2027	5.44	N/A	4.43	4.43	N/A	3.38	4.43	N/A	3.38
2027/2028	6.28	N/A	4.90	4.91	N/A	3.46	4.91	N/A	3.47
2028/2029	7.00	N/A	5.71	5.23	N/A	3.75	5.23	N/A	3.81
2029/2030	7.38	N/A	6.13	5.34	N/A	4.04	5.34	N/A	4.08
2030/2031	7.92	N/A	6.48	5.85	N/A	4.43	5.86	N/A	4.44
2031/2032	8.85	N/A	7.69	6.57	N/A	4.83	6.57	N/A	5.33
2032/2033	9.91	N/A	8.07	6.85	N/A	5.76	6.86	N/A	5.48
2033/2034	10.08	N/A	8.53	6.99	N/A	6.25	6.99	N/A	6.28
2034/2035	11.11	N/A	9.68	7.33	N/A	6.85	7.33	N/A	7.01
2035/2036	11.43	N/A	10.12	7.68	N/A	6.80	7.68	N/A	6.97
2036/2037	11.96	N/A	11.08	7.95	N/A	6.94	7.95	N/A	7.12
2037/2038	12.47	N/A	11.96	8.24	N/A	7.47	8.24	N/A	7.69

2038/2039	13.09	N/A	12.57	8.59	N/A	7.86	8.59	N/A	8.10
2039/2040	14.24	N/A	14.02	9.06	N/A	8.33	9.07	N/A	8.60
2040/2041	14.92	N/A	14.42	9.38	N/A	8.74	9.38	N/A	9.03
2041/2042	14.72	N/A	14.54	9.59	N/A	9.15	9.59	N/A	9.65
2042/2043	14.93	N/A	14.76	9.66	N/A	9.30	9.66	N/A	9.93
2043/2044	16.38	N/A	16.23	10.19	N/A	9.62	10.19	N/A	10.42
2044/2045	17.38	N/A	17.53	10.65	N/A	10.09	10.65	N/A	11.00
2045/2046	17.46	N/A	17.97	11.06	N/A	10.58	11.06	N/A	11.49

Winter	Low Alternative Fuel Costs			Low Natural Gas Use			No Purchased Allowances After 2030		
	WA	ID	OR	WA	ID	OR	WA	ID	OR
2025/2026	3.89	N/A	2.89	4.39	N/A	3.13	3.89	N/A	2.89
2026/2027	4.43	N/A	3.38	5.77	N/A	4.43	4.43	N/A	3.38
2027/2028	4.91	N/A	3.47	6.73	N/A	4.89	4.91	N/A	3.47
2028/2029	5.23	N/A	3.81	7.51	N/A	5.53	5.23	N/A	3.81
2029/2030	5.34	N/A	4.10	7.95	N/A	5.96	5.35	N/A	3.73
2030/2031	5.85	N/A	4.37	8.63	N/A	6.68	9.14	N/A	3.80
2031/2032	6.57	N/A	5.30	9.73	N/A	7.33	15.24	N/A	4.91
2032/2033	6.86	N/A	5.45	10.81	N/A	7.83	15.65	N/A	6.06
2033/2034	6.99	N/A	6.36	10.98	N/A	8.63	15.90	N/A	6.76
2034/2035	7.33	N/A	6.98	12.12	N/A	9.89	14.11	N/A	7.51
2035/2036	7.68	N/A	6.96	12.61	N/A	10.34	10.94	N/A	8.17
2036/2037	7.95	N/A	7.12	13.16	N/A	11.05	11.27	N/A	8.72
2037/2038	8.24	N/A	7.67	13.68	N/A	11.93	12.17	N/A	9.51
2038/2039	8.59	N/A	8.09	14.42	N/A	12.54	12.02	N/A	10.07
2039/2040	9.07	N/A	8.58	15.75	N/A	14.00	11.67	N/A	10.84
2040/2041	9.38	N/A	9.01	16.46	N/A	14.43	12.05	N/A	11.51
2041/2042	9.59	N/A	9.52	16.28	N/A	14.56	12.26	N/A	12.34
2042/2043	9.66	N/A	9.74	16.65	N/A	14.79	11.76	N/A	12.82
2043/2044	10.19	N/A	10.37	18.32	N/A	16.26	12.71	N/A	13.69
2044/2045	10.65	N/A	11.05	19.38	N/A	17.53	13.13	N/A	14.59
2045/2046	11.06	N/A	11.52	19.51	N/A	17.99	13.01	N/A	15.18

Winter	No Climate Programs			No Growth			Preferred Resource Strategy		
	WA	ID	OR	WA	ID	OR	WA	ID	OR
2025/2026	2.98	N/A	2.89	3.89	N/A	2.89	3.89	N/A	2.89
2026/2027	3.34	N/A	3.38	4.43	N/A	3.38	4.43	N/A	3.38
2027/2028	3.44	N/A	3.46	4.91	N/A	3.46	4.91	N/A	3.47
2028/2029	3.57	N/A	3.55	5.23	N/A	3.61	5.23	N/A	3.81
2029/2030	3.50	N/A	3.57	5.34	N/A	3.86	5.34	N/A	4.12

2030/2031	3.53	N/A	3.48	5.85	N/A	4.20	5.85	N/A	4.61
2031/2032	3.64	N/A	3.56	6.57	N/A	4.99	6.57	N/A	5.24
2032/2033	3.89	N/A	3.85	6.85	N/A	5.42	6.86	N/A	5.52
2033/2034	3.98	N/A	3.93	6.99	N/A	5.90	6.99	N/A	6.29
2034/2035	4.13	N/A	4.06	7.33	N/A	6.53	7.33	N/A	7.01
2035/2036	4.20	N/A	4.10	7.68	N/A	6.50	7.68	N/A	6.97
2036/2037	4.42	N/A	4.31	7.95	N/A	6.65	7.95	N/A	7.12
2037/2038	4.64	N/A	4.58	8.24	N/A	7.17	8.24	N/A	7.69
2038/2039	4.79	N/A	4.73	8.59	N/A	7.58	8.59	N/A	8.10
2039/2040	4.96	N/A	4.98	9.07	N/A	8.05	9.07	N/A	8.60
2040/2041	5.20	N/A	5.16	9.38	N/A	8.47	9.38	N/A	9.03
2041/2042	5.34	N/A	5.34	9.59	N/A	8.89	9.59	N/A	9.65
2042/2043	5.16	N/A	5.24	9.66	N/A	9.04	9.66	N/A	9.93
2043/2044	5.33	N/A	5.42	10.19	N/A	9.36	10.19	N/A	10.42
2044/2045	5.65	N/A	5.71	10.65	N/A	9.82	10.65	N/A	11.00
2045/2046	5.98	N/A	6.07	11.06	N/A	10.32	11.06	N/A	11.49

Winter	RCP 6.5 Weather			RCP 8.5 Weather			Resiliency		
	WA	ID	OR	WA	ID	OR	WA	ID	OR
2025/2026	3.89	N/A	2.89	3.89	N/A	2.89	3.89	N/A	2.89
2026/2027	4.43	N/A	3.38	4.43	N/A	3.38	4.43	N/A	3.38
2027/2028	4.91	N/A	3.47	4.91	N/A	3.46	4.91	N/A	3.47
2028/2029	5.23	N/A	3.80	5.23	N/A	3.78	5.23	N/A	3.81
2029/2030	5.34	N/A	4.08	5.34	N/A	4.10	5.34	N/A	3.96
2030/2031	5.85	N/A	4.26	5.85	N/A	4.43	5.85	N/A	4.47
2031/2032	6.57	N/A	5.32	6.57	N/A	5.35	6.57	N/A	5.41
2032/2033	6.86	N/A	5.73	6.86	N/A	5.62	6.86	N/A	5.65
2033/2034	6.99	N/A	6.34	6.99	N/A	6.29	6.99	N/A	6.35
2034/2035	7.33	N/A	6.98	7.33	N/A	6.96	7.33	N/A	7.01
2035/2036	7.68	N/A	6.94	7.68	N/A	6.92	7.68	N/A	6.97
2036/2037	7.95	N/A	7.10	7.95	N/A	7.08	7.95	N/A	7.12
2037/2038	8.24	N/A	7.66	8.24	N/A	7.64	8.24	N/A	7.69
2038/2039	8.59	N/A	8.07	8.59	N/A	8.04	8.59	N/A	8.10
2039/2040	9.07	N/A	8.56	9.07	N/A	8.53	9.07	N/A	8.60
2040/2041	9.38	N/A	8.99	9.38	N/A	8.96	9.38	N/A	9.03
2041/2042	9.59	N/A	9.60	9.59	N/A	9.57	9.59	N/A	9.65
2042/2043	9.66	N/A	9.89	9.66	N/A	9.86	9.66	N/A	9.93
2043/2044	10.19	N/A	10.36	10.19	N/A	10.30	10.19	N/A	10.42
2044/2045	10.65	N/A	10.94	10.65	N/A	10.85	10.65	N/A	11.00
2045/2046	11.06	N/A	11.43	11.06	N/A	11.34	11.06	N/A	11.49

Winter	Social Cost of Greenhouse Gas

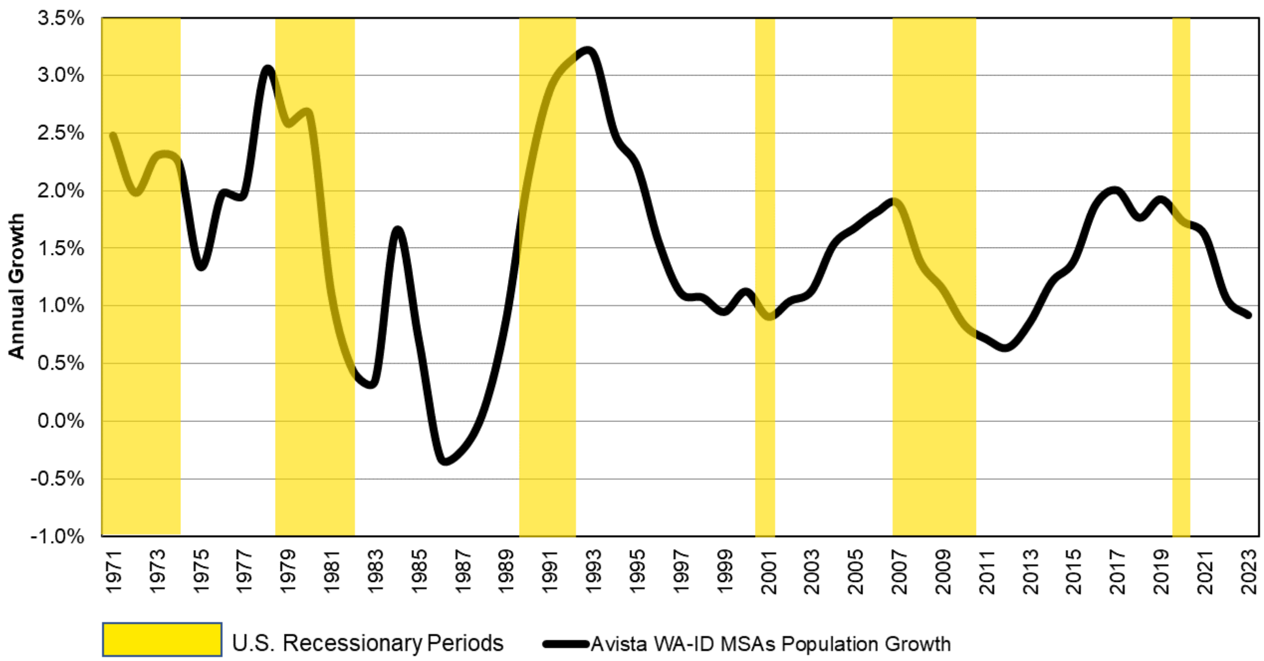
	WA	ID	OR
2025/2026	3.89	N/A	2.89
2026/2027	4.43	N/A	3.38
2027/2028	4.90	N/A	3.47
2028/2029	5.21	N/A	3.81
2029/2030	5.33	N/A	3.87
2030/2031	5.84	N/A	4.63
2031/2032	6.56	N/A	7.99
2032/2033	6.84	N/A	6.92
2033/2034	6.97	N/A	7.18
2034/2035	7.33	N/A	7.93
2035/2036	7.69	N/A	6.38
2036/2037	7.97	N/A	6.92
2037/2038	8.26	N/A	7.52
2038/2039	8.60	N/A	7.69
2039/2040	9.07	N/A	9.47
2040/2041	9.38	N/A	9.04
2041/2042	9.60	N/A	11.36
2042/2043	9.67	N/A	10.19
2043/2044	10.20	N/A	10.28
2044/2045	10.65	N/A	12.29
2045/2046	11.09	N/A	13.98

Appendix 3.1: Economic Considerations

Population

Population growth is increasingly a result of net migration to Avista's service area as more people move here. Net migration is strongly associated with both service area and national employment growth through the business cycle. The regional business cycle follows the U.S. business cycle, meaning regional economic expansions or contractions follow national economic trends.[1] Econometric analysis shows when regional employment growth is stronger than U.S. growth over the business cycle, it is associated with increased in-migration and the reverse holds true. Figure 1.1 shows annual population growth since 1971 and highlights the recessions in yellow. During all deep economic downturns since the mid-1970s, reduced population growth rates in Avista's service territory led to lower load growth.[2] The Great Recession reduced population growth from nearly 2% in 2007 to less than 1% from 2010 to 2013. Accelerating service area employment growth in 2013 helped push population growth above 1% after 2014.

Figure 1.1: MSA Population Growth and U.S. Recessions, 1971-2023

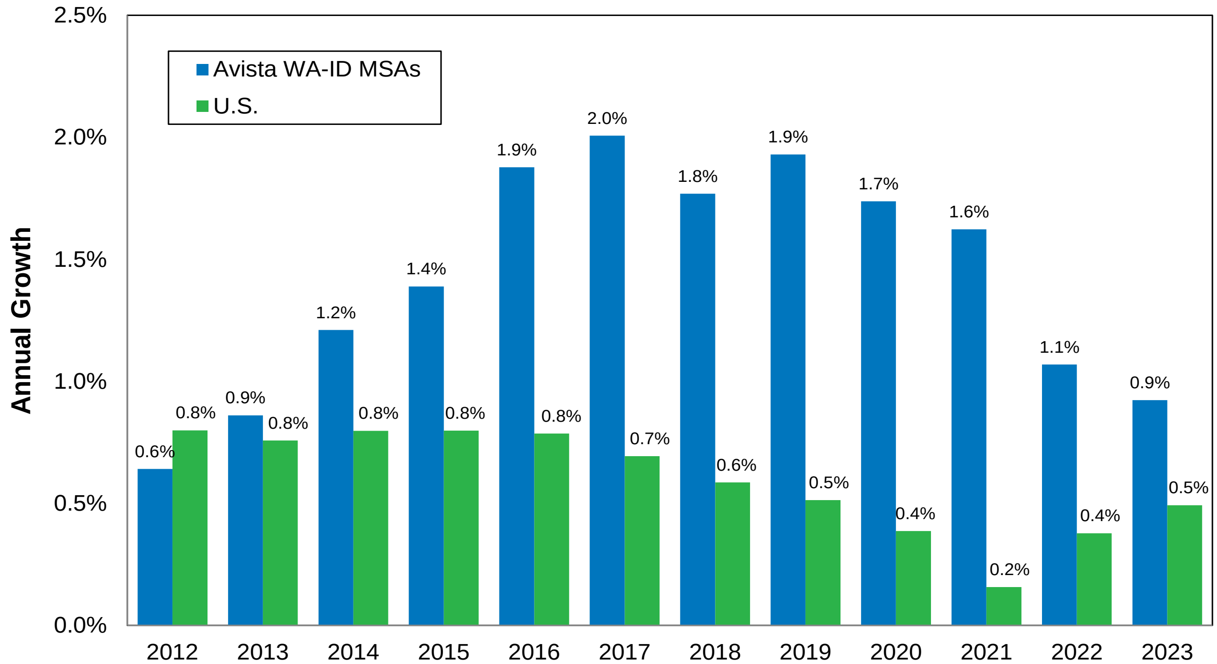


[1] *An Exploration of Similarities between National and Regional Economic Activity in the Inland Northwest*, Monograph No. 11, May 2006. http://www.ewu.edu/cbpa/centers-and-institutes/ippea/monograph-series.xml.

[2] Data Source: Bureau of Economic Development, U.S. Census, and National Bureau of Economic Research.

Figure 1.2 shows population growth since 2012.[3] Service area population growth between 2010 and 2012 was lower than the U.S.; however, it was closely associated with the strength of regional employment growth relative to the U.S. over the same period. The same can be said for the increase in service area population growth in 2014 relative to the U.S. population growth. The association of employment growth to population growth has a one-year lag. The relative strength of service area employment growth in year "y" is positively associated with service area population growth in year "y+1". Econometric estimates using historical data show when holding the U.S. employment-growth constant, every 1% increase in service area employment growth is associated with a 0.4% increase in population growth in the next year.

Figure 1.2: Avista and U.S. MSA Population Growth, 2012-2023



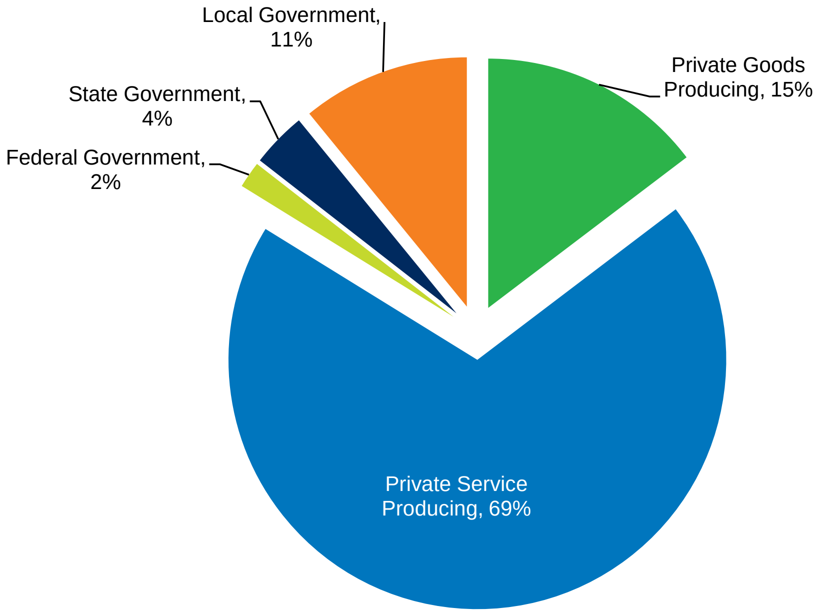
Employment

Given the correlation between population and employment growth, it is useful to examine the distribution of employment and employment performance since 2012. The Inland Northwest is a services-based economy rather than its former natural resources-based manufacturing economy. Figure 1.3 shows the breakdown of non-farm employment for all three-service area MSAs from the Bureau of Labor and Statistics. Almost 70% of employment in the three MSAs is in private services (69%), followed by government (17%) and private goods-producing sectors (15%). Farming accounts for 1% of total

[3] Data Source: Bureau of Economic Analysis, U.S. Census, and Washington State Office of Financial Management.

employment. Spokane and Coeur d'Alene MSAs are major providers of health and higher education services to the Inland Northwest.

Figure 1.3: Avista's MSA Non-Farm Employment Breakdown by Major Sector, 2023



Following the Great Recession, regional employment recovery did not materialize until 2013, when services employment started to grow.[4] Service area employment growth began to match or exceed U.S. growth rates by the fourth quarter 2014. Since the COVID-19 induced recession in 2020, service area employment has more than recovered from the losses resulting from the nationwide shutdowns. Figure 1.4 compares Avista's Washington and Idaho MSAs and the U.S. non-farm employment growth for 2012 to 2023.

[4] Data Source: Bureau of Labor and Statistics.

Figure 1.4: Avista and U.S. Non-Farm Employment Growth, 2012-2023

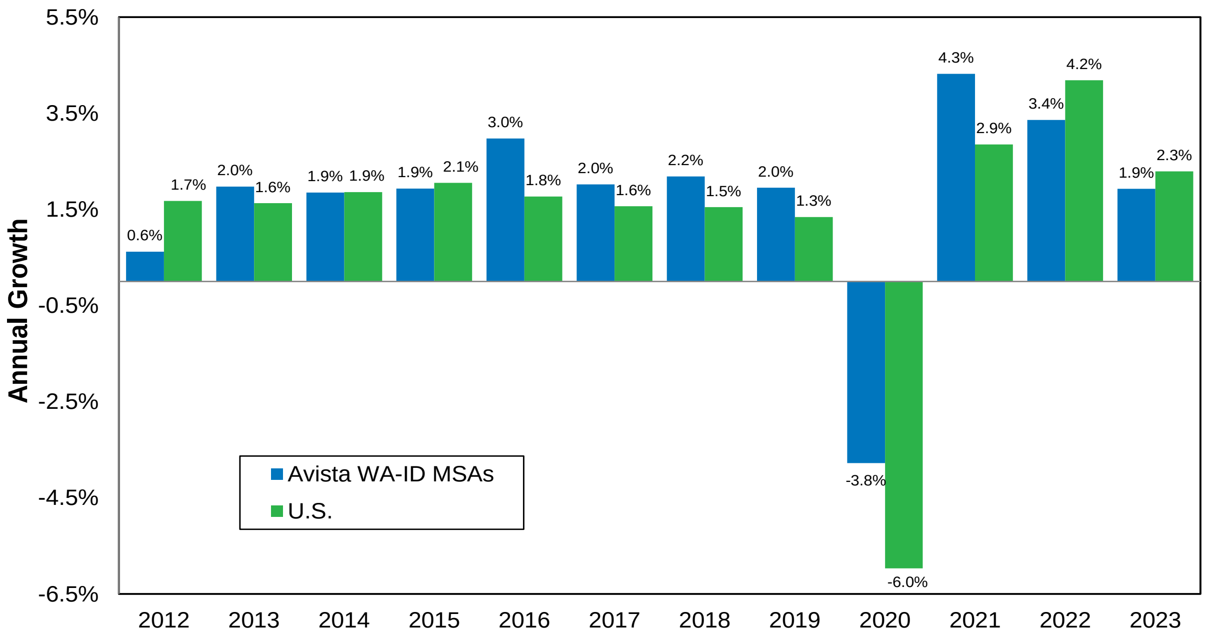


Figure 1.5 shows the distribution of personal income, a broad measure of both earned income and transfer payments, for Avista's Washington and Idaho MSAs.[5] Regular income includes net earnings from employment, and investment income in the form of dividends, interest, and rent. Personal current transfer payments include money income and in-kind transfers received through unemployment benefits, low-income food assistance, Social Security, Medicare, and Medicaid.

Transfer payments in Avista's service area in 1970 accounted for 12% of the local economy. The income share of transfer payments has nearly doubled over the last 40 years locally to 23%. Although 56% of personal income is from net earnings, transfer payments still account for more than one in every five dollars of personal income. Recent years have seen transfer payments become the fastest growing component of regional personal income. This growth in regional transfer payments reflects an aging regional population, a surge of military veterans, and the lingering impacts of the COVID-19 transfer payments to households, including enhanced unemployment benefits.

Figure 1.6 shows the real (inflation adjusted) average annual growth per capita income by MSA for Avista's service area and the U.S. overall. Although between 1980 and 1990, the service area experienced significantly lower income growth compared to the U.S. because of the back-to-back recessions of the early 1980s according to the Bureau of Economic Analysis. The impacts of these recessions were more negative in the service area compared to the U.S., so the ratio of service area per capita income to U.S. per

[5] Data Source: Bureau of Economic Analysis.

capita income fell from 93% in the 1970s to around 85% by the mid-1990s. The income ratio has not recovered.

Figure 1.5: MSA Personal Income Breakdown by Major Source, 2022

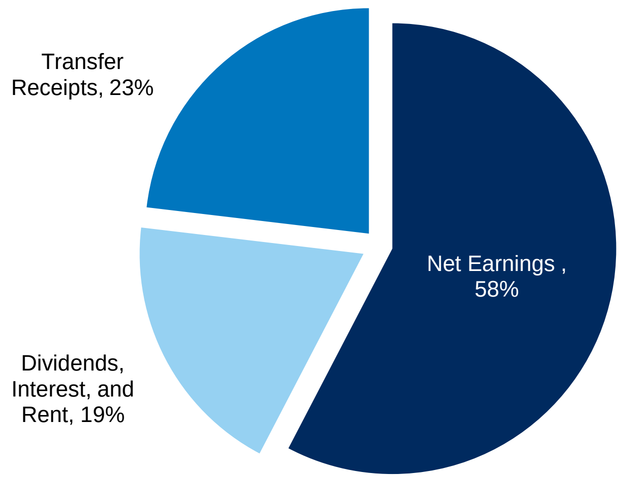
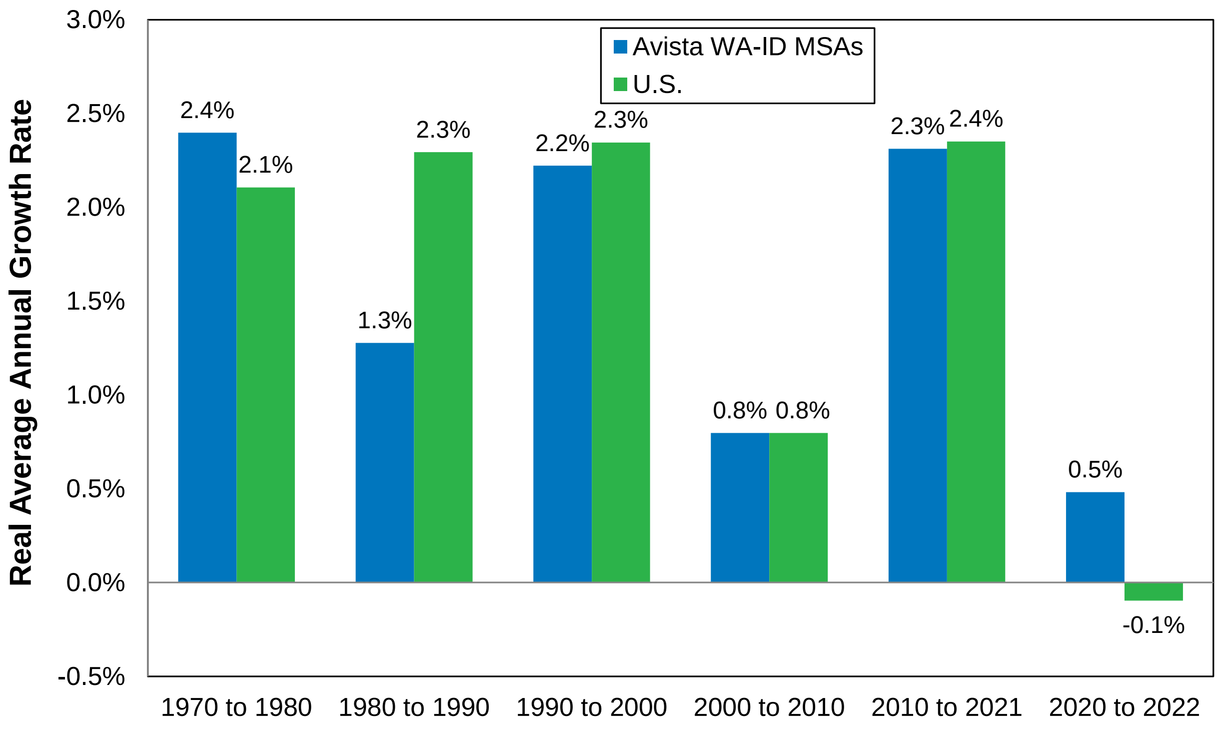


Figure 1.6: Avista and U.S. MSA Real Personal Income Growth



Overview of the Medium-Term Retail Load Forecast

As described above, the load forecast for the 2025 IRP was done in three phases. The following section describes the first phase – the development of a medium-term forecast for the period 2026-2029. The forecast serves as the basis for the second phase, an end-use forecast for the remaining period 2029 to 2045.

The medium-term forecast is based on a monthly use per customer (UPC) forecast and a monthly customer forecast for each customer class in most rate schedules.[6] The load forecast multiplies the customer and UPC forecasts. The UPC and customer forecasts are generated using time-series econometrics, as shown in Equation 1.1.

Equation 1.1: Generating Schedule Total Load

$$F(kWh_{t,y_c+j,s}) = F(kWh/C_{t,y_c+j,s}) \times F(C_{t,y_c+j,s})$$

Where:

- $\mathrm{F}(\mathrm{kWh}_{\mathrm{t,y_c+j,s}})$ = the forecast for month t, year j = 1,…,5 beyond the current year, y_c ,for schedule s.
- $\mathrm{F}(\mathrm{kWh}/\mathrm{C}_{\mathrm{t,y_c+j,s}})$ = the UPC forecast.
- $\mathrm{F}(\mathrm{C}_{\mathrm{t,y_c+j,s}})$ = the customer forecast.

UPC Forecast Methodology

The econometric modeling for UPC is a variation of the "fully integrated" approach expressed by Faruqui (2000) in the following equation:[7]

Equation 1.2: Use Per Customer Regression Equation

$$kWh/C_{t,y,s} = \alpha W_{t,y} + \beta Z_{t,y} + \epsilon_{t,y}$$

The model uses actual historical weather, UPC, and non-weather drivers to estimate the regression in Equation 1.2. To develop the forecast, normal weather replaces actual weather (W) along with the forecasted values for the Z variables (Faruqui, pp. 6-7). Here, W is a vector of heating degree day (HDD) and cooling degree day (CDD) variables; Z is a vector of non-weather variables; and $\varepsilon_{t,y}$ is an uncorrelated N(0,σ) error term. For non-weather sensitive schedules, W = 0.

The W variables are HDDs and CDDs. Depending on the rate schedule, the Z variables may include real average energy price (RAP); the U.S. Federal Reserve Industrial Production Index (IP); residential natural gas penetration (GAS); non-weather seasonal

[6] For schedules representing a single customer, where there is no customer count and for street lighting, Avista forecasts total load directly without first forecasting UPC.

[7] Faruqui, Ahmad (2000). *Making Forecasts and Weather Normalization Work Together*, Electric Power Research Institute, Publication No. 1000546, Tech Review, March 2000.

dummy variables (SD); trend functions (T); and dummy variables for outliers (OL) and periods of structural change (SC). RAP is measured as the average annual price (schedule total revenue divided by schedule total usage) divided by the Consumer Price Index (CPI), less energy. For most schedules, the only non-weather variables are SD, SC, and OL. See Table 1.1 for the occurrence RAP and IP.

If the error term appears to be non-white noise, then the forecasting performance of Equation 1.2 can be improved by converting it into an (ARIMA) "transfer function" model such that $\epsilon_{t,y} = \text{ARIMA}\epsilon_{t,y}(p,d,q)(p_k,d_k,q_k)_k$. The term p is the autoregressive (AR) order, d is the differencing order, and q is the (MA) order. The term p_k is the order of seasonal AR terms, d_k is the order of seasonal differencing, and q_k is the seasonal order of MA terms. The seasonal values relate to "k," or the frequency of the data, with the current monthly data set, k = 12.

Certain rate schedules, such as lighting, use simpler regression and smoothing methods because they offer the best fit for irregular usage without seasonal or weather-related behavior, are in a long-run steady decline, or are seasonal and unrelated to weather. Over the 2024-2028 period, Avista defines normal weather for the load forecast as a 20-year moving average of degree-days taken from the National Oceanic and Atmospheric Administration's Spokane International Airport data. Normal weather updates only occur when a full year of new data is available. For example, normal weather for 2018 is the 20-year average of degree-days for the 1998 to 2017 period; and 2019 is the average of the 1999 to 2018 period. This medium-term forecast uses the 20-year average from the 2004 to 2023 period to develop the 2024 to 2028 forecast.

The choice of a 20-year moving average for defining normal weather reflects several factors. First, climate research from the National Aeronautics and Space Administration's (NASA) Goddard Institute for Space Studies (GISS) shows a shift in temperature starting almost 30 years ago. The GISS research finds summer temperatures in the Northern Hemisphere increased one degree Fahrenheit above the 1951-1980 reference period; the increase started roughly 30 years ago in the 1981-1991 period.[8] An in-house analysis of temperature in Avista's Spokane/Kootenai service area, using the same 1951-1980 reference period, also reflects an upward shift in temperature starting about 30-years ago. As provided in Chapter 5, the longer-term temperature assumption in the IRP uses the Representative Concentration Pathways (RCP) 8.5 for June, July, August, and September, and the RCP 4.5 for the remainder of the year.

The second factor in using a 20-year moving average is the volatility of the moving average as a function of the years used to calculate the average. The 10 and 15-year moving averages show considerably more year-to-year volatility than the 20-year moving average. This volatility can obscure longer-term trends and leads to overly sharp changes

[8] See Hansen, J.; M. Sato; and R. Ruedy (2013). *Global Temperature Update Through 2012*, http://www.nasa.gov/topics/earth/features/2012-temps.html.

in forecasted loads when applying the updated definition of normal weather each year. These sharp changes would also cause excessive volatility in the revenue and earnings forecasts.

As noted earlier, if non-weather drivers appear in Equation 1.2, then they must also be in the five-year forecast used to generate the UPC forecast. The assumption in the five-year forecast is for RAP to be constant through 2028.

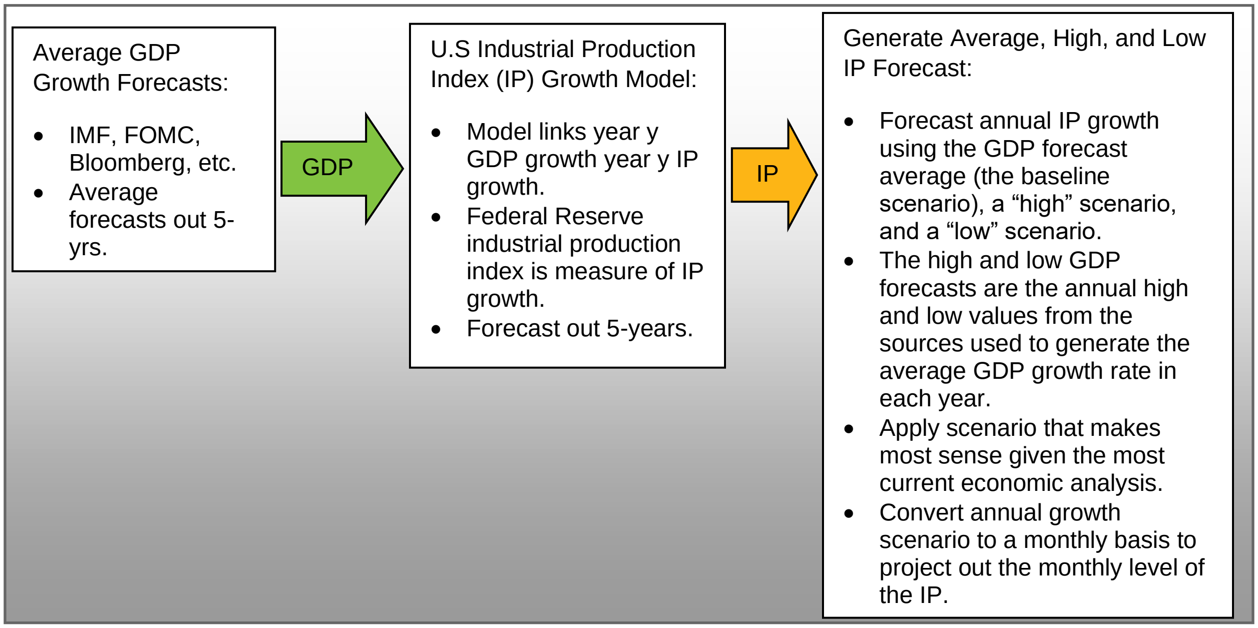
Table 1.1: UPC Models Using Non-Weather Driver Variables

Schedule	Variables	Comment
Washington:		
Residential Schedule 1	GAS	Ratio of natural gas residential schedule 101 customers in WA to electric residential schedule 1 customers in WA.
Industrial Schedules 11, 21, and 25	IP	
Idaho:		
Residential Schedule 1	GAS	Ratio of natural gas residential schedule 101 customers in ID to electric residential schedule 1 customers in ID.
Industrial Schedules 11 and 21	IP	

The forecasts for GDP reflect the average of forecasts from multiple sources including the Bloomberg survey of forecasts, the Philadelphia Federal Reserve survey of forecasters, the Wall Street Journal survey of forecasters and other sources. Averaging forecasts reduces the systematic errors of a single-source forecast and assumes macroeconomic factors flow through the UPC in the industrial rate schedules. Figure 1.7 shows the methodology for forecasting IP growth.

*This methodology was used in Idaho, Oregon and Washington for the years 2025-2028 and was calibrated to meet customer expectations and load in the AEG end use forecasts as discussed in Chapter 3.

Figure 1.7: Forecasting IP Growth



Appendix 3.2: Customer Counts

Table 1: Customer Count by State and Class

Residential	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
WA	161,429	161,501	161,573	161,645	161,717	161,789	161,862	161,934	162,006	162,078
ID	80,127	82,131	83,640	85,197	86,722	88,212	89,714	91,198	92,706	94,239
OR	96,768	97,288	97,737	98,188	98,641	99,097	99,554	100,013	100,475	100,938

Commercial	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
WA	15,227	15,215	15,203	15,191	15,179	15,167	15,155	15,143	15,131	15,119
ID	10,173	10,278	10,370	10,471	10,566	10,664	10,760	10,858	10,955	11,053
OR	12,117	12,133	12,143	12,157	12,168	12,181	12,193	12,206	12,218	12,231

Industrial	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
WA	91	91	91	91	91	91	91	91	91	91
ID	66	66	66	66	66	66	66	66	66	66
OR	25	25	25	25	25	25	25	25	25	25

Residential	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
WA	162,150	162,223	162,295	162,367	162,439	162,512	162,584	162,657	162,729	162,802
ID	95,798	97,383	98,993	100,631	102,295	103,987	105,707	107,455	109,232	111,039
OR	101,404	101,872	102,342	102,814	103,288	103,765	104,244	104,725	105,208	105,693

Commercial	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
WA	15,107	15,095	15,083	15,071	15,059	15,047	15,035	15,023	15,011	14,999
ID	11,150	11,247	11,344	11,441	11,538	11,636	11,733	11,830	11,927	12,024
OR	12,243	12,255	12,268	12,280	12,292	12,305	12,317	12,329	12,342	12,354

Industrial	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
WA	91	91	91	91	91	91	91	91	91	91
ID	66	66	66	66	66	66	66	66	66	66
OR	25	25	25	25	25	25	25	25	25	25

Table 1: Energy Intensity per Customer (Dth)

State	Class	2026	2030	2035	2040	2045
Washington	Residential	77.1	73.8	67.0	60.8	55.9
Washington	Commercial	497.1	430.8	358.8	299.5	257.1
Washington	Industrial	3,221.9	3,133.7	3,011.7	2,913.5	2,846.2
Idaho	Residential	81.5	75.4	68.8	63.2	58.7
Idaho	Commercial	359.2	345.0	331.2	322.7	322.1
Idaho	Industrial	2,894.9	2,846.1	2,757.6	2,683.3	2,628.6
Oregon	Residential	56.1	52.6	48.1	43.3	38.7
Oregon	Commercial	275.8	264.2	249.6	235.4	219.7
Oregon	Industrial	2,107.5	1,436.4	724.9	417.7	347.7

Figure 1: Energy Intensity per Residential Customer (Dth)

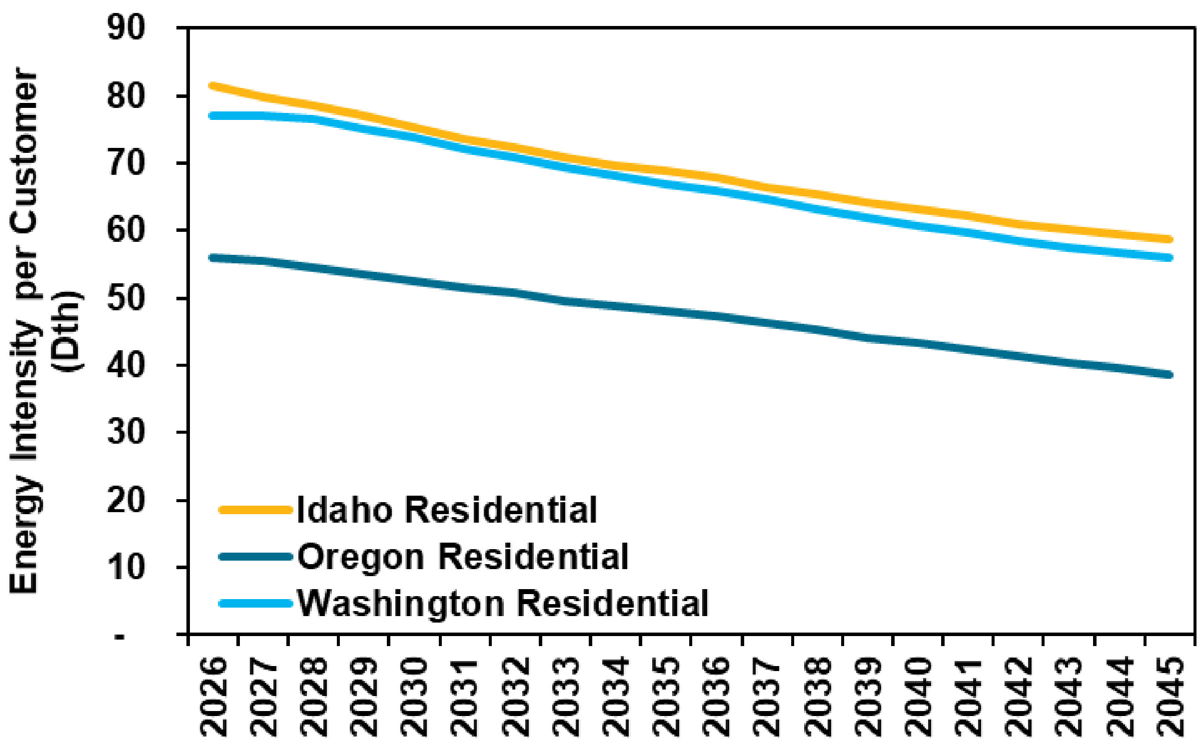


Figure 2: Energy Intensity per Commercial Customer (Dth)

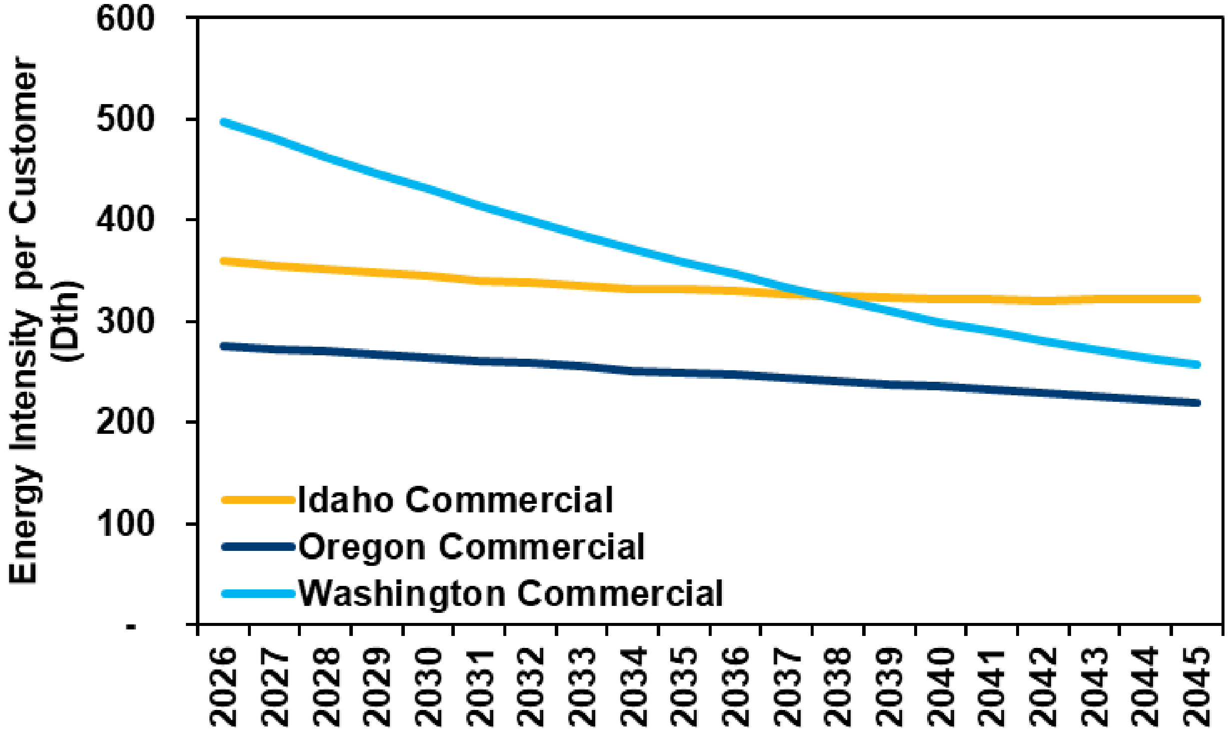
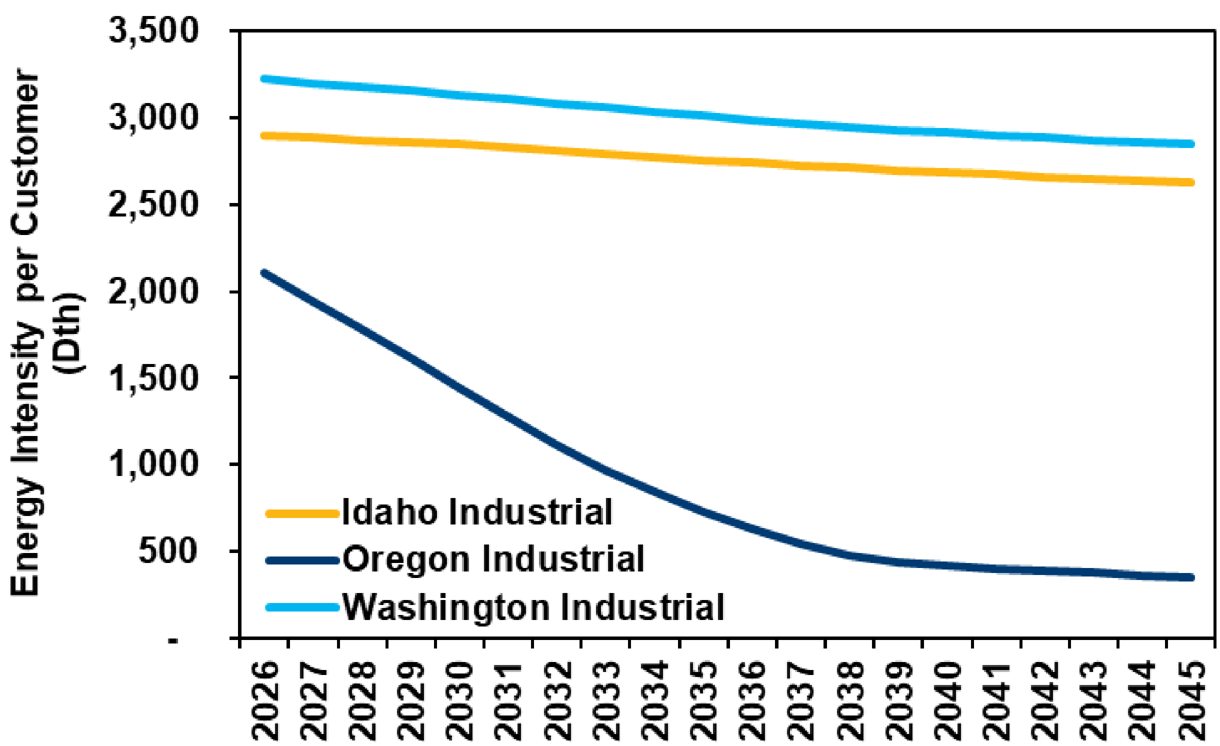


Figure 3: Energy Intensity per Residential Customer (Dth)



MONTHLY HEATING DEGREE DAYS – RCP 4.5

Klamath Falls

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	1,046	859	821	671	487	345	237	273	397	602	856	1,079
2027	1,046	858	821	671	486	344	237	273	397	602	856	1,078
2028	1,045	892	820	670	486	344	237	273	397	602	855	1,077
2029	1,044	857	820	670	486	344	237	273	397	601	855	1,077
2030	1,044	857	819	669	485	344	237	272	396	601	854	1,076
2031	1,043	856	819	669	485	344	237	272	396	600	854	1,076
2032	1,043	890	819	669	485	343	236	272	396	600	853	1,075
2033	1,042	855	818	668	485	343	236	272	396	600	853	1,074
2034	1,041	855	818	668	484	343	236	272	395	599	852	1,074
2035	1,041	854	817	668	484	343	236	272	395	599	852	1,073
2036	1,040	888	817	667	484	343	236	272	395	599	851	1,072
2037	1,040	853	816	667	483	342	236	271	395	598	851	1,072
2038	1,039	853	816	666	483	342	236	271	395	598	850	1,071
2039	1,038	853	815	666	483	342	235	271	394	598	850	1,071
2040	1,038	886	815	666	483	342	235	271	394	597	849	1,070
2041	1,037	852	814	665	482	342	235	271	394	597	849	1,069
2042	1,037	851	814	665	482	341	235	271	394	597	848	1,069
2043	1,036	851	813	664	482	341	235	270	393	596	848	1,068
2044	1,035	884	813	664	481	341	235	270	393	596	847	1,067
2045	1,035	850	812	664	481	341	235	270	393	596	847	1,067

La Grande

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	1,009	832	740	584	400	264	193	224	346	545	784	1,030
2027	1,008	832	739	583	399	263	193	224	345	545	783	1,029
2028	1,007	857	738	583	399	263	193	224	345	544	782	1,028
2029	1,006	830	737	582	398	263	193	224	345	544	781	1,027
2030	1,005	829	737	581	398	263	193	223	344	543	781	1,026
2031	1,004	828	736	581	398	262	192	223	344	543	780	1,025
2032	1,003	853	735	580	397	262	192	223	343	542	779	1,024
2033	1,002	826	734	580	397	262	192	223	343	541	778	1,023
2034	1,001	825	733	579	396	261	192	222	343	541	777	1,022
2035	1,000	825	733	578	396	261	192	222	342	540	776	1,021
2036	999	849	732	578	395	261	191	222	342	540	776	1,019
2037	998	823	731	577	395	261	191	222	342	539	775	1,018
2038	997	822	730	576	395	260	191	221	341	539	774	1,017
2039	995	821	730	576	394	260	191	221	341	538	773	1,016
2040	994	846	729	575	394	260	191	221	341	537	772	1,015
2041	993	819	728	575	393	260	190	221	340	537	772	1,014

2042	992	818	727	574	393	259	190	221	340	536	771	1,013
2043	991	818	726	573	393	259	190	220	339	536	770	1,012
2044	990	842	726	573	392	259	190	220	339	535	769	1,011
2045	989	816	725	572	392	258	190	220	339	535	768	1,010

Medford

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	762	608	551	423	285	176	79	97	201	374	600	794
2027	762	607	550	422	285	176	79	97	200	373	599	793
2028	761	629	550	422	284	176	79	97	200	373	598	792
2029	760	606	549	421	284	176	79	96	200	372	598	791
2030	759	605	548	421	284	175	79	96	200	372	597	790
2031	758	605	548	420	283	175	79	96	200	372	596	790
2032	758	626	547	420	283	175	79	96	199	371	596	789
2033	757	603	547	420	283	175	79	96	199	371	595	788
2034	756	603	546	419	283	175	79	96	199	370	594	787
2035	755	602	546	419	282	175	79	96	199	370	594	786
2036	754	623	545	418	282	174	79	96	199	370	593	785
2037	754	601	544	418	282	174	79	96	198	369	592	784
2038	753	600	544	417	281	174	78	95	198	369	592	784
2039	752	600	543	417	281	174	78	95	198	368	591	783
2040	751	621	543	416	281	174	78	95	198	368	591	782
2041	750	598	542	416	280	173	78	95	198	368	590	781
2042	750	598	541	416	280	173	78	95	197	367	589	780
2043	749	597	541	415	280	173	78	95	197	367	589	779
2044	748	618	540	415	280	173	78	95	197	366	588	779
2045	747	596	540	414	279	173	78	95	197	366	587	778

Roseburg

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	671	561	522	414	283	180	111	114	192	332	533	696
2027	670	560	521	413	282	180	111	114	192	331	533	695
2028	669	579	520	412	282	179	111	114	191	331	532	693
2029	668	558	519	411	281	179	111	114	191	330	531	692
2030	667	557	519	411	281	179	110	113	191	330	530	691
2031	666	557	518	410	280	179	110	113	191	329	529	690
2032	665	576	517	409	280	178	110	113	190	328	528	689
2033	663	555	516	409	279	178	110	113	190	328	527	688
2034	662	554	515	408	279	178	110	113	190	327	526	687
2035	661	553	514	407	278	177	109	112	189	327	525	685
2036	660	572	513	407	278	177	109	112	189	326	525	684
2037	659	551	512	406	277	177	109	112	189	326	524	683
2038	658	550	512	405	277	176	109	112	188	325	523	682

2039	657	549	511	405	276	176	109	112	188	325	522	681
2040	656	568	510	404	276	176	109	111	188	324	521	680
2041	655	547	509	403	276	176	108	111	187	324	520	679
2042	653	546	508	403	275	175	108	111	187	323	519	677
2043	652	545	507	402	275	175	108	111	187	322	518	676
2044	651	564	507	401	274	175	108	111	186	322	518	675
2045	650	544	506	401	274	174	108	111	186	321	517	674

Spokane

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	1,087	931	777	565	342	213	101	118	255	535	865	1,130
2027	1,085	929	776	564	341	212	101	118	254	534	863	1,128
2028	1,083	955	774	563	341	212	101	118	254	533	862	1,126
2029	1,081	926	773	562	340	212	101	118	253	532	860	1,124
2030	1,079	924	772	561	339	211	100	118	253	531	859	1,122
2031	1,077	923	770	560	339	211	100	117	252	530	857	1,120
2032	1,075	949	769	559	338	210	100	117	252	529	856	1,118
2033	1,073	919	768	558	338	210	100	117	252	528	854	1,116
2034	1,072	918	766	557	337	210	100	117	251	527	853	1,114
2035	1,070	916	765	556	336	209	100	117	251	526	851	1,112
2036	1,068	942	764	555	336	209	99	116	250	525	850	1,110
2037	1,066	913	762	554	335	209	99	116	250	524	848	1,108
2038	1,064	911	761	553	335	208	99	116	249	523	847	1,106
2039	1,062	909	759	552	334	208	99	116	249	522	845	1,104
2040	1,060	935	758	551	333	208	99	115	248	521	844	1,102
2041	1,058	906	757	550	333	207	98	115	248	521	842	1,101
2042	1,056	905	755	549	332	207	98	115	248	520	841	1,099
2043	1,054	903	754	548	332	206	98	115	247	519	839	1,097
2044	1,053	929	753	547	331	206	98	115	247	518	838	1,095
2045	1,051	900	751	546	331	206	98	114	246	517	836	1,093

MONTHLY HEATING DEGREE DAYS – RCP 6.5

Klamath Falls

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	1,045	858	821	670	486	344	237	273	397	602	856	1,078
2027	1,044	857	820	670	486	344	237	273	396	601	854	1,076
2028	1,043	890	819	669	485	343	236	272	396	600	853	1,075
2029	1,041	855	817	668	484	343	236	272	395	599	852	1,074
2030	1,040	854	816	667	484	342	236	271	395	599	851	1,072
2031	1,039	853	815	666	483	342	236	271	394	598	850	1,071
2032	1,037	885	814	665	482	342	235	271	394	597	849	1,069
2033	1,036	850	813	664	482	341	235	270	393	596	848	1,068

2034	1,034	849	812	663	481	341	235	270	393	595	847	1,067
2035	1,033	848	811	663	480	340	234	270	392	595	845	1,065
2036	1,032	881	810	662	480	340	234	269	392	594	844	1,064
2037	1,030	846	809	661	479	339	234	269	391	593	843	1,062
2038	1,029	845	808	660	479	339	233	269	391	592	842	1,061
2039	1,028	844	807	659	478	338	233	268	390	592	841	1,060
2040	1,026	876	806	658	477	338	233	268	390	591	840	1,058
2041	1,025	841	805	657	477	338	232	268	389	590	839	1,057
2042	1,024	840	804	656	476	337	232	267	389	589	838	1,055
2043	1,022	839	803	656	475	337	232	267	388	588	837	1,054
2044	1,021	872	802	655	475	336	232	267	388	588	836	1,053
2045	1,020	837	800	654	474	336	231	266	387	587	834	1,051

La Grande

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	1,009	832	739	584	399	264	193	224	345	545	784	1,030
2027	1,007	831	738	583	399	263	193	224	345	544	782	1,028
2028	1,006	855	737	582	398	263	193	224	344	543	781	1,027
2029	1,004	828	736	581	398	262	192	223	344	543	780	1,025
2030	1,003	827	735	580	397	262	192	223	343	542	779	1,023
2031	1,001	826	733	579	396	261	192	222	343	541	777	1,022
2032	999	850	732	578	396	261	192	222	342	540	776	1,020
2033	998	823	731	577	395	261	191	222	342	539	775	1,019
2034	996	822	730	576	395	260	191	221	341	538	774	1,017
2035	995	820	729	575	394	260	191	221	341	538	773	1,015
2036	993	845	728	575	393	259	190	221	340	537	771	1,014
2037	992	818	727	574	393	259	190	220	340	536	770	1,012
2038	990	816	725	573	392	259	190	220	339	535	769	1,011
2039	988	815	724	572	391	258	189	220	338	534	768	1,009
2040	987	840	723	571	391	258	189	219	338	533	766	1,007
2041	985	813	722	570	390	257	189	219	337	532	765	1,006
2042	984	811	721	569	390	257	189	219	337	532	764	1,004
2043	982	810	720	568	389	257	188	218	336	531	763	1,003
2044	981	835	719	567	388	256	188	218	336	530	762	1,001
2045	979	808	718	566	388	256	188	218	335	529	761	1,000

Medford

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	762	607	550	422	285	176	79	97	201	373	599	793
2027	760	606	549	422	284	176	79	96	200	373	598	792
2028	759	627	548	421	284	175	79	96	200	372	597	790
2029	757	604	547	420	283	175	79	96	199	371	596	789
2030	756	603	546	419	283	175	79	96	199	370	594	787

2031	755	602	545	418	282	174	79	96	199	370	593	786
2032	753	622	544	417	281	174	79	96	198	369	592	784
2033	752	599	543	417	281	174	78	95	198	368	591	783
2034	750	598	542	416	280	173	78	95	197	368	590	781
2035	749	597	541	415	280	173	78	95	197	367	589	780
2036	747	618	540	414	279	173	78	95	197	366	588	778
2037	746	595	539	414	279	172	78	95	196	365	587	777
2038	745	594	538	413	278	172	78	94	196	365	585	775
2039	743	593	537	412	278	172	77	94	196	364	584	774
2040	742	613	536	411	277	171	77	94	195	363	583	772
2041	740	590	535	410	277	171	77	94	195	363	582	771
2042	739	589	534	410	276	171	77	94	195	362	581	769
2043	738	588	533	409	276	170	77	94	194	361	580	768
2044	736	609	532	408	275	170	77	93	194	361	579	766
2045	735	586	531	407	275	170	77	93	193	360	578	765

Roseburg

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	671	561	522	413	282	180	111	114	192	332	533	695
2027	669	559	520	412	282	180	111	114	192	331	532	694
2028	668	578	519	411	281	179	111	114	191	330	530	692
2029	666	557	518	410	280	179	110	113	191	329	529	690
2030	664	555	517	409	280	178	110	113	190	328	528	689
2031	663	554	515	408	279	178	110	113	190	328	527	687
2032	661	573	514	407	278	177	109	112	189	327	525	685
2033	660	551	513	406	278	177	109	112	189	326	524	684
2034	658	550	512	405	277	177	109	112	188	325	523	682
2035	656	549	511	404	276	176	109	112	188	324	522	680
2036	655	567	509	403	276	176	108	111	187	324	520	679
2037	653	546	508	402	275	175	108	111	187	323	519	677
2038	652	545	507	401	274	175	108	111	187	322	518	676
2039	650	544	506	401	274	174	108	111	186	321	517	674
2040	649	562	504	400	273	174	107	110	186	321	515	672
2041	647	541	503	399	272	174	107	110	185	320	514	671
2042	645	540	502	398	272	173	107	110	185	319	513	669
2043	644	538	501	397	271	173	107	109	184	318	512	668
2044	642	557	500	396	270	172	106	109	184	318	511	666
2045	641	536	498	395	270	172	106	109	183	317	509	664

Spokane

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	1,087	931	777	564	342	213	101	118	255	535	865	1,130
2027	1,085	929	776	563	341	212	101	118	254	534	863	1,128

2028	1,083	955	774	562	341	212	101	118	254	532	861	1,126
2029	1,080	925	773	561	340	211	101	118	253	531	860	1,124
2030	1,078	923	771	560	339	211	100	117	253	530	858	1,121
2031	1,076	922	770	559	339	211	100	117	252	529	856	1,119
2032	1,074	947	768	558	338	210	100	117	252	528	855	1,117
2033	1,072	918	767	557	337	210	100	117	251	527	853	1,115
2034	1,070	916	765	556	337	209	100	117	251	526	851	1,113
2035	1,068	914	764	555	336	209	99	116	250	525	850	1,111
2036	1,066	940	762	554	335	209	99	116	250	524	848	1,108
2037	1,064	911	761	553	335	208	99	116	249	523	846	1,106
2038	1,062	909	759	551	334	208	99	116	249	522	845	1,104
2039	1,060	907	758	550	333	207	99	115	248	521	843	1,102
2040	1,058	933	756	549	333	207	98	115	248	520	842	1,100
2041	1,056	904	755	548	332	207	98	115	247	519	840	1,098
2042	1,053	902	753	547	331	206	98	115	247	518	838	1,096
2043	1,051	900	752	546	331	206	98	115	246	517	837	1,093
2044	1,049	926	750	545	330	205	98	114	246	516	835	1,091
2045	1,047	897	749	544	329	205	97	114	245	515	833	1,089

MONTHLY HEATING DEGREE DAYS – RCP 8.5

Klamath Falls

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	1,045	858	820	670	486	344	237	273	397	601	855	1,077
2027	1,043	856	818	669	485	343	236	272	396	600	853	1,075
2028	1,040	888	817	667	484	343	236	272	395	599	851	1,073
2029	1,038	852	815	666	483	342	235	271	394	598	850	1,070
2030	1,036	851	813	664	482	341	235	270	393	596	848	1,068
2031	1,034	849	812	663	481	340	234	270	393	595	846	1,066
2032	1,032	881	810	662	480	340	234	269	392	594	844	1,064
2033	1,030	845	808	660	479	339	233	269	391	593	843	1,062
2034	1,028	844	807	659	478	338	233	268	390	591	841	1,059
2035	1,025	842	805	658	477	338	233	268	389	590	839	1,057
2036	1,023	874	803	656	476	337	232	267	389	589	837	1,055
2037	1,021	838	802	655	475	336	232	267	388	588	836	1,053
2038	1,019	837	800	654	474	336	231	266	387	587	834	1,051
2039	1,017	835	798	652	473	335	231	265	386	585	832	1,048
2040	1,015	867	797	651	472	334	230	265	385	584	831	1,046
2041	1,013	831	795	650	471	334	230	264	385	583	829	1,044
2042	1,011	830	793	648	470	333	229	264	384	582	827	1,042
2043	1,009	828	792	647	469	332	229	263	383	581	825	1,040
2044	1,006	860	790	646	468	331	228	263	382	579	824	1,038
2045	1,004	825	789	644	467	331	228	262	381	578	822	1,036

La Grande

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	1,008	832	739	583	399	263	193	224	345	545	783	1,029
2027	1,006	830	737	582	398	263	193	224	345	544	782	1,027
2028	1,004	854	736	581	398	262	192	223	344	543	780	1,025
2029	1,002	826	734	580	397	262	192	223	343	541	778	1,023
2030	1,000	825	733	578	396	261	192	222	342	540	777	1,021
2031	998	823	731	577	395	261	191	222	342	539	775	1,019
2032	996	847	730	576	394	260	191	221	341	538	773	1,017
2033	994	820	728	575	394	260	190	221	340	537	772	1,014
2034	992	818	727	574	393	259	190	220	340	536	770	1,012
2035	990	816	725	572	392	259	190	220	339	535	769	1,010
2036	988	840	724	571	391	258	189	219	338	534	767	1,008
2037	985	813	722	570	390	257	189	219	337	533	765	1,006
2038	983	811	721	569	389	257	188	219	337	531	764	1,004
2039	981	809	719	568	389	256	188	218	336	530	762	1,002
2040	979	833	718	567	388	256	188	218	335	529	761	1,000
2041	977	806	716	565	387	255	187	217	335	528	759	998
2042	975	804	715	564	386	255	187	217	334	527	757	996
2043	973	803	713	563	385	254	187	216	333	526	756	994
2044	971	827	712	562	385	254	186	216	333	525	754	991
2045	969	799	710	561	384	253	186	215	332	524	753	989

Medford

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	761	607	550	422	284	176	79	97	200	373	598	792
2027	759	605	548	421	284	175	79	96	200	372	597	790
2028	757	625	547	420	283	175	79	96	199	371	595	788
2029	755	602	545	418	282	174	79	96	199	370	594	786
2030	753	600	544	417	281	174	78	95	198	369	592	784
2031	751	599	542	416	281	174	78	95	198	368	590	782
2032	749	619	541	415	280	173	78	95	197	367	589	779
2033	747	595	539	414	279	173	78	95	197	366	587	777
2034	745	594	538	413	278	172	78	94	196	365	585	775
2035	743	592	536	412	278	172	77	94	195	364	584	773
2036	740	612	535	410	277	171	77	94	195	363	582	771
2037	738	589	533	409	276	171	77	94	194	362	581	769
2038	736	587	532	408	275	170	77	93	194	361	579	767
2039	734	586	530	407	274	170	77	93	193	360	577	764
2040	732	606	529	406	274	169	76	93	193	359	576	762
2041	730	582	528	405	273	169	76	93	192	358	574	760
2042	728	581	526	404	272	168	76	92	192	357	573	758

2043	726	579	525	403	271	168	76	92	191	356	571	756
2044	724	599	523	402	271	167	76	92	191	355	569	754
2045	722	576	522	400	270	167	75	92	190	354	568	752

Roseburg

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	670	560	521	413	282	180	111	114	192	331	533	695
2027	668	559	520	412	281	179	111	114	191	330	531	693
2028	666	577	518	410	280	179	110	113	191	329	529	690
2029	664	555	516	409	280	178	110	113	190	328	528	688
2030	662	553	515	408	279	178	110	113	189	327	526	686
2031	660	552	513	407	278	177	109	112	189	326	524	684
2032	658	570	512	405	277	176	109	112	188	325	523	682
2033	656	548	510	404	276	176	109	112	188	324	521	680
2034	654	547	508	403	275	175	108	111	187	323	519	678
2035	652	545	507	401	274	175	108	111	187	322	518	675
2036	650	563	505	400	273	174	108	110	186	321	516	673
2037	648	541	504	399	273	174	107	110	185	320	515	671
2038	646	540	502	398	272	173	107	110	185	319	513	669
2039	644	538	501	396	271	173	107	109	184	318	511	667
2040	642	556	499	395	270	172	106	109	184	317	510	665
2041	640	535	497	394	269	172	106	109	183	316	508	663
2042	638	533	496	393	268	171	106	108	182	315	507	661
2043	636	531	494	392	268	171	105	108	182	314	505	659
2044	634	550	493	390	267	170	105	108	181	313	504	657
2045	632	528	491	389	266	169	105	107	181	312	502	655

Spokane

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	1,087	930	777	564	342	213	101	118	255	534	865	1,130
2027	1,084	929	775	563	341	212	101	118	254	533	863	1,128
2028	1,082	954	774	562	340	212	101	118	254	532	861	1,125
2029	1,080	925	772	561	340	211	100	118	253	531	859	1,123
2030	1,077	923	770	560	339	211	100	117	253	530	857	1,120
2031	1,075	921	769	558	338	210	100	117	252	529	856	1,118
2032	1,073	946	767	557	338	210	100	117	251	528	854	1,116
2033	1,071	917	766	556	337	210	100	117	251	527	852	1,113
2034	1,068	915	764	555	336	209	99	116	250	526	850	1,111
2035	1,066	913	762	554	335	209	99	116	250	524	848	1,109
2036	1,064	939	761	553	335	208	99	116	249	523	847	1,106
2037	1,062	909	759	551	334	208	99	116	249	522	845	1,104
2038	1,059	907	758	550	333	207	99	115	248	521	843	1,102
2039	1,057	905	756	549	333	207	98	115	248	520	841	1,099

2040	1,055	931	754	548	332	207	98	115	247	519	839	1,097
2041	1,053	902	753	547	331	206	98	115	247	518	838	1,095
2042	1,051	900	751	546	330	206	98	114	246	517	836	1,093
2043	1,048	898	750	545	330	205	98	114	246	516	834	1,090
2044	1,046	923	748	543	329	205	97	114	245	515	832	1,088
2045	1,044	894	747	542	328	204	97	114	245	514	831	1,086

MONTHLY HEATING DEGREE DAYS – 20 YEAR AVERAGE

Klamath Falls

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	1,047	859	822	671	487	345	237	273	397	603	857	1,079
2027	1,047	859	822	671	487	345	237	273	397	603	857	1,079
2028	1,047	892	822	671	487	345	237	273	397	603	857	1,079
2029	1,047	859	822	671	487	345	237	273	397	603	857	1,079
2030	1,047	859	822	671	487	345	237	273	397	603	857	1,079
2031	1,047	859	822	671	487	345	237	273	397	603	857	1,079
2032	1,047	892	822	671	487	345	237	273	397	603	857	1,079
2033	1,047	859	822	671	487	345	237	273	397	603	857	1,079
2034	1,047	859	822	671	487	345	237	273	397	603	857	1,079
2035	1,047	859	822	671	487	345	237	273	397	603	857	1,079
2036	1,047	892	822	671	487	345	237	273	397	603	857	1,079
2037	1,047	859	822	671	487	345	237	273	397	603	857	1,079
2038	1,047	859	822	671	487	345	237	273	397	603	857	1,079
2039	1,047	859	822	671	487	345	237	273	397	603	857	1,079
2040	1,047	892	822	671	487	345	237	273	397	603	857	1,079
2041	1,047	859	822	671	487	345	237	273	397	603	857	1,079
2042	1,047	859	822	671	487	345	237	273	397	603	857	1,079
2043	1,047	859	822	671	487	345	237	273	397	603	857	1,079
2044	1,047	892	822	671	487	345	237	273	397	603	857	1,079
2045	1,047	859	822	671	487	345	237	273	397	603	857	1,079

La Grande

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	1,010	833	740	585	400	264	194	225	346	546	785	1,032
2027	1,010	833	740	585	400	264	194	225	346	546	785	1,032
2028	1,010	860	740	585	400	264	194	225	346	546	785	1,032
2029	1,010	833	740	585	400	264	194	225	346	546	785	1,032
2030	1,010	833	740	585	400	264	194	225	346	546	785	1,032
2031	1,010	833	740	585	400	264	194	225	346	546	785	1,032
2032	1,010	860	740	585	400	264	194	225	346	546	785	1,032
2033	1,010	833	740	585	400	264	194	225	346	546	785	1,032
2034	1,010	833	740	585	400	264	194	225	346	546	785	1,032

2035	1,010	833	740	585	400	264	194	225	346	546	785	1,032
2036	1,010	860	740	585	400	264	194	225	346	546	785	1,032
2037	1,010	833	740	585	400	264	194	225	346	546	785	1,032
2038	1,010	833	740	585	400	264	194	225	346	546	785	1,032
2039	1,010	833	740	585	400	264	194	225	346	546	785	1,032
2040	1,010	860	740	585	400	264	194	225	346	546	785	1,032
2041	1,010	833	740	585	400	264	194	225	346	546	785	1,032
2042	1,010	833	740	585	400	264	194	225	346	546	785	1,032
2043	1,010	833	740	585	400	264	194	225	346	546	785	1,032
2044	1,010	860	740	585	400	264	194	225	346	546	785	1,032
2045	1,010	833	740	585	400	264	194	225	346	546	785	1,032

Medford

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	763	609	551	423	285	176	80	97	201	374	600	795
2027	763	609	551	423	285	176	80	97	201	374	600	795
2028	763	631	551	423	285	176	80	97	201	374	600	795
2029	763	609	551	423	285	176	80	97	201	374	600	795
2030	763	609	551	423	285	176	80	97	201	374	600	795
2031	763	609	551	423	285	176	80	97	201	374	600	795
2032	763	631	551	423	285	176	80	97	201	374	600	795
2033	763	609	551	423	285	176	80	97	201	374	600	795
2034	763	609	551	423	285	176	80	97	201	374	600	795
2035	763	609	551	423	285	176	80	97	201	374	600	795
2036	763	631	551	423	285	176	80	97	201	374	600	795
2037	763	609	551	423	285	176	80	97	201	374	600	795
2038	763	609	551	423	285	176	80	97	201	374	600	795
2039	763	609	551	423	285	176	80	97	201	374	600	795
2040	763	631	551	423	285	176	80	97	201	374	600	795
2041	763	609	551	423	285	176	80	97	201	374	600	795
2042	763	609	551	423	285	176	80	97	201	374	600	795
2043	763	609	551	423	285	176	80	97	201	374	600	795
2044	763	631	551	423	285	176	80	97	201	374	600	795
2045	763	609	551	423	285	176	80	97	201	374	600	795

Roseburg

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	672	562	523	414	283	180	111	114	192	332	534	697
2027	672	562	523	414	283	180	111	114	192	332	534	697
2028	672	582	523	414	283	180	111	114	192	332	534	697
2029	672	562	523	414	283	180	111	114	192	332	534	697
2030	672	562	523	414	283	180	111	114	192	332	534	697
2031	672	562	523	414	283	180	111	114	192	332	534	697

2032	672	582	523	414	283	180	111	114	192	332	534	697
2033	672	562	523	414	283	180	111	114	192	332	534	697
2034	672	562	523	414	283	180	111	114	192	332	534	697
2035	672	562	523	414	283	180	111	114	192	332	534	697
2036	672	582	523	414	283	180	111	114	192	332	534	697
2037	672	562	523	414	283	180	111	114	192	332	534	697
2038	672	562	523	414	283	180	111	114	192	332	534	697
2039	672	562	523	414	283	180	111	114	192	332	534	697
2040	672	582	523	414	283	180	111	114	192	332	534	697
2041	672	562	523	414	283	180	111	114	192	332	534	697
2042	672	562	523	414	283	180	111	114	192	332	534	697
2043	672	562	523	414	283	180	111	114	192	332	534	697
2044	672	582	523	414	283	180	111	114	192	332	534	697
2045	672	562	523	414	283	180	111	114	192	332	534	697

Spokane

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	1,089	932	779	566	343	213	101	119	255	536	866	1,132
2027	1,089	932	779	566	343	213	101	119	255	536	866	1,132
2028	1,089	960	779	566	343	213	101	119	255	536	866	1,132
2029	1,089	932	779	566	343	213	101	119	255	536	866	1,132
2030	1,089	932	779	566	343	213	101	119	255	536	866	1,132
2031	1,089	932	779	566	343	213	101	119	255	536	866	1,132
2032	1,089	960	779	566	343	213	101	119	255	536	866	1,132
2033	1,089	932	779	566	343	213	101	119	255	536	866	1,132
2034	1,089	932	779	566	343	213	101	119	255	536	866	1,132
2035	1,089	932	779	566	343	213	101	119	255	536	866	1,132
2036	1,089	960	779	566	343	213	101	119	255	536	866	1,132
2037	1,089	932	779	566	343	213	101	119	255	536	866	1,132
2038	1,089	932	779	566	343	213	101	119	255	536	866	1,132
2039	1,089	932	779	566	343	213	101	119	255	536	866	1,132
2040	1,089	960	779	566	343	213	101	119	255	536	866	1,132
2041	1,089	932	779	566	343	213	101	119	255	536	866	1,132
2042	1,089	932	779	566	343	213	101	119	255	536	866	1,132
2043	1,089	932	779	566	343	213	101	119	255	536	866	1,132
2044	1,089	960	779	566	343	213	101	119	255	536	866	1,132
2045	1,089	932	779	566	343	213	101	119	255	536	866	1,132

Annual Load Net of Energy Efficiency (Thousand Dekatherms)

***All cases not listed below match the PRS**

Year	PRS				
	Idaho	Oregon	Washington	Oregon Transport	Washington Transport
2026	10,377	8,823	20,307	2,606	3,181
2027	10,401	8,749	20,063	2,593	3,159
2028	10,396	8,661	19,695	2,580	3,137
2029	10,389	8,545	19,216	2,566	3,114
2030	10,373	8,441	18,760	2,551	3,090
2031	10,321	8,320	18,239	2,534	3,066
2032	10,319	8,224	17,808	2,517	3,041
2033	10,289	8,102	17,335	2,500	3,017
2034	10,286	7,993	16,910	2,483	2,994
2035	10,325	7,922	16,558	2,467	2,972
2036	10,364	7,853	16,203	2,452	2,952
2037	10,333	7,734	15,777	2,439	2,936
2038	10,345	7,614	15,393	2,428	2,921
2039	10,327	7,479	14,975	2,417	2,909
2040	10,363	7,379	14,644	2,407	2,897
2041	10,398	7,266	14,331	2,399	2,886
2042	10,391	7,137	13,970	2,391	2,878
2043	10,455	7,025	13,717	2,383	2,869
2044	10,515	6,928	13,468	2,375	2,860
2045	10,565	6,816	13,223	2,368	2,852

Year	High Electrification			High Growth on Gas System		
	Idaho	Oregon	Washington	Idaho	Oregon	Washington
2026	10,377	8,823	20,307	10,850	9,155	20,596
2027	10,401	8,748	19,877	10,923	9,213	20,592
2028	10,282	8,436	18,976	11,018	9,271	20,467
2029	9,833	8,016	17,624	11,050	9,241	20,038
2030	9,401	7,586	16,384	11,083	9,230	19,645
2031	8,942	7,195	15,141	11,105	9,221	19,230
2032	8,528	6,792	14,007	11,165	9,225	18,880
2033	8,053	6,347	12,816	11,177	9,208	18,454
2034	7,590	5,899	11,688	11,223	9,199	18,086
2035	7,187	5,528	10,690	11,288	9,252	17,752
2036	6,831	5,172	9,783	11,380	9,326	17,459
2037	6,325	4,711	8,752	11,404	9,345	17,101
2038	5,794	4,207	7,701	11,469	9,354	16,782
2039	5,266	3,682	6,703	11,532	9,364	16,471

2040	4,742	3,179	5,766	11,642	9,411	16,233
2041	4,188	2,633	4,851	11,716	9,444	15,962
2042	3,614	2,074	3,960	11,802	9,488	15,732
2043	3,041	1,446	3,119	11,917	9,512	15,545
2044	2,511	854	2,360	12,058	9,593	15,410
2045	1,888	190	1,562	12,155	9,649	15,238

Year	Hybrid Heating			Initiative 2066		
	Idaho	Oregon	Washington	Idaho	Oregon	Washington
2026	10,377	8,823	20,307	10,377	8,823	20,605
2027	10,401	8,749	20,063	10,401	8,749	20,557
2028	10,339	8,613	19,633	10,396	8,661	20,392
2029	10,271	8,453	19,088	10,389	8,545	20,105
2030	10,192	8,296	18,563	10,373	8,441	19,824
2031	10,073	8,129	17,970	10,321	8,320	19,493
2032	10,003	7,982	17,464	10,319	8,224	19,217
2033	9,901	7,806	16,911	10,289	8,102	18,915
2034	9,821	7,641	16,402	10,286	7,993	18,640
2035	9,782	7,515	15,962	10,325	7,922	18,415
2036	9,743	7,392	15,520	10,364	7,853	18,190
2037	9,629	7,214	14,998	10,333	7,734	17,921
2038	9,549	7,031	14,508	10,345	7,614	17,670
2039	9,438	6,830	13,981	10,327	7,479	17,396
2040	9,375	6,661	13,534	10,363	7,379	17,182
2041	9,305	6,476	13,096	10,398	7,266	16,984
2042	9,192	6,272	12,607	10,391	7,137	16,750
2043	9,142	6,075	12,216	10,455	7,025	16,593
2044	9,093	5,894	11,832	10,515	6,928	16,437
2045	9,020	5,688	11,435	10,565	6,816	16,289

Year	Low Natural Gas Use			No Growth		
	Idaho	Oregon	Washington	Idaho	Oregon	Washington
2026	10,112	8,606	20,366	10,377	8,823	20,058
2027	10,026	8,526	20,300	10,401	8,645	19,581
2028	9,958	8,450	20,117	10,396	8,461	18,999
2029	9,843	8,297	19,617	10,389	8,248	18,323
2030	9,722	8,159	19,153	10,373	8,049	17,684
2031	9,589	8,020	18,666	10,321	7,836	16,998
2032	9,486	7,888	18,242	10,319	7,649	16,412
2033	9,339	7,734	17,744	10,289	7,439	15,799
2034	9,217	7,583	17,299	10,286	7,244	15,242
2035	9,109	7,478	16,887	10,325	7,084	14,764
2036	9,020	7,386	16,513	10,364	6,929	14,295

2037	8,875	7,243	16,074	10,333	6,728	13,773
2038	8,761	7,085	15,670	10,345	6,529	13,298
2039	8,647	6,924	15,273	10,327	6,318	12,802
2040	8,566	6,787	14,945	10,363	6,139	12,392
2041	8,458	6,635	14,585	10,398	5,951	12,008
2042	8,360	6,480	14,256	10,391	5,748	11,590
2043	8,281	6,306	13,967	10,455	5,565	11,273
2044	8,219	6,164	13,720	10,515	5,394	10,966
2045	8,127	5,998	13,435	10,565	5,216	10,671

Year	RCP 6.5			RCP 8.5		
	Idaho	Oregon	Washington	Idaho	Oregon	Washington
2026	10,376	8,818	20,304	10,375	8,813	20,302
2027	10,399	8,739	20,058	10,396	8,730	20,053
2028	10,392	8,647	19,688	10,388	8,632	19,680
2029	10,383	8,525	19,206	10,378	8,506	19,196
2030	10,366	8,417	18,748	10,360	8,393	18,735
2031	10,313	8,291	18,224	10,304	8,263	18,210
2032	10,310	8,191	17,792	10,300	8,158	17,775
2033	10,278	8,065	17,316	10,268	8,027	17,298
2034	10,274	7,951	16,890	10,262	7,910	16,869
2035	10,311	7,875	16,535	10,298	7,829	16,513
2036	10,349	7,803	16,179	10,334	7,752	16,155
2037	10,317	7,678	15,752	10,301	7,623	15,726
2038	10,327	7,555	15,366	10,310	7,495	15,339
2039	10,309	7,415	14,946	10,290	7,352	14,918
2040	10,343	7,311	14,614	10,322	7,243	14,584
2041	10,376	7,194	14,300	10,355	7,122	14,268
2042	10,368	7,060	13,937	10,345	6,984	13,905
2043	10,431	6,944	13,684	10,406	6,864	13,650
2044	10,489	6,843	13,433	10,463	6,759	13,398
2045	10,538	6,727	13,187	10,511	6,639	13,150

Year	Average Case Weather		
	Idaho	Oregon	Washington
2026	10,868	10,609	19,454
2027	10,990	10,584	19,361
2028	11,147	10,596	19,342
2029	11,244	10,511	19,157
2030	11,359	10,467	19,042
2031	11,469	10,419	18,920
2032	11,627	10,418	18,877
2033	11,683	10,315	18,665

2034	11,788	10,260	18,539
2035	11,895	10,202	18,418
2036	12,059	10,194	18,390
2037	12,124	10,084	18,211
2038	12,246	10,024	18,124
2039	12,372	9,962	18,050
2040	12,554	9,950	18,064
2041	12,627	9,834	17,921
2042	12,758	9,767	17,874
2043	12,888	9,699	17,827
2044	13,077	9,680	17,872
2045	13,151	9,569	17,758

AVISTA NATURAL GAS CONSERVATION POTENTIAL ASSESSMENT FOR 2026-2045

Prepared for: Avista Corporation

By: Applied Energy Group, Inc., proudly part of ICF

Date: February 28, 2025

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1 | Introduction

In May 2023, Avista Corporation (Avista) engaged Applied Energy Group (AEG) to conduct a Conservation Potential Assessment (CPA) for its Washington and Idaho service areas. AEG first performed an electric CPA for Avista in 2013; since then, AEG has performed both electric and natural gas CPAs for Avista's subsequent planning cycles. The CPA is a 20-year study of electric and natural gas conservation potential, performed in accordance with Washington Initiative 937 and associated Washington Administrative Code provisions. This study provides data on conservation resources to support the development of Avista's 2025 Integrated Resource Plan (IRP). For reporting purposes, the potential results are separated by fuel. This report documents the natural gas CPA.

Notable updates from prior CPAs include:

- For the residential sector, the study still incorporates Avista's GenPOP residential saturation survey from 2012, which provides a more localized look at Avista's customers than regional surveys. The survey provided the foundation for the base year market characterization and energy market profiles. The Northwest Energy Efficiency Alliance's (NEEA's) 2016 Residential Building Stock Assessment II (RBSA) supplemented the GenPOP survey to account for trends in the intervening years.
    - Note that the 2022 RBSA was published in April 2024, too late in the study process to be integrated into the baseline.
- The list of energy conservation measures was updated with research from the Regional Technical Forum (RTF). Connected Thermostats were removed from potential in all states due to the intention of the RTF to sunset that measure at the end of 2025.
- The study incorporates updated forecasting assumptions that align with the most recent Avista load forecast.
- Updated information from the US Energy Information Administrations Residential and Commercial Building Energy Consumption Surveys (RECS 2020 and CBECS 2018, both datasets released in 2022-2023) was used to supplement base year characterization of residential and commercial customers

Enhancement retained from the previous CPA include:

- The residential segmentation differentiates low-income customers from others, with unique market characterization, building shell and usage characteristics.
- For the commercial sector, the analysis was performed for the major building types in the service territory. Results from NEEA's 2019 Commercial Building Stock Assessment (CBSA), including hospital and university data, provided useful information for this analysis. Measure characterizations continue to use data from the Northwest Power and Conservation Council's 2021 Power Plan where this is the most current source, including measure data, adoption rates, and updated measure applicability.

Summary of Report Contents

The report is divided into the following chapters, summarizing the approach, assumptions, and results of the electric CPA.

- **Chapter 2 – Energy Efficiency Analysis Approach and Data Development.** A detailed description of AEG's approach to estimating the energy efficiency potential and documentation of data sources used.

- **Chapter 3 – Energy Efficiency Market Characterization.** Presents how Avista's customers use natural gas today and what equipment is currently being used.
- **Chapter 4 – Energy Efficiency Baseline Projection.** Presents the baseline end-use projections developed for each sector and state, as well as a summary.
- **Chapter 5 – Conservation Potential.** Energy efficiency potential results for each state across all sectors and separately for each sector.
- **Chapter 6 – Sector-Level Energy Efficiency Potential.** Summary of energy efficiency potential for each market sector within Avista's service territory for both Washington and Idaho. This chapter includes a detailed breakdown of potential by measure type, vintage, market segment, end use, and state.
- **Chapter 7 – Demand Response Potential.** Natural gas demand response potential results for each state across all sectors and separately for each sector.

Volume 2, Appendices

- **The appendices** for this report are provided in separate spreadsheets accompanying the delivery of this report and consist of the following:
- **Oregon Low-Income Conservation Potential.** Memo describing methodology and results of this additional study.
- **Natural Gas Transportation Customer Conservation Potential.** Memo describing methodology and results of this additional study.
- **Market Profiles.** Detailed market profiles for each market segment. Includes equipment saturation, unit energy consumption or energy usage index, energy intensity, and total consumption.
- **Market Adoption Rates.** Documentation of the ramp rates used in this analysis. These were adapted from the 2021 Power Plan electrical power conservation supply curve workbooks for the estimation of achievable natural gas potential.
- **Measure Data.** List of measures and input assumptions, along with baseline definitions and efficiency options by market sector analyzed.

There are three types of tables presented in the report to easily distinguish between the types of data presented. There is one type of table for each: general Avista data, Washington-specific data, and Idaho-specific data.

Abbreviations and Acronyms

Error! Reference source not found. provides a list of abbreviations and acronyms used in this report, along with an explanation.

Table 1-1 Explanation of Abbreviations and Acronyms

Acronym	Explanation
ACS	U.S. Census American Community Study
AEG	Applied Energy Group
AEO	EIA's Annual Energy Outlook
BEST	AEG's Building Energy Simulation Tool
C&I	Commercial and Industrial
CBSA	NEEA's Commercial Building Stock Assessment
COMMEND	EPRI's Commercial End-Use Planning System
CPA	Conservation Potential Assessment
DEEM	AEG's Database of Energy Efficiency Measures
DEER	California Database for Energy Efficient Resources
DR	Demand Response
DSM	Demand Side Management
EIA	Energy Information Administration
EPRI	Electric Power Research Institute
EUI	Energy Use Index
HDD	Heating Degree Day
HVAC	Heating Ventilation and Air Conditioning
IFSA	NEEA's Industrial Facilities Site Assessment
IRP	Integrated Resource Plan
LoadMAP	AEG's Load Management Analysis and Planning™ tool
NEEA	Northwest Energy Efficiency Alliance
NWPCC	Northwest Power and Conservation Council
O&M	Operations and Maintenance
RBSA	NEEA's Residential Building Stock Assessment
REEPS	EPRI's Residential End-Use Energy Planning System
RTF	NWPCC's Regional Technical Forum
TRC	Total Resource Cost test
TRM	Technical Reference Manual
UCT	Utility Cost Test
UEC	Unit Energy Consumption
WSEC	2015 Washington State Energy Code
Acronym	Explanation
ACS	U.S. Census American Community Study
AEG	Applied Energy Group
AEO	EIA's Annual Energy Outlook
BEST	AEG's Building Energy Simulation Tool

2 | Energy Efficiency Analysis Approach and Development

This section describes the analysis approach taken and the data sources used to develop the energy efficiency potential estimates. The demand response analysis discussion can be found in 7 |

Overview of Analysis Approach

To perform the potential analysis, AEG used a bottom-up approach following the major steps listed below. These steps are described in more detail throughout this section.

0. Perform a market characterization to describe sector-level electricity use for the residential, commercial, and industrial sectors for the base year 2021. The market characterization included extensive use of Avista data and other secondary data sources from NEEA and the Energy Information Administration (EIA).
1. Develop a baseline projection of energy consumption and peak demand by sector, segment, and end use for 2021 through 2045.
2. Define and characterize several hundred conservation measures to be applied to all sectors, segments, and end uses.
3. Estimate technical, achievable technical, and achievable economic energy savings at the measure level for 2026 through 2045. Achievable economic potential was assessed using the Utility Cost Test (UCT) test for Avista's Idaho territory and the Total Resource Cost (TRC) test for Avista's Washington territory. Comparison with NWPCC Methodology

It is important to note that electricity is the primary focus of the regionwide potential assessed in the NWPCC's Plans. Natural gas impacts are typically assessed when they overlap with electricity measures (e.g., gas water heating impacts in an electrically heated "Built Green Washington" home). Although Avista is a dual-fuel utility, this study focuses on natural gas measures and programs, which exhibit noticeable differences from electric programs, notably regarding avoided costs. To account for this, AEG sometimes adapted NWPCC methodologies rather than using them directly from the source. This adaptation is especially relevant in the development of ramp rates when achievability was determined not to be applicable to a specific natural gas measure or program.

A primary objective of the study was to estimate natural gas potential consistent with the NWPCC's analytical methodologies and procedures for electric utilities. While developing Avista's 2025 - 2045 CPA, AEG relied on an approach vetted and adapted through the successful completion of CPAs referencing the NWPCC's Fifth, Sixth, Seventh, and now 2021 Power Plans. Among other aspects, this approach involves using consistent:

- Data sources: Avista surveys, regional surveys, market research, and assumptions
- Measures and assumptions: Avista TRM, 2021 Power Plan supply curves and RTF work products
- Potential factors: 2021 Power Plan ramp rates
- Levels of potential: technical, achievable technical, and achievable economic
- Cost-effectiveness approaches: assessed potential under the UCT for Idaho and TRC for Washington, including non-energy impacts (and non-gas energy impacts), which may be quantified and monetized, as well as operations and maintenance (O&M) impacts within the TRC.
- Conservation credit: applied NWPCC 10% conservation credit to avoided energy costs in Washington for energy benefits. This is incorporated into the TRC calculation.

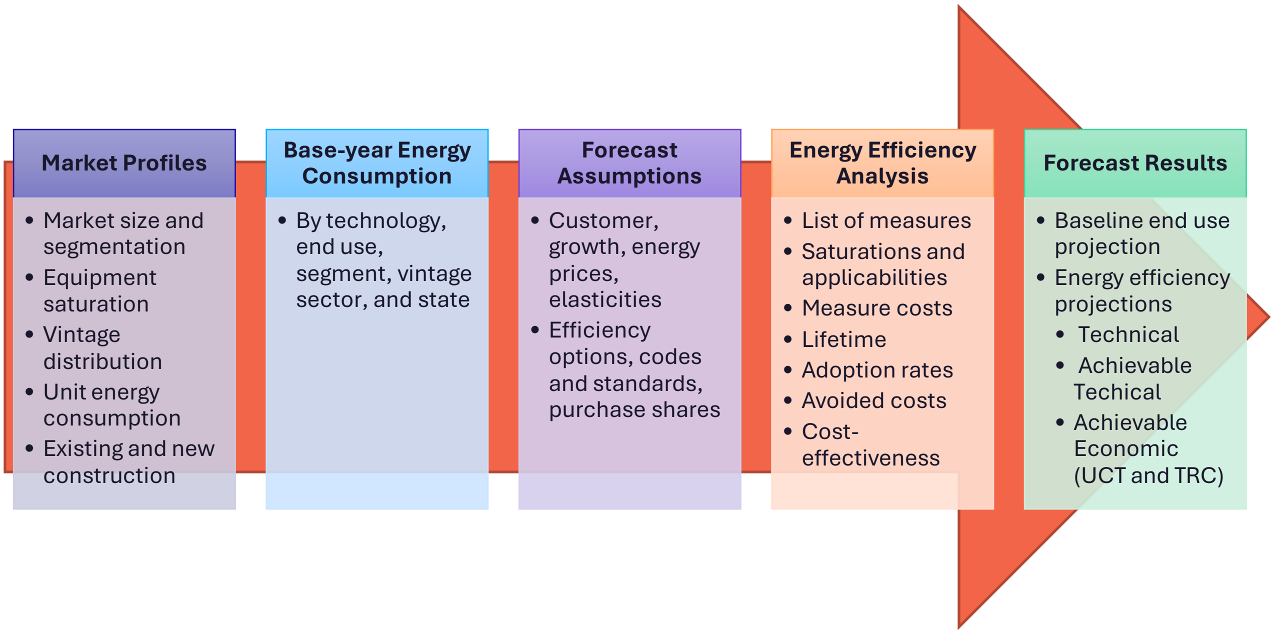
LoadMAP Model

AEG used its Load Management Analysis and Planning tool (LoadMAP™) version 5.0 to develop both the baseline projection and the estimates of potential. AEG developed LoadMAP in 2007 and has enhanced it over time, using it for the Electric Power Research Institute (EPRI) National Potential Study and numerous utility-specific forecasting and potential studies since that time. Built in Excel, the LoadMAP framework (see Figure 2-1) is both accessible and transparent and has the following key features:

- Embodies the basic principles of rigorous end-use models (such as EPRI's REEPS and COMMEND) but in a more simplified, accessible form.
- Includes stock-accounting algorithms that treat older, less efficient appliance/equipment stock separately from newer, more efficient equipment. Equipment is replaced according to the measure life and appliance vintage distributions defined by the user.
- Balances the competing needs of simplicity and robustness. This is done by incorporating important modeling details related to equipment saturations, efficiencies, vintage, and the like, where market data are available, and treats end uses separately to account for varying importance and availability of data resources.
- Isolates new construction from existing equipment and buildings and treats purchase decisions for new construction and existing buildings separately. This is especially relevant in the state of Washington where the 2015 Washington State Energy Code (WSEC) substantially enhances the efficiency of the new construction market.
- Uses a simple logic for appliance and equipment decisions. Other models available for this purpose embody complex decision-choice algorithms or diffusion assumptions. The model parameters tend to be difficult to estimate or observe, and sometimes produce anomalous results that require calibration or even overriding. The LoadMAP approach allows the user to drive the appliance and equipment choices year by year directly in the model. This flexible approach allows users to import the results from diffusion models or to input individual assumptions. The framework also facilitates sensitivity analysis.
- Includes appliance and equipment models customized by end use. For example, the logic for water heating is distinct from furnaces and fireplaces.
- Can accommodate various levels of segmentation. Analysis can be performed at the sector level (e.g., total residential) or for customized segments within sectors (e.g., housing type, state, or income level).
- Natively outputs model results in a detailed line-by-line summary file, allowing for review of input assumptions, cost-effectiveness results, and potential estimates at a granular level. Also allows for the development of IRP supply curves, both at the achievable technical and achievable economic potential levels.
- Can incorporate conservation measures, demand-response options, combined heat and power, distributed generation options, and fuel switching.

Consistent with the segmentation scheme and market profiles described below, LoadMAP provides projections of baseline energy use by sector, segment, end use, and technology for existing and new buildings. It provides forecasts of total energy use and energy efficiency savings associated with the various types of potential.

Figure 2-1 LoadMAP Analysis Framework



Definitions of Potential

AEG's approach for this study adheres to the approaches and conventions outlined in the National Action Plan for Energy Efficiency's Guide for Conducting Potential Studies and is consistent with the methodology used by the Northwest Power and Conservation Council to develop its regional power plans. The guide represents the most credible and comprehensive industry practice for specifying conservation potential. Two types of potential were developed as part of this effort:

- **Technical Potential** is the theoretical upper limit of conservation potential. It assumes that customers adopt all feasible efficient measures regardless of their cost. At the time of existing equipment failure, customers replace their equipment with the most efficient option available. In new construction, customers and developers choose the efficient equipment option relative to applicable codes and standards. Non-equipment measures, which may be realistically installed apart from equipment replacements, are implemented according to ramp rates developed by the NWPCC for its 2021 Power Plan, applied to 100% of the applicable market. This case is provided primarily for planning and informational purposes.
- **Achievable Technical Potential** refines Technical Potential by applying market adoption rates that account for market barriers, customer awareness and attitudes, program maturity, and other factors that may affect market penetration of energy efficiency measures. AEG used achievability assumptions from the NWPCC's 2021 Power Plan, adjusted for Avista's recent program accomplishments, as the customer adoption rates for this study. For the achievable technical case, ramp rates are applied to between 85% - 100% of the applicable market, per NWPCC methodology. This achievability factor represents potential that all available mechanisms, including utility programs, updated codes and standards, and market transformation, can reasonably acquire. Thus, the market applicability assumptions utilized in this study include savings outside of utility programs. The market adoption factors can be found in Appendix D.
- UCT Achievable Economic Potential further refines achievable technical potential by applying a cost-effectiveness screen. The UCT test assesses cost-effectiveness from the utility's perspective. This test compares lifetime energy benefits to the costs of delivering the measure through a utility program, excluding monetized non-energy impacts. The costs are the incentive, as a percent of the

incremental cost of the given measure, relative to the relevant baseline (e.g., the federal standard for lost opportunity and no action for retrofits), plus any administrative costs that are incurred by the program to deliver and implement the measure. If the benefits outweigh the costs (that is, if the UCT ratio is greater than 1.0), a given measure is included in the economic potential.

- TRC Achievable Economic Potential also refines achievable technical potential through cost-effectiveness analysis. The TRC test assesses cost-effectiveness from a combined utility and participant perspective. As such, this test includes the full cost of the measure and non-energy impacts realized by the customer (if quantifiable and monetized). AEG also assessed the impacts of non-gas savings following the NWPCC methodology. For the assessment, AEG used a calibration credit for space heating equipment consumption to account for secondary heating equipment present in an average home as well as other electric end-use impacts, such as cooling and interior lighting (as applicable), on a measure-by-measure basis.

Market Characterization

To estimate the savings potential from energy efficient measures, it is necessary to understand how much energy is used today and what equipment is currently being used. The characterization begins with a segmentation of Avista's electricity footprint to quantify energy use by sector, segment, end-use application, and the current set of technologies used. To complete this step, AEG relied on information from Avista, NEEA, and secondary sources, as necessary.

Segmentation for Modeling Purposes

The market assessment first defined the market segments (building types, end uses, and other dimensions) that are relevant in the Avista service territory. The segmentation scheme for this project is presented in Table 2-1.

Table 2-1 Overview of Avista Analysis Segmentation Scheme

Dimension	Segmentation Variable	Description
1	Sector	Residential, commercial, industrial
2	Segment	Residential: single family, multifamily, manufactured home, differentiated by income level Commercial: small office, large office, restaurant, retail, grocery, college, school, health, lodging, warehouse, and miscellaneous Industrial: total
3	Vintage	Existing and new construction
4	End uses	Heating, secondary heating, water heating, food preparation, process, and miscellaneous (as appropriate by sector)
5	Appliances/end uses and technologies	Technologies such as furnaces, water heaters, and process heating by application, etc.
6	Equipment efficiency levels for new purchases	Baseline and higher-efficiency options as appropriate for each technology

With the segmentation scheme defined, AEG then performed a high-level market characterization of natural gas sales in the base year to allocate sales to each customer segment. AEG used Avista data and secondary sources to allocate energy use and customers to the various sectors and segments such that the total customer count, and energy consumption matched the Avista system totals from billing data. This information provided control totals at a sector level for calibrating LoadMAP to known data for the base year.

Market Profiles

The next step was to develop market profiles for each sector, customer segment, end use, and technology. The market profiles provide the foundation for the development of the baseline projection and the potential estimates. A market profile includes the following elements:

- ***Market size*** is a representation of the number of customers in the segment. For the residential sector, it is the number of households. In the commercial sector, it is floor space measured in square feet. For the industrial sector, it is the number of employees.
- ***Saturations*** define the fraction of homes or square feet with the various technologies (e.g., homes with electric space heating).
  - Conditioned space accounts for the fraction of each building that is conditioned by the end use, applying to cooling and heating end uses.
  - The whole-building approach measures shares of space in a building with an end use regardless of the portion of each building served by the end use. Examples are commercial refrigeration, food service, and domestic water heating and appliances.
  - The 100% saturation approach applies to end uses generally present in every building or home and are set to 100% in the base year.
- ***UEC (unit energy consumption) or EUI (energy use index)*** describes the amount of energy consumed in 2021 by a specific technology in buildings that have the technology. UECs are expressed in therms/household for the residential sector, and EUIs are expressed in therms/square foot for the commercial sector, or therms/employee for the industrial sector.
- ***Annual Energy Intensity*** for the residential sector represents the average energy use for the technology across all homes in 2021 and is the product of the saturation and UEC. The commercial and industrial sectors represent the average use for the technology across all floor space or employees in 2021 and is the product of the saturation and EUI.
- ***Annual Usage*** is the annual energy use by an end-use technology in the segment. It is the product of the market size and intensity and is quantified in therms or dtherms.

The market characterization is presented in Chapter 3, and market profiles are presented in Appendix C.

Baseline Projection

The next step was to develop the baseline projection of annual natural gas use for 2021 through 2045 by customer segment and end use in the absence of new utility energy efficiency programs. The savings from past programs are embedded in the forecast, but the baseline projection assumes that those past programs cease to exist in the future. Possible savings from future programs are captured by the potential estimates. The projection includes the impacts of known codes and standards, which will unfold over the study timeframe. All such mandates that were defined as of January 2024 are included in the baseline.

The baseline projection is the foundation for the analysis of savings from future conservation efforts as well as the metric against which potential savings are measured. Although AEG's baseline projection aligns closely with Avista's, it is not Avista's official load forecast.

Inputs to the baseline projection include:

- Avista's official forecast (Heating Degree Days base 65°F (HDD65)), calibrated to actual sales
- Current economic growth forecasts (i.e., customer growth, income growth, changes in weather (HDD65 normalization)))
- Natural gas price forecasts

- Trends in fuel shares and equipment saturations
- Existing and approved changes to building codes and equipment standards
- Avista's internally developed sector-level projections for natural gas sales

The baseline projection is presented in Chapter 4.

Conservation Measure Analysis

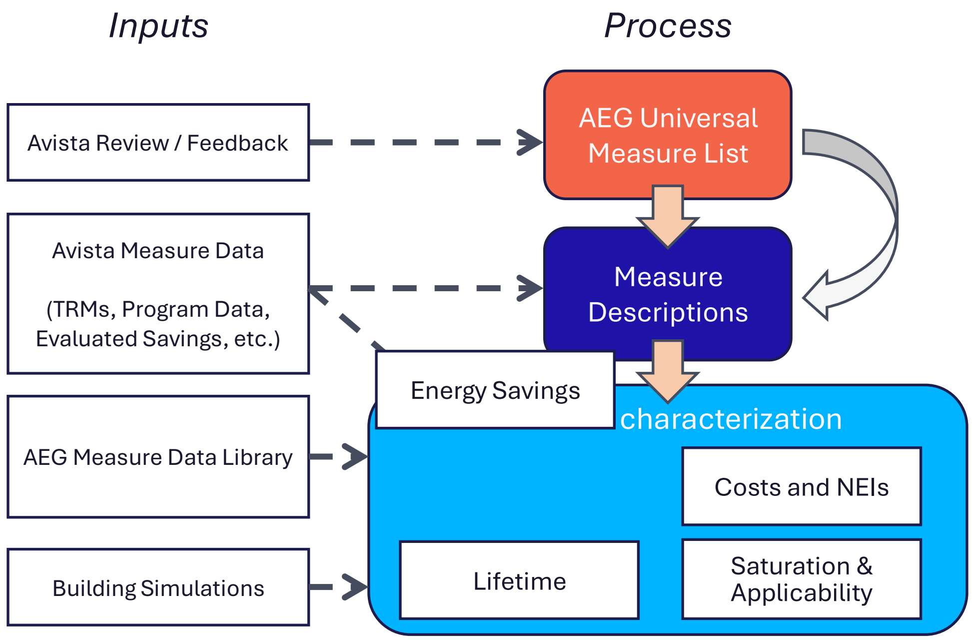
This section describes the framework used to assess conservation measures' savings, costs, and other attributes. These characteristics form the basis for measure-level cost-effectiveness analyses and for determining measure savings. For all measures, AEG assembled information to reflect equipment performance, incremental costs, and equipment lifetimes. We used this information combined with Avista's avoided cost data to inform the economic screens that Leadetermine economically feasible measures.

Conservation Measures

Error! Reference source not found. outlines the framework for conservation measure analysis. The framework involves identifying the list of measures to include in the analysis, determining their applicability to each sector and segment, fully characterizing each measure. Potential measures include the replacement of a unit that has failed or is at the end of its useful life with an efficient unit, retrofit, or early replacement of equipment, improvements to the building envelope, the application of controls to optimize energy use, and other actions resulting in improved energy efficiency.

AEG compiled a robust list of conservation measures for each customer sector, drawing upon Avista's measure database, the RTF, and the 2021 Power Plan deemed measures database, as well as a variety of secondary sources. This universal list of conservation measures covers all major types of end-use equipment, as well as devices and actions to reduce energy consumption. Avista provided feedback during each step to ensure measure assumptions and results lined up with programmatic experience.

Figure 2-2 Approach for Conservation Measure Assessment



The selected measures are categorized into the two following types according to the LoadMAP taxonomy:

- **Equipment measures** are efficient energy-consuming pieces of equipment that save energy by providing the same service with a lower energy requirement than a standard unit. An example is an ENERGY STAR® residential water heater (UEF 0.64) that replaces a standard efficiency water heater (UEF 0.58). For equipment measures, many efficiency levels may be available for a given technology, ranging from the baseline unit (often determined by code or standard) up to the most efficient product commercially available. These measures are applied on a stock-turnover basis and are generally referred to as lost opportunity measures by the NWPCC because once a purchase decision is made, there will not be another opportunity to improve the efficiency of the equipment until its effective useful life is reached. The 2021 Power Plan's "Lost Opportunity" ramp rates are primarily applied to equipment measures.
- **Non-equipment measures** save energy by reducing the need for delivered energy but do not involve replacement or purchase of major end-use equipment (such as a furnace or water heater). An example would be a programmable thermostat that is pre-set to run heating systems only when people are home. Non-equipment measures can apply to more than one end use or fuel type. For instance, the addition of wall insulation will affect the energy use of both space heating and cooling. The 2021 Power Plan's "Retrofit" ramp rates are primarily applied to non-equipment measures. Non-equipment measures typically fall into one of the following categories:
    - Building shell (windows, insulation, roofing material)
    - Equipment controls (thermostat, water heater setback)
    - Equipment maintenance (cleaning filters, changing setpoints)
    - Whole-building design (building orientation, advanced new construction designs)
    - Commissioning and Retrocommissioning (initial or ongoing monitoring of building energy systems to optimize energy use)

We developed a preliminary list of conservation measures, which was distributed to the Avista project team for review. The list was finalized after incorporating comments. Next, the project team characterized measure savings, incremental cost, service life, non-energy impacts, and other performance factors, drawing upon data from the Avista measure database, the 2021 Power Plan, the RTF deemed measure workbooks, simulation modeling, and other well-vetted sources as required. Following the measure characterization, we performed an economic screening of each measure, which serves as the basis for developing the economic and achievable potential scenarios. Measure data can be found in Appendix C. Table 2-2 summarizes the number of measures evaluated for each segment within each sector.

Table 2-2 Number of Measures Evaluated

Sector	Total Measures	Measure Permutations w/ 2 Vintages	Measure Permutations w/ All Segments & States
Residential	64	128	1,536
Commercial	76	152	3,040
Industrial	43	86	172
Total Measures Evaluated	**183**	**366**	**4,748**

Data Development

This section details the data sources used in this study, followed by a discussion of how these sources were applied. In general, data sources were applied in the following order: Avista data, Northwest regional data, and well-vetted national or other regional secondary sources. Data were adapted to local conditions, for example, by using local sources for measure data and local weather for building simulations.

Avista Data

Our highest priority data sources for this study were those that were specific to Avista.

- ***Customer Data:*** Avista provided billing data for the development of customer counts and energy use for each sector. We also used the results of the Avista GenPOP survey, a residential saturation survey.
- ***Load Forecasts:*** Avista provided forecasts, by sector and state, of energy consumption, customer counts, weather actuals for 2021, as well as weather-normal HDD65.
- ***Economic Information:*** Avista provided a discount rate as well as avoided cost forecasts consistent with those utilized in the IRP.
- ***Program Data:*** Avista provided information about past and current programs, including program descriptions, goals, and achievements to date.
- ***Avista TRM:*** Avista provided energy conservation measure assumptions within current programs. We utilized this as a primary source of measure information, supplemented secondary data.

Northwest Energy Efficiency Alliance Data

The NEEA conducts research for the Northwest region. The NEEA surveys were used extensively to develop base saturation and applicability assumptions for many of the non-equipment measures within the study. The following studies were particularly useful:

- RBSA II, Single-Family Homes Report 2016-2017.
- RBSA II, Manufactured Homes Report 2016-2017.

- RBSA II, Multifamily Buildings Report 2016-2017.
- 2019 Commercial Building Stock Assessment (CBSA), May 21, 2020.
- 2014 Industrial Facilities Site Assessment (IFSA), December 29, 2014.

Northwest Power and Conservation Council Data

Several sources of data were used to characterize the conservation measures. We used the following regional data sources and supplemented them with AEG's data sources to fill in any gaps.

- RTF Deemed Measures. The NWPCC RTF maintains databases of deemed measure savings data.
- NWPCC 2021 Power Plan Conservation Supply Curve Workbooks. To develop its 2021 Power Plan, the Council used workbooks with detailed information about measures.
- NWPCC, MC and Loadshape File, September 29, 2016. The Council's load shape library was utilized to convert CPA results into hourly conservation impacts for use in Avista's IRP process.

AEG Data

AEG maintains several databases and modeling tools that we use for forecasting and potential studies. Relevant data from these tools have been incorporated into the analysis and deliverables for this study.

- ***AEG Energy Market Profiles:*** AEG maintains regional profiles of end-use consumption. The profiles include market size, fuel shares, unit consumption estimates, annual energy use by fuel (electricity and natural gas), customer segment, and end use for ten (10) regions in the U.S. The U.S. Energy Information Administration (EIA) surveys (RECS, CBECS, and MECS), as well as state-level statistics and local customer research provide the foundation for these regional profiles.
- ***Building Energy Simulation Tool (BEST):*** AEG's BEST is a derivative of the DOE 2.2 building simulation model, used to estimate base-year UECs and EUIs, as well as measure savings for the HVAC-related measures.
- ***AEG's Database of Energy Efficiency Measures (DEEM):*** AEG maintains an extensive database of measure data, drawing upon reliable sources including the California Database for Energy Efficient Resources (DEER), the EIA Technology Forecast Updates – Residential and Commercial Building Technologies – Reference Case, RS Means cost data, and Grainger Catalog Cost data.
- ***Recent studies:*** AEG has conducted numerous studies of energy efficiency potential in the last five years, both within the region and across the country. We checked our input assumptions and analysis results against the results from these other studies both within the region and across the country.

Other Secondary Data and Reports

Finally, a variety of secondary data sources and reports were used for this study. The main sources include:

- ***Annual Energy Outlook (AEO):*** Conducted each year by the U.S. EIA, the AEO presents yearly projections and analysis of energy topics. For this study, we used data from the 2023 AEO.
- ***EIA Survey Data (RECS, CBECS, MECS):*** Used to supplement end use saturations and consumption where more local data was not available. This study used data from the 2020 RECS, 2018 CBECS, and 2018 MECS, which are the most recent data sets available.
- ***Local Weather Data:*** Weather from National Oceanic and Atmospheric Administration's National Climatic Data Center for Spokane, Washington and Coure d'Alene in Idaho were used as the basis for building simulations.
- ***Other relevant regional sources:*** These include reports from the Consortium for Energy Efficiency, the Environmental Protection Agency, and the American Council for an Energy-Efficient

Economy. When using data from outside the region, especially weather-sensitive data, AEG adapted assumptions for use within Avista's territory.

Data Application

We now discuss how the data sources described above were used for each step of the study.

Data Application for Market Characterization

To construct the high-level market characterization of natural gas consumption and market size units (households for residential, floor space for commercial, and employees for industrial), we primarily used Avista's billing data as well as secondary data from AEG's Energy Market Profiles database.

- **Residential Segments.** To distinguish low-income households within each housing segment, AEG cross referenced geographic data from Avista's customer database with data from the US Census American Community Survey to estimate the presence of low-income households within Avista's service territory. "Low Income" was defined by household size. In Washington the threshold is 80% of Area Median Income, and in Idaho it is 200% of the Federal Poverty Level. Data from NEEA's Residential Building Stock Assessment (RBSA II, 2016) was used to differentiate energy characteristics of low-income households, including differences in building shells, energy use per customer, and presence of energy-using equipment.
- **C&I Segments**. Customers and sales were allocated to building type based on intensity and floor space data from the 2019 Commercial Building Stock Assessment (CBSA) by state, with some adjustments between the C&I sectors to better group energy use by facility type and predominate end uses.

Data Application for Market Profiles

The specific data elements for the market profiles, together with the key data sources, are shown in Table 2-3. To develop the market profiles for each segment, AEG performed the following steps:

1. Developed control totals for each segment. These include market size, segment-level annual natural gas use, and annual intensity. Control totals were based on Avista's actual sales and customer-level information found in Avista's customer billing database.
4. Developed existing appliance saturations and the energy characteristics of appliances, equipment, and buildings using equipment flags within Avista's billing data; NEEA's RBSA, CBSA, and IFSA; U.S. EIA's surveys and AEO; and the American Community Survey.
5. Ensured calibration to control totals for annual natural gas sales in each sector and segment.
6. Compared and cross-checked with other recent AEG studies.
7. Worked with Avista staff to vet the data against their knowledge and experience.

Table 2-3 Data Applied for the Market Profiles

Model Inputs	Description	Key Sources
Market size	Base-year residential dwellings, commercial floor space, and industrial employment	Avista billing data Avista GenPOP Survey NEEA RBSA and CBSA AEO 2023
Annual intensity	Residential: Annual use per household Commercial: Annual use per square foot Industrial: Annual use per employee	Avista billing data US DOE RECS and CBECS data NEEA RBSA and CBSA AEO 2023 Other recent studies
Appliance/equipment saturations	Fraction of dwellings with an appliance/technology Percentage of C&I floor space/employment with equipment/technology	Avista GenPOP Survey NEEA RBSA, CBSA, and IFSA ACS AEG's Energy Market Profiles
UEC/EUI for each end-use technology	UEC: Annual natural gas use in homes and buildings that have the technology EUI: Annual natural gas use per square foot/employee for a technology in floor space that has the technology	HVAC uses: BEST simulations using prototypes developed for Avista Engineering analysis RTF workbooks if applicable AEO 2023 Recent AEG studies
Appliance/equipment age distribution	Age distribution for each technology	RBSA, CBSA, and recent AEG studies
Efficiency options for each technology	List of available efficiency options and annual energy use for each technology	Avista current program offerings AEO 2023 RTF and NWPCC 2021 Plan data

Data Application for Baseline Projection

Table 2-4 summarizes the LoadMAP model inputs required for the baseline projection. These inputs are required for each segment within each sector, as well as for new construction and existing dwellings/buildings.

Table 2-4 Data Needs for Baseline Projection and Potentials Estimation in LoadMAP

Model Inputs	Description	Key Sources
Customer growth forecasts	Forecasts of new construction in residential, commercial, and industrial sectors	Avista load forecast AEO 2023 economic growth forecast
Equipment purchase shares for baseline projection	For each equipment/technology, purchase shares for each efficiency level; specified separately for existing equipment replacement and new construction	Shipments data from AEO and ENERGY STAR AEO 2023 regional forecast assumptions[1] Appliance/efficiency standards analysis Avista program results and evaluation reports
Utilization model parameters	Price elasticities, elasticities for other variables (income, weather)	EPRI's REEPS and COMMEND models Avista short-term forecast calibration AEO 2023

[1] We developed baseline purchase decisions using the EIA's AEO report, which utilizes the National Energy Modeling System to produce a self-consistent supply and demand economic model. We calibrated equipment purchase options to match distributions/allocations of efficiency levels to manufacturer shipment data for recent years.

Table 2-5 Residential Natural Gas Equipment Standards

End-Use	Technology	2021	2022	2023	2024	2025
Space Heating	Furnace – Direct Fuel	AFUE 80%			AFUE 90%	
	Boiler – Direct Fuel	AFUE 80%				
Secondary Heating	Fireplace	N/A				
Water Heating	Water Heater <= 55 gal.	UEF 0.58				
	Water Heater > 55 gal.	UEF 0.76				
Appliances	Clothes Dryer	CEF 3.30				
	Stove/Oven	N/A				
Miscellaneous	Pool Heater	TE 0.82				
	Miscellaneous	N/A				

Table 2-6 Commercial and Industrial Natural Gas Equipment Standards

End-Use	Technology	2021		2022	2023	2024	2025
Space Heating	Furnace		AFUE 80% / TE 0.80			TE 0.90	
	Boiler		Average around AFUE 80% / TE 0.80 (varies by size)				
	Unit Heater		Standard (intermittent ignition and power venting or automatic flue damper)				
Water Heater	Water Heating		TE 0.80				
Food Preparation	Fryer	N/A		ENERGY STAR 3.0			
	Steamer	N/A		ENERGY STAR 1.2			
Miscellaneous	Pool Heater		TE 0.82				

Conservation Measure Data Application

Table 2-7 details the energy efficiency data inputs to the LoadMAP model, describes each input, and identifies the key sources used in the analysis.

Table 2-7 Data Needs for Measure Characteristics in LoadMAP

Model Inputs	Description	Key Sources
Energy Impacts	The annual reduction in consumption attributable to each specific measure. Savings were developed as a percentage of the energy end use that the measure affects.	Avista measure data NWPCC 2021 Plan conservation workbooks RTF workbooks AEG BEST Other secondary sources
Costs	Equipment Measures: Includes the full cost of purchasing and installing the equipment on a per-household, per-square-foot, per employee or per service point basis for the residential, commercial, and industrial sectors, respectively. Non-equipment measures: Existing buildings – full installed cost. New Construction - the costs may be either the full cost of the measure, or as appropriate, the incremental cost of upgrading from a standard level to a higher efficiency level.	Avista measure data NWPCC 2021 Plan conservation workbooks, RTF AEO 2023 Other secondary sources
Measure Lifetimes	Estimates derived from the technical data and secondary data sources that support the measure demand and energy savings analysis.	Avista measure data NWPCC 2021 Plan conservation workbooks , RTF AEO 2023 AEG DEEM DEER Other secondary sources
Applicability	Estimate of the percentage of dwellings in the residential sector, square feet in the commercial sector, or employees in the industrial sector where the measure is applicable and where it is technically feasible to implement.	RBSA, CBSA WSEC for limitations on new construction NWPCC 2021 Plan conservation workbooks RTF workbooks Other secondary sources
On Market and Off Market Availability	Expressed as years for equipment measures to reflect when the equipment technology is available or no longer available in the market.	AEG appliance standards and building codes analysis

Data Application for Cost-effectiveness Screening

All cost and benefit values were analyzed as real dollars, converted from nominal provided by Avista. We applied Avista's long-term discount rate of 4.29% excluding inflation. LoadMAP is configured to vary this by market sector (e.g., residential and commercial) if Avista develops alternative values in the future.

Estimates of Customer Adoption

- Two parameters are needed to estimate the timing and rate of customer adoption in the potential forecasts. **Technical diffusion curves for non-equipment measures.** Equipment measures are installed when existing units fail. Non-equipment measures do not have this natural periodicity, so rather than installing all available non-equipment measures in the first year of the projection (instantaneous potential), they are phased in according to adoption schedules that generally align with the diffusion of similar equipment measures. Like the 2022 CPA, we applied the "Retrofit" ramp rates from the 2021 Power Plan directly as diffusion curves. For technical potential, these rates summed up to 100% by the 20th year for all measures.

- **Adoption rates.** Customer adoption rates or take rates are applied to technical potential to estimate Technical Achievable Potential. For equipment measures, the Council's "Lost Opportunity" ramp rates were applied to technical potential with a maximum achievability of 85%-100%, depending on the measure. For non-equipment measures, the Council's "Retrofit" ramp rates have already been applied to calculate technical diffusion. In this case, we multiply each of these by 85% (for most measures) to calculate Achievable Technical Potential. Adoption rates are presented in Appendix D.

3 | Energy Efficiency Market Characterization

This chapter presents how Avista's customers in Washington and Idaho use natural gas in 2021, the base year of the study. We begin with a high-level summary of energy use by state and then delve into each sector.

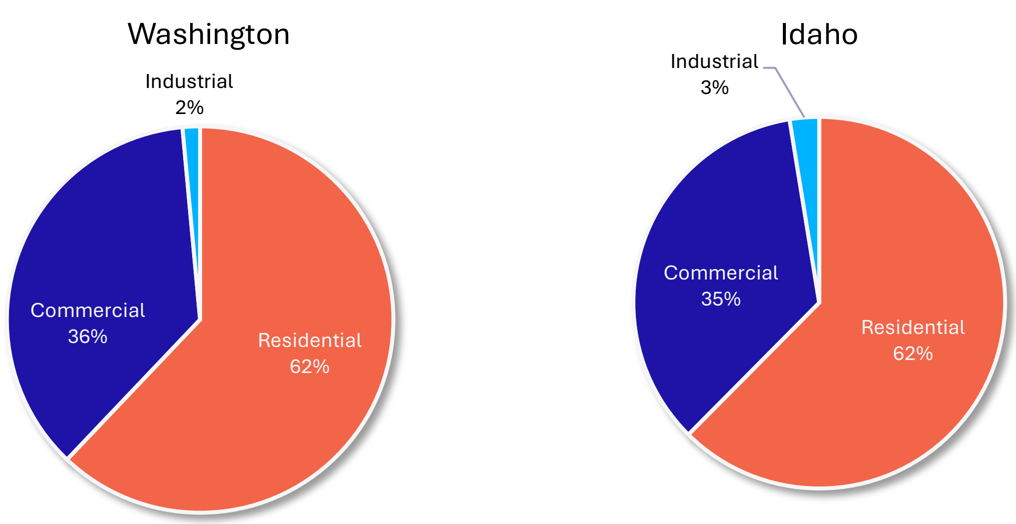
Energy Use Summary

Avista's total natural gas consumption for the residential, commercial, and industrial sectors in 2021 was 27,285,801 dtherms (dtherms or dth); 18,288,700 dtherms in Washington and 8,997,101 dtherms in Idaho. As shown in Table 3-1 and , the residential sector accounts for the largest share of annual energy use at 62%, followed by the commercial sector at approximately 35%.

Table 3-1 Residential Sector Control Totals, 2021

	Washington		Idaho	
Sector	Natural Gas Usage (Dth)	% of Annual Use	Natural Gas Usage (Dth)	% of Annual Use
Residential	11,356,811	62.1%	5,617,143	62.4%
Commercial	6,665,122	36.4%	3,149,752	35.0%
Industrial	266,766	1.5%	230,206	2.6%
Total	**18,288,700**	**100%**	**8,997,101**	**100%**

Figure 3-1 Avista Sector-Level Natural Gas Use (2021)



Residential Sector

Washington Characterization

The total number of households and natural gas sales for the service territory were obtained from Avista's actual sales. In 2021, there were 157,808 households in the state of Washington that used a total of 11,356,811 dtherms, resulting in an average use per household of 720 therms per year. Table 3-2 and Figure 3-2 shows the total number of households and natural gas sales in the six residential segments for each state. These values represent weather actuals for 2021 and were adjusted within LoadMAP to normal weather using heating degree day, base 65°F, using data provided by Avista.

Table 3-2 Residential Sector Control Totals, Washington, 2021

Segment	Households	Natural Gas Use (dtherms)	Annual Use/Customer (therms/HH)
Single Family	84,836	7,324,885	863
Multi-Family	8,705	431,675	496
Mobile Home	5,136	305,566	595
Low Income - Single Family	39,810	2,481,707	623
Low Income – Multi-Family	15,263	546,435	358
Low Income – Mobile Home	4,057	266,544	657
Total	**157,808**	**11,356,811**	**720**

Figure 3-2 Residential Natural Gas Use by Segment, Washington, 2021

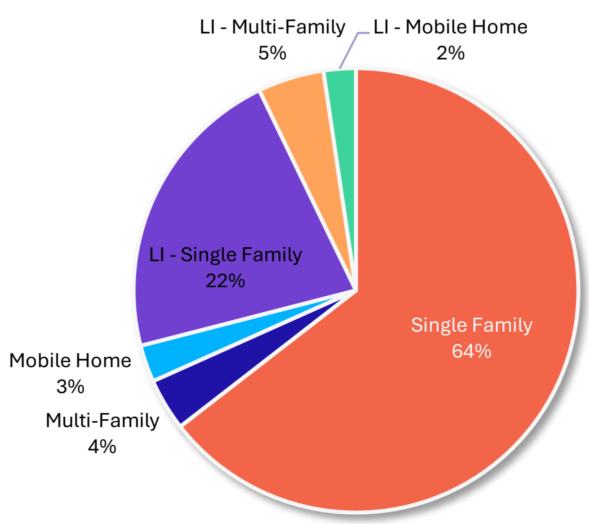


Figure 3-3 and Table 3-3 show the distribution of annual natural gas consumption by end use for an average residential household. Space heating comprises most of the load at 83%, followed by water heating at 12%. Appliances, secondary heating, and miscellaneous loads make up the remaining portion (5%) of the total load.

The market profiles provide the foundation for development of the baseline projection and the potential estimates. The average market profile for the residential sector is presented in Table 3-3.

Figure 3-3 Residential Natural Gas Use by End Use, Washington, 2021

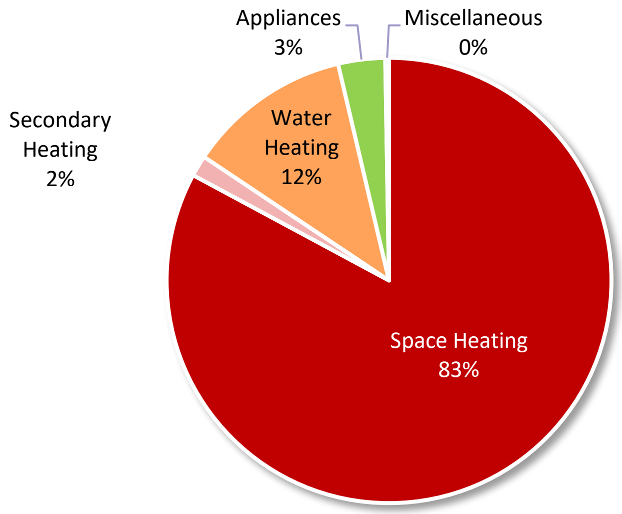
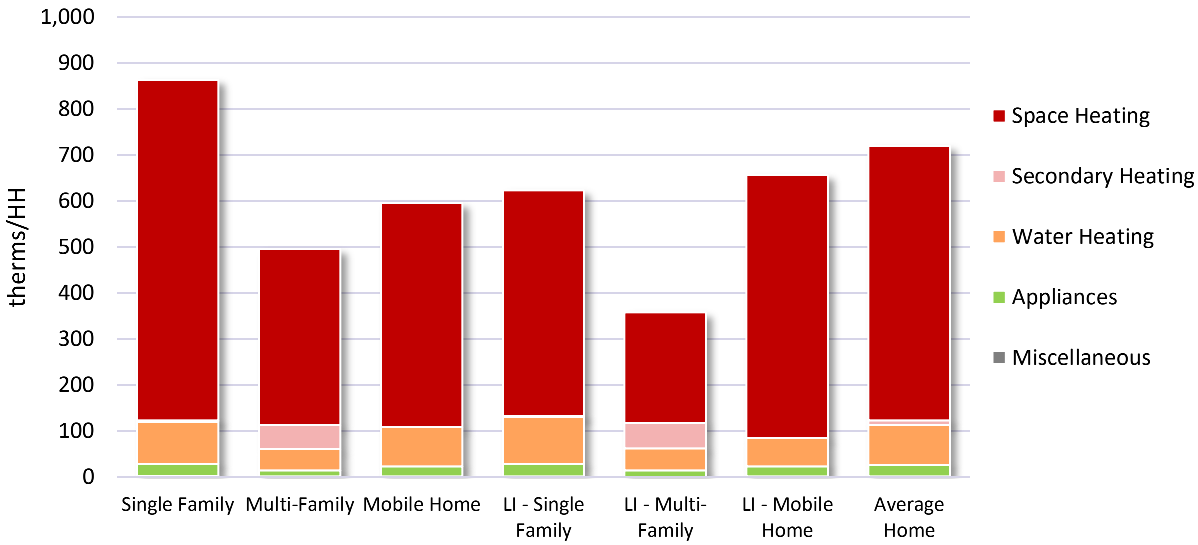


Table 3-3 Average Market Profile for the Residential Sector, Washington, 2021

End Use	Technology	Saturation	UEC (therms)	Intensity (therms/HH)	Usage (dtherms)
Space Heating	Furnace - Direct Fuel	84.8%	685	581	9,175,585
	Boiler - Direct Fuel	2.4%	628	15	233,076
Secondary Heating	Fireplace	5.1%	216	11	172,769
Water Heating	Water Heater (<= 55 Gal)	55.1%	156	86	1,356,503
	Water Heater (>55 Gal)	0.0%	148	0	457
Appliances	Clothes Dryer	28.4%	23	6	101,141
	Stove/Oven	58.6%	31	18	286,622
Miscellaneous	Pool Heater	0.9%	106	1	15,120
	Miscellaneous	100%	1	1	15,539
Total				**720**	**11,356,811**

Figure 3-4 presents average natural gas intensities by end use and housing type. Single family homes consume substantially more energy in space heating because single family homes are larger and more walls are exposed to the outside environment, compared to multifamily dwellings with many shared walls. Additional exposed walls increase heat transfer, resulting in greater heating loads. Water heating consumption is also higher in single family homes due to a greater number of occupants.

Figure 3-4 Residential Energy Intensity by End Use and Segment, Washington, 2021



Idaho Characterization

In 2021, there were 80,127 households in Avista's Idaho territory that used a total of 5,617,143 dtherms, resulting in an average use per household of 701 therms per year. Table 3-4 and Figure 3-5 shows the total number of households and natural gas sales in the six residential segments for each state.

Table 3-4 Residential Sector Control Totals, Idaho, 2021

Segment	Households	Natural Gas Use (dtherms)	Annual Use/Customer (therms/HH)
Single Family	55,954	4,471,261	799
Multi-Family	8,690	379,050	436
Mobile Home	5,585	261,344	468
Low Income – Single Family	6,505	377,733	581
Low Income – Multi-Family	2,685	85,112	317
Low Income – Mobile Home	708	42,642	603
Total	**80,127**	**5,617,143**	**701**

Figure 3-5 Residential Natural Gas Use by Segment, Idaho, 2021

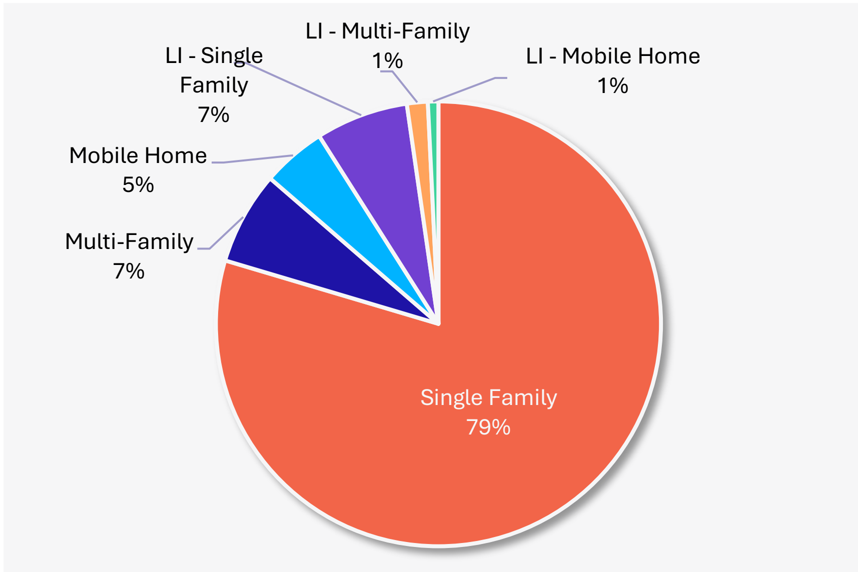


Figure 3-6 and

Table 3-5 show the distribution of annual natural gas consumption by end use for an average residential household. Space heating comprises most of the load at 84%, followed by water heating at 12%. Appliances, secondary heating, and miscellaneous loads make up the remaining portion (4%) of the total load.

Figure 3-6 Residential Natural Gas Use by End Use, Idaho, 2021

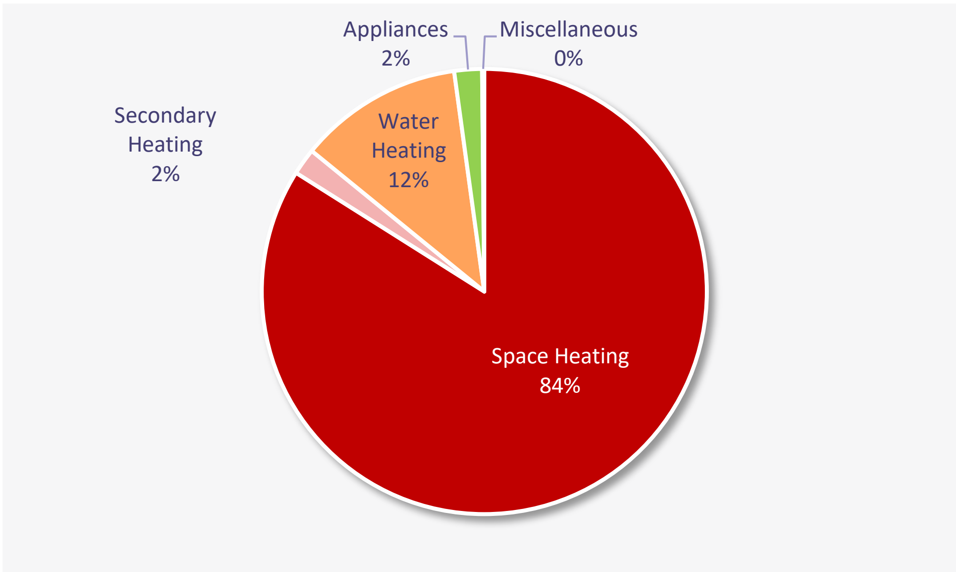
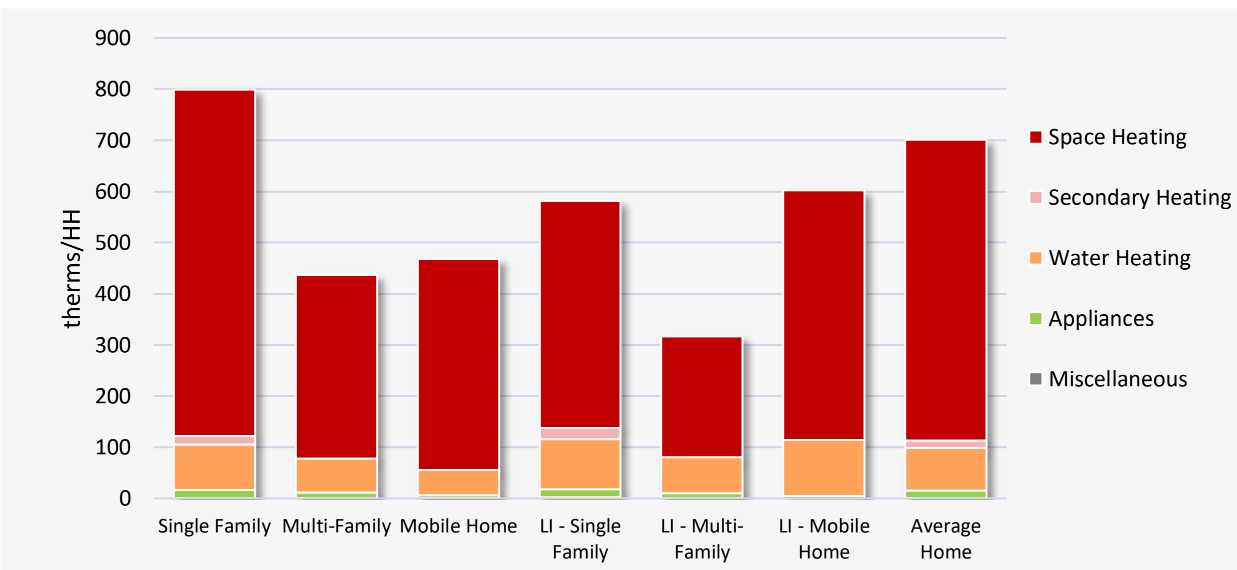


Table 3-5 Average Market Profile for the Residential Sector, Idaho 2021

End Use	Technology	Saturation	UEC (therms)	Intensity (therms/HH)	Usage (dtherms)
Space Heating	Furnace - Direct Fuel	88.0%	669	589	4,715,719
	Boiler - Direct Fuel	0.0%	-	-	-
Secondary Heating	Fireplace	6.0%	225	14	108,339
Water Heating	Water Heater (<= 55 Gal)	50.9%	152	77	618,978
	Water Heater (>55 Gal)	4.3%	151	7	52,229
Appliances	Clothes Dryer	16.2%	22	4	28,672
	Stove/Oven	34.7%	30	11	84,402
Miscellaneous	Pool Heater	0.3%	106	0	2,848
	Miscellaneous	100%	1	1	5,958
Total				**701**	**5,617,143**

Figure 3-7 presents average natural gas intensities by end use and housing type. Single family homes consume substantially more energy in space heating. Water heating consumption is higher in single family homes as well, due to a greater number of occupants, which increases the demand for hot water.

Figure 3-7 Residential Energy Intensity by End Use and Segment, Idaho, 2021 (Annual Therms/HH)



Commercial Sector

Washington Characterization

The total natural gas consumed by commercial customers in Avista's Washington service area in 2021 was 6,665,122 dtherm. The total number of non-residential accounts and natural gas sales for the Washington service territory were obtained from Avista's customer account database. AEG separated the commercial and industrial accounts by analyzing the SIC codes and rate codes assigned in the billing system. Energy use from accounts where the customer type could not be identified were distributed proportionally to all C&I segments. Once the billing data was analyzed, the final segment control totals were derived by distributing the total 2021 non-residential load to the sectors and segments according to the proportions in the billing data.

Table 3-6 shows the final allocation of energy to each segment in the commercial sector, as well as the energy intensity on a square-foot basis. Intensities for each segment were derived from a combination of the 2021 CBSA and equipment saturations extracted from Avista's database.

Table 3-6 Commercial Sector Control Totals, Washington, 2021

Segment	Description	Intensity (therms/Sq Ft)	Natural Gas Use (dtherms)
Office	Traditional office-based businesses including finance, insurance, law, government buildings, etc.	0.53	536,771
Restaurant	Sit-down, fast food, coffee shop, food service, etc.	2.60	747,786
Retail	Department stores, services, boutiques, strip malls etc.	0.79	1,547,664
Grocery	Supermarkets, convenience stores, market, etc.	0.55	125,630
School	Day care, pre-school, elementary, secondary schools	0.28	187,678
College	College, university, trade schools, etc.	0.59	182,118
Health	Health practitioner office, hospital, urgent care centers, etc.	0.99	243,745
Lodging	Hotel, motel, bed and breakfast, etc.	0.67	370,063
Warehouse	Large storage facility, refrigerated/unrefrigerated warehouse	0.57	688,567
Miscellaneous	Catchall for buildings not included in other segments, includes churches, recreational facilities, public assembly, correctional facilities, etc.	0.95	2,035,100
Total		**0.78**	**6,665,122**

Figure 3-8 shows the distribution of annual natural gas consumption by segment across all commercial buildings. The three segments with the highest natural gas usage in 2021 are miscellaneous (30%), retail (23%), and restaurant (11%).

Figure 3-8 Commercial Natural Gas Use by Segment, Washington, 2021

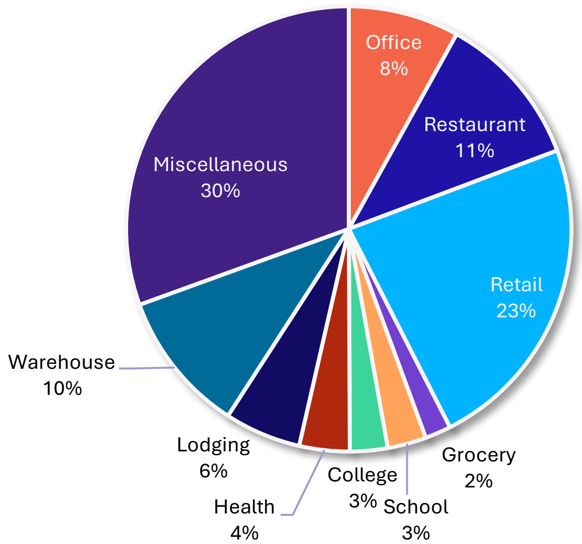


Figure 3-9 shows the distribution of natural gas consumption by end use for the entire commercial sector. Space heating is the largest end use, followed by water heating and food preparation. The miscellaneous end use is quite small, as expected.

Figure 3-9 Commercial Sector Natural Gas Use by End Use, Washington, 2021

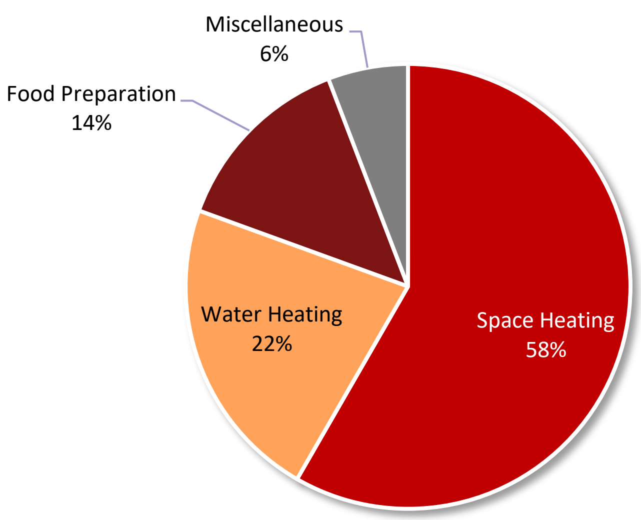


Figure 3-10 presents average natural gas intensities by end use and segment. In Washington, restaurants use the most natural gas in the service territory. Avista customer account data informed the market profile by providing information on saturation of key equipment types. Secondary data was used to develop estimates of energy intensity and square footage and fill in saturations for any equipment types not included in the database.

Figure 3-10 Commercial Energy Usage Intensity by End Use and Segment, Washington, 2021

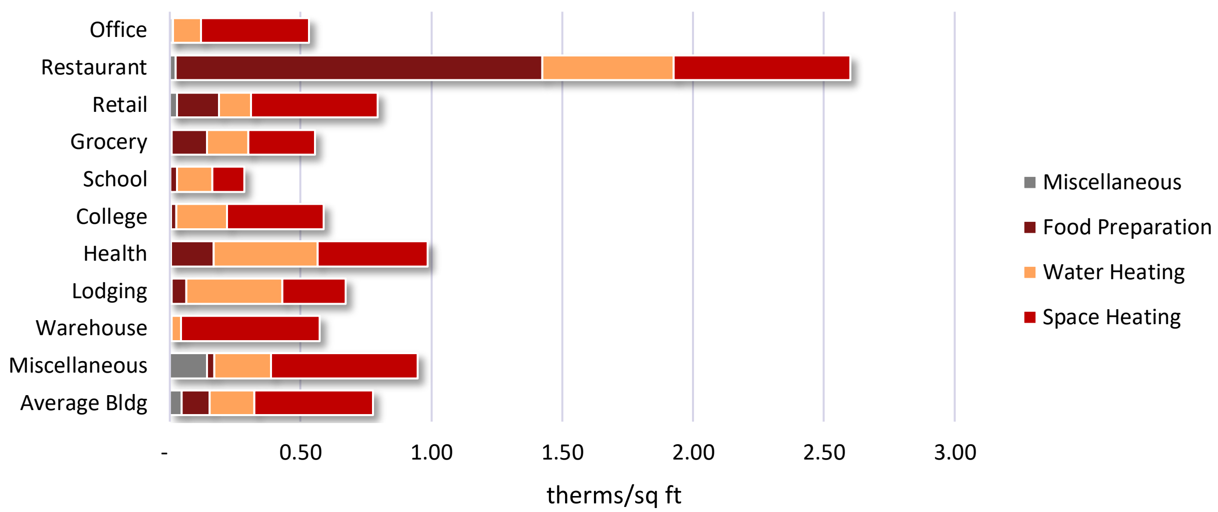


Table 3-7 shows the average market profile for the commercial sector as a whole, representing a composite of all segments and buildings.

Table 3-7 Average Market Profile for the Commercial Sector, Washington, 2021

End Use	Technology	Saturation	EUI (therms/ Sq Ft)	Intensity (therms/Sq Ft)	Usage (dtherms)
Space Heating	Furnace	52.4%	0.55	0.29	2,485,626
	Boiler	21.9%	0.66	0.15	1,247,409
	Unit Heater	5.9%	0.31	0.02	156,793
Water Heating	Water Heater	58.7%	0.29	0.17	1,481,152
Food Preparation	Oven	11.3%	0.08	0.01	73,181
	Conveyor Oven	5.6%	0.13	0.01	62,609
	Double Rack Oven	5.6%	0.20	0.01	95,114
	Fryer	8.0%	0.44	0.04	300,472
	Broiler	13.3%	0.12	0.02	133,574
	Griddle	17.5%	0.08	0.01	118,981
	Range	17.8%	0.07	0.01	113,457
	Steamer	1.9%	0.07	0.00	10,828
	Commercial Food Prep Other	0.2%	0.02	0.00	221
Miscellaneous	Pool Heater	1.0%	0.06	0.00	5,419
	Miscellaneous	100%	0.04	0.04	383,287
Total				**0.78**	**6,665,122**

Idaho Characterization

The total natural gas consumed by commercial customers in Avista's Idaho service area in 2021 was 3,149,752 dtherm. Table 3-8 shows the final allocation of energy to each segment in the commercial sector, as well as the energy intensity on a square-foot basis. Intensities for each segment were derived from a combination of the 2021 CBSA and equipment saturations extracted from Avista's database.

Table 3-8 Commercial Sector Control Totals, Idaho, 2021

Segment	Description	Intensity (therms/Sq Ft)	Natural Gas Use (dtherms)
Office	Traditional office-based businesses including finance, insurance, law, government buildings, etc.	0.53	226,954
Restaurant	Sit-down, fast food, coffee shop, food service, etc.	2.60	139,154
Retail	Department stores, services, boutiques, strip malls etc.	0.79	959,894
Grocery	Supermarkets, convenience stores, market, etc.	0.55	58,138
School	Day care, pre-school, elementary, secondary schools	0.28	184,533
College	College, university, trade schools, etc.	0.59	179,370
Health	Health practitioner office, hospital, urgent care centers, etc.	1.01	102,436
Lodging	Hotel, motel, bed and breakfast, etc.	0.67	170,255
Warehouse	Large storage facility, refrigerated/unrefrigerated warehouse	0.57	334,864
Miscellaneous	Catchall for buildings not included in other segments, includes churches, recreational facilities, public assembly, correctional facilities, etc.	0.95	794,154
Total		**0.70**	**3,149,752**

Figure 3-11 shows the distribution of annual natural gas consumption by segment across all commercial buildings. The three segments with the highest natural gas usage in 2021 are retail (31%), miscellaneous (25%), and warehouse (11%).

Figure 3-11 Commercial Natural Gas Use by Segment, Idaho, 2021

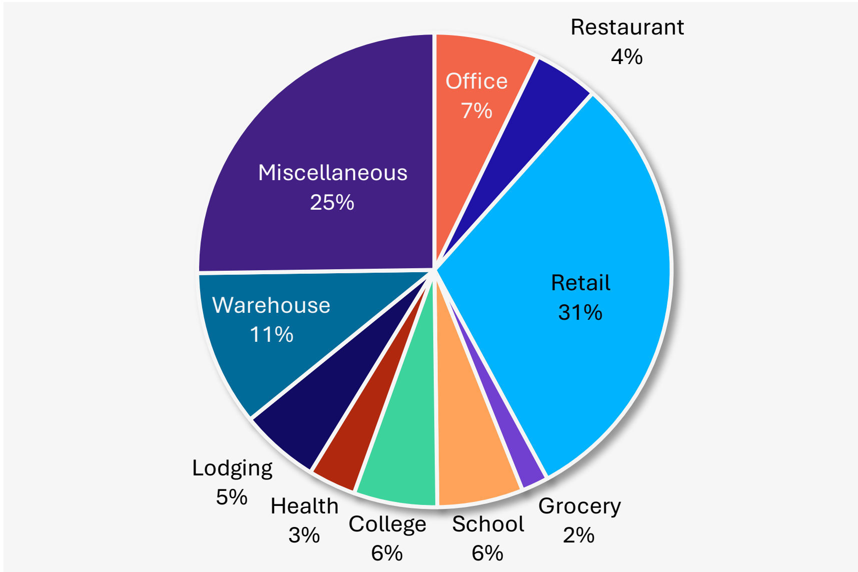


Figure 3-12 shows the distribution of natural gas consumption by end use for the entire commercial sector. Space heating is the largest end use, followed by water heating and food preparation. The miscellaneous end use is quite small, as expected.

Figure 3-12 Commercial Sector Natural Gas Use by End Use, Idaho, 2021

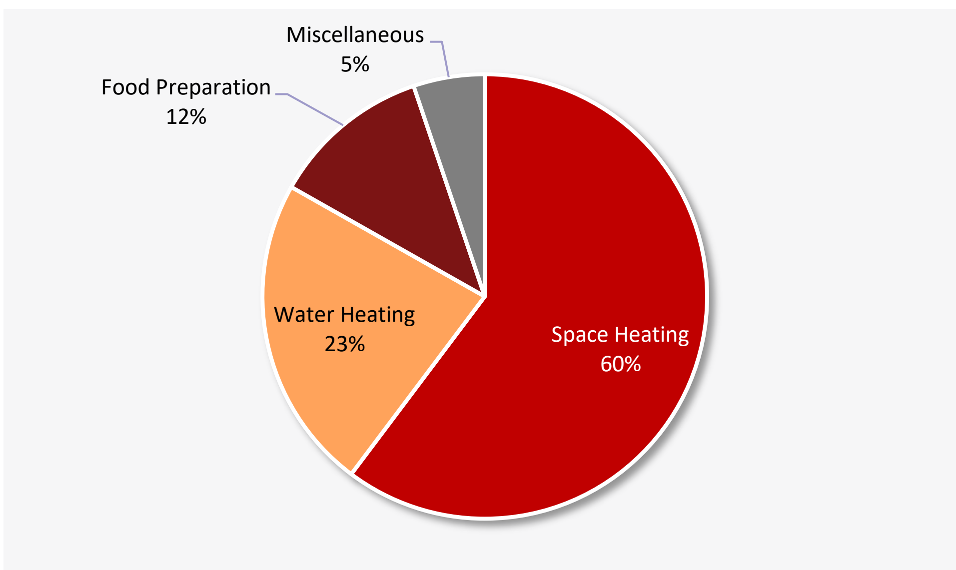


Figure 3-13 presents average natural gas intensities by end use and segment. In Idaho, restaurants use the most natural gas in the service territory. Avista customer account data informed the market profile by providing information on saturation of key equipment types. Secondary data was used to develop estimates of energy intensity and square footage and fill in saturations for any equipment types not included in the database.

Figure 3-13 Commercial Energy Usage Intensity by End Use and Segment, Idaho, 2021

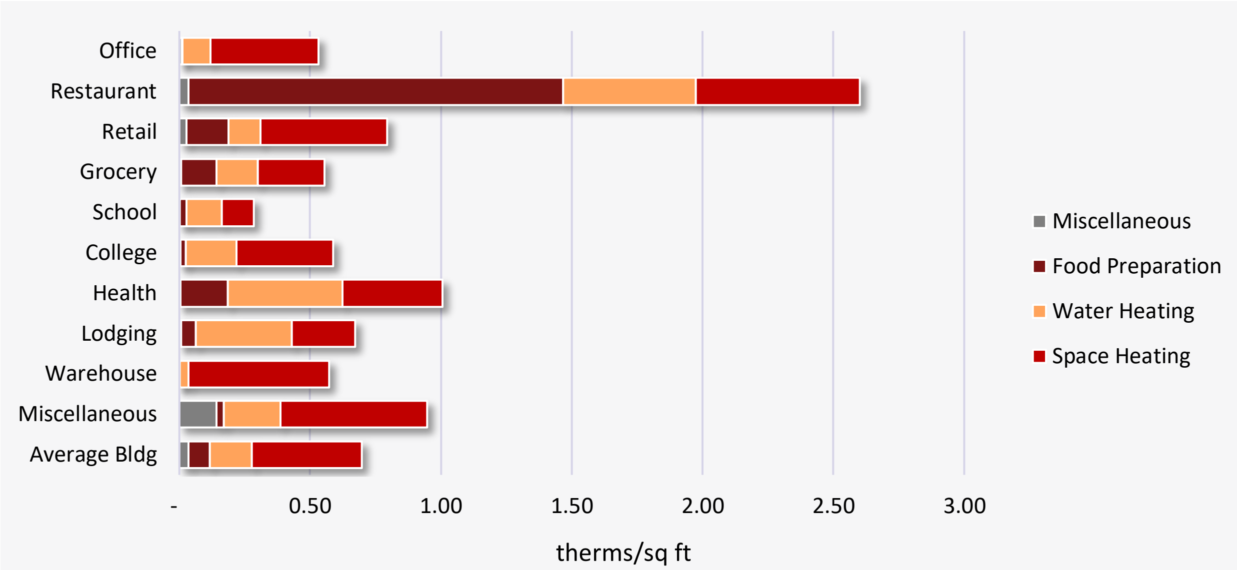


Table 3-9 shows the average market profile for the commercial sector as a whole, representing a composite of all segments and buildings.

Table 3-9 Average Market Profile for the Commercial Sector, Idaho, 2021

End Use	Technology	Saturation	EUI (therms/ Sq Ft)	Intensity (therms/Sq Ft)	Usage (dtherms)
Space Heating	Furnace	50.1%	0.53	0.26	1,194,251
	Boiler	24.5%	0.56	0.14	621,861
	Unit Heater	6.2%	0.29	0.02	81,760
Water Heating	Water Heater	60.5%	0.26	0.16	722,590
Food Preparation	Oven	9.7%	0.09	0.01	40,281
	Conveyor Oven	4.8%	0.16	0.01	34,461
	Double Rack Oven	4.8%	0.24	0.01	52,353
	Fryer	6.8%	0.44	0.03	134,342
	Broiler	11.1%	0.07	0.01	33,837
	Griddle	15.2%	0.05	0.01	33,185
	Range	16.0%	0.05	0.01	32,941
	Steamer	2.6%	0.04	00.0	4,364
	Commercial Food Prep Other	0.3%	0.01	0.00	118
Miscellaneous	Pool Heater	0.9%	0.05	0.00	2,146
	Miscellaneous	100%	0.04	0.04	161,261
Total				**0.70**	**3,149,752**

Industrial Sector

Table 3-10 Industrial Sector Control Totals, 2021

Segment	Intensity (therms/employee)	Natural Gas Usage (dtherms)
Washington Industrial	1,699	266,766
Idaho Industrial	2,327	230,206

Washington Characterization

The total natural gas consumed by industrial customers in Avista's Washington service area in 2021 was 266,766 dtherms. Like in the commercial sector, customer account data was used to allocate usage among segments. Energy intensity was derived from AEG's Energy Market Profiles database. Most industrial measures are installed through custom programs, where the unit of measure is not as necessary to estimate potential.

Figure 3-14 shows the distribution of annual natural gas consumption by end use for all industrial customers. Two major sources were used to develop this consumption profile. The first was AEG's analysis of warehouse usage as part of the commercial sector. We begin with this prototype as a starting point to represent non-process loads. We then added in process loads using our Energy Market Profiles database, which summarizes usage by end use and process type.

Figure 3-14 Industrial Natural Gas Use by End Use, Washington, 2021

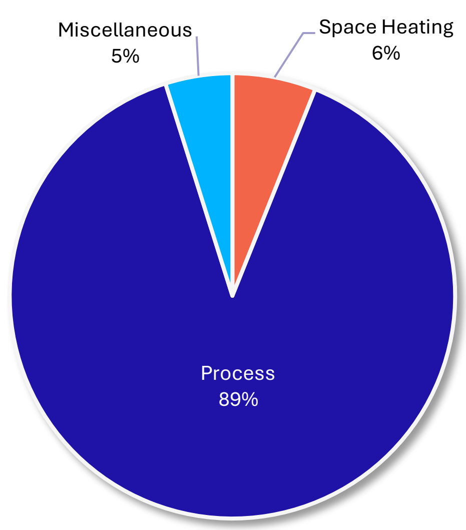


Table 3-11 shows the composite market profile for the Washington industrial sector. Process cooling is very small and represents niche technologies such as gas-driven absorption chillers.

Table 3-11 Average Natural Gas Market Profile for the Industrial Sector, Washington, 2021

End Use	Technology	Saturation	EUI (therms/ Sq Ft)	Intensity (therms/ Sq Ft)	Usage (dtherms)
Space Heating	Furnace	32.3%	103.12	33.3	5,230
	Boiler	51.5%	103.12	53.2	8,346
	Unit Heater	16.2%	103.12	16.7	2,615
Process	Process Boiler	100%	750.42	750.4	117,823
	Process Heating	100%	686.11	686.1	107,725
	Process Cooling	100%	6.65	6.7	1,045
	Other Process	100%	70.14	70.1	11,012
Miscellaneous	Miscellaneous	100%	82.61	82.6	12,971
Total				**1,699.1**	**266,766**

Idaho Characterization

The total natural gas consumed by industrial customers in Avista's Idaho service area in 2021 was 230,206 dtherms.

Figure 3-15 shows the distribution of annual natural gas consumption by end use for all industrial customers. Two major sources were used to develop this consumption profile. The first was AEG's analysis of warehouse usage as part of the commercial sector. We begin with this prototype as a starting point to represent non-process loads. We then added in process loads using our Energy Market Profiles database, which summarizes usage by end use and process type.

Figure 3-15 Industrial Natural Gas Use by End Use, Idaho, 2021

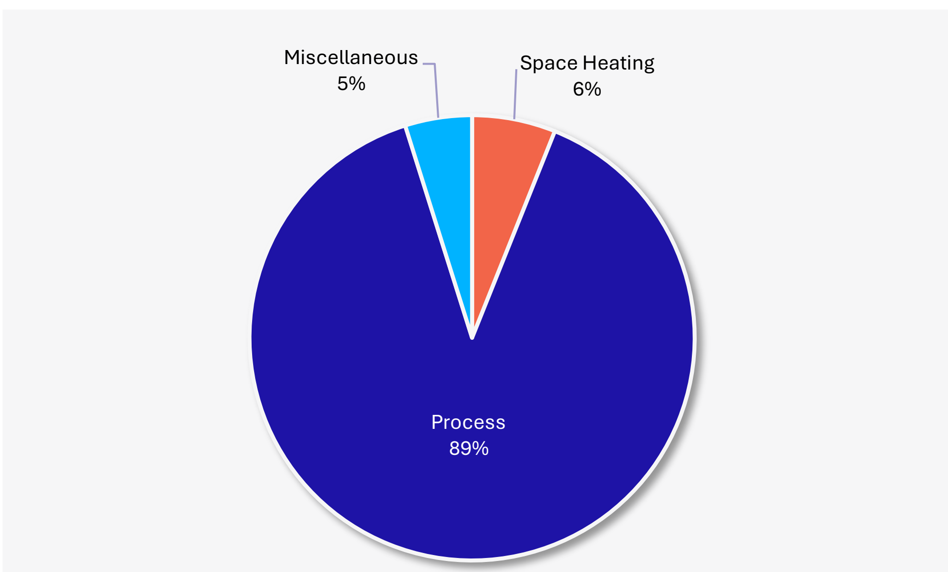


Table 3-12 shows the composite market profile for the industrial sector. Process cooling is very small and represents technologies such as gas-driven absorption chillers.

Table 3-12 Average Natural Gas Market Profile for the Industrial Sector, Idaho, 2021

End Use	Technology	Saturation	EUI (therms/ Sq Ft)	Intensity (therms/ Sq Ft)	Usage (dtherms)
Space Heating	Furnace	32.3%	141.24	45.6	4,513
	Boiler	51.5%	141.24	72.8	7,203
	Unit Heater	16.2%	141.24	22.8	2,257
Process	Process Boiler	100.0%	1,027.79	1,027.8	101,675
	Process Heating	100.0%	939.70	939.7	92,961
	Process Cooling	100.0%	9.11	9.1	901
	Other Process	100.0%	96.06	96.1	9,503
Miscellaneous	Miscellaneous	100.0%	113.14	113.1	11,193
Total				**2,327.0**	**230,206**

4 | Baseline Projection

Prior to developing estimates of energy efficiency potential, AEG developed a baseline end use projection to quantify the likely future consumption in the absence of any future conservation programs. The baseline projection is the foundation for the analysis of savings from future conservation efforts as well as the metric against which potential savings are measured.

The baseline projection quantifies natural gas consumption for each sector, customer segment, end use and technology. The end use forecast includes the relatively certain impacts of codes and standards that will unfold over the study timeframe; all such mandates that were defined as of January 2024 are included.

Other inputs to the projection include:

- 2021 energy consumption based on the market profiles
- Economic growth forecasts (i.e., customer growth, income growth)
- Natural gas price forecasts, trends in fuel shares and equipment saturations, and
- Appliance/equipment standards and building codes and purchase decisions
- Avista's internally developed sector-level projections for natural gas sales.

The baseline also includes projected naturally occurring energy efficiency during the potential forecast period. AEG's LoadMAP efficiency choice model uses energy and cost data as well as current purchase trends to evaluate technologies and predict future purchase shares. AEG also modeled the adoption of electrification measures of natural gas customers and included the future effects of this reduction of natural gas equipment stock in Avista's territory. These purchase data all feed into the stock accounting algorithm to predict and track equipment stock and energy usage for each market segment.

AEG then calculated hourly profiles of the end use projection using a combination of region-specific load shapes from the National Renewable Energy Laboratory's (NREL) end use load profiles, Avista's load research data and engineering simulations. Shapes were collected at the sector, segment, end use or technology level where available. These load shapes were then customized to Avista's seasonal loads and normalized so the value for each hour represents 1/8760th of the year. The energy from baseline projection for each end use and technology was applied to each shape to compute hourly profiles.

This chapter presents the baseline projections developed for each sector and state (as well as a summary), which include projections of annual use in dtherms. Annual energy use for 2021 reflects weather-normalized values, while future years of energy use reflect normal weather, as defined by Avista.

Overall Baseline Projection

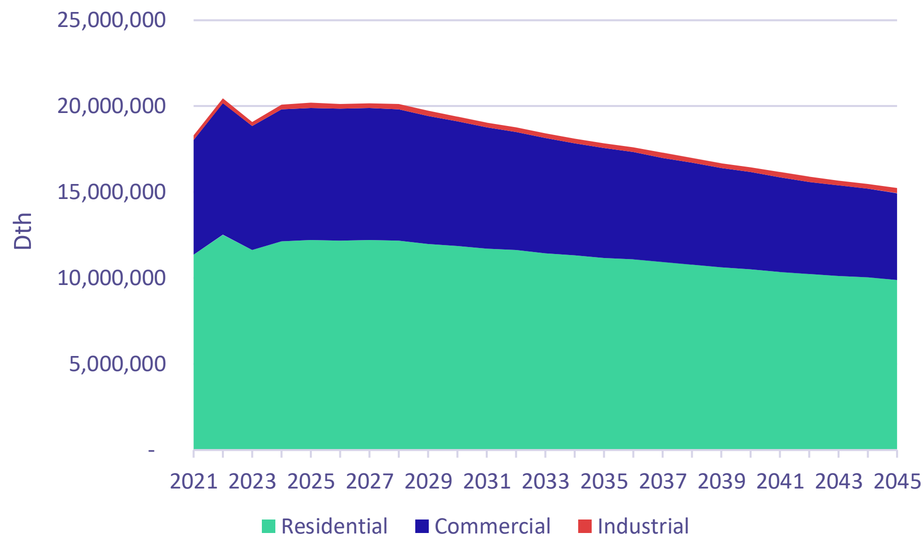
Washington

Table 4-1 and **Error! Reference source not found.** summarize the baseline projection for annual use by sector for Avista's Washington service territory. The forecast shows annual decreases, driven by fuel switching efforts and legislation in the residential and commercial sectors.

Table 4-1Baseline Projection Summary by Sector, Washington (dtherms)

Sector	2021	2023	2024	2025	2035	2045	% Change ('21-'45)
Residential	11,356,811	11,630,212	12,159,351	12,236,470	11,179,884	9,890,243	-12.91%
Commercial	6,665,122	7,218,289	7,667,169	7,663,059	6,384,073	5,059,004	-24.10%
Industrial	266,766	252,241	281,169	287,631	287,771	286,099	7.25%
Total	**18,288,700**	**19,100,743**	**20,107,689**	**20,187,160**	**17,851,728**	**15,235,347**	**-16.70%**

Figure 4-1Baseline Projection Summary by Sector, Washington



Idaho

Table 4-2 and

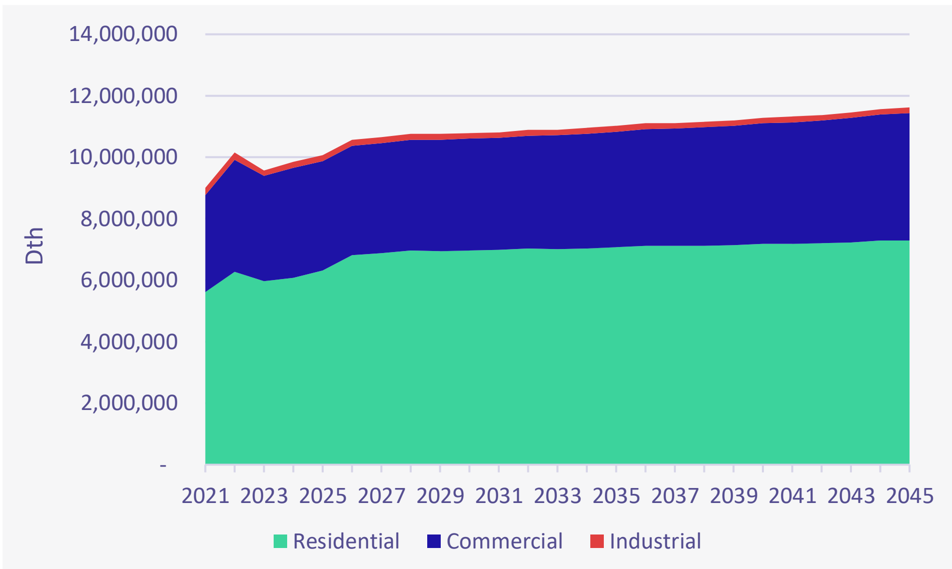
Sector	2021	2023	2024	2025	2035	2045	% Change ('21-'45)
Residential	5,617,143	5,981,078	6,072,239	6,315,645	7,069,672	7,295,165	29.87%
Commercial	3,149,752	3,415,640	3,595,593	3,562,749	3,758,630	4,144,068	31.57%
Industrial	230,206	182,526	181,383	188,351	185,889	183,603	-20.24%
Total	**8,997,101**	**9,579,244**	**9,849,215**	**10,066,745**	**11,014,191**	**11,622,835**	**29.18%**

Figure 4-2 summarize the baseline projection for annual use by sector for Avista's Idaho service territory. The forecast shows modest annual growth, driven by the residential and commercial sectors.

Table 4-2 Baseline Projection Summary by Sector, Idaho (dtherms)

Sector	2021	2023	2024	2025	2035	2045	% Change ('21-'45)
Residential	5,617,143	5,981,078	6,072,239	6,315,645	7,069,672	7,295,165	29.87%
Commercial	3,149,752	3,415,640	3,595,593	3,562,749	3,758,630	4,144,068	31.57%
Industrial	230,206	182,526	181,383	188,351	185,889	183,603	-20.24%
Total	**8,997,101**	**9,579,244**	**9,849,215**	**10,066,745**	**11,014,191**	**11,622,835**	**29.18%**

Figure 4-2 Baseline Projection Summary by Sector, Idaho



Residential Sector

Washington Projection

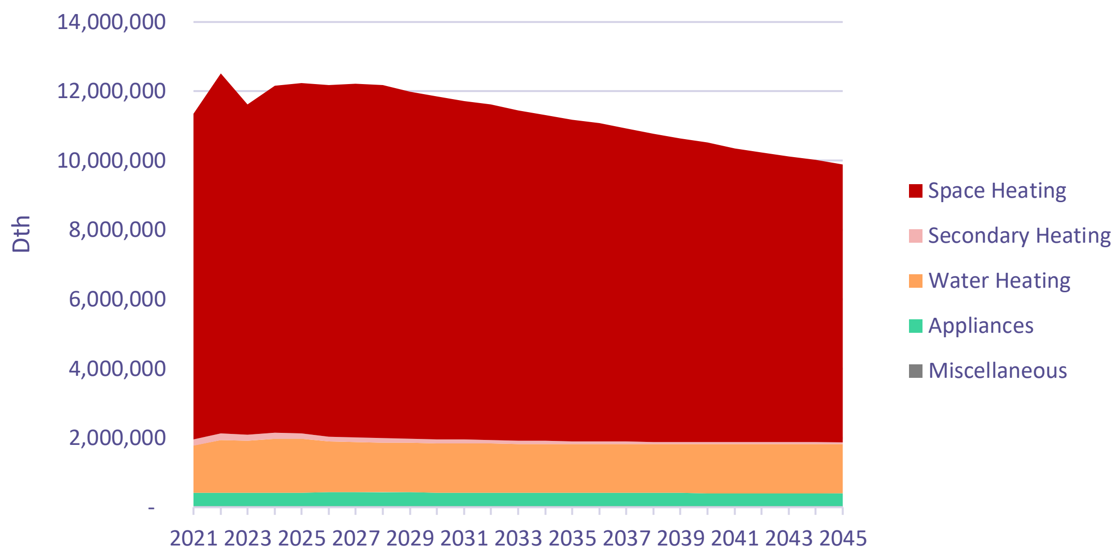
Table 4-3 and Figure 4-3 present the baseline projection for natural gas at the end-use level for the residential sector. Overall, residential use decreases from 11,356,811 dtherms in 2021 to 9,890,243 dtherms in 2045 (-12.91%). Factors affecting growth include codes and standards affecting the installation of new gas equipment, as well as a decrease in equipment consumption due to standards and naturally occurring efficiency.

We model gas-fired fireplaces as secondary heating. These consume energy and may heat a space but are rarely used as the primary heating technology. As such, they are estimated to be more aesthetic and less weather-dependent. This end use grows faster than others since new homes are more likely to install a unit, increasing fireplace stock. Miscellaneous is a very small end use, including technologies with low penetration, such as gas barbeques.

Table 4-3 Residential Baseline Projection by End Use, Washington (dtherms)

End Use	2021	2023	2024	2025	2035	2045	% Change ('21-'45)
Space Heating	9,408,661	9,539,528	10,012,135	10,099,097	9,272,544	8,017,334	-14.79%
Miscellaneous	30,658	31,268	31,334	31,348	31,309	31,262	1.97%
Appliances	387,763	393,126	394,321	395,192	383,108	370,660	-4.41%
Secondary Heating	172,769	169,949	172,549	163,178	88,431	49,878	-71.13%
Water Heating	1,356,961	1,496,342	1,549,013	1,547,656	1,404,491	1,421,109	4.73%
Total	**11,356,811**	**11,630,212**	**12,159,351**	**12,236,470**	**11,179,884**	**9,890,243**	**-12.91%**

Figure 4-3 Residential Baseline Projection by End Use, Washington



Idaho Projection

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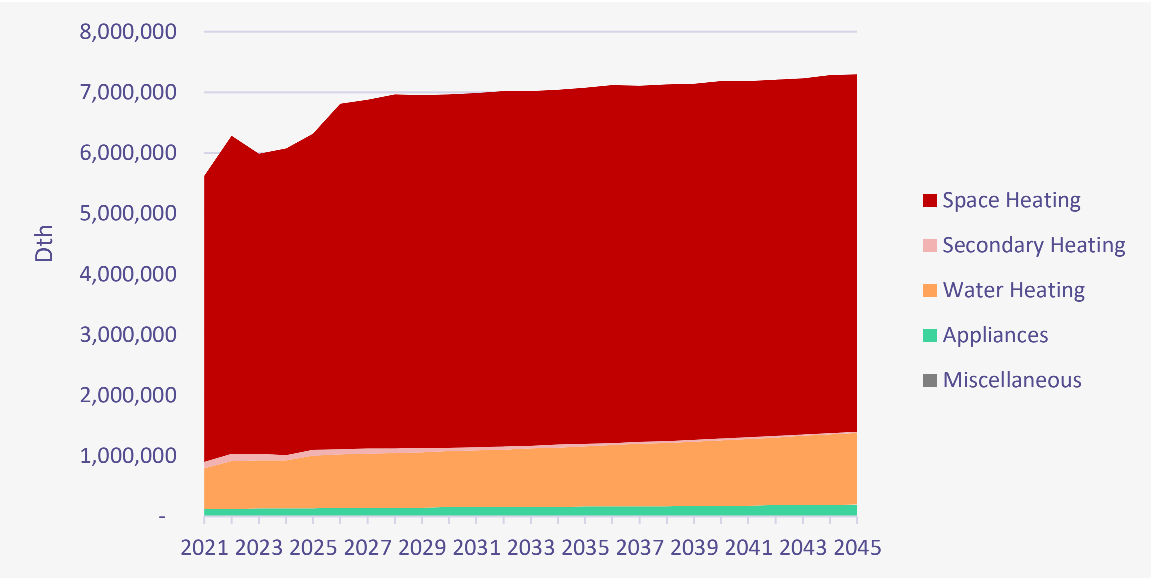
End Use	2021	2023	2024	2025	2035	2045	% Change ('21-'45)
Space Heating	4,715,719	4,948,665	5,055,098	5,213,185	5,871,465	5,901,498	25.15%
Miscellaneous	8,806	9,192	9,363	9,531	11,197	13,144	49.27%
Appliances	113,073	119,819	122,972	126,121	150,686	179,644	58.87%
Secondary Heating	108,339	105,374	97,544	97,482	41,789	17,210	-84.11%
Water Heating	671,206	798,028	787,262	869,327	994,535	1,183,668	76.35%
Total	**5,617,143**	**5,981,078**	**6,072,239**	**6,315,645**	**7,069,672**	**7,295,165**	**29.87%**

Figure 4-4 present the baseline projection for natural gas at the end-use level for the residential sector. Overall, residential use increases from 5,617,143 dtherms in 2021 to 7,295,165 dtherms in 2045, an increase of 29.87%. Avista's customers in the Idaho territory are not affected by the same codes as those in Washington, and therefore are not restricted in the installation of new gas equipment.

Table 4-4 Residential Baseline Projection by End Use, Idaho (dtherms)

End Use	2021	2023	2024	2025	2035	2045	% Change ('21-'45)
Space Heating	4,715,719	4,948,665	5,055,098	5,213,185	5,871,465	5,901,498	25.15%
Miscellaneous	8,806	9,192	9,363	9,531	11,197	13,144	49.27%
Appliances	113,073	119,819	122,972	126,121	150,686	179,644	58.87%
Secondary Heating	108,339	105,374	97,544	97,482	41,789	17,210	-84.11%
Water Heating	671,206	798,028	787,262	869,327	994,535	1,183,668	76.35%
Total	**5,617,143**	**5,981,078**	**6,072,239**	**6,315,645**	**7,069,672**	**7,295,165**	**29.87%**

Figure 4-4 Residential Baseline Projection by End Use, Idaho



Commercial Sector

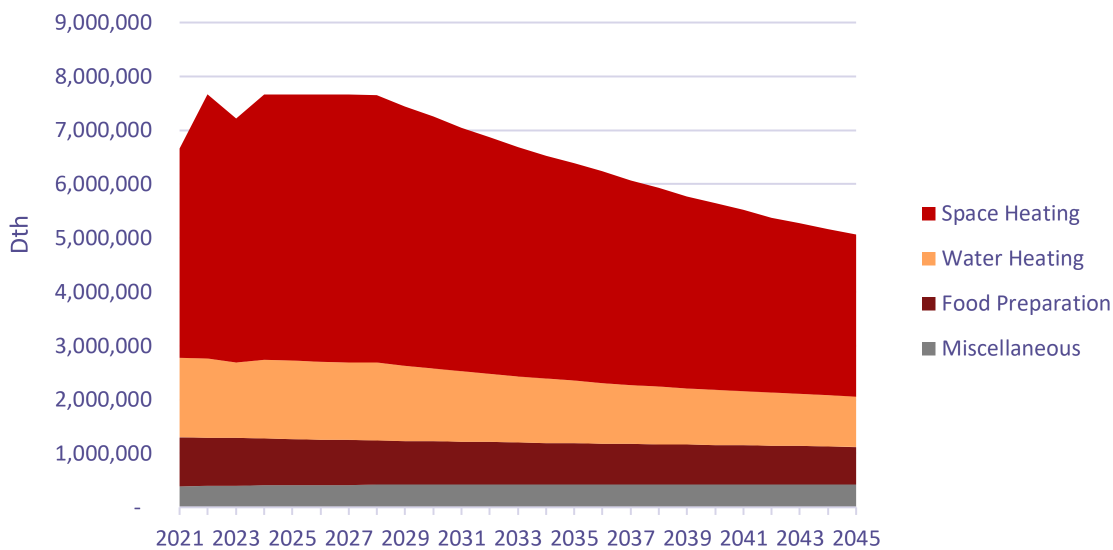
Washington Projection

Annual natural gas use in the commercial sector decreases 24.10% during the overall forecast horizon, starting at 6,665,122 dtherms in 2021, and decreasing to 5,059,004 dtherms in 2045. Table 4-5 and **Error! Reference source not found.** present the baseline projection at the end-use level for the commercial sector, as a whole. Similar to the residential sector, consumption is decreasing due to more stringent building codes affecting the installation of new gas equipment.

Table 4-5 Commercial Baseline Projection by End Use, Washington (dtherms)

Sector	2021	2023	2024	2025	2035	2045	% Change ('21-'45)
Space Heating	3,886,828	4,531,546	4,927,924	4,941,394	4,034,863	3,004,776	-22.69%
Water Heating	388,706	401,637	405,668	409,277	427,854	424,294	9.16%
Appliances	1,481,152	1,401,713	1,462,912	1,454,023	1,158,843	933,066	-37.00%
Miscellaneous	908,437	883,393	870,665	858,365	762,512	696,868	-23.29%
Total	**6,665,122**	**7,218,289**	**7,667,169**	**7,663,059**	**6,384,073**	**5,059,004**	**-24.10%**

Figure 4-5 Commercial Baseline Projection by End Use, Washington



Idaho Projection

Annual natural gas use in the Idaho commercial sector grows 31.57% during the forecast horizon, starting at 3,149,752 dtherms in 2021, and increasing to 4,144,068 dtherms in 2045. Table 4-6 and

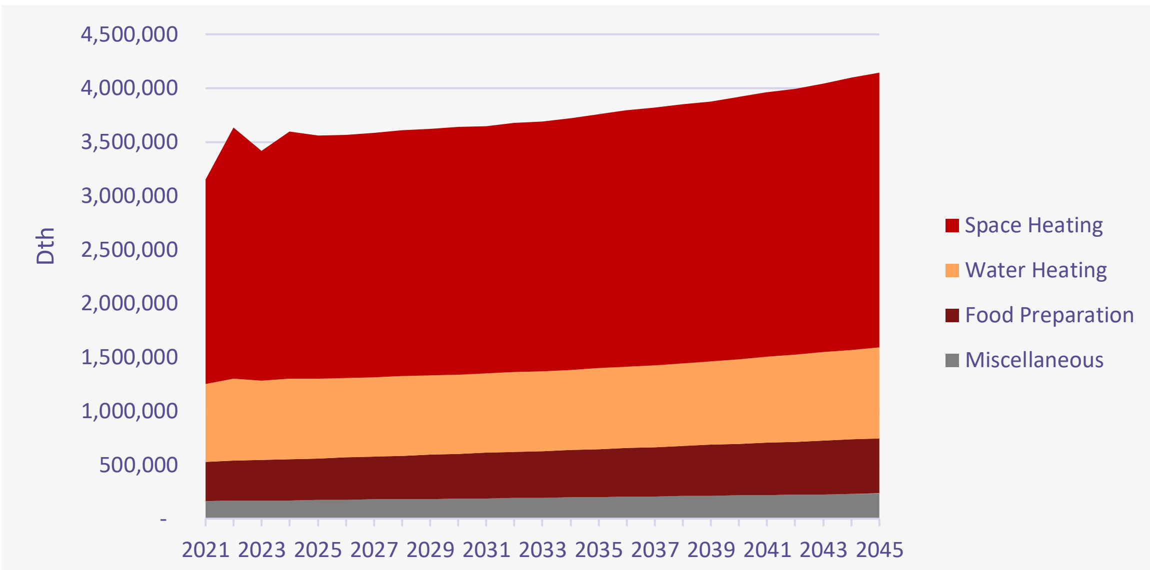
End Use	2021	2023	2024	2025	2035	2045	% Change ('21-'45)
Space Heating	1,897,872	2,130,579	2,292,981	2,262,225	2,359,571	2,551,388	34.43%
Miscellaneous	163,408	168,369	170,932	173,502	201,461	234,025	43.22%
Water Heating	722,590	739,547	749,078	739,042	751,584	845,247	16.97%
Food Preparation	365,882	377,145	382,602	387,980	446,014	513,408	40.32%
Total	**3,149,752**	**3,415,640**	**3,595,593**	**3,562,749**	**3,758,630**	**4,144,068**	**31.57%**

Figure 4-6 present the baseline projection at the end-use level for the commercial sector. Similar to the residential sector, market size is increasing and usage per square foot is decreasing slightly.

Table 4-6 Commercial Baseline Projection by End Use, Idaho (dtherms)

End Use	2021	2023	2024	2025	2035	2045	% Change ('21-'45)
Space Heating	1,897,872	2,130,579	2,292,981	2,262,225	2,359,571	2,551,388	34.43%
Miscellaneous	163,408	168,369	170,932	173,502	201,461	234,025	43.22%
Water Heating	722,590	739,547	749,078	739,042	751,584	845,247	16.97%
Food Preparation	365,882	377,145	382,602	387,980	446,014	513,408	40.32%
Total	**3,149,752**	**3,415,640**	**3,595,593**	**3,562,749**	**3,758,630**	**4,144,068**	**31.57%**

Figure 4-6 Commercial Baseline Projection by End Use, Idaho



Industrial Sector

Washington Projection

Industrial sector usage increases throughout the planning horizon. Table 4-7 and

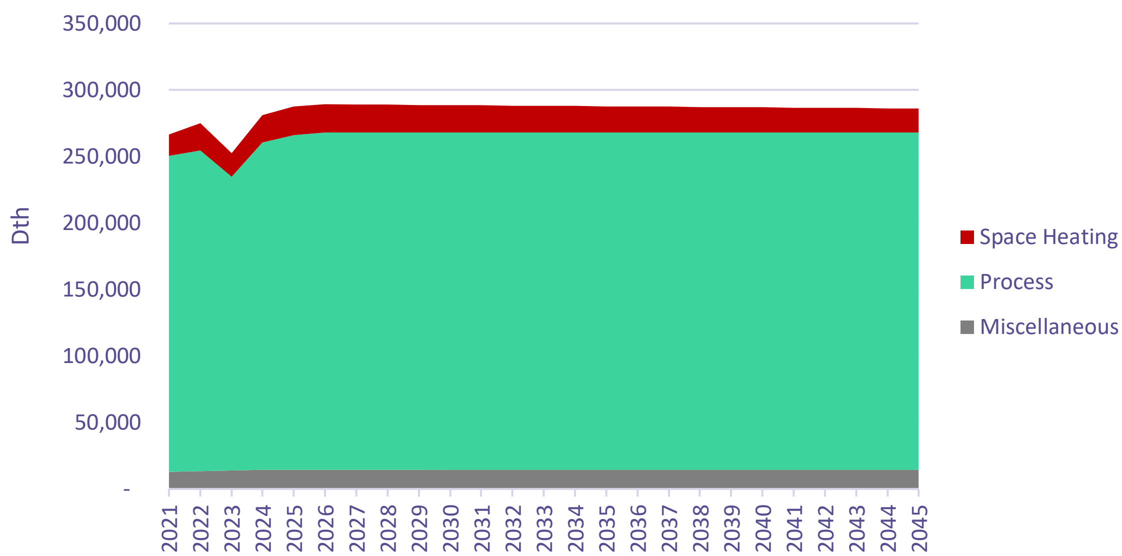
End Use	2021	2023	2024	2025	2035	2045	% Change ('21-'45)
Space Heating	16,191	17,429	20,527	21,389	19,525	17,853	10.26%
Miscellaneous	12,971	13,957	14,216	14,376	14,485	14,485	11.67%
Process	237,604	220,855	246,427	251,865	253,761	253,761	6.80%
Total	**266,766**	**252,241**	**281,169**	**287,631**	**287,771**	**286,099**	**7.25%**

Figure 4-7 present the projection at the end-use level. Overall, industrial annual natural gas use increases from 266,766 dtherms in 2021 to 286,099 dtherms in 2045, an increase of 7.25%.

Table 4-7 Industrial Baseline Projection by End Use, Washington (dtherms)

End Use	2021	2023	2024	2025	2035	2045	% Change ('21-'45)
Space Heating	16,191	17,429	20,527	21,389	19,525	17,853	10.26%
Miscellaneous	12,971	13,957	14,216	14,376	14,485	14,485	11.67%
Process	237,604	220,855	246,427	251,865	253,761	253,761	6.80%
Total	**266,766**	**252,241**	**281,169**	**287,631**	**287,771**	**286,099**	**7.25%**

Figure 4-7 Industrial Baseline Projection by End Use, Washington



Idaho Projection

Industrial annual natural gas use decreases from 230,206 dtherms in 2021 to 183,603 dtherms in 2045, a decrease of 20.24%. Table 4-8 and

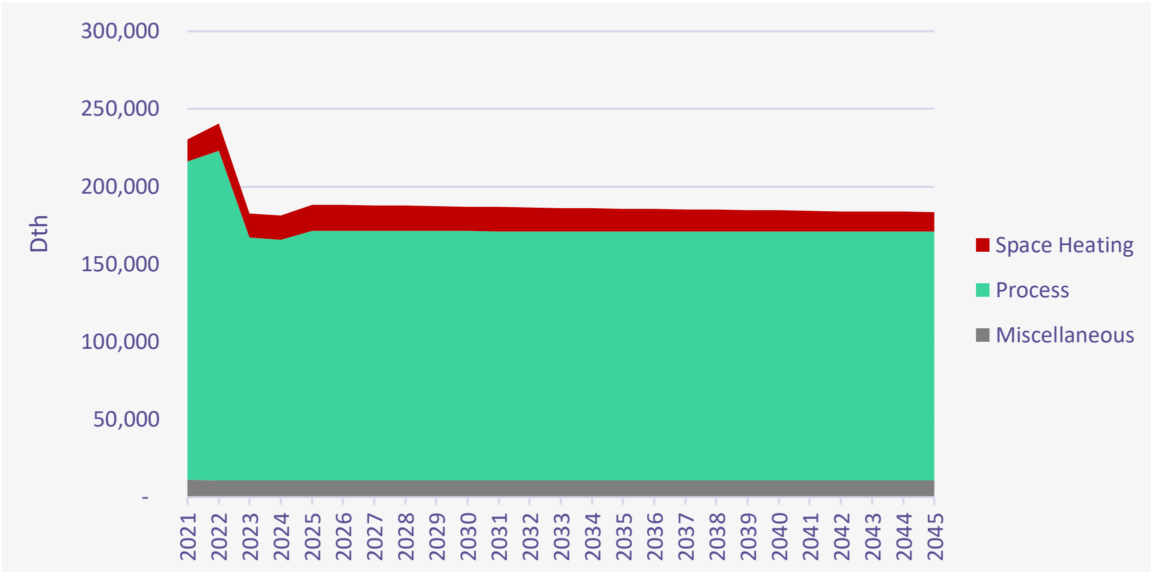
End Use	2021	2023	2024	2025	2035	2045	% Change ('21-'45)
Space Heating	13,972	15,279	15,631	16,971	14,716	12,666	-9.35%
Miscellaneous	11,193	10,845	10,849	10,847	10,834	10,819	-3.34%
Process	205,041	156,403	154,903	160,533	160,339	160,117	-21.91%
Total	**230,206**	**182,526**	**181,383**	**188,351**	**185,889**	**183,603**	**-20.24%**

Figure 4-8 present the projection at the end-use level.

Table 4-8 Industrial Baseline Projection by End Use, Idaho (dtherms)

End Use	2021	2023	2024	2025	2035	2045	% Change ('21-'45)
Space Heating	13,972	15,279	15,631	16,971	14,716	12,666	-9.35%
Miscellaneous	11,193	10,845	10,849	10,847	10,834	10,819	-3.34%
Process	205,041	156,403	154,903	160,533	160,339	160,117	-21.91%
Total	**230,206**	**182,526**	**181,383**	**188,351**	**185,889**	**183,603**	**-20.24%**

Figure 4-8 Industrial Baseline Projection by End Use, Idaho



5 | Conservation Potential

This chapter presents the conservation potential across all sectors for Avista's Washington and Idaho territories. Conservation potential includes every measure considered in the measure list, regardless of delivery mechanism (program implementation, etc.). Year-by-year annual energy savings are available in the LoadMAP model and measure assumption summary, provided to Avista at the conclusion of the study. Please note that all savings are at the customer site.

Washington Overall Energy Efficiency Potential

Error! Reference source not found. and Figure 5-1 summarize the conservation savings in terms of annual energy use for all measures for four levels of potential relative to the baseline projection.

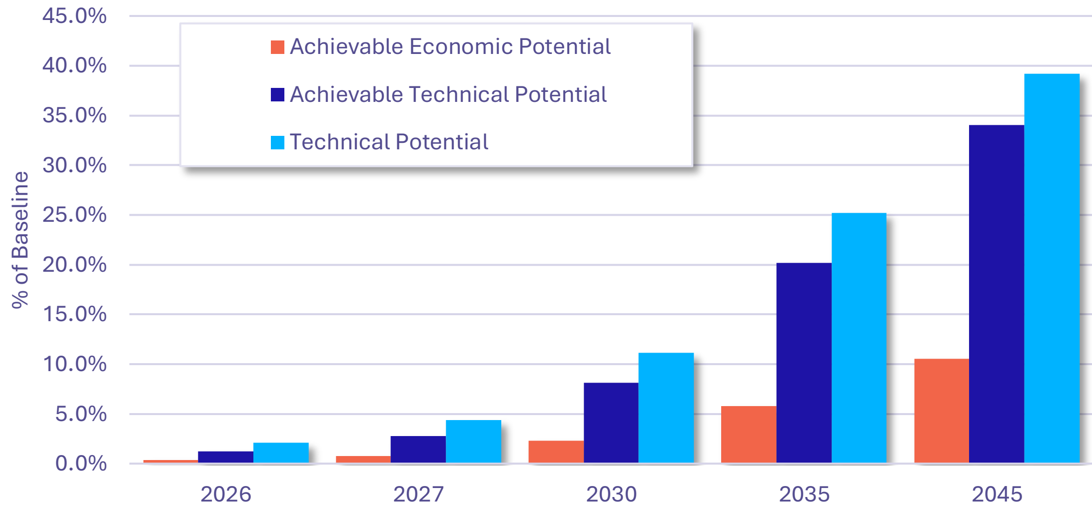


Figure 5-2 displays the cumulative energy conservation forecasts, which reflect the effects of persistent savings in prior years and new savings.

- *Technical Potential* reflects the adoption of all conservation measures regardless of cost-effectiveness. Efficient equipment makes up all lost opportunity installations and all retrofit measures are installed, regardless of achievability. First-year savings are 420,042 dtherms, or 2.1% of the baseline projection. Cumulative savings in 2045 are 5,974,486 dtherms, or 39.2% of the baseline.
- *Achievable Technical Potential* refines Technical Potential by applying market adoption rates to each measure. The market adoption rates estimate the percentage of customers who would be likely to select each measure given market barriers, customer awareness and attitudes, program maturity, and other factors that affect market penetration of conservation measures. First-year savings are 245,009 dtherms, or 1.2% of the baseline projection. Cumulative savings in 2045 are 5,183,435 dtherms, or 34.0% of the baseline.
- *TRC Achievable Economic Potential* refines Achievable Technical Potential by applying the TRC economic cost-effectiveness screen, which compares lifetime energy benefits to the total customer and utility costs of delivering the measure through a utility program, including monetized non-energy impacts. For the TRC, AEG also applied (1) benefits for non-gas energy savings, such as electric HVAC savings for weatherization, (2) the NWPCC's calibration credit to space heating savings to reflect that additional fuels may be used as a supplemental heat source within an average home, and (3) a 10% conservation credit to avoided costs per the NWPCC

methodologies. First-year savings are 71,740 dtherms, or 0.4% of the baseline projection. Cumulative savings in 2045 are 1,601,274 dtherms, or 10.5% of the baseline.

Table 5-1 Summary of Energy Efficiency Potential, Washington

Scenario	2026	2027	2030	2035	2045
Baseline Forecast (dtherms)	20,130,837	20,175,109	19,396,729	17,851,728	15,235,347
Cumulative Savings (dtherms)					
TRC Achievable Economic Potential	71,740	155,226	448,283	1,028,874	1,601,274
Achievable Technical Potential	245,009	560,714	1,575,447	3,599,528	5,183,435
Technical Potential	420,042	884,857	2,154,937	4,498,938	5,974,486
Energy Savings (% of Baseline)					
TRC Achievable Economic Potential	0.4%	0.8%	2.3%	5.8%	10.5%
Achievable Technical Potential	1.2%	2.8%	8.1%	20.2%	34.0%
Technical Potential	2.1%	4.4%	11.1%	25.2%	39.2%

Figure 5-1 Cumulative Energy Efficiency Potential as % of Baseline Projection, Washington

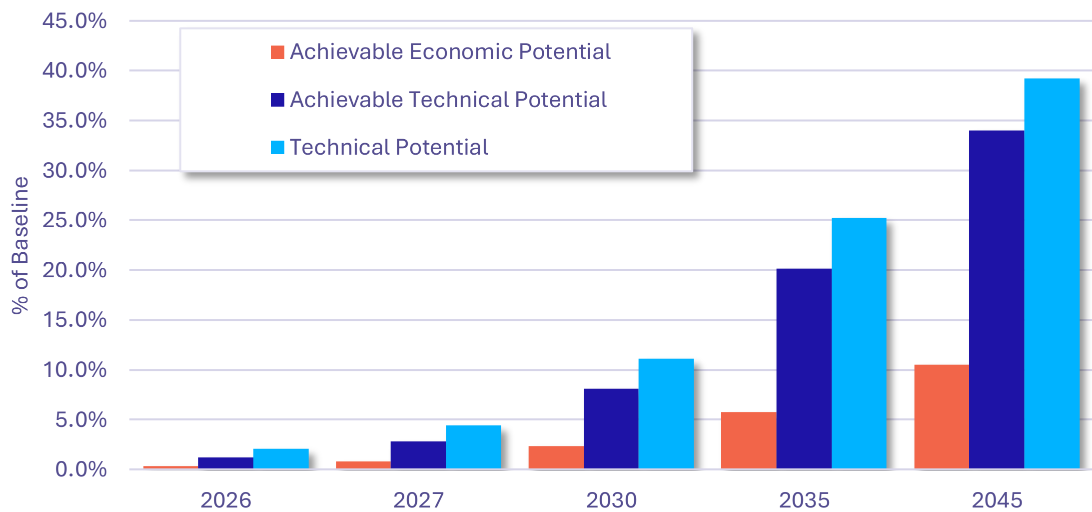
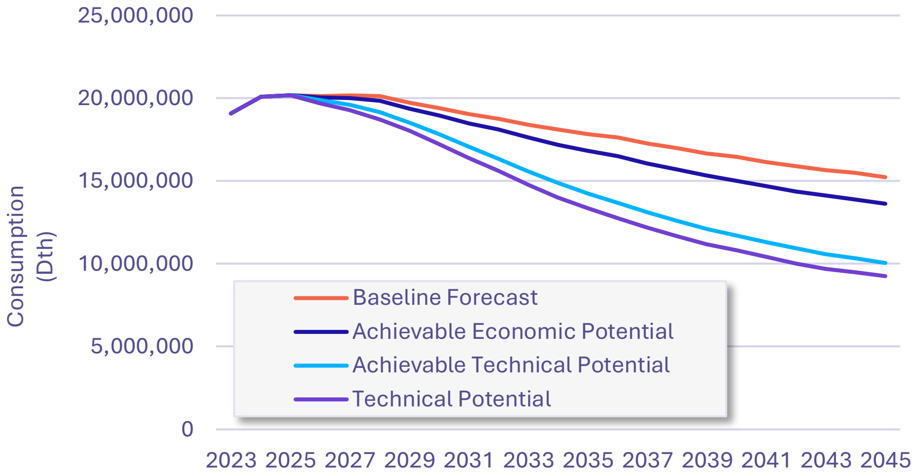


Figure 5-2 Baseline Projection and Energy Efficiency Forecasts, Washington



Idaho Overall Energy Efficiency Potential

Table 5-2 and Figure 5-3 summarize the conservation savings in terms of annual energy use for all measures for four levels of potential relative to the baseline projection. Figure 5-4 displays the cumulative energy conservation forecasts, which reflect the effects of persistent savings in prior years in addition to new savings.

- *Technical Potential* first-year savings in 2023 are 161,379 dtherms, or 1.5% of the baseline projection. Cumulative savings in 2045 are 2,509,059 dtherms, or 21.6% of the baseline.
- *Achievable Technical Potential* first-year savings are 95,484 dtherms, or 0.9% of the baseline projection. Cumulative savings in 2045 are 2,019,632 dtherms, or 17.4% of the baseline
- *UCT Achievable Economic Potential* first-year savings are 26,527 dtherms, or 0.2% of the baseline projection. Cumulative savings in 2045 are 600,730 dtherms, or 5.2% of the baseline

Table 5-2 Summary of Energy Efficiency Potential, Idaho

Scenario	2026	2027	2030	2035	2045
Baseline Forecast (dtherms)	10,563,771	10,646,120	10,792,588	11,014,191	11,622,835
Cumulative Savings (dtherms)					
UCT Achievable Economic Potential	26,257	60,181	141,546	355,518	600,730
Achievable Technical Potential	95,484	210,216	613,432	1,493,222	2,019,632
Technical Potential	161,379	338,723	843,810	1,918,908	2,509,059
Energy Savings (% of Baseline)					
UCT Achievable Economic Potential	0.2%	0.6%	1.3%	3.2%	5.2%
Achievable Technical Potential	0.9%	2.0%	5.7%	13.6%	17.4%
Technical Potential	1.5%	3.2%	7.8%	17.4%	21.6%

Figure 5-3 Cumulative Energy Efficiency Potential as % of Baseline Projection, Idaho

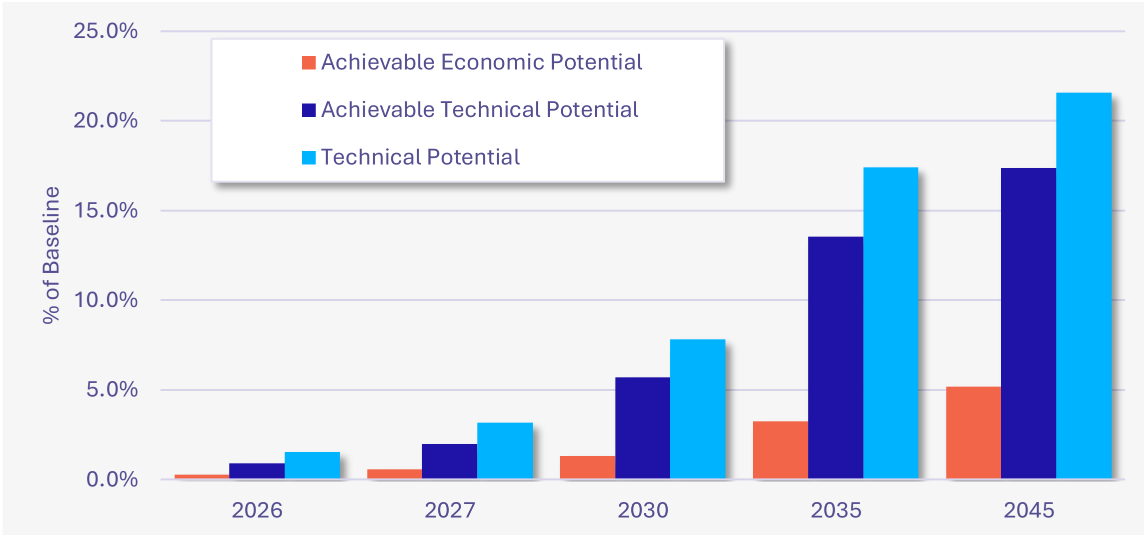
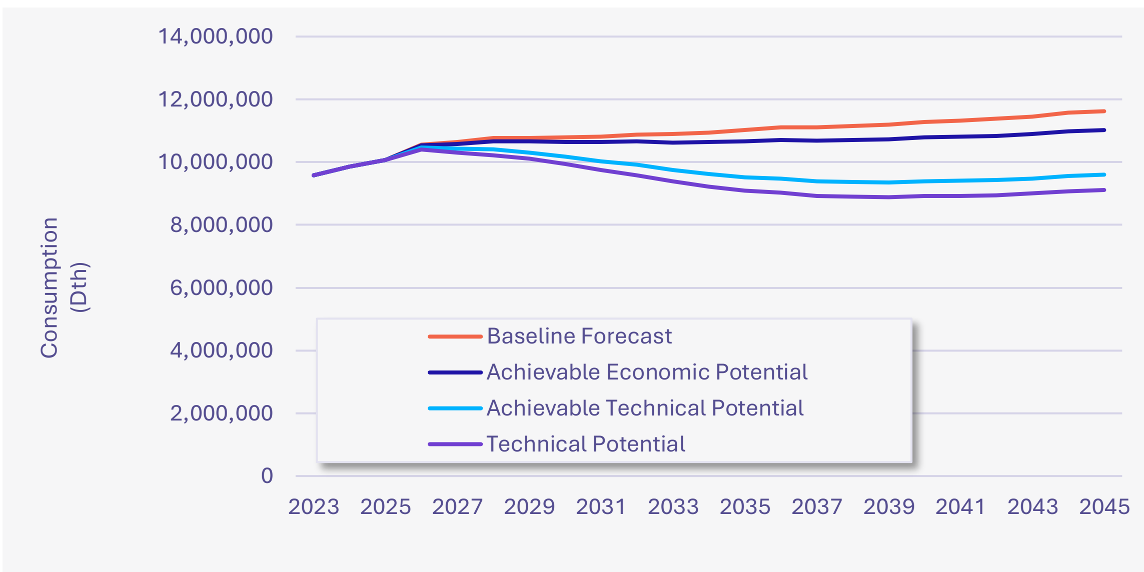


Figure 5-4 Baseline Projection and Energy Efficiency Forecasts, Idaho



6 | Sector-Level Energy Efficiency Potential

This chapter provides energy efficiency potential at the sector level.

Residential Sector

Washington Potential

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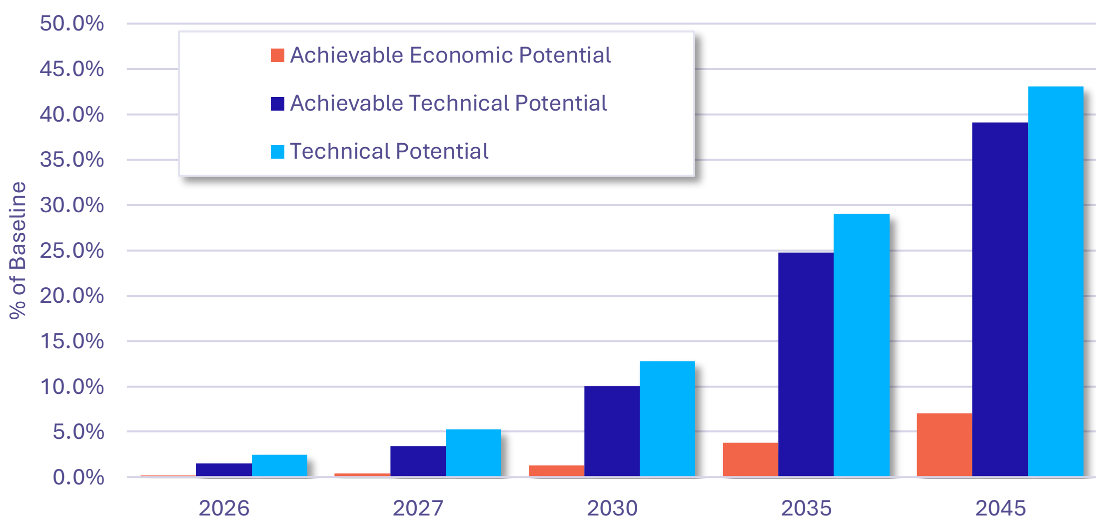
Figure 6-1 summarize the energy efficiency potential for the residential sector. In 2026, TRC achievable economic potential is 19,132 dtherms, or 0.2% of the baseline projection. By 2045, cumulative savings are 694,094 dtherms, or 7.0% of the baseline.

Table 6-1 Residential Energy Conservation Potential Summary, Washington

Scenario	2026	2027	2030	2035	2045
Baseline Forecast (dtherms)	12,180,331	12,226,885	11,857,137	11,179,884	9,890,243
Cumulative Savings (dtherms)					
TRC Achievable Economic Potential	19,132	45,189	150,548	424,381	694,094
Achievable Technical Potential	178,769	421,508	1,189,255	2,766,099	3,869,722
Technical Potential	302,288	641,042	1,510,653	3,243,233	4,260,407
Energy Savings (% of Baseline)					
TRC Achievable Economic Potential	0.2%	0.4%	1.3%	3.8%	7.0%
Achievable Technical Potential	1.5%	3.4%	10.0%	24.7%	39.1%
Technical Potential	2.5%	5.2%	12.7%	29.0%	43.1%

Figure 6-1 Cumulative Residential Potential as % of Baseline Projection, Washington



Error! Reference source not found. presents the forecast of cumulative energy savings by end use. Space heating makes up a majority of potential followed by water heating.

Figure 6-2 Residential TRC Achievable Economic Potential – Cumulative Savings by End Use, Washington

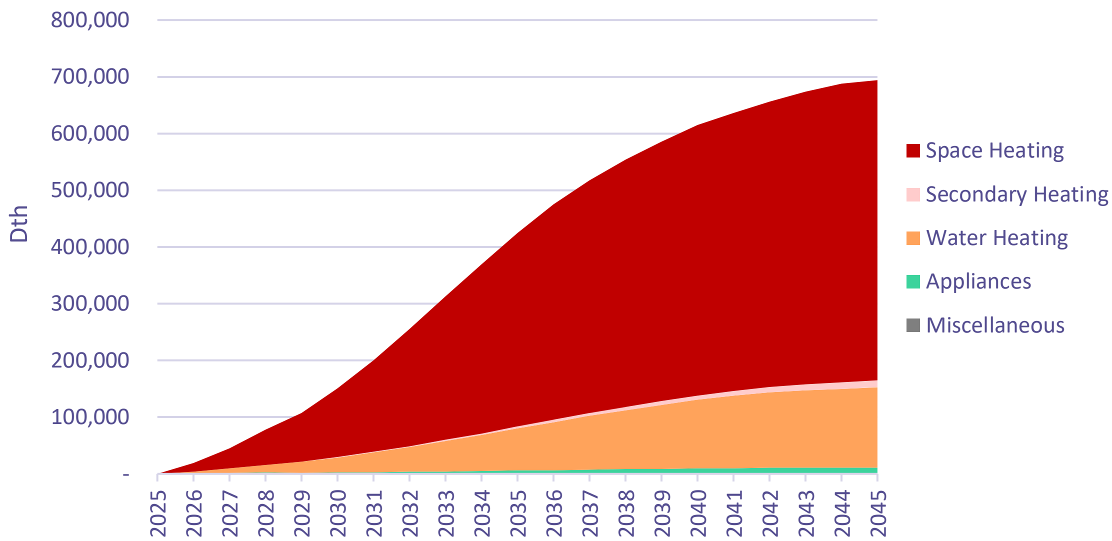


Table 6-2 identifies the top 20 residential measures by cumulative 2026 and 2045 savings. Furnaces, ceiling insulation, clothes washers, and air sealing are the top measures.

Table 6-2 Residential Top Measures in 2026 and 2045, TRC Achievable Economic Potential, Washington

Rank	Measure / Technology	2026 Cumulative dtherms	% of Total	2045 Cumulative dtherms	% of Total
1	Furnace	6,063	31.7%	252,172	36.3%
2	Insulation - Ceiling Installation	4,872	25.5%	85,451	12.3%
3	Clothes Washer - CEE Tier 2	3,131	16.4%	25,511	3.7%
4	Building Shell - Air Sealing (Infiltration Control)	1,063	5.6%	20,339	2.9%
5	Insulation - Ducting	576	3.0%	10,091	1.5%
6	Insulation - Ceiling Upgrade	546	2.9%	9,495	1.4%
7	Stove/Oven	464	2.4%	9,784	1.4%
8	Ducting - Repair and Sealing - Aerosol	419	2.2%	57,284	8.3%
9	Home Energy Management System (HEMS)	410	2.1%	57,291	8.3%
10	Water Heater (<= 55 Gal)	368	1.9%	49,898	7.2%
11	Insulation - Wall Cavity Installation	351	1.8%	4,920	0.7%
12	Insulation - Wall Sheathing	215	1.1%	3,030	0.4%
13	Home Energy Reports	186	1.0%	25,435	3.7%
14	Boiler	119	0.6%	9,082	1.3%
15	Water Heater - Drainwater Heat Recovery	117	0.6%	41,161	5.9%
16	Gas Boiler - Thermostatic Radiator Valves	81	0.4%	9,758	1.4%
17	Windows - Low-e Storm Addition	56	0.3%	792	0.1%
18	Ducting - Repair and Sealing	47	0.2%	6,730	1.0%
19	Water Heater - Pipe Insulation	21	0.1%	3,388	0.5%
20	Gas Boiler - Pipe Insulation	14	0.1%	83	0.0%
	Subtotal	**19,118**	**99.9%**	**681,694**	**98.2%**
	Total Savings in Year	**19,132**	**100.0%**	**694,094**	**100.0%**

Idaho Potential

Table 6-3 and

Figure 6-3 summarize the energy efficiency potential for the residential sector. In 2026, UCT achievable economic potential is 13,858 dtherms, or 0.2% of the baseline projection. By 2045, cumulative savings are 244,613 dtherms, or 3.4% of the baseline.

Table 6-3 Residential Energy Conservation Potential Summary, Idaho

Scenario	2026	2027	2030	2035	2045
Baseline Forecast (dtherms)	6,806,909	6,872,961	6,966,076	7,069,672	7,295,165
Cumulative Savings (dtherms)					
Achievable Economic UCT Potential	13,858	33,833	63,666	164,876	244,613
Achievable Technical Potential	64,854	146,531	433,389	1,085,990	1,352,671
Technical Potential	101,847	218,656	533,177	1,296,120	1,598,531
Energy Savings (% of Baseline)					
Achievable Economic UCT Potential	0.2%	0.5%	0.9%	2.3%	3.4%
Achievable Technical Potential	1.0%	2.1%	6.2%	15.4%	18.5%
Technical Potential	1.5%	3.2%	7.7%	18.3%	21.9%

Figure 6-3 Cumulative Residential Potential as % of Baseline Projection, Idaho

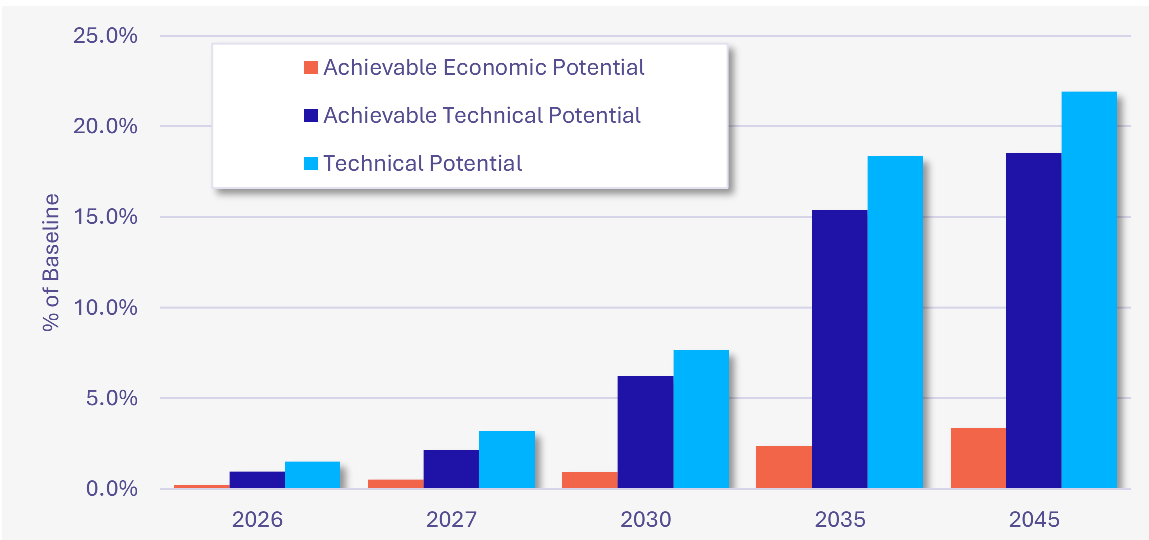


Figure 6-4 presents the forecast of cumulative energy savings by end use. Space heating makes up a majority of potential followed by water heating.

Figure 6-4 Residential UCT Achievable Economic Potential – Cumulative Savings by End Use, Idaho

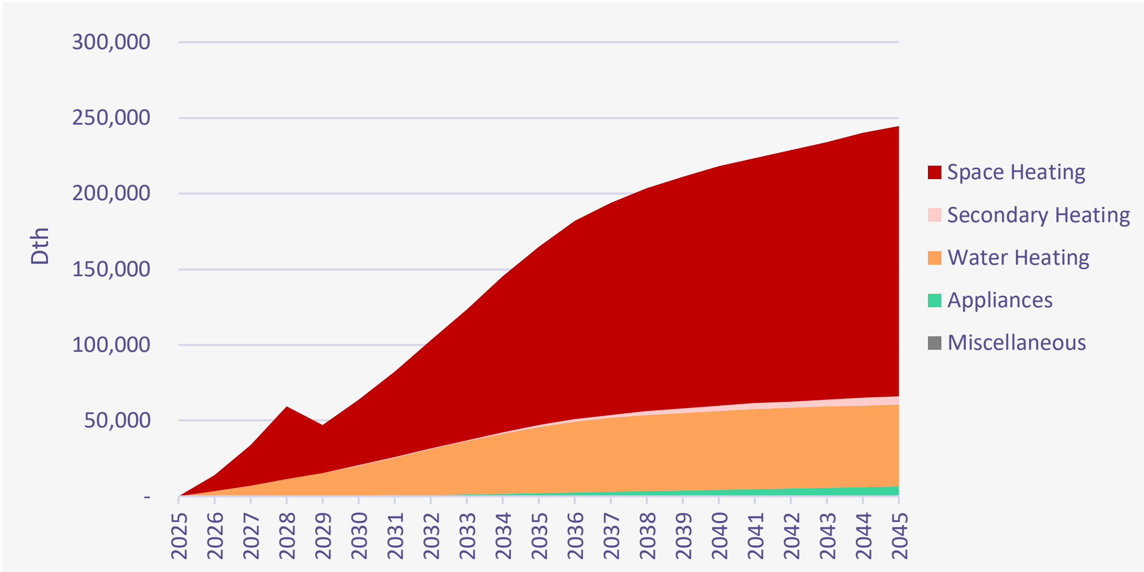


Table 6-4 identifies the top 20 residential measures by cumulative 2026 and 2045 savings. Furnaces, ceiling insulation, clothes washers, and aerators are the top measures.

Table 6-4 Residential Top Measures in 2026 and 2045, TRC Achievable Economic Potential, Idaho

Rank	Measure / Technology	2026 Cumulative dtherms	% of Total	2045 Cumulative dtherms	% of Total
1	Furnace	5,855	42.2%	44,423	18.2%
2	Insulation - Ceiling Installation	3,663	26.4%	69,252	28.3%
3	Clothes Washer - CEE Tier 2	1,862	13.4%	16,871	6.9%
4	Water Heater - Faucet Aerators	716	5.2%	15,641	6.4%
5	Water Heater - Low-Flow Showerheads	670	4.8%	14,319	5.9%
6	Building Shell - Air Sealing (Infiltration Control)	455	3.3%	9,099	3.7%
7	Insulation - Ceiling Upgrade	279	2.0%	5,437	2.2%
8	ENERGY STAR Home Design	153	1.1%	29,219	11.9%
9	Home Energy Reports	104	0.7%	17,067	7.0%
10	Stove/Oven	62	0.5%	5,586	2.3%
11	Ducting - Repair and Sealing - Aerosol	17	0.1%	2,936	1.2%
12	Water Heater - Pipe Insulation	12	0.1%	2,010	0.8%
13	Fireplace	8	0.1%	5,345	2.2%
14	Circulation Pump - Controls	1	0.0%	404	0.2%
	Subtotal	**13,858**	**100.0%**	**237,610**	**97.1%**
	Total Savings in Year	**13,858**	**100.0%**	**244,613**	**100.0%**

Commercial Sector

Washington Potential

Table 6-5 and

Figure 6-5 summarize the energy conservation potential for the commercial sector. In 2026, TRC achievable economic potential is 50,960 dtherms, or 0.7% of the baseline projection. By 2045, cumulative savings are 874,645 dtherms, or 17.3% of the baseline.

Table 6-5 Commercial Energy Conservation Potential Summary, Washington

Scenario	2026	2027	2030	2035	2045
Baseline Forecast (dtherms)	7,661,189	7,659,040	7,250,905	6,384,073	5,059,004
Cumulative Savings (dtherms)					
Achievable Economic TRC Potential	50,960	106,715	289,032	585,542	874,645
Achievable Technical	64,581	135,857	377,308	814,031	1,280,611
Technical Potential	115,750	239,787	633,697	1,232,844	1,675,560
Energy Savings (% of Baseline)					
Achievable Economic TRC Potential	0.7%	1.4%	4.0%	9.2%	17.3%
Achievable Technical	0.8%	1.8%	5.2%	12.8%	25.3%
Technical Potential	1.5%	3.1%	8.7%	19.3%	33.1%

Figure 6-5 Cumulative Commercial Potential as % of Baseline Projection, Washington

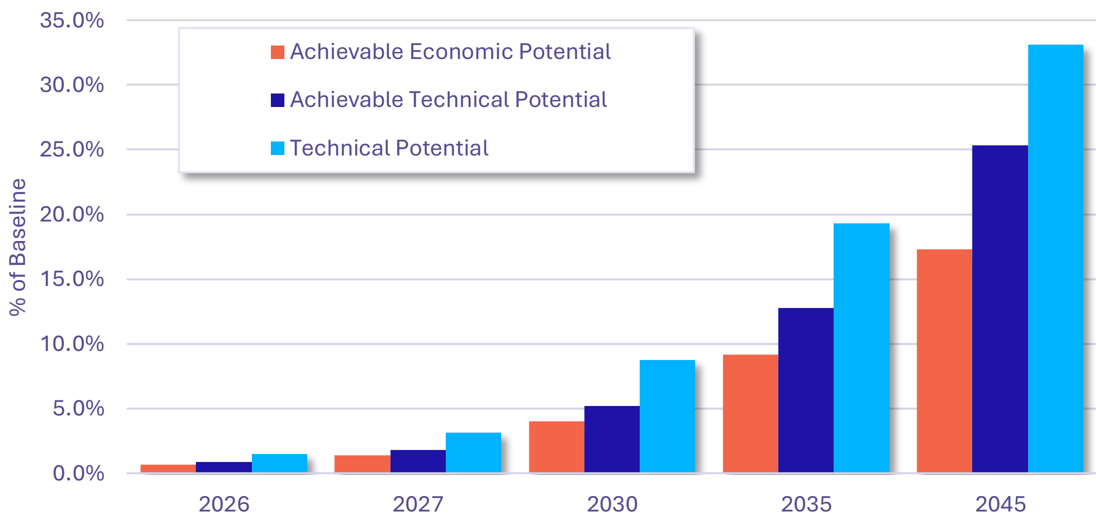


Figure 6-6 presents the cumulative forecast of energy savings by end use. Space heating makes up a majority of the potential early, but water heating and food preparation equipment upgrades provide increased savings opportunities in the later years.

Figure 6-6 Commercial TRC Achievable Economic Potential – Cumulative Savings by End Use, Washington

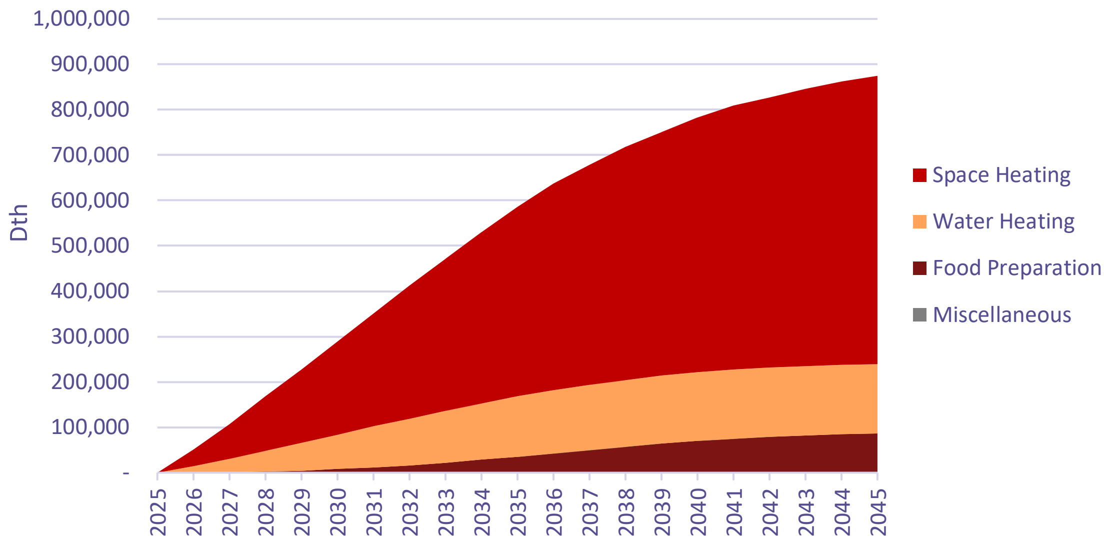


Table 6-6 identifies the top 20 commercial measures by cumulative savings in 2026 and 2045. Demand Controlled Ventilation and Destratification Fans are the top measures, providing space heating savings, followed by Strategic Energy Management and Retrocommissioning and several HVAC and space heating measures, along with water heater controls.

Table 6-6 Commercial Top Measures in 2023 and 2035, TRC Achievable Economic Potential, Washington

Rank	Measure / Technology	2026 Cumulative dtherms	% of Total	2045 Cumulative dtherms	% of Total
1	Ventilation - Demand Controlled	11,512	22.6%	69,390	7.9%
2	Destratification Fans (HVLS)	6,454	12.7%	76,738	8.8%
3	HVAC - Energy Recovery Ventilator	4,873	9.6%	64,414	7.4%
4	Water Heater - Pipe Insulation	4,861	9.5%	33,466	3.8%
5	Strategic Energy Management	3,286	6.4%	44,680	5.1%
6	Retrocommissioning	3,048	6.0%	44,020	5.0%
7	Commercial Laundry - Ozone Treatment	2,105	4.1%	14,530	1.7%
8	Gas Boiler - Stack Economizer	1,900	3.7%	13,246	1.5%
9	Circulation Pump - Controls	1,469	2.9%	9,691	1.1%
10	Gas Boiler - Thermostatic Radiator Valves	1,149	2.3%	20,529	2.3%
11	Water Heater	1,134	2.2%	44,216	5.1%
12	Gas Boiler - Insulate Steam Lines/Condensate Tank	979	1.9%	12,967	1.5%
13	Gas Boiler - Hot Water Reset	919	1.8%	16,170	1.8%
14	Water Heater - Pre-Rinse Spray Valve	726	1.4%	4,727	0.5%
15	Water Heater - ENERGY STAR Dishwasher (3.0)	606	1.2%	4,162	0.5%
16	Boiler	586	1.1%	21,375	2.4%
17	Gas Boiler - Maintenance	580	1.1%	1,638	0.2%
18	Infiltration Control - Loading Dock Sealing	521	1.0%	5,891	0.7%
19	Gas Boiler - High Turndown Burner	482	0.9%	3,118	0.4%
20	Refrigeration - Heat Recovery	469	0.9%	8,437	1.0%
	Subtotal	**47,659**	**93.5%**	**513,406**	**58.7%**
	Total Savings in Year	**50,960**	**100.0%**	**874,645**	**100.0%**

Idaho Potential

Table 6-7 and

Figure 6-7 summarize the energy conservation potential for the commercial sector. In 2026, UCT achievable economic potential is 11,641 dtherms, or 0.5% of the baseline projection. By 2045, cumulative savings are 575,363 dtherms, or 13.9% of the baseline.

Table 6-7 Commercial Energy Conservation Potential Summary, Idaho

Scenario	2026	2027	2030	2035	2045
Baseline Forecast (dtherms)	3,568,688	3,585,222	3,639,395	3,758,630	4,144,068
Cumulative Savings (dtherms)					
Achievable Economic UCT Potential	11,998	25,531	75,251	183,328	342,501
Achievable Technical	29,850	62,110	175,849	398,037	651,225
Technical Potential	58,576	118,140	305,571	611,862	892,159
Energy Savings (% of Baseline)					
Achievable Economic UCT Potential	0.3%	0.7%	2.1%	4.9%	8.3%
Achievable Technical	0.8%	1.7%	4.8%	10.6%	15.7%
Technical Potential	1.6%	3.3%	8.4%	16.3%	21.5%

Figure 6-7 Cumulative Commercial Potential as % of Baseline Projection, Idaho

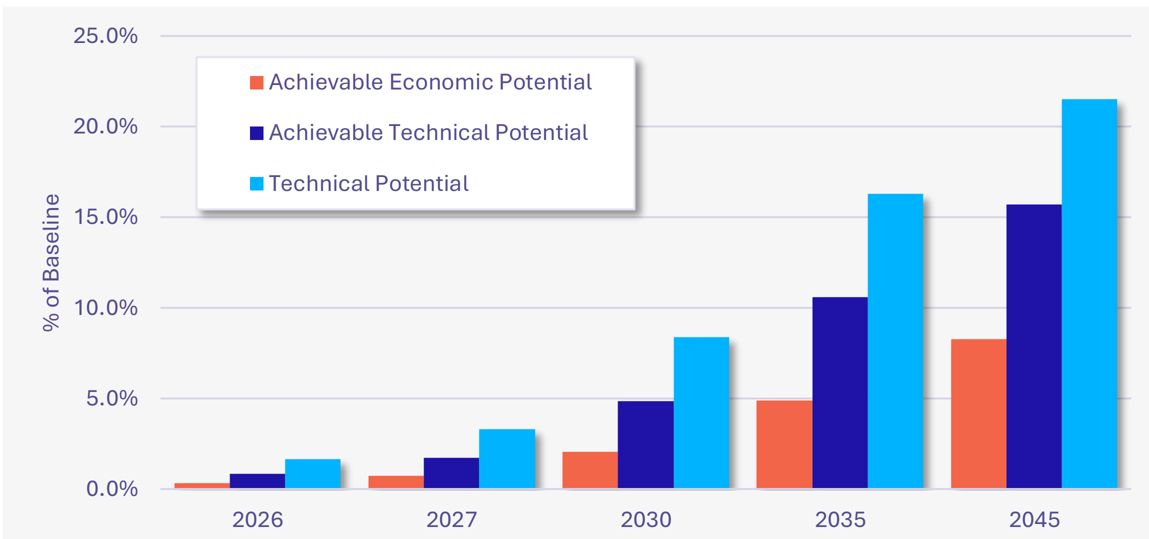


Figure 6-8 presents forecasts of energy savings by end use as a percent of total annual savings and cumulative savings. Space heating makes up a majority of the potential early, but food preparation equipment upgrades provide substantial savings opportunities in the later years.

Figure 6-8 Commercial UCT Achievable Economic Potential – Cumulative Savings by End Use, Idaho

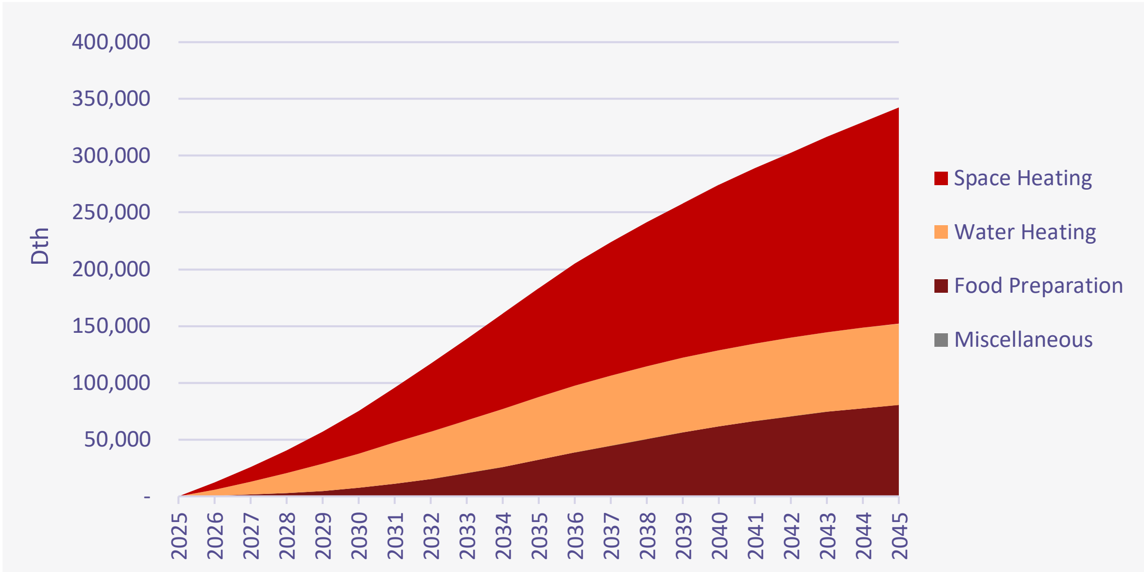


Table 6-8 identifies the top 20 commercial measures by cumulative savings in 2026 and 2045. Pipe Insulation is the top measure, followed by HVAC energy recovery ventilator, retrocommissioning, and boiler economizers.

Table 6-8 Commercial Top Measures in 2026 and 2045, TRC Achievable Economic Potential, Idaho

Rank	Measure / Technology	2026 Cumulative dtherms	% of Total	2045 Cumulative dtherms	% of Total
1	Water Heater - Pipe Insulation	2,212	18.4%	16,126	4.7%
2	HVAC - Energy Recovery Ventilator	1,805	15.0%	30,097	8.8%
3	Retrocommissioning	1,300	10.8%	18,855	5.5%
4	Gas Boiler - Stack Economizer	784	6.5%	6,492	1.9%
5	Circulation Pump - Controls	626	5.2%	3,956	1.2%
6	Commercial Laundry - Ozone Treatment	543	4.5%	4,701	1.4%
7	Gas Boiler - Thermostatic Radiator Valves	498	4.1%	10,130	3.0%
8	Water Heater	494	4.1%	26,886	7.8%
9	Boiler	386	3.2%	14,536	4.2%
10	Gas Boiler - Insulate Steam Lines/Condensate Tank	385	3.2%	5,196	1.5%
11	Gas Boiler - Hot Water Reset	371	3.1%	6,684	2.0%
12	Fryer	356	3.0%	37,786	11.0%
13	Water Heater - Pre-Rinse Spray Valve	307	2.6%	2,333	0.7%
14	Strategic Energy Management	276	2.3%	5,001	1.5%
15	Water Heater - ENERGY STAR Dishwasher (3.0)	246	2.0%	1,946	0.6%
16	Refrigeration - Heat Recovery	201	1.7%	4,259	1.2%
17	Water Heater - Solar System	192	1.6%	1,622	0.5%
18	Unit Heater	146	1.2%	18,435	5.4%
19	Water Heater - Low-Flow Showerheads	128	1.1%	1,039	0.3%
20	Water Heater - Faucet Aerators/Low Flow Nozzles	117	1.0%	797	0.2%
	Subtotal	**11,374**	**94.8%**	**216,877**	**63.3%**
	Total Savings in Year	**11,998**	**100.0%**	**342,501**	**100.0%**

Industrial Sector

Washington Potential

Table 6-9 and Figure 6-9 summarize the energy conservation potential for the industrial sector. In 2026, TRC achievable economic potential is 1,649 dtherms, or 0.6% of the baseline projection. By 2045, cumulative savings reach 32,536 dtherms, or 11.4% of the baseline. Industrial potential is a lower percentage of overall baseline compared to the residential and commercial sectors. While large, custom process optimization and controls measures are present in potential, these are not applicable to all processes, which limits potential at the technical level. Additionally, the remaining customers are smaller and tend to have lower process end-use shares, further lowering industrial potential.

Table 6-9 Industrial Energy Conservation Potential Summary, Washington

Scenario	2026	2027	2030	2035	2045
Baseline Forecast (dtherms)	289,317	289,184	288,687	287,771	286,099
Cumulative Savings (dtherms)					
Achievable Economic TRC Potential	1,649	3,322	8,703	18,951	32,536
Achievable Technical	1,659	3,349	8,884	19,399	33,102
Technical Potential	2,004	4,027	10,587	22,861	38,519
Energy Savings (% of Baseline)					
Achievable Economic TRC Potential	0.6%	1.1%	3.0%	6.6%	11.4%
Achievable Technical	0.6%	1.2%	3.1%	6.7%	11.6%
Technical Potential	0.7%	1.4%	3.7%	7.9%	13.5%

Figure 6-9 Cumulative Industrial Potential as % of Baseline Projection, Washington

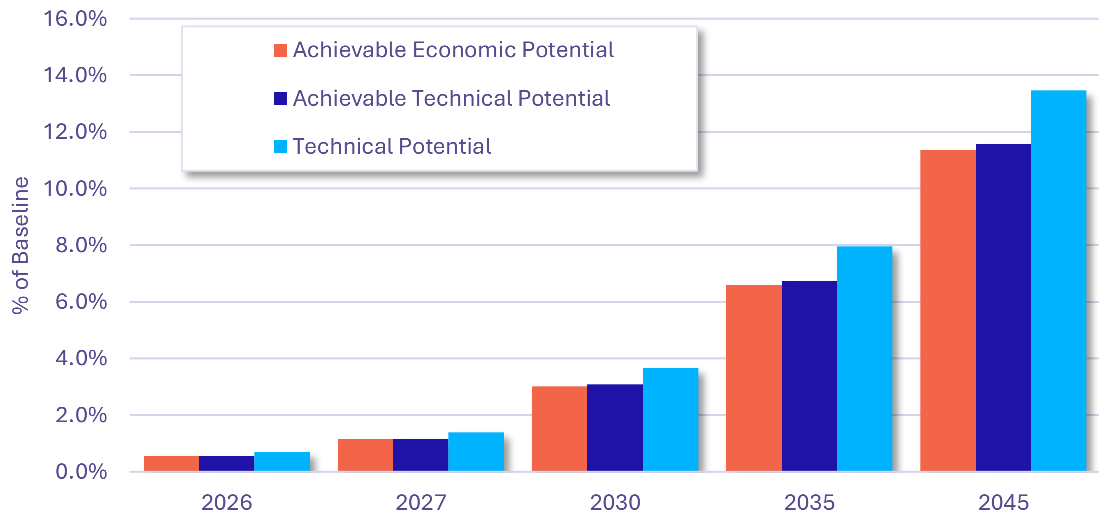


Figure 6-10 presents the forecast of cumulative energy savings by end use.

Figure 6-10 Industrial TRC Achievable Economic Potential – Cumulative Savings by End Use, Washington

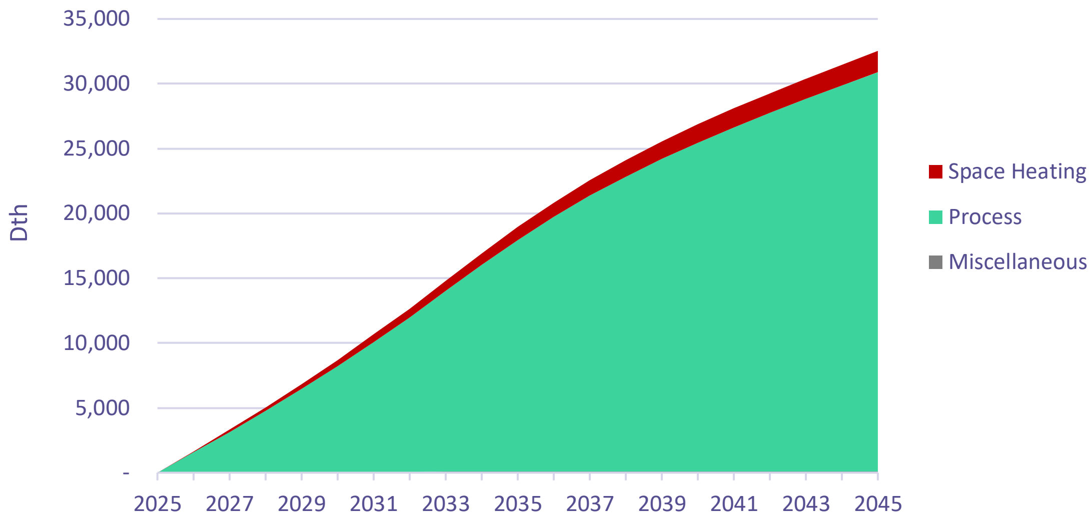


Table 6-10 identifies the top 20 industrial measures by cumulative 2026 and 2045 savings. Process Heat Recovery and Process Boiler control measures have the largest potential savings.

Table 6-10 Industrial Top Measures in 2026 and 2045, TRC Achievable Economic Potential, Washington

Rank	Measure / Technology	2026 Cumulative dtherms	% of Total	2045 Cumulative dtherms	% of Total
1	Process - Heat Recovery	806	48.9%	15,072	46.3%
2	Process Boiler - Steam Trap Replacement	208	12.6%	3,931	12.1%
3	Retrocommissioning	100	6.1%	1,942	6.0%
4	Strategic Energy Management	95	5.8%	2,145	6.6%
5	Process Boiler - Maintenance	81	4.9%	246	0.8%
6	Process Boiler - Insulate Steam Lines/Condensate Tank	68	4.1%	1,289	4.0%
7	Process Boiler - High Turndown Burner	65	4.0%	585	1.8%
8	Process Boiler - Stack Economizer	57	3.5%	496	1.5%
9	Process - Insulate Heated Process Fluids	54	3.3%	1,078	3.3%
10	Destratification Fans (HVLS)	48	2.9%	749	2.3%
11	Process Boiler - Insulate Hot Water Lines	29	1.7%	541	1.7%
12	Process Boiler - Burner Control Optimization	17	1.0%	2,896	8.9%
13	Ventilation - Demand Controlled	15	0.9%	103	0.3%
14	Unit Heater	5	0.3%	539	1.7%
	Subtotal	**1,649**	**100.0%**	**31,612**	**97.2%**
	Total Savings in Year	**1,649**	**100.0%**	**32,536**	**100.0%**

Idaho Potential

Table 6-11 and

Figure 6-11 summarize the energy conservation potential for the industrial sector. In 2026, UCT achievable economic potential is 401 dtherms, or 0.2% of the baseline projection. By 2045, cumulative savings reach 13,615 dtherms, or 7.4% of the baseline. Industrial potential is a lower percentage of overall baseline compared to the residential and commercial sectors. While large, custom process optimization and controls measures are present in potential, these are not applicable to all processes which limits potential at the technical level. Additionally, since the largest customers were excluded from this analysis due to their status as transport-only customers making them ineligible to participate in energy efficiency programs for the utility, the remaining customers are smaller and tend to have lower process end-use shares, further lowering industrial potential.

Table 6-11 Industrial Energy Conservation Potential Summary, Idaho

Scenario	2026	2027	2030	2035	2045
Baseline Forecast (dtherms)	188,175	187,937	187,118	185,889	183,603
Cumulative Savings (dtherms)					
Achievable Economic UCT Potential	401	818	2,628	7,313	13,615
Achievable Technical	779	1,575	4,194	9,195	15,736
Technical Potential	957	1,926	5,062	10,926	18,369
Energy Savings (% of Baseline)					
Achievable Economic UCT Potential	0.2%	0.4%	1.4%	3.9%	7.4%
Achievable Technical	0.4%	0.8%	2.2%	4.9%	8.6%
Technical Potential	0.5%	1.0%	2.7%	5.9%	10.0%

Figure 6-11 Cumulative Industrial Potential as % of Baseline Projection, Idaho

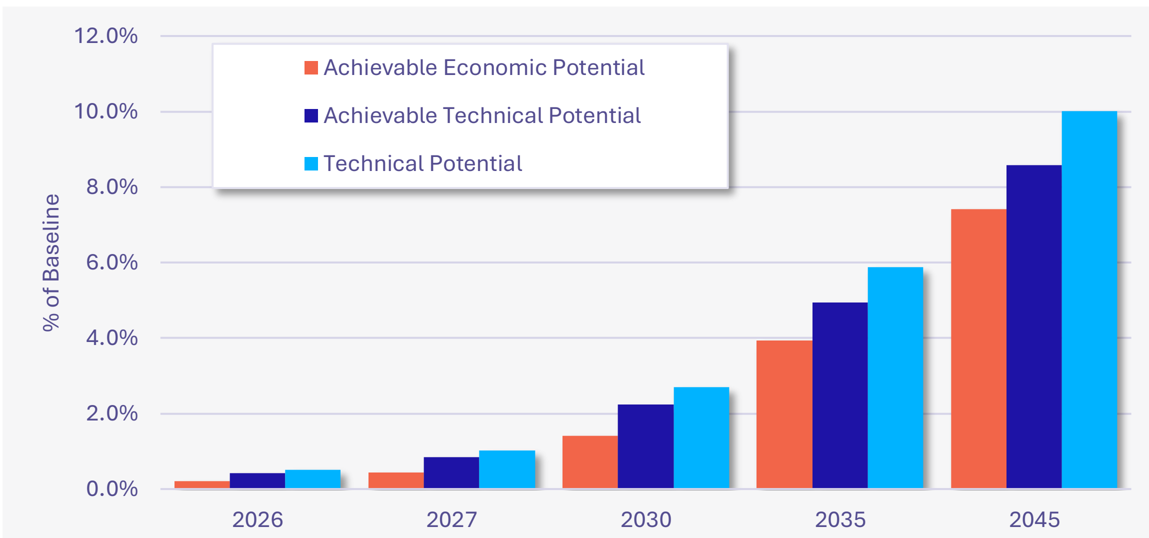


Figure 6-12 presents forecasts of energy savings by end use as a percent of total annual savings and cumulative savings.

Figure 6-12 Industrial UCT Achievable Economic Potential – Cumulative Savings by End Use, Idaho

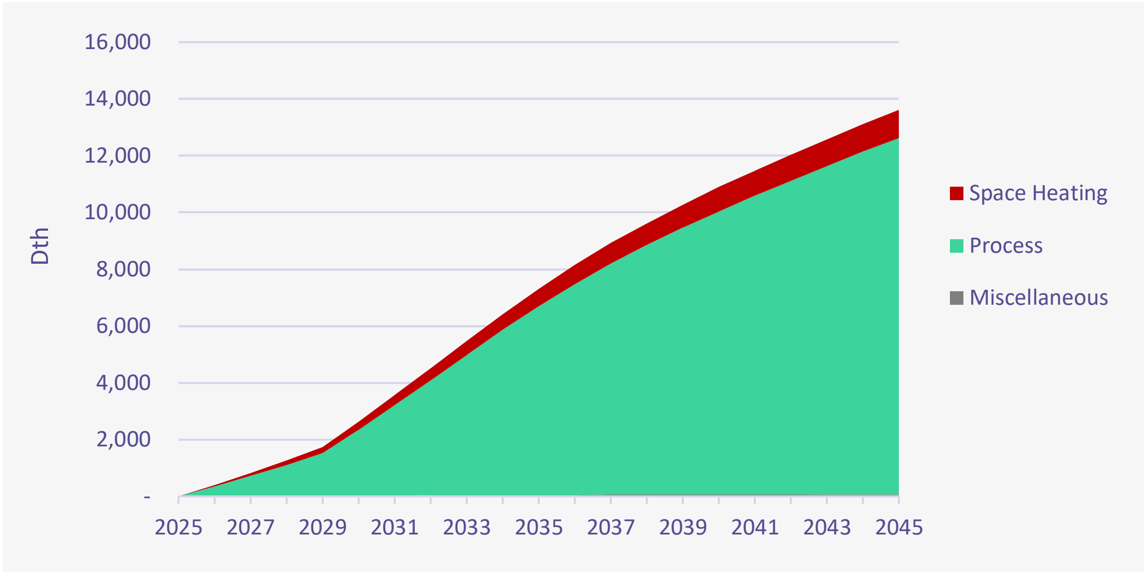


Table 6-12 identifies the top 20 industrial measures by cumulative 2026 and 2045 savings.

Table 6-12 Industrial Top Measures in 2026 and 2045, UCT Achievable Economic Potential, Idaho

Rank	Measure / Technology	2026 Cumulative dtherms	% of Total	2045 Cumulative dtherms	% of Total
1	Process Boiler - Steam Trap Replacement	96	24.0%	1,816	13.3%
2	Retrocommissioning	47	11.8%	915	6.7%
3	Strategic Energy Management	45	11.3%	1,012	7.4%
4	Process Boiler - Maintenance	38	9.4%	116	0.8%
5	Process Boiler - Insulate Steam Lines/Condensate Tank	31	7.8%	601	4.4%
6	Process Boiler - High Turndown Burner	30	7.5%	272	2.0%
7	Destratification Fans (HVLS)	28	7.1%	400	2.9%
8	Process Boiler - Stack Economizer	26	6.6%	232	1.7%
9	Process - Insulate Heated Process Fluids	25	6.3%	497	3.7%
10	Process Boiler - Insulate Hot Water Lines	13	3.3%	254	1.9%
11	Ventilation - Demand Controlled	8	2.1%	41	0.3%
12	Process Boiler - Burner Control Optimization	8	1.9%	1,347	9.9%
13	Unit Heater	4	1.0%	417	3.1%
	Subtotal	**401**	**100.0%**	**7,918**	**58.2%**
	Total Savings in Year	**401**	**100.0%**	**13,615**	**100.0%**

7 | Demand Response Potential

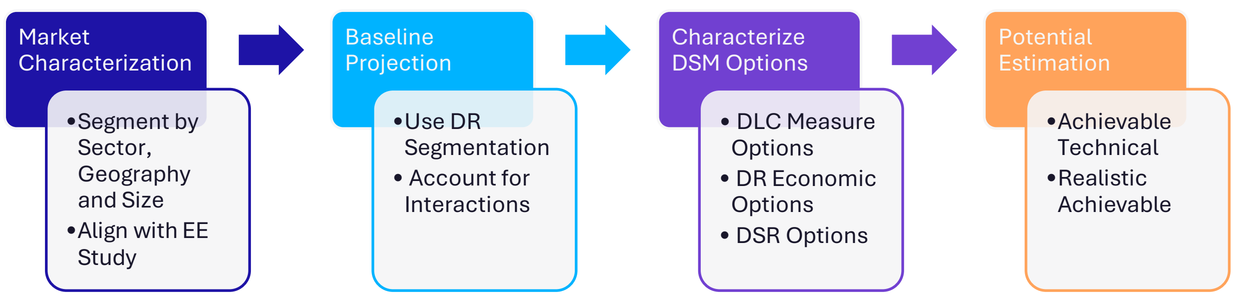
This study is the second time AEG has estimated demand response (DR) potential for natural gas in the Avista territory. Natural gas DR is an emerging market with only a few programs offered in the US. To estimate potential, AEG referenced the most current natural gas DR program data and addressed gaps utilizing information from the electric DR study.

The current study provides demand response potential and cost estimates for the 25-year planning horizon (2026-2045) to inform the development of Avista's 2025 IRP. Through this assessment, AEG sought to develop reliable estimates of the magnitude, timing, and costs of DR resources likely available to Avista over the planning horizon. The analysis focuses on resources assumed achievable during the planning horizon, recognizing known market dynamics that may hinder resource acquisition. DR analysis results will also be incorporated into subsequent DR planning and program development efforts.

Study Approach

Figure 7-1 outlines the analysis approach used to develop potential and cost estimates, with each step described in more detail in the subsections that follow.

Figure 7-1 Demand Response Analysis Approach



AEG estimated demand response potential across the following scenarios:

- **Achievable Technical Potential or Stand Alone**. In this scenario, program options are treated as if they are the only programs running in the Avista territory and are viewed in a vacuum. Potential demand savings cannot be added in this scenario since it does not account for program overlap.
- **Realistic Achievable Potential or Integrated**.[2] In this scenario, the program options are treated as if the programs were run simultaneously. To account for participation, overlap across programs that make use of the same end-use, a program hierarchy is employed. For programs that affect the same end use, the model selects the most likely program a customer would participate in, and eligible participants were chosen for that program first. The remaining pool of eligible participants will then be available to participate in the secondary program. This scenario allows for potential to be added up as it removes any double counting of savings.

Market Characterization

The first step in the DR analysis was to segment customers by service class and develop characteristics for each segment. The two relevant characteristics for DR potential analysis are end-

[2] For this study, the participation in the considered programs is not expected to overlap. Therefore, only the Realistic Achievable Potential is shown.

use saturations of the controllable equipment types in each market segment and coincident peak demand in the base year. Market characteristics, including equipment saturation and base year peak consumption, are consistent with the energy efficiency analysis (see Chapter 2 for more information on the market profiles).

As in previous studies, AEG used Avista's rate schedules as the basis for customer segmentation by state and customer class. Table 7-1 summarizes the market segmentation developed for this study.

Table 7-1 Market Segmentation

Market Dimensions	Segmentation Variable	Description
1	State	Washington Idaho Oregon
2	Customer Class	Residential Commercial Industrial

Baseline Forecast

Once the customer segments were defined and characterized, AEG developed the baseline projection. Load and consumption characteristics, including customer counts and peak-hour demand values, were provided by Avista and aligned with the natural gas energy efficiency analysis.

Customer Counts

Avista provided actual customer counts by rate schedule for Washington and Idaho over the 2019-2023 timeframe and forecasted customer counts over the 2024-2028 period. AEG used this data to calculate the growth rates by customer class across the final two forecasted years, and projected customer counts through 2045. The average annual customer growth rate for all sectors was 0.6% in Washington and 0.7% in Idaho.

Table 7-2 Baseline Customer Forecast by Customer Class, Washington

State	2026	2027	2028	2035	2045
Residential	161,986	161,986	161,986	161,986	161,986
Commercial	15,232	15,220	15,208	15,125	15,006
Industrial	90	89	88	82	73

Table 7-3 Baseline Customer Forecast by Customer Class, Idaho

State	2026	2027	2028	2035	2045
Residential	88,643	90,152	91,615	102,964	121,658
Commercial	10,111	10,217	10,318	11,082	12,273
Industrial	67	67	67	67	67

Table 7-4 Baseline Customer Forecast by Customer Class, Oregon

State	2026	2027	2028	2035	2045
Residential	96,198	96,715	97,162	100,930	106,568
Commercial	12,170	12,209	12,242	12,521	12,930
Industrial	25	25	25	25	25

Winter Peak Load Forecasts by State

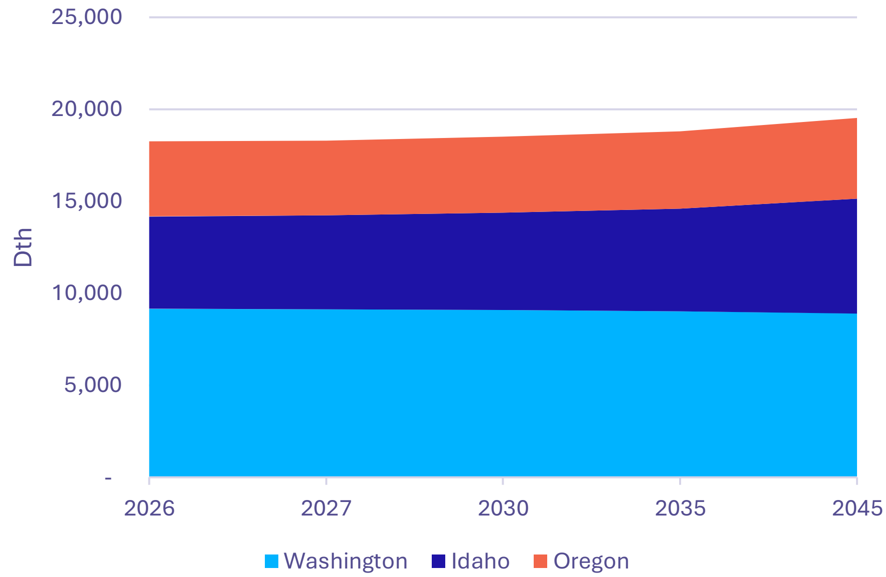
Winter peak load forecasts were developed by state and customer class by multiplying the per customer peak-hour demand values by class by the forecasted customer counts. Table 7-5 shows the winter system peak for selected future years. The system peak is expected to increase by 7% between 2026 and 2045.

Table 7-5 Baseline February Winter System Peak Forecast (Dth @Generation) by State

State	2026	2027	2028	2035	2045
Washington	9,217	9,207	9,193	9,094	8,956
Idaho	5,060	5,115	5,185	5,611	6,288
Oregon	4,090	4,107	4,121	4,240	4,416
Grand Total	18,367	18,428	18,500	18,946	19,660

Figure 7-2 shows the contribution to the estimated system coincident winter peak by state. In 2026, system peak load for the winter is 18,367 dtherms at generation. Washington contributes 50% to the winter system peak, while Idaho and Oregon contribute 28% and 22%, respectively. Winter coincident peak load is expected to grow by an average of 0.4% annually from 2026-2045.

Figure 7-2 Coincident Peak Load Forecast by State (Winter)



Characterize Demand Response Program Options

Next, AEG identified and described the viable DR programs for inclusion in the analysis and developed assumptions for key program parameters, including per customer impacts, participation rates, program eligibility, and program costs. AEG considered the characteristics and applicability of a comprehensive list of options available that could be feasibly run in Avista's territory. Once a list of DR options was determined, AEG characterized each option.

Each selected option is described briefly below.

Program Descriptions

DLC Smart Thermostats – Heating

These programs use the two-way communicating ability of smart thermostats to cycle heating end uses on and off during events. The program targets Avista's Residential and Commercial customers with qualifying equipment in Washington, Idaho, and Oregon. This program is assumed to be a Bring Your Own Thermostat (BYOT) program; therefore, no equipment or installation costs were estimated and is only considered for the residential sector in the state of Washington for this study due to AMI constraints.

Third Party Contracts

Third Party Contracts are assumed to be available for large commercial and industrial customers and is considered for all three states in the Avista territory for this study. This program is based on a firm curtailment strategy targeting large process and heating loads. It is also assumed that participating customers will agree to reduce demand by a specific amount or curtail consumption to a predefined level at the time of an event. In return, they receive a fixed incentive payment in the form of capacity credits or reservation payments (typically expressed as $/therm-month or $/therm-year). Customers are paid to be on call even though actual load curtailments may not occur. The amount of the capacity payment typically varies with the load commitment level. In addition to the fixed capacity payment, participants typically receive a payment for gas reduction during events. Because it is a firm, contractual arrangement for a specific level of load reduction, enrolled loads represent a firm resource and can be counted toward installed capacity requirements. Penalties may be assessed for under-performance or non-performance. Events may be called on a day-of or day-ahead basis as conditions warrant.

This option is typically delivered by load aggregators and is most attractive for customers with high natural gas demand and flexibility in their operations. Industry experience indicates that aggregation of customers with smaller-sized loads is less attractive financially due to lower economies of scale. In addition, customers with 24x7 operations, continuous processes, or with obligations to continue providing service (such as schools and hospitals) are not often good candidates for this option.

Behavioral DR

Behavioral DR is structured like traditional demand response interventions, but it does not rely on enabling technologies, nor does it offer financial incentives to participants. Participants are notified of an event and simply asked to reduce their consumption during the event window. Generally, notification occurs the day prior to the event and are deployed utilizing a phone call, email, or text message. The next day, customers may receive post-event feedback that includes personalized results and encouragement. This program is assumed to be offered to residential customers only and is considered for all three states for this study.

Program Assumptions and Characteristics

The key parameters required to estimate the potential for a DR program are participation rate, per-participant load reduction, and eligibility or end use saturations. The development of these parameters is based on research findings and a review of available information on the topic, including national program survey databases, evaluation studies, program reports, and regulatory filings. AEG's assumptions of these parameters are described below.

Participation Rate Assumptions

Table 7-6 below shows the steady-state participation rate assumptions for each demand side management (DSM) option as well as the basis for the assumptions.

Table 7-6 DSM Steady-State Participation Rates (Percent of Eligible Customers)

DSM Option	Residential Service	Commercial Service	Industrial Service	Basis for Assumption
Behavioral	12%		-	PG&E rollout with six waves (2017) - 60% of Electric Behavioral Program Participation
DLC Smart Thermostats - BYOT	9%		-	NWPC Smart Thermostat cooling assumption - 60% of Electric Smart Thermostat Program Participation
Third Party Contracts	-	5%	13%	Industry Experience - 60% of Electric Third Party Contracts Program Participation. Commercial adjusted to reflect challenge of reducing heating loads

Load Reduction Assumptions

Table 7-7 presents the per participant load reductions for each DSM option and explains the basis for these assumptions.

Table 7-7 DSM Per Participant Impact Assumptions

DSM Option	Residential Service	Commercial Service	Industrial Service	Basis for Assumption
Behavioral	2%		-	PG&E Natural Gas Behavioral DR Pilot rollout with six waves
DLC Smart Thermostats - BYOT	0.8 Therms		-	Con Edison BYOT Smart Thermostat Pilot Program results – average savings per participant
Third Party Contracts	-	8%	8%	De-rated BYOT Residential impact for Third Party accounting for less discretionary load

Other Cross-cutting Assumptions

In addition to the above program-specific assumptions, there are three that affect all programs:

- **Discount rate.** A nominal discount rate of 6.51% was used to calculate the net present value of costs over the useful life of each DR program. All cost results are shown in nominal dollars.
- **Line losses.** Avista provided forecasted line loss factors averaging 5.6% which AEG used to convert estimated demand savings at the customer meter level to the generator level. Results in the next section are reported at the generator level.
- **Shifting and saving.** Each program varies in the way energy is shifted or saved throughout the day. For example, customers on the DLC Central AC program are likely to pre-cool their homes prior to the event and turn their AC units back on after the event (snapback effect). The results in this report only show the savings during the event window and not before and after the event.

DR Potential Results

This section presents analysis results for demand savings and levelized costs for all considered DR programs. As mentioned above, the integrated and stand-alone results are synonymous. Therefore, only one set of results are shown in this section assuming all programs can be run simultaneously.

Summary TOU Opt-in Scenario

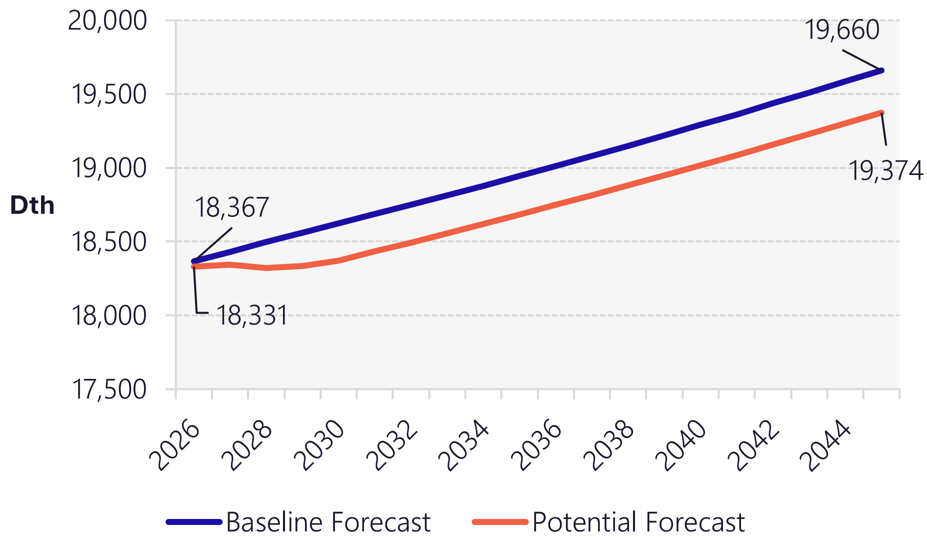
Table 7-8 and Figure 7-3 show the total winter demand savings for selected years. These savings represent integrated savings from all available DR options in Avista's Washington, Idaho, and Oregon service territories.

- The total potential savings are expected to increase from 36 Dth in 2026 to 287 Dth by 2045. The percentage of system peak increases from 0.2% in 2026 to 1.5% by 2045.

Table 7-8 Summary of Integrated Potential (Dtherms @ Generator)

	2026	2027	2028	2035	2045
Baseline Forecast	18,367	18,428	18,500	18,946	19,660
Achievable Potential	36	86	179	262	287
Achievable Potential (% of baseline)	0.2%	0.5%	1.0%	1.4%	1.5%
Potential Forecast	18,331	18,342	18,321	18,684	19,374

Figure 7-3 Summary of Integrated Potential (Dtherms @ Generator)



Results

Key findings include:

- The largest potential option is DLC Smart Thermostats - BYOT, contributing 236 dtherms by 2045.
- Behavioral and Third Party Contracts program options offer a potential reduction in peak natural gas demand of 30 and 21 dtherms, respectively by 2045.

Potential by DSM Option

Figure 7-4 and Table 7-9 show the total winter demand savings from individual DR options for selected years. These savings represent integrated savings from all available DR options in Avista's Washington, Idaho, and Oregon service territories. Currently Washington is the only state in the Avista territory with AMI for natural gas customers. Due to the increased effectiveness of a Smart Thermostat program with use of AMI, the DLC Smart Thermostats – BYOT Program is only considered for the state of Washington. Even so, the DLC Smart Thermostats – BYOT Program is projected to save the most of all programs at 236 dtherms by 2045 while the Behavioral DR and Third Party Contracts Programs are projected to reduce peak demand by 30 and 21 dtherms by 2045, respectively.

Figure 7-4 Summary of Potential by Option – (Dtherms @ Generator)

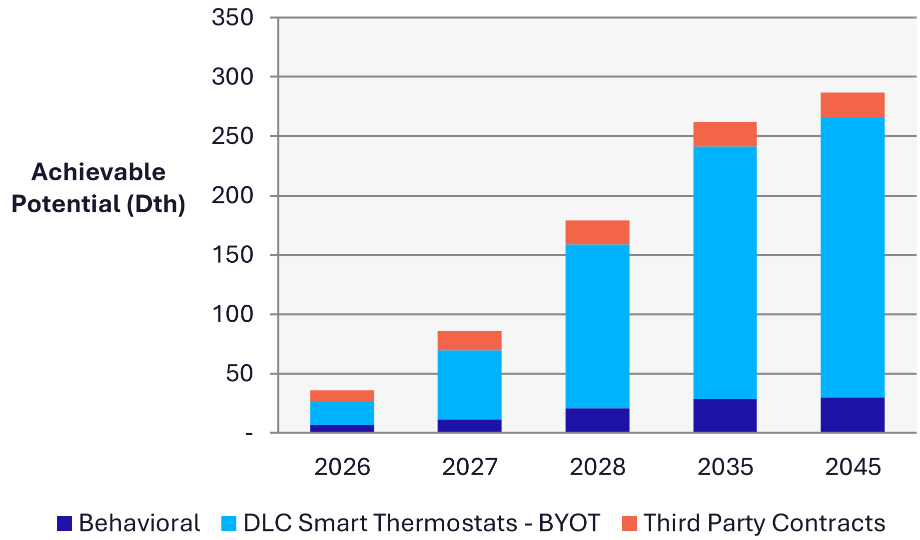


Table 7-9 Summary of Potential by Option – (Dtherms @ Generator)

Summer Potential	2026	2027	2028	2035	2045
Baseline Forecast	**18,367**	**18,428**	**18,500**	**18,946**	**19,660**
Achievable Potential	**36**	**86**	**179**	**262**	**287**
Achievable Potential (%)	**0.2%**	**0.5%**	**1.0%**	**1.4%**	**1.5%**
Behavioral	7	11	21	28	30
DLC Smart Thermostats - BYOT	19	59	138	213	236
Third Party Contracts	10	16	20	20	21

Potential by Sector

Table 7-10, Table 7-11, and Table 7-12 show the total winter demand savings by class for Washington, Idaho, and Oregon respectively. Washington is projected to save 128 dtherms (1.4% of winter system peak demand) by 2045, Idaho is projected to save 94 dtherms (1.5% of winter system peak demand) by 2045, and Oregon is projected to save 64 dtherms (1.5% of winter system peak demand) by 2045.

The residential sector contributes 87% of the total load across all three states while commercial and industrial contribute 15% and 7% respectively. This is due primarily to the low number of industrial natural gas customers in Avista's territory.

Table 7-10 Potential by Sector – Dtherms @Generator, Washington

	2026	2027	2028	2035	2045
Baseline Forecast	**9,217**	**9,207**	**9,193**	**9,094**	**8,956**
Achievable Potential (Dth)	**22**	**49**	**93**	**125**	**128**
Residential	16.4	40	82	115	118
Commercial	4.9	8	10	10	10
Industrial	0.3	1	1	1	1

Table 7-11 Potential by Sector – Dtherms @Generator, Idaho

	2026	2027	2028	2035	2045
Baseline Forecast	**5,060**	**5,115**	**5,185**	**5,611**	**6,288**
Achievable Potential (Dth)	**8**	**21**	**50**	**80**	**94**
Residential	5.5	17	44	74	88
Commercial	2.4	4	5	5	5
Industrial	0.3	1	1	1	1

Table 7-12 Potential by Sector – Dtherms @Generator, Oregon

	2026	2027	2028	2035	2045
Baseline Forecast	**4,090**	**4,107**	**4,121**	**4,240**	**4,416**
Achievable Potential (Dth)	**6**	**16**	**37**	**57**	**64**
Residential	4.1	12	32	53	60
Commercial	2.0	3	4	4	4
Industrial	0.0	0	0	0	0

Figure 7-5 Potential by Sector –Dtherms @Generator, Washington

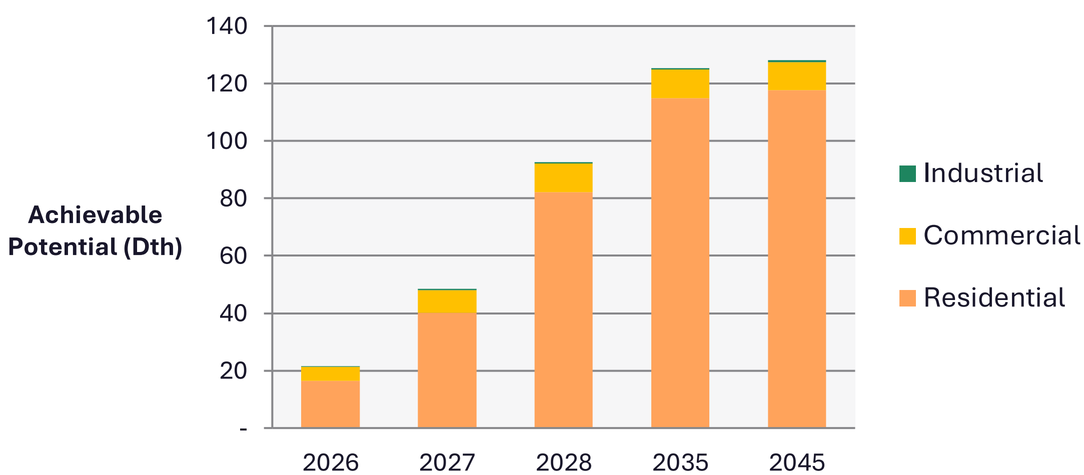


Figure 7-6 Potential by Sector –Dtherms @Generator, Idaho

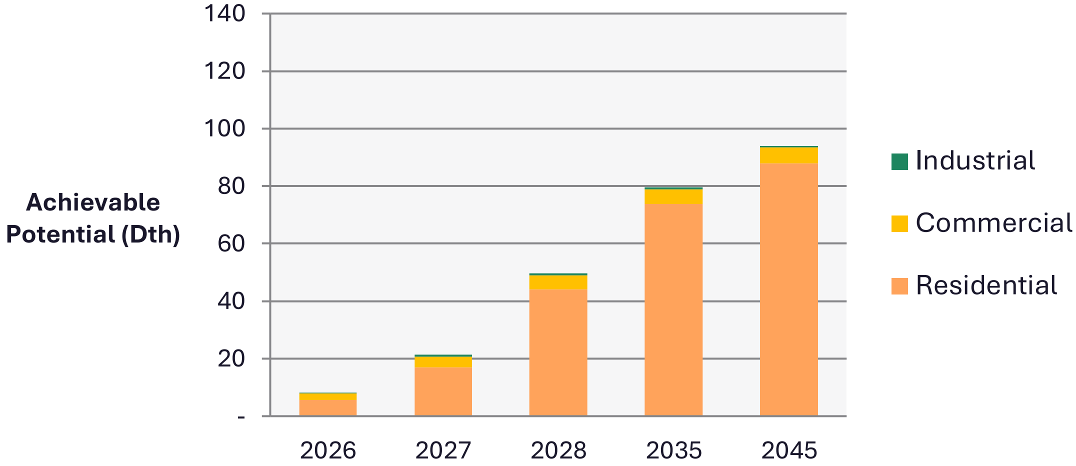
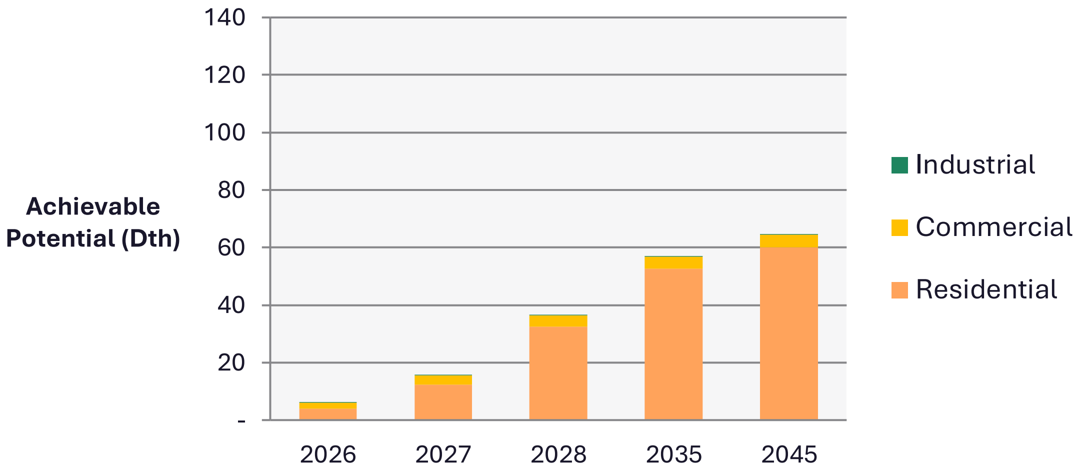


Figure 7-7 Potential by Sector –Dtherms @Generator, Oregon



- Levelized Costs

Table 7-13 presents the levelized costs per dekatherm of equivalent generation capacity over 2026-2035 for Washington, Idaho, and Oregon. The ten-year NPV dekatherm potential by program is shown for reference in the first column.

Key findings include:

- The Third Party Contracts Program is expected to be the cheapest program to run per dekatherm savings at approximately $4,429/dekatherm-year. Capacity-based and energy-based payments to the third-party constitutes the major cost component for this option as well as the cost to the vendor for program operation.
- The Behavioral Program has the highest levelized cost among all the DR program over ten years at $13,790/dekatherm-year system-wide. The main contributors to the high cost compared to low savings are O&M and administrative costs.

Table 7-13 Levelized Program Costs and Potential

Program	NPV Dth Potential	Levelized Costs ($/Dth)
Behavioral	169.67	$13,789.84
DLC Smart Thermostats - BYOT	579.18	$7,821.25
Third Party Contracts	141.71	$4,429.17

A | Oregon Low-Income Conservation Potential

Background

To support initiatives to serve low-income customers and reduce energy burden in its Oregon natural gas service territory, Avista Corporation (Avista) engaged Applied Energy Group (AEG) to assess the energy efficiency potential for Oregon low-income households. This analysis leverages the natural gas conservation potential assessment (CPA) AEG was already performing for Avista's Washington and Idaho service territories, incorporating Oregon-specific data to ensure results are directly applicable to Avista's Oregon low-income customers.

This memo presents a high-level summary of potential results, followed by an overview of AEG's methodology, identification of key data sources, customer segmentation analysis, and more detailed potential results.

Results Summary

A summary of the energy efficiency potential for Oregon low-income customers is presented in **Error! Reference source not found.**. As shown, achievable and cost-effective energy efficiency potential represents approximately 6% of baseline sales by 2045.

AEG notes the following considerations in reviewing these results:

- The study relied on the best available data from Avista and secondary sources. Sources did not include on-site assessments of low-income customer equipment efficiency or practices. Therefore, current conditions and remaining opportunities were estimated using information about typical characteristics by market segment.
- Achievable economic potential was estimated from the Total Resource Cost (TRC) perspective, consistent with standard cost-effectiveness practices for energy efficiency in Oregon.
- Energy efficiency programs serving low-income customers are often not required to be cost-effective. Achievable technical potential provides an estimate of what could be possible if cost-effectiveness is not considered.

Table A - 1 Summary of Energy Efficiency Potential

Scenario	2026	2027	2030	2035	2045
Baseline Forecast (dtherms)	901,274	904,673	896,310	879,805	856,427
Cumulative Savings (dtherms)					
Achievable Economic TRC Potential	2,068	4,856	14,095	39,976	51,164
Achievable Technical	9,275	20,777	63,138	155,234	189,919
Technical Potential	13,847	29,842	78,653	186,112	221,549
Energy Savings (% of Baseline)					
Achievable Economic TRC Potential	0.2%	0.5%	1.6%	4.5%	6.0%
Achievable Technical	1.0%	2.3%	7.0%	17.6%	22.2%
Technical Potential	1.5%	3.3%	8.8%	21.2%	25.9%

Methodology

AEG used a bottom-up approach to perform the potential analysis, following the steps listed:

1. Perform a customer segmentation analysis to estimate the number of Avista Oregon residential customers in each housing type and considered low-income, and the energy consumption of each segment.
2. Perform a market characterization to describe sector-level natural gas use for residential low-income customers for the base year, 2021. The characterization included extensive use of Avista data and other secondary data sources from Northwest Energy Efficiency Alliance (NEEA) and the Energy Information Administration (EIA).
3. Develop a residential baseline projection of energy consumption by segment, end use, and technology for 2026 through 2045.
4. Define and characterize energy efficiency measures to be applied to all segments and end uses.
5. Estimate technical, achievable technical, and achievable economic energy efficiency potential at the measure level for 2026 through 2045.

Key Data Sources

AEG used Avista's 2024 Washington and Idaho CPA as the foundation for this assessment. Key updates from the Washington CPA assumptions to reflect the Oregon market and potential included:

- Input and market characterization data were specific to Avista's Oregon low-income customers. The CPA model generally formed the basis for measure cost assumptions and savings estimates.
- With the CPA measure list as the starting point, AEG worked with Avista to identify measures in active programs serving low-income customers, avoiding measures that are inappropriate for these segments due to costs or other concerns.
- The model reflects baseline conditions in alignment with Oregon's state building codes.

Where data gaps existed in Avista's data, AEG relied on national and regional data sources for assumptions in the potential model. **Error! Reference source not found.** summarizes key data sources used and how they informed the study.

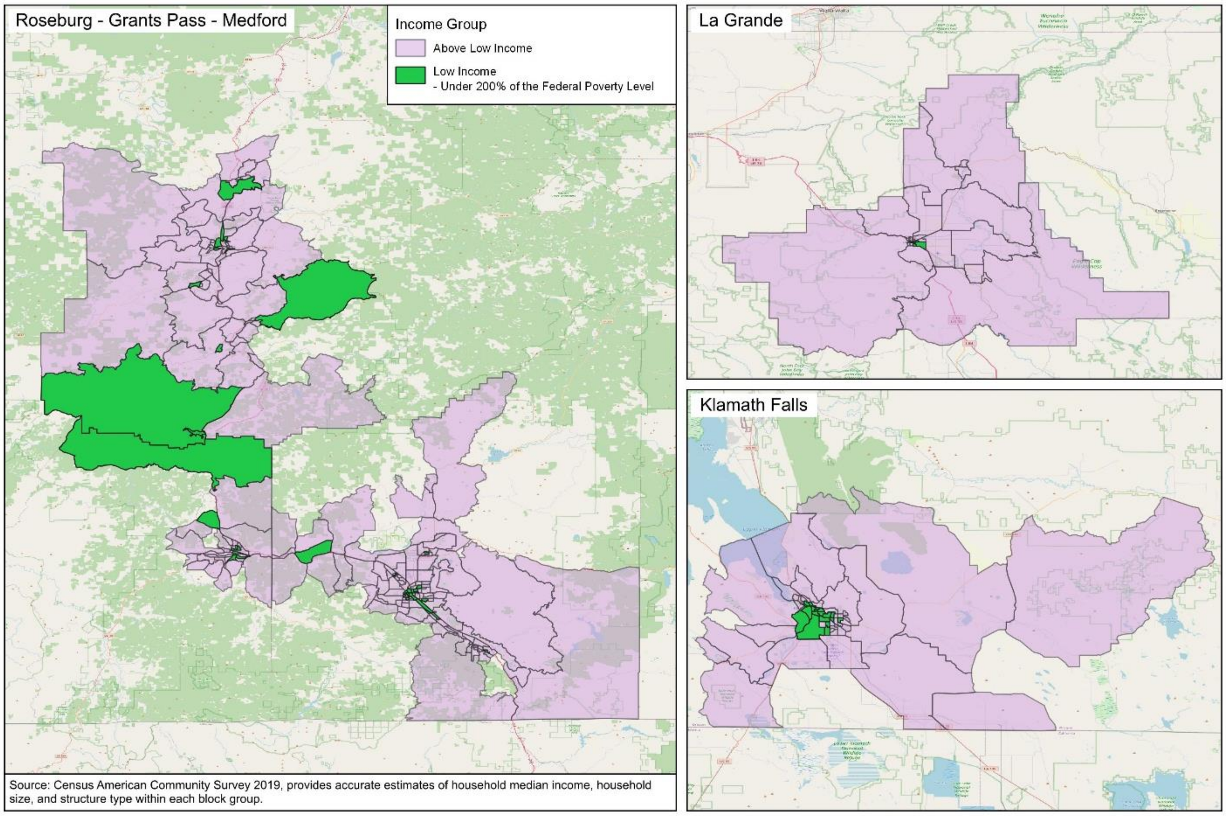
Table A - 2 Key Data Source Summary

Data Source	Used For:
Avista Data	Development of customer counts and energy use for each segment type, comparison baseline forecast, customer counts forecast, presence of equipment, end use load distribution, economics inputs, scenario development
US Census American Community Survey (ACS)	Household characteristics in block groups
Northwest Power and Conservation Council's 2021 Power Plan	Technical achievable ramp rate library and study methodology
NEEA's Residential Building Stock Assessment II (RBSA), Single-Family Homes Report 2016-2017	Benchmark equipment saturations, normalized end use and equipment intensity (therms per household)
US Energy Information Administration (EIA) 2015 Residential Energy Consumption Survey (RECS)	Estimated equipment use per unit, end use distribution of natural gas use by segment type, benchmarking equipment presence (saturation)
EIA's 2020 Annual Energy Outlook	Reference baseline purchase assumptions, equipment lifetimes and costs

Customer Segmentation Analysis

To estimate the number of Avista customers in Oregon to include in the low-income assessment, AEG mapped address data back to corresponding geographic "block groups" in the ACS census data. Each block groups was then processed to analyze average household size and income, producing a distribution of households into income buckets for places where Avista customers reside. The low-income threshold corresponds with 200% of the Federal Poverty Level. The maps in **Error! Reference source not found.** shows the distribution of different income groups through Avista's Oregon service territory.

Figure A - 1 Income Group Map



Once the percentage of customers in each housing type and income group was known, AEG used RBSA data to investigate differences in energy consumption for each grouping, enabling a comparison of natural gas usage per household across categories. Combining the geographic/demographic analysis with RBSA data on usage differences by income level, AEG was able to produce an expanded residential profile with data-driven variation by income group. **Error! Reference source not found.** shows the customer energy consumption by income level in the base year, 2021. While AEG fully characterized the residential customer populations, only low-income customers are included in the potential analysis.

Table A - 3 Customer Counts and Energy Consumption by Dwelling Type and Income Level, 2021

Segment	Households	Natural Gas Consumption (Dth)	Intensity (Dth/household)
Single Family - Regular Income	58,913	3,770,739	64,006
Single Family - Low Income	12,289	662,559	53,917
Multi-Family - Regular Income	7,707	183,230	23,774
Multi-Family - Low Income	4,428	88,679	20,026
Mobile Home - Regular Income	7,066	253,416	35,864
Mobile Home - Low Income	2,197	113,191	51,514
Total	**92,600**	**5,071,813**	**54,771**

Potential Results

Error! Reference source not found. presents the annual potential savings relative to the baseline projection. Based on the ramp rates used, a majority of the identified potential is assumed to be acquired over 10 years.

Table A - 2 Cumulative Energy Efficiency Potential as % of Baseline Projection

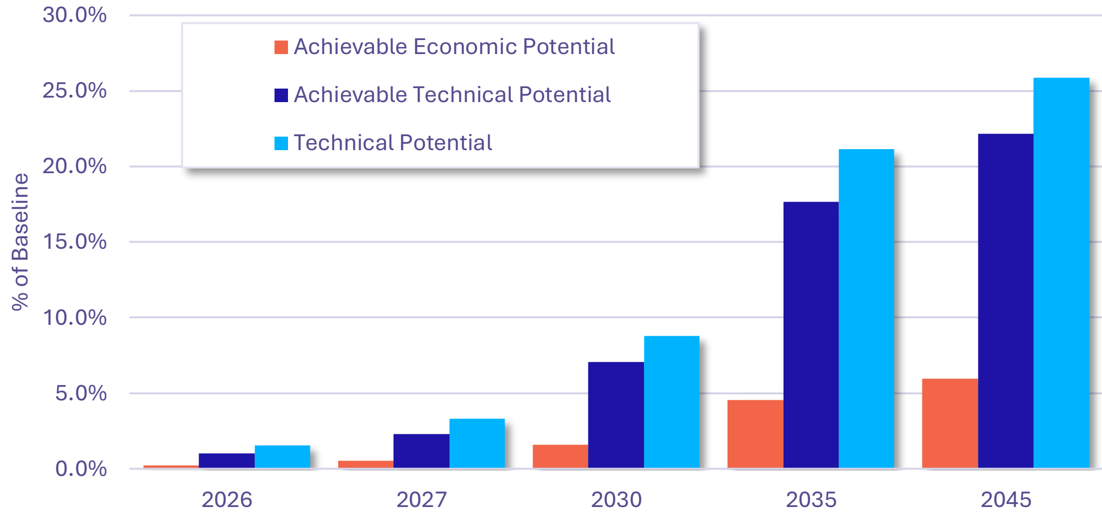
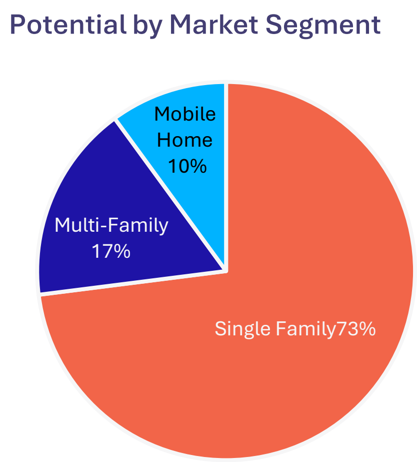


Figure A-3 Achievable Economic Potential, 2045



presents the percentage of achievable economic potential in 2045 by market segment and end use. Single family dwellings account for 73% of low-income achievable economic potential. Space heating accounts for 76% of low-income achievable economic potential.

Figure A-3 Achievable Economic Potential, 2045

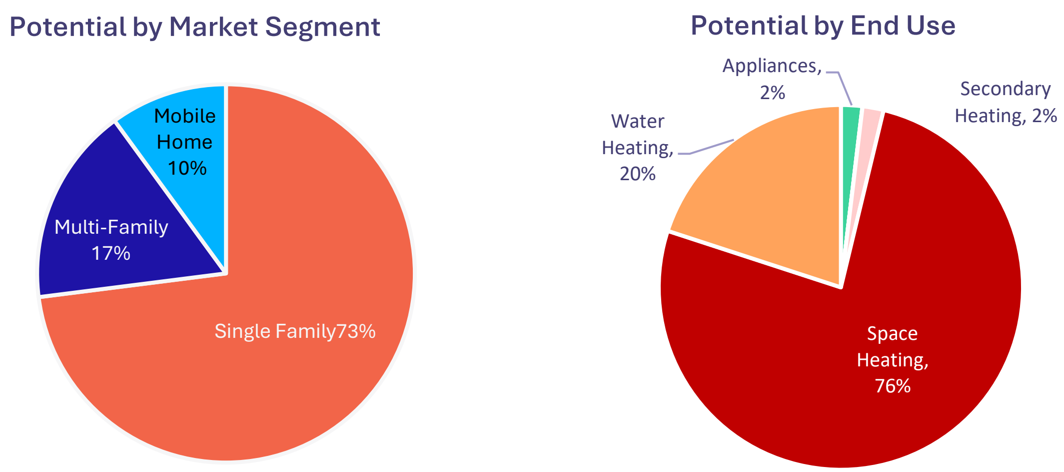
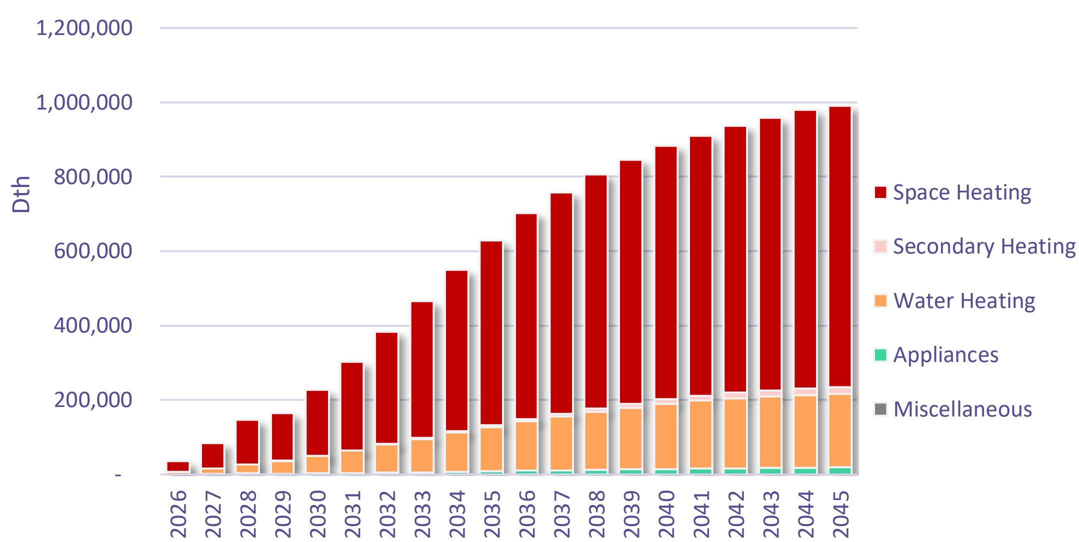


Figure A- presents a forecast of cumulative achievable economic potential by end use. Space heating accounts for the majority of potential but declines slightly in the mid-2020s due to a future furnace standard.

Figure A-4 Cumulative TRC Achievable Economic Potential by End Use



Error! Reference source not found. identifies the top measures by cumulative 2026 and 2036 achievable economic potential. Furnaces, insulation, and clothes washers are the top measures.

Table A - 4 Top Measures in 2026 and 2036, Achievable Economic Potential

Rank	Measure/Technology	2026 Cumulative Dth	% of Total	2036 Cumulative Dth	% of Total
1	Furnace	12,297	35.1%	152,477	21.7%
2	Insulation - Ceiling Installation	8,932	25.5%	167,787	23.9%
3	Clothes Washer - CEE Tier 2	4,993	14.2%	40,570	5.8%
4	Building Shell - Air Sealing (Infiltration Control)	1,517	4.3%	32,651	4.7%
5	Insulation - Ceiling Upgrade	1,143	3.3%	21,155	3.0%
6	Water Heater - Faucet Aerators	716	2.0%	14,393	2.1%
7	Insulation - Ducting	683	1.9%	12,115	1.7%
8	Water Heater - Low-Flow Showerheads	670	1.9%	13,209	1.9%
9	Stove/Oven	543	1.5%	8,638	1.2%
10	Ducting - Repair and Sealing - Aerosol	466	1.3%	49,907	7.1%
11	Home Energy Management System (HEMS)	410	1.2%	43,745	6.2%
12	Insulation - Wall Cavity Installation	375	1.1%	6,404	0.9%
13	Water Heater (<= 55 Gal)	368	1.0%	24,632	3.5%
14	Insulation - Wall Cavity Upgrade	365	1.0%	7,027	1.0%
15	Insulation - Wall Sheathing	307	0.9%	5,399	0.8%
	Subtotal	**33,785**	**96%**	**600,110**	**86%**
	Total Savings in Year	**35,058**	**100.0%**	**701,329**	**100.0%**

B | Natural Gas Transportation Customer Conservation Potential

Background

Avista Corporation (Avista) engaged Applied Energy Group (AEG) to assess the conservation potential at Washington and Oregon natural gas transportation customer[3] facilities to inform the extent to which energy efficiency savings at these facilities could help Avista comply with new regulations. In Washington and Oregon, Avista's transportation customers are currently exempt from funding energy efficiency programs and thus are not eligible to participate in natural gas energy efficiency programs administered by Avista and the Energy Trust of Oregon in Washington and Oregon, respectively.

In Washington, the Washington Utilities and Transportation Commission continues to consider whether pursuing all cost-effective conservation, as required by Initiative 937, requires utilities to fund energy efficiency programs for natural gas transportation customers. In Oregon, Executive Order 20-04, passed in March 2020, limits statewide greenhouse gas emissions from large stationary sources, transportation fuel, and other liquid and gaseous fuels by new goals established by the Oregon Department of Environmental Quality (DEQ). The Climate Protection Program (CPP) formalizes emission reduction requirements for Oregon's natural gas utilities, including the responsibility for on-site emissions of natural gas transportation customers.

The remainder of this memo presents high-level study results, followed by an overview of AEG's methodology, identification of key data sources, potential results, and considerations and recommendations as Avista considers new program options to reach these customers.

Results Summary

Error! Reference source not found. and **Error! Reference source not found.** summarize the energy efficiency potential at transportation customer sites in Washington and Oregon, respectively. AEG notes the following considerations in reviewing these results:

- The potential represents expected levels of savings using average assumptions across customers and equipment. However, a small number of customers represent a majority of transportation customer consumption (the top 21% of the largest Washington transportation customers make up roughly 76% of Avista Washington transportation load). Therefore, actual energy efficiency impacts may vary widely depending on whether these large customers choose to participate in potential programs and customer-specific characteristics. As such, these results should be viewed as planning assumptions that are likely to differ in practice.
- The study relied on the best available data from Avista and secondary sources, which did not include on-site assessments of transportation customer equipment efficiency or practices. Therefore, current conditions and remaining opportunities were estimated using information about typical characteristics by market segment (i.e., business or industry type).

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[3] Transportation customers are non-residential natural gas consumers, typically large industrial users, who purchase natural gas from an alternate supplier but use Avista's distribution system to deliver the fuel to their sites.

- Achievable economic potential was estimated from the Total Resource Cost (TRC) perspective, consistent with standard cost-effectiveness practices for energy efficiency in Washington and Oregon.

Table B- 1 Summary Potential Results – Reference Case, Washington

	2026	2027	2030	2035	2045
Baseline Projection (dtherms)	3,178,623	3,163,094	3,117,080	3,062,121	2,992,666
Cumulative Savings (dtherms)					
Achievable Economic Potential	20,752	42,028	110,865	229,109	349,006
Achievable Technical Potential	34,221	66,368	161,137	315,616	462,712
Technical Potential	47,376	91,576	218,534	412,652	585,248
Cumulative Savings (% of Baseline)					
Achievable Economic Potential	0.7%	1.3%	3.6%	7.5%	11.7%
Achievable Technical Potential	1.1%	2.1%	5.2%	10.3%	15.5%
Technical Potential	1.5%	2.9%	7.0%	13.5%	19.6%

Table B- 2 Summary Potential Results – Reference Case, Oregon

	2026	2027	2030	2035	2045
Baseline Projection (dtherms)	2,613,245	2,608,079	2,592,387	2,572,641	2,545,358
Cumulative Savings (dtherms)					
Achievable Economic Potential	12,657	25,566	68,517	151,714	251,405
Achievable Technical Potential	16,434	32,521	83,285	176,741	284,374
Technical Potential	22,040	43,467	109,505	225,146	353,597
Cumulative Savings (% of Baseline)					
Achievable Economic Potential	0.5%	1.0%	2.6%	5.9%	9.9%
Achievable Technical Potential	0.6%	1.2%	3.2%	6.9%	11.2%
Technical Potential	0.8%	1.7%	4.2%	8.8%	13.9%

Methodology

AEG used a bottom-up approach to perform the potential analysis, following the steps listed:

1. Perform a customer segmentation analysis to estimate the number of Avista Washington and Oregon transportation customers in each market segment and the energy consumption of each segment.
2. Perform a market characterization to describe sector-level natural gas use for transportation customers for the base year, 2021. The characterization included extensive use of Avista data and other secondary data sources from the US Energy Information Administration (EIA).
3. Develop a baseline projection of energy consumption by segment, end use, and technology for 2026 through 2045.
4. Define and characterize energy efficiency measures to be applied to all segments and end uses.
5. Estimate technical, achievable technical, and achievable economic potential for 2026 through 2045.

Key Data Sources

AEG used Avista's 2024 Washington Natural Gas Conservation Potential Assessment (CPA) as the foundation for this assessment. The Washington CPA assessed natural gas energy efficiency potential for Avista's residential, commercial, and industrial sales customers, but excluded transportation customers. Key updates AEG made to Washington CPA assumptions to reflect Washington and Oregon transportation customers, loads, and potential included:

- Input and market characterization data for this analysis were specific to Avista's Washington and Oregon transportation customers, including baseline sales, forecasts, and industry designations. The Washington CPA generally formed the basis for the measure cost assumptions and savings percentage estimates.
- AEG benchmarked the distribution of end use loads with data from the EIA's Commercial Building and Manufacturing Energy Consumption Surveys and discussed notable differences with Avista to ensure that they accurately reflected known aspects of those customers. For example, if a particular manufacturing sector showed a greater proportion of space heating load than expected compared to MECS data, Avista could confirm that their Oregon transportation customers was dominated by a facility with significant conditioned space and whose product line did not require as much natural gas use.
- The assessment leveraged the Washington CPA measure list.

Where data gaps existed in Avista data, AEG relied on national and regional data sources for assumptions in the potential model. **Error! Reference source not found.** summarizes key data sources used for the analysis and how each informed the study.

Table B- 3 Key Data Source Summary

Data Source	Used for
Avista Utility Data	Load segmentation by industry/building type, presence of equipment, end use load distribution, comparison baseline forecast, economics inputs, scenario development
Northwest Power and Conservation Council's 2021 Power Plan	Technical Achievable ramp rate library and study methodology
NEEA's 2019 and 2014 Commercial Building Stock Assessment (CBSA)	Benchmark equipment saturations, normalized end use and equipment intensity (therms per sq.ft)
EIA 2018 Manufacturing Energy Consumption Survey (MECS) and 2018 Commercial Building Energy Consumption Survey (CBECS)	Estimated equipment use per unit, end use distribution of natural gas use by business/industry type, benchmarking equipment presence (saturation)
EIA's 2023 Annual Energy Outlook	Reference baseline purchase assumptions, equipment lifetimes and costs

Potential Results

AEG developed achievable economic potential based on assumptions regarding the rate at which potential could be acquired. The achievable economic potential started with standard ramp rate assumptions from the Northwest Power and Conservation Council's (Council's) 2021 Power Plan, mapped to natural gas measures.[4]

[4] The Council's 2021 Power Plan only covers electric measures. To adapt these ramp rates for this natural gas assessment, AEG mapped gas measures to the same or similar electric measure, consistent with the methodology from the Washington Natural Gas CPA.

Error! Reference source not found. presents the annual potential savings relative to the baseline projection. Based on the ramp rates used, a majority of the identified potential is assumed to be acquired over the first 10 years of the study period.

Figure B - 1 Reference Case Cumulative Potential, Washington

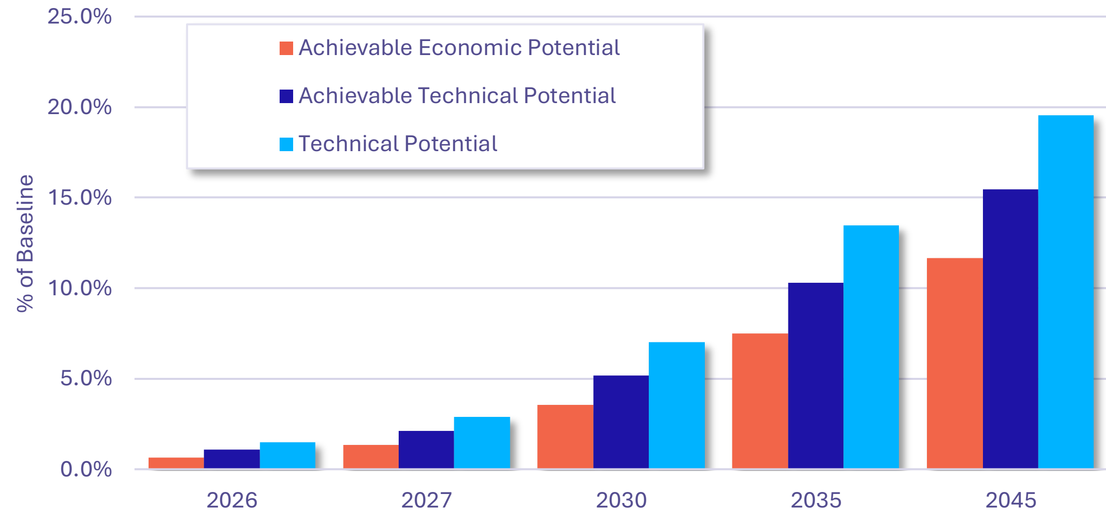
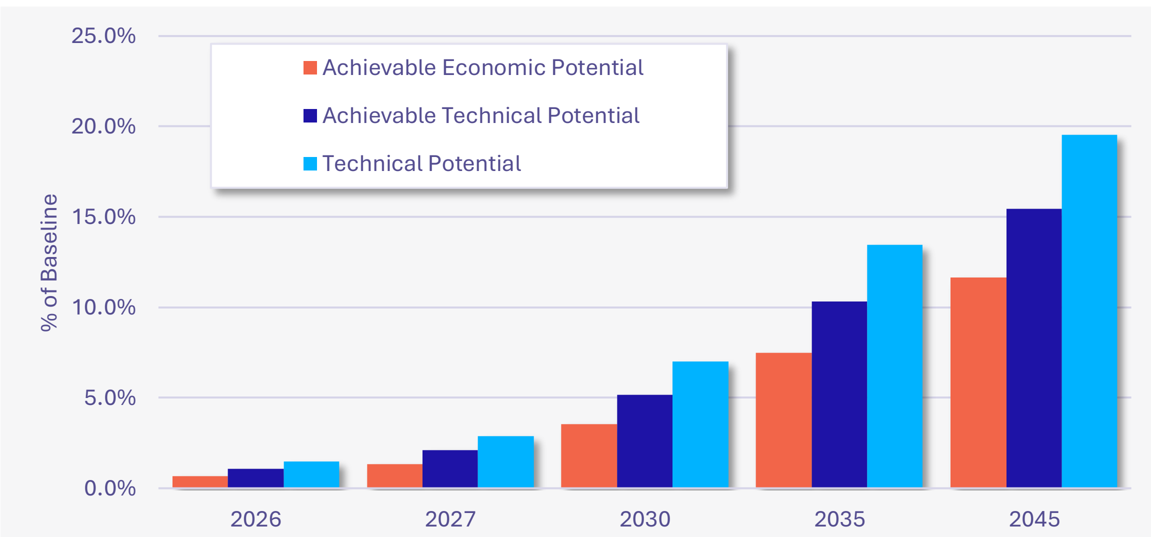
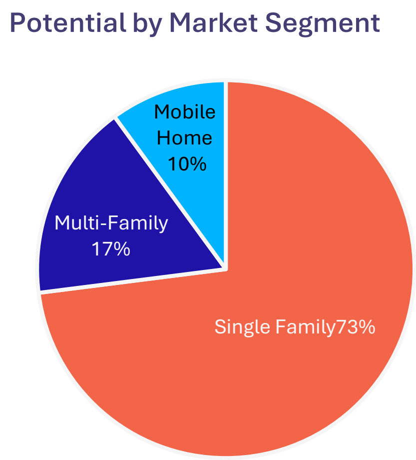


Figure B - 2 Reference Case Cumulative Potential, Oregon



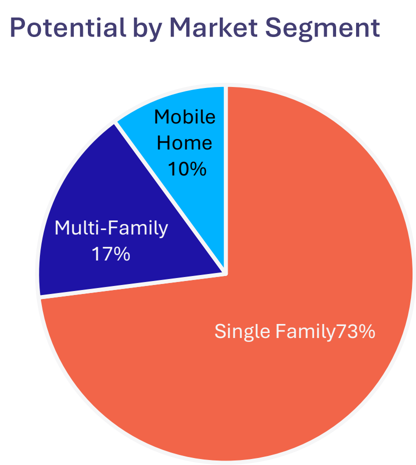
Commercial Potential Results

Figure A-3 Achievable Economic Potential, 2045



presents the percentage of achievable economic potential in 2045 by market segment and end use. Single family dwellings account for 73% of low-income achievable economic potential. Space heating accounts for 76% of low-income achievable economic potential.

Figure A-3 Achievable Economic Potential, 2045



and **Error! Reference source not found.** present the percentage of achievable economic potential 2045 by market segment and end use, respectively. The majority of Avista's commercial transportation customers are Health (71% in Oregon) and College (69% in Washington). Space heating accounts for the largest share of end use potential in both states, representing 51% and 70% of cumulative commercial achievable economic potential in Oregon and Washington, respectively.

Figure B-3 Commercial Achievable Economic Potential by Market Segment, 2045

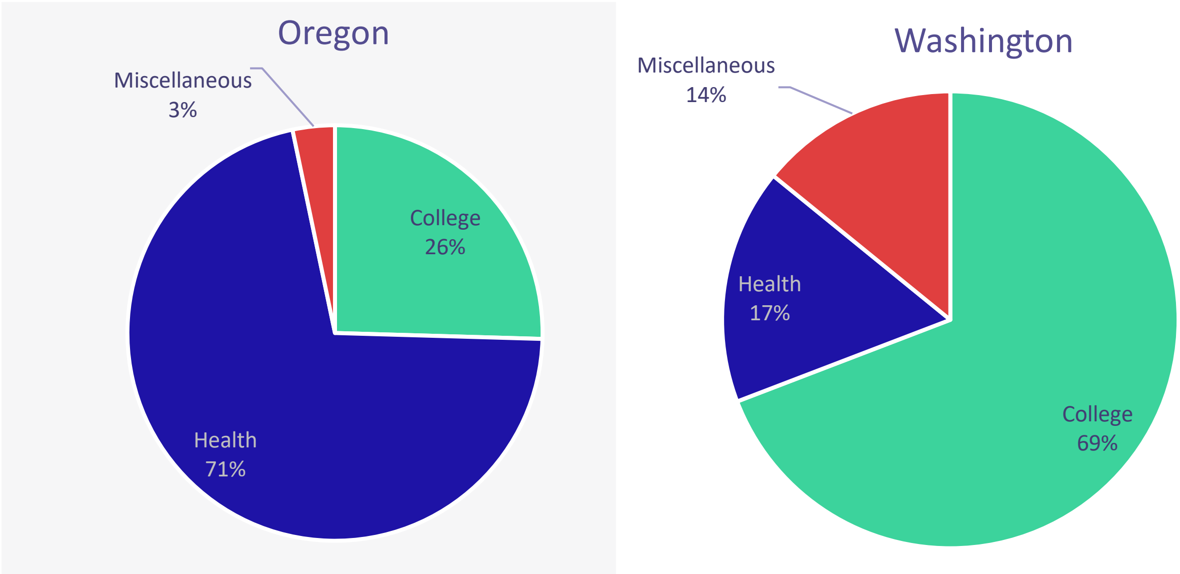
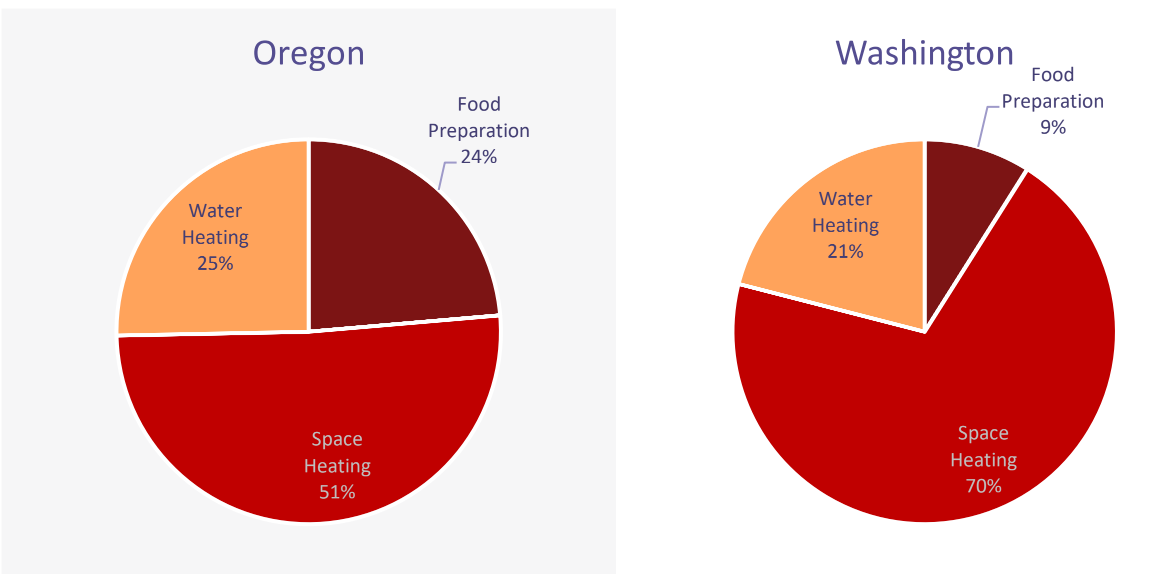


Figure B-4 Commercial Achievable Economic Potential by End Use, 2045



Cumulative commercial achievable economic potential is provided in Figure A- presents a forecast of cumulative achievable economic potential by end use. Space heating accounts for the majority of potential but declines slightly in the mid-2020s due to a future furnace standard.
Figure A- for Oregon and Figure B- for Washington.

Figure B-5 Cumulative Achievable Economic Commercial Potential by End Use, Oregon

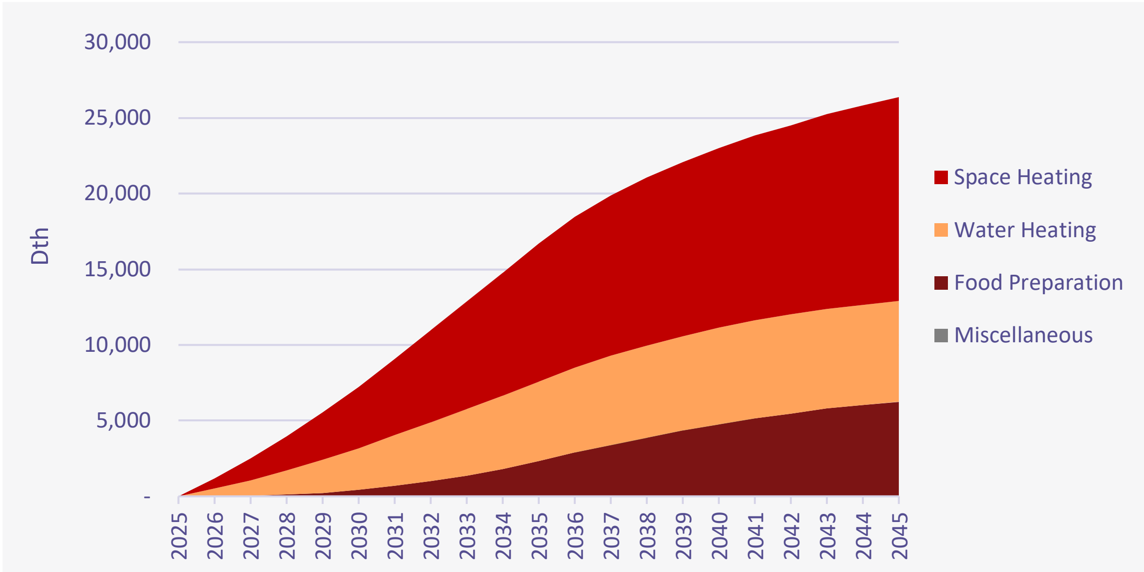
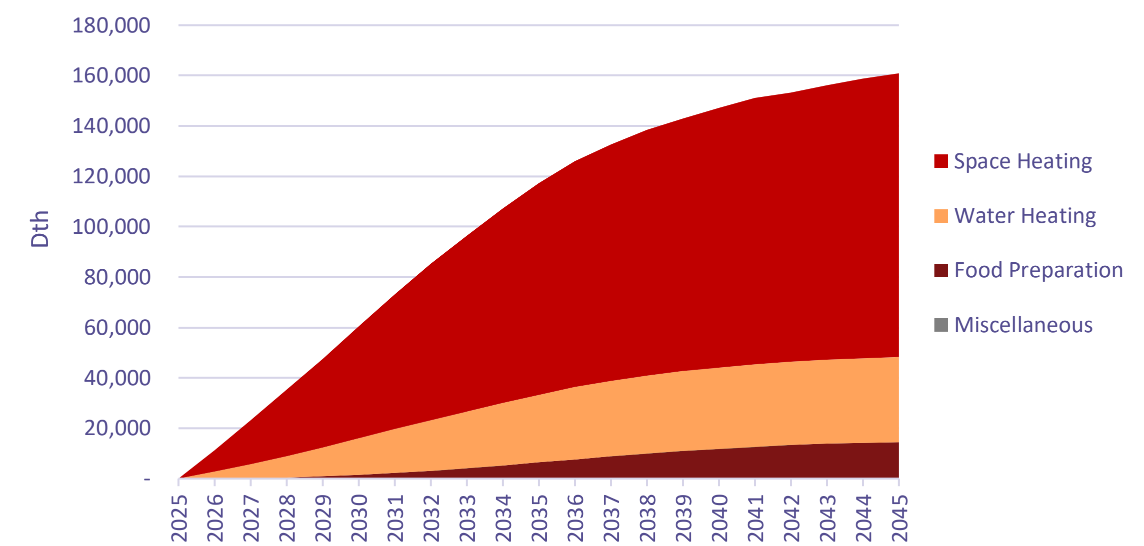


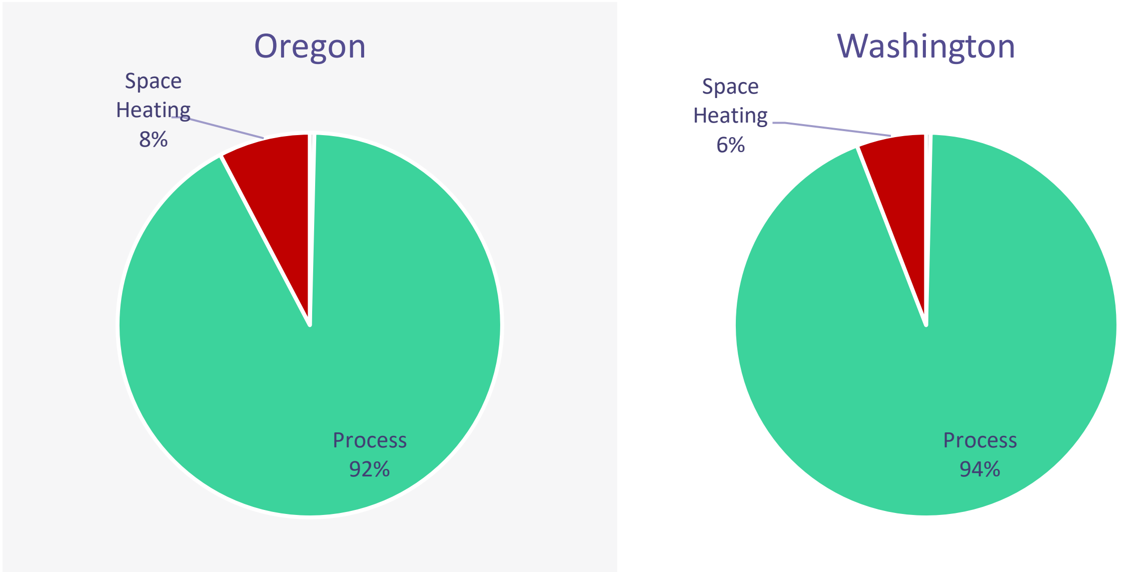
Figure B-6 Cumulative Achievable Economic Commercial Potential by End Use, Washington



Industrial Potential Results

Figure B- presents the cumulative industrial potential in 2045 by end use. Industrial process end use accounts for 94% of Oregon's identified industrial achievable economic potential process and 92% of Washington's identified industrial achievable economic potential.

Figure B-7 Industrial Achievable Economic Potential by End Use, 2045



Cumulative industrial achievable economic potential is provided in Figure B- for Oregon and Figure B- for Washington.

Figure B-8 Cumulative Achievable Economic Industrial Potential by End Use, Oregon

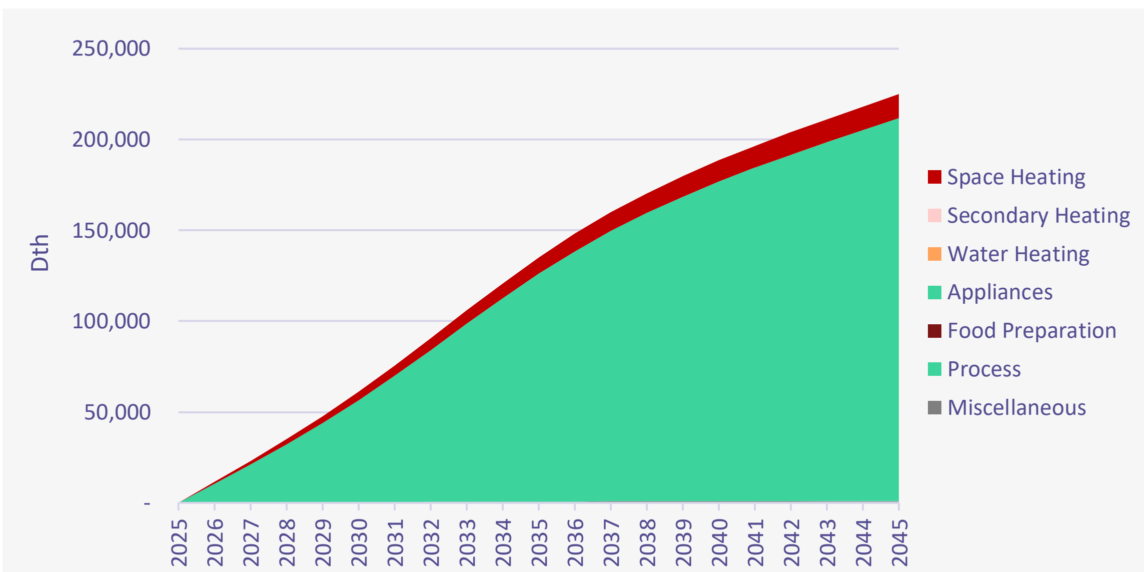
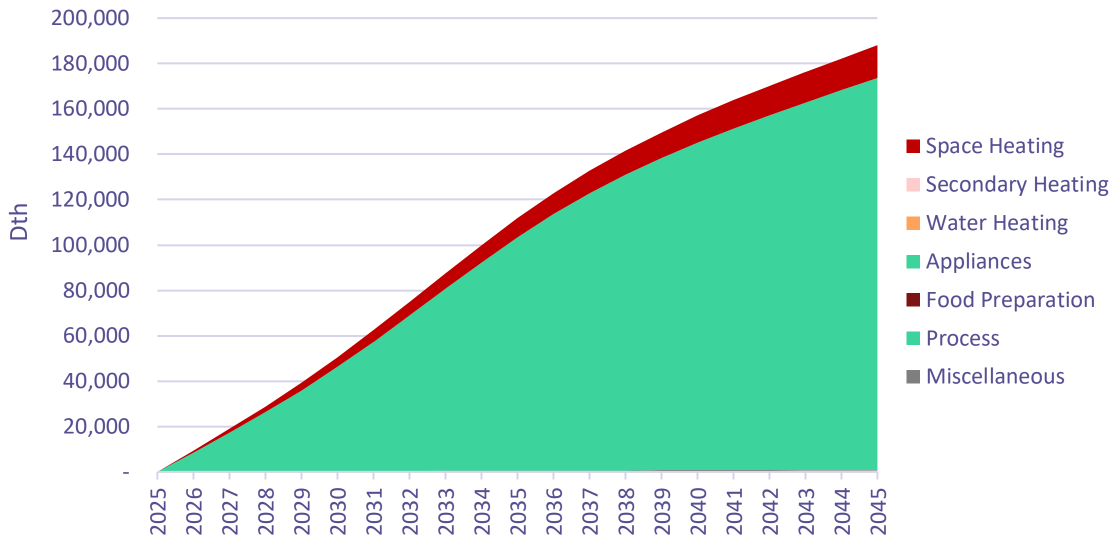


Figure B-9 Cumulative Achievable Economic Industrial Potential by End Use, Washington



Considerations and Recommendations

This assessment was a first step in identifying and realizing natural gas energy efficiency (and associated greenhouse gas emissions reductions) within Avista's transportation customer base. While program design is outside the scope of this assessment, AEG notes the following items for Avista as it determines the best way to achieve these savings:

- Many of the inputs into the analysis are averages across market segments based on the best available data sources and may not reflect the available potential at any individual site. **To address this, AEG recommends that Avista consider sponsoring audits of specific transportation customer sites to better understand current equipment and practices to refine estimates of available potential for these customers.**
- Because a small number of customers account for a large amount of transportation customer consumption, whether these customers choose to participate in future programs will significantly affect the amount of savings that Avista is able to achieve. This uncertainty could increase or decrease acquisition levels relative to the potential identified in this assessment. **As Avista considers new program designs for transportation customers, AEG recommends targeted outreach to the largest customers to understand their likelihood of participating in future programs, including to what extent and on what timeline.**

C | MARKET PROFILES

This appendix presents the market profiles for each sector and segment for Washington and Idaho, in the embedded spreadsheet.

Avista 2024 - Natural Gas Market Profiles.xl

D | MARKET ADOPTION (RAMP) Rates

This appendix presents the Power Council's 2021 Power Plan ramp rates we applied to technical potential to estimate Technical Achievable Potential.

Table B - 1 Measure Ramp Rates Used in CPA

Ramp Rate	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
LO12Med	11%	22%	33%	44%	55%	65%	72%	79%	84%	88%	91%	94%	96%	97%	99%	100%	100%	100%	100%	100%
LO5Med	4%	10%	16%	24%	32%	42%	53%	64%	75%	84%	91%	96%	99%	100%	100%	100%	100%	100%	100%	100%
LO1Slow	1%	1%	2%	3%	5%	9%	13%	19%	26%	34%	43%	53%	63%	72%	81%	87%	92%	96%	98%	100%
LO50Fast	45%	66%	80%	89%	95%	98%	99%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
LO20Fast	22%	38%	48%	57%	64%	70%	76%	80%	84%	88%	90%	92%	94%	95%	96%	97%	98%	98%	99%	100%
LOEven20	5%	10%	15%	20%	25%	30%	35%	40%	45%	50%	55%	60%	65%	70%	75%	80%	85%	90%	95%	100%
LO3Slow	1%	1%	3%	6%	11%	18%	26%	36%	46%	57%	67%	76%	83%	88%	92%	95%	97%	98%	99%	100%
LO80Fast	76%	83%	88%	92%	95%	97%	98%	99%	99%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Retro12Med	11%	11%	11%	11%	11%	10%	8%	6%	5%	4%	3%	3%	2%	2%	1%	1%	0%	0%	0%	0%
Retro5Med	4%	5%	6%	8%	9%	10%	11%	11%	11%	9%	7%	5%	3%	1%	1%	0%	0%	0%	0%	0%
Retro1Slow	0%	1%	1%	1%	2%	3%	4%	6%	7%	8%	9%	10%	10%	9%	8%	7%	5%	4%	2%	2%
Retro50Fast	45%	21%	14%	9%	6%	3%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Retro20Fast	22%	16%	11%	8%	7%	6%	5%	5%	4%	3%	3%	2%	2%	1%	1%	1%	1%	1%	1%	0%
RetroEven20	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
Retro3Slow	1%	1%	2%	3%	5%	7%	8%	10%	11%	11%	10%	9%	7%	6%	4%	3%	2%	1%	1%	1%

E | Measure Data

Measure level assumptions and data are available in the "Avista 2024 DSM Potential Study Measure Assumptions" workbook provided to Avista alongside this file.

Avista 2024 DSM
Natural Gas CPA Mea

Applied Energy Group, Inc.
2300 Clayton Road
Suite 1370
Concord, CA 94520
P: 510-982-3526

Energy Trust of Oregon Background

Energy Trust of Oregon, Inc. (Energy Trust) is an independent nonprofit organization dedicated to helping investor-owned utility customers in Oregon and southwest Washington benefit from saving energy and generating renewable power. Energy Trust funding comes from utility customers and is invested on their behalf in lowest-cost energy efficiency and clean, renewable energy. In 1999, Oregon energy restructuring legislation (SB 1149) required Oregon's two largest electric utilities—Portland General Electric and Pacific Power—to collect a public purpose charge from their customers to support energy conservation in K-12 schools, low-income housing energy assistance, and energy efficiency and renewable energy programs for residential and business customers.

In 2001, Energy Trust entered into a grant agreement with the Oregon Public Utility Commission (OPUC) to invest the majority of revenue from the 3 percent public purpose charge in energy efficiency and renewable energy programs[1]. Every dollar invested in energy efficiency by Energy Trust will save residential, commercial, and industrial customers nearly $3 in deferred utility investment in generation, transmission, fuel purchase and other costs. Appreciating these benefits, natural gas companies asked Energy Trust to provide service to their customers—NW Natural in 2003, Cascade Natural Gas in 2006 and Avista in 2017. These arrangements stemmed from settlement agreements reached in Oregon Public Utility Commission processes.

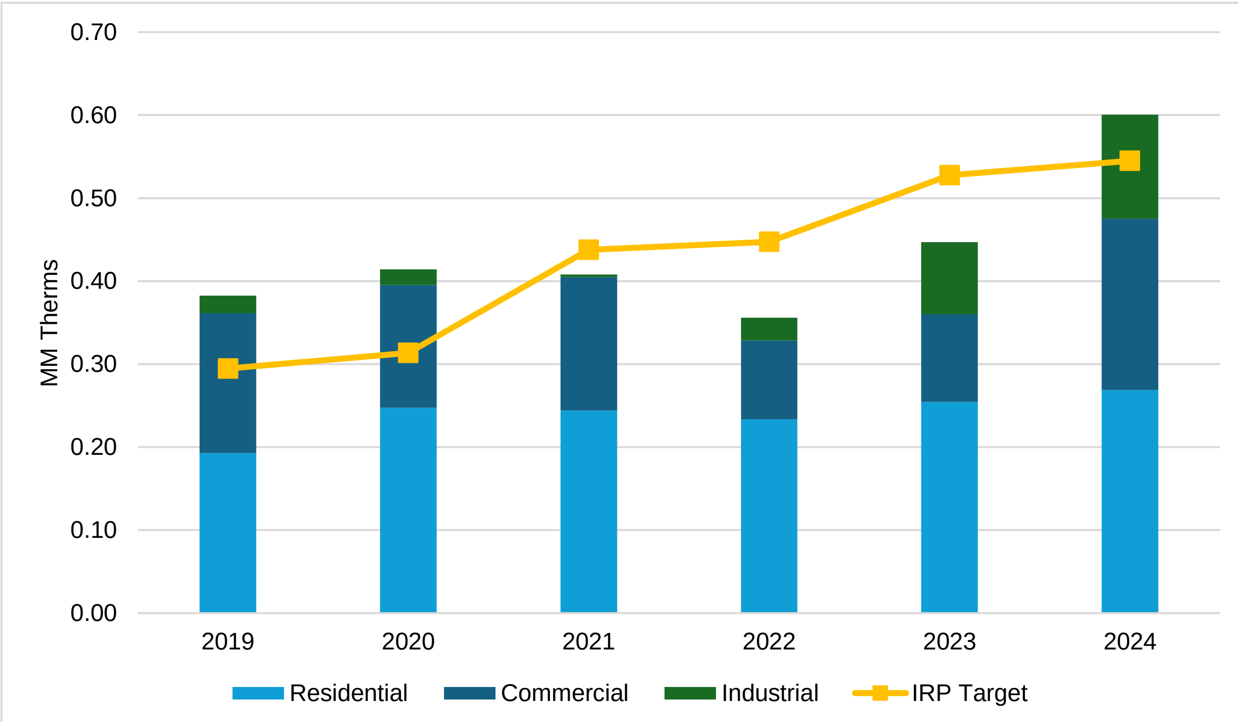
Energy Trust's model of delivering energy efficiency programs as a single entity across the five overlapping service territories of Oregon's investor-owned gas and electric utilities has experienced a great deal of success. Since its inception, Energy Trust has saved more than 965 aMW of electricity and 100 million annual therms. This equates to more than 42.9 million metric tons of CO_2 emissions avoided and is a significant factor contributing to the relatively flat energy sales observed by both gas and electric utilities from 2014 to 2023—with electric sales decreasing and natural gas sales very slightly increasing—as shown in OPUC utility statistic books.[2]

Energy Trust serves residential, commercial, firm, interruptible, and transport industrial customers in Avista's natural gas service territory in the areas of Medford, Klamath Falls, and La Grande, Oregon. In 2024, Energy Trust's programs achieved savings of 600,509 therms—equivalent to about 110% of the IRP target, as shown in

[1] Energy Trust's funding mechanism was updated in 2021 from HB 3141. See https://olis.oregonlegislature.gov/liz/2021R1/Downloads/PublicTestimonyDocument/5138 for more information.
[2] OPUC 2023 Stat book – 10 Year Summary Tables: https://www.oregon.gov/puc/forms/Forms%20and%20Reports/2023-Oregon-Utility-Statistics-Book.pdf

Figure ***1***. As seen in the figure, 2021 is the first year Energy Trust savings in Avista's Oregon service territory are below the IRP target. While savings remained relatively consistent with 2020, Energy Trust projected growth in 2021 as an extension of increased efficiency activities seen in 2020 as a result of pandemic related market conditions. However, supply chain and labor difficulties experienced in 2021 slowed down the rate of growth Energy Trust was able to achieve. This gap widened in 2022 and nearly closed in 2023. Energy Trust is working with Avista to further develop program delivery infrastructure to accelerate savings acquisition to meet carbon reduction requirements in context with related least-cost planning principles.

Figure 1 – Achieved Savings by Sector vs. IRP Targets for Avista Service Territory



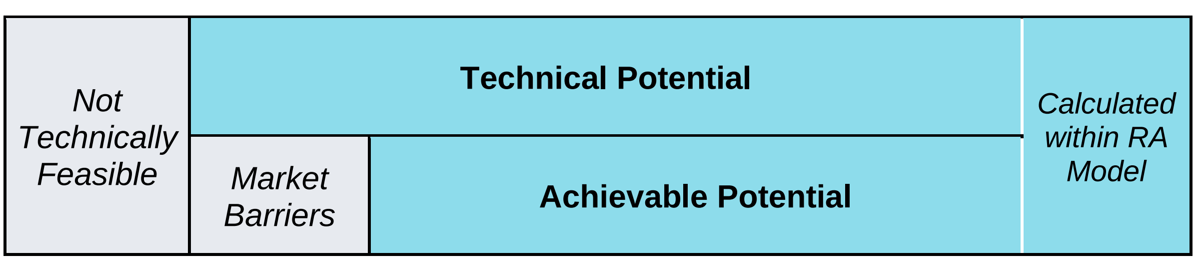
In addition to administering energy efficiency programs on behalf of the utilities, Energy Trust also provides each utility with a 20-year forecast of cost-effective energy efficiency savings potential expected to be achieved by Energy Trust. The results are used by Avista and other utilities in Integrated Resource Plans (IRP) to inform the energy efficiency resource potential in their territory that can be used in their resource mix to meet their customers' projected load.

Energy Trust 20-Year Forecast Methodology

20-Year Forecast Overview

Energy Trust developed a DSM resource forecast for Avista using its resource assessment modeling tool (hereinafter the "RA Model") to identify the total 20-year cost-effective modeled savings potential. This potential is subsequently 'deployed' exogenously of the model to estimate the final savings forecast for each of the 20 years. There are four types of potential that are calculated to develop the final savings potential estimate. These are shown in Figure ***2*** and discussed in greater detail in the sections below.

Figure 2 – Types of Potential Calculated in 20-year Forecast Determination



		Not Cost-Effective	**Cost-Effective Achievable Potential**		
			Program Design & Market Penetration	**Final Program Savings Potential**	*Developed with Programs & Other Market Information*

The RA Model utilizes the modeling platform Analytica®[3], an object-flow based modeling platform that is designed to visually show how different objects and parts of the model interrelate and flow throughout the modeling process. The model utilizes multidimensional tables and arrays to compute large, complex datasets in a relatively simple user interface. Energy Trust then deploys this cost-effective potential exogenously to the RA model into an annual savings projection based on past program experience, knowledge of current and developing markets, and future codes and standards. This final 20-year savings projection is provided to Avista for inclusion in in their CROME Model as a reduction to demand on the system.

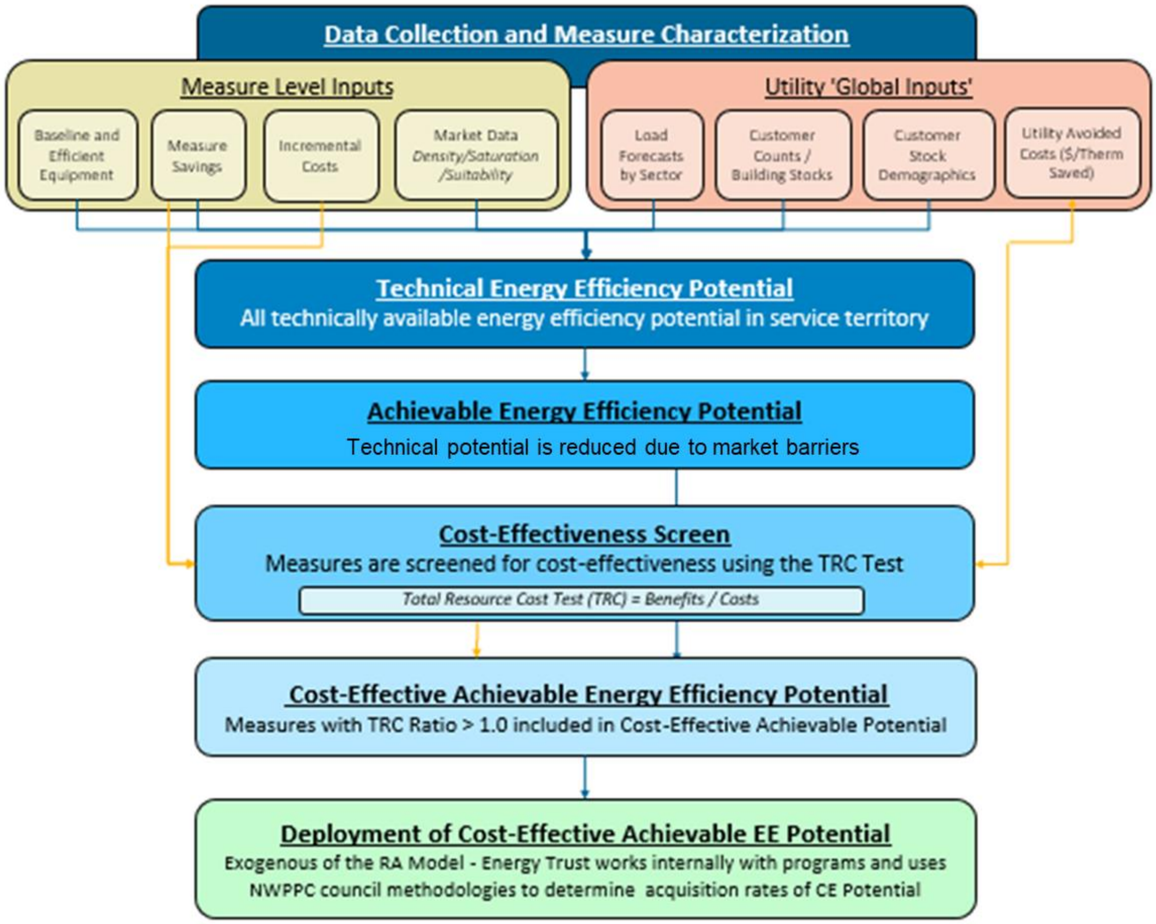
20-Year Forecast Detailed Methodology

Energy Trust's 20-year forecast for DSM savings follows six overarching steps from initial calculations to deployed savings, as shown in

[3] http://www.lumina.com/why-analytica/what-is-analytica1/

Figure ***3***. The first five steps in the varying shades of blue nodes - *Data Collection and Measure Characterization* to *Cost-Effective Achievable Energy Efficiency Potential* - are calculated within Energy Trust's RA Model. This results in the total cost-effective potential that is achievable over the 20-year forecast. The actual deployment of these savings (the acquisition percentage of the total potential each year, represented in the green node of the flow chart) is done exogenously of the RA model. The remainder of this section provides further detail on each of the steps shown below.

Figure 3 - Energy Trust's 20-Year DSM Forecast Determination Flow Chart



1. Data Collection and Measure Characterization

The first step of the modeling process is to identify and characterize a list of measures to include in the model, as well as receive and format utility 'global' inputs for use in the model. Energy Trust compiles and loads a list of commercially available and emerging technology measures for residential, commercial, industrial, and agricultural applications installed in new or existing structures. The list of measures is meant to reflect the full suite of measures offered by Energy Trust, plus a spectrum of emerging technologies.[4] In addition to identifying and characterizing applicable measures, Energy Trust collects necessary data to scale the measure level savings to a given service territory (known as 'global inputs').

- ***Measure Level Inputs:***
  Once the measures have been identified for inclusion in the model, they must be characterized in order to determine their savings potential and cost-effectiveness. The characterization inputs are determined through a combination of Energy Trust

[4] An emerging technology is defined as technology that is not yet commercially available but is in some stage of development with a reasonable chance of becoming commercially available within a 20-year timeframe. The model is capable of quantifying costs, potential, and risks associated with uncertain, but high-saving emerging technology measures. The savings from emerging technology measures are reduced by a risk-adjustment factor based on what stage of development the technology is in. The working concept is that the incremental risk-adjusted savings from emerging technology measures will result in a reasonable amount of savings over standard measures for those few technologies that eventually come to market without having to try and pick winners and losers.

primary data analysis, regional secondary sources[5], and engineering analysis. There are over 30 measure level inputs that feed into the model, but on a high level, the inputs are organized into the following categories:

1. ***Measure Definition and Equipment Identification***: This is the definition of the efficient equipment and the baseline equipment it is replacing (e.g., wall insulation greater than or equal to R11 replacing wall insulation with an R value of four or less). A measure's replacement type is also determined in this step – retrofit, replace on burnout, or new construction.
2. ***Measure Savings****:* natural gas savings associated with an efficient measure calculated by comparing the baseline and efficient measure consumptions.
3. ***Incremental Costs****:* The incremental cost of an efficient measure over the baseline. The definition of incremental cost depends upon the replacement type of the measure. If a measure is a retrofit measure, the incremental cost of a measure is the full cost of the equipment and installation. If the measure is a replace on burnout or new construction measure, the incremental cost of the measure is the difference between the cost of the efficient measure and the cost of the baseline equipment.
4. ***Market Data****:* Market data of a measure includes the density, saturation, and suitability of a measure. The density is the number of measure units that can be installed per scaling basis (e.g., the average number of showers per home for showerhead measures). Saturation is the share of equipment that is already efficient (e.g., 50% of the showers already have a low flow showerhead). Suitability of a measure is a percentage that represents the percent of installation opportunities where the measure can actually be installed. These data inputs are generally derived from regional market data sources such as NEEA's Residential and Commercial Building Stock Assessments.

- ***Utility Global Inputs:***

  The RA Model requires several utility-level inputs to create the DSM forecast. These inputs include:

  1. ***Customer and Load Forecasts****:* These inputs are essential to scale the measure level savings to a utility service territory. For example, residential measures are characterized on a 'per home' scaling basis, so the measure densities are calculated as the number of measures per home. The model then takes the number of homes that Avista has forecasted to scale the measure level potential to their entire service territory.
  2. ***Customer Stock Demographics****:* These data points are utility specific and identify the percentage of customer building stock that utilize different fuels for space and water heating. The RA Model uses these inputs to segment the total stock to the portion that is applicable to a measure (e.g., gas water heaters are only applicable to customers that have gas water heat).
  3. ***Utility Avoided Costs****:* Avoided costs are the net present value of avoided energy purchases and delivery costs associated with energy savings. Energy Trust calculates these values based on inputs provided by Avista. The avoided cost components are discussed in other sections

[5] Secondary Regional Data sources include: The Northwest Power Planning Council (NWPPC), the Regional Technical Forum (the technical arm of the NWPPC), and market reports such as NEEA's Residential and Commercial Building Stock Assessments (RBSA and CBSA).

of this IRP. Avoided costs are the primary benefit of energy efficiency in the cost-effectiveness screen.

2. Calculate Technical Energy Efficiency Potential

Once measures have been characterized and utility data loaded into the model, the next step is to determine the technical potential of energy that could be saved. Technical potential is defined as the total energy savings potential of a measure that could be achieved regardless of cost or market barriers, representing the maximum potential energy savings available. The model calculates technical potential by multiplying the number of applicable units of a measure in the service territory by the measure's savings. The model determines the total number of applicable units for a measure utilizing several of the measure level and utility inputs referenced above:

Total applicable units =	*Measure Density * Baseline Saturation * Suitability Factor * Heat Fuel Multipliers (if applicable) * Total Utility Stock (e.g., # of homes)*
Technical Potential =	*Total Applicable Units * Measure Savings*

This savings potential does not consider the various cost and market barriers that will limit the adoption of efficiency measures.

3. Calculate Achievable Energy Efficiency Potential

Achievable potential is simply a reduction of the technical potential to account for market barriers that prevent the adoption of the measures identified in the technical potential. This is done by applying a factor to reflect the maximum achievability for each measure. Energy Trust first updated its methodology in Avista's 2020 IRP to reflect the maximum achievability estimated by the Northwest Power and Conservation Council for the 2021 Power Plan, and has done so again for the 2025 IRP. While in past power plans a universal assumption of 85% was used, these factors now typically range from 85% to 95%.[6]

Achievable Potential =	*Technical Potential * Maximum Achievability Factor*

4. Determine Cost-effectiveness of Measure using TRC Screen

The RA Model screens all DSM measures in every year of the forecast horizon using the Total Resource Cost (TRC) test. This test evaluates the total present value of all benefits attributable to the measure divided by the total present value of all costs. A TRC test value greater than or equal to 1.0 means the value of benefits is equal to or exceeds the costs and the measure is cost-effective and contributes to the total amount of cost-effective potential. The TRC is expressed formulaically as follows:

TRC = Present Value of Benefits / Present Value of Costs

Where the Present Value of Benefits includes the sum of the following two components:

a) Avoided Costs: The present value of natural gas energy saved over the life of the measure, as determined by the total therms saved multiplied by Avista's avoided cost per therm. The net present-value of these benefits is calculated based on the measure's expected lifespan using the company's discount rate.

[6] For details on this, see https://www.nwcouncil.org/sites/default/files/2019_0813_p5.pdf.

b) Non-energy benefits are also included when present and quantifiable by a reasonable and practical method (e.g., water savings from low-flow showerheads or operations and maintenance cost reductions from advanced controls).

Where the *Present Value of Costs* includes:

a) Incentives paid to the participant; and
b) The participant's remaining out-of-pocket costs for the installed cost of the measures after incentives, minus state and federal tax credits.

The cost-effectiveness screen is a critical component for Energy Trust modeling and program planning because Energy Trust is only allowed to incentivize cost-effective measures unless an exception has been granted by the OPUC.

5. Quantify the Cost-Effective Achievable Energy Efficiency Potential

The RA Model's final output of potential is the quantified cost-effective achievable potential. If a measure passes the TRC test described above, then the achievable savings from a measure is included in this potential. If the measure does not pass the TRC test above, the measure's potential is not included in cost-effective achievable potential. However, the cost-effectiveness screen is overridden for some measures under two specific conditions:

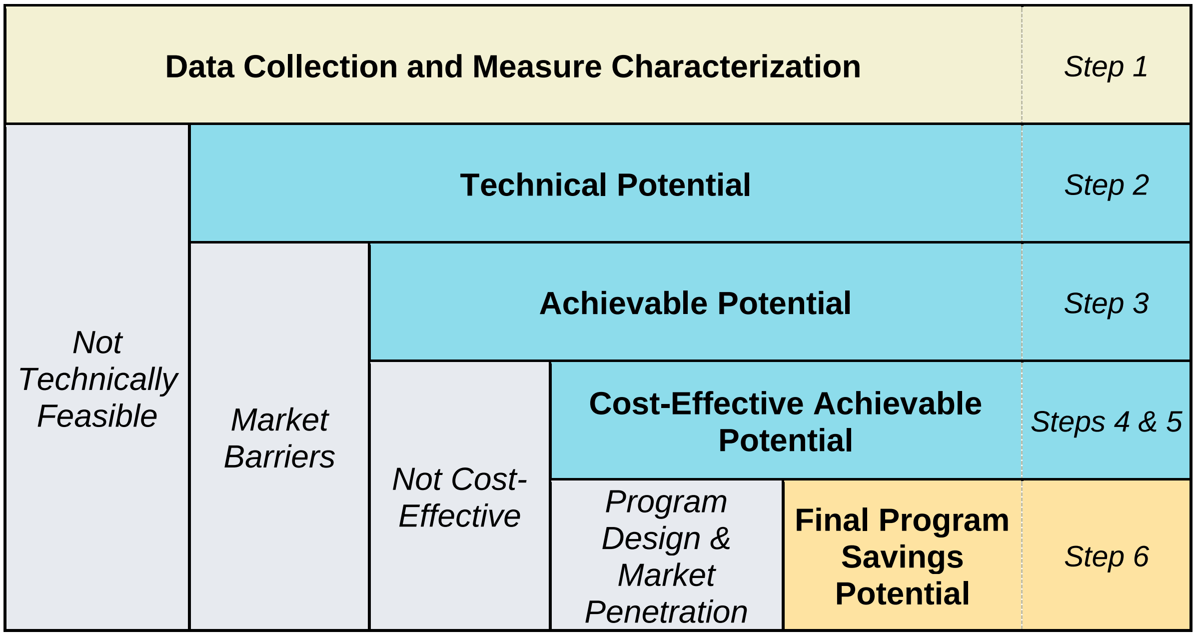
1) The OPUC has granted an exception to offer non-cost-effective measures under strict conditions or,
2) When the measure is not cost-effective using utility-specific avoided costs, but the measure is cost-effective when using blended gas avoided costs for all of the gas utilities Energy Trust serves and is therefore offered by Energy Trust programs.

6. Deployment of Cost-Effective Achievable Energy Efficiency Potential

After determining the 20-year cost-effective achievable modeled potential, Energy Trust develops a savings projection based on past program experience, knowledge of current and developing markets, and future codes and standards. The savings projection is a 20-year forecast of energy savings that will result in a reduction of load on Avista's system. This savings forecast includes savings from program activity for existing measures and emerging technologies, expected savings from market transformation efforts that drive improvements in codes and standards, and a forecast of savings from very large projects that are not characterized in Energy Trust's RA Model but consistently appear in Energy Trust's historic savings record and have been a source of overachievement against IRP targets in prior years for other utilities that Energy Trust serves.

Figure ***4*** below reiterates the types of potential shown in
Figure ***2***, and how the steps described above and in the flow chart fit together.

Figure 4 - The Progression to Program Savings Projections



Forecast Results (Base Case)

The results of Energy Trust's forecast are shown below.

RA Model Results – Technical, Achievable and Cost-Effective Achievable Potential

The RA Model produces results by potential type, as well as several other useful outputs, including a supply curve based on the levelized cost of energy efficiency measures. This section discusses the overall model results by potential type and provides an overview of the supply curve. These results do not include the application of ramp rates applied in Step 6 described above.

Forecasted Savings by Sector

Table 1 summarizes the technical, achievable, and cost-effective potential for Avista's system in Oregon. These savings represent the total 20-year cumulative savings potential identified in the RA Model by the three types identified in

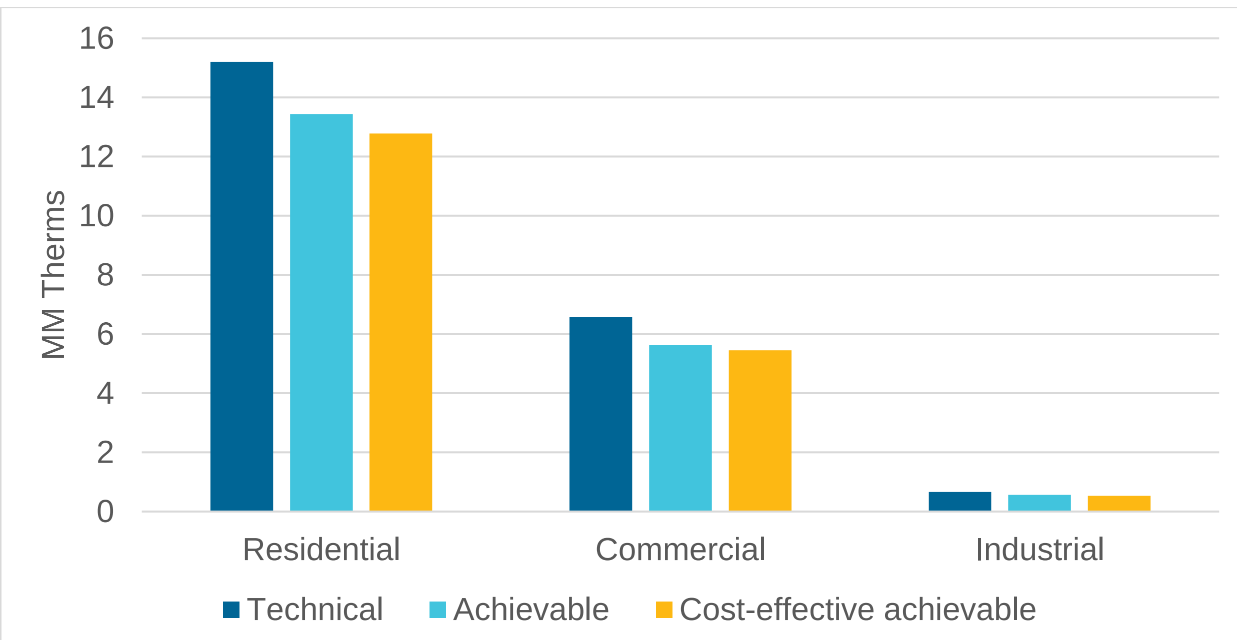
Figure *4* above. Modeled savings represent the full spectrum of potential identified in Energy Trust's resource assessment model through time, prior to deployment of these savings into the final annual savings projection.

Table 1 - Summary of Draft Total First-Year Modeled Savings Potential – 2025-2044

Sector	Technical Potential (Million Therms)	Achievable Potential (Million Therms)	Cost-Effective Achievable Potential (Million Therms)
Residential[7]	15.2	13.4	12.8
Commercial	6.6	5.6	5.5
Industrial	0.7	0.6	0.5
Total	**22.5**	**19.6**	**18.8**

Figure 5 shows total first-year forecasted savings potential across the three sectors Energy Trust serves, as well as the type of potential identified in Avista's service territory. Residential sales make up the majority of Avista's service in Oregon, which is reflected in the potential. Industrial sales represent a small percentage of the total sales in Oregon for Avista, and subsequently shows little savings potential. 80% of the industrial technical potential is cost-effective, while in the residential and commercial sectors, cost-effective achievable potential is 84% and 83% of technical potential, respectively.

Figure 5 – Total First-Year Savings Potential by Sector and Type 2025-2044 (Millions of Therms)

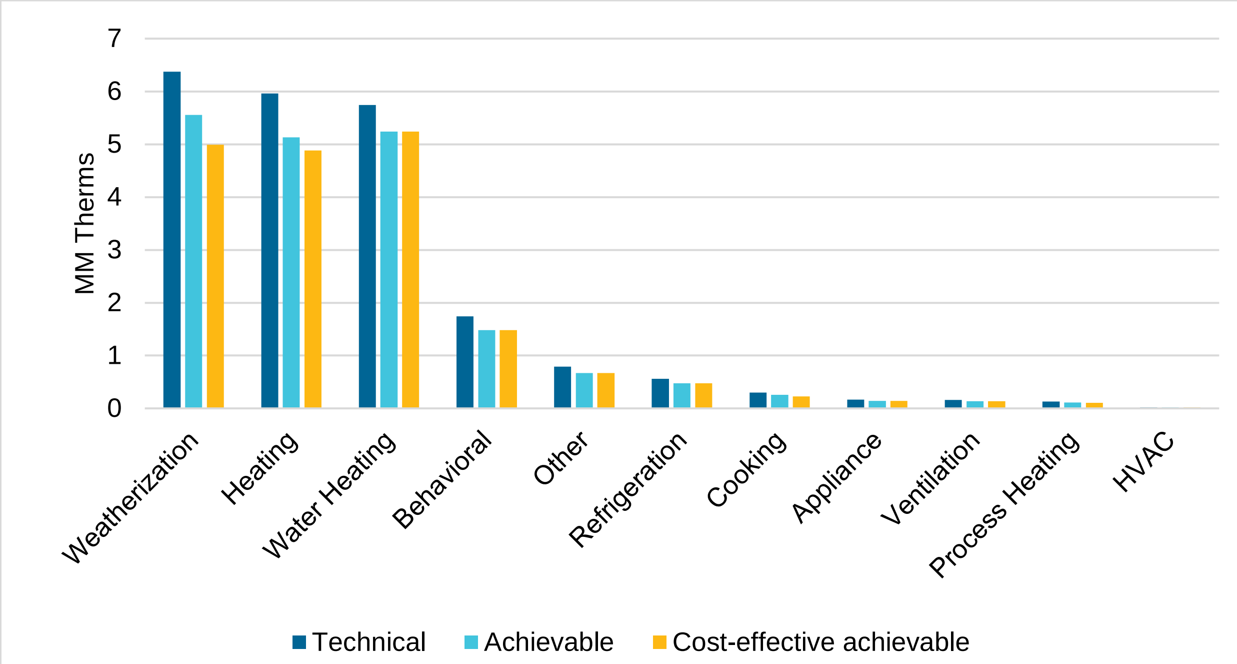


Cost-Effective Achievable Savings by End-Use

[7] Residential sector savings potential reflect the load and stock forecast from Avista's residential customers in Oregon, excluding low-income customers modeled separately by AEG.

Figure *6* below provides a breakdown of Avista's 20-year total first-year savings potential by end use.

Figure 6 – 20-year Total First-Year Savings Potential by End Use



As is typical for a gas utility, the top saving end uses are weatherization, heating, and water heating. A large portion of the water heating end-use is attributable to new construction homes due to how Energy Trust assigns end uses to the New Homes pathways offered through Energy Trust's residential programs. The New Home pathways are packages of measures in new construction homes with savings that span several end-uses. Energy Trust assigns an end-use to each of the New Homes pathways based on the end-use that achieves the most significant savings in the package. For example, the most cost-effective New Home pathway that was identified by the model (because it achieves the most savings for the least cost) was designated as a water heating end-use, though the package includes several other efficient gas equipment measures.

In addition to the New Homes pathway savings, the water heating end-use includes water heating equipment from all sectors. The behavioral end use consists primarily of potential from Energy Trust's commercial strategic energy management measure, a service where Energy Trust energy experts provide training and support to facilities teams and staff to identify operations and maintenance changes that make a difference in a building's energy use.

Contribution of Emerging Technologies

As mentioned earlier in this report, Energy Trust includes a suite of emerging technologies in its model. The emerging technologies included in the model are listed in Table 2.

Table 2 - Emerging Technologies Included in the Model

Residential	Commercial	Industrial

• Attic Insulation R-60 • Cellular Shades • Gas Absorption Heat Pump Water Heater • Gas-Fired Heat Pump • Thin Triple Pane Windows • Wall Insulation R-30	• Condensing Gas Rooftop Unit • Gas Absorption Heat Pump Hot Water • Gas-Fired Heat Pump • Gas RTU Advanced Tier 1 • Thin Triple Pane Windows • Zero Net Energy	• Advanced Wall Insulation • Gas-Fired Heat Pump Water Heater

Energy Trust recognizes that emerging technologies are inherently uncertain and applies a risk factor to hedge against that uncertainty. The risk factor for each emerging technology is used to characterize the inherent uncertainty in the ability for emerging technologies to produce reliable future savings. This risk factor is determined based on qualitative risk categories, including:

- Market risk
- Technical risk
- Data source risk

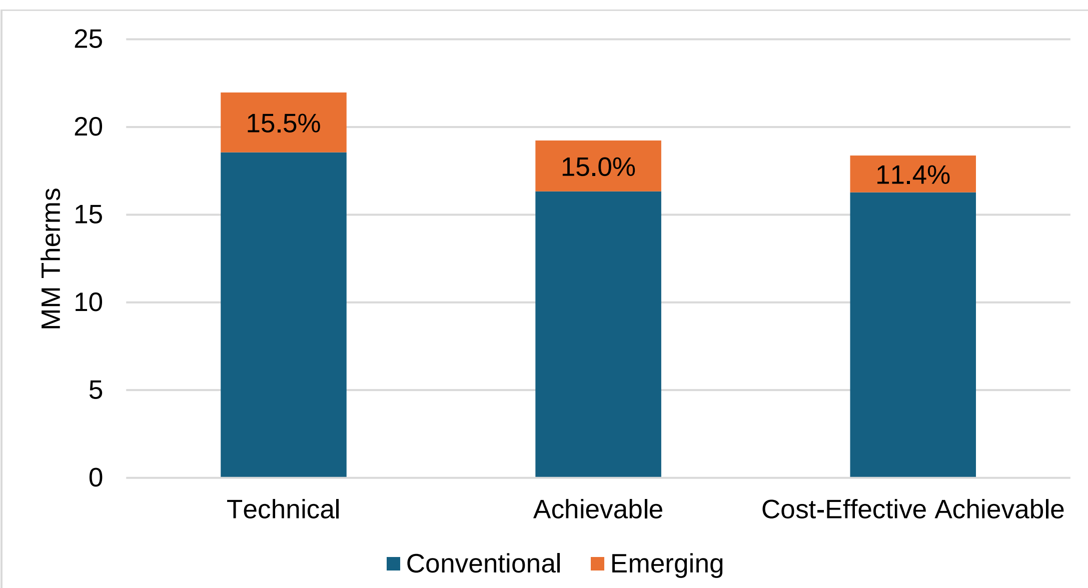
The framework for assigning the risk factor is shown in Table 3. Each emerging technology was assessed within each risk category and then a total weighted score was then calculated. Well-established and well-studied technologies have lower risk factors and nascent, unevaluated technologies have higher risk factors. This risk factor is then applied as a multiplier to reduce the incremental savings potential of the measure.

Table 3 - Emerging Technology Risk Factor Score Card

	Emerging Technology Risk Factor				
Risk Category	**10%**	**30%**	**50%**	**70%**	**90%**
Market Risk (25% weighting)	**High Risk:** • Requires new/changed business model • Start-up, or small manufacturer • Significant changes to infrastructure • Requires training of contractors. Consumer acceptance barriers exist.			**Low Risk:** • Trained contractors • Established business models • Already in U.S. Market • Manufacturer committed to commercialization	
Technical Risk (25% weighting)	**High Risk:** Prototype in first field tests. A single or unknown approach	Low volume manufacturer. Limited experience	New product with broad commercial appeal	Proven technology in different application or different region	**Low Risk:** Proven technology in target application. Multiple potentially viable approaches.
Data Source Risk (50% weighting)	**High Risk:** Based only on manufacturer claims	Manufacturer case studies	Engineering assessment or lab test	Third party case study (real world installation)	**Low Risk:** Evaluation results or multiple third-party case studies

Figure 7 below shows the amount of emerging technology savings within each type of potential. While emerging technologies make up a reasonable percentage of the technical and achievable potential, between 15% and 16%, once the cost-effectiveness screen is applied, the relative share of emerging technologies drops to 11% of total cost-effective achievable potential. This is because some of these technologies are still in early stages of development and are quite expensive. Though Energy Trust includes factors to account for forecasted decreases in cost and increased savings from these technologies over time where applicable, some are not cost-effective at any point over the planning horizon.

Figure 7 – Total First-Year Savings Contribution of Emerging Technologies by Potential Type



Cost-Effective Override Effect

Table 4 shows the savings potential in the RA model that was added by employing the cost-effectiveness override option in the model. As discussed in the methodology section, the cost-effectiveness override option forces non-cost-effective potential into the cost-effective potential results and is used when a measure meets one of the following two criteria:

1. A measure is offered under an OPUC exception.
2. When the measure is not cost-effective using Avista-specific avoided costs, but the measure is cost-effective when using blended gas avoided costs for all of the gas utilities Energy Trust serves and is therefore offered by Energy Trust programs.

Table 4 – Total First-Year Cost-Effective Savings Potential (2025-2044) due to Cost-Effectiveness Exception (Millions of Therms)

Sector	With Cost Effectiveness Override	Without Cost Effectiveness Override	Difference
Residential	12.8	12.3	(0.5)
Commercial	5.5	5.5	-
Industrial	0.5	0.5	-
Total	**18.8**	**18.2**	**(0.5)**[8]

In this IRP, approximately 3% of the cost-effective potential identified by the model is due to the use of the cost-effective override. The measures that had this option applied to them included residential attic, floor, and wall insulation, windows and storm windows, multifamily windows, gas heated new manufactured homes, clothes washers, and market solutions whole-home building tracks.

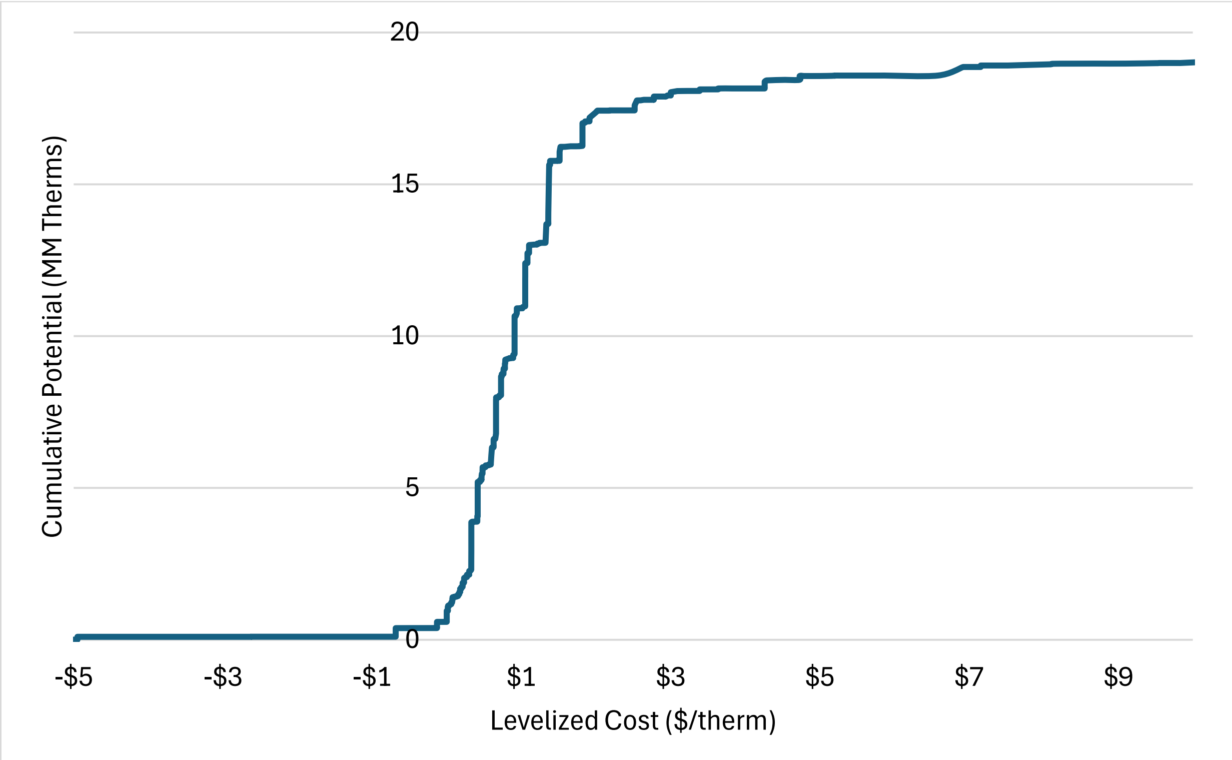
Supply Curves and Levelized Cost Outputs

An additional output of the RA Model is a resource supply curve developed from the levelized cost of energy of each measure. The supply curve graphically depicts the total potential that could be saved at various costs. The levelized cost provides a consistent basis for comparing efficiency measures and other resources with different lifetimes. The levelized cost calculation starts with the incremental cost of a given measure. The total cost is amortized over the estimated measure lifetime using Avista's discount rate. The annualized measure cost is then divided by the annual natural gas savings. Some measures have negative levelized costs because these measures have non-energy benefits that are greater than the total cost of the measure over the same period.

Figure ***8*** below shows the supply curve developed for this IRP that can be used for comparing demand-side and supply-side resources. The cost-effective potential, without override, identified in this assessment is approximately 18.2 million therms, which translates to approximately $3.86/therm on this graph. This is not a precise point, however, since measures around this point will save natural gas at different times in relation to Avista's peak periods and therefore have varying capacity values that function to make them more or less cost-effective. Consequently, measures on either side of this point may or may not be cost effective. Finally, after approximately $3/therm, additional potential comes at rapidly increasing cost increments.

[8] Difference column may not exactly equal the difference between the two values of potential—with and without the cost-effectiveness exception—due to rounding.

Figure 8 – Natural Gas Efficiency Supply Curve



Deployed Results – Final Savings Projection

The results of the final savings projection show that Energy Trust can achieve 3.2 million annual therm savings across Avista's system in Oregon from 2025 to 2030 and 13.9 million therms by the end of 2044. This represents an 18.4 percent cumulative load reduction by 2044 and is an average of a 0.9 percent incremental annual load reduction. The cumulative final savings projection is shown in Table 5, which shows the technical, achievable, and cost-effective achievable potential for comparison.

Table 5 - 20-Year Total First-Year Savings Potential by Type (Millions of Therms)

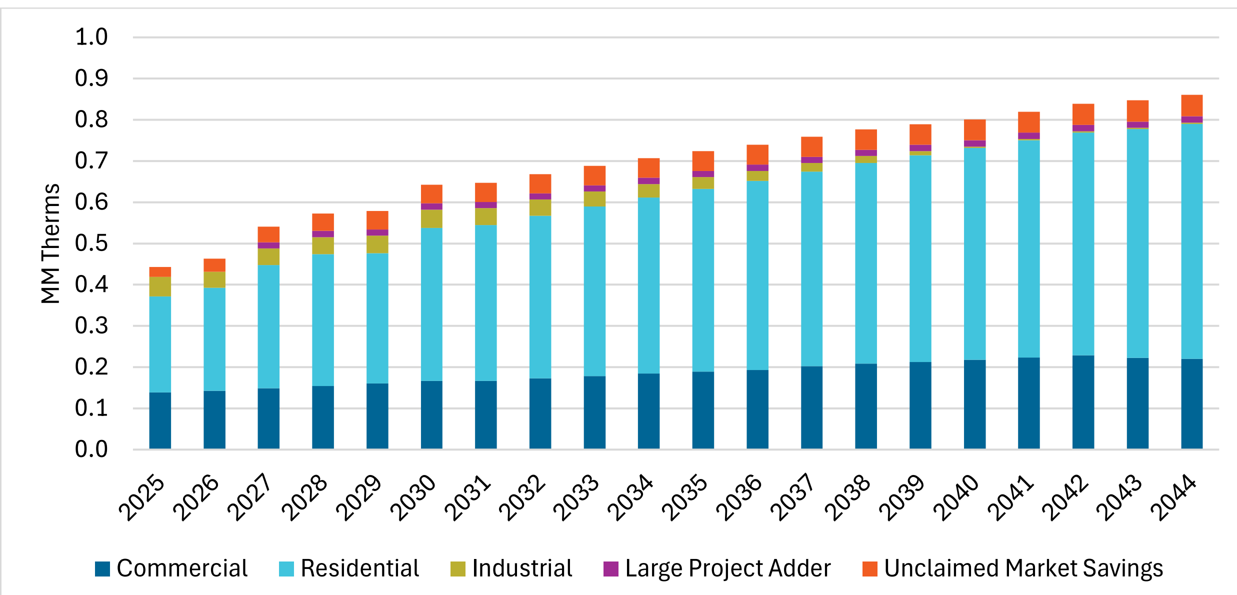
	Technical Potential	Achievable Potential	Cost-Effective Achievable Potential	Energy Trust Deployed Savings Projection
Residential	15.2	13.4	12.8	8.5
Commercial	6.6	5.6	5.5	3.7
Industrial	0.7	0.6	0.5	0.5
Exogenous[9]	-	-	-	1.2
Total	**22.5**	**19.6**	**18.8**	**13.9**

9 The final deployed savings projection includes savings calculated outside of the modeling process consisting of the large project adder and unclaimed market savings.

The final deployed savings projection is less than the modeled cost-effective achievable potential. The primary reason for this additional step down in savings is lost opportunity measures. These measures are meant to replace failed equipment or be installed in new construction. They are considered lost opportunity measures because programs have one opportunity to influence the installation of efficient equipment when the existing equipment fails or when the new building is built. This is because these measures must be installed at that specific point in time, and if the efficient equipment is not installed, then the opportunity is lost until the equipment fails again. Energy Trust assumes that most lost opportunity measures have gradually increasing annual adoption rates as time passes due to increasing program influence and increasing codes and standards. In addition to lost opportunities, some retrofit measures (notably insulation and windows) face market barriers that inhibit them from achieving full market penetration by the end of the time period.

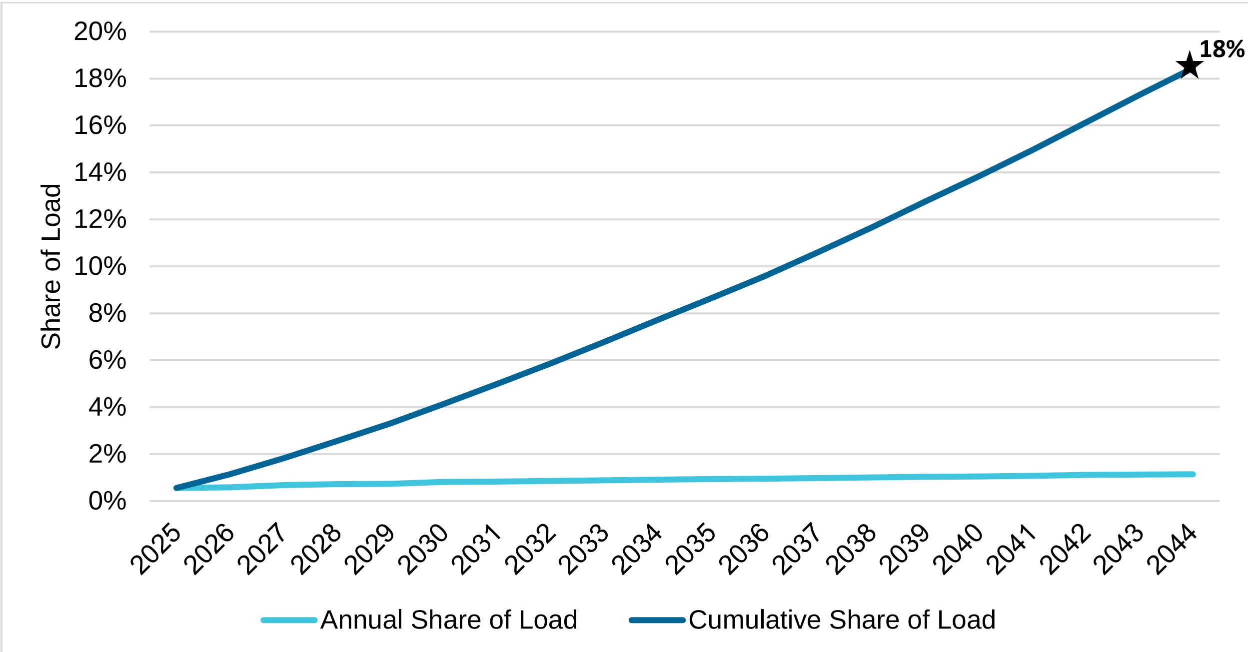
Figure 9 below shows the annual savings projection by sector. Savings totals in years 2025 through 2030 reflect Energy Trust's multiyear planning and strategic plan, while in 2031 and beyond NWPCC ramp rates take over. Savings growth throughout the forecast horizon is expected to be fairly consistent.

Figure 9 – Annual Deployed Final Savings Potential by Sector



Finally, Figure 10 shows the annual and cumulative savings as a percentage of Avista's load forecast in Oregon. Annually, the savings as a percentage of load varies from about 0.6% at its lowest to 1.1% at its highest, as represented on the left axis and the blue line. Cumulatively, the savings as a percentage of load builds to 18.4% by 2044.

Figure 10 – Annual and Cumulated Forecasted Savings as a Percentage of Avista Load Forecast



Comparison to 2023 IRP Savings Projection

Figure 11 below shows the annual deployed savings potential discussed above compared to Avista's previous IRP completed in 2023. Near-term savings projections in the 2025 IRP are lower than in 2023 to reflect updated market conditions and Energy Trust program expectations from the multiyear planning process. Efficiency potential estimates in the 2025 IRP, and especially in the residential sector, are sufficient to support steady growth throughout the forecast horizon. Savings projections in the 2023 IRP peak in 2034 and then decline as market potential in the industrial and commercial sectors become exhausted. The combination of a lower savings starting point and a more linear growth rate leave enough market potential to support growth throughout the forecast period. For context, the 2025 IRP achieves 62% of technical potential while the 2023 forecast captured 55% as shown in table 6 below.

Figure 11 – Annual Deployed Final Savings Projection Compared to 2023

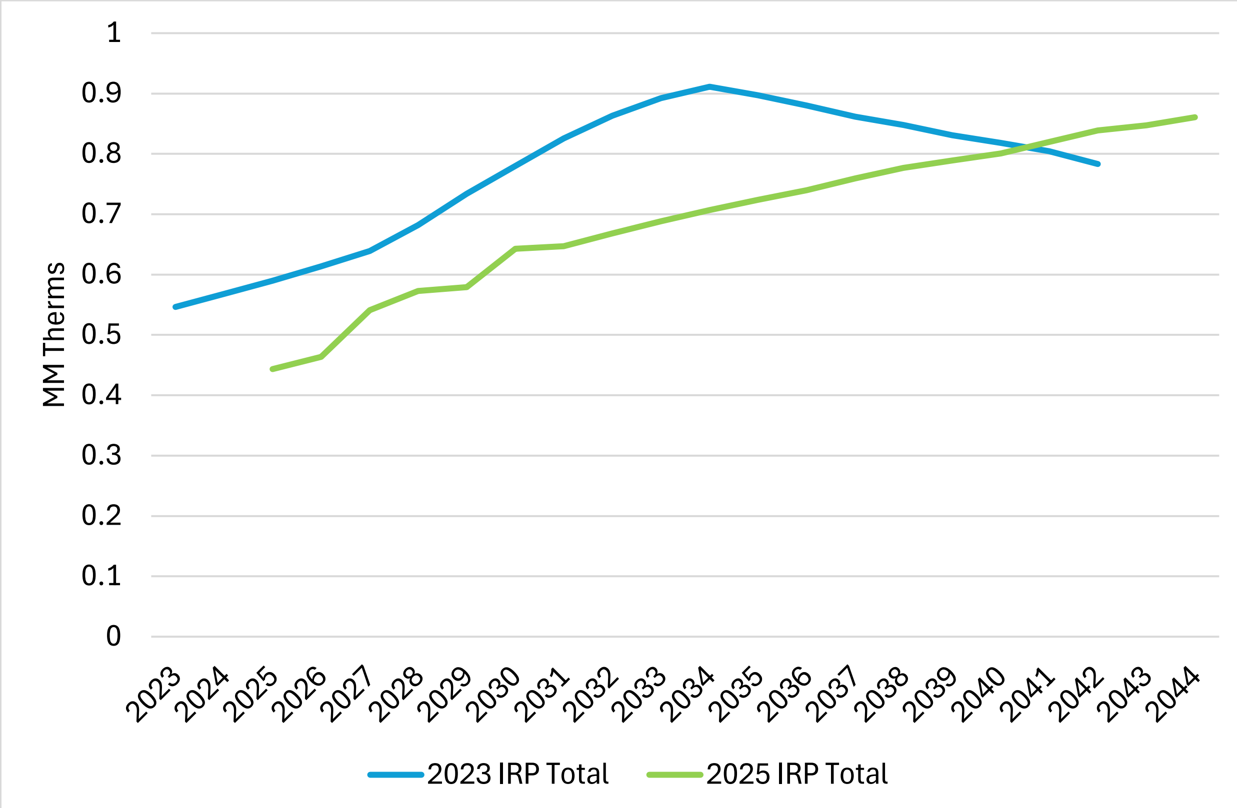


Table 6 below compares the modeled potential between this study and the 2023 IRP. Savings are down in each category of potential in the 2025 IRP compared to the 2023 IRP, however a higher share of cost-effective potential is reflected in the final deployment. This is primarily due to the reduced load and stock forecast in the 2025 IRP compared to the 2023 IRP. The 2025 IRP also has a lower proportion of emerging technology potential. Energy Trust applies a different ramp rate to emerging technologies than the ramp rate applied to conventional technologies. The emerging technology ramp rate places emerging technologies at the beginning of an adoption curve when the model demonstrates that they become market ready and cost-effective.

Table 6 - 20-Year First-Year Savings Potential by IRP Vintage (Millions of Therms)

	2023 IRP	2025 IRP	Difference
Technical	27.6	22.4	(5.2)
Achievable	22.3	19.6	(2.7)
Cost-Effective	21.6	18.8	(2.9)
Deployed	15.4	14.7	(0.7)

Table 7 details the individual changes contributing to the 2.9 MM therm decrease in cost-effective achievable potential shown above. Changes in load and stock forecast is the largest contributor, followed by measures updates.

Table 7 – Difference Between 2023 and 2025 Total First-Year Cost-Effective Achievable Potential (Millions of Therms)

	Difference: 2023 to 2025	Share of Difference
Load and Stock Forecast	-5.65	51%
Emerging Technology	-0.82	7%
Measure Updates	+3.75	34%
Avoided Costs	-0.36	3%
Discount Rate	-0.11	1%
CE Override	+0.43	4%
Total	**-2.9**	

Deployed Results – Peak Day Results

In the state of Oregon and around the region, there is an increased focus on the peak savings contributions of energy efficiency and the related impact on capacity investments. This new focus has led some utilities to embark on efforts to avoid or delay distribution system reinforcements. Therefore, Avista and Energy Trust have collaborated to develop estimates of peak day contributions from the energy efficiency measures in the Energy Trust forecast.

Peak day coincident factors are the percentage of annual savings that occur on a peak day and are shown in Table 8 below. Avista is still reviewing this methodology and for the purpose of this analysis, Energy Trust utilized the peak day factors that are used in the avoided costs used to screen measures for cost-effectiveness to determine the cost-effective achievable resource per the description above. These include residential and commercial space heating factors developed by NW Natural and hot water, process load (flat), and clothes washer factors sourced from load shapes developed by the Northwest Power and Conservation Council for electric measures that are analogous to gas equipment. The peak day factors are the highest for the space heating load shapes, which align with a winter system peak that is typical of natural gas utilities.

Table 8 - Peak Day Coincident Factors by Load Profile

Load Profile	Peak Day Factor	Source
Residential Space Heating	1.98%	NW Natural
Commercial Space Heating	1.77%	NW Natural
Water Heating	0.36%	NWPCC
Clothes Washer	0.30%	NWPCC
Process Load	0.20%	NWPCC

Figure below shows the annual, deployed peak day savings potential based upon the results of the 20-year forecast developed for this IRP. Each measure analyzed is assigned a load shape and the appropriate peak day factor is applied to the annual savings to calculate the overall DSM contribution to peak day capacity. This is equal to 219,871 total first-year therms in Avista's Oregon service territory over the 20-year forecast, as shown in Table 9 below.

Figure 12 - Annual Deployed Peak Day DSM Savings Contribution by Sector[9]

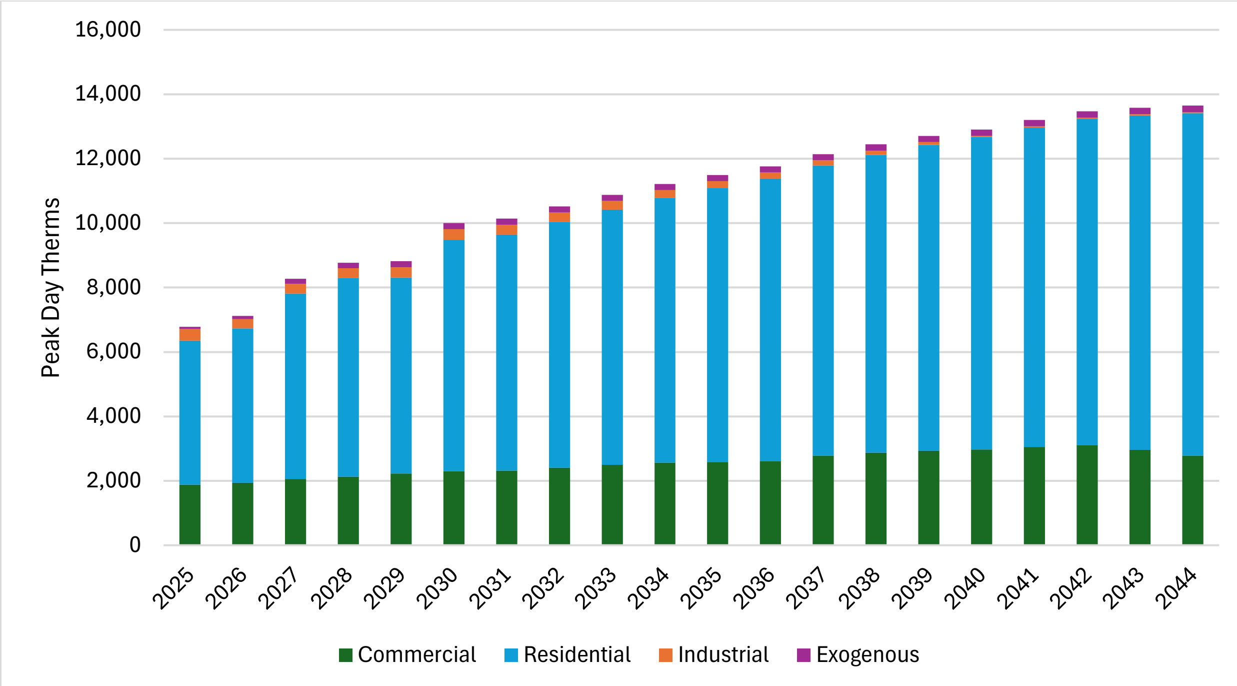


Table 9 – Total First-Year Deployed Peak Day DSM Savings Contribution by Sector (Therms)

Sector	Total First-Year Peak Day Savings (Therms)
Residential	161,328
Commercial	50,995
Industrial	3,950
Exogenous[9]	3,598
Total	**219,871**

Scenario Runs

For the 2025 IRP, Energy Trust modeled two scenarios for Avista—one looking at electrification and another at high growth on the gas system. Both scenarios were designed to reflect differences in avoided costs. These scenarios are outlined in the bullets below:

- *Base Case:* Expected load forecast with expected compliance and carbon prices and system coincident peak factors.
- *Electrification:* Expected load forecast with high carbon and compliance prices and system coincident peak factors.
- *High Growth on the Gas System:* Expected load forecast with low carbon and compliance prices and system coincident peak factors.

Both scenarios resulted in extremely slight increases in cost-effective achievable potential in the residential sector, as well as in commercial for the high growth scenario. Neither scenario resulted in meaningful differences in savings potential and thus neither presented deployment implications. These increases are driven by increases in cost-effective achievable potential for a residential whole home pathway for both scenarios, and commercial efficient windows for the high growth scenario. The inputs and results are summarized in tables 10 and 11 below.

Table 10 – Average Annual Avoided Costs 2025-2024

Load Profile	Reference ACs	High Growth on Gas System ACs	Electrification ACs	% Difference Base to High Growth on Gas System	% Difference Base to Electrification
DHW	$1.54	$1.61	$1.57	5%	2%
Flat	$1.47	$1.54	$1.50	5%	3%
Res Heating	$2.02	$2.07	$2.04	3%	1%
Com Heating	$2.00	$2.05	$2.01	3%	1%
Clotheswasher	$1.53	$1.61	$1.57	5%	3%

Table 11 – Cost-Effective Achievable Potential – Total First-Year Savings 2025-2044 (MM Therms)

Sector	Reference ACs	High Growth on Gas System ACs	Electrification ACs	% Difference Base to High Growth on Gas System	% Difference Base to Electrification
Residential	12.7758	12.7759	12.7759	0.0008%	0.0008%
Commercial	5.4517	5.4530	5.4517	0.0243%	0.0000%
Industrial	0.5307	0.5307	0.5307	0.0000%	0.0000%
Total	18.7581	18.7596	18.7582	0.0076%	0.0005%

APPENDIX 4.3: ENVIRONMENTAL EXTERNALITIES OVERVIEW (OREGON JURISDICTION ONLY)

The methodology for determining avoided costs from reduced incremental natural gas usage considers commodity and variable transportation costs including new supply resource options as discussed in Chapter 6.

Per traditional economic theory and industry practice, an environmental externality factor is typically added to the avoided cost when there is an opportunity to displace traditional supply-side resources with an alternative resource with no adverse environmental impact.

REGULATORY GUIDANCE

The Oregon Public Utility Commission (OPUC) issued Order 93-965 (UM-424) to address how utilities should consider the impact of environmental externalities in planning for future energy resources. The Order required analysis on the potential natural gas cost impacts from emitting carbon dioxide (CO_2) and nitric-oxide (NOx).

The OPUC's Order No. 07-002 in Docket UM 1056 (Investigation Into Integrated Resource Planning) established the following guideline for the treatment of environmental costs used by energy utilities that evaluate demand-side and supply-side energy choices:

> UM 1056, Guideline 8 - Environmental Costs
>
> *"Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for carbon dioxide (CO_2), nitrogen oxides (NOx), sulfur oxides (SO_2), and mercury (Hg) emissions. Utilities should analyze the range of potential CO2 regulatory costs in Order No. 93-695, from $0 - $40 (1990$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for nitrogen oxides (NOx), sulfur dioxide (SO2), and mercury (Hg), if applicable.*

In June 2008, the OPUC issued Order 08-338 (UM1302) which revised UM1056, Guideline 8. The revised guideline requires the utility should construct a base case portfolio to reflect what it considers to be the most likely regulatory compliance future for the various emissions. Additionally the guideline requires the utility to develop several compliance scenarios ranging from the present CO2 regulatory level to the upper reaches of credible proposals and each scenario should include a time profile of CO2 costs. The utility is also required to include a "trigger point" analysis in which the utility must determine at what level of carbon costs its selection of portfolio resources would be significantly different.

ANALYSIS

The supply-side implication of environmental externalities generally relates to combustion of fuel to move or compress natural gas. Avista's direct gas distribution system infrastructure relies solely on the upstream line pressure of the interstate pipeline transportation network to distribute natural gas to its customers and thus does not directly combust fuels that result in any CO_2, NOx, SO2, or Hg emissions.

Upstream gas system infrastructure (pipelines, storage facilities, and gathering systems), however, do produce CO_2 emissions via compressors used to pressurize and move natural gas.

Table 3.2.1 summarizes a range of environmental cost adders we believe capture several compliance futures including our expected scenario. The CO2 cost adders reflect outlooks we obtained the social cost of carbon at 2.5% and the cost of a community climate investment in the CPP.

The guidelines also call for a trigger point analysis that reflects a "turning point" at which an alternate resource portfolio would be selected at different carbon cost adders levels. This can be found in Chapter 8. Conceptually, there could be differing levels of cost adders applicable to pipeline transported supply versus in service territory LNG storage gas. We do acknowledge there is influence to the avoided costs which would impact the cost effectiveness of demand-side measures in the DSM business planning process.

CONSERVATION COST ADVANTAGE

For this IRP, we also incorporated a 10 percent environmental externality factor into our assessment of the cost-effectiveness of existing demand-side management programs. Our assessment of prospective demand-side management opportunities is based on an avoided cost stream that includes this 10 percent factor.

Environmental externalities were evaluated in the IRP by adding the cost per therm equivalent of the externality cost values to supply-side resources as described in OPUC Order No. 93-965.

REGULATORY FILING

Avista will file revised cost-effectiveness limits (CELs) based upon the updated avoided costs available from this IRP process within the prescribed regulatory timetable.

TABLE 1: ENVIRONMENTAL EXTERNALITIES COST ADDER ANALYSIS SCC @ 2.5%

			2026	2030	2035	2040	2045
Social Cost of Carbon	NOx – Annual	$/short ton	$ 7.20	$ 7.20	$ 7.20	$ 7.20	$ 7.20
		$/lb	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00
		lbs/therm	0.0656	0.0656	0.0656	0.0656	0.0656
		NOx Adder $/therm	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00
	NOx – Seasonal	$/short ton	$ 290	$ 290	$ 290	$ 290	$ 290
		$/lb	$ 0.15	$ 0.15	$ 0.15	$ 0.15	$ 0.15
		lbs/therm	0.06556	0.06556	0.06556	0.06556	0.06556
		NOx Adder $/therm	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01
	CO2	$/Metric Ton	$ 121.03	$ 139.53	$ 166.57	$ 199.91	$ 235.04
		$/lb	$ 0.0549	$ 0.0633	$ 0.0756	$ 0.0907	$ 0.1066
		lbs/therm	11.70	11.70	11.70	11.70	11.70
		CO2 Adder $/therm	$ 0.64228	$ 0.74	$ 0.88	$ 1.06	$ 1.25

TABLE 2: ENVIRONMENTAL EXTERNALITIES COST ADDER ANALYSIS CCI

			2026	2030	2035	2040	2045
Community Climate Investments	NOx – Annual	$/short ton	$ 7	$ 7	$ 7	$ 7	$ 7
		$/lb	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00
		lbs/therm	0.0656	0.0656	0.0656	0.0656	0.0656
		NOx Adder $/therm	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00
	NOx – Seasonal	$/short ton	$ 290	$ 290	$ 290	$ 290	$ 290
		$/lb	$ 0.15	$ 0.15	$ 0.15	$ 0.15	$ 0.15
		lbs/therm	0.066	0.066	0.066	0.066	0.066
		NOx Adder $/therm	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01
	CO2	$/Metric Ton	$ 141.00	$ 157.00	$ 182.00	$ 210.00	$ 241.00
		$/lb	$ 0.0640	$ 0.0712	$ 0.0826	$ 0.0953	$ 0.1093
		lbs/therm	11.7	11.7	11.7	11.7	11.7
		CO2 Adder $/therm	$ 0.75	$ 0.83	$ 0.97	$ 1.11	$ 1.28

Energy Efficiency (DSM) Annual Savings

Year	Idaho	Oregon	Washington	Oregon Transport	Washington Transport
2026	26,257	48,408	71,740	12,657	20,752
2027	60,181	105,306	155,226	25,566	42,028
2028	101,353	166,262	251,510	39,049	64,022
2029	106,048	225,724	341,747	53,291	86,848
2030	141,546	294,020	448,283	68,517	110,865
2031	181,546	365,640	561,887	84,772	135,455
2032	224,383	440,160	681,346	101,614	160,122
2033	267,382	517,054	798,806	118,740	183,986
2034	312,308	596,059	916,396	135,579	207,156
2035	355,518	677,047	1,028,874	151,714	229,109
2036	394,823	759,353	1,133,217	166,580	248,943
2037	426,656	842,415	1,218,622	179,721	265,384
2038	454,871	926,695	1,296,341	191,436	280,040
2039	479,244	1,012,099	1,362,119	201,890	292,485
2040	503,271	1,098,821	1,424,373	211,621	304,387
2041	524,167	1,187,438	1,473,597	220,368	314,880
2042	543,024	1,278,357	1,512,186	228,404	323,398
2043	562,880	1,370,722	1,550,262	236,365	332,519
2044	582,937	1,464,778	1,581,395	243,971	341,024
2045	600,730	1,547,925	1,601,274	251,405	349,006

Energy Efficiency (DSM) Annual Cost (Nominal $)

Year	Idaho	Oregon	Washington	Oregon Transport	Washington Transport
2026	$528,778	$6,845,874	$1,485,107	$5,324	$156,841
2027	$745,955	$6,930,404	$1,816,533	$6,236	$168,077
2028	$933,912	$7,080,727	$2,207,958	$7,802	$178,068
2029	$873,134	$7,255,709	$2,602,190	$9,169	$187,374
2030	$1,028,222	$7,621,501	$3,078,456	$10,763	$197,334
2031	$1,184,679	$8,188,909	$3,583,955	$12,554	$203,539
2032	$1,298,846	$8,618,797	$4,004,802	$13,751	$198,147
2033	$1,387,076	$8,954,438	$4,342,127	$15,925	$193,640
2034	$1,483,242	$8,976,248	$4,559,960	$16,123	$190,133
2035	$1,493,308	$9,279,905	$4,581,568	$17,515	$184,948
2036	$1,460,326	$9,248,141	$4,454,170	$16,632	$178,180
2037	$1,358,423	$9,080,747	$4,175,945	$14,890	$157,649

2038	$1,306,152	$9,033,593	$3,844,128	$13,647	$142,085
2039	$1,265,341	$9,048,727	$3,484,161	$12,237	$129,517
2040	$1,270,941	$9,225,634	$3,106,657	$10,918	$118,181
2041	$1,268,212	$9,227,929	$2,733,846	$9,803	$107,267
2042	$1,268,922	$9,482,001	$2,348,103	$10,539	$90,970
2043	$1,289,687	$9,362,904	$2,060,676	$10,142	$84,619
2044	$1,321,965	$9,594,980	$1,619,383	$8,862	$77,834
2045	$1,365,110	$8,466,124	$1,382,268	$8,888	$77,498

NATURAL GAS COST PER DEKATHERM (NOMINAL $) - EXPECTED

AECO Basin

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	3.08	2.68	2.38	2.19	2.32	2.45	2.61	2.65	2.57	2.54	2.87	3.31
2027	3.50	3.34	2.84	2.44	2.39	2.58	2.69	2.70	2.62	2.71	3.01	3.34
2028	3.70	3.41	2.95	2.51	2.51	2.59	2.69	2.71	2.53	2.57	3.24	3.42
2029	3.82	3.52	3.01	2.50	2.49	2.67	2.78	2.74	2.58	2.62	3.08	3.47
2030	3.82	3.63	3.34	2.79	2.61	2.69	2.73	2.72	2.52	2.55	3.25	3.44
2031	3.71	3.37	3.06	2.80	2.81	2.91	2.96	2.96	2.75	2.88	3.34	3.66
2032	3.78	3.39	3.13	2.99	3.01	3.03	3.12	3.15	3.02	3.06	3.64	3.93
2033	4.07	3.83	3.52	3.31	3.32	3.34	3.45	3.45	3.17	3.21	3.81	4.06
2034	4.22	3.99	3.64	3.50	3.51	3.54	3.62	3.64	3.38	3.41	3.99	4.18
2035	4.43	4.07	3.79	3.60	3.60	3.67	3.77	3.75	3.56	3.60	4.19	4.35
2036	4.50	4.20	3.90	3.81	3.83	3.84	3.97	3.95	3.73	3.78	4.33	4.64
2037	4.72	4.37	4.05	3.93	3.88	3.91	4.04	4.01	3.84	3.92	4.49	4.66
2038	4.93	4.60	4.26	4.05	4.06	4.08	4.25	4.12	4.04	4.04	4.79	4.97
2039	5.16	4.78	4.41	4.16	4.17	4.19	4.31	4.19	4.05	4.13	4.95	5.09
2040	5.52	5.16	4.75	4.47	4.48	4.56	4.68	4.54	4.45	4.54	5.32	5.43
2041	5.61	5.33	4.87	4.62	4.64	4.62	4.75	4.65	4.58	4.67	5.44	5.71
2042	5.91	5.53	5.12	4.79	4.82	4.87	4.90	4.78	4.67	4.81	5.67	5.85
2043	5.95	5.66	5.20	4.87	4.89	4.93	5.05	4.98	4.87	4.93	5.79	6.00
2044	6.28	5.93	5.50	5.08	5.08	5.17	5.30	5.11	5.09	5.18	6.00	6.21
2045	6.51	6.15	5.68	5.27	5.27	5.42	5.50	5.27	5.29	5.44	6.34	6.54

Malin Basin

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	4.10	3.72	3.38	3.04	3.02	3.00	3.35	3.44	3.41	3.51	3.82	4.15
2027	4.43	4.42	3.76	3.19	3.13	3.04	3.25	3.26	3.26	3.58	3.87	4.23
2028	4.62	4.09	3.67	3.17	3.14	2.94	3.15	3.15	3.38	3.60	3.89	4.12
2029	4.68	4.11	3.54	3.12	3.04	3.03	3.10	3.18	3.35	3.48	4.14	4.51
2030	5.01	4.47	4.09	3.40	3.13	3.04	3.01	3.15	3.38	3.50	4.24	4.82
2031	5.14	4.29	3.86	3.41	3.23	3.26	3.27	3.42	3.55	3.71	4.28	4.81
2032	5.05	4.26	3.85	3.44	3.51	3.45	3.57	3.77	3.85	4.01	4.66	5.14
2033	5.43	4.80	4.34	3.88	3.79	3.77	3.78	3.92	4.04	4.22	4.87	5.35
2034	5.63	4.89	4.42	4.09	3.99	3.99	4.00	4.17	4.22	4.40	5.01	5.36
2035	5.57	4.98	4.55	4.12	4.02	3.91	3.92	4.30	4.47	4.38	5.12	5.30
2036	5.40	4.82	4.53	4.24	4.18	4.18	4.19	4.21	4.30	4.51	5.11	5.36
2037	5.45	4.88	4.56	4.77	4.73	4.38	4.36	4.36	4.48	4.68	5.38	5.54
2038	5.75	5.13	4.91	4.55	4.50	4.52	4.49	4.47	4.59	4.82	5.39	6.03
2039	6.29	5.38	5.14	4.70	4.65	4.64	4.63	4.61	4.70	4.91	5.48	5.66

2040	6.11	5.70	5.50	4.99	5.00	5.04	5.01	5.54	5.61	5.26	5.79	6.00
2041	5.61	5.33	4.87	4.62	4.64	4.62	4.75	4.65	4.58	4.67	5.44	5.71
2042	5.91	5.53	5.12	4.79	4.82	4.87	4.90	4.78	4.67	4.81	5.67	5.85
2043	5.95	5.66	5.20	4.87	4.89	4.93	5.05	4.98	4.87	4.93	5.79	6.00
2044	6.28	5.93	5.50	5.08	5.08	5.17	5.30	5.11	5.09	5.18	6.00	6.21
2045	6.51	6.15	5.68	5.27	5.27	5.42	5.50	5.27	5.29	5.44	6.34	6.54

Rockies Basin

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	4.21	3.84	3.22	2.81	2.79	3.19	3.05	3.22	3.26	3.28	3.86	4.53
2027	4.60	4.41	3.69	3.17	3.10	3.28	3.23	3.31	3.37	3.28	3.95	4.58
2028	4.85	4.46	3.62	3.19	3.24	3.40	3.45	3.51	3.37	3.37	3.99	4.50
2029	4.69	4.33	3.68	3.28	3.33	3.43	3.45	3.48	3.45	3.51	4.12	4.54
2030	4.87	4.54	4.14	3.59	3.43	3.46	3.48	3.50	3.53	3.61	4.22	4.62
2031	4.86	4.44	3.98	3.71	3.66	3.65	3.73	3.77	3.84	3.89	4.41	4.73
2032	5.00	4.63	4.24	3.95	3.87	3.85	3.85	3.89	3.93	4.02	4.63	4.96
2033	5.22	4.88	4.55	4.14	4.08	4.09	4.14	4.16	4.20	4.30	4.89	5.17
2034	5.32	5.09	4.74	4.42	4.30	4.36	4.40	4.45	4.47	4.60	5.12	5.47
2035	5.64	5.31	4.92	4.53	4.39	4.47	4.49	4.50	4.58	4.67	5.29	5.55
2036	5.65	5.31	4.98	4.68	4.60	4.61	4.63	4.68	4.80	4.89	5.48	5.75
2037	5.81	5.50	5.20	4.89	4.76	4.76	4.78	4.83	4.90	5.06	5.73	5.93
2038	6.16	5.83	5.40	5.04	4.96	4.96	4.98	4.98	5.08	5.23	5.86	6.04
2039	6.30	5.94	5.53	5.19	5.07	5.11	5.12	5.13	5.23	5.37	6.00	6.20
2040	6.68	6.35	5.92	5.58	5.50	5.55	5.54	5.51	5.63	5.75	6.42	6.62
2041	6.79	6.48	6.02	5.67	5.59	5.61	5.65	5.67	5.74	5.87	6.54	6.73
2042	6.98	6.70	6.23	5.85	5.76	5.80	5.84	5.88	5.95	6.05	6.74	6.94
2043	7.12	6.79	6.36	5.93	5.86	5.89	5.94	5.96	6.05	6.17	6.84	7.05
2044	7.44	7.13	6.67	6.22	6.14	6.17	6.22	6.22	6.33	6.45	7.11	7.39
2045	7.66	7.39	6.87	6.41	6.34	6.36	6.39	6.40	6.53	6.65	7.36	7.61

Stanfield Basin

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	3.88	3.55	3.11	2.82	2.88	2.80	3.11	3.17	3.12	3.24	3.60	3.98
2027	4.26	4.15	3.46	2.99	2.89	2.78	2.96	3.08	3.10	3.24	3.64	4.04
2028	4.43	3.95	3.42	3.03	3.00	2.80	2.91	2.92	3.13	3.27	3.76	4.03
2029	4.26	3.82	3.29	2.86	2.90	2.91	2.92	2.95	3.18	3.36	3.88	4.09
2030	4.75	4.28	3.91	3.23	3.02	2.97	2.96	3.10	3.22	3.42	4.13	4.60
2031	4.79	4.11	3.67	3.22	3.17	3.19	3.20	3.31	3.42	3.62	4.18	4.66
2032	4.73	4.15	3.72	3.31	3.35	3.40	3.47	3.56	3.63	3.84	4.48	4.93
2033	5.13	4.54	4.18	3.66	3.66	3.66	3.67	3.75	3.85	4.10	4.70	5.03
2034	5.15	4.65	4.30	3.89	3.88	3.90	3.90	3.96	4.05	4.32	4.83	5.18
2035	5.31	4.84	4.42	3.93	3.86	3.84	3.79	3.91	4.01	4.32	4.91	5.15
2036	5.16	4.76	4.41	4.10	4.07	4.12	4.10	4.10	4.18	4.45	4.98	5.22

2037	5.20	4.77	4.51	4.32	4.28	4.31	4.27	4.30	4.38	4.65	5.20	5.45
2038	5.55	5.10	4.82	4.47	4.44	4.43	4.38	4.43	4.52	4.76	5.26	5.46
2039	5.59	5.25	5.05	4.61	4.58	4.58	4.51	4.56	4.64	4.86	5.38	5.54
2040	5.96	5.65	5.37	4.92	4.95	4.99	4.90	4.95	4.95	5.21	5.67	5.89
2041	6.10	5.75	5.52	5.03	4.99	4.97	5.00	5.07	5.04	5.27	5.77	6.01
2042	6.29	6.01	5.77	5.28	5.29	5.32	5.26	5.31	5.36	5.56	6.03	6.23
2043	6.44	6.17	5.89	5.40	5.39	5.38	5.36	5.42	5.48	5.67	6.12	6.39
2044	6.75	6.47	6.21	5.68	5.66	5.66	5.60	5.73	5.74	5.95	6.41	6.70
2045	7.00	6.75	6.41	5.90	5.81	5.78	5.67	5.84	5.84	6.10	6.64	6.92

Station 2 Basin

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	3.00	2.62	2.28	2.13	2.26	2.39	2.54	2.57	2.52	2.47	2.78	3.22
2027	3.41	3.31	2.75	2.38	2.34	2.53	2.68	2.63	2.56	2.62	2.90	3.23
2028	3.57	3.35	2.85	2.38	2.37	2.49	2.62	2.62	2.41	2.45	3.10	3.27
2029	3.71	3.45	2.86	2.40	2.39	2.56	2.71	2.66	2.43	2.47	2.92	3.33
2030	3.65	3.51	3.17	2.72	2.54	2.62	2.70	2.67	2.41	2.44	3.12	3.32
2031	3.57	3.34	2.94	2.75	2.76	2.84	2.90	2.90	2.64	2.77	3.28	3.54
2032	3.63	3.33	2.98	2.89	2.89	2.91	3.00	3.02	2.87	2.90	3.49	3.78
2033	3.89	3.73	3.34	3.19	3.19	3.20	3.30	3.28	3.00	3.03	3.63	3.87
2034	4.00	3.80	3.43	3.34	3.35	3.37	3.46	3.45	3.21	3.24	3.83	3.96
2035	4.19	3.97	3.54	3.43	3.44	3.50	3.57	3.51	3.35	3.39	3.94	4.07
2036	4.19	4.00	3.63	3.65	3.72	3.73	3.88	3.81	3.62	3.67	4.22	4.49
2037	4.37	4.12	3.77	3.82	3.81	3.83	3.98	3.90	3.74	3.80	4.42	4.55
2038	4.78	4.52	4.09	3.94	3.95	3.97	4.08	3.93	3.88	3.87	4.62	4.78
2039	4.95	4.68	4.18	4.01	4.02	4.03	4.15	4.02	3.89	3.95	4.78	4.90
2040	5.32	5.00	4.54	4.33	4.35	4.41	4.49	4.26	4.24	4.31	5.14	5.22
2041	5.38	5.18	4.62	4.39	4.40	4.39	4.51	4.38	4.31	4.38	5.24	5.45
2042	5.68	5.35	4.80	4.59	4.61	4.63	4.60	4.50	4.37	4.47	5.02	5.51
2043	5.60	5.29	4.68	4.72	4.74	4.71	4.79	4.86	4.61	4.56	5.24	5.66
2044	5.94	5.41	4.86	4.97	5.00	5.00	5.06	4.83	4.87	4.85	5.64	5.91
2045	6.22	5.68	5.19	5.13	5.16	5.18	5.20	4.82	4.97	5.03	6.01	6.19

Sumas Basin

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	4.05	3.67	3.08	2.69	2.77	3.10	3.25	3.24	3.16	3.23	3.78	4.23
2027	4.48	4.37	3.58	2.94	2.90	2.89	2.95	2.95	2.98	3.18	3.87	4.33
2028	4.75	4.45	3.51	2.77	2.92	2.99	2.97	3.07	3.04	3.19	3.81	4.14
2029	4.36	4.06	3.54	2.93	2.92	2.95	2.95	2.96	3.06	3.27	3.88	4.66
2030	4.83	4.34	4.01	3.20	3.03	2.99	2.91	2.96	3.07	3.17	3.97	4.73
2031	5.01	4.20	3.84	3.25	3.23	3.22	3.19	3.26	3.33	3.53	4.15	4.83
2032	5.00	4.32	4.01	3.39	3.41	3.43	3.42	3.45	3.49	3.66	4.37	5.07
2033	5.32	4.73	4.30	3.71	3.71	3.73	3.71	3.75	3.80	3.86	4.62	5.29

2034	5.41	4.92	4.41	4.02	3.91	3.95	3.93	4.05	3.99	3.97	4.88	5.59
2035	5.81	5.11	4.68	3.98	3.95	3.92	3.91	3.92	4.08	4.27	4.99	5.66
2036	5.78	4.94	4.72	4.20	4.14	4.09	4.18	4.21	4.16	4.42	5.14	5.62
2037	5.70	5.14	4.64	4.37	4.30	4.34	4.31	4.32	4.39	4.53	5.31	5.69
2038	5.93	5.41	5.06	4.51	4.49	4.52	4.48	4.46	4.53	4.64	5.52	5.65
2039	5.86	5.43	5.20	4.66	4.64	4.64	4.62	4.55	4.66	4.77	5.70	5.87
2040	6.31	5.88	5.53	4.98	4.97	5.01	5.00	4.96	5.00	5.14	6.11	6.27
2041	6.47	6.07	5.63	5.11	5.09	5.07	5.07	5.07	5.13	5.24	6.21	6.44
2042	6.70	6.27	5.92	5.36	5.33	5.39	5.34	5.29	5.38	5.48	6.50	6.66
2043	6.82	6.38	6.03	5.49	5.48	5.52	5.44	5.41	5.51	5.56	6.64	6.84
2044	7.20	6.69	6.26	5.77	5.78	5.79	5.74	5.69	5.75	5.90	6.86	7.17
2045	7.47	6.98	6.47	6.09	6.11	6.02	5.90	5.88	5.93	6.08	7.16	7.41

NATURAL GAS COST PER DEKATHERM (NOMINAL $) - HIGH

AECO Basin

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	3.22	2.88	2.69	2.57	2.77	2.98	3.25	3.35	3.31	3.43	3.74	4.19
2027	4.48	4.36	3.90	3.49	3.36	3.65	3.82	3.94	3.78	3.85	4.19	4.68
2028	5.04	4.80	4.28	3.91	3.87	3.90	3.99	4.19	4.06	4.25	4.72	5.15
2029	5.66	5.36	4.92	4.37	4.23	4.64	4.58	4.56	4.31	4.31	5.00	5.39
2030	5.75	5.55	5.20	4.83	4.68	4.71	4.77	4.76	4.36	4.61	5.27	5.40
2031	5.68	5.18	4.86	4.66	4.70	4.83	4.96	5.08	4.74	4.86	5.39	5.70
2032	5.97	5.81	5.70	5.48	5.51	5.84	5.92	5.91	5.73	6.08	6.45	6.70
2033	7.12	7.04	6.70	6.23	6.31	6.23	6.26	6.30	6.16	6.06	6.71	6.96
2034	7.59	6.93	6.74	6.63	6.70	6.81	7.22	7.23	7.21	7.22	7.71	8.00
2035	7.94	7.68	7.46	7.30	7.21	7.29	7.36	7.50	7.20	7.41	7.85	8.07
2036	8.32	7.87	7.57	7.48	7.24	7.92	7.98	7.82	7.62	7.76	8.25	8.57
2037	8.44	8.65	8.16	8.28	7.99	8.07	8.03	7.88	7.72	7.92	8.45	8.81
2038	9.50	9.16	8.73	8.37	8.22	8.24	8.37	8.06	8.51	8.36	9.19	9.33
2039	9.64	9.45	9.26	9.33	9.18	8.89	9.41	9.40	9.09	8.82	9.59	10.43
2040	11.24	11.08	10.75	10.30	10.21	10.04	10.62	10.34	9.94	10.04	10.95	10.93
2041	11.21	10.61	10.58	9.83	9.48	10.02	10.34	10.17	10.13	9.75	10.46	11.13
2042	11.38	10.98	10.09	10.11	10.42	10.06	10.02	9.63	10.24	10.16	10.94	11.06
2043	11.01	11.43	10.76	10.28	10.24	10.22	10.83	10.86	10.30	10.90	12.10	12.68
2044	12.59	11.92	11.58	10.85	11.68	11.50	11.85	11.05	11.13	10.95	12.78	13.47
2045	13.71	12.86	12.31	11.65	11.36	11.34	11.64	11.20	11.42	11.43	12.67	14.12

Malin Basin

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	4.24	3.92	3.70	3.43	3.47	3.53	3.99	4.14	4.15	4.41	4.69	5.03
2027	5.41	5.44	4.81	4.24	4.10	4.11	4.37	4.50	4.43	4.72	5.05	5.57
2028	5.96	5.48	5.00	4.57	4.51	4.25	4.44	4.63	4.90	5.28	5.37	5.85

2029	6.52	5.96	5.45	4.99	4.78	5.00	4.90	4.99	5.08	5.17	6.05	6.43
2030	6.95	6.39	5.94	5.43	5.20	5.06	5.05	5.18	5.22	5.56	6.26	6.77
2031	7.11	6.10	5.66	5.27	5.12	5.18	5.27	5.53	5.54	5.69	6.33	6.85
2032	7.25	6.68	6.42	5.93	6.01	6.26	6.37	6.53	6.56	7.04	7.47	7.91
2033	8.49	8.01	7.52	6.79	6.78	6.66	6.58	6.77	7.02	7.06	7.76	8.25
2034	9.01	7.84	7.53	7.23	7.18	7.27	7.60	7.76	8.06	8.21	8.74	9.19
2035	9.08	8.59	8.22	7.83	7.63	7.53	7.51	8.05	8.10	8.19	8.78	9.01
2036	9.21	8.48	8.20	7.91	7.59	8.26	8.20	8.09	8.19	8.48	9.03	9.28
2037	9.17	9.16	8.68	9.12	8.85	8.54	8.35	8.23	8.36	8.69	9.35	9.69
2038	10.31	9.70	9.38	8.88	8.67	8.68	8.61	8.40	9.06	9.14	9.79	10.38
2039	10.78	10.05	9.99	9.87	9.66	9.34	9.73	9.81	9.74	9.60	10.13	11.00
2040	11.83	11.63	11.50	10.82	10.73	10.53	10.94	11.35	11.10	10.77	11.43	11.50
2041	11.82	11.08	11.28	10.33	9.92	10.45	10.66	10.63	10.64	10.42	10.92	11.49
2042	11.82	11.51	10.84	11.36	11.64	10.56	10.51	10.21	10.98	10.95	11.46	11.51
2043	11.54	12.00	11.55	10.88	10.78	10.77	11.26	11.35	10.97	11.69	12.58	13.87
2044	13.94	12.51	12.34	11.55	12.34	12.07	12.30	11.72	11.84	11.78	13.37	14.00
2045	14.28	13.52	13.09	12.35	12.04	11.78	11.98	12.66	12.93	12.15	13.14	14.56

Rockies Basin

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	4.35	4.04	3.54	3.19	3.24	3.72	3.69	3.92	4.00	4.18	4.73	5.41
2027	5.58	5.43	4.75	4.22	4.07	4.35	4.36	4.55	4.53	4.42	5.13	5.91
2028	6.19	5.85	4.95	4.59	4.60	4.70	4.74	4.99	4.90	5.05	5.47	6.23
2029	6.52	6.17	5.59	5.16	5.06	5.40	5.25	5.30	5.18	5.20	6.04	6.46
2030	6.80	6.47	5.99	5.62	5.50	5.48	5.51	5.53	5.37	5.67	6.24	6.58
2031	6.83	6.25	5.78	5.57	5.56	5.57	5.73	5.88	5.83	5.87	6.45	6.76
2032	7.19	7.05	6.81	6.43	6.37	6.66	6.66	6.65	6.64	7.04	7.44	7.73
2033	8.28	8.09	7.73	7.06	7.07	6.98	6.95	7.01	7.19	7.15	7.78	8.06
2034	8.69	8.03	7.85	7.56	7.49	7.63	8.00	8.04	8.31	8.41	8.85	9.29
2035	9.15	8.92	8.59	8.23	8.00	8.09	8.08	8.25	8.21	8.48	8.95	9.27
2036	9.46	8.97	8.65	8.35	8.01	8.69	8.64	8.55	8.69	8.87	9.40	9.67
2037	9.53	9.78	9.31	9.24	8.88	8.92	8.77	8.70	8.78	9.06	9.69	10.08
2038	10.73	10.39	9.87	9.36	9.12	9.12	9.11	8.91	9.56	9.55	10.27	10.39
2039	10.79	10.61	10.38	10.36	10.08	9.81	10.22	10.33	10.27	10.06	10.65	11.55
2040	12.40	12.28	11.92	11.41	11.23	11.03	11.48	11.32	11.13	11.26	12.05	12.12
2041	12.40	11.76	11.73	10.87	10.44	11.01	11.25	11.18	11.29	10.95	11.56	12.15
2042	12.45	12.15	11.20	11.18	11.36	10.99	10.96	10.73	11.52	11.39	12.01	12.15
2043	12.18	12.57	11.92	11.34	11.21	11.19	11.71	11.84	11.48	12.15	13.16	13.73
2044	13.74	13.12	12.74	11.99	12.73	12.49	12.77	12.16	12.37	12.23	13.89	14.64
2045	14.86	14.10	13.50	12.79	12.43	12.28	12.53	12.32	12.67	12.64	13.70	15.20

Stanfield Basin

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec

2026	4.02	3.75	3.43	3.21	3.33	3.33	3.75	3.87	3.86	4.14	4.47	4.86
2027	5.24	5.17	4.51	4.04	3.86	3.85	4.08	4.32	4.27	4.38	4.82	5.38
2028	5.77	5.34	4.75	4.43	4.37	4.11	4.20	4.40	4.65	4.95	5.24	5.76
2029	6.10	5.67	5.20	4.74	4.64	4.89	4.72	4.76	4.91	5.06	5.80	6.01
2030	6.68	6.20	5.76	5.26	5.09	4.99	4.99	5.14	5.06	5.48	6.15	6.56
2031	6.76	5.92	5.47	5.08	5.07	5.11	5.20	5.42	5.41	5.60	6.23	6.69
2032	6.92	6.56	6.29	5.80	5.85	6.20	6.27	6.32	6.35	6.87	7.29	7.70
2033	8.19	7.75	7.36	6.58	6.65	6.55	6.47	6.60	6.84	6.94	7.59	7.92
2034	8.53	7.59	7.40	7.02	7.07	7.17	7.50	7.55	7.89	8.13	8.55	9.00
2035	8.82	8.45	8.09	7.64	7.47	7.46	7.38	7.66	7.65	8.13	8.57	8.87
2036	8.98	8.42	8.08	7.77	7.49	8.20	8.11	7.97	8.07	8.42	8.90	9.14
2037	8.92	9.05	8.62	8.68	8.39	8.47	8.25	8.16	8.26	8.65	9.17	9.60
2038	10.11	9.66	9.29	8.80	8.60	8.59	8.51	8.37	9.00	9.09	9.66	9.81
2039	10.08	9.93	9.90	9.78	9.59	9.29	9.62	9.76	9.68	9.55	10.03	10.88
2040	11.68	11.58	11.37	10.75	10.68	10.48	10.84	10.75	10.45	10.72	11.30	11.39
2041	11.71	11.03	11.23	10.24	9.84	10.37	10.59	10.58	10.59	10.36	10.78	11.44
2042	11.75	11.46	10.75	10.61	10.89	10.51	10.38	10.16	10.93	10.90	11.30	11.44
2043	11.50	11.95	11.44	10.81	10.74	10.68	11.14	11.30	10.91	11.65	12.43	13.07
2044	13.05	12.46	12.28	11.45	12.25	11.99	12.14	11.68	11.78	11.73	13.19	13.95
2045	14.20	13.47	13.04	12.29	11.90	11.70	11.81	11.77	11.97	12.09	12.98	14.51

Station 2 Basin

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	3.14	2.82	2.60	2.51	2.71	2.92	3.18	3.28	3.26	3.37	3.66	4.09
2027	4.39	4.32	3.81	3.43	3.31	3.60	3.80	3.87	3.73	3.76	4.08	4.56
2028	4.91	4.73	4.19	3.78	3.74	3.80	3.91	4.10	3.94	4.13	4.58	5.00
2029	5.55	5.29	4.77	4.28	4.13	4.54	4.50	4.47	4.16	4.16	4.84	5.25
2030	5.58	5.43	5.02	4.75	4.61	4.64	4.73	4.71	4.25	4.50	5.14	5.27
2031	5.54	5.15	4.74	4.61	4.66	4.75	4.90	5.02	4.63	4.75	5.32	5.57
2032	5.82	5.74	5.54	5.37	5.40	5.72	5.81	5.78	5.58	5.93	6.30	6.55
2033	6.95	6.94	6.52	6.10	6.18	6.09	6.10	6.13	5.98	5.88	6.52	6.76
2034	7.37	6.75	6.54	6.48	6.55	6.64	7.06	7.04	7.04	7.05	7.56	7.79
2035	7.70	7.58	7.21	7.14	7.06	7.11	7.16	7.26	6.98	7.20	7.60	7.79
2036	8.01	7.66	7.30	7.32	7.13	7.81	7.89	7.68	7.51	7.64	8.14	8.41
2037	8.08	8.40	7.88	8.17	7.92	7.99	7.97	7.77	7.61	7.80	8.38	8.69
2038	9.34	9.09	8.56	8.27	8.11	8.13	8.20	7.86	8.35	8.20	9.02	9.13
2039	9.43	9.36	9.03	9.18	9.03	8.73	9.25	9.22	8.93	8.64	9.43	10.25
2040	11.04	10.92	10.54	10.16	10.07	9.89	10.43	10.07	9.74	9.82	10.77	10.72
2041	10.99	10.46	10.33	9.59	9.25	9.78	10.11	9.90	9.86	9.46	10.26	10.88
2042	11.15	10.80	9.78	9.91	10.20	9.82	9.72	9.35	9.93	9.81	10.29	10.72
2043	10.66	11.07	10.23	10.13	10.09	10.01	10.56	10.74	10.04	10.54	11.56	12.34
2044	12.24	11.40	10.94	10.75	11.59	11.32	11.61	10.78	10.91	10.62	12.41	13.17
2045	13.42	12.40	11.82	11.51	11.25	11.09	11.34	10.74	11.11	11.02	12.35	13.78

Sumas Basin

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	4.19	3.87	3.40	3.08	3.22	3.63	3.89	3.94	3.90	4.13	4.65	5.11
2027	5.46	5.39	4.63	3.99	3.87	3.96	4.07	4.19	4.15	4.32	5.05	5.67
2028	6.09	5.84	4.84	4.17	4.29	4.30	4.26	4.55	4.56	4.87	5.29	5.87
2029	6.20	5.90	5.45	4.81	4.66	4.93	4.74	4.77	4.79	4.96	5.80	6.59
2030	6.76	6.26	5.86	5.23	5.11	5.01	4.94	4.99	4.91	5.23	5.99	6.69
2031	6.98	6.01	5.64	5.11	5.12	5.14	5.19	5.37	5.32	5.51	6.20	6.86
2032	7.20	6.74	6.57	5.87	5.91	6.23	6.22	6.21	6.20	6.69	7.18	7.84
2033	8.38	7.94	7.47	6.63	6.70	6.62	6.51	6.60	6.78	6.71	7.52	8.19
2034	8.79	7.87	7.51	7.16	7.11	7.22	7.53	7.64	7.82	7.78	8.61	9.41
2035	9.32	8.72	8.36	7.69	7.56	7.54	7.50	7.67	7.71	8.08	8.65	9.38
2036	9.59	8.60	8.39	7.87	7.55	8.17	8.19	8.09	8.06	8.39	9.06	9.54
2037	9.41	9.42	8.75	8.72	8.42	8.50	8.30	8.19	8.27	8.54	9.27	9.84
2038	10.49	9.98	9.52	8.84	8.65	8.68	8.61	8.40	9.01	8.96	9.92	10.00
2039	10.34	10.10	10.05	9.83	9.65	9.34	9.72	9.75	9.70	9.46	10.34	11.21
2040	12.03	11.80	11.53	10.81	10.70	10.49	10.93	10.77	10.50	10.64	11.74	11.77
2041	12.08	11.35	11.33	10.32	9.94	10.47	10.66	10.58	10.67	10.33	11.23	11.87
2042	12.17	11.72	10.89	10.69	10.93	10.59	10.46	10.14	10.94	10.83	11.77	11.87
2043	11.89	12.16	11.58	10.90	10.83	10.81	11.22	11.29	10.94	11.54	12.95	13.52
2044	13.51	12.68	12.34	11.55	12.37	12.12	12.29	11.63	11.79	11.68	13.64	14.43
2045	14.67	13.70	13.10	12.47	12.20	11.94	12.04	11.81	12.06	12.07	13.50	15.00

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Low Carbon Fuel Alternative Resources and Offsets for IRP Evaluation

NW Natural, Avista, and Cascade

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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%).

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

Feedstock	Description
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.

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

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

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.

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

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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

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.

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

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.
8 Siloxane only exists in biogas from landfills and WRRF.

LFG Constituent	Typical Concentration Range	Upgrading Technology for Removal
		• 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.

- 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.

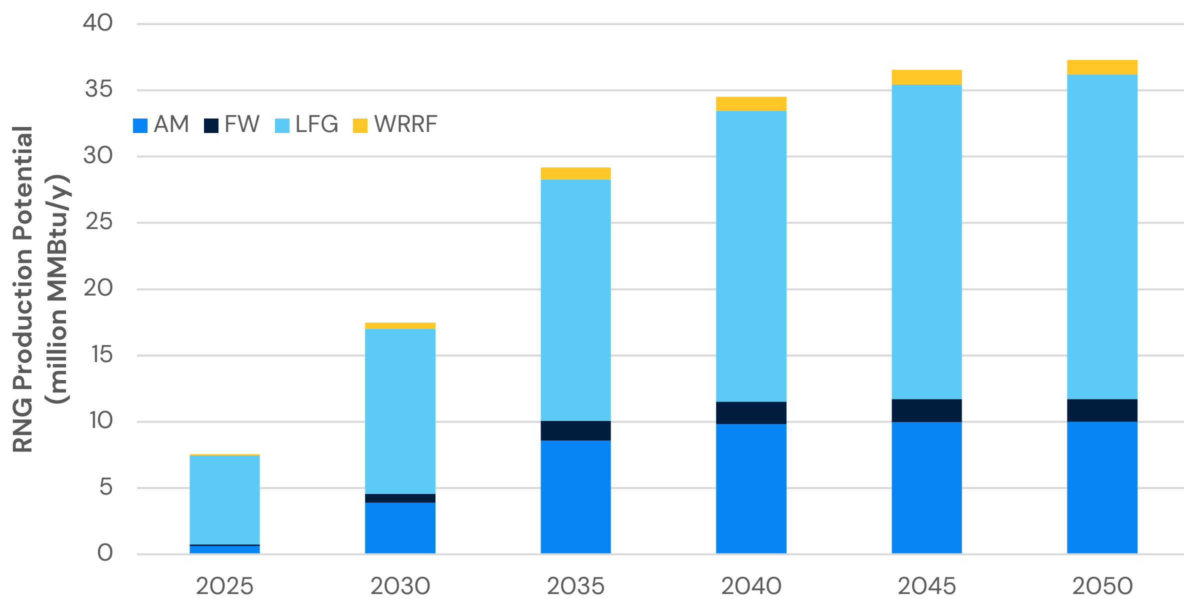
The treated sludge from the WRRF can be landfilled, and during processing it can be treated via anaerobic digestion, thereby producing methane which can be used for beneficial use with the appropriate capture and conditioning systems put in place.

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)

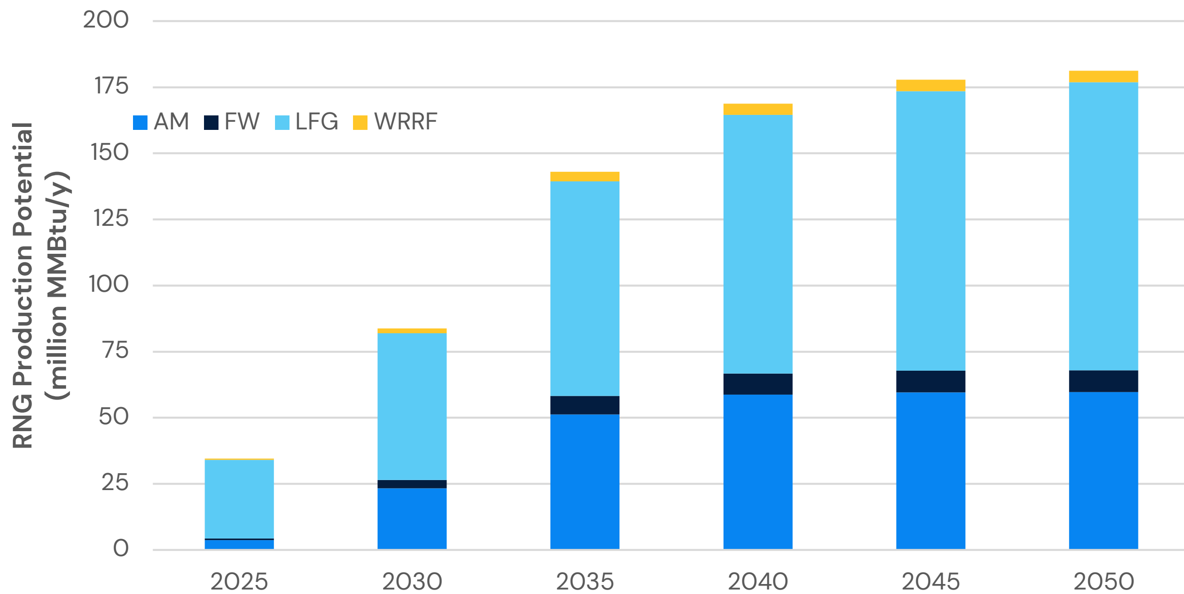


[9] US EPA, Opportunities for Combined Heat and Power at Wastewater Treatment Facilities, October 2011. Available online here.

[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.

[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
O&M Costs	
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

Factor	Cost Elements Considered	Costs
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
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

Factor	Cost Elements Considered	Costs
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
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).

[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.

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
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)

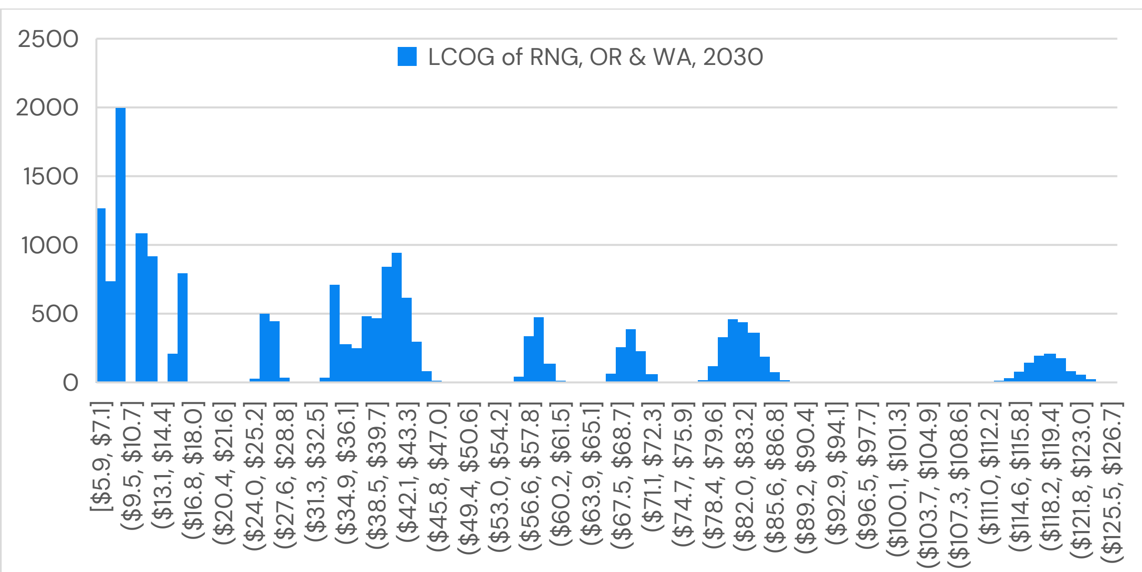


Exhibit 18. Summary of Monte Carlo Simulation Results for RNG in Oregon and Washington (2050)

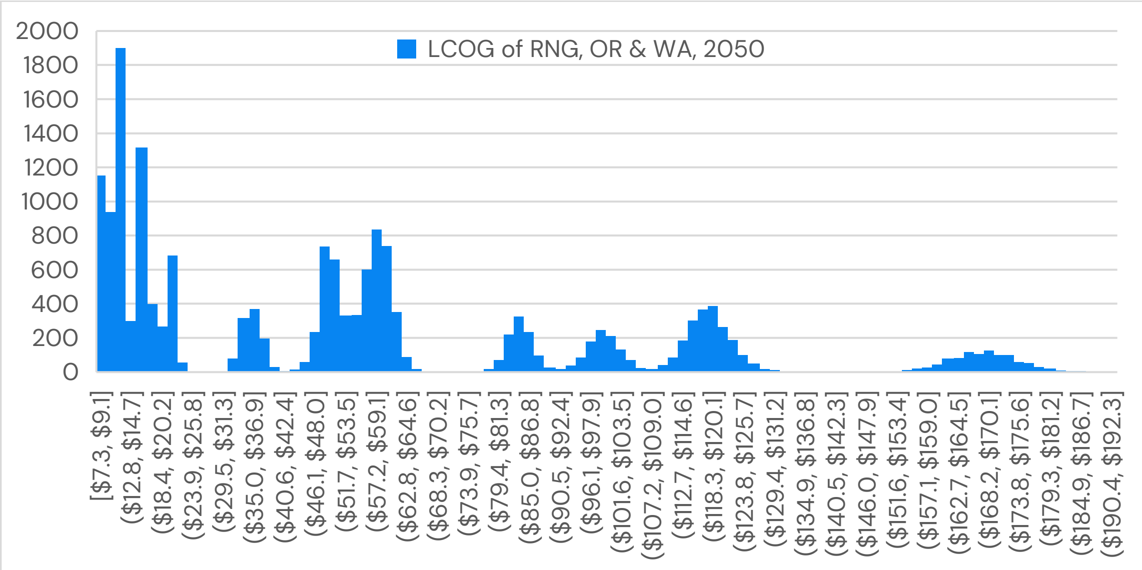


Exhibit 19. Summary of Monte Carlo Simulation Results for RNG domestically (2030)

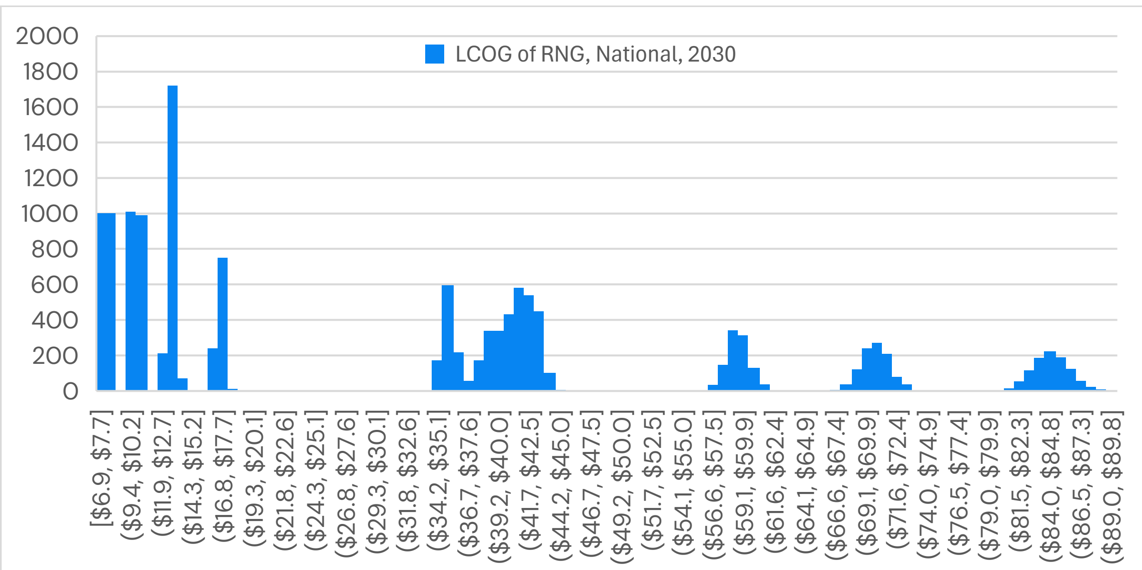
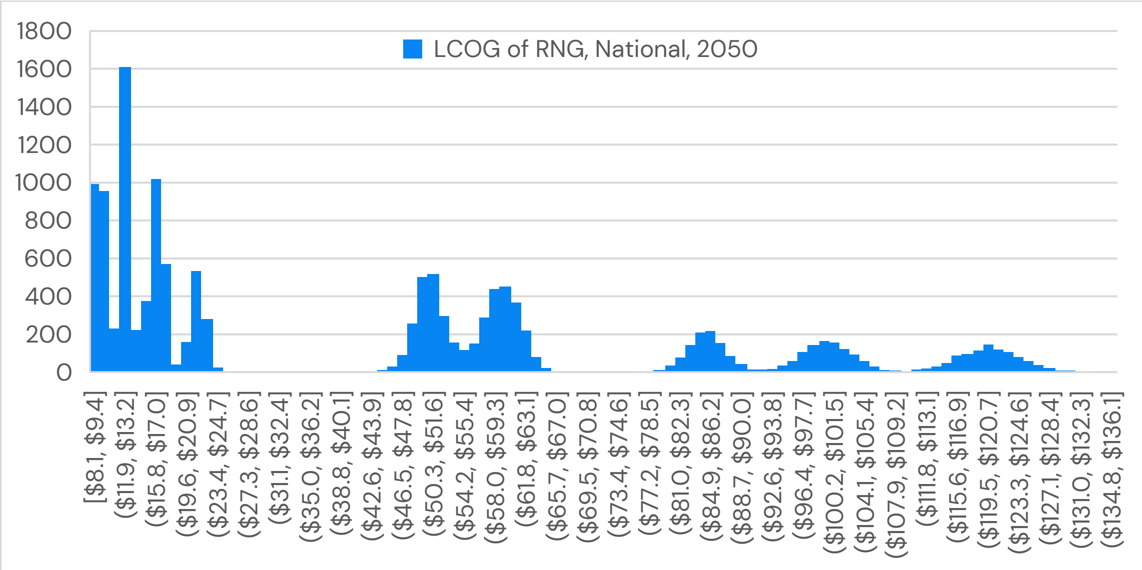


Exhibit 20. Summary of Monte Carlo Simulation Results for RNG domestically (2050)



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

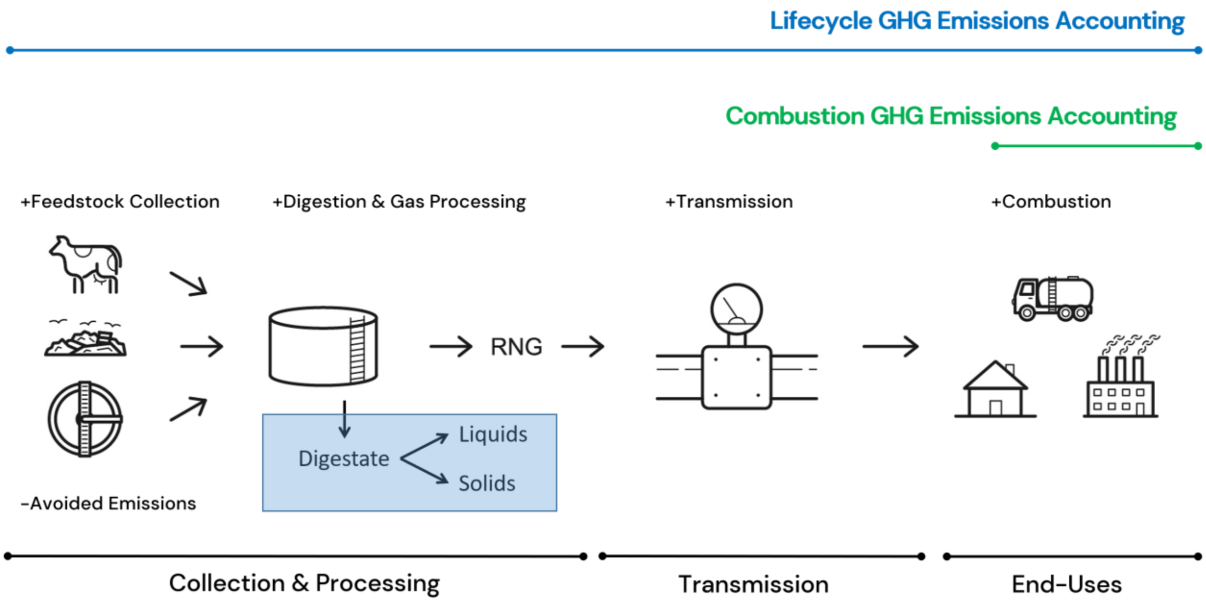


Exhibit 21 shows how life cycle GHG emissions from RNG are generated along the three key stages of the RNG supply chain.

- **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.

[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.

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

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

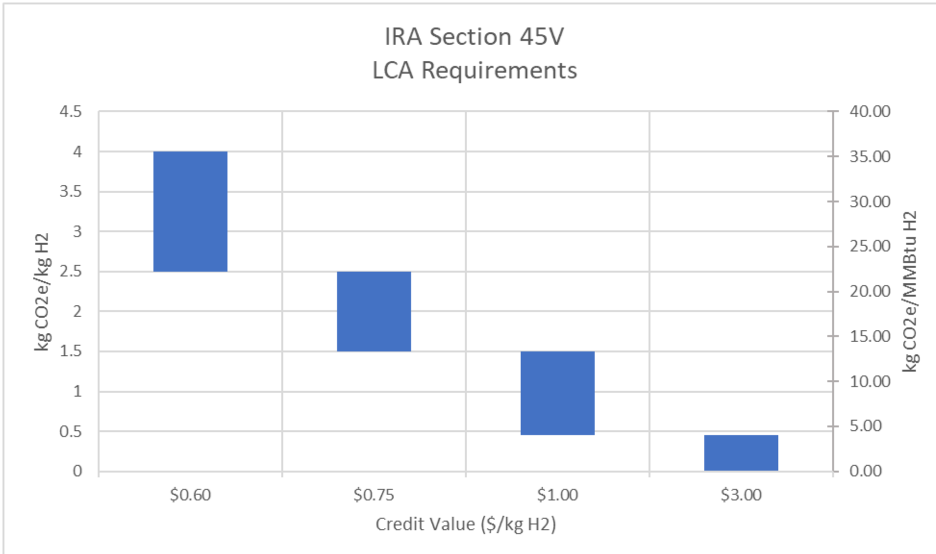
Several governing bodies have begun to define "Clean Hydrogen" according to its carbon intensity. In the US, the definition of Clean Hydrogen was established to be less than 4 kg CO_2e/kg H_2 under the Bipartisan Infrastructure Law, and further defined by categories under the Inflation Reduction Act (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

[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.

Qualified facilities, which are to be required to meet certain wage and apprenticeship requirements as defined in the IRA.

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)

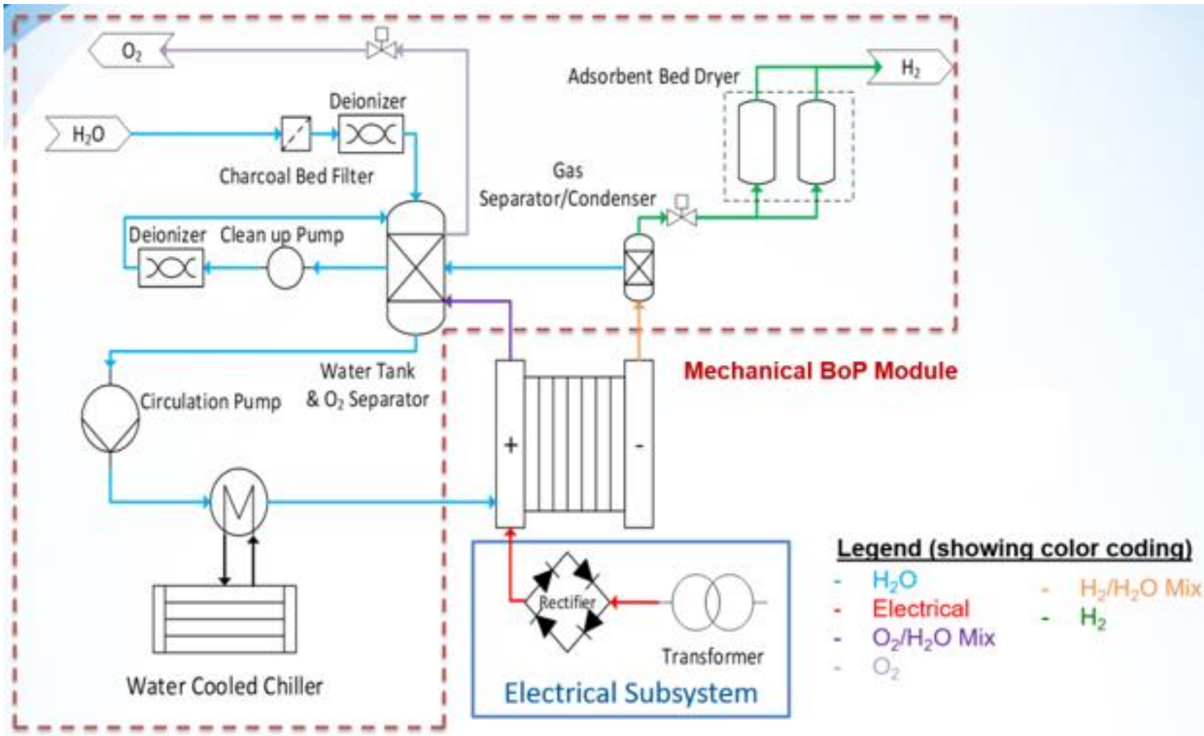
Levelized Cost of Hydrogen

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

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

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 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		

[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
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
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

Input	Value	Comments
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

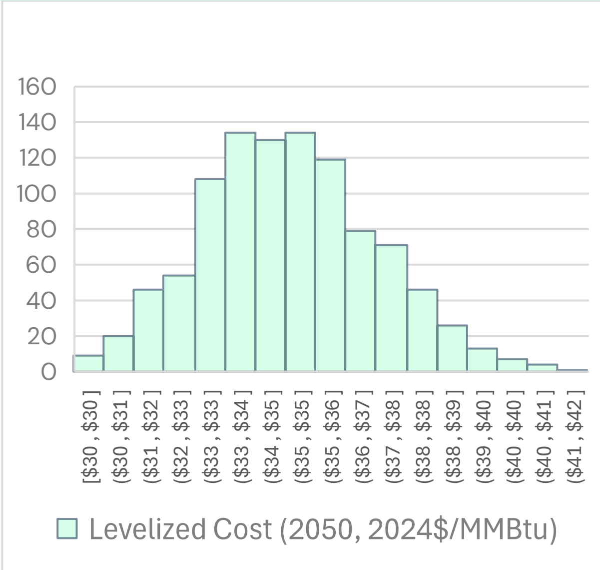
Year	Levelized Cost	Resource Potential	GHG Emissions	Levelized Cost	Resource Potential	GHG Emissions
Unit	$2024 per MMBtu	BBtu (1000 MMBtu) per year	CO_2e kg/ MMBtu	$2024 per MMBtu	BBtu (1000 MMBtu) per year	CO_2e kg/ MMBtu
	Green H_2 – Solar (NW)			**Green H_2 – Solar (National)**		
2025	$29.11	197	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

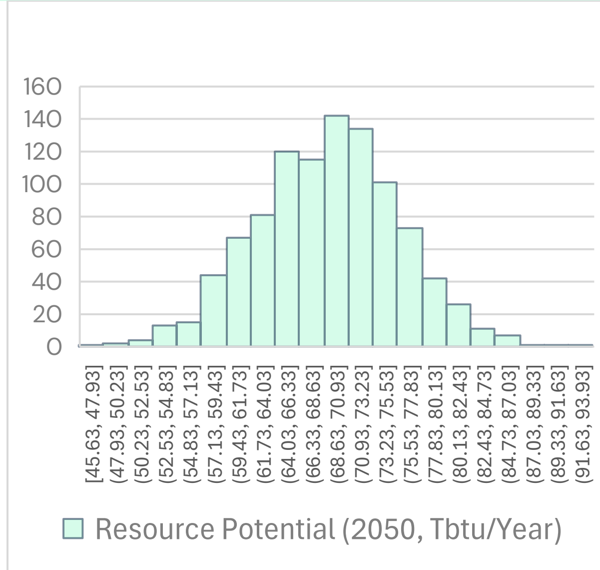
The impact of the Monte Carlo process on costs is illustrated in Exhibit 30. The histogram depicts the number of the 1,000 Monte Carlo cases (y-axis) that fall within various cost ranges/technical potential ranges (x-axis) for each type of green and pink hydrogen.[25]

[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

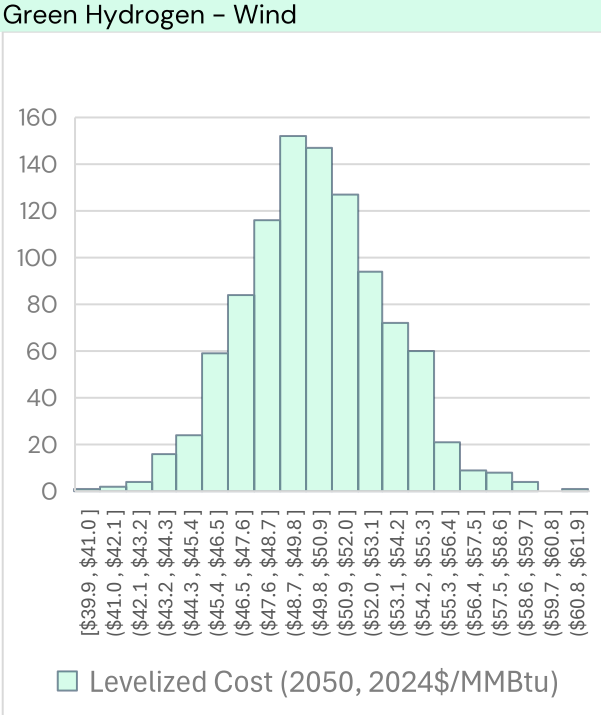


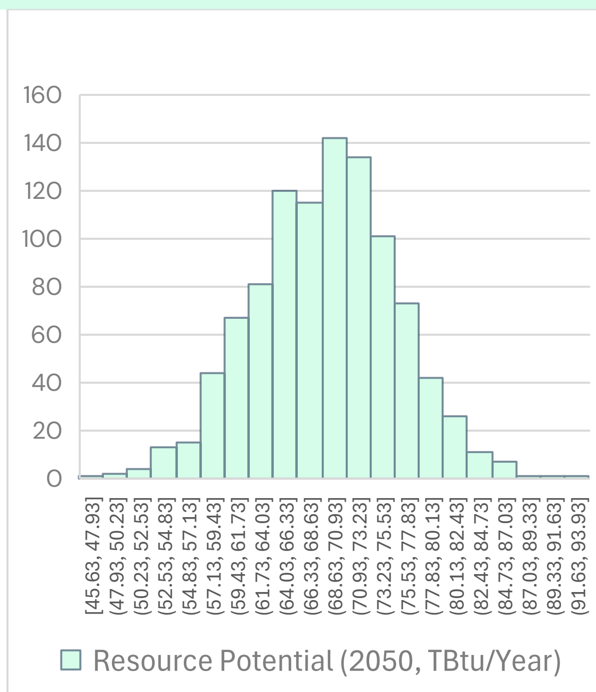


	Levelized Cost
Mean	$34.77
Max	$41.23
Min	$29.64
IQR	$2.78

	Resource Potential
Mean	69
Max	92
Min	46
IQR	9

Green Hydrogen – Wind

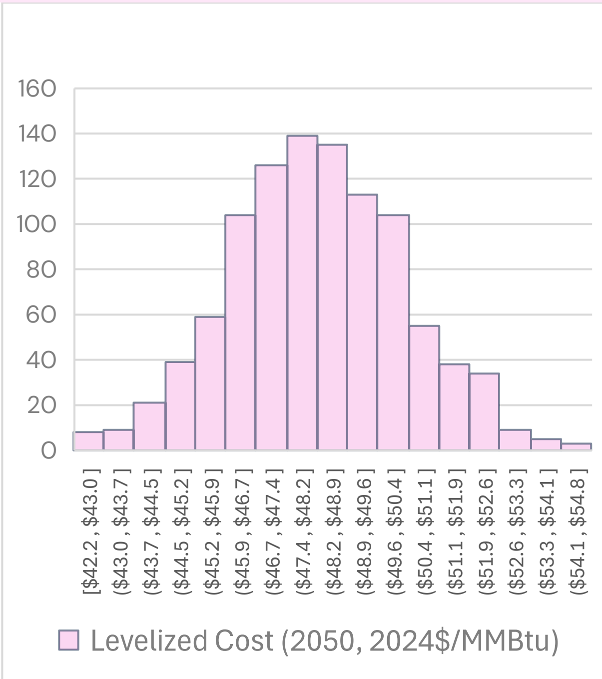


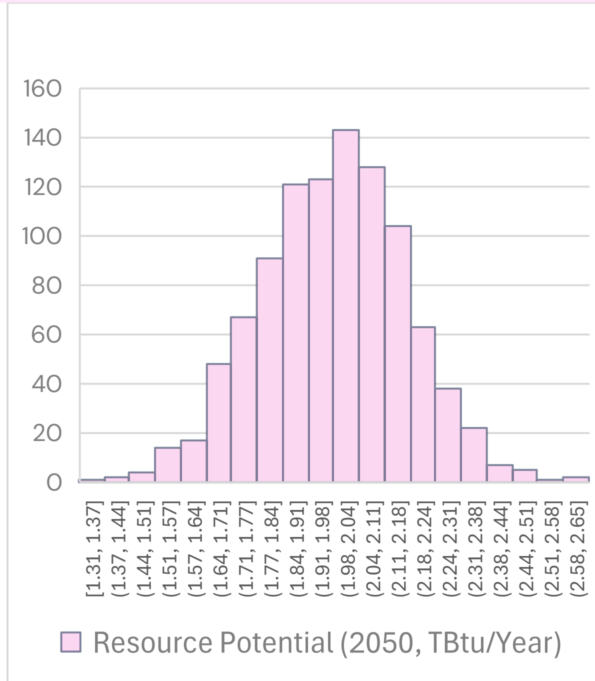


	Levelized Cost
Mean	$50.28
Max	$61.15
Min	$39.95
IQR	$4.02

	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

	Resourc e 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

Input	Value	Comments
RNG Share of Feedstock	5%	Optimized to reduce carbon intensity to receive IRA tax credits
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

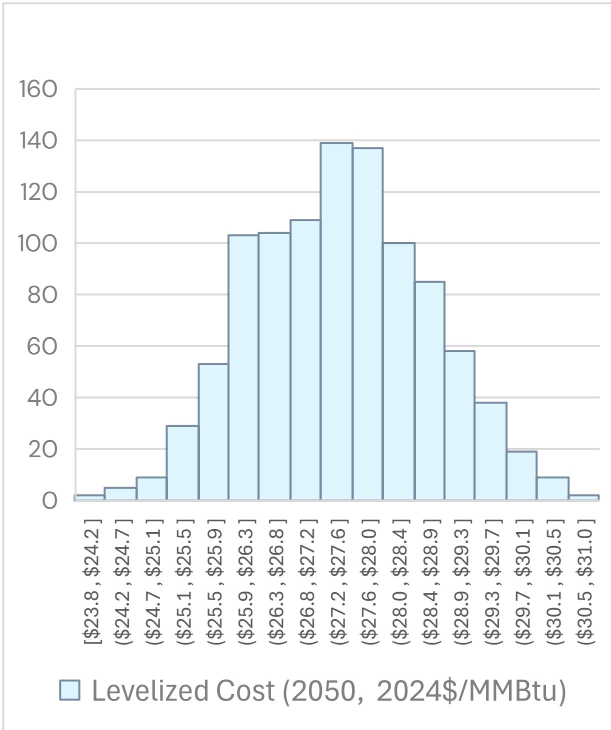
Exhibit 32 shows the hydrogen production results from natural gas and RNG used in an ATR facility for national and regional (OR and WA) basis and Exhibit 32 shows a summary of the range of regional and national results for 2050. ICF assumes the PTC for hydrogen production satisfies all requirements under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

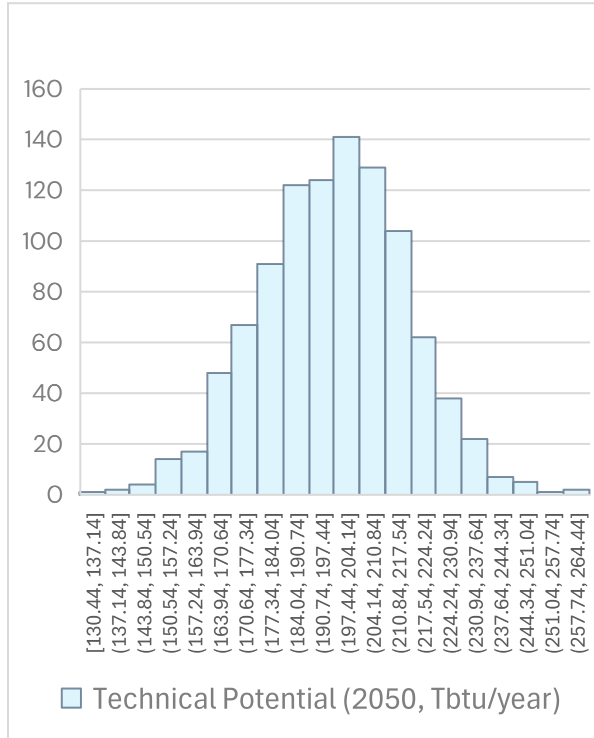
Exhibit 32. Summary of Results for Blue Hydrogen

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		

Input	Value	Comments
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
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

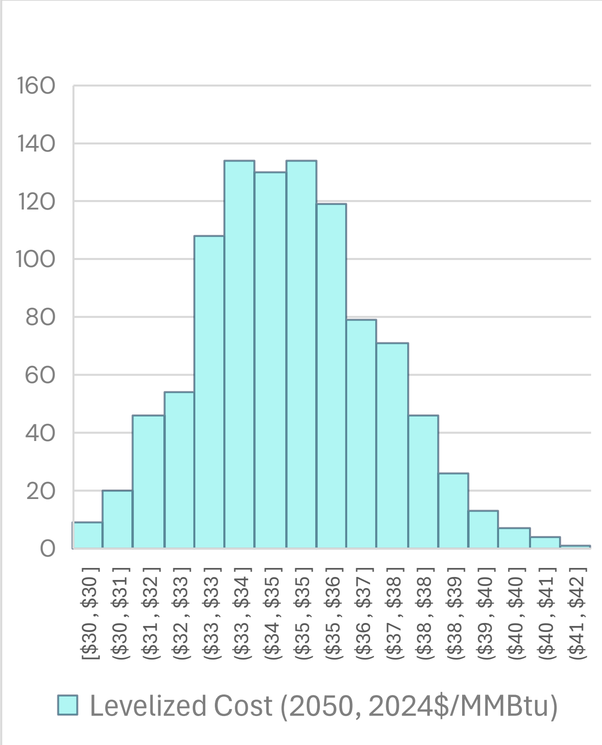
Exhibit 35 shows the turquoise results for national and regional (OR and WA) basis and Exhibit 35 shows a summary of the range of regional and national results for 2050. ICF assumes the PTC for both solar, wind and nuclear energy as well as the PTC for hydrogen production satisfies all requirements under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

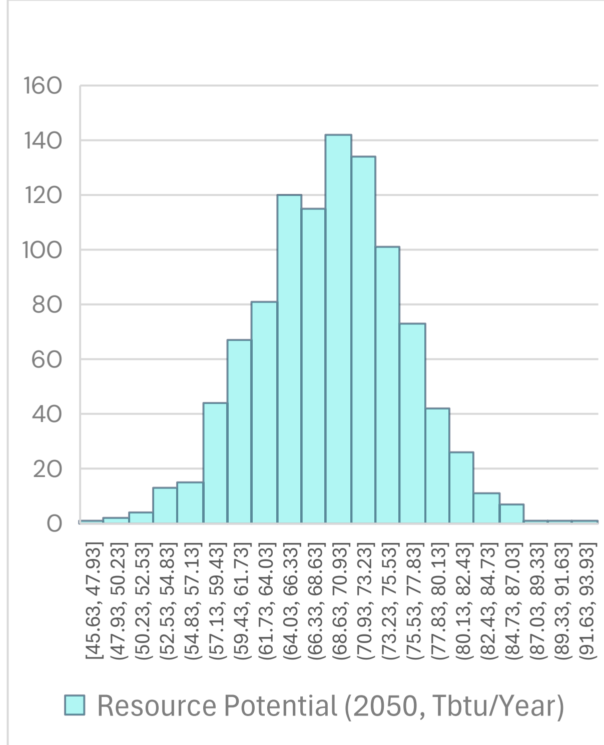
Exhibit 35. Summary of Results for Turquoise Hydrogen

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

[26] More information available online here.

at lower pressures and higher 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

Feedstock	Description
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

Feedstock for RNG	Potential Resources for Assessment
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

Component	Btu/lb, dry	MMBtu/ton, dry
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

Energy Crop	Btu/lb, dry	MMBtu/ton, dry
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)

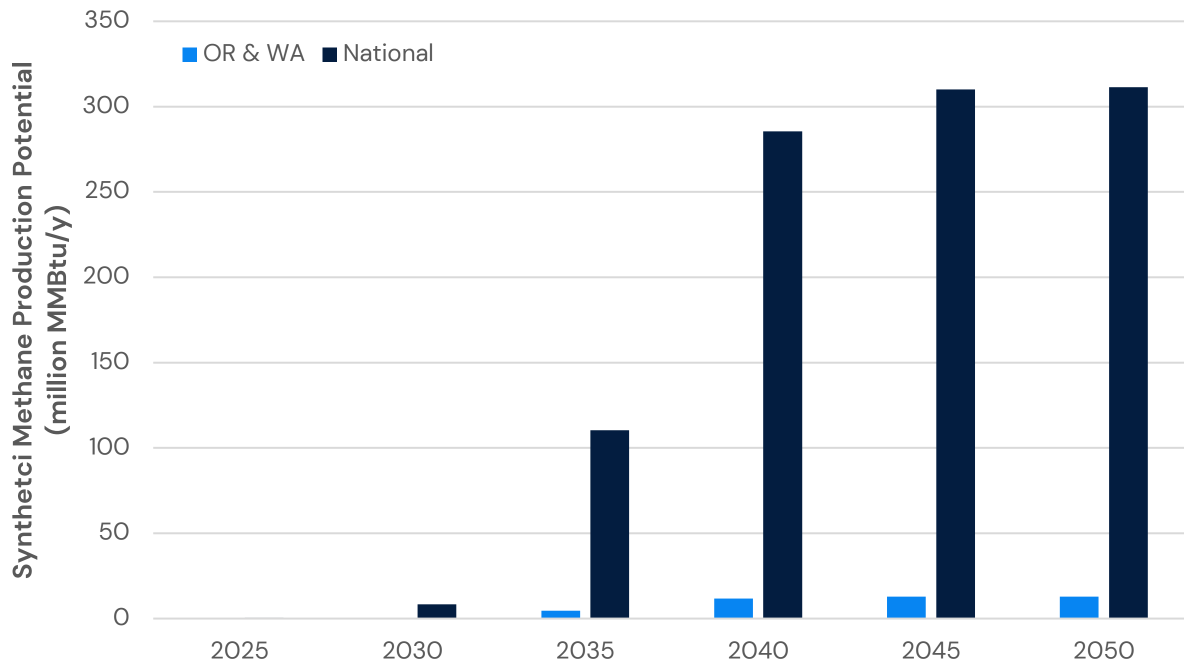


Exhibit 45. Synthetic Methane via P2G Resource Potential Projection (OR & WA, million MMBtu/y)

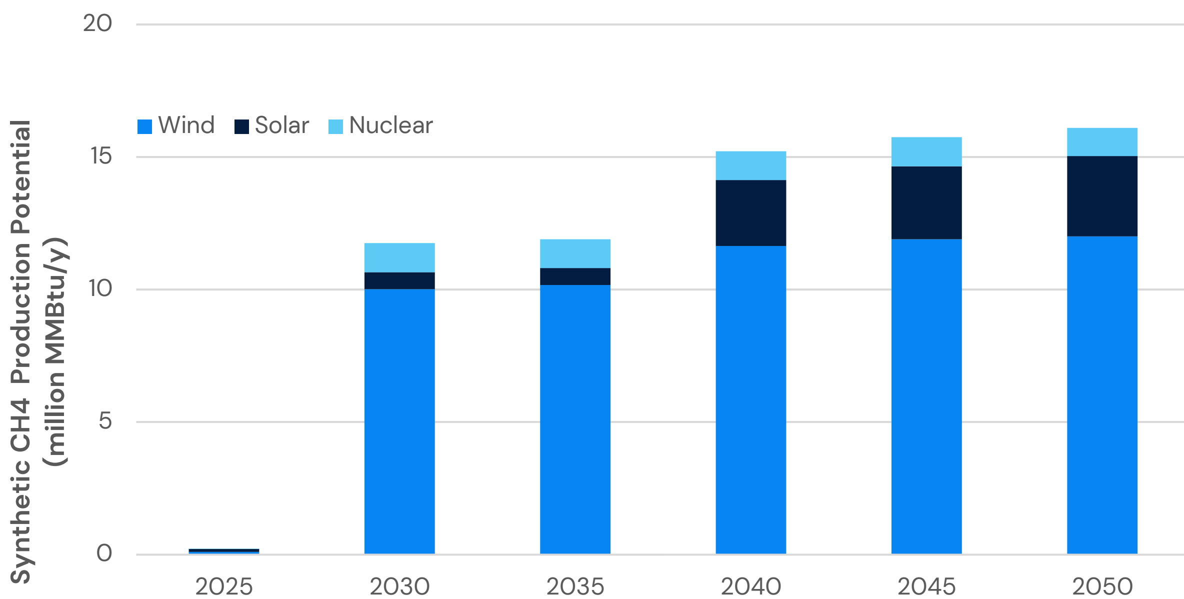
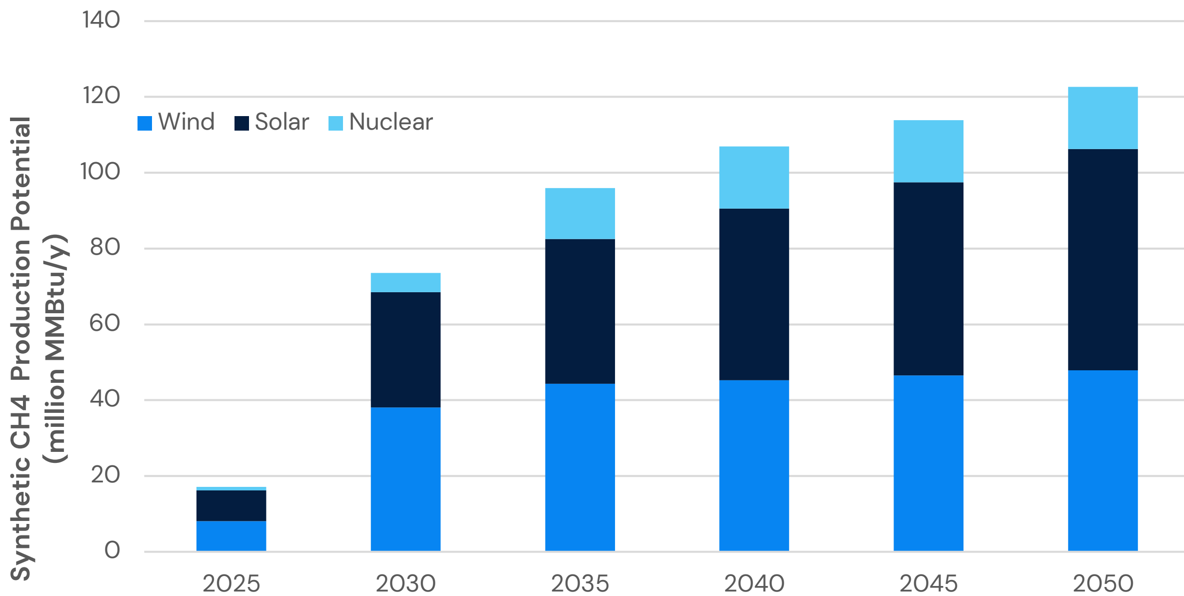


Exhibit 46. Synthetic Methane via P2G Resource Potential Projection (National, million MMBtu/y)



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.

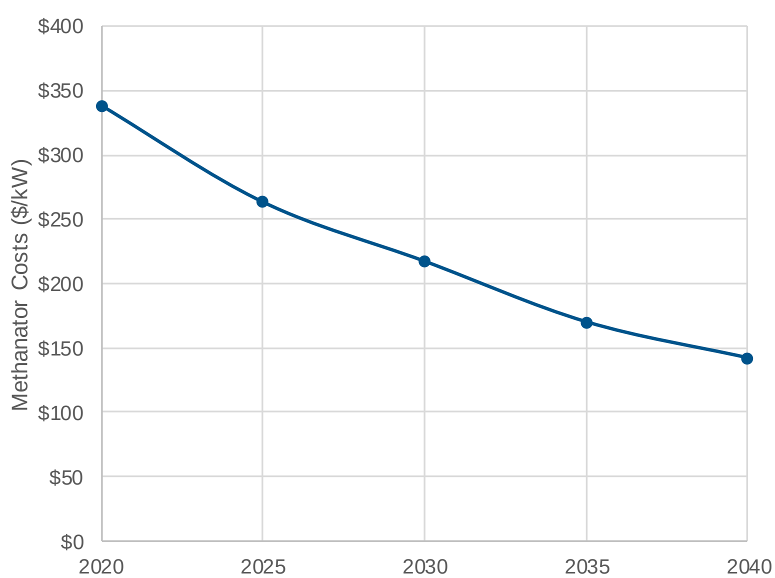
Exhibit 47. ICF Synthetic Methane Assumptions

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.

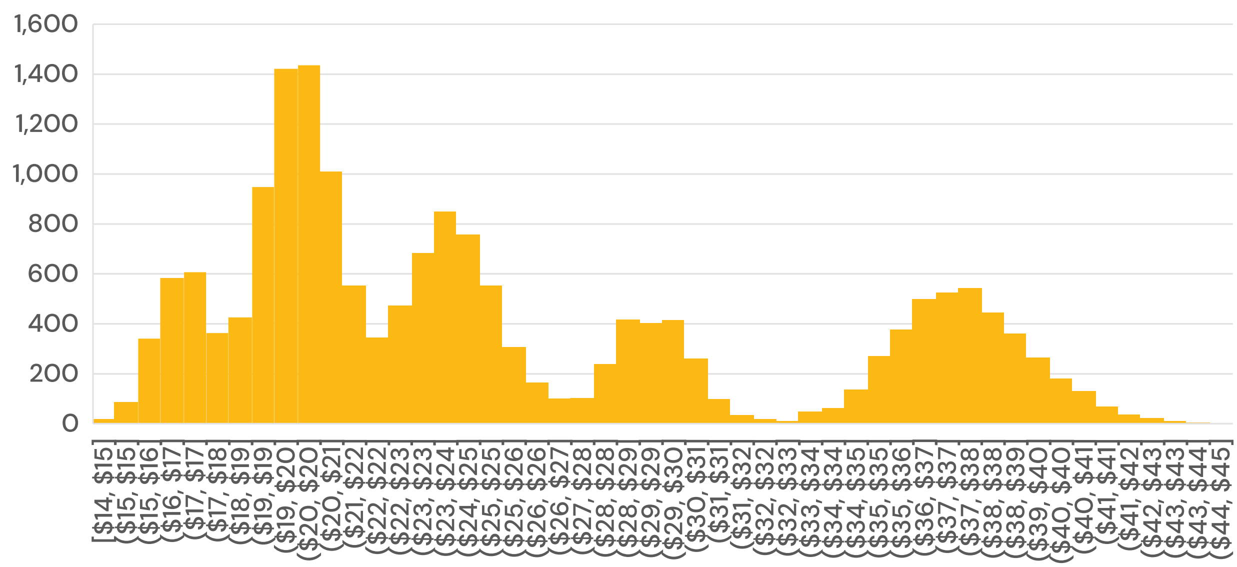
Exhibit 49. Synthetic CH4 from Biomass Levelized Cost Projection Base Case Results ($/MMBtu)

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)

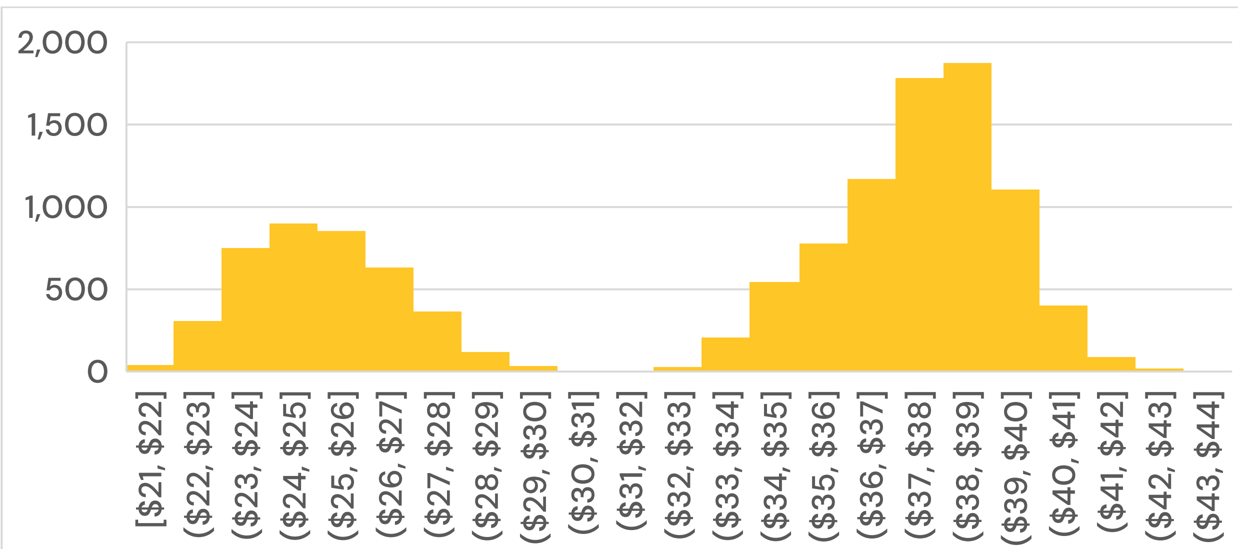
Electricity Source for P2G (NW)	2030	2050
Wind	$34-$46	$55-84
Solar	$29-$40	$44-61
Nuclear	$35-$42	$59-$77

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)

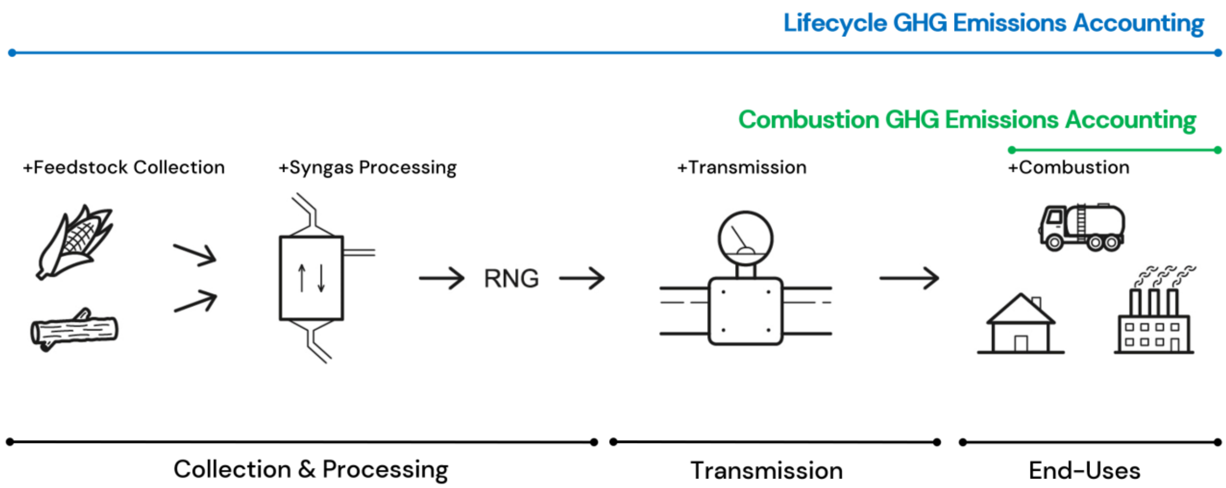


ICF found that the cost of CO_2 would be a marginal contributor to the overall cost of the system, and that it would be available at a low cost (e.g., less than $50 per ton).

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.

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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).

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).

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.

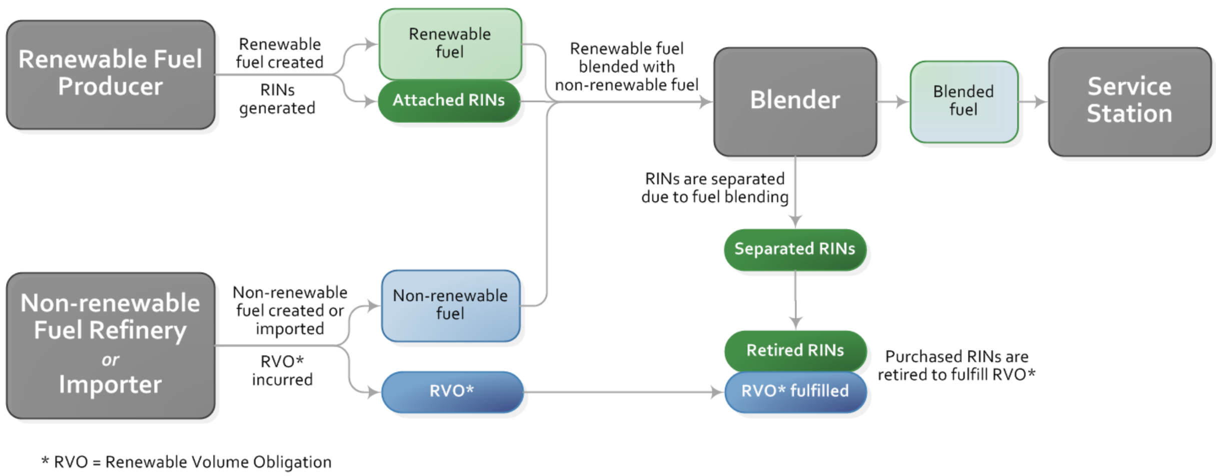
Overview of ICF Approach to RIN Forecasting

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

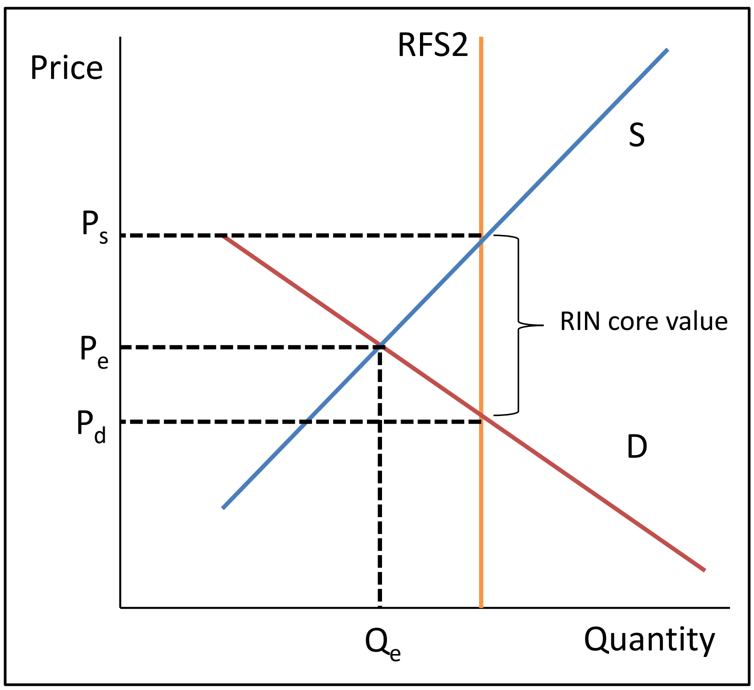
RIN Type	Description / Biofuel	Min GHG Reductions	RFS Qualifying Categories
D3	Cellulosic Biofuel	60% GHG savings	Cellulosic, Advanced or Renewable
D4	Biomass-Based Diesel	50% GHG savings	Biomass-Based Diesel, Advanced or Renewable Diesel
D5	Advanced Biofuel	50% GHG savings	Advanced or Renewable
D6	Renewable 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.

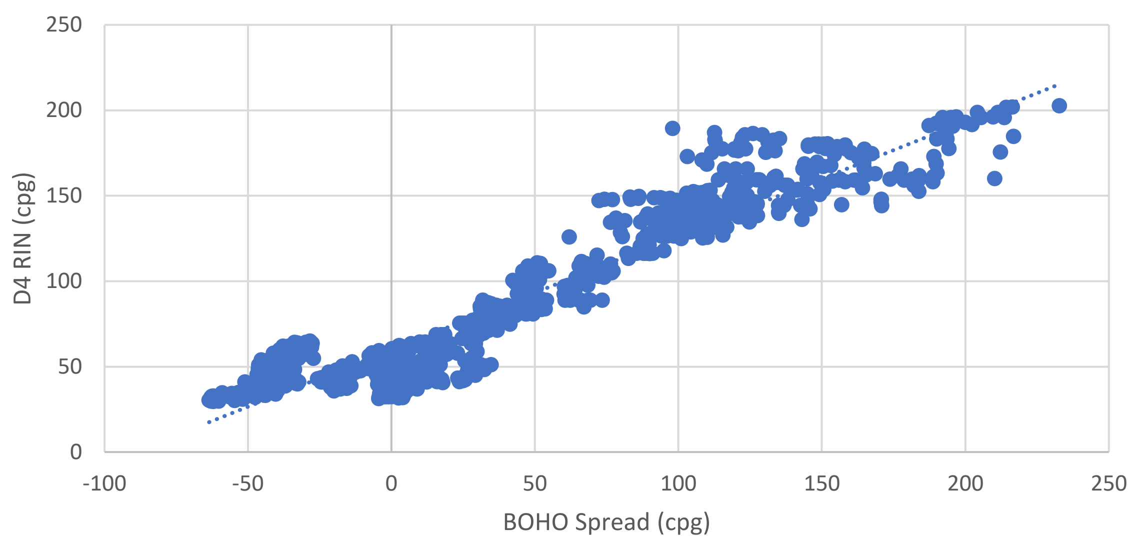
D6 RIN pricing. ICF models the D6 RIN price assuming the EPA sets the Renewable Fuels RVOs at 15 billion gallons. This volume is expected to remain well above the blend wall. We do not model increasing gasoline demand; rather, we model decreasing gasoline demand domestically due to increased efficiency (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)

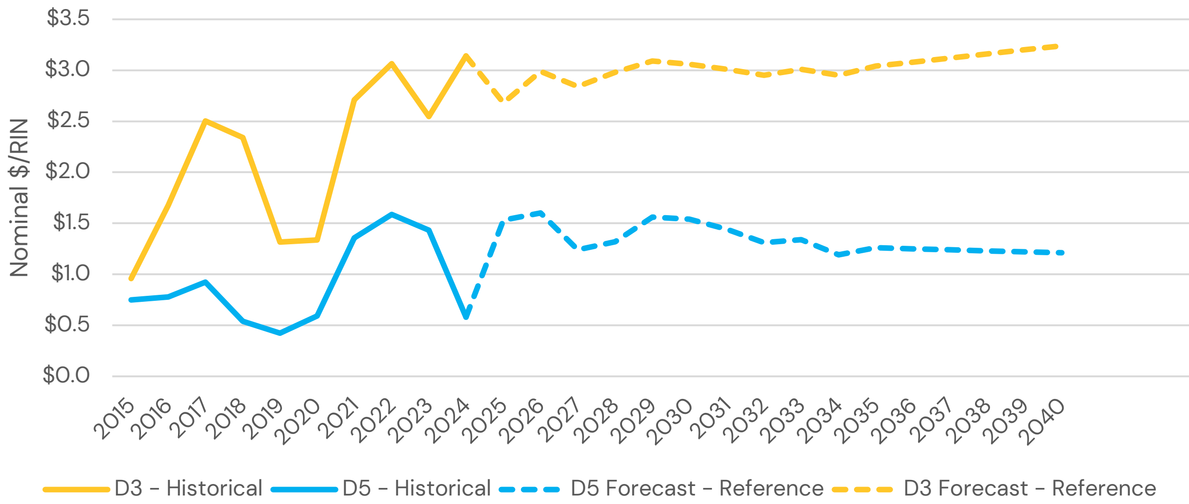
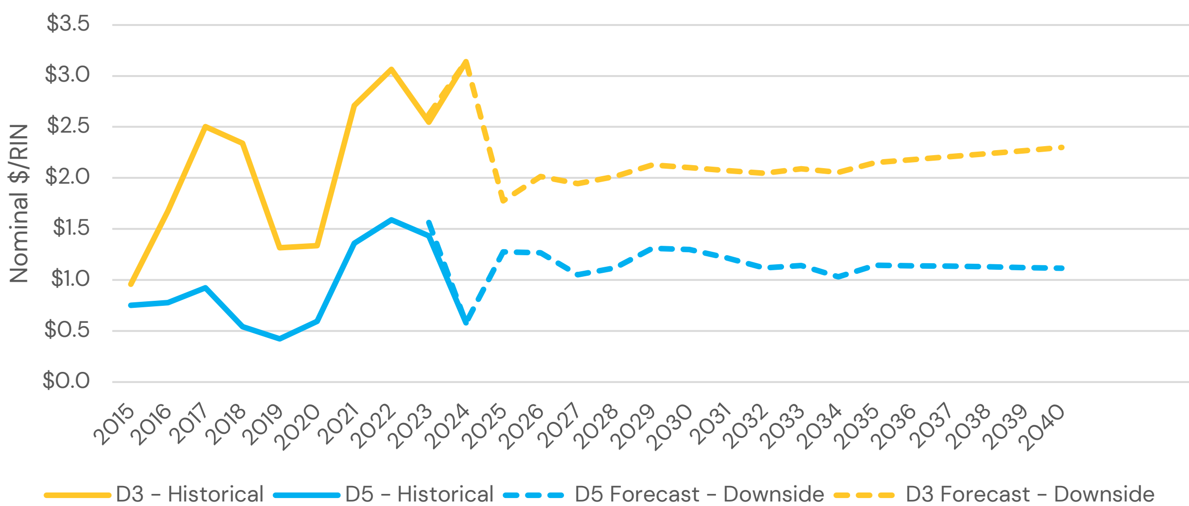


Exhibit 62. ICF's RIN Price Forecast, Downside Case (nominal dollars)



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.

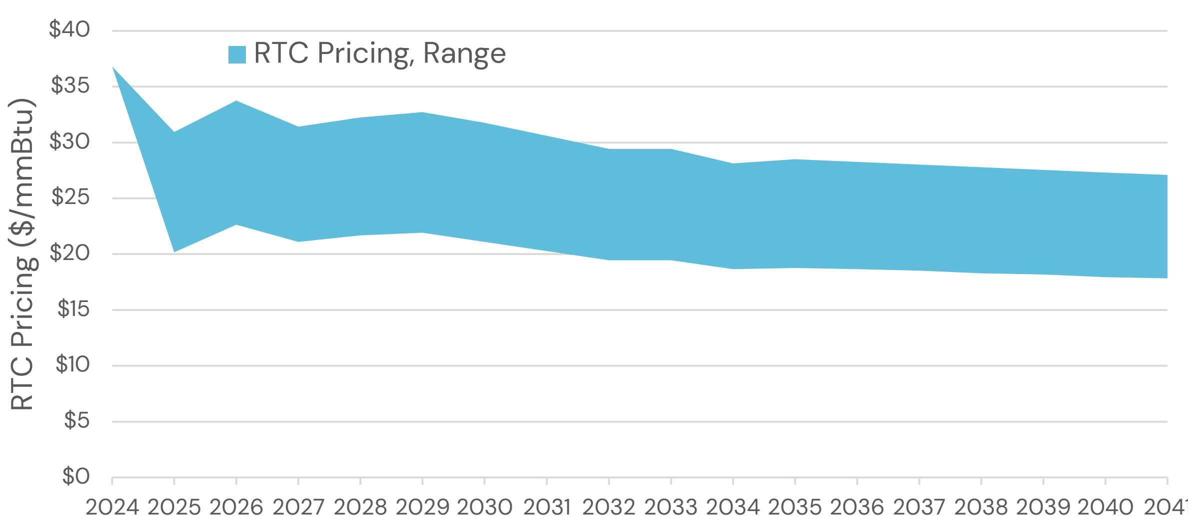
It is also possible a similar situation occurs in 2025. In the previous update ICF covered the gap between CNG dispensing demand and the 2025 RVOs. ICF's estimates suggest that to hit the 2025 RVO, CNG dispensing capacity would need to increase, implying an increase in the use of CNG as a transportation 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)



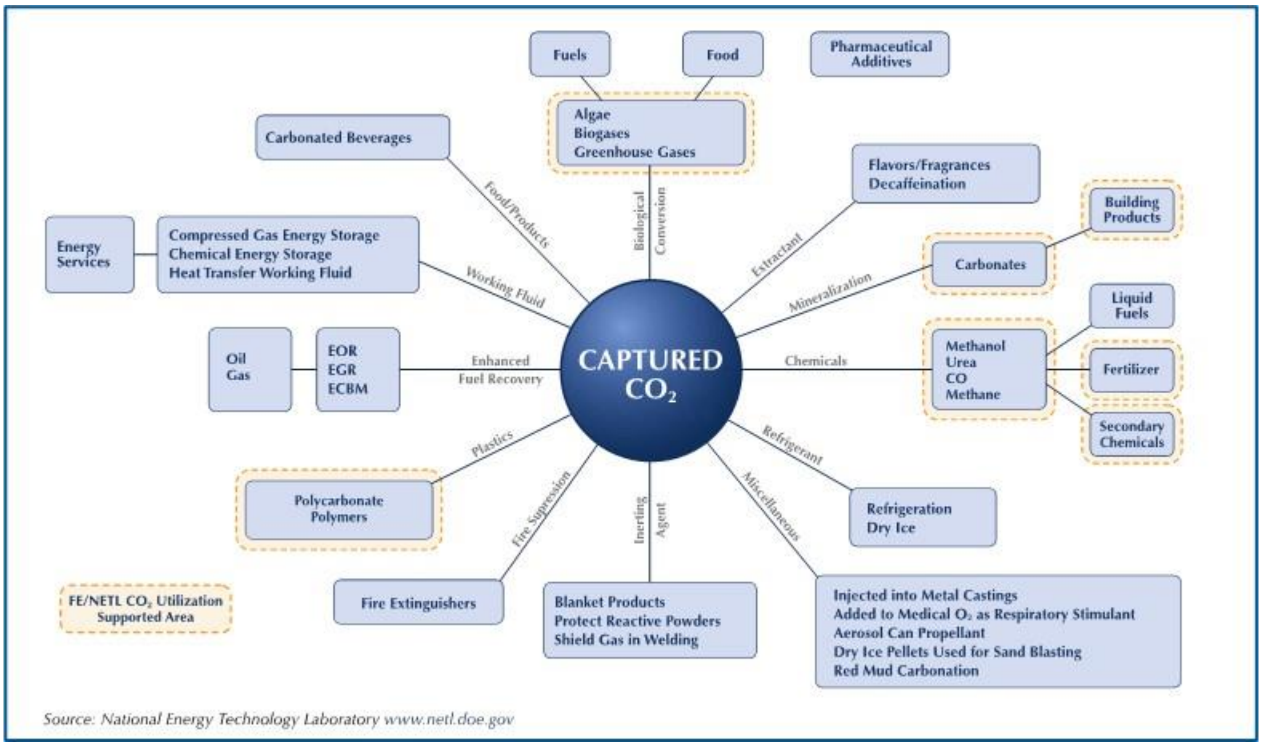
Carbon Capture, Use, and Storage

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

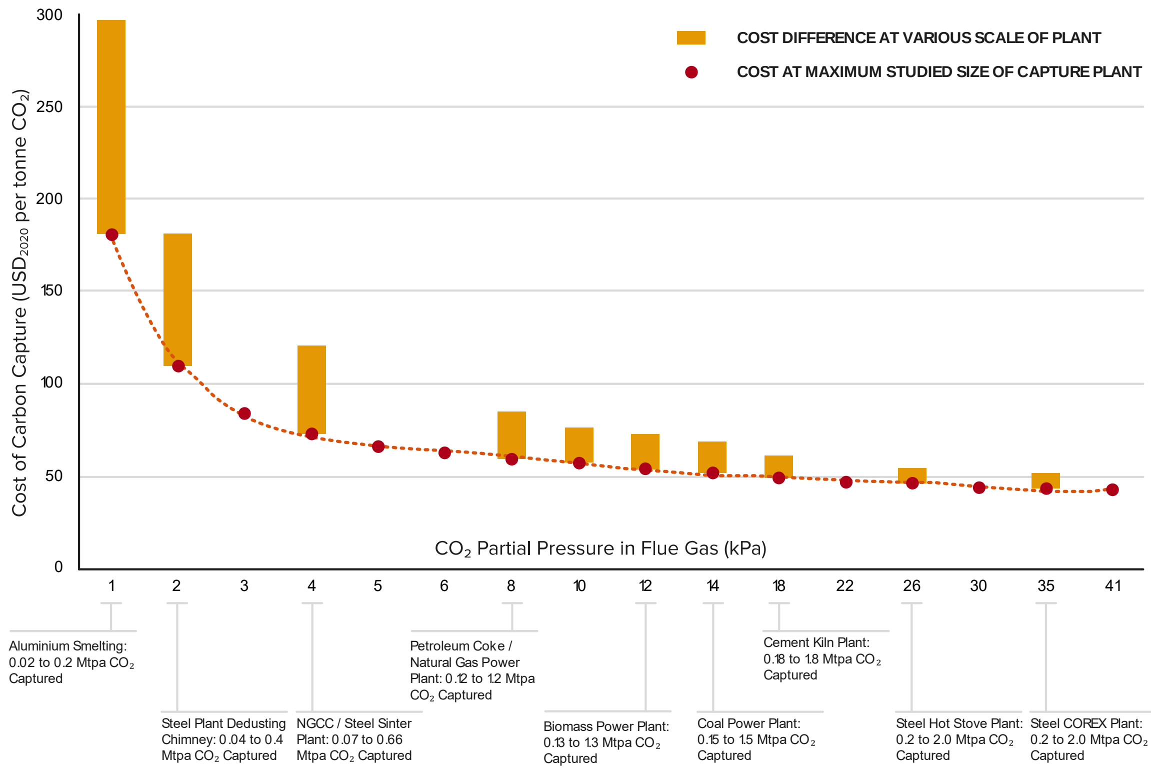
There are many technologies available to capture CO_2 from flue gas and process gas streams including several kinds of post-combustion capture (e.g., absorption by chemical solvents, adsorption by solid sorbents, membrane separation, cryogenic separation, and pressure swing adsorption). The major competitor 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 <u>in</u>flows (discounted at the operator's weighted average cost of capital) that exactly equals the net present value of cash <u>out</u>flows (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 <u>after</u> 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 <u>net</u> 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

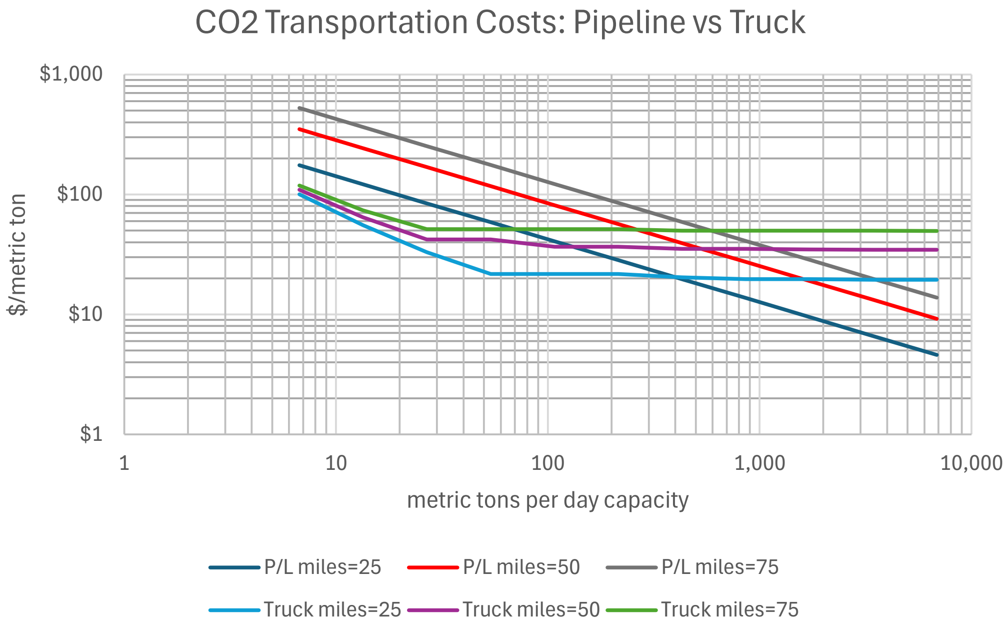
ICF's costs of pipeline transportation are based on standard engineering calculations for what diameter of pipeline is needed to transport a given volume of CO_2 and certain assumptions about how CO_2 volumes from individual power plants and other sources get aggregated into larger pipelines for long-distance, 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.

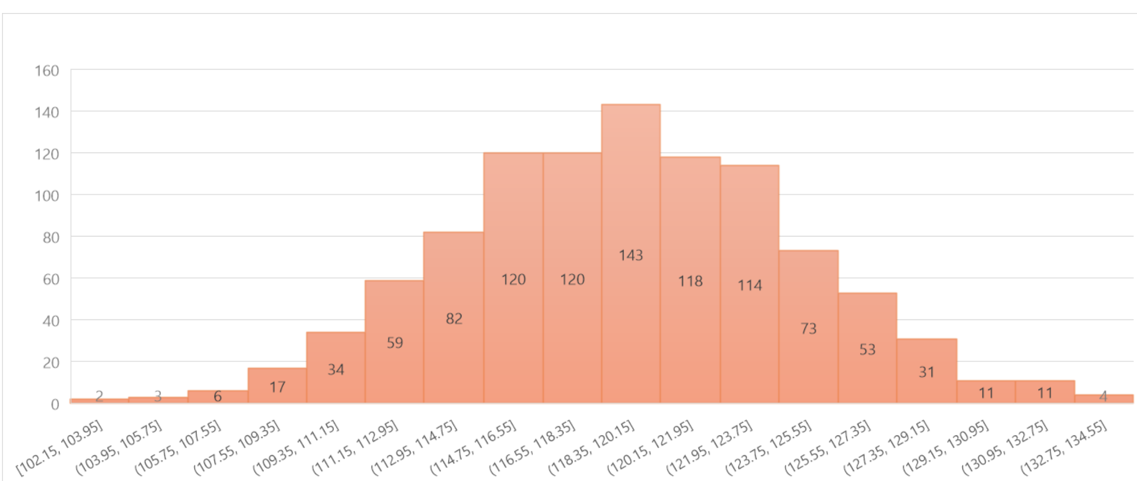
Exhibit 71. CCUS Cost for Base Case Assumptions (2050)

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%

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

2045	0%	13%	0%	4%	1%	82%
2050	0%	14%	0%	3%	1%	82%

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.

[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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About ICF

ICF (NASDAQ:ICFI) is a global consulting services company with approximately 9,000 full-time and part-time employees, but we are not your typical consultants. At ICF, business analysts and policy specialists work together with digital strategists, data scientists and creatives. We combine unmatched industry expertise with cutting-edge engagement capabilities to help organizations solve their most complex challenges. Since 1969, public and private sector clients have worked with ICF to navigate change and shape the future.

Weighted Average Cost of Capital

State	Discount Factor
Idaho	6.67%
Oregon	6.71%
Washington	6.51%

ALTERNATIVE FUELS AVAILABLE SUPPLY (THOUSANDS OF DEKATHERMS)

Expected

Year	Blue Hydrogen 1	Green H2-Wind+Electrolysis 1	GreenH2-Solar+Electrolysis 1	Microwave Pyrolysis 1
2030	2,667	3,734	3,734	10
2031	3,544	4,957	4,957	14
2032	4,421	6,181	6,181	18
2033	5,299	7,404	7,404	23
2034	6,176	8,628	8,628	27
2035	7,053	9,851	9,851	31
2036	7,313	9,672	9,672	194
2037	7,572	9,493	9,493	356
2038	7,832	9,314	9,314	519
2039	8,091	9,136	9,136	681
2040	8,350	10,745	10,745	844
2041	8,447	10,777	10,777	844
2042	8,544	10,810	10,810	845
2043	8,641	10,842	10,842	845
2044	8,738	10,875	10,875	845
2045	8,835	10,907	10,907	846

Year	Animal Manure 4	Animal Manure 5	Landfill Gas 1	Landfill Gas 2	Landfill Gas 3	Landfill Gas 4	Landfill Gas 5
2030	123	185	197	197	395	493	691
2031	158	237	217	217	434	543	760
2032	193	290	236	236	473	591	827
2033	225	338	255	255	510	637	892
2034	251	377	272	272	545	681	953
2035	272	407	289	289	577	722	1,010
2036	286	429	303	303	607	758	1,062
2037	296	445	317	317	633	792	1,108
2038	303	455	329	329	657	821	1,149
2039	308	462	339	339	677	847	1,186
2040	311	467	348	348	695	869	1,217
2041	313	469	356	356	711	888	1,244
2042	314	471	362	362	724	905	1,267
2043	315	473	368	368	735	919	1,286
2044	315	473	372	372	744	930	1,302
2045	316	474	376	376	752	940	1,316

Year	Wastewater 1	Wastewater 2	Wastewater 3	Wastewater 4	Wastewater 5
2030	7	7	7	36	14
2031	9	9	9	44	18
2032	10	10	10	52	20
2033	12	12	12	59	23
2034	13	13	13	65	26
2035	14	14	14	71	28
2036	15	15	15	75	30
2037	16	16	16	78	31
2038	16	16	16	81	32
2039	16	16	16	83	33
2040	17	17	17	84	34
2041	17	17	17	85	34
2042	17	17	17	86	34
2043	17	17	17	86	35
2044	17	17	17	87	35
2045	18	18	18	87	35

Year	Food Waste 3	Biomass 1	Biomass 2	Biomass 3	GreenH2-BiogenicCO2 1
2030	42	58	77	58	184
2031	54	103	137	103	253
2032	67	180	240	180	319
2033	77	307	409	307	386
2034	87	501	668	501	401
2035	93	767	1,022	767	400
2036	99	1,082	1,442	1,082	459
2037	102	1,396	1,862	1,396	640
2038	104	1,662	2,216	1,662	762
2039	106	1,856	2,475	1,856	962
2040	107	1,983	2,644	1,983	1,295
2041	108	2,060	2,747	2,060	1,397
2042	108	2,105	2,807	2,105	1,406
2043	108	2,131	2,841	2,131	1,406
2044	109	2,145	2,860	2,145	1,406
2045	109	2,153	2,871	2,153	1,407

Low

Year	Blue Hydrogen 1	Green H2-Wind+Electrolysis 1	GreenH2-Solar+Electrolysis 1	Microwave Pyrolysis 1
2030	2,264	3,170	3,170	8
2031	2,831	3,960	3,960	11

2032	3,398	4,751	4,751	14
2033	3,965	5,541	5,541	17
2034	4,532	6,331	6,331	20
2035	5,099	7,121	7,121	23
2036	5,076	7,263	7,263	119
2037	5,053	7,404	7,404	215
2038	5,029	7,546	7,546	311
2039	5,006	7,688	7,688	407
2040	4,983	6,411	6,411	504
2041	4,817	6,155	6,155	483
2042	4,652	5,899	5,899	461
2043	4,486	5,643	5,643	440
2044	4,321	5,386	5,386	419
2045	4,155	5,130	5,130	398

Year	Animal Manure 4	Animal Manure 5	Landfill Gas 1	Landfill Gas 2	Landfill Gas 3	Landfill Gas 4	Landfill Gas 5
2030	105	157	168	168	335	419	587
2031	127	191	177	177	354	442	619
2032	150	224	186	186	372	465	651
2033	169	254	194	194	389	486	680
2034	185	277	202	202	404	505	707
2035	196	295	209	209	417	522	730
2036	199	298	210	210	421	526	736
2037	198	297	211	211	422	528	739
2038	195	293	211	211	422	527	738
2039	191	286	210	210	419	524	733
2040	186	279	208	208	415	519	726
2041	179	268	203	203	405	506	709
2042	172	257	197	197	393	492	689
2043	164	246	191	191	381	476	667
2044	156	234	184	184	368	460	643
2045	149	223	177	177	354	442	619

Year	Wastewater 1	Wastewater 2	Wastewater 3	Wastewater 4	Wastewater 5
2030	6	6	6	31	12
2031	7	7	7	35	14
2032	8	8	8	40	16
2033	9	9	9	45	18
2034	9	9	9	48	19
2035	10	10	10	51	20
2036	10	10	10	52	21

2037	11	11	11	52	21
2038	10	10	10	52	21
2039	10	10	10	51	20
2040	10	10	10	50	20
2041	10	10	10	49	19
2042	9	9	9	47	19
2043	9	9	9	45	18
2044	8	8	8	43	17
2045	8	8	8	41	16

Year	Food Waste 3	Biomass 1	Biomass 2	Biomass 3	GreenH2-BiogenicCO2 1
2030	36	49	65	49	157
2031	44	77	103	77	204
2032	52	132	176	132	247
2033	58	224	298	224	291
2034	64	363	484	363	295
2035	68	554	739	554	289
2036	68	728	971	728	306
2037	68	898	1,197	898	408
2038	67	1,035	1,380	1,035	472
2039	66	1,128	1,504	1,128	583
2040	64	1,183	1,578	1,183	773
2041	62	1,174	1,565	1,174	796
2042	59	1,145	1,526	1,145	764
2043	57	1,105	1,473	1,105	729
2044	54	1,060	1,413	1,060	694
2045	51	1,013	1,350	1,013	662

COMPLIANCE MECHANISMS COST PER MTCO2e (Nominal $)

Expected

Year	Allowance	CCI	Animal Manure 4 (RTC)	Animal Manure 5 (RTC)	Food Waste 3 (RTC)
2026	$44	$141	$1,428	$1,225	$1,496
2027	$49	$144	$1,459	$1,251	$1,529
2028	$55	$148	$1,493	$1,280	$1,565
2029	$62	$152	$1,531	$1,312	$1,605
2030	$70	$157	$1,571	$1,346	$1,646
2031	$79	$162	$1,613	$1,382	$1,689
2032	$89	$167	$1,657	$1,420	$1,734
2033	$91	$172	$1,703	$1,460	$1,781
2034	$93	$177	$1,749	$1,499	$1,828
2035	$95	$182	$1,794	$1,537	$1,874
2036	$97	$187	$1,839	$1,575	$1,920
2037	$99	$193	$1,885	$1,614	$1,968
2038	$101	$198	$1,933	$1,656	$2,017
2039	$103	$204	$1,981	$1,696	$2,067
2040	$106	$210	$2,032	$1,740	$2,119
2041	$108	$216	$2,084	$1,785	$2,173
2042	$110	$222	$2,136	$1,829	$2,227
2043	$113	$228	$2,189	$1,874	$2,281
2044	$115	$234	$2,244	$1,920	$2,338
2045	$117	$241	$2,301	$1,968	$2,397

Year	Landfill Gas 1 (RTC)	Landfill Gas 2 (RTC)	Landfill Gas 3 (RTC)	Landfill Gas 4 (RTC)	Landfill Gas 5 (RTC)
2026	$1,003	$494	$347	$275	$230
2027	$1,029	$505	$354	$280	$233
2028	$1,057	$517	$362	$286	$238
2029	$1,088	$531	$371	$293	$244
2030	$1,121	$545	$381	$301	$250
2031	$1,155	$561	$392	$309	$257
2032	$1,191	$577	$403	$318	$264
2033	$1,228	$595	$416	$328	$272
2034	$1,266	$613	$428	$337	$280
2035	$1,303	$629	$439	$346	$287
2036	$1,342	$647	$451	$355	$295
2037	$1,381	$664	$463	$364	$303
2038	$1,422	$683	$476	$375	$311
2039	$1,464	$702	$489	$385	$319

2040	$1,508	$722	$502	$395	$328
2041	$1,553	$742	$516	$406	$337
2042	$1,599	$762	$530	$416	$345
2043	$1,646	$783	$543	$427	$354
2044	$1,695	$804	$558	$438	$363
2045	$1,745	$826	$572	$449	$371

Year	Wastewater 1 (RTC)	Wastewater 2 (RTC)	Wastewater 3 (RTC)	Wastewater 4 (RTC)	Wastewater 5 (RTC)
2026	$1,388	$1,229	$502	$355	$269
2027	$1,426	$1,260	$511	$360	$271
2028	$1,468	$1,297	$523	$367	$276
2029	$1,514	$1,337	$537	$376	$282
2030	$1,563	$1,380	$553	$387	$290
2031	$1,616	$1,425	$571	$399	$299
2032	$1,670	$1,473	$589	$412	$309
2033	$1,729	$1,524	$610	$428	$321
2034	$1,787	$1,575	$630	$442	$332
2035	$1,844	$1,625	$648	$455	$342
2036	$1,902	$1,675	$666	$467	$351
2037	$1,963	$1,728	$686	$480	$360
2038	$2,027	$1,783	$707	$495	$372
2039	$2,089	$1,838	$726	$507	$381
2040	$2,158	$1,897	$748	$523	$393
2041	$2,227	$1,958	$771	$539	$404
2042	$2,298	$2,018	$792	$552	$414
2043	$2,370	$2,080	$812	$566	$423
2044	$2,444	$2,145	$834	$580	$433
2045	$2,522	$2,212	$857	$595	$443

Year	Under 25MMBtu/hr-Industrial	25-50MMBtu/hr-Industrial	50-100MMBtu/hr-Industrial	100-200MMBtu/hr-Industrial
2026	N/A	N/A	N/A	N/A
2027	N/A	N/A	N/A	N/A
2028	N/A	N/A	N/A	N/A
2029	N/A	N/A	N/A	N/A
2030	$523	$286	$274	$171
2031	$537	$294	$282	$177
2032	$551	$303	$290	$182
2033	$565	$311	$298	$188
2034	$579	$320	$306	$193

2035	$593	$328	$315	$199
2036	$624	$353	$339	$221
2037	$655	$378	$364	$243
2038	$687	$404	$391	$267
2039	$720	$431	$418	$291
2040	$754	$460	$446	$316
2041	$772	$470	$456	$324
2042	$789	$481	$467	$332
2043	$807	$493	$478	$340
2044	$825	$504	$490	$348
2045	$844	$516	$502	$356

Year	200-400MMBtu/hr-Industrial	800-1600MMBtu/hr-Industrial	Direct Air Capture-DAC
2026	N/A	N/A	N/A
2027	N/A	N/A	N/A
2028	N/A	N/A	N/A
2029	N/A	N/A	N/A
2030	$126	$72	$709
2031	$131	$75	$715
2032	$135	$79	$721
2033	$139	$82	$727
2034	$144	$85	$733
2035	$148	$89	$738
2036	$169	$108	$759
2037	$190	$128	$780
2038	$212	$149	$802
2039	$235	$171	$824
2040	$259	$194	$847
2041	$265	$199	$855
2042	$272	$204	$863
2043	$278	$209	$871
2044	$285	$215	$879
2045	$292	$220	$887

High

Year	Allowance	Animal Manure 4 (RTC)	Animal Manure 5 (RTC)	Food Waste 3 (RTC)
2026	$56	$1,606	$1,375	$1,688
2027	$64	$1,641	$1,405	$1,724
2028	$72	$1,680	$1,438	$1,765
2029	$81	$1,722	$1,474	$1,809
2030	$93	$1,768	$1,513	$1,855

2031	$101	$1,815	$1,553	$1,904
2032	$116	$1,865	$1,596	$1,954
2033	$118	$1,917	$1,641	$2,007
2034	$119	$1,969	$1,685	$2,060
2035	$125	$2,019	$1,728	$2,111
2036	$127	$2,069	$1,771	$2,163
2037	$134	$2,121	$1,815	$2,217
2038	$137	$2,176	$1,862	$2,272
2039	$141	$2,229	$1,907	$2,328
2040	$144	$2,287	$1,956	$2,387
2041	$148	$2,346	$2,006	$2,447
2042	$149	$2,404	$2,056	$2,508
2043	$155	$2,464	$2,106	$2,570
2044	$162	$2,526	$2,159	$2,634
2045	$166	$2,589	$2,212	$2,700

Year	Landfill Gas 1 (RTC)	Landfill Gas 2 (RTC)	Landfill Gas 3 (RTC)	Landfill Gas 4 (RTC)	Landfill Gas 5 (RTC)
2026	$1,134	$560	$397	$316	$259
2027	$1,163	$573	$405	$321	$263
2028	$1,195	$587	$415	$327	$269
2029	$1,230	$602	$425	$335	$275
2030	$1,266	$619	$437	$344	$283
2031	$1,305	$637	$449	$353	$291
2032	$1,345	$655	$461	$363	$299
2033	$1,388	$675	$475	$374	$309
2034	$1,430	$695	$489	$385	$318
2035	$1,472	$714	$501	$395	$327
2036	$1,515	$734	$515	$405	$335
2037	$1,560	$754	$529	$416	$344
2038	$1,607	$775	$544	$428	$354
2039	$1,654	$797	$559	$439	$364
2040	$1,703	$819	$574	$451	$374
2041	$1,754	$842	$590	$463	$384
2042	$1,806	$865	$605	$475	$393
2043	$1,860	$888	$621	$487	$403
2044	$1,915	$913	$637	$499	$412
2045	$1,972	$937	$654	$512	$422

Year	Wastewater 1 (RTC)	Wastewater 2 (RTC)	Wastewater 3 (RTC)	Wastewater 4 (RTC)	Wastewater 5 (RTC)

2026	$1,575	$1,393	$584	$407	$306
2027	$1,617	$1,429	$594	$412	$308
2028	$1,664	$1,471	$608	$419	$313
2029	$1,716	$1,516	$625	$430	$321
2030	$1,772	$1,565	$643	$442	$330
2031	$1,831	$1,617	$664	$455	$340
2032	$1,893	$1,671	$685	$470	$351
2033	$1,960	$1,729	$709	$487	$365
2034	$2,026	$1,787	$732	$503	$377
2035	$2,091	$1,843	$754	$517	$388
2036	$2,156	$1,900	$775	$531	$398
2037	$2,225	$1,960	$797	$546	$410
2038	$2,297	$2,023	$822	$563	$423
2039	$2,368	$2,084	$843	$577	$433
2040	$2,445	$2,151	$869	$595	$447
2041	$2,525	$2,220	$895	$613	$460
2042	$2,604	$2,289	$920	$628	$471
2043	$2,686	$2,359	$944	$644	$481
2044	$2,770	$2,432	$969	$660	$492
2045	$2,859	$2,508	$996	$676	$504

Low

Year	Animal Manure 4 (RTC)	Animal Manure 5 (RTC)	Food Waste 3 (RTC)
2026	$1,242	$1,066	$1,301
2027	$1,269	$1,089	$1,329
2028	$1,299	$1,114	$1,361
2029	$1,332	$1,142	$1,395
2030	$1,367	$1,172	$1,430
2031	$1,404	$1,203	$1,468
2032	$1,441	$1,235	$1,507
2033	$1,482	$1,270	$1,548
2034	$1,521	$1,304	$1,589
2035	$1,560	$1,337	$1,629
2036	$1,599	$1,370	$1,669
2037	$1,639	$1,405	$1,710
2038	$1,682	$1,441	$1,752
2039	$1,723	$1,476	$1,795
2040	$1,768	$1,515	$1,840
2041	$1,813	$1,553	$1,887
2042	$1,858	$1,592	$1,934
2043	$1,904	$1,630	$1,982
2044	$1,952	$1,671	$2,031

2045	$2,001	$1,712	$2,082

Year	Landfill Gas 1 (RTC)	Landfill Gas 2 (RTC)	Landfill Gas 3 (RTC)	Landfill Gas 4 (RTC)	Landfill Gas 5 (RTC)
2026	$866	$423	$297	$236	$194
2027	$888	$433	$303	$240	$198
2028	$913	$443	$309	$246	$203
2029	$939	$455	$317	$252	$208
2030	$967	$468	$326	$258	$213
2031	$996	$482	$335	$266	$219
2032	$1,027	$496	$345	$273	$226
2033	$1,059	$511	$356	$281	$233
2034	$1,092	$526	$367	$290	$240
2035	$1,124	$541	$376	$297	$246
2036	$1,157	$555	$386	$305	$252
2037	$1,191	$571	$397	$313	$259
2038	$1,226	$587	$408	$322	$266
2039	$1,262	$603	$419	$330	$273
2040	$1,300	$620	$431	$339	$280
2041	$1,339	$638	$443	$348	$288
2042	$1,379	$655	$455	$357	$295
2043	$1,420	$673	$466	$366	$302
2044	$1,462	$692	$479	$375	$309
2045	$1,505	$711	$491	$384	$317

Year	Wastewater 1 (RTC)	Wastewater 2 (RTC)	Wastewater 3 (RTC)	Wastewater 4 (RTC)	Wastewater 5 (RTC)
2026	$1,194	$1,061	$430	$302	$228
2027	$1,227	$1,088	$439	$305	$231
2028	$1,263	$1,120	$449	$311	$235
2029	$1,303	$1,154	$462	$319	$240
2030	$1,346	$1,192	$476	$328	$248
2031	$1,391	$1,231	$491	$339	$255
2032	$1,438	$1,272	$507	$350	$264
2033	$1,488	$1,316	$525	$363	$274
2034	$1,539	$1,360	$542	$375	$284
2035	$1,588	$1,403	$557	$386	$292
2036	$1,638	$1,447	$573	$396	$299
2037	$1,690	$1,492	$590	$407	$307
2038	$1,745	$1,540	$608	$420	$317
2039	$1,799	$1,586	$624	$430	$324

2040	$1,857	$1,637	$644	$444	$334
2041	$1,918	$1,690	$663	$457	$344
2042	$1,978	$1,742	$680	$469	$352
2043	$2,040	$1,796	$698	$480	$360
2044	$2,105	$1,851	$717	$492	$368
2045	$2,171	$1,909	$736	$504	$377

LEVELIZED ANNUAL COST OF ELECTRIFICATION EQUIVALENT TO ONE DEKATHERM PER DAY (NOMINAL $)

Year	Washington					
	Residential			Commercial		
	Space Heat	Water Heat	Other	Space Heat	Water Heat	Other
2026	$29.62	$37.87	$67.60	$33.43	$38.61	$25.74
2027	$28.79	$39.61	$70.43	$33.31	$40.50	$27.74
2028	$27.77	$41.36	$73.47	$33.18	$42.58	$29.85
2029	$29.27	$43.35	$76.89	$35.07	$44.84	$32.13
2030	$30.94	$45.44	$80.60	$37.21	$47.33	$34.56
2031	$32.73	$47.65	$84.69	$39.53	$50.09	$37.15
2032	$34.70	$49.93	$89.10	$42.12	$53.07	$39.91
2033	$51.19	$92.22	$116.84	$44.70	$56.33	$42.91
2034	$53.95	$96.96	$123.05	$47.42	$59.74	$46.11
2035	$56.80	$102.16	$129.89	$50.33	$63.51	$49.56
2036	$60.03	$107.59	$137.23	$53.59	$67.62	$53.26
2037	$63.41	$113.42	$145.20	$57.06	$72.08	$57.22
2038	$67.24	$119.28	$153.53	$60.95	$76.80	$61.42
2039	$71.30	$125.45	$162.41	$65.13	$81.87	$65.91
2040	$76.51	$131.60	$171.70	$70.18	$87.30	$70.65
2041	$82.16	$138.13	$181.67	$75.68	$93.18	$75.73
2042	$88.21	$144.69	$192.19	$81.55	$99.37	$80.71
2043	$94.14	$151.36	$202.97	$87.32	$105.65	$85.51
2044	$100.40	$158.10	$214.12	$93.30	$112.07	$90.09
2045	$105.46	$165.42	$225.98	$98.59	$118.72	$94.37

Year	Klamath Falls					
	Residential			Commercial		
	Space Heat	Water Heat	Other	Space Heat	Water Heat	Other
2026	$60.84	$65.01	$107.58	$178.54	$129.68	$288.56
2027	$62.73	$68.31	$112.48	$182.83	$135.83	$302.65
2028	$64.66	$71.90	$117.90	$186.78	$142.50	$317.48
2029	$66.68	$75.64	$123.77	$190.57	$149.47	$333.06
2030	$69.27	$79.59	$130.17	$196.63	$156.95	$349.41
2031	$72.01	$83.81	$137.21	$202.68	$165.05	$366.64
2032	$75.19	$88.22	$144.80	$210.61	$173.66	$384.72
2033	$116.69	$168.72	$196.68	$217.89	$182.95	$403.86
2034	$120.40	$178.32	$207.92	$223.98	$193.20	$424.26
2035	$125.27	$188.02	$219.82	$232.63	$203.75	$445.44
2036	$130.35	$198.52	$232.79	$241.47	$215.14	$467.83
2037	$135.56	$209.70	$246.80	$250.06	$227.24	$491.29

2038	$141.57	$220.98	$261.43	$260.37	$239.46	$515.32
2039	$148.55	$232.03	$276.52	$272.87	$251.98	$540.14
2040	$155.87	$243.57	$292.64	$285.81	$265.22	$565.87
2041	$163.62	$255.47	$309.73	$299.43	$279.12	$592.76
2042	$172.25	$267.03	$327.44	$314.86	$292.96	$619.86
2043	$181.14	$278.92	$345.71	$330.63	$307.29	$647.59
2044	$190.39	$291.57	$365.00	$346.61	$322.26	$675.66
2045	$199.86	$304.52	$384.82	$362.79	$337.35	$704.12

Year	La Grande					
	Residential			Commercial		
	Space Heat	Water Heat	Other	Space Heat	Water Heat	Other
2026	$36.42	$43.93	$57.88	$250.40	$176.41	$458.27
2027	$37.19	$46.23	$60.26	$254.26	$185.34	$480.90
2028	$37.89	$48.63	$62.69	$257.39	$194.57	$504.56
2029	$38.64	$51.36	$65.30	$261.23	$205.15	$530.09
2030	$39.73	$54.07	$67.93	$268.90	$215.78	$556.56
2031	$40.80	$56.93	$70.67	$276.31	$227.11	$584.33
2032	$41.82	$59.94	$73.52	$283.37	$239.10	$613.44
2033	$69.63	$119.77	$109.23	$288.96	$252.76	$644.75
2034	$71.10	$126.39	$114.24	$295.42	$266.45	$677.11
2035	$73.22	$133.24	$119.40	$305.30	$280.71	$710.96
2036	$75.35	$140.51	$124.84	$315.25	$295.75	$746.63
2037	$77.54	$148.08	$130.50	$325.34	$311.38	$783.95
2038	$80.00	$155.81	$136.28	$336.95	$327.18	$822.36
2039	$83.15	$162.97	$141.76	$352.52	$342.49	$861.70
2040	$86.43	$170.01	$147.21	$369.03	$357.72	$901.98
2041	$89.83	$177.56	$152.99	$386.23	$374.32	$944.70
2042	$93.32	$185.22	$158.87	$403.74	$391.20	$988.17
2043	$96.87	$193.13	$164.93	$421.53	$408.83	$1,032.79
2044	$100.54	$201.18	$171.12	$439.46	$426.41	$1,077.48
2045	$104.32	$209.64	$177.57	$457.56	$444.76	$1,123.21

Year	Medford					
	Residential			Commercial		
	Space Heat	Water Heat	Other	Space Heat	Water Heat	Other
2026	$60.33	$42.36	$94.49	$71.48	$44.12	$55.25
2027	$60.69	$44.83	$98.92	$71.44	$46.25	$58.03
2028	$60.86	$47.53	$103.82	$71.04	$48.63	$60.97
2029	$60.75	$50.51	$109.26	$70.17	$51.28	$64.09
2030	$62.79	$53.56	$115.14	$72.30	$54.17	$67.34
2031	$64.95	$56.82	$121.62	$74.53	$57.37	$70.75
2032	$67.12	$60.38	$128.70	$76.75	$60.90	$74.35

2033	$100.49	$111.12	$163.37	$79.00	$64.74	$78.15
2034	$102.88	$118.13	$173.08	$81.33	$68.83	$82.14
2035	$106.83	$125.58	$183.65	$84.83	$73.31	$86.33
2036	$110.98	$133.49	$195.08	$88.55	$78.16	$90.73
2037	$115.24	$142.10	$207.54	$92.38	$83.44	$95.38
2038	$119.77	$151.35	$220.93	$96.41	$89.13	$100.21
2039	$124.51	$160.90	$235.11	$100.68	$95.19	$105.23
2040	$130.86	$169.76	$249.61	$106.26	$101.48	$110.30
2041	$137.61	$178.97	$265.06	$112.22	$108.22	$115.61
2042	$144.94	$188.18	$281.30	$118.66	$115.35	$121.00
2043	$152.62	$197.02	$297.70	$125.42	$122.67	$126.41
2044	$160.65	$206.15	$314.85	$132.43	$130.30	$131.85
2045	$168.87	$215.54	$332.44	$139.53	$138.20	$137.36

Year	Roseburg					
	Residential			Commercial		
	Space Heat	Water Heat	Other	Space Heat	Water Heat	Other
2026	$57.41	$39.48	$92.84	$188.11	$86.32	$197.56
2027	$57.79	$41.78	$97.19	$184.37	$90.99	$207.58
2028	$58.12	$44.25	$101.97	$179.66	$96.00	$218.09
2029	$58.09	$46.92	$107.24	$172.48	$101.41	$229.21
2030	$60.19	$49.66	$112.96	$176.24	$107.11	$240.83
2031	$62.33	$52.72	$119.35	$179.35	$113.48	$253.09
2032	$64.54	$56.05	$126.33	$182.29	$120.49	$266.09
2033	$95.05	$102.07	$158.31	$185.46	$127.96	$279.78
2034	$98.51	$108.46	$167.70	$190.89	$136.00	$294.19
2035	$102.33	$115.56	$178.10	$196.90	$144.79	$309.40
2036	$106.53	$122.74	$189.16	$203.63	$153.82	$325.21
2037	$111.03	$130.34	$201.08	$210.68	$163.40	$341.75
2038	$115.61	$138.83	$214.09	$217.30	$173.90	$359.10
2039	$120.48	$147.31	$227.71	$224.39	$184.65	$376.99
2040	$126.84	$155.58	$241.93	$235.36	$195.64	$395.31
2041	$133.62	$164.11	$257.06	$246.99	$207.18	$414.45
2042	$140.96	$172.55	$272.94	$259.58	$218.91	$433.77
2043	$148.67	$180.65	$289.00	$272.97	$230.55	$453.18
2044	$156.75	$189.03	$305.81	$286.70	$242.50	$472.69
2045	$165.00	$197.59	$323.05	$300.62	$254.65	$492.46

ALTERNATIVE FUELS AVAILABLE SUPPLY (THOUSANDS OF DEKATHERMS)

Expected

Year	Blue Hydrogen 1	Green H2-Wind+Electrolysis 1	GreenH2-Solar+Electrolysis 1	Microwave Pyrolysis 1
2030	2,667	3,734	3,734	10
2031	3,544	4,957	4,957	14
2032	4,421	6,181	6,181	18
2033	5,299	7,404	7,404	23
2034	6,176	8,628	8,628	27
2035	7,053	9,851	9,851	31
2036	7,313	9,672	9,672	194
2037	7,572	9,493	9,493	356
2038	7,832	9,314	9,314	519
2039	8,091	9,136	9,136	681
2040	8,350	10,745	10,745	844
2041	8,447	10,777	10,777	844
2042	8,544	10,810	10,810	845
2043	8,641	10,842	10,842	845
2044	8,738	10,875	10,875	845
2045	8,835	10,907	10,907	846

Year	Animal Manure 4	Animal Manure 5	Landfill Gas 1	Landfill Gas 2	Landfill Gas 3	Landfill Gas 4	Landfill Gas 5
2030	123	185	197	197	395	493	691
2031	158	237	217	217	434	543	760
2032	193	290	236	236	473	591	827
2033	225	338	255	255	510	637	892
2034	251	377	272	272	545	681	953
2035	272	407	289	289	577	722	1,010
2036	286	429	303	303	607	758	1,062
2037	296	445	317	317	633	792	1,108
2038	303	455	329	329	657	821	1,149
2039	308	462	339	339	677	847	1,186
2040	311	467	348	348	695	869	1,217
2041	313	469	356	356	711	888	1,244
2042	314	471	362	362	724	905	1,267
2043	315	473	368	368	735	919	1,286
2044	315	473	372	372	744	930	1,302
2045	316	474	376	376	752	940	1,316

Year	Wastewater 1	Wastewater 2	Wastewater 3	Wastewater 4	Wastewater 5
2030	7	7	7	36	14
2031	9	9	9	44	18
2032	10	10	10	52	20
2033	12	12	12	59	23
2034	13	13	13	65	26
2035	14	14	14	71	28
2036	15	15	15	75	30
2037	16	16	16	78	31
2038	16	16	16	81	32
2039	16	16	16	83	33
2040	17	17	17	84	34
2041	17	17	17	85	34
2042	17	17	17	86	34
2043	17	17	17	86	35
2044	17	17	17	87	35
2045	18	18	18	87	35

Year	Food Waste 3	Biomass 1	Biomass 2	Biomass 3	GreenH2-BiogenicCO2 1
2030	42	58	77	58	184
2031	54	103	137	103	253
2032	67	180	240	180	319
2033	77	307	409	307	386
2034	87	501	668	501	401
2035	93	767	1,022	767	400
2036	99	1,082	1,442	1,082	459
2037	102	1,396	1,862	1,396	640
2038	104	1,662	2,216	1,662	762
2039	106	1,856	2,475	1,856	962
2040	107	1,983	2,644	1,983	1,295
2041	108	2,060	2,747	2,060	1,397
2042	108	2,105	2,807	2,105	1,406
2043	108	2,131	2,841	2,131	1,406
2044	109	2,145	2,860	2,145	1,406
2045	109	2,153	2,871	2,153	1,407

Low

Year	Blue Hydrogen 1	Green H2-Wind+Electrolysis 1	GreenH2-Solar+Electrolysis 1	Microwave Pyrolysis 1
2030	2,264	3,170	3,170	8
2031	2,831	3,960	3,960	11

2032	3,398	4,751	4,751	14
2033	3,965	5,541	5,541	17
2034	4,532	6,331	6,331	20
2035	5,099	7,121	7,121	23
2036	5,076	7,263	7,263	119
2037	5,053	7,404	7,404	215
2038	5,029	7,546	7,546	311
2039	5,006	7,688	7,688	407
2040	4,983	6,411	6,411	504
2041	4,817	6,155	6,155	483
2042	4,652	5,899	5,899	461
2043	4,486	5,643	5,643	440
2044	4,321	5,386	5,386	419
2045	4,155	5,130	5,130	398

Year	Animal Manure 4	Animal Manure 5	Landfill Gas 1	Landfill Gas 2	Landfill Gas 3	Landfill Gas 4	Landfill Gas 5
2030	105	157	168	168	335	419	587
2031	127	191	177	177	354	442	619
2032	150	224	186	186	372	465	651
2033	169	254	194	194	389	486	680
2034	185	277	202	202	404	505	707
2035	196	295	209	209	417	522	730
2036	199	298	210	210	421	526	736
2037	198	297	211	211	422	528	739
2038	195	293	211	211	422	527	738
2039	191	286	210	210	419	524	733
2040	186	279	208	208	415	519	726
2041	179	268	203	203	405	506	709
2042	172	257	197	197	393	492	689
2043	164	246	191	191	381	476	667
2044	156	234	184	184	368	460	643
2045	149	223	177	177	354	442	619

Year	Wastewater 1	Wastewater 2	Wastewater 3	Wastewater 4	Wastewater 5
2030	6	6	6	31	12
2031	7	7	7	35	14
2032	8	8	8	40	16
2033	9	9	9	45	18
2034	9	9	9	48	19
2035	10	10	10	51	20
2036	10	10	10	52	21

2037	11	11	11	52	21
2038	10	10	10	52	21
2039	10	10	10	51	20
2040	10	10	10	50	20
2041	10	10	10	49	19
2042	9	9	9	47	19
2043	9	9	9	45	18
2044	8	8	8	43	17
2045	8	8	8	41	16

Year	Food Waste 3	Biomass 1	Biomass 2	Biomass 3	GreenH2-BiogenicCO2 1
2030	36	49	65	49	157
2031	44	77	103	77	204
2032	52	132	176	132	247
2033	58	224	298	224	291
2034	64	363	484	363	295
2035	68	554	739	554	289
2036	68	728	971	728	306
2037	68	898	1,197	898	408
2038	67	1,035	1,380	1,035	472
2039	66	1,128	1,504	1,128	583
2040	64	1,183	1,578	1,183	773
2041	62	1,174	1,565	1,174	796
2042	59	1,145	1,526	1,145	764
2043	57	1,105	1,473	1,105	729
2044	54	1,060	1,413	1,060	694
2045	51	1,013	1,350	1,013	662

COMPLIANCE MECHANISMS AVAILABLE SUPPLY (MTCO2e)

Expected

Year	Allowances (Free)	Allowances (Given)	Allowance	CCI	Animal Manure 4 (RTC)	Animal Manure 5 (RTC)
2026	160,206	640,824	4,310,970	91,348	19,471	29,207
2027	108,473	614,679	3,891,848	91,212	29,382	44,073
2028	64,527	580,747	3,472,726	121,331	39,293	58,939
2029	28,370	539,026	3,053,604	120,727	49,203	73,805
2030	0	489,518	2,634,482	120,349	59,114	88,671
2031	0	469,492	2,516,058	119,826	73,349	110,023
2032	0	449,467	2,397,633	119,601	87,583	131,375
2033	0	429,441	2,279,209	119,122	101,818	152,727
2034	0	409,415	2,160,785	118,804	116,052	174,079
2035	0	389,389	2,042,361	118,908	130,287	195,430
2036	0	369,364	1,923,936	119,058	134,074	201,111
2037	0	349,338	1,805,512	118,670	137,862	206,792
2038	0	329,312	1,687,088	118,296	141,649	212,473
2039	0	309,287	1,568,664	117,769	145,436	218,154
2040	0	289,261	1,450,239	117,622	149,223	223,835
2041	0	269,235	1,331,815	117,371	149,688	224,532
2042	0	249,209	1,213,391	116,961	150,152	225,228
2043	0	220,283	1,103,867	116,752	150,616	225,925
2044	0	191,357	994,343	116,723	151,081	226,621
2045	0	162,431	884,819	116,418	151,545	227,318

Year	Landfill Gas 1 (RTC)	Landfill Gas 2 (RTC)	Landfill Gas 3 (RTC)	Landfill Gas 4 (RTC)	Landfill Gas 5 (RTC)
2026	44,457	44,457	88,915	88,915	177,830
2027	50,976	50,976	101,953	101,953	203,905
2028	57,495	57,495	114,990	114,990	229,981
2029	64,014	64,014	128,028	128,028	256,056
2030	70,533	70,533	141,066	141,066	282,132
2031	77,052	77,052	154,104	154,104	308,208
2032	83,571	83,571	167,142	167,142	334,283
2033	90,090	90,090	180,179	180,179	360,359
2034	96,609	96,609	193,217	193,217	386,434
2035	103,128	103,128	206,255	206,255	412,510
2036	107,352	107,352	214,704	214,704	429,408
2037	111,577	111,577	223,153	223,153	446,307
2038	115,801	115,801	231,603	231,603	463,205

2039	120,026	120,026	240,052	240,052	480,104
2040	124,251	124,251	248,501	248,501	497,002
2041	126,276	126,276	252,551	252,551	505,102
2042	128,301	128,301	256,601	256,601	513,203
2043	130,326	130,326	260,651	260,651	521,303
2044	132,351	132,351	264,702	264,702	529,403
2045	134,376	134,376	268,752	268,752	537,503

Year	Wastewater 1 (RTC)	Wastewater 2 (RTC)	Wastewater 3 (RTC)	Wastewater 4 (RTC)	Wastewater 5 (RTC)
2026	924	924	924	3,234	3,234
2027	1,269	1,269	1,269	4,440	4,440
2028	1,613	1,613	1,613	5,646	5,646
2029	1,958	1,958	1,958	6,853	6,853
2030	2,303	2,303	2,303	8,059	8,059
2031	2,748	2,748	2,748	9,618	9,618
2032	3,193	3,193	3,193	11,177	11,177
2033	3,639	3,639	3,639	12,736	12,736
2034	4,084	4,084	4,084	14,295	14,295
2035	4,530	4,530	4,530	15,854	15,854
2036	4,702	4,702	4,702	16,457	16,457
2037	4,874	4,874	4,874	17,060	17,060
2038	5,047	5,047	5,047	17,664	17,664
2039	5,219	5,219	5,219	18,267	18,267
2040	5,392	5,392	5,392	18,871	18,871
2041	5,427	5,427	5,427	18,993	18,993
2042	5,462	5,462	5,462	19,116	19,116
2043	5,497	5,497	5,497	19,238	19,238
2044	5,532	5,532	5,532	19,361	19,361
2045	5,567	5,567	5,567	19,484	19,484

Year	Food Waste 3 (RTC)	Under 25MMBtu/hr-Industrial	25-50MMBtu/hr-Industrial	50-100MMBtu/hr-Industrial
2026	5,353	0	0	0
2027	8,078	0	0	0
2028	10,803	0	0	0
2029	13,528	0	0	0
2030	16,252	0	0	0
2031	20,166	0	0	0
2032	24,080	0	0	0
2033	27,993	0	0	0

2034	31,907	0	0	0
2035	35,820	11,657	5,791	4,788
2036	36,862	23,320	11,586	9,580
2037	37,903	34,991	17,383	14,374
2038	38,944	46,667	23,184	19,170
2039	39,985	58,350	28,989	23,969
2040	41,027	70,040	34,796	28,771
2041	41,154	70,030	34,791	28,767
2042	41,282	70,020	34,786	28,763
2043	41,410	70,010	34,781	28,759
2044	41,537	70,000	34,776	28,755
2045	41,665	69,990	34,771	28,751

Year	100-200MMBtu/hr-Industrial	200-400MMBtu/hr-Industrial	800-1600MMBtu/hr-Industrial	Direct Air Capture-DAC
2026	0	0	0	0
2027	0	0	0	0
2028	0	0	0	0
2029	0	0	0	0
2030	0	0	0	0
2031	0	0	0	0
2032	0	0	0	0
2033	0	0	0	0
2034	0	0	0	0
2035	7,270	17,598	28,136	136,289
2036	14,544	35,205	56,287	300,259
2037	21,823	52,823	84,454	491,909
2038	29,105	70,450	112,637	711,240
2039	36,391	88,087	140,836	958,252
2040	43,682	105,735	169,051	1,232,944
2041	43,676	105,720	169,027	1,314,253
2042	43,669	105,704	169,002	1,395,562
2043	43,663	105,689	168,978	1,476,871
2044	43,657	105,674	168,954	1,558,180
2045	43,651	105,659	168,930	1,639,488

Low

Year	CCI	Animal Manure 4 (RTC)	Animal Manure 5 (RTC)	Food Waste 3 (RTC)
2026	89,623	17,494	26,240	4,810
2027	89,442	25,667	38,500	7,057
2028	119,094	33,840	50,759	9,304

2029	118,107	42,012	63,019	11,551
2030	117,369	50,185	75,278	13,798
2031	116,651	58,987	88,480	16,217
2032	116,037	67,787	101,681	18,637
2033	115,223	76,587	114,880	21,056
2034	114,458	85,386	128,079	23,476
2035	114,209	94,185	141,278	25,895
2036	114,106	93,158	139,738	25,612
2037	113,465	92,130	138,195	25,330
2038	112,687	91,101	136,652	25,047
2039	111,885	90,071	135,107	24,764
2040	111,355	89,041	133,561	24,480
2041	110,682	85,489	128,234	23,504
2042	110,005	81,937	122,906	22,527
2043	109,135	78,384	117,576	21,550
2044	108,625	74,829	112,244	20,573
2045	107,752	71,274	106,911	19,596

Year	Landfill Gas 1 (RTC)	Landfill Gas 2 (RTC)	Landfill Gas 3 (RTC)	Landfill Gas 4 (RTC)	Landfill Gas 5 (RTC)
2026	41,564	41,564	83,128	83,128	166,256
2027	46,143	46,143	92,286	92,286	184,573
2028	50,722	50,722	101,444	101,444	202,889
2029	55,301	55,301	110,602	110,602	221,204
2030	59,879	59,879	119,759	119,759	239,518
2031	62,815	62,815	125,630	125,630	251,260
2032	65,750	65,750	131,500	131,500	263,000
2033	68,684	68,684	137,369	137,369	274,737
2034	71,618	71,618	143,236	143,236	286,473
2035	74,552	74,552	149,103	149,103	298,206
2036	74,471	74,471	148,941	148,941	297,883
2037	74,389	74,389	148,778	148,778	297,556
2038	74,307	74,307	148,613	148,613	297,226
2039	74,223	74,223	148,447	148,447	296,893
2040	74,140	74,140	148,279	148,279	296,558
2041	71,953	71,953	143,906	143,906	287,813
2042	69,766	69,766	139,532	139,532	279,064
2043	67,578	67,578	135,156	135,156	270,311
2044	65,389	65,389	130,778	130,778	261,556
2045	63,199	63,199	126,398	126,398	252,797

Year	Wastewater 1 (RTC)	Wastewater 2 (RTC)	Wastewater 3 (RTC)	Wastewater 4 (RTC)	Wastewater 5 (RTC)
2026	843	843	843	2,950	2,950
2027	1,121	1,121	1,121	3,923	3,923
2028	1,399	1,399	1,399	4,896	4,896
2029	1,677	1,677	1,677	5,869	5,869
2030	1,955	1,955	1,955	6,842	6,842
2031	2,219	2,219	2,219	7,766	7,766
2032	2,483	2,483	2,483	8,689	8,689
2033	2,747	2,747	2,747	9,613	9,613
2034	3,011	3,011	3,011	10,537	10,537
2035	3,274	3,274	3,274	11,461	11,461
2036	3,263	3,263	3,263	11,421	11,421
2037	3,252	3,252	3,252	11,381	11,381
2038	3,240	3,240	3,240	11,341	11,341
2039	3,229	3,229	3,229	11,300	11,300
2040	3,217	3,217	3,217	11,260	11,260
2041	3,097	3,097	3,097	10,841	10,841
2042	2,978	2,978	2,978	10,422	10,422
2043	2,858	2,858	2,858	10,002	10,002
2044	2,738	2,738	2,738	9,583	9,583
2045	2,618	2,618	2,618	9,163	9,163

APPENDIX 7.1: WA GRC REQUIREMENTS

For its Washington service territory, Avista agreed to include in its 2025 Natural Gas IRP, a natural gas system decarbonization plan for complying with the Climate Commitment Act (CCA) with the following elements.

i. The Natural Gas IRP's decarbonization plan shall include a supply curve of decarbonization resources by price and availability, e.g. energy efficiency bundle 1 costs X$/ton of carbon dioxide equivalent (CO2e) reduction and can reduce Y tons of CO2e, dairy RNG costs A$/ton and can reduce B tons of CO2e.

The Avista 2025 Natural Gas IRP has included a variety of supplies to decarbonize its energy delivered to the end user based on inputs from ICF (Appendix 6.1). The resources in Figures 1 to Figure 8 below show those supply side or demand side options (energy efficiency) available to the model to meet climate goals as laid out in the CCA. Each figure represents the cost per metric ton of carbon dioxide equivalent combined with the estimated potential of the resource over time.

Figure 1: RNG – Animal Manure and Food Waste (Modeled in 2025 IRP)

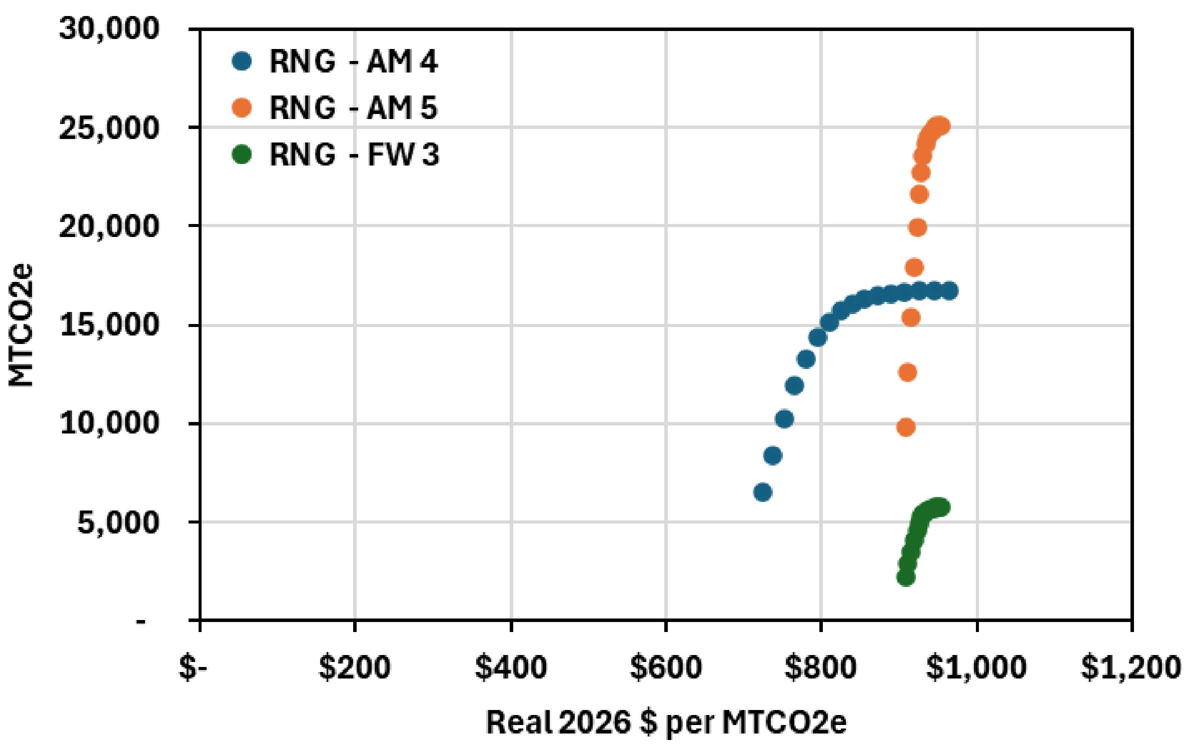


Figure 2: RNG – Landfill Gas (Modeled in 2025 IRP)

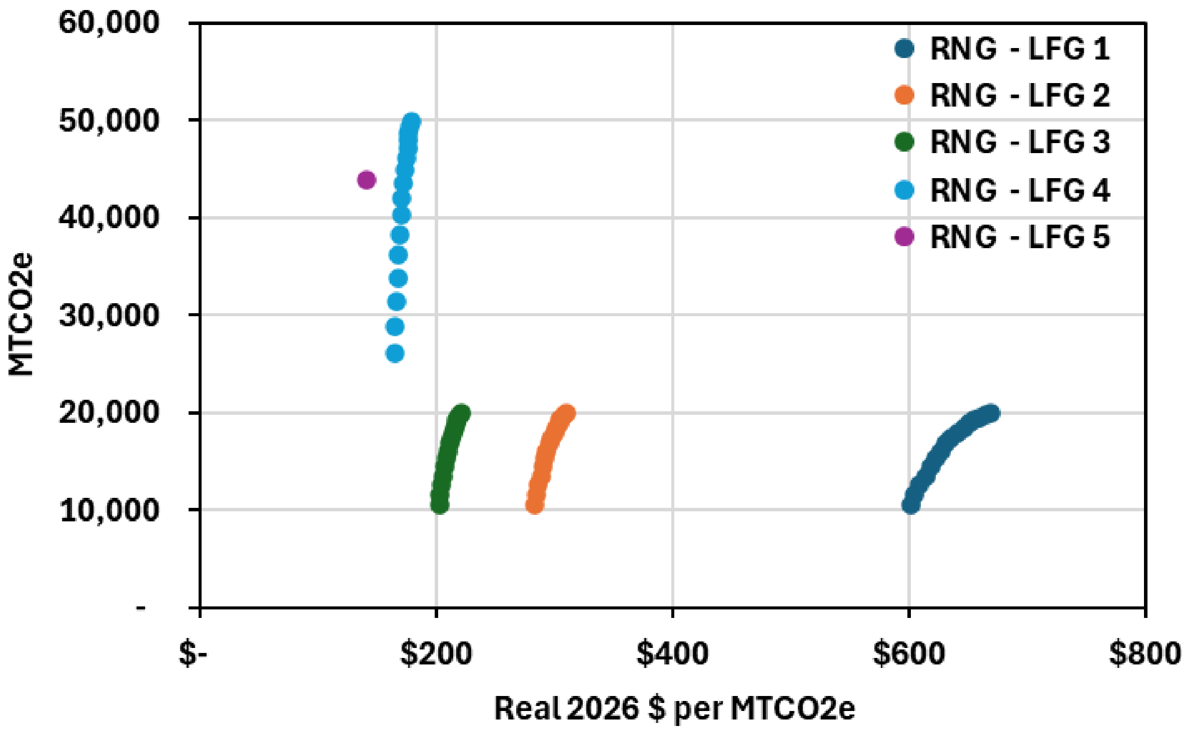


Figure 3: RNG – Waste Water (Modeled in 2025 IRP)

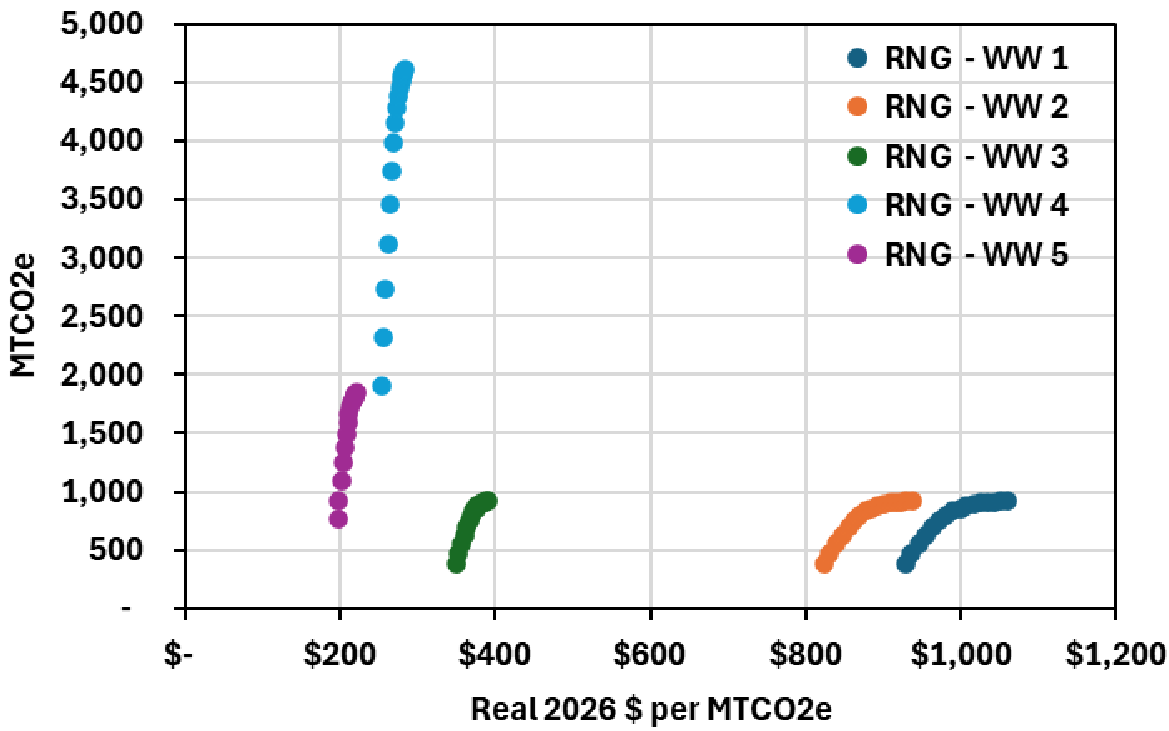


Figure 4: Green Hydrogen by Production Type (Modeled in 2025 IRP)

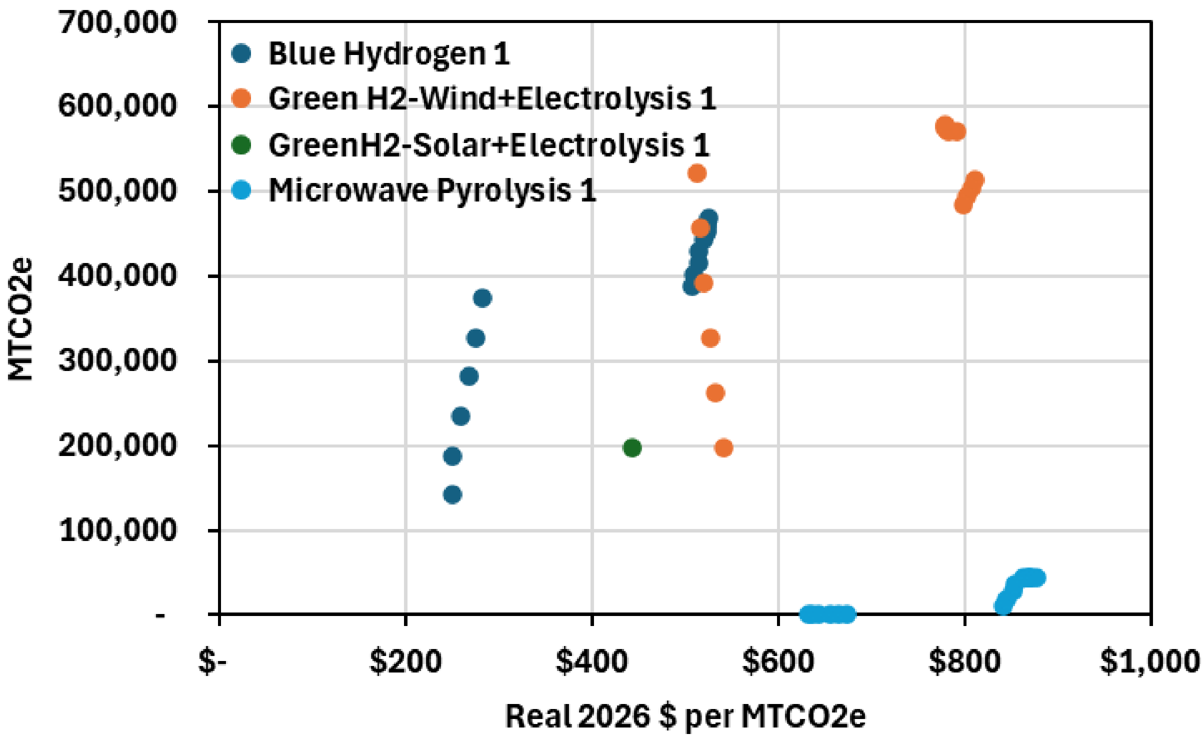


Figure 5: Synthetic Methane by Process Type (Modeled in 2025 IRP)

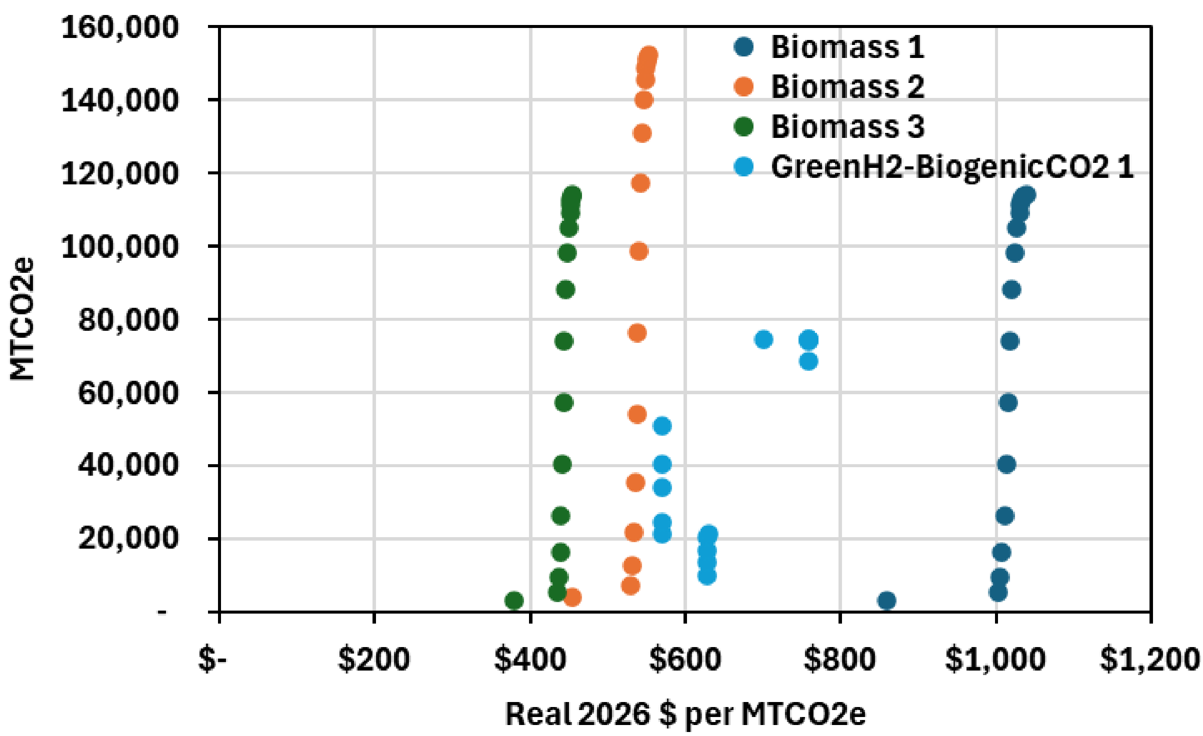


Figure 6: CCUS (Modeled in 2025 IRP)

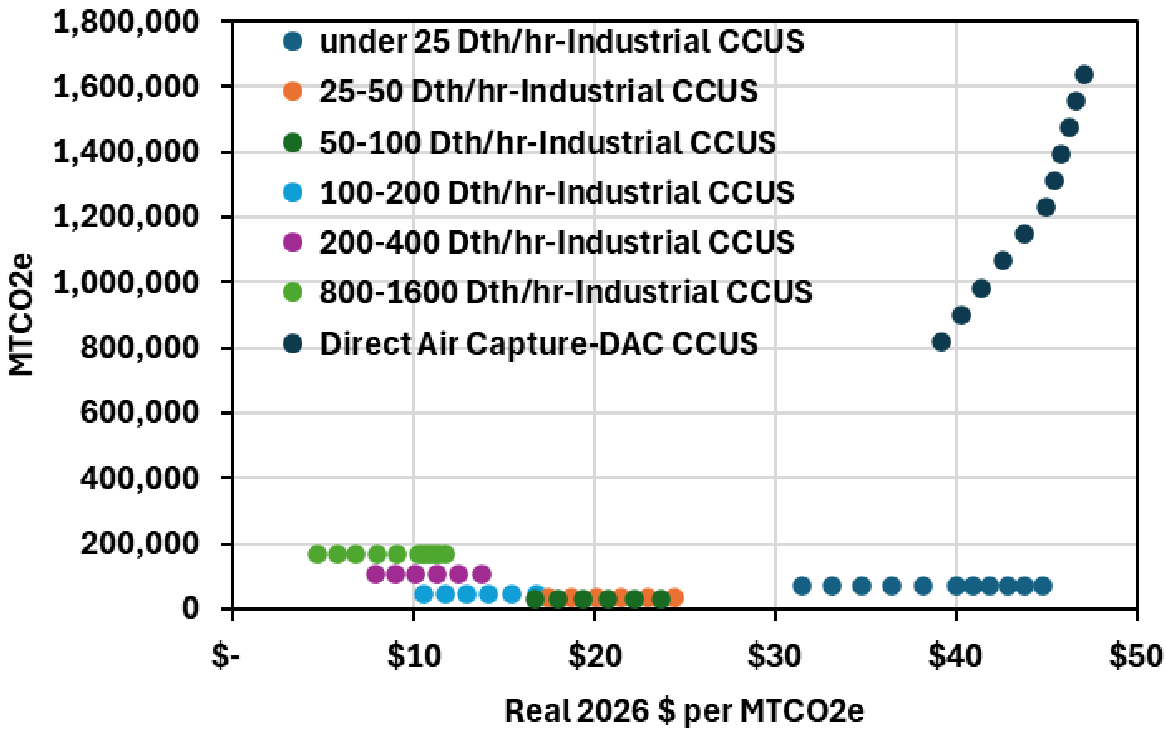
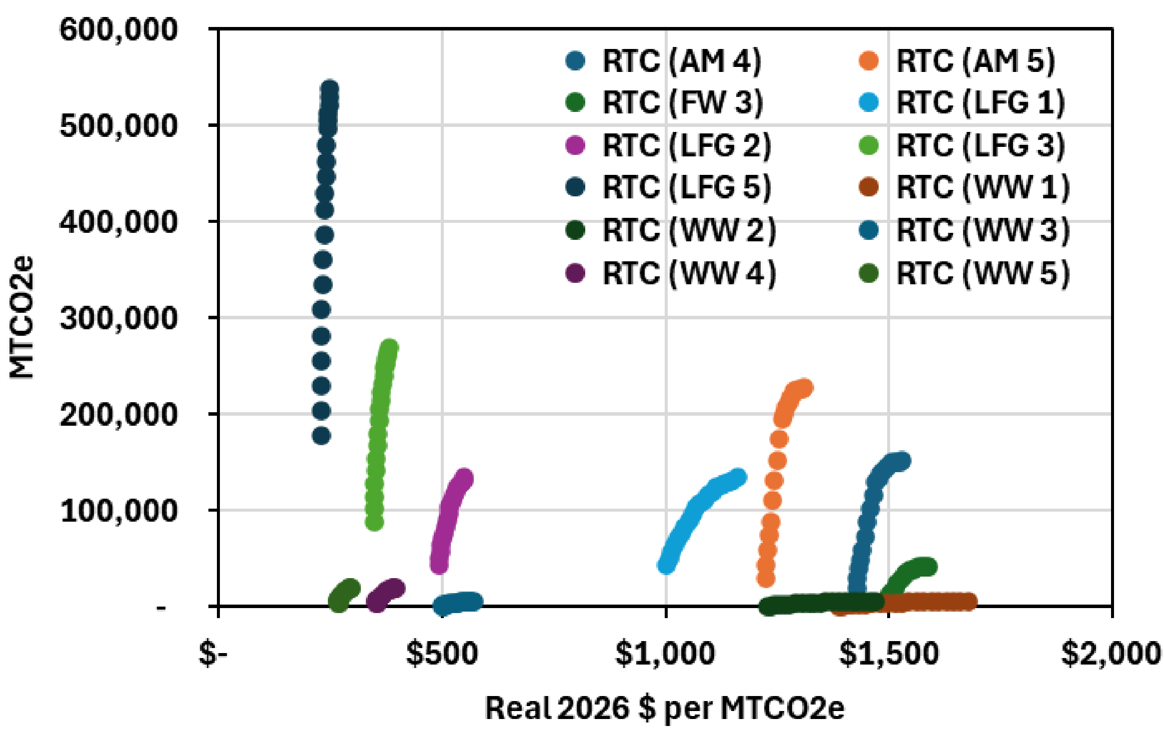
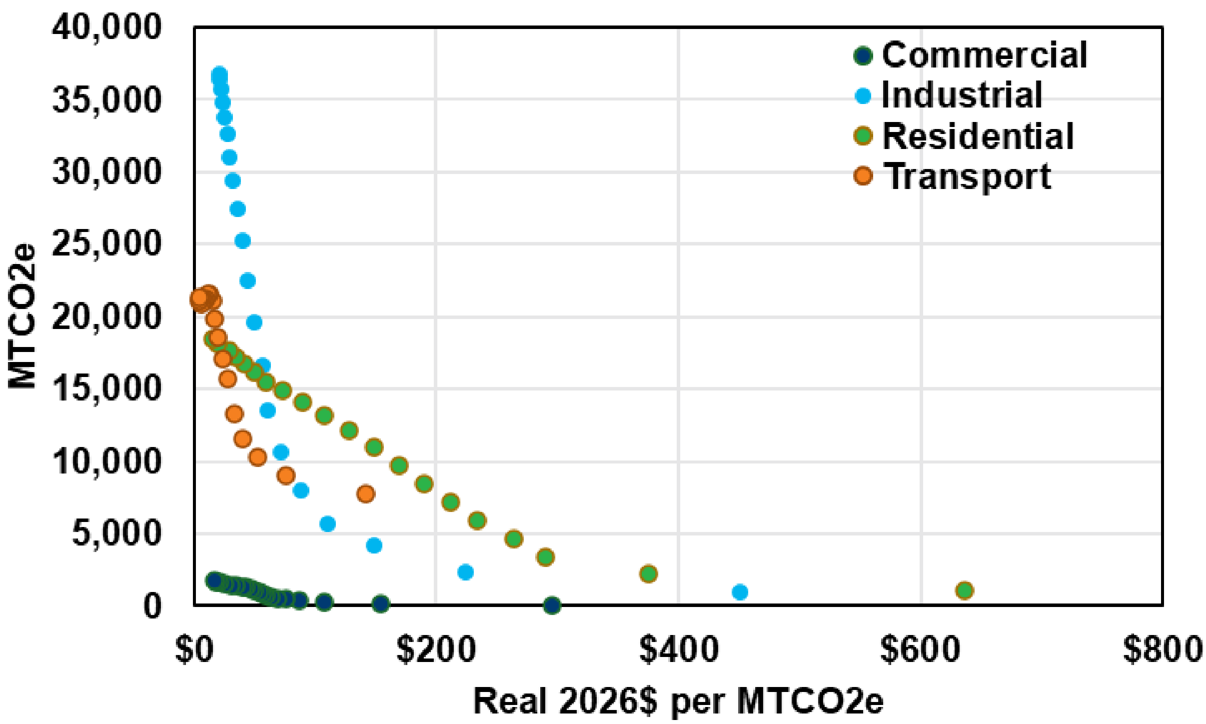


Figure 7: Renewable Thermal Credits - (Modeled in 2025 IRP)



Energy Efficiency is based on the 2025 year of the study provided by AEG as discussed in Chapter 4 and found in Appendix 4.

Figure 8: Energy Efficiency WA CPA - (Modeled in 2025 IRP)



ii. The decarbonization plan shall consider a comprehensive set of strategies, programs, incentives and other measures to encourage new and existing customers to adopt fully energy efficient appliances and equipment or other decarbonization measures, which could include electrification.

Chapter 4 includes a summary of the demand side resources considered in the 2025 IRP, including electrification. Chapter 2 discusses the Preferred Resource Strategy selected in the IRP to meet the CCA requirements, and ultimately the Company's decarbonization plan for this IRP. Appendix 4 has all Conservation Potential Assessments (CPAs) included for a full analysis of considerations.

iii. The decarbonization plan shall include targets for the ratio of new gas customers added relative to new electric customers added in future years.

This is updated in the "No Growth" case and includes no new customers after 2025 in Washington. If no new gas customers are added to the system, the ratio would be 0 as the numerator would be 0 in the following equation.

$$\text{Ratio of New Gas Customers to New Electric Customers} = \frac{\text{New Gas Customers}}{\text{New Electric Customers}}$$

Because the ratio of new gas customers relative to new electric customers is already expected to be 0, any such future target would also be 0.

Impact Results Overview

Dollar Year is 2025   Aggregation Scheme is 546 Unaggregated   Run ID is 469772

Economic Indicators by Impact

Impact	Employment	Labor Income	Value Added	Output
1 - Direct	85.53	$4,162,180.24	$6,759,802.36	$17,718,078.00
2 - Indirect	28.46	$2,236,288.43	$3,566,643.49	$7,108,142.73
3 - Induced	29.49	$1,803,670.28	$3,219,959.99	$5,383,365.82
Totals	143.48	$8,202,138.94	$13,546,405.83	$30,209,586.55

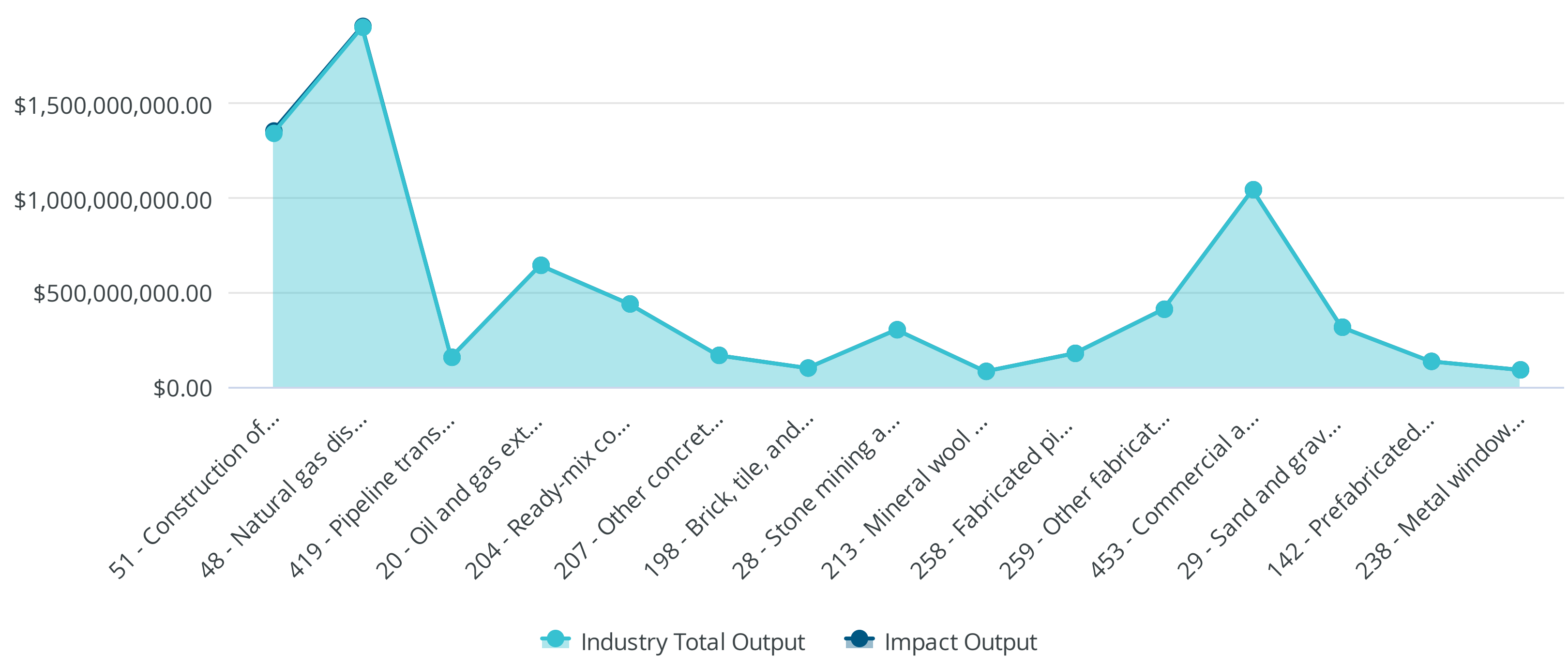
Tax Results

Impact	Sub County General	Sub County Special Districts	County	State	Federal	Total
1 - Direct	$130,883.46	$206,378.30	$80,029.15	$425,305.41	$970,538.43	$1,813,134.76
2 - Indirect	$50,628.72	$79,831.74	$31,393.79	$190,258.99	$527,138.23	$879,251.46
3 - Induced	$43,066.25	$67,907.19	$27,185.87	$163,274.54	$444,710.79	$746,144.65
Totals	$224,578.43	$354,117.23	$138,608.81	$778,838.95	$1,942,387.45	$3,438,530.86

Direct Leakages

Institutional Commodity Sales	Margin	Imports to Region
N/A	N/A	N/A

Top 15 Industries by Impact Output as Percentage of Total Industry Output



Industries by Impact Output as Percentage of Total Industry Output

	Display Code	Display Description	Industry Total Output	Impact Output	Percentage of Total Industry Output
1	51	Construction of new m...	$1,344,152,784.86	$12,598,078.00	.94%
2	48	Natural gas distribution	$1,906,556,996.63	$5,155,971.77	.27%
3	419	Pipeline transportation	$156,242,741.16	$123,034.89	.08%
4	20	Oil and gas extraction	$643,903,195.65	$354,416.08	.06%
5	204	Ready-mix concrete m...	$439,124,561.31	$217,187.39	.05%
6	207	Other concrete produ...	$166,556,410.77	$63,370.09	.04%
7	198	Brick, tile, and other st...	$99,204,424.51	$29,345.95	.03%
8	28	Stone mining and qua...	$302,406,487.17	$87,046.64	.03%
9	213	Mineral wool manufac...	$81,621,617.02	$20,428.42	.03%
10	258	Fabricated pipe and pi...	$177,207,749.67	$39,640.15	.02%
11	259	Other fabricated meta...	$411,069,682.32	$75,512.28	.02%
12	453	Commercial and indus...	$1,044,986,005.77	$167,286.64	.02%
13	29	Sand and gravel mining	$315,791,799.63	$44,312.48	.01%
14	142	Prefabricated wood b...	$134,689,047.99	$18,634.24	.01%
15	238	Metal window and doo...	$89,674,106.08	$11,926.55	.01%
16	203	Cement manufacturing	$85,469,875.76	$10,249.45	.01%
17	395	Wholesale - Machiner...	$3,042,830,238.32	$362,140.62	.01%
18	401	Wholesale - Wholesal...	$1,265,851,456.47	$142,923.69	.01%
19	30	Other clay, ceramic, r...	$19,990,917.12	$2,217.62	.01%
20	31	Potash, soda, and bor...	$22,363,200.86	$2,469.98	.01%
21	214	Miscellaneous nonme...	$31,026,925.41	$3,146.23	.01%
22	156	Asphalt shingle and co...	$679,811,541.45	$68,669.89	.01%

Impact Results Overview

Dollar Year is 2025   Aggregation Scheme is 546 Unaggregated   Run ID is 469780

Economic Indicators by Impact

Impact	Employment	Labor Income	Value Added	Output
1 - Direct	117.38	$4,739,489.73	$7,598,313.26	$22,568,905.26
2 - Indirect	35.16	$2,767,633.46	$4,445,541.01	$8,837,562.04
3 - Induced	34.70	$2,121,946.06	$3,788,286.14	$6,333,540.51
Totals	187.24	$9,629,069.26	$15,832,140.41	$37,740,007.82

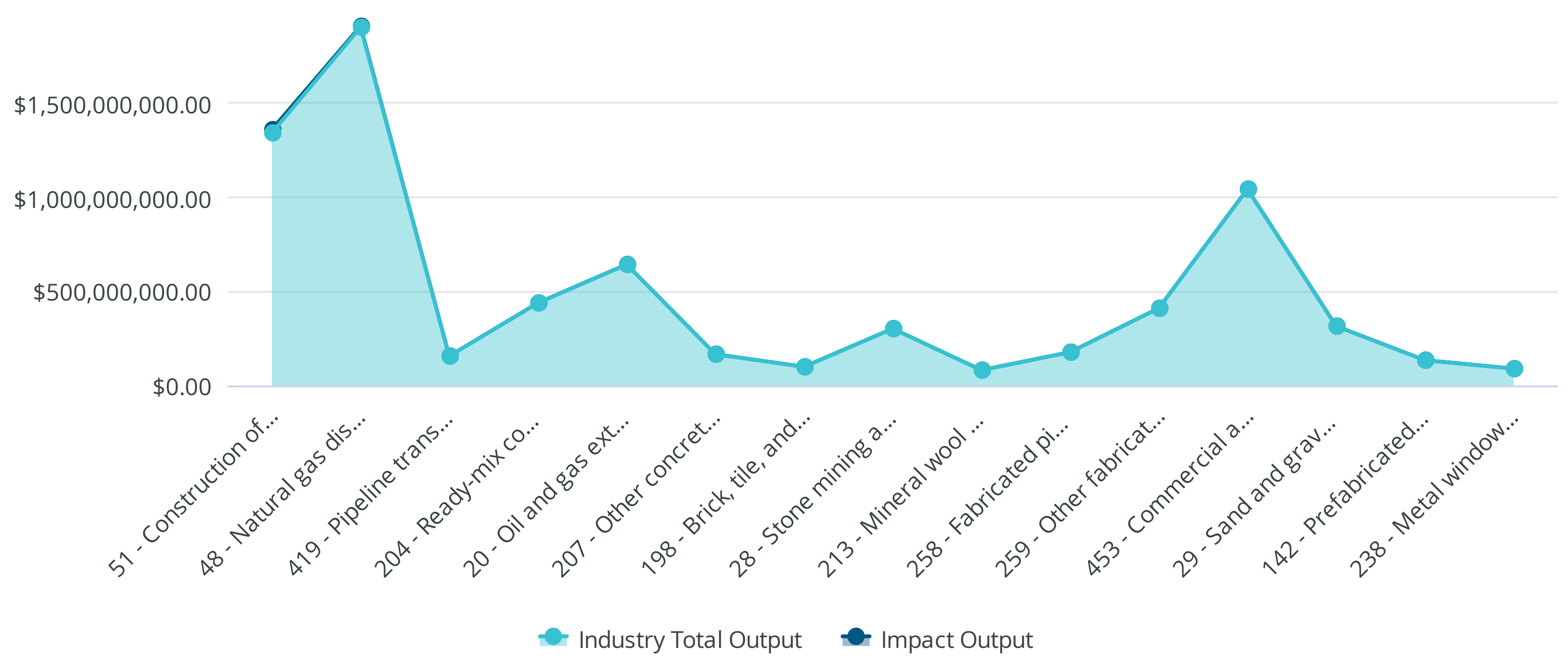
Tax Results

Impact	Sub County General	Sub County Special Districts	County	State	Federal	Total
1 - Direct	$141,536.34	$223,175.82	$86,632.57	$474,625.45	$1,080,375.42	$2,006,345.60
2 - Indirect	$64,505.53	$101,712.81	$39,975.00	$238,788.42	$654,519.80	$1,099,501.55
3 - Induced	$50,669.85	$79,896.62	$31,985.70	$192,092.93	$523,188.51	$877,833.61
Totals	$256,711.72	$404,785.25	$158,593.26	$905,506.80	$2,258,083.73	$3,983,680.77

Direct Leakages

Institutional Commodity Sales	Margin	Imports to Region
N/A	N/A	N/A

Top 15 Industries by Impact Output as Percentage of Total Industry Output



Industries by Impact Output as Percentage of Total Industry Output

	Display Code	Display Description	Industry Total Output	Impact Output	Percentage of Total Industry Output
1	51	Construction of new m...	$1,344,152,784.86	$17,534,612.52	1.30%
2	48	Natural gas distribution	$1,906,556,996.63	$5,077,422.98	.27%
3	419	Pipeline transportation	$156,242,741.16	$121,840.71	.08%
4	204	Ready-mix concrete m...	$439,124,561.31	$301,661.67	.07%
5	20	Oil and gas extraction	$643,903,195.65	$350,501.47	.05%
6	207	Other concrete produ...	$166,556,410.77	$87,984.50	.05%
7	198	Brick, tile, and other st...	$99,204,424.51	$40,765.54	.04%
8	28	Stone mining and qua...	$302,406,487.17	$120,748.53	.04%
9	213	Mineral wool manufac...	$81,621,617.02	$28,390.88	.03%
10	258	Fabricated pipe and pi...	$177,207,749.67	$55,117.09	.03%
11	259	Other fabricated meta...	$411,069,682.32	$104,437.75	.03%
12	453	Commercial and indus...	$1,044,986,005.77	$224,346.61	.02%
13	29	Sand and gravel mining	$315,791,799.63	$61,526.55	.02%
14	142	Prefabricated wood b...	$134,689,047.99	$25,837.27	.02%
15	238	Metal window and doo...	$89,674,106.08	$16,541.91	.02%
16	203	Cement manufacturing	$85,469,875.76	$14,052.74	.02%
17	395	Wholesale - Machiner...	$3,042,830,238.32	$497,489.21	.02%
18	30	Other clay, ceramic, r...	$19,990,917.12	$3,075.36	.02%
19	31	Potash, soda, and bor...	$22,363,200.86	$3,429.37	.02%
20	214	Miscellaneous nonme...	$31,026,925.41	$4,366.88	.01%
21	156	Asphalt shingle and co...	$679,811,541.45	$94,989.03	.01%
22	206	Concrete pipe manufa...	$22,393,029.90	$2,935.95	.01%

Impact Results Overview

Dollar Year is 2025   Aggregation Scheme is 546 Unaggregated   Run ID is 471189

Economic Indicators by Impact

Impact	Employment	Labor Income	Value Added	Output
1 - Direct	120.93	$3,815,920.37	$5,619,728.73	$20,427,613.81
2 - Indirect	29.91	$2,364,127.37	$3,853,802.08	$7,621,726.95
3 - Induced	28.72	$1,755,340.79	$3,133,965.52	$5,239,605.30
Totals	179.56	$7,935,388.53	$12,607,496.33	$33,288,946.06

Tax Results

Impact	Sub County General	Sub County Special Districts	County	State	Federal	Total
1 - Direct	$84,247.99	$132,842.85	$51,777.39	$334,877.74	$821,118.38	$1,424,864.35
2 - Indirect	$58,412.83	$92,105.82	$36,158.34	$209,932.82	$562,917.98	$959,527.78
3 - Induced	$41,921.21	$66,101.69	$26,463.05	$158,914.60	$432,803.42	$726,203.97
Totals	$184,582.03	$291,050.37	$114,398.77	$703,725.16	$1,816,839.78	$3,110,596.10

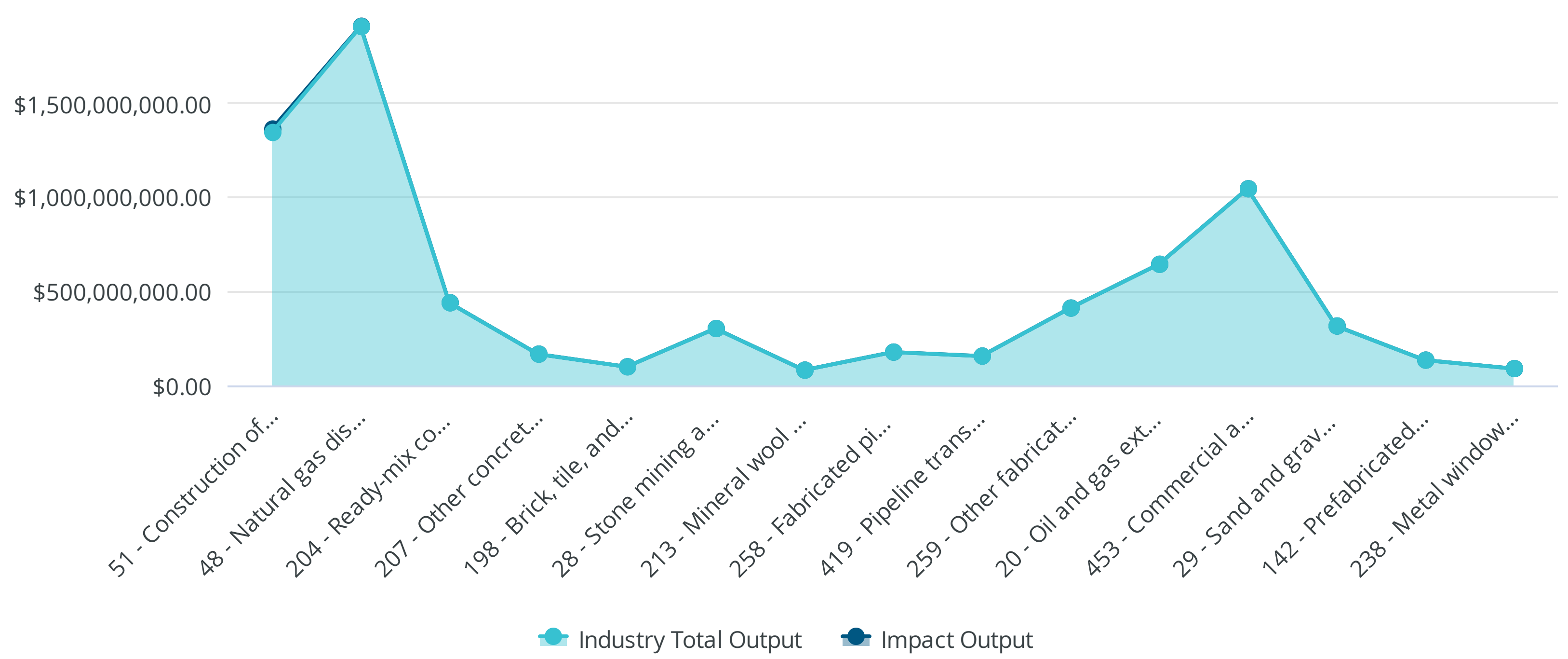
Direct Leakages

Institutional Commodity Sales	Margin	Imports to Region
N/A	N/A	N/A

Industries by Impact Output as Percentage of Total Industry Output

	Display Code	Display Description	Industry Total Output	Impact Output	Percentage of Total Industry Output
1	51	Construction of new m...	$1,344,152,784.86	$18,461,861.08	1.37%
2	48	Natural gas distribution	$1,906,556,996.63	$2,001,430.80	.10%
3	204	Ready-mix concrete m...	$439,124,561.31	$316,711.32	.07%
4	207	Other concrete produ...	$166,556,410.77	$92,332.25	.06%
5	198	Brick, tile, and other st...	$99,204,424.51	$42,811.54	.04%
6	28	Stone mining and qua...	$302,406,487.17	$126,538.07	.04%
7	213	Mineral wool manufac...	$81,621,617.02	$29,833.49	.04%
8	258	Fabricated pipe and pi...	$177,207,749.67	$57,949.53	.03%
9	419	Pipeline transportation	$156,242,741.16	$49,625.25	.03%
10	259	Other fabricated meta...	$411,069,682.32	$108,946.63	.03%
11	20	Oil and gas extraction	$643,903,195.65	$141,642.42	.02%
12	453	Commercial and indus...	$1,044,986,005.77	$223,303.26	.02%
13	29	Sand and gravel mining	$315,791,799.63	$64,563.57	.02%
14	142	Prefabricated wood b...	$134,689,047.99	$27,062.93	.02%
15	238	Metal window and doo...	$89,674,106.08	$17,333.71	.02%
16	203	Cement manufacturing	$85,469,875.76	$14,463.50	.02%
17	395	Wholesale - Machiner...	$3,042,830,238.32	$514,086.42	.02%
18	30	Other clay, ceramic, r...	$19,990,917.12	$3,221.73	.02%
19	31	Potash, soda, and bor...	$22,363,200.86	$3,598.59	.02%
20	214	Miscellaneous nonme...	$31,026,925.41	$4,580.31	.01%
21	156	Asphalt shingle and co...	$679,811,541.45	$99,161.04	.01%
22	239	Sheet metal work man...	$398,959,709.39	$54,732.54	.01%

Top 15 Industries by Impact Output as Percentage of Total Industry Output



Impact Results Overview

Dollar Year is 2025 Aggregation Scheme is 546 Unaggregated Run ID is 469771

Economic Indicators by Impact

Impact	Employment	Labor Income	Value Added	Output
1 - Direct	79.80	$3,845,973.13	$7,348,981.09	$17,491,756.24
2 - Indirect	21.34	$1,984,149.41	$3,650,814.15	$6,599,875.68
3 - Induced	21.11	$1,479,580.49	$2,965,479.08	$4,692,962.93
Totals	122.25	$7,309,703.03	$13,965,274.32	$28,784,594.86

Tax Results

Impact	Sub County General	Sub County Special Districts	County	State	Federal	Total
1 - Direct	$109,444.11	$173,406.05	$88,410.22	$689,515.20	$1,026,766.59	$2,087,542.17
2 - Indirect	$39,486.93	$62,537.90	$31,895.90	$254,863.32	$525,351.58	$914,135.64
3 - Induced	$34,893.35	$55,275.12	$28,186.97	$223,542.53	$405,293.57	$747,191.54
Totals	$183,824.39	$291,219.08	$148,493.09	$1,167,921.05	$1,957,411.74	$3,748,869.34

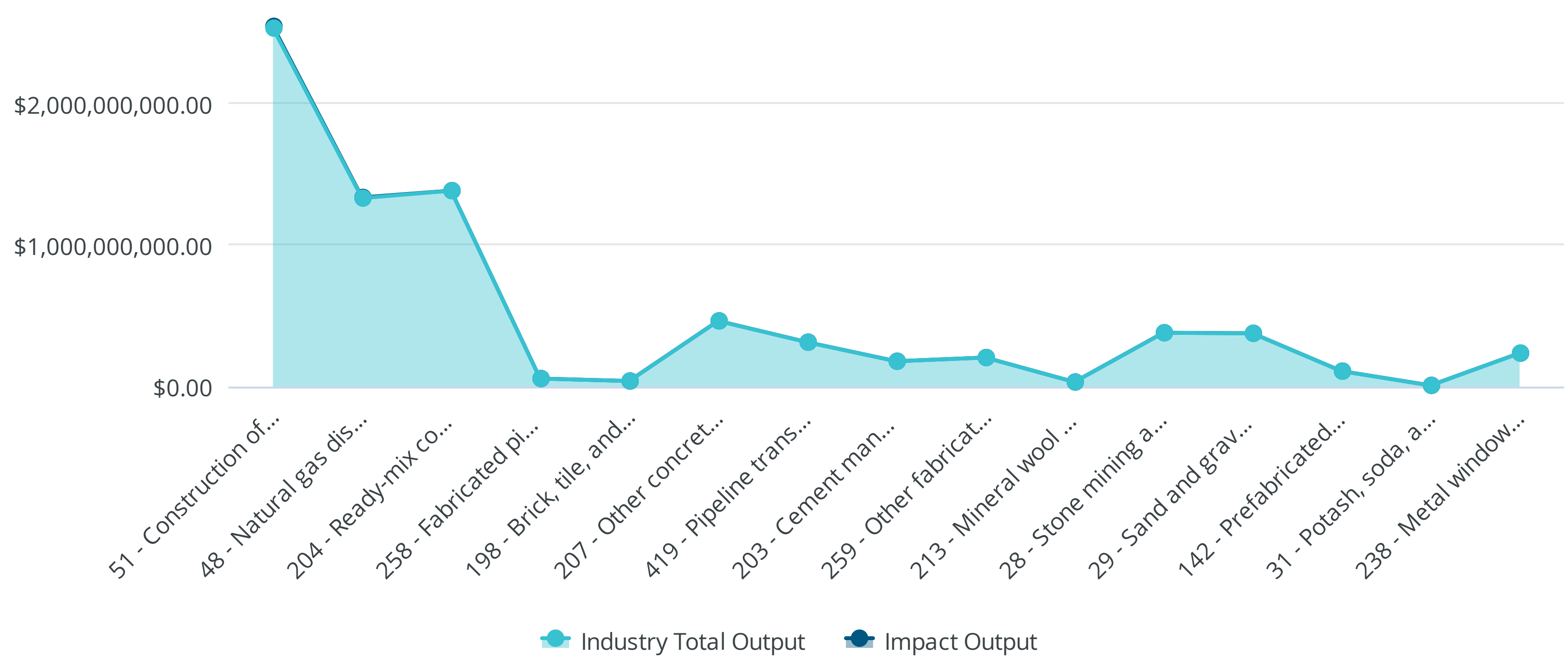
Direct Leakages

Institutional Commodity Sales	Margin	Imports to Region
N/A	N/A	N/A

Industries by Impact Output as Percentage of Total Industry Output

	Display Code	Display Description	Industry Total Output	Impact Output	Percentage of Total Industry Output
1	51	Construction of new m...	$2,530,323,556.97	$12,459,429.25	.49%
2	48	Natural gas distribution	$1,330,211,506.84	$5,046,192.74	.38%
3	204	Ready-mix concrete m...	$1,382,819,907.83	$312,396.09	.02%
4	258	Fabricated pipe and pi...	$56,901,593.63	$12,578.61	.02%
5	198	Brick, tile, and other st...	$39,535,932.51	$7,513.57	.02%
6	207	Other concrete produ...	$463,711,805.08	$86,556.01	.02%
7	419	Pipeline transportation	$313,522,399.18	$55,914.00	.02%
8	203	Cement manufacturing	$178,949,927.04	$30,390.79	.02%
9	259	Other fabricated meta...	$205,136,969.53	$34,583.60	.02%
10	213	Mineral wool manufac...	$32,488,615.29	$5,380.82	.02%
11	28	Stone mining and qua...	$380,145,469.54	$61,973.22	.02%
12	29	Sand and gravel mining	$376,320,589.30	$41,064.53	.01%
13	142	Prefabricated wood b...	$109,244,417.23	$11,743.00	.01%
14	31	Potash, soda, and bor...	$8,583,366.19	$909.45	.01%
15	238	Metal window and doo...	$236,236,819.31	$24,522.99	.01%
16	156	Asphalt shingle and co...	$498,902,678.66	$51,528.86	.01%
17	239	Sheet metal work man...	$1,098,706,441.07	$82,150.51	.01%
18	240	Ornamental and archi...	$293,878,195.34	$21,394.14	.01%
19	395	Wholesale - Machiner...	$5,520,331,451.56	$341,206.25	.01%
20	453	Commercial and indus...	$3,346,058,055.32	$202,699.14	.01%
21	236	Fabricated structural ...	$696,129,833.35	$41,756.92	.01%
22	34	Other nonmetallic min...	$8,275,559.30	$482.84	.01%

Top 15 Industries by Impact Output as Percentage of Total Industry Output



Impact Results Overview

Dollar Year is 2025 Aggregation Scheme is 546 Unaggregated Run ID is 469778

Economic Indicators by Impact

Impact	Employment	Labor Income	Value Added	Output
1 - Direct	112.25	$4,523,026.49	$8,469,733.12	$22,851,574.00
2 - Indirect	27.88	$2,585,686.32	$4,795,959.70	$8,743,936.28
3 - Induced	25.73	$1,802,918.39	$3,613,334.72	$5,718,291.24
Totals	165.86	$8,911,631.21	$16,879,027.54	$37,313,801.52

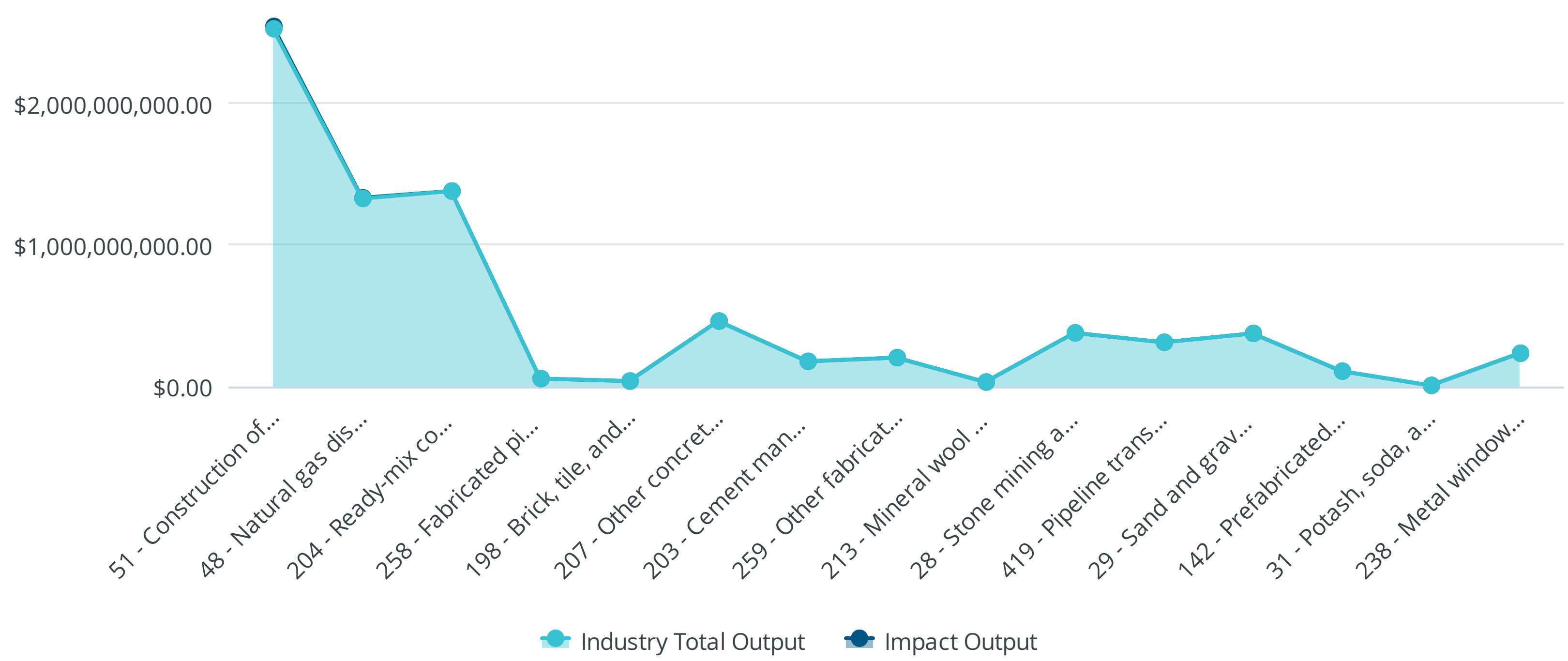
Tax Results

Impact	Sub County General	Sub County Special Districts	County	State	Federal	Total
1 - Direct	$119,077.67	$188,654.12	$96,188.89	$749,302.99	$1,184,064.82	$2,337,288.49
2 - Indirect	$53,029.07	$83,989.01	$42,835.14	$341,779.80	$686,946.75	$1,208,579.77
3 - Induced	$42,510.50	$67,341.55	$34,340.12	$272,343.92	$493,853.13	$910,389.23
Totals	$214,617.24	$339,984.68	$173,364.15	$1,363,426.72	$2,364,864.70	$4,456,257.49

Direct Leakages

Institutional Commodity Sales	Margin	Imports to Region
N/A	N/A	N/A

Top 15 Industries by Impact Output as Percentage of Total Industry Output



Industries by Impact Output as Percentage of Total Industry Output

	Display Code	Display Description	Industry Total Output	Impact Output	Percentage of Total Industry Output
1	51	Construction of new m...	$2,530,323,556.97	$17,729,574.00	.70%
2	48	Natural gas distribution	$1,330,211,506.84	$5,139,810.02	.39%
3	204	Ready-mix concrete m...	$1,382,819,907.83	$443,872.25	.03%
4	258	Fabricated pipe and pi...	$56,901,593.63	$17,885.66	.03%
5	198	Brick, tile, and other st...	$39,535,932.51	$10,675.41	.03%
6	207	Other concrete produ...	$463,711,805.08	$122,939.63	.03%
7	203	Cement manufacturing	$178,949,927.04	$43,129.73	.02%
8	259	Other fabricated meta...	$205,136,969.53	$48,980.73	.02%
9	213	Mineral wool manufac...	$32,488,615.29	$7,648.28	.02%
10	28	Stone mining and qua...	$380,145,469.54	$87,983.78	.02%
11	419	Pipeline transportation	$313,522,399.18	$57,990.38	.02%
12	29	Sand and gravel mining	$376,320,589.30	$58,334.48	.02%
13	142	Prefabricated wood b...	$109,244,417.23	$16,665.14	.02%
14	31	Potash, soda, and bor...	$8,583,366.19	$1,291.44	.02%
15	238	Metal window and doo...	$236,236,819.31	$34,803.65	.01%
16	156	Asphalt shingle and co...	$498,902,678.66	$72,999.56	.01%
17	239	Sheet metal work man...	$1,098,706,441.07	$116,734.27	.01%
18	240	Ornamental and archi...	$293,878,195.34	$30,320.69	.01%
19	395	Wholesale - Machiner...	$5,520,331,451.56	$482,445.15	.01%
20	236	Fabricated structural ...	$696,129,833.35	$59,039.10	.01%
21	453	Commercial and indus...	$3,346,058,055.32	$281,628.05	.01%
22	34	Other nonmetallic min...	$8,275,559.30	$684.38	.01%

Impact Results Overview

Dollar Year is 2025 Aggregation Scheme is 546 Unaggregated Run ID is 483707

Economic Indicators by Impact

Impact	Employment	Labor Income	Value Added	Output
1 - Direct	114.73	$3,703,271.79	$6,098,436.03	$20,427,613.81
2 - Indirect	24.88	$2,297,316.43	$4,331,025.36	$8,028,273.81
3 - Induced	21.61	$1,514,515.94	$3,038,825.37	$4,810,238.81
Totals	161.23	$7,515,104.16	$13,468,286.77	$33,266,126.43

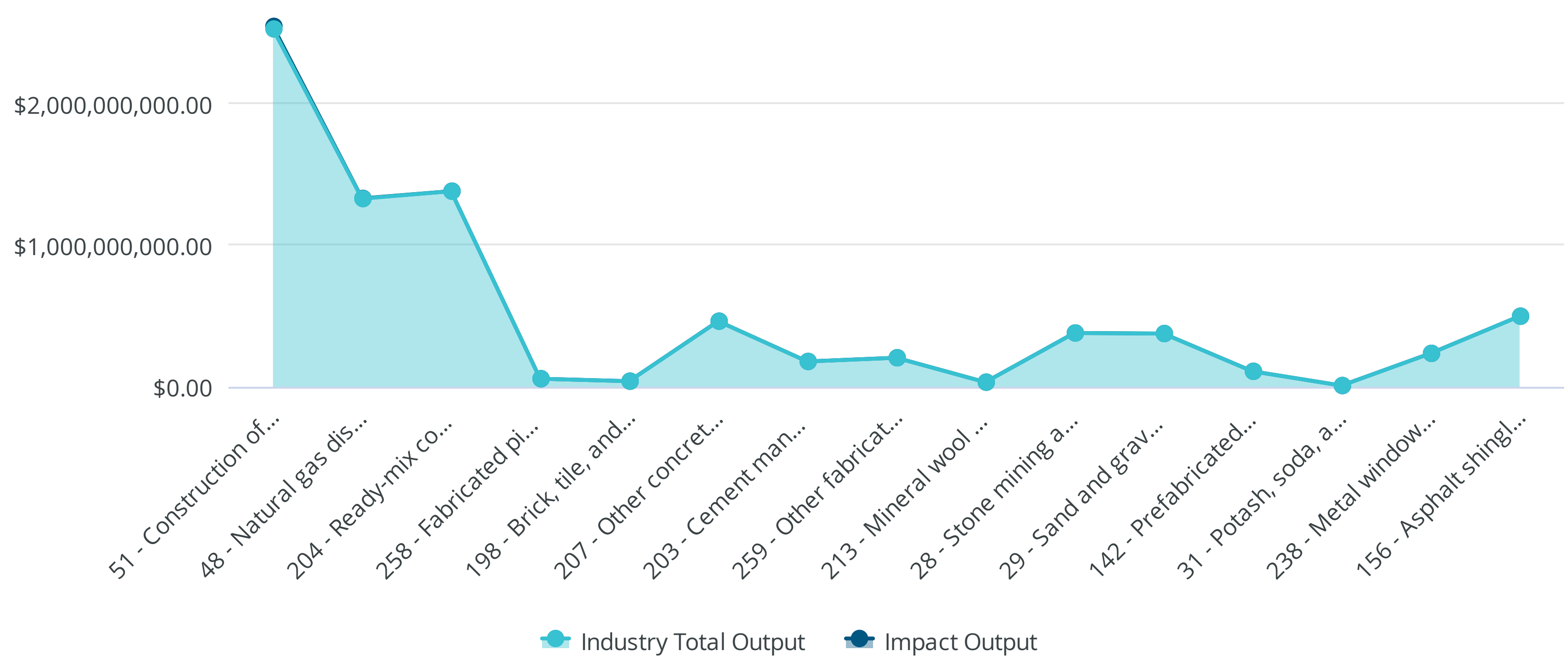
Tax Results

Impact	Sub County General	Sub County Special Districts	County	State	Federal	Total
1 - Direct	$63,737.14	$103,529.22	$52,152.08	$398,091.70	$912,081.69	$1,529,591.82
2 - Indirect	$50,154.89	$81,501.08	$41,047.66	$318,254.24	$614,223.60	$1,105,181.47
3 - Induced	$35,906.00	$58,353.11	$29,386.97	$227,056.51	$414,774.49	$765,477.08
Totals	$149,798.03	$243,383.41	$122,586.70	$943,402.45	$1,941,079.78	$3,400,250.37

Direct Leakages

Institutional Commodity Sales	Margin	Imports to Region
N/A	N/A	N/A

Top 15 Industries by Impact Output as Percentage of Total Industry Output



Industries by Impact Output as Percentage of Total Industry Output

	Display Code	Display Description	Industry Total Output	Impact Output	Percentage of Total Industry Output
1	51	Construction of new m...	$2,530,323,556.97	$18,461,861.08	.73%
2	48	Natural gas distribution	$1,330,211,506.84	$1,981,514.46	.15%
3	204	Ready-mix concrete m...	$1,382,819,907.83	$461,255.53	.03%
4	258	Fabricated pipe and pi...	$56,901,593.63	$18,604.11	.03%
5	198	Brick, tile, and other st...	$39,535,932.51	$11,088.31	.03%
6	207	Other concrete produ...	$463,711,805.08	$127,657.13	.03%
7	203	Cement manufacturing	$178,949,927.04	$44,737.70	.03%
8	259	Other fabricated meta...	$205,136,969.53	$50,638.26	.02%
9	213	Mineral wool manufac...	$32,488,615.29	$7,952.27	.02%
10	28	Stone mining and qua...	$380,145,469.54	$91,313.64	.02%
11	29	Sand and gravel mining	$376,320,589.30	$60,629.45	.02%
12	142	Prefabricated wood b...	$109,244,417.23	$17,256.91	.02%
13	31	Potash, soda, and bor...	$8,583,366.19	$1,328.83	.02%
14	238	Metal window and doo...	$236,236,819.31	$36,103.06	.02%
15	156	Asphalt shingle and co...	$498,902,678.66	$75,533.40	.02%
16	239	Sheet metal work man...	$1,098,706,441.07	$121,295.27	.01%
17	240	Ornamental and archi...	$293,878,195.34	$31,393.32	.01%
18	395	Wholesale - Machiner...	$5,520,331,451.56	$498,170.73	.01%
19	236	Fabricated structural ...	$696,129,833.35	$60,853.94	.01%
20	34	Other nonmetallic min...	$8,275,559.30	$708.85	.01%
21	453	Commercial and indus...	$3,346,058,055.32	$282,791.92	.01%
22	206	Concrete pipe manufa...	$50,146,410.93	$4,113.85	.01%

APPENDIX 10.1: DISTRIBUTION SYSTEM MODELING

OVERVIEW

The primary goal of distribution system planning is to design for present needs and to plan for future expansion in order to serve demand growth. This allows Avista to satisfy current demand-serving requirements, while taking steps toward meeting future needs. Distribution system planning identifies potential problems and areas of the distribution system that require reinforcement. By knowing when and where pressure problems may occur, the necessary reinforcements can be incorporated into normal maintenance. Thus, more costly reactive and emergency solutions can be avoided.

COMPUTER MODELING

When designing new main extensions, computer modeling can help determine the optimum size facilities for present and future needs. Undersized facilities are costly to replace, and oversized facilities incur unnecessary expenses to Avista and its customers.

THEORY AND APPLICATION OF STUDY

Natural gas network load studies have evolved in the last decade to become a highly technical and useful means of analyzing the operation of a distribution system. Using a pipeline fluid flow formula, a specified parameter of each pipe element can be simultaneously solved. Through years of research, pipeline equations have been refined to the point where solutions obtained closely represent actual system behavior.

Avista conducts network load studies using GL Noble Denton's Synergi® 4.8.0 software. This computer-based modeling tool runs on a Windows operating system and allows users to analyze and interpret solutions graphically.

CREATING A MODEL

To properly study the distribution system, all natural gas main information is entered (length, pipe roughness and size) into the model. "Main" refers to all pipelines supplying services.
Nodes are placed at all pipe intersections, beginnings and ends of mains, changes in pipe diameter/material, and to identify all large customers. A model element connects two nodes together. Therefore, a "to node" and a "from node" will represent an element between those two nodes. Almost all of the elements in a model are pipes.

Regulators are treated like adjustable valves in which the downstream pressure is set to a known value. Although specific regulator types can be entered for realistic behavior, the expected flow passing through the actual regulator is determined and the modeled regulator is forced to accommodate such flows.

FLUID MECHANICS OF THE MODEL

Pipe flow equations are used to determine the relationships between flow, pressure drop, diameter and pipe length. For all models, the Fundamental Flow equation (FM) is used due to its demonstrated reliability.

Efficiency factors are used to account for the equivalent resistance of valves, fittings and angle changes within the distribution system. Starting with a 95 percent factor, the efficiency can be changed to fine tune the model to match field results.

Pipe roughness, along with flow conditions, creates a friction factor for all pipes within a system. Thus, each pipe may have a unique friction factor, minimizing computational errors associated with generalized friction values.

LOAD DATA

All studies are considered steady state; all natural gas entering the distribution system must equal the natural gas exiting the distribution system at any given time.

Customer loads are obtained from Avista's customer billing system and converted to an algebraic format so loads can be generated for various conditions. Customer Management Module (CMM), an add-on application for Synergi, processes customer usage history and generates a base load (non-temperature dependent) and heat load (varying with temperature) for each customer.

In the event of a peak day or an extremely cold weather condition, it is assumed that all curtailable loads are interrupted. Therefore, the models will be conducted with only core loads.

DETERMINING NATURAL GAS CUSTOMERS' MAXIMUM HOURLY USAGE

DETERMINING DESIGN PEAK HOURLY LOAD

The design peak hourly load for a customer is estimated by adding the hourly base load and the hourly heat load for a design temperature. This estimate reflects highest system hourly demands, as shown in Table 1:

Table 1 - Determining Peak* Hourly Load

Peak Hourly Base Load	+	Peak Hourly Heat Load	=	Peak Hourly Load

This method differs from the approach that is used for IRP peak day load planning. The primary reason for this difference is due to the importance of responding to hourly peaking in the distribution system, while IRP resource planning focuses on peak day requirements to the city gate.

APPLYING LOADS

Having estimated the peak loads for all customers in a particular service area, the model can be loaded. The first step is to assign each load to the respective node or element.

GENERATING LOADS

Temperature-based and non-temperature-based loads are established for each node or element, thus loads can be varied based on any temperature (HDD). Such a tool is necessary to evaluate the difference in flow and pressure due to different weather conditions.

GEOGRAPHIC INFORMATION SYSTEM (GIS)

Several years ago Avista converted the natural gas facility maps to GIS. While the GIS can provide a variety of map products, the true power lies in the analytical capabilities. A GIS consists of three components: spatial operations, data association and map representation.

A GIS allows analysts to conduct spatial operations (relating a feature or facility to another geographically). A spatial operation is possible if a facility displayed on a map maintains a relationship to other facilities. Spatial relationships allow analysts to perform a multitude of queries, including:

- Identify electric customers adjacent to natural gas mains who are not currently using natural gas
- Display the number of customers assigned to particular pipes in Emergency Operating Procedure zones (geographical areas defined to aid in the safe isolation in the event of an emergency)
- Classify high-pressure pipeline proximity criteria

The second component of the GIS is data association. This allows analysts to model relationships between facilities displayed on a map to tabular information in a database. Databases store facility information, such as pipe size, pipe material, pressure rating, or related information (e.g., customer databases, equipment databases and work management systems). Data association allows interactive queries within a map-like environment.

Finally, the GIS provides a means to create maps of existing facilities in different scales, projections and displays. In addition, the results of a comparative or spatial analysis can be presented pictorially. This allows users to present complex analyses rapidly and in an easy-to-understand method.

BUILDING SYNERGI® MODELS FROM A GIS

The GIS can provide additional benefits through the ease of creation and maintenance of load studies. Avista can create load studies from the GIS based on tabular data (attributes) installed during the mapping process.

MAINTENANCE USING A GIS

The GIS helps maintain the existing distribution facility by allowing a design to be initiated on a GIS. Currently, design jobs for the company’s natural gas system are managed through Avista’s Maximo tool. Once jobs are completed, the as-built information is automatically updated on GIS, eliminating the need to convert physical maps to a GIS at a later date. Because the facility is updated, load studies can remain current by refreshing the analysis.

DEVELOPING A PRESENT CASE LOAD STUDY

In order for any model to have accuracy, a present case model has to be developed that reflects what the system was doing when downstream pressures and flows are known. To establish the present case, pressure recording instruments located throughout the distribution system are used.

These field instruments record pressure and temperature throughout the winter season. Various locations recording simultaneously are used to validate the model. Customer loads on Synergi® are generated to correspond with actual temperatures recorded on the instruments. An accurate model’s downstream pressures will match the corresponding field instrument’s pressures. Efficiency factors are adjusted to further refine the model's pressures and better match the actual conditions.

Since telemetry at the gate stations record hourly flow, temperature and pressure, these values are used to validate the model. All loads are representative of the average daily temperature and are defined as hourly flows. If the load generating method is truly accurate, all natural gas entering the actual system (physical) equals total natural gas demand solved by the simulated system (model).

DEVELOPING A PEAK CASE LOAD STUDY

Using the calculated peak loads, a model can be analyzed to identify the behavior during a peak day. The efficiency factors established in the present case are used throughout subsequent models.

ANALYZING RESULTS

After a model has been balanced, several features within the Synergi® model are used to interpret results. Color plots are generated to depict flow direction, pressure, and pipe diameter with specific break points. Reinforcements can be identified by visual inspection. When user edits are completed and the model is re-balanced, pressure changes can be visually displayed, helping identify optimum reinforcements.

PLANNING CRITERIA

In most instances, models resulting in node pressures below 15 psig indicate a likelihood of distribution low pressure, and therefore necessitate reinforcements. For most Avista distribution systems, a minimum of 15 psig will ensure deliverability as natural gas exits the distribution mains and travels through service pipelines to a customer's meter. Some Avista distribution areas operate at lower pressures and are assigned a minimum pressure of 5 psig for model results. Given a lower operating pressure, service pipelines in such areas are sized accordingly to maintain reliability.

DETERMINING MAXIMUM CAPACITY FOR A SYSTEM

Using a peak day model, loads can be prorated at intervals until area pressures drop to 15 psig. At that point, the total amount of natural gas entering the system equals the maximum capacity before new construction is necessary. The difference between natural gas entering the system in this scenario and a peak day model is the maximum additional capacity that can be added to the system.

Since the approximate natural gas usage for the average customer is known, it can be determined how many new customers can be added to the distribution system before necessitating system reinforcements. The above models and procedures are utilized with new construction proposals or pipe reinforcements to determine the potential increase in capacity.

FIVE-YEAR FORECASTING

The intent of the load study forecasting is to predict the system's behavior and reinforcements necessary within the next five years. Various Avista personnel provide information to determine where and why certain areas may experience growth.

By combining information from Avista's demand forecast, IRP planning efforts, regional growth plans and area developments, proposals for pipeline reinforcements and expansions are evaluated with Synergi®.

Appendix 10.2

Oregon Public Utility Commission Order No. 16-109 (the Order) included the following language:

> Finally, as part of the IRP-vetting process and subsequent rate proceedings, we expect that Avista conduct and present comprehensive analyses of its system upgrades. Such analyses should provide: (1) a comprehensive cost-benefit analysis of whether and when the investment should be built; (2) evaluation of a range of alternative build dates and the impact on reliability and customer rates; (3) credible evidence on the likelihood of disruptions based on historical experience; (4) evidence on the range of possible reliability incidents; (5) evidence about projected loads and customers in the area; and (6) adequate consideration of alternatives, including the use of interruptibility or increased demand-side measures to improve reliability and system resiliency.

In order to address this portion of the Order, Avista has prepared this appendix, which includes documentation addressing the six points above for each of the natural gas distribution system enhancements included in the 2021 Natural Gas Integrated Resource Plan (IRP) for Avista's Oregon service territory. Each of these three enhancement projects represents a significant, discrete project which is out of the ordinary course of business (that is to say, different from <u>ongoing</u> capital investment to address Federal or State regulatory requirements, relocation of pipe or facilities as requested by others, failed pipe or facilities, etc., all of which occur routinely over time and which are discussed below).

The routine, ongoing capital investments can be loosely classified in the following categories (which are not mutually exclusive):

- Safety – Ongoing safety related capital investment includes the repair or replacement of obsolete or failed pipe and facilities. This category includes, but is not necessarily limited to, investment to address deteriorated or isolated steel pipe, cathodic protection, and the replacement of pipeline which has been built over, as well as the remedy of shallow pipe or the repair or replacement of leaking pipe.
- System Maintenance – Ongoing capital investment related to system maintenance includes replacement of facilities or pipe that has reached the end of their useful lives, as well as other general investment required to maintain Avista's ability to reliably serve customers.
- Relocation Requested by Others – Ongoing capital investment related to relocation requested by others falls primarily into two categories, relocation requested by other parties which is required under the terms of our franchise agreements (such as

relocations required to accommodate road or highway construction or relocation), or relocation requested by customers or others (in which case the customer would be responsible for the cost of the immediate request, but in which case Avista may perform additional work, such as the replacement of a steel service with polyethylene to reduce future maintenance or cathodic protection requirements on that pipe).

- Mandated System Investment – Ongoing capital investment in this category is driven by Federal or State regulatory requirements, such as investment that results from TIMP/DIMP programs, among other programs.

Avista's Aldyl-A replacement program has been addressed in substantial detail in Oregon Public Utility Commission Docket UG-246, Avista/500-501.

2025 Natural Gas Integrated Resource Plan
Technical Advisory Committee Meeting No. 1 Agenda
Wednesday, February 14, 2024
Virtual Meeting

Topic	Time (PTZ)	Staff
Introductions	9:00	Tom Pardee
January Peak Event	9:10	Tom Pardee
Work Plan	9:30	Tom Pardee
RNG Acquisition	9:50	Michael Whitby
Break	10:20	
Customer Impacts	10:30	Tom Pardee
Modeling Update	11:00	Michael Brutocao
State Policy Update	11:30	Tom Pardee
Planned Scenarios	11:55	Tom Pardee

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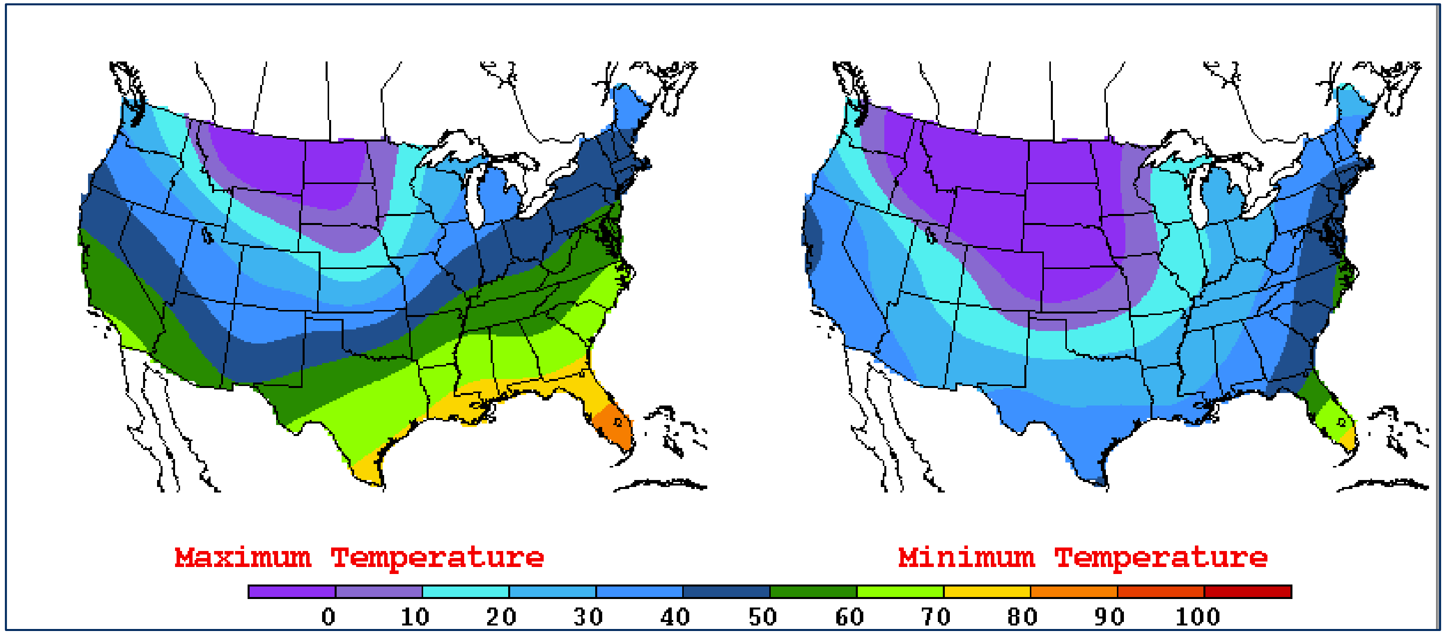
Gas market winter update

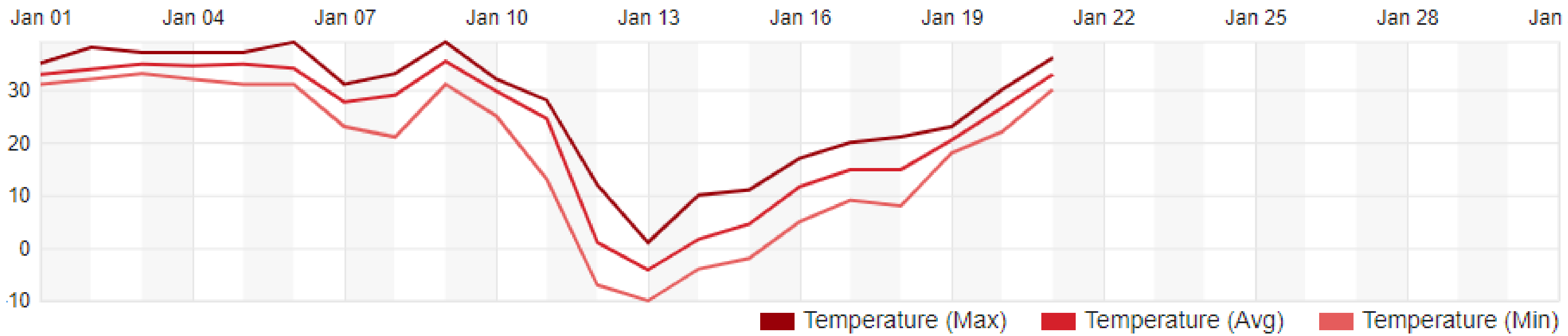
February 14, 2024

After a mild Nov/Dec, winter finally arrives MLK weekend

Overnight lows 1/12-1/13

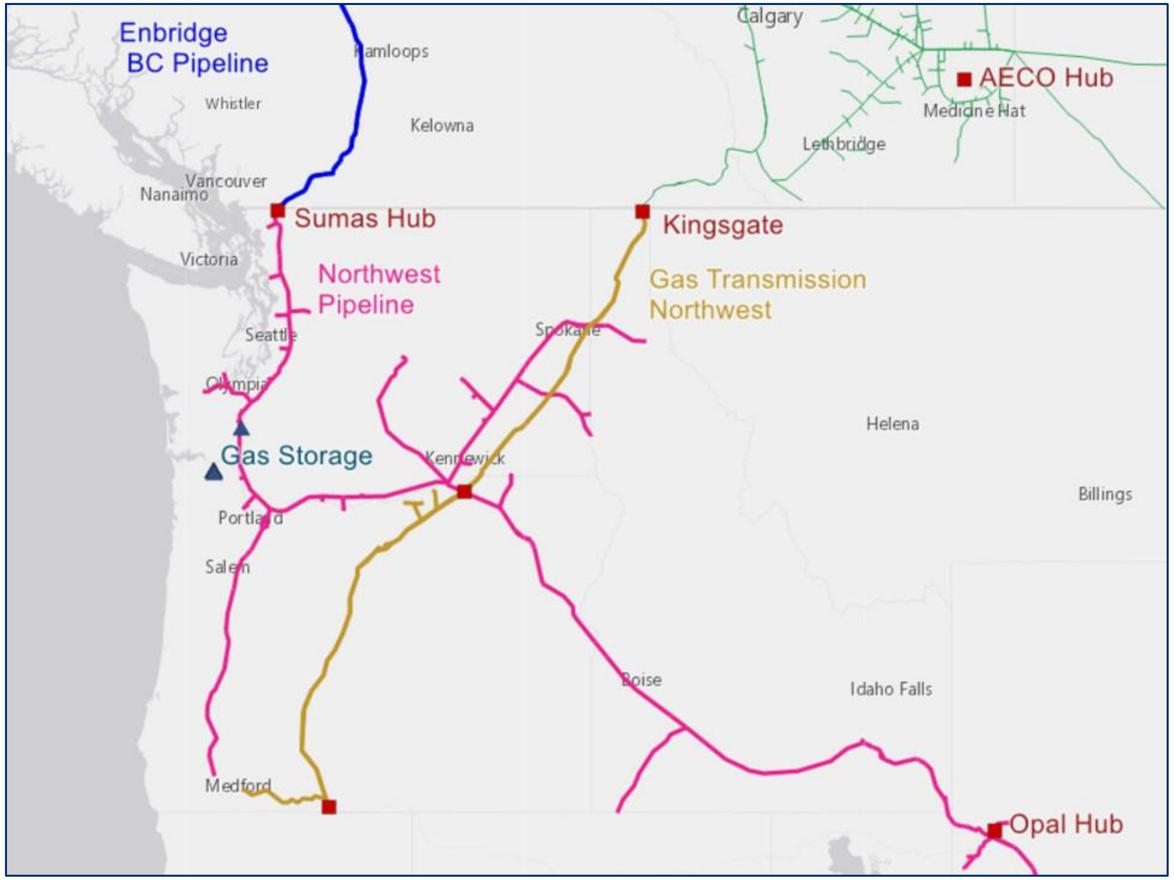
- Spokane: -10
- Calgary: -33
- Vancouver: 7
- Seattle: 15
- Portland: 15
- Boise: 10





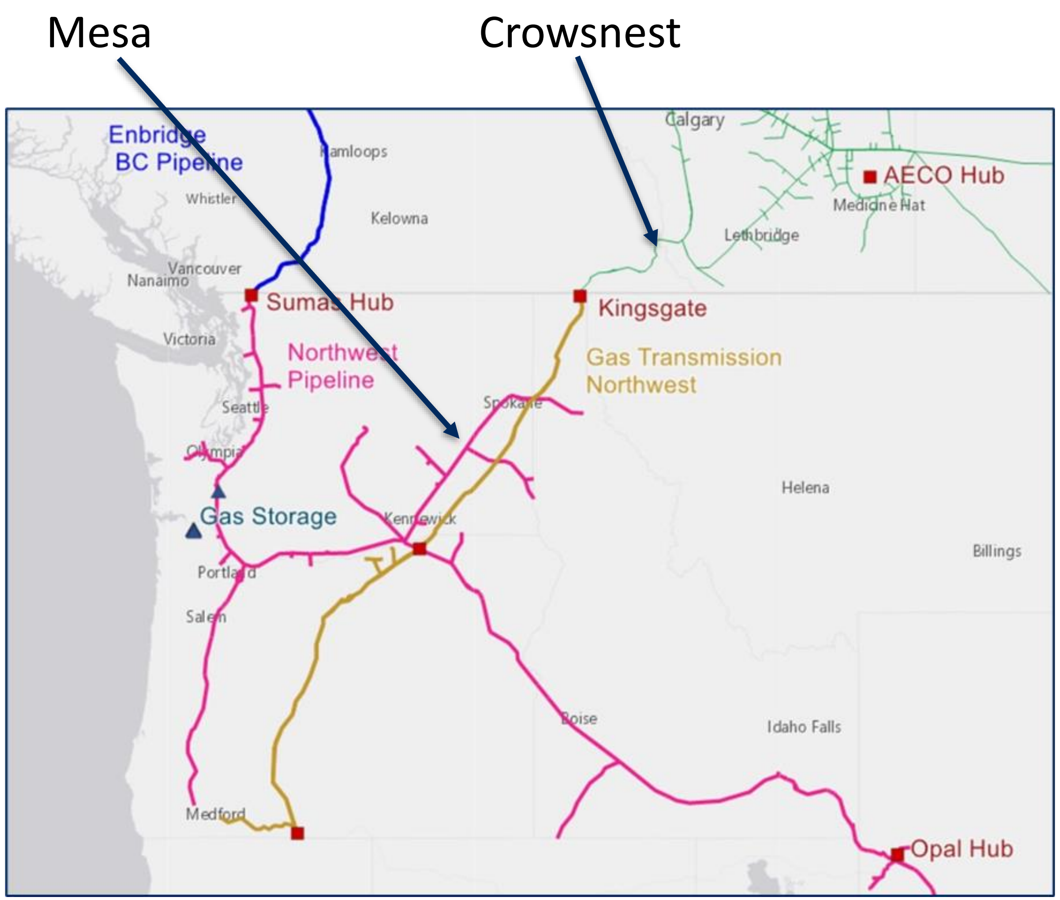
MLK Weekend

- Extremely cold temperatures region wide.
- Avista LDC sets peak load records on consecutive days 1/12 (Fri),1/13 (Sat).
- The two main pipeline systems (GTN, NWP) serving the region experienced infrastructure failures on successive days.



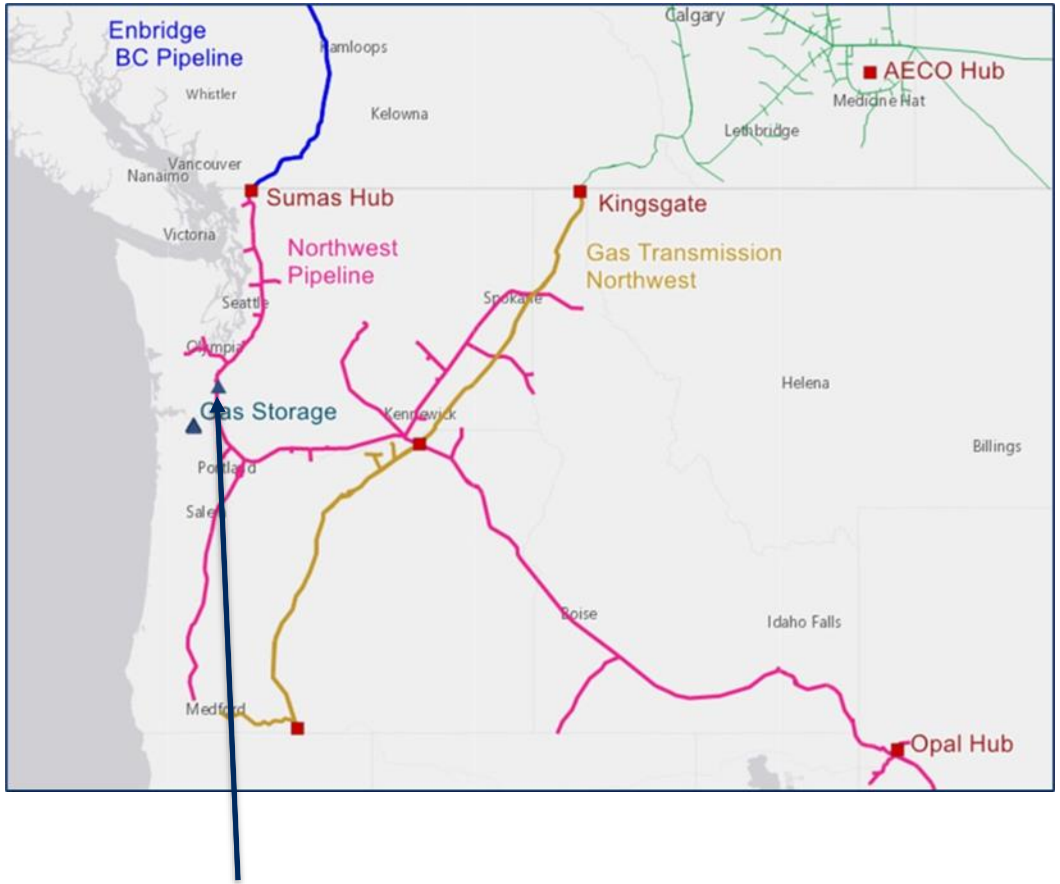
GTN – Compressor failure

- Crowsnest compressor fails morning of 1/12/24.
- GTN issues Force Majeure. Posts capacity reduction of 800k dth south of Kingsgate. (25% of GTN capacity)
- Avista is first LDC offtake customer from GTN south of Kingsgate and had higher impacts due to this
- Pressure on GTN starts to fall early afternoon on 1/12.
- GTN issues request for aid.
- Avista LDC declares gas EOP and requests that customers conserve gas.
- Northwest pipeline reverses flow at Mesa compressor to boost pressure on GTN.
- Avista monitors pressure throughout the night. By late morning on 1/13 pressure was climbing.
- Avista ends gas EOP around noon on 1/13.

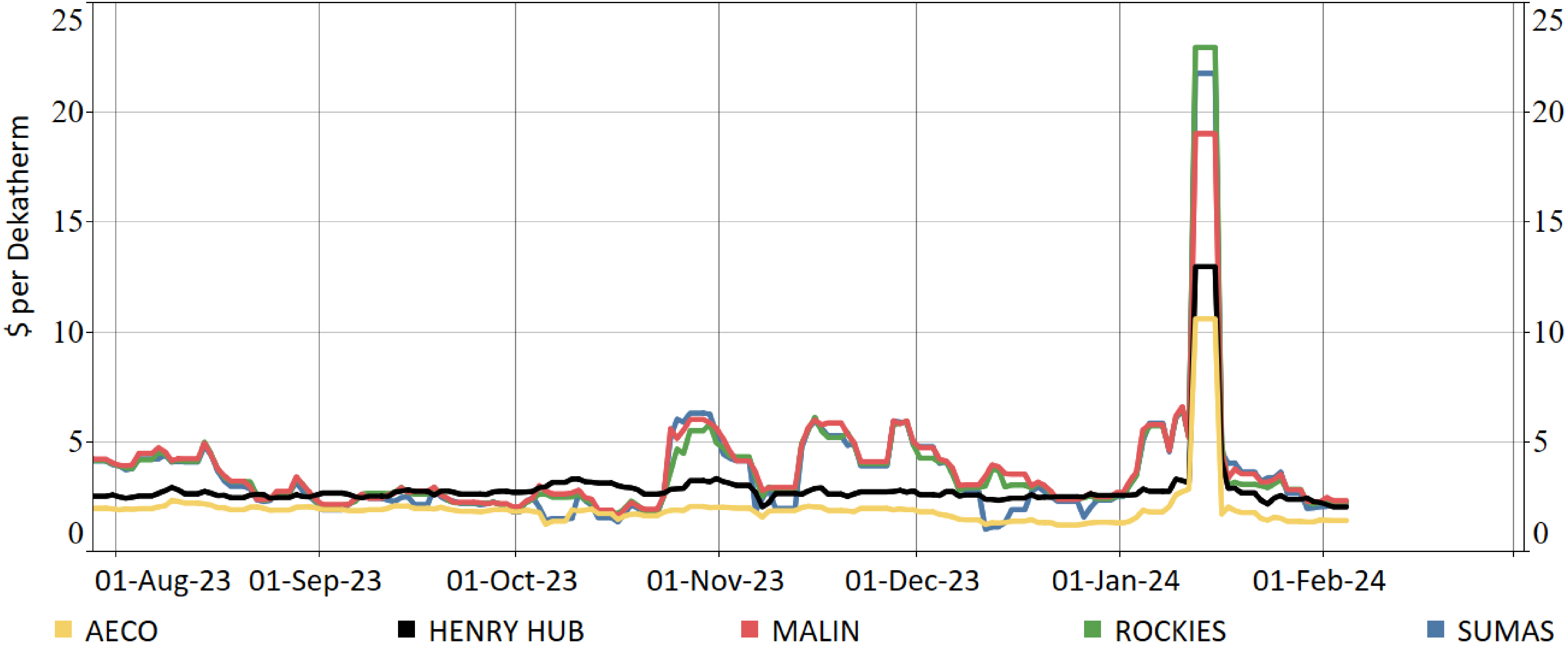


Jackson Prairie – Gas Supply impact

- At approximately 1 PM on 1/13 operators at JP lost communication with the facility. Withdrawal flows dropped from 1.1 bcf/d to zero. Pressure in I-5 corridor starts to drop.
- NWP activates Northwest Mutual assistance agreement. Requests regional stakeholder shed non-essential load and bring on available supply to preserve pressure.
- Around 3 PM, on-site crews manually open valves to allow free flow of 0.5 bcf/d.
- At approximately 6:30 PM operators regained communications link to JP. Flows ramped back up to 1.1 bcf/d. NWP terminated the NMAA.

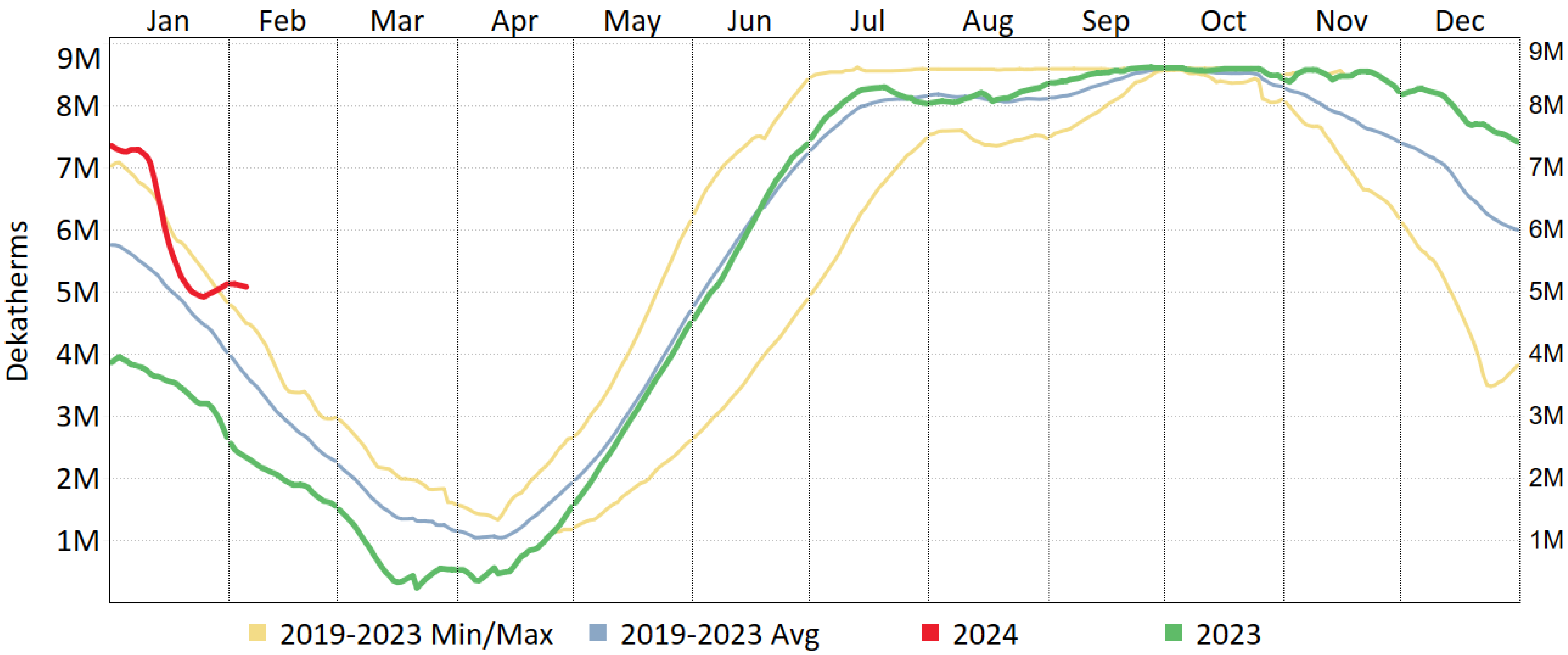


Day Ahead Prices



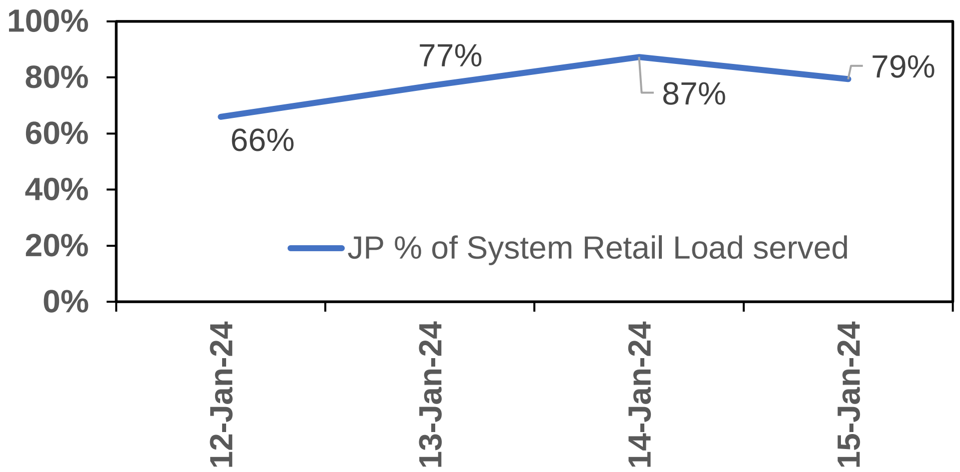
- Avista withdraws 1.32 Bcf over 5 days (1/12-1/16)
- JP total withdrawal 4.77 Bcf of 25 Bcf capacity

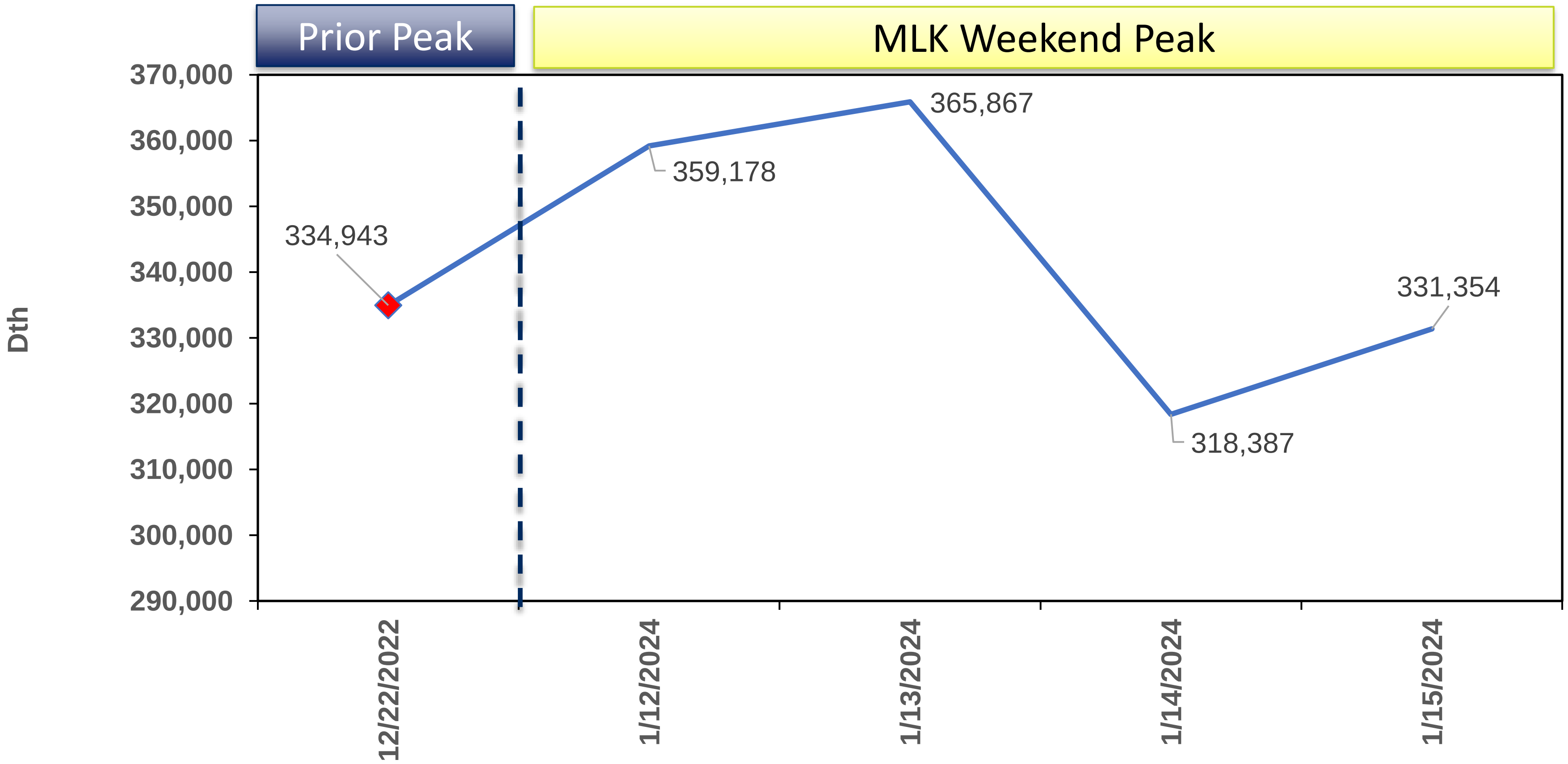
Avista JP Storage



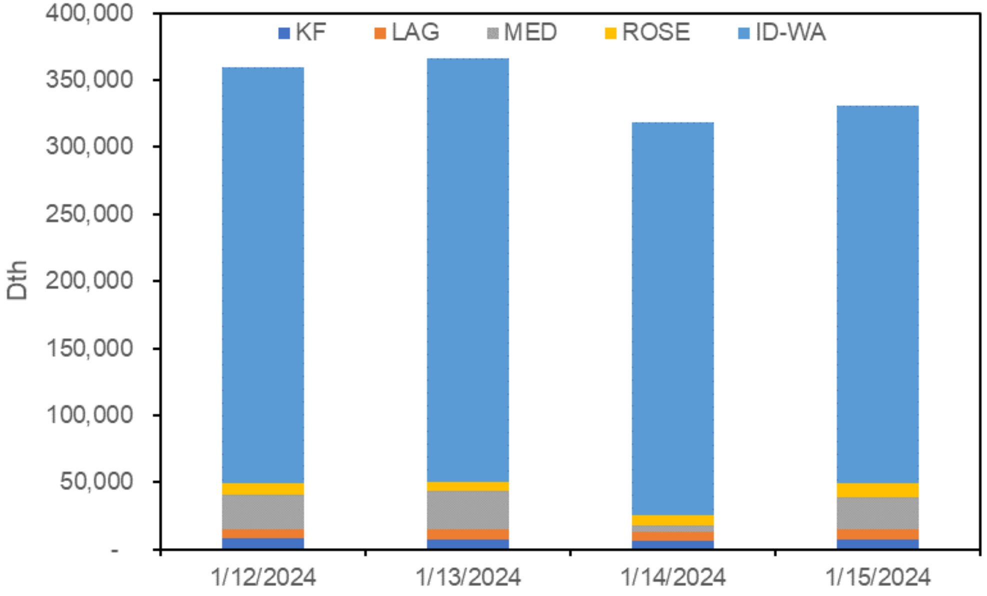
*Min, Max, and Averages since 2019

Peak Demand

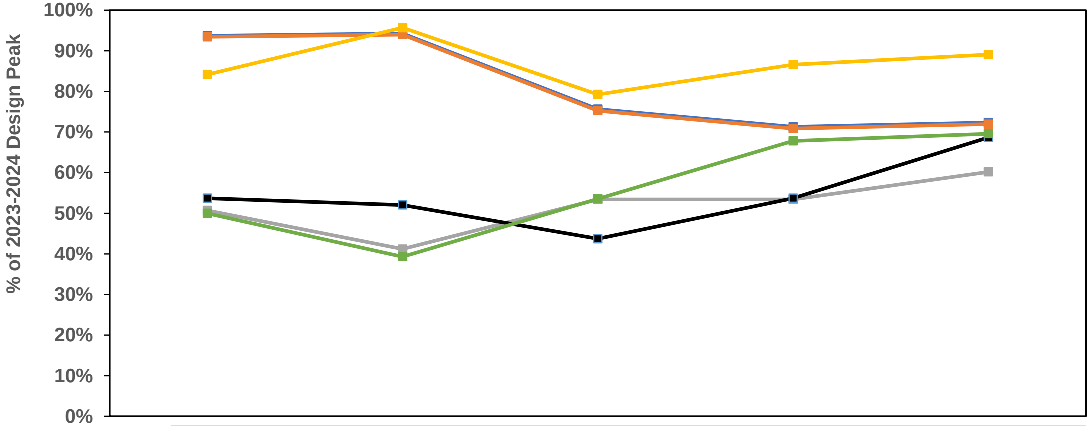

100%
80%
60%
40%
20%
0%
77%
79%
87%
66%
JP % of System Retail Load served
12-Jan-24
13-Jan-24
14-Jan-24
15-Jan-24


Prior Peak
MLK Weekend Peak
Dth
370,000
360,000
350,000
340,000
330,000
320,000
310,000
300,000
290,000
365,867
359,178
334,943
331,354
318,387
12/22/2022
1/12/2024
1/13/2024
1/14/2024
1/15/2024

Demand by Area



Total Dth: 359,178 365,867 318,387 331,354



	1/12/2024	1/13/2024	1/14/2024	1/15/2024	1/16/2024
ID	94%	94%	76%	71%	72%
WA	93%	94%	75%	71%	72%
KF	51%	41%	53%	53%	60%
LaGrande	84%	96%	79%	87%	89%
Med	54%	52%	44%	54%	69%
Rose	50%	39%	54%	68%	70%

Work Plan

TAC 1 – 2025 Gas IRP

February 14, 2024

Schedule and Topics

- **TAC 1: Wed. February 14, 2024: 9:00 am to 12:00 pm (PTZ)**
  - January Peak Event
  - Work Plan
  - RNG Acquisition
  - Customer Impacts
  - Modeling Update
  - State Policy Update
  - Planned Scenarios for Feedback
- **TAC 2: Wed. April 24, 2024: 10:30 am to 12:00 pm (PTZ)**
  - Feedback from prior TAC (10 min.)
  - Action Items from 2023 IRP (30 min.)
  - Chosen Model Methodology and modeling overview (50 min.)
- **TAC 3: Wed. 15 May 2024: 10:30 am to 12:00 pm (PTZ)**
  - Feedback from prior TAC (10 min.)
  - Distribution System Modeling (45 min.)
  - Non-Pipe Alternatives (NPA) in Distribution Planning (20 min.)
  - Oregon Staff Recommendation on NPA (15 min.)
- **TAC 4: Wed. 5 June 2024: 10:30 am to 12:00 pm (PTZ)**
  - Feedback from prior TAC (10 min.)
  - Future Climate Analysis Update (45 min.)
  - Historic weather comparison (15 min.)
  - Peak Day Methodology (20 min.)
- **TAC 5: Wed. 26 June 2024: 10:30 am to 12:00 pm (PTZ)**
  - Feedback from prior TAC (10 min.)
  - GHG assumptions and Climate pricing (40 min.)
  - Current natural gas resources (40 min.)
- **TAC 6: Wed. 17 July 2024: 10:30 am to 12:00 pm (PTZ)**
  - Feedback from prior TAC (10 min.)
  - Load Forecast – AEG (80 min.)

Schedule and Topics

- **TAC 7: Wed. 7 Aug. 2024: 10:30 am to 12:00 pm (PTZ)**
  - Feedback from prior TAC (10 min.)
  - Natural Gas Market Overview and Price Forecast (40 min.)
  - New Resource Options Costs and Assumptions (40 min.)
- **TAC 8: Wed. 28 Aug. 2024: 10:30 am to 12:00 pm (PTZ)**
  - Feedback from prior TAC (10 min.)
  - Conservation Potential Assessment (AEG) (30 min.)
  - Demand Response Potential Assessment (AEG) (20 min.)
  - Conservation Potential Assessment (ETO) (30 min.)
- **TAC 9: Wed. 18 Sep. 2024: 10:30 am to 12:00 pm (PTZ)**
  - Feedback from prior TAC (10 min.)
  - NEI Study (Placeholder if study is conducted) (30 min.)
  - Avoided Costs Methodology (20 min.)
  - All assumptions review (30 min.)
- **TAC 10: Wed. 6 Nov. 2024: 9:00 am to 12:00 pm (PTZ)**
  - Scenario Results (30 min.)
  - Scenario Risks (30 min.)
  - PRS Overview of selections and risk (30 min.)
  - Per Customer Costs by Scenario (15 min.)
  - Cost per MTCO2e by Scenario (15 min.)
  - Open Questions (60 min.)
- **Sep. 2024 -** Virtual Public Meeting- Natural Gas & Electric IRP
  - Recorded presentation
  - Daytime comment and question session (12pm to 1pm- PTZ)
  - Evening comment and question session (6pm to 7pm- PTZ)

Work Plan Summary

- This plan outlines the process Avista will follow to develop its 2025 Gas IRP for filing with the Idaho, Oregon, and Washington Commissions by April 1, 2025. Avista uses a transparent public process to solicit technical expertise and stakeholder feedback throughout the development of the IRP through a series of Technical Advisory Committee (TAC) meetings and public outreach to ensure its planning process considers input from all interested parties prior to Avista's decisions on how to meet future customer gas needs. Avista posts all meetings announcements, meeting minutes, videos, final IRP documents and data on its website at https://www.myavista.com/about-us/integrated-resource-planning. Avista will communicate with its TAC members through email and Microsoft Teams for any meeting information and data sharing outside of TAC meetings. Avista will provide all information related to TAC meeting content prior to, or shortly after, each TAC meeting if any updates to presentations or data have been made. Final data and documents will be made available upon filing of the IRP.

- The 2025 IRP process will explore the use of new modeling techniques. The models under consideration include PLEXOS, as used in the 2023 IRP, but it is also considering internally developed tools are under exploration. Costs of models have been steadily increasing and have created an opportunity to evaluate alternative modeling options to help contain costs to customers while providing the same level of analysis and considerations necessary in an IRP. Avista may use Avista's Electric IRP's PRiSM for certain resource selection options but intends to investigate alternative options to PLEXOS for the ability to provide this functionality in a timely manner for all jurisdictions. Avista will share outcomes of modeling comparisons prior to a decision to move toward a selected model.

- Avista contracted with Applied Energy Group (AEG) to assist with key activities including the energy efficiency and demand response potential studies. AEG will also provide the IRP with a long-term energy forecast using end use techniques to improve estimates for building and transportation electrification scenarios. Avista also intends to align the IRP's load forecast and resource options with this study. The Energy Trust of Oregon (ETO) will continue to provide results for the Avista Oregon territories and will be directly input into the model as a cost and load savings.

- Avista intends to use both detailed site-specific and generic resource assumptions in the development of the 2025 IRP. The assumptions will utilize Avista's research of similar gas producing technologies, engineering studies, vendor estimates and market studies. Avista will rely on publicly available data to the maximum extent possible and provide its cost and operating characteristic assumptions and model for review and input by stakeholders. The IRP may model certain resources as Purchase Agreements rather than Company ownership if third party ownership is likely to be lower cost. Future Requests for Proposals (RFP) will ultimately decide final resource selection and ownership type based on third party resource options and potential self-build resources specific to Avista's service territory.

Work Plan Summary (cont.)

- Avista intends to create a Preferred Resource Strategy (PRS) using market and policy assumptions based on final rules from the Climate Commitment Act (CCA) for Washington. In Oregon the Climate Protection Plan (CPP) will be included as a scenario as the Department of Environmental Quality moves to re-establish the program in 2024. Conversations with the TAC as to methods and logic to include in scenarios will be discussed including beginning the program in 2025 for the PRS. Final CPP rules, that may be the same, will not be known until after the modeling and process of the 2025 IRP is completed. A similar outcome is possible with the Climate Commitment Act (CCA). A public initiative providing sufficient signatures was submitted to the Legislature where it can be repealed, altered or voted on in the November 2024 election. A further outcome includes the possibility of joining the California cap and trade program. This will also alter program rules of the CCA to conform to the California cap and trade program rules more closely. Finally, a least cost planning methodology will be used in Idaho. For Washington resource selection, Avista will solve its PRS to include least reasonable cost for meeting state energy policies including energy costs, societal externalities such as Social Cost of Greenhouse Gas , and the non-energy impacts of resource on public health (air emissions), safety, and economic development . Resource selection will solve for state clean energy requirements and Avista's energy and capacity planning standards. Avista will track certain customer metrics the PRS creates to assist in measuring customer equity.

- The plan will also include a chapter outlining the key components of the PRS with a description of which state policy is driving each resource need. The IRP will include a limited number of scenarios to address alternative futures in the gas market and public policy, such as limited RNG and building electrification. TAC meetings help determine the underlying assumptions used in the IRP including market scenarios and portfolio studies. Although, Avista will also engage customers using a public outreach and an informational event as well as provide transparent information on the IRP website. The IRP process is technical and data intensive; public comments are encouraged as timely input and participation ensures inclusion in the process resulting in a resource plan submitted according to the proposed schedule in this Work Plan to meet regulatory deadlines. Avista will make all data available to the public *except* where it contains market intelligence or proprietary information. The planned schedule for this data is shown in Exhibit 1. Avista intends to release slides and data five days prior to its discussion at Technical Advisory Committee meetings and expects any comments within two weeks after the meeting.

Sections in IRP

1. **Introduction and Planning Environment**
    a. Customers
    b. Integrated Resource Planning
    c. Planning Model
    d. Planning Environment
2. **Demand Forecasts**
    a. Demand Areas
    b. Customer Forecasts
    c. Electrification of Natural Gas Customers
    d. Use-per-Customer Forecast
    e. Weather Forecast
    f. Peak Day Design Temperature
    g. Load Forecast
    h. Scenario Analysis
    i. Alternative Forecasting Methodologies
    j. Key Issues
3. **Demand Side Resources**
    a. Avoided Cost
    b. Idaho and Washington Conservation Potential Assessment
    c. Pursuing Cost-Effective Energy Efficiency
    d. Washington and Idaho Energy Efficiency Potential
    e. Demand Response
    f. Building Electrification
4. **Current Resources and New Resource Options**
    a. Natural Gas Commodity Resources
    b. Transportation Resources
    c. Storage Resources
    d. Incremental Supply-Side Resource Options
    e. Alternative Fuel Supply Options
    f. Project Evaluation - Build or Buy
    g. Avista's Natural Gas Procurement Plan
    h. Market-Related Risks and Risk Management
5. **Policy Issues**
    a. Avista's Environmental Objective
    b. Natural Gas Greenhouse Gas System Emissions
    c. Local Distribution Pipeline Emissions - Methane Study
    d. State and Regional Level Policy Considerations
    e. Idaho
    f. Oregon
    g. Washington
    h. Federal Legislation
    i. Customer Market study
    j. Key Takeaways
6. **Preferred Resource Strategy**
    a. Planning Model Overview
    b. Stochastic Analysis
    c. Resource Integration
    d. Carbon Policy Resource Utilization Summary
    e. Resource Utilization
    f. Demand and Deliverability Balance
    g. New Resource Options and Considerations
    h. Energy Efficiency Resources
    i. Preferred Resource Strategy (PRS)
    j. Monte Carlo Risk Analysis
    k. Estimated Price Impacts
7. **Alternate Scenarios**
    a. Alternate Demand Scenarios
    b. Deterministic – Portfolio Evaluation and Scenario Results
    c. Demand
    d. PRS Scenarios
    e. Electrification Scenarios
    f. Supply Scenarios
    g. Other Scenarios
    h. Washington Climate Commitment Act Allowances
    i. Oregon Community Climate Investments
    j. Natural Gas Use
    k. Synthetic Methane
    l. Renewable Natural Gas
    m. Emissions
    n. Cost Comparison
    o. Regulatory Requirements
8. **Distribution Planning**
    a. Distribution System Planning
    b. Network Design Fundamentals
    c. Computer Modeling
    d. Determining Peak Demand
    e. Distribution System Enhancements
    f. Conservation Resources
    g. Distribution Scenario Decision-Making Process
    h. Planning Results
    i. Non-Pipe Alternatives
9. **Equity Considerations**
    i. Overview
    j. Equity Metrics
10. **Action Plan**
    a. Avista's 2025 IRP Action Items
    b. 2025-2026 Action Plan

Major Timeline

Exhibit 1: Major 2025 Gas IRP Assumption Timeline	
Task	**Target Date**
Market Price Assumptions	August 2024
CCA/Other GHG Pricing Assumptions	June 2024
Natural Gas price forecast	August 2024
New Resource Options Cost & Availability	August 2024
AEG Deliverables Final Energy Forecast Energy Efficiency and Demand Response Potential Assessment	August 2024
Due date for study requests from TAC members	July 30, 2024
Determine portfolio & market future studies	July 2024
Finalize resource selection model assumptions	September 2024

Next Steps

- Feedback from TAC of areas missing or additional topics needed to add to the workplan
  - Please submit areas of concern by March 15th, 2024
- File Plan by April 1, 2024

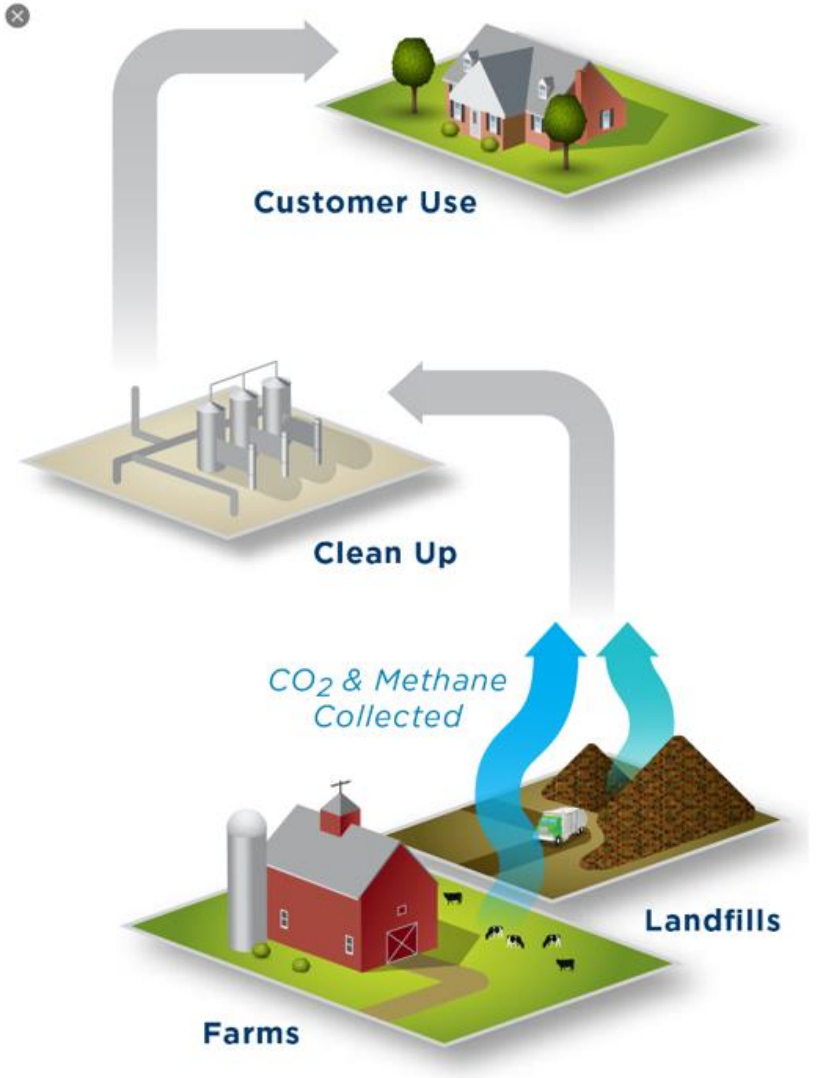
Renewable Natural Gas Acquisition

TAC 1 – 2025 Gas IRP

February 14, 2024

Procurement Process

RNG is a drop-in replacement for Natural Gas
Keep the pipes Change the fuel
Regardless of procurement strategy



Primary pathways to RNG procurement:
Buy: • Avista has commenced an annual RFP cycle to test the market for least cost RNG project investments and RNG offtake opportunities **Build:** • Avista has considered developing RNG capital investment projects as self-build projects at a feedstock host sites

Procurement - Build

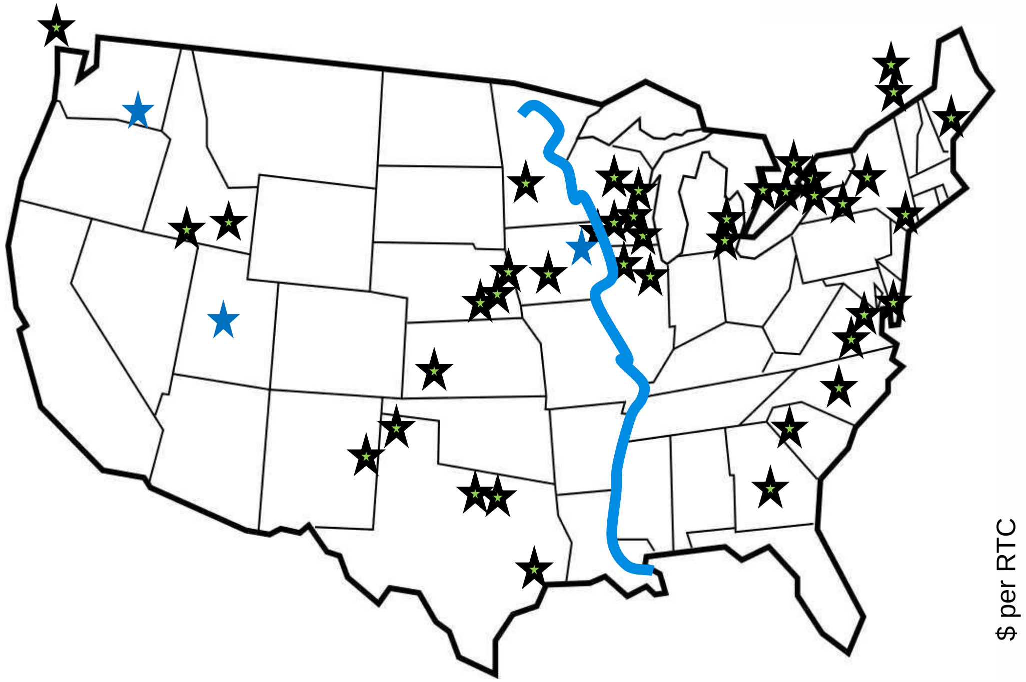
- **Avista has considered developing RNG projects under Oregon SB 98 and Washington HB 1257. Through this effort Avista has developed an understanding of the costs and risks associated RNG development. Some observations and challenges include:**
  - Cost varies by feedstock type and distance to interconnection point.
  - Utilities desiring to develop RNG projects are fully dependent on a feedstock host site with an owner that is willing to collaborate and cooperate and be patient with the development lead times & the regulatory process.
  - The regulatory process, timing, and uncertainty of cost recovery is undesirable as compared to “buy” alternatives.
  - Private developers are nimble, may build at a lower cost and can access all markets.
  - Higher risk profile

Procurement - Buy

- **Avista has commenced an annual RFP process in 2022 seeking:**
- Bundled or unbundled RNG RTC supply
- RNG Projects – Investment/partnering opportunities (Build)
- Long Term (15 year) RNG Offtake opportunities (Buy)

- **Some observations from the RFP process:**
- RNG Developers are offering lower coast as compared to Marketers/Brokers
- Nearly all RFP proposals have been for unbundled RNG environmental attributes only proposals.
- Projects are distributed across North America with only two in the PNW.
- RNG developers are nimble, may build at a lower cost and can access all markets.
- Lower risk profile

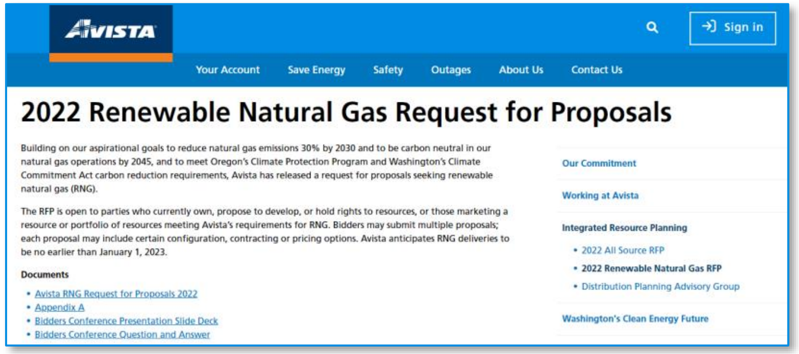
2022 Request for Proposals for Renewable Natural Gas



15 Respondents

47 Projects

7.8 – 9.5 M RTCs


Sign in
Your Account
Save Energy
Safety
Outages
About Us
Contact Us

2022 Renewable Natural Gas Request for Proposals

Building on our aspirational goals to reduce natural gas emissions 30% by 2030 and to be carbon neutral in our natural gas operations by 2045, and to meet Oregon's Climate Protection Program and Washington's Climate Commitment Act carbon reduction requirements, Avista has released a request for proposals seeking renewable natural gas (RNG).

The RFP is open to parties who currently own, propose to develop, or hold rights to resources, or those marketing a resource or portfolio of resources meeting Avista's requirements for RNG. Bidders may submit multiple proposals; each proposal may include certain configuration, contracting or pricing options. Avista anticipates RNG deliveries to be no earlier than January 1, 2023.

Documents

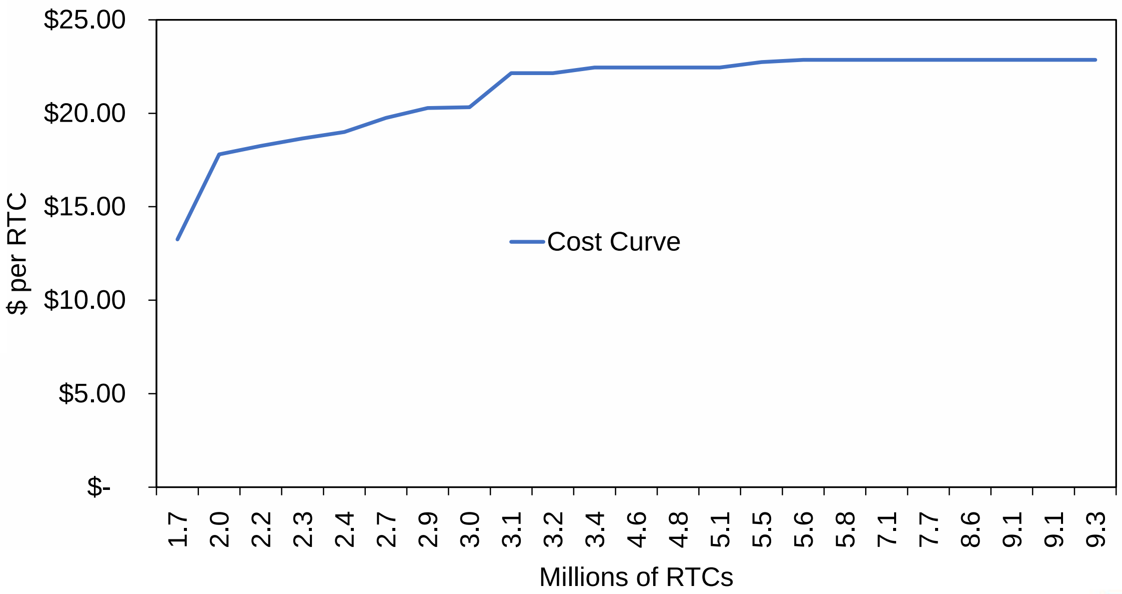
- Avista RNG Request for Proposals 2022
- Appendix A
- Bidders Conference Presentation Slide Deck
- Bidders Conference Question and Answer

Our Commitment

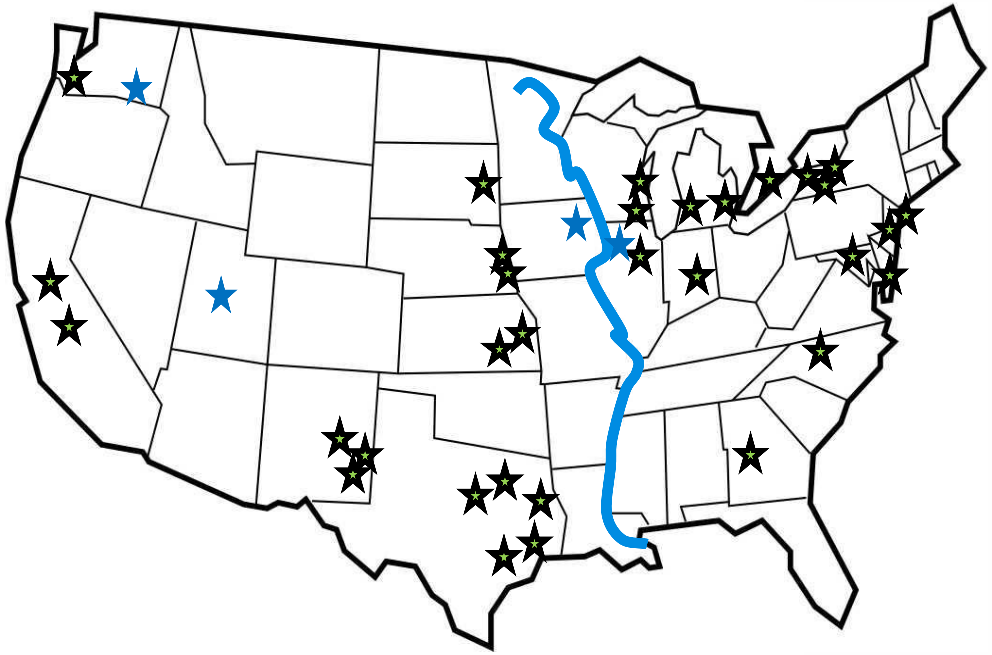
Working at Avista

Integrated Resource Planning
- 2022 All Source RFP
- 2022 Renewable Natural Gas RFP
- Distribution Planning Advisory Group

Washington's Clean Energy Future



2023 Request for Proposals for Renewable Natural Gas



12 Respondents

22 + Projects

10 M RTCs – RNG

14 M RTCs – Alt Fuels

AVISTA

Your Account Save Energy Safety Outages About Us

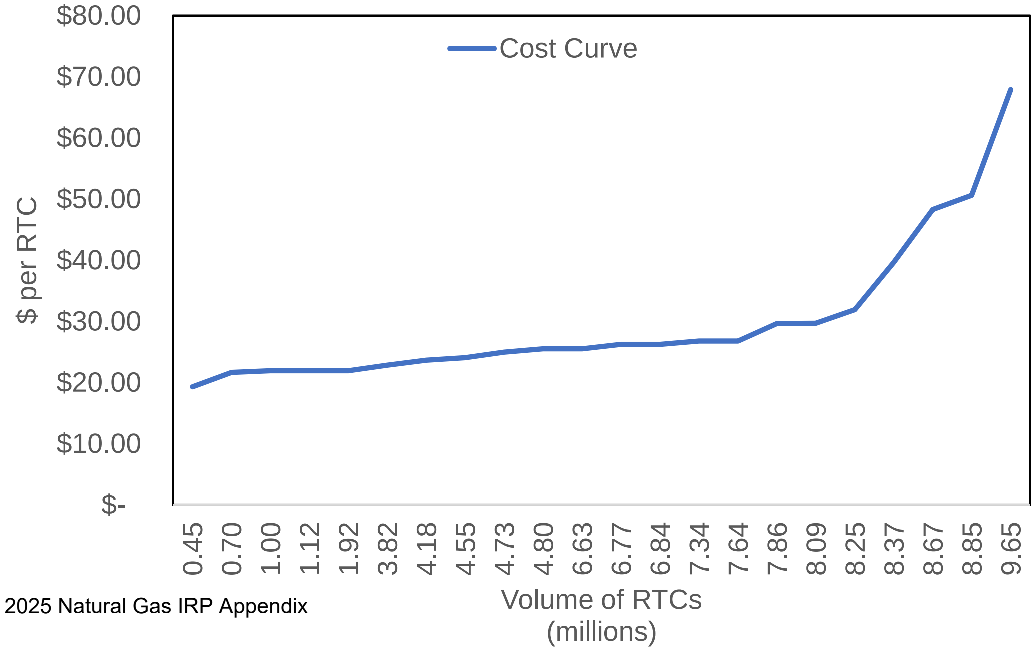
2023 RNG/RSG Request for Proposals

Building on our aspirational goals to reduce natural gas emissions 30% by 2030 and to be carbon neutral in our natural gas operations by 2045, and to meet Oregon's Climate Protection Program and Washington's Climate Commitment Act carbon reduction requirements, Avista has released a request for proposals seeking renewable natural gas (RNG) / Responsibly Sourced Gas (RSG).

The RFP is open to parties who currently own, propose to develop, or hold rights to resources, or those marketing a resource or portfolio of resources meeting Avista's requirements for RNG/RSG. Bidders may submit multiple proposals; each proposal may include certain configuration, contracting or pricing options. Avista anticipates RNG/RSG deliveries to be no earlier than January 1, 2024.

Documents

- Avista RNG Request for Proposals 2023
- Exhibit A
- RNG & RSG Request for Proposals Bidders Conference Presentation
- RNG/RSG Vendor Template
- RNG RFP Bidders Conference Questions and Answers



2022-2023 Offtake Contracts for RNG

Avista has executed four RNG contracts with Pine Creek Renewable Natural Gas

<u>Horn Rapids Landfill RNG - Richland, Washington</u>

- 15 Year off-take contract
- Deliveries expected Q1 2024

<u>Black Hawk County Landfill RNG - Waterloo, Iowa</u>

- 15 Year off-take contract
- Deliveries expected Q4 2024

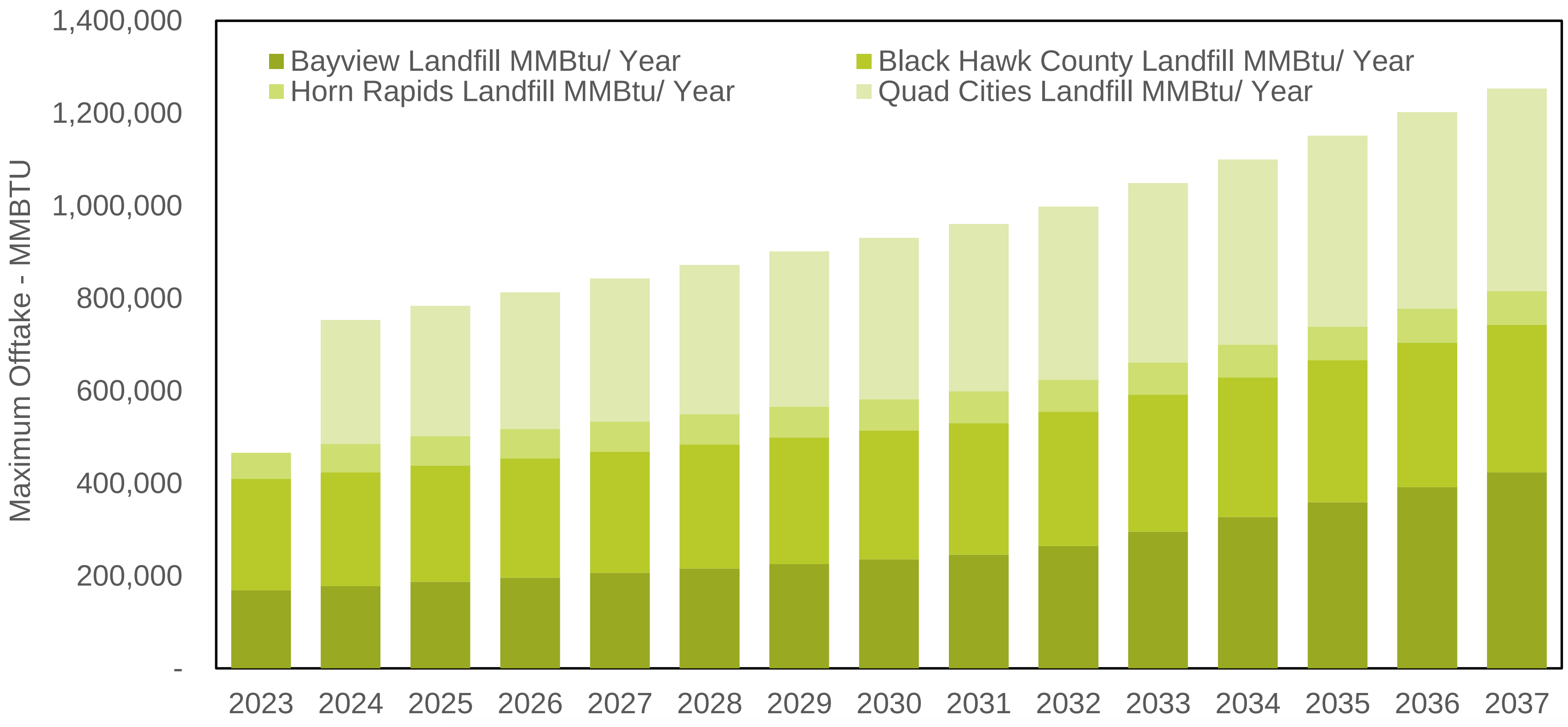
<u>Bayview Landfill RNG – Elberta, Utah</u>

- 15 Year off-take contract
- Deliveries expected Q1 2024

<u>Quad Cities Landfill Facility RNG - Milan, Illinois</u>

- 15 Year off-take contract
- Deliveries expected Q4 2024

Pine Creek RNG Offtake Supply Contracts



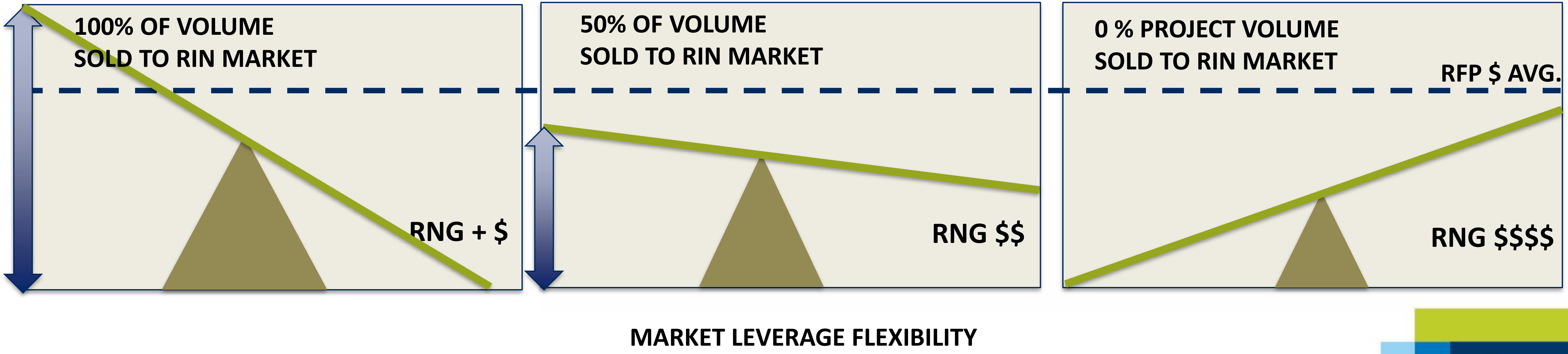
RNG Offtake Contract & Market Structure

- Contract Duration: 15 Years commencing in 2024 - 2025
- Contracts represent 50% & 100% of RNG Project Volumes:
- Environmental Attributes only (unbundled) purchased as Renewable Thermal Certificates (RTC)
- Attribute Tracking: tracked in M-RETS
- Developer RNG produces or mints and sells Environmental Attributes as RTC's and RIN's

RNG Offtake Market Structure

Volume of RIN's pointed to Transportation Market (EPA RSF) (% Flexible):

1. RIN's produce revenue
2. RNG developer administers RIN transactions and shares % of RIN revenue with Avista
3. RIN revenues subsidize Avista net RNG cost (RNG cap price - RIN Revenue = subsidized RNG cost)
4. Through this structure Avista customers enjoy RNG at below RNG market cost
5. The higher the value of the RIN the more Revenue



Customer Impacts

TAC 1 – 2025 Gas IRP

February 14, 2024

Customer Impact Considerations

Possible methods to add equity into the 2025 Gas IRP:

1) Add an Equity Chapter
2) Include metric results in the IRP Equity chapter and others, including:
   - GHG emissions
   - Rates
   - Energy Burden
   - Potential for other air emissions
3) Map out Avista “named communities”
4) Distribution equity: Non-Pipe Alternatives (NPA) for any distribution upgrade
   - This topic will be discussed in detail in TAC 2 with distribution planning
5) NEI Study?

Energy Justice Core Tenets with IRPs

- **Recognition:**
  - Identify Named Communities
  - Quantify Energy Burden
- **Distribution:**
  - Performance measures
  - Account for Non-Energy Impacts
- **Procedural:**
  - Open Technical Advisory Committee Meetings
  - On-line Customer Oriented Planning Sessions
- **Restorative:**
  - Energy Efficiency Programs
  - Non-Pipe Alternative
    - Distribution Planning

NEI Study Request Overview

Avista is seeking assistance to identify societal non energy impacts (NEI) for resource decisions in the natural gas distribution business. As Avista and other regional utilities will be seeking alternative natural gas fuel supplies over the coming decades to comply with state clean energy policies. Avista seeks to understand costs and benefits to resource decisions going beyond reduction in greenhouse gas emissions.

Avista seeks to understand NEI's for the following resource alternatives:

- Renewable Natural Gas
- Hydrogen & Synthetic Methane
- Natural Gas

Study Overview

Area of Study	Generalized Approach
Public Health	Air emissions contributed due to consumption of hydrocarbons consumed during the <u>production</u> of the fuel. Such as PM2.5, SO_2, NO_X, and GHG. Also include difference in methane or other GHG as compared to traditional natural gas.
Safety	Fatalities and injuries resulting from operations of production
Land Use	Consider the footprint of facilities that are above and beyond the standard calculations considered as part of alternative facility construction for the required energy. Displacement of land that was beyond the facility's footprint may also be considered.
Water Use	Identify water usage and impact of usage on process with return of a product back to a clean product (i.e. fracking water not always useful after usage)
Economic	Induced economic impact to the facilities construction and operation, including job growth.
Community Odor Pollution	Aromatic quality of the air in the community including mercaptan and organic decomposition. This should also consider the air quality of processes to create fuels.
Process Bi-products	Value in the creation of biproducts such as carbon black, biochar, fertilizers, carbon fiber, or graphite.
Local Distribution Pipeline	Impacts related increase or decrease in requirement to the Local Distribution Company (LDC) pipeline network, includes qualify of gas and volume impacts

Study Summary

- For each fuel type discussed below a cost estimate in a US $ per dekatherm equivalent for each NEI is required

- If the NEI impact is related to construction, these benefits may be levelized over the life of the project when calculating the $ per dekatherm equivalent.

- For processes requiring electricity for production, NEI's for the electric demand is not required, but the electric consumption shall be provided (i.e. kWh per mmBTU).

Modeling Update

TAC 1 – 2025 Gas IRP

February 14, 2024

Timeline: IRP Modeling Software

Prior to 2023		2023 IRP		2025 IRP
SENDOUT®	→	PLEXOS®	→	?

Potential 2025 IRP Modeling Software

SENDOUT®

- "SENDOUT is used by energy companies as the foundation for gas supply planning and asset valuation analytical processes. Hitachi Energy gas analytics solution set incorporates scenario and stochastic analysis and simulates forward curves and related trading behavior. The software suite provides an assessment of gas portfolio costs, reliability, risks, and opportunities, revealing the impact of potential operating, weather, and price conditions." [1]

PLEXOS®

- "PLEXOS® is a powerful simulation engine that provides analytics and decision-support to modellers, generators, and market analysts—offering flexible and precise simulations across electric, water, gas and renewable energy markets." [2]

Avista CROME - What'sBest!®

- "What's*Best!* is an add-in to Excel that allows you to build large scale optimization models in a free form layout within a spreadsheet. What's*Best!* combines the proven power of Linear, Nonlinear (convex and nonconvex/Global), Quadratic, Quadratically Constrained, Second Order Cone, Semi-Definite, Stochastic, and Integer optimization with Microsoft Excel -- the most popular and flexible business modeling environment in use today." [3] Avista would use this software functionality to build and solve CROME (Comprehensive Resource Optimization Model in Excel)

[1] https://www.hitachienergy.com/products-and-solutions/energy-portfolio-management/enterprise/sendout
[2] https://www.energyexemplar.com/hubfs/Brochures/PLEXOS%20Gas%20-%20Brochure%20-%20A4.pdf
[3] https://www.lindo.com/index.php/products/what-sbest-and-excel-optimization

Selection Criterion

TRANSPARENCY	FLEXIBILITY
SPEED	COST

TRANSPARENCY

Avista CROME - What'sBest!®

- Modeled in Microsoft Excel
- Accessible platform used by large and diverse population
- Inputs, assumptions, constraints, logic, and results are accessible without license
- Requires license to solve
- Documentation not complete

PLEXOS®

- Increasingly common software among gas and electric utilities
- Requires license to view, solve, and read documentation

SENDOUT®

- Updates are no longer available
- LDC use throughout the northwest is decreasing
- Requires license to view, solve, and read documentation

FLEXIBILITY

PLEXOS BY ENERGY EXEMPLAR

Avista CROME - What'sBest!®

- Ability to model new concepts is not constrained
- Data files are limited to size of spreadsheet
- Instant output of model results in required usable format
- Understanding of calculations and methods used within the program

PLEXOS®

- Receives regular updates
- Workarounds available to model unique scenarios and resources
- Large database files produced
- Data needs manipulation to understand and provide in usable format

SENDOUT®

- Not easily flexible to include climate programs and emission factors
- Large database files produced
- Data needs manipulation to understand and provide in usable format

SPEED

Avista CROME - What'sBest!®

- Initial testing indicates sufficient speed to meet IRP deadlines
- Ability to run multiple instances per license

PLEXOS®

- Sufficient speed to meet 2023 IRP deadlines
- Ability to run on multiple computers with upgrade to base modeling software
- Cloud-based service available

SENDOUT®

- Sufficient speed to meet IRP deadlines prior to 2023
- Ability to run on multiple computers
- Has not been tested with new policies (CCA, CPP) and unique resources

COST

Avista CROME - What'sBest!®

- Software is purchased and only cost would be to add licenses as needed
- Relatively inexpensive when compared to alternatives
- Likely least cost option when considering software upgrades

PLEXOS®

- Annual subscription-based software
- Relatively expensive
- Time to familiarize new and infrequent users to software and modeling interface

SENDOUT®

- Software is purchased and no additional costs
- Time to familiarize new and infrequent users to software and modeling interface

*Additional computer hardware, training and computer costs are not included

Timeline: IRP Modeling Software

Prior to 2023

SENDOUT®

→

2023 IRP

PLEXOS®*

→

2025 IRP

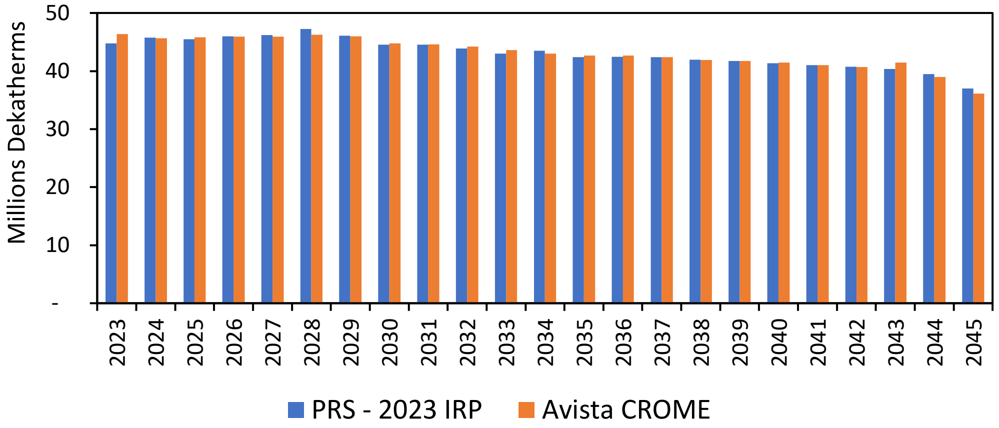
2025 IRP

- What's Best!
- PLEXOS
- SENDOUT
- Other

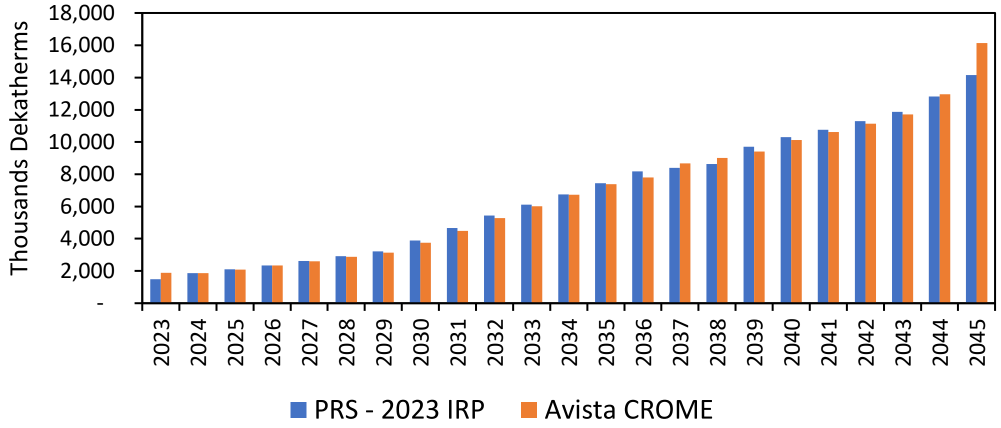
*Need to decide on extending contract in late March 2024

Initial Deterministic Model Comparison

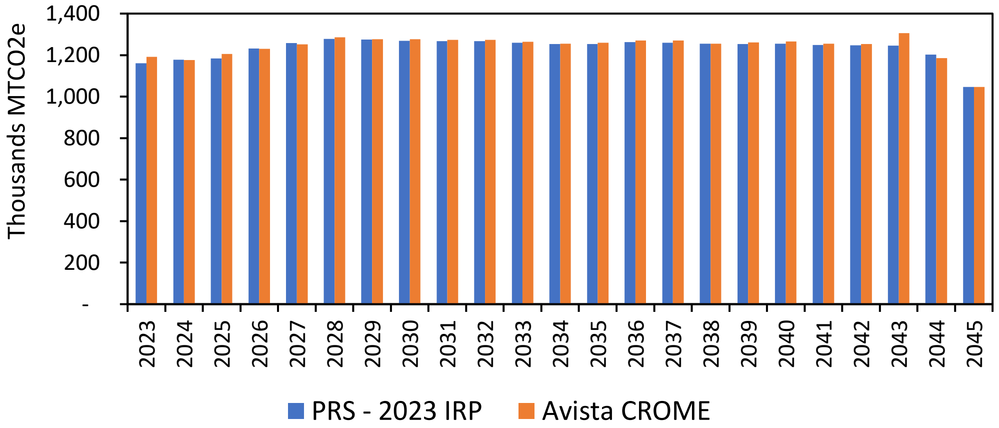
Natural Gas



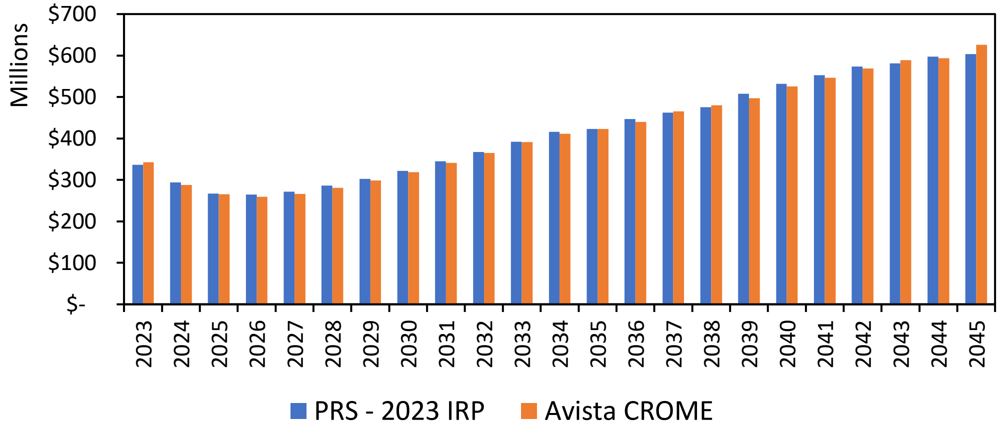
Renewables*



Compliance Mechanisms**



Annual System Costs

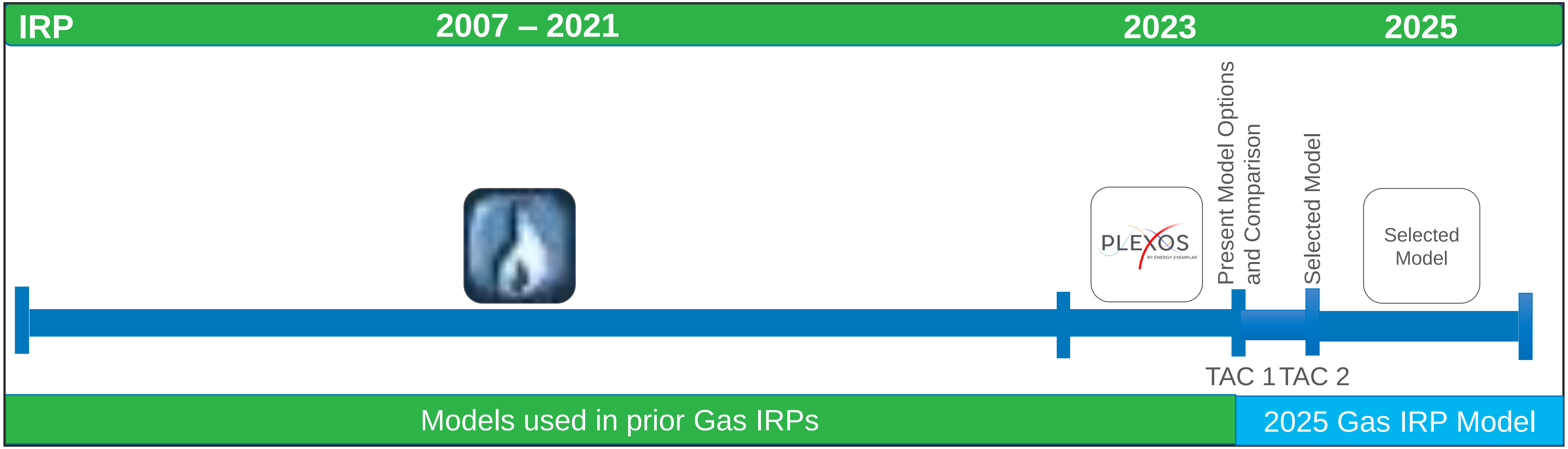


*Includes RNG, H2, and Synthetic Methane

** Includes Allowances and CCIs

Next Steps

- Continue validating CROME built with What's Best
- Chosen model methodology update - TAC 2



State Policy Update

TAC 1 – 2025 Gas IRP

February 14, 2024

Building Codes in Washington

- In November 2023, the building code updates were voted into code by the SBCC
  - Under the new rules, a builder will need five credits for a home of less than 1,500 square feet. That's double the prior requirement. For a home between 1,500 and 5,000 square feet, they will need eight credits, up from five
  - More credits are given for the use of an electric heat pump than a natural gas furnace
  - These codes are effective March 15, 2024
  - The standard reference design shall be a heat pump water heater meeting efficiency standards of Table C404.2 of chapter 51-11C WAC

 [CR102_WSEC_R_EPCA_complete_101823.pdf (wa.gov)]

Space Heat Source Credits

TABLE R406.2

((~~FUEL NORMALIZATION~~)) ENERGY EQUALIZATION CREDITS

System Type	Description of Heating Sources	Credits	
		All Other	Group R-2[a]
1	For combustion heating system using equipment meeting minimum federal efficiency standards for the equipment listed in Table C403.3.2(5) or C403.3.2(6)	((~~-3.0~~)) 0	0
2	For an initial heating system using a heat pump that meets federal standards for the equipment listed in Table C403.3.2(2) and supplemental heating provided by electric resistance or a combustion furnace meeting minimum standards listed in Table C403.3.2(5)[b]	((~~0~~)) 1.5	0
3	For heating system based on electric resistance only (either forced air or zonal)	((~~-1.0~~)) 0.5	-0.5
4[c]	For a heating system using a heat pump that meets federal standards for the equipment listed in Table C403.3.2(2) or C403.3.2(9) **or** Air to water heat pump units that are configured to provide both heating and cooling and are rated in accordance with AHRI 550/590	((~~1.5~~)) 3.0	2.0
5	For heating system based on electric resistance with: 1. Inverter-driven ductless mini-split heat pump system installed in the largest zone in the dwelling **or** 2. With 2 kW or less total installed heating capacity per dwelling	((~~0.5~~)) 2.0	0

a See Section R401.1 and *residential building* in Section R202 for Group R-2 scope.

b The gas back-up furnace will operate as fan-only when the heat pump is operating. The heat pump shall operate at all temperatures above 38°F (3.3°C) (or lower). Below that "changeover" temperature, the heat pump would not operate to provide space heating. The gas furnace provides heating below 38°F (3.3°C) (or lower).

c Additional points for this HVAC system are included in Table R406.3.

Source: CR102_WSEC_R_EPCA_complete_101823.pdf (wa.gov)

CCA

- In November 2023, signatures were delivered under initiative 2117 to repeal legislation establishing the cap and invest program

Possible Outcomes of CCA	Potential Benefits	Potential Drawbacks
Legislature votes to repeal	Certainty of outcome without legal delay or ballot initiative to voters	Uncertainty of future climate program or what to do with funds from auctions
Draft and pass an alternative initiative	Gives the legislature a chance to fix program elements	-May not fix all program issues leading to risk in program -Subject to voter approval alongside original version of I-2117
Link to California	-Create a more robust marketplace for allowances, same trading system (potential cost/credit) -Washington would recognize projects located in the other jurisdictions	-More entities in the pool for allowances or offsets, new -Compliance period moves to every 3 years
Refuses to Act	People will decide in November 2024 election	Create uncertainties if program is repealed
Voters Repeal	Certainty of outcome without legal delay	Uncertainty of future climate program or what to do with funds from auctions

CPP

- On December 20, 2023 it was ruled the DEQ did not fully comply with notice requirements during the rulemaking process for the program, thereby invalidating the final rules and the program

- On January 22, 2024 the DEQ moves to re-establish the CPP
  - Process takes about 12 months (including public comment period)
  - DEQ will propose the rules for adoption to the Environmental Quality Commission (governing body)
  - The rules could change during the rulemaking process, including having new elements or shifting timelines per the DEQ

Next Steps

- Work with the TAC to develop scenarios to consider risks involved in different pathways for state policy and the various potential outcome
- Determine a base case for state policy for use in the Preferred Resource Selection (PRS) scenario

Planned Scenarios

TAC 1 – 2025 Gas IRP

February 14, 2024

Scenarios

Preferred Resource Case	***Our expected case based on assumptions and costs with a least risk and least cost resource selection. This scenario includes all known policies and orders from Idaho, Oregon and Washington***
Preferred Resource Case (Low/High) Prices	Same as PRS, but includes a scenario with a low-price curve for natural gas and a scenario with a high price curve for natural gas
Preferred Resource Case CCA Ceiling Prices	PRS assumptions with a high cost for allowances
Preferred Resource Case with CPP	PRS assumptions, but includes the CPP expectations going forward from 2025
Electrification (low,expected,high) conversion costs	A low case to show the risk involved with energy delivered through the natural gas infrastructure moving to the electric system with different levels of conversion costs
Hybrid Heating Case	A scenario to include hybrid heating for temperatures below 40 degrees Fahrenheit
High Customer Case	A high case to measure risk of additional customer and meeting our emissions and energy obligations
Limited RNG Availability	A scenario to show costs and supply options if RNG availability is smaller than expected
High RNG Costs	A scenario to measure resource selection with a higher-than-expected set of RNG costs by source
Interrupted Supply	A scenario to show the impacts and risks associated with large scale supply impacts and the ability for Avista to provide the needed energy to our customers
Carbon Intensity	Include carbon intensity of all resources from Preferred Resource Case including upstream emissions on natural gas
Natural Gas Only	A case to help compare costs of resource decisions from climate policy. This case assumes no alternative fuels or climate policy with natural gas, energy efficiency and demand response as the expected future resource options
Social Cost of Carbon	A scenario to value resources in all locations using the Social Cost of Carbon @ 2.5% and includes upstream emissions
Average Case	Non climate change projected 20-year history of average daily weather and excludes peak day

2025 Natural Gas Integrated Resource Plan

Technical Advisory Committee Meeting No. 2 Agenda

Wednesday, April 24, 2024

Virtual Meeting

Topic	Time (PTZ)	Staff
Agenda/Meeting Guidelines	10:30	Tom Pardee
Action Items	10:40	Tom Pardee
Modeling/Assumptions Overview	11:00	Tom Pardee
CROME High Level Overview	11:25	Michael Brutocao

Microsoft Teams meeting

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2023 Gas IRP Action Items

Summary of Acknowledgement

- Idaho – Acknowledged (November 1, 2023)
- Oregon – Pending short term acknowledgment
- Washington – No word on acknowledgment

Avista – 2023 Gas IRP Actions

1. ETO identified 546,000 therms in the 2023 IRP verses 427,000 therms of planned savings in the 2023 ETO Budget and Action Plan. Avista will work with ETO to meet IRP gross savings target of 568,000 therms in 2024.
2. New program offered by ETO for interruptible customers in 2023 to save 15,000 therms.
3. Engage Oregon stakeholders to explore additional new offerings for interruptible and low-income customers to work towards identified savings of 375,000 therms in 2024.
4. In Washington purchase allowances or offsets for compliance to the Climate Commitment Act for years 2023, 2024, 2025 and 2026 to comply with emissions reduction targets.
5. Begin to offer a Washington transport customer EE program by 2024 with the goal of saving 35,000 therms
6. Explore methods for using Non-Energy Impact (NEI) values in future IRP analysis to account for social costs in Washington to ensure equitable outcomes.
7. Explore using end use modeling techniques for forecasting customer demand.
8. Consider contracting with an outside entity to help value supply side resource options such as synthetic methane, renewable natural gas, carbon capture, and green hydrogen.
9. Regarding high pressure distribution or city gate station capital work, Avista does not expect any supply side or distribution resource additions to be needed in our Oregon territory for the next four years, based on current projections. However, should conditions warrant that capital work is needed on a high-pressure distribution line or city gate station in order to deliver safe and reliable services to our customers, the Company is not precluded from doing such work. Examples of these necessary capital investments include the following:
   - Natural gas infrastructure investment not included as discrete projects in IRP
     - Consistent with the preceding update, these could include system investment to respond to mandates, safety needs, and/or maintenance of system associated with reliability
       - Including, but not limited to Aldyl A replacement, capacity reinforcements, cathodic protection, isolated steel replacement, etc.
     - Anticipated PHMSA guidance or rules related to 49 CFR Part §192 that will likely require additional capital to comply
       - Officials from both PHMSA and the AGA have indicated it is not prudent for operators to wait for the federal rules to become final before improving their systems to address these expected rules.
     - Other special contract projects not known at the time the IRP was published
   - Other non-IRP investments common to all jurisdictions that are ongoing, for example:
     - Enterprise technology projects & programs
     - Corporate facilities capital maintenance and improvements

IPUC - Recommendations

No.	Recommendation	2025 IRP
1	Staff recommends the Company's 2023 Natural Gas IRP be acknowledged and accepted for filing contingent on the Company submitting a compliance filing with an updated DSM Avoided Cost table that does not include a National Carbon Tax starting in 2030; and	✓
2	Staff recommends that the Commission require the Company to include updates on PLEXOS® implementation, model validation, and enhancements in its semi-annual Natural Gas Updates with the Commission.	✓

OPUC - Recommendations

No.	Recommendation	2025 IRP
1	Do not acknowledge 8.64 million therms of RNG in 2023.	Removed
2	For the IRP Update the Company should update the load forecast with a downscaling methodology using Multivariate Adaptive Constructed Analogs as employed by Oregon State University's Institute of Natural Resources.	✓
3	Regardless of the analytical approach taken to create the PRS, future IRPs should include alternative resource portfolios that represent different utility decisions.	✓
4	Future IRPs should include stress testing of the RPS and alternative resource portfolios and provide metrics comparing the severity and variability of risk in alternative portfolios.	✓
5	In 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.	✓
6	Avista work with the TAC to develop additional scenarios and sensitivities for the next IRP, including for example: greater price variation for low carbon resources, high cost for low carbon resources, omission of any highly uncertain resource, or utilization of only existing resources.	✓
7	To start to understand baseline electrification occurring naturally, Staff recommends Avista use advanced metering infrastructure data and Form 10Q data to capture customer behavior as discussed in Section 6.3. At the IRP update, Avista should present that information in the attached worksheet templates (Attachment B).	✓
8	In the IRP update, Avista should clarify whether it has precedent agreements or other contracts for the GTN Xpress. If so, Avista should explain its capacity on this new expansion.	No Agreements with GTN Xpress

OPUC Staff - Expectations

No.	Expectation	2025 IRP
1	At a TAC meeting for the next IRP, Avista should provide an estimate of the capacity in MW of electrolyzers, renewable generation, and methanation equipment needed in each year to include synthetic methane in the Oregon PRS. The Company should also provide the cost and quantity of CO_2 needed in each year in key portfolios to support synthetic methane production. Lastly, the Company should seek alignment from participants regarding price and availability forecasts and approaches for modeling risk.	✔
2	Avista should provide an RNG procurement update in its next IRP Update including a comparison of projected and actual procurement; RNG prices secured; a description of how the Company has leveraged other carbon markets to reduce RNG costs; and how the Company is applying the environmental attributes of the RNG procured to CPP compliance. Further, where actuals volumes of RNG used for CPP compliance are less than those projected, the Company should describe its plan to address those compliance deficiencies.	✔
3	The next IRP should show a load forecast that reflects GCM trends by downscaling the model appropriately onto the Company's Oregon service territory.	✔
4	For the next IRP, engage the TAC regarding the GCM model downscaling methodology proposed for the next IRP.	✔
5	For the next IRP, include a scenario of future weather informed by the RCP 6.0 model.	✔
6	For the next IRP, include a scenario of no future customer growth beyond 2027.	✔
7	Continue to work with TAC members on how to model customer growth impacts from HB 3409 and the potential for further Oregon electrification policies reflecting those in place in Washington.	✔
8	For the next IRP, update its customer growth modeling to reflect the line extension allowance decision flowing from Docket No. UG 461.	✔
9	For the next IRP, update its application of IRA credits to all applicable resources, including electrification resources.	✔
10	Scenarios and sensitivities developed for the next IRP should include complex possible futures that capture plausible sources of risk due to uncertainty; Avista should explore its resource portfolios against these scenarios. Avista should run stochastic analysis for price and demand assumptions consistent within scenarios and report risk severity metrics for each scenario.	✔
11	Avista should engage stakeholders and the TAC to seek input on any additional modeling methodologies or techniques to better capture risk.	✔
12	Avista should work with Staff and the TAC to investigate PLEXOS' ability to integrate risk aversion.	✔
13	In its next IRP, Avista include a qualitative risk matrix in the next IRP that consolidates risk assessment for each resource in one chart and provides a narrative risk assessment about each resource option's potential for negative outcomes due to uncertainty.	✔

OPUC Staff - Expectations

No.	Expectation	2025 IRP
14	The Company should conduct a review, comparing projections from this IRP to actuals of their resource assumptions, quantitative least-cost/least risk predictions, and forecasts.	✓
15	Avista should work with the TAC to develop electrification modeling that reflects refined customer attrition assumptions.	✓
16	The next IRP include electrification modeling assumptions that decrease capacity costs, distribution system costs, and other appropriate expenses corresponding with reduced demand from electrification.	Discussion
17	Future IRPs should include a scenario with significantly increased residential heat pump adoption and the corresponding shift in winter load from the gas system to the electric system.	✓
18	Avista should work with the TAC to more fully explore and model the potential of dual fuel heat pumps in the next IRP, for example by ensuring that the use of some dual fuel heat pumps is represented in Monte Carlo risk analysis.	✓
19	Before the next IRP, Staff expects Avista to work with the TAC to consider Staff's revised Electrification Incentive Strategy (see Attachment A).	Discussion
20	Staff expects Avista to work with the TAC to identify a PacifiCorp IRP scenario reflecting electrification that Avista might use to generate a load forecast for its next IRP. Before the next IRP, Avista should work with PacifiCorp to collect the load forecasts used in planning that most closely reflects a building electrification scenario for the overlapping territories. With these load forecast results, Avista should discuss with PacifiCorp supporting commentary regarding supply-side and demand-side resource impacts, rate impacts, and associated GHG emissions with each scenario/portfolio. Avista should discuss with the TAC the extent to which the Company might be able to model the equivalent in its next IRP.	TBD - Need data from Electric Utilities
21	Before the next IRP, Staff expects Avista to host electrification workshops, addressing the issues listed in Section 6.4 to support a discussion on a proactive resource strategy.	✓
22	Avista should update its distribution system planning practices and its future IRP processes as outlined in Attachment C.	✓
23	Avista should apply distribution system planning practices as outlined in Attachment C to the Sutherlin project and should continue to explore targeted electrification to offset demand at the Sutherlin gate station.	✓
24	For future IRPs, the Company should discuss in a TAC meeting how Avista envisions avoided costs determinations aligning with resource portfolios made up of higher priced fuels and declining natural gas, and how that will be reflected in its next IRP.	✓
25	In the next IRP, Avista should include a workpaper of the fixed fees paid on each unit of capacity under contract and provide an update on potential or existing plans to retire firm capacity contracts.	✓

WUTC Staff - Recommendations

Topic	No.	Recommendations
Equity	1	Review the Cascade Natural Gas general rate case final order with the TAC and the EAG together, consider how the core tenets of energy justice apply to Avista's planning processes, and prepare to implement the order's equity framework. Dedicate time in the work plan for this topic.
	2	Staff recommends that Avista consult with its equity advisory group to develop equity criteria for the siting of distribution projects and reinforcements.
Changing Regulatory and Incentive Landscape	3	Include full accounting of the IRA in the 2025 IRP and provide sufficient time in the work plan for discussion within advisory groups.
	4	Work with the Department of Ecology, Staff, and advisory groups, to discuss the implication of this "cap" and how it is likely to be achieved.
	5	Provide a robust discussion of the "invest" portion of the "cap-and- invest" and discussion of the downstream impacts of CCA investments.
	6	Account for and provide a narrative discussion regarding electrification driven by the CCA and discuss the CCA within its advisory group early in the IRP development process.
Climate change impacts	7	Adopt representative concentration pathway (RCP) 8.5.
	8	For greater clarity, for tables like Table 2.3, replace with time series graphs with appropriate box and whisker plots.
	9	Revisit and update the winter peaking climate data and methodology as evidence and climate models improve.
Load forecasting	10	Where the specifics of future energy codes are unknown, project a forecast trend that accords with statutory goals and mandates.
	11	Develop a building stock attrition rate to represent the loss of customers due to buildings being demolished, remodeled without gas service due to incompatible use cases, or otherwise leaving gas service unrelated to changes in the price competitiveness of gas services.
	12	Adopt future building codes that are already imbedded in law as foundational assumptions for the primary demand forecast and not as a scenario.
	13	Analyze risks to customers and the distributional effects through the lens of equity, energy justice, and access to energy efficiency and electrification resources.
	14	Dynamically model the anticipated comparative costs between its natural gas services and electric utility services into the future as well as the interplay of customers, by class, responding to changing comparative cost.
	15	Incorporate the distributional analysis discussed below into the comparative cost analysis.

WUTC Staff - Recommendations

Topic	No.	Recommendations
Demand-side Potential Assessments	16	Continue to refine the methods and approach of leveraging potential assessments for achieving equitable outcomes.
	17	Segment customers with different levels of gas to electric conversion costs rather than modifying costs only by scenario.
	18	Consider audits of specific transportation customer sites to better understand current equipment and practices to refine estimates of available potential for these customers.
	19	Target outreach to the largest transportation customers to understand their likelihood of participating in future energy efficiency programs, including to what extent and on what timeline, when considering program design.
Social Cost of Greenhouse Gasses Calculations	20	Explicitly note costs of greenhouse gas emissions established in RCW80.28.395 when analyzing avoided costs.
	21	Clearly account for emissions occurring in the gathering, transmission, and distribution of natural gas, providing itemization, a total value of these emissions, and the ratio of these emissions to throughput for the purposes of avoided cost calculations.
	22	Incorporate distribution system emissions data into Distribution Scenario Decision-Making Process criteria if applicable.
	23	Include both the cost of compliance with the CCA and the SCGHG for conservation in the base case in the 2025 IRP.
	24	When calculating the natural gas energy efficiency target for 2024- 2025, use the avoided cost from the Social Cost of Carbon Case in Appendix 6.4.
Alternative Fuels	25	Consider hydrogen and landfill gas for the purposes of lowest reasonable cost analysis unless it can demonstrate a reason not to consider these fuels.
	26	Convert figures similar to 4.16 through figure 4.21 to time series graphs featuring box and whisker plots.
IRP Modeling	27	Highlight and offer appropriate cautions in its analysis wherever PLEXOS yields results or behaviors that would be unlikely to be anticipated or enacted by a human planner.
	28	Highlight and offer appropriate caution in its analysis wherever PLEXOS uses resources in its portfolio in a manner that does not accord with current best practices or current technological means.
	29	Rely upon human expertise to vet and verify all results generated by PLEXOS.
Decarbonization Plan and Electrification Analysis	30	Consult with the TAC and parties to the GRC to discuss what a decarbonization plan should entail, submit a specific workplan, and provide a decarbonization plan in the 2025 IRP.
	31	Refine the electrification analysis with input from interested persons.
	32	Refine assumptions around electrifying loads and run additional sensitivities that illuminate a range of possible costs of electrification depending on how loads electrify.

Secondary Actions and Attachments

OPUC Staff - Requests

Request 1: Future IRPs should include a clearer explanation of the PRS, and a more transparent presentation of the assumptions and processes used in creating the PRS, including examples noted by Staff.

Request 2: Staff requests Avista engage the TAC in discussion of the value of NPVRR analysis relative to levelized-cost analysis.

Request 3: Avista engage the TAC in considering the merits and drawbacks of modeling state specific resource and system investments.

Request 4: Staff requests that the latest information on possible distribution projects, including any proposed traditional investments or proposed NPA, be included in future IRP Updates.

Request 5: Staff requests that the possible impacts (at least on the Company's revenue requirement and scenario analysis) of line extension allowance elimination be taken up by the TAC with the goal of determining how to best reflect expected impacts in future IRPs.

Request 6: Staff requests that the Company report to the TAC in late 2024 on the low-income hybrid heating pilot including relevant program details, progress to-date, lessons learned, findings about the potential of such a program to meet CPP compliance and to mitigate upward rate pressure, and learnings on how to model such a program in future IRPs.

Request 7: Staff requests Avista vet demand response modeling parameters (such as costs, increments, potential, and ramp rates) with TAC members.

Request 8: Staff requests that Avista engage the TAC in a discussion of how the value of Interruptible loads can be folded into resource planning.

Request 9: Staff requests Avista engage a representative set of Interruptible customers to study interest in participating in demand response offerings, and under what conditions, with results to be shared with the TAC.

Request 10: In the IRP Update, Staff requests that Avista include a table of expected CPP compliance costs.

OPUC Staff – Attachment A

- **Ratepayer Incentive Value**

  The Ratepayer Incentive Value includes both the cost of the ratepayer to convert and the benefit the ratepayer's decision to electrify provides to gas system operations and downstream costs. Staff expects the feasibility of conversion to be constrained by the equipment lifecycle costs (equipment costs and operation costs over the lifetime of the appliance) and available electric grid capacity. Equipment cost calculations could foreseeably leverage precedent used within the Docket No. UM 1893, available policy incentives, and data collected from regional electric appliance sales and Energy Trust of Oregon heat pump programs. Staff is not convinced that electric rates are the best indicator of operation costs. Instead, Staff requests Avista work with Energy Trust and electric utilities to consider bill impacts or other metrics to measure operation costs by end-use. In any event, given the sensitivity of lifecycle costs to region, Staff stresses that Avista use regionally appropriate efficiencies, equipment and operation costs, and weather forecasts for Avista's service territory.141 Moreover, Staff believes that understanding the Ratepayer Incentive Value of electrification will require some form of scenario and data sharing between gas and electric utilities to identify where electrification is feasible based on available capacity on the electric grid to handle the new entry of electric appliances. To determine the benefits the ratepayer provides to the system through their decision to electrify, Staff requests the Company consider how the decision provides downstream benefits such as reduced emissions, reduced need for higher-cost alternative fuels, reduced transportation and distribution costs over the long term. The decision to electrify may also provide reliability benefits to the gas system during winter peak through released firm pipeline capacity. In determining a compensation cost for these savings and gas system operation benefits Staff sees benefit in considering existing electric sector incentives, including time-of-use rates, net metering, and capacity payments. Staff recognizes that the price to switch out appliances and electric rates rising above marginal cost are key considerations in a property owner's decision to electrify. If the benefit of the ratepayers' investment is greater than the costs, it can indicate new entry of the electric unit and a corresponding retirement of the gas unit.

- **Policy Incentives**

  Policy incentives include external, non-ratepayer funding sources. These can supplement an incentive strategy without impacting gas rates. For example, the IRA provides tax credits and rebates to reduce the purchase cost for electric panel upgrades and heat pumps, whose high costs can be a barrier to electrification. Notably, maximizing IRA incentives is crucial in the near term, as available IRA incentives decrease annually and are unavailable after 2032. As shown in the figure below, in the workpapers accompanying the IRP, Avista forecasts that the cost of electrification will increase year over year and spike in 2032 with the termination of IRA financing. This suggests that it will be incrementally more expensive for Avista to incentivize electrification over time. Figure 7 below shows Avista's forecasted cost for electric space heat inclusive of a 50 percent reduction in conversion costs for IRA incentives and increasing electric rates.

- **Company Cost Value**

  The Company Cost Value portion of the incentive strategy looks at the cost to the Company to proactively incentivize electrification. In other words, what portion of the Ratepayer Incentive Value is the Company willing to pay? Staff recognizes that electrification reduces consumption. This manifests as a cost to the LDC through reduced returns and lost capital investment opportunities. Unless the company can anticipate a return on the investment, their willingness to incentivize electrification is lower because of these reduced revenue requirements. Using avoided cost calculations may help to understand Avista's willingness to pay. Staff anticipates working with the Company to deepen conversation around electrification and avoided cost within the Docket No. UM 1893.

- **Conclusion**

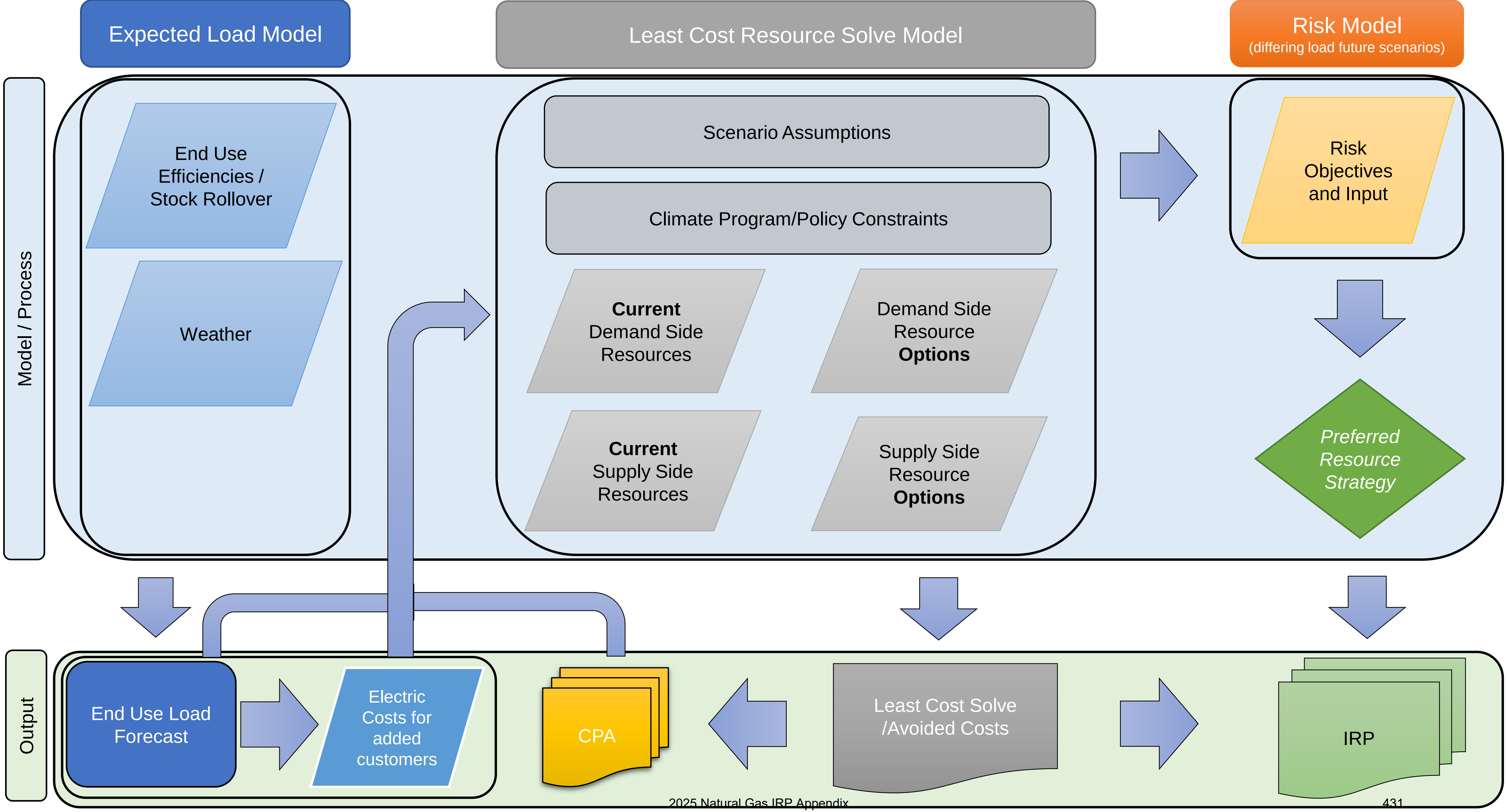
  As discussed in more detail in Section 6.4, Staff is interested in hearing from stakeholders when identifying the right incentive level. Staff recognizes that this will likely require the sharing of data and scenarios between gas and electric utilities and recommends possible pathways in Section 6.3. Moreover, an electrification incentive strategy should be considered alongside other energy efficiency and weatherization programs.

OPUC Staff – Attachment C

The Company should update its DSP practices and IRP processes to include:

1. Future distribution system planning should identify the rationale for projects as either Safety/General System Reliability, or Customer Growth/Reliability Related to Growth. a. When proposing growth-driven projects in IRPs the utility should be prepared to present project data on: relationship to CPP compliance strategy, modeling and verified measurement, local load forecast, and assessment of alternatives through the NPA framework.
2. Future distribution system planning should include an NPA framework in Oregon. The framework should include:
   a. NPA analysis will be performed for supply-side resources (these include but are not limited to all resources upstream of Avista's distribution system and city gates, and supply-side contracts) and for distribution system reinforcements and expansion projects that exceed a threshold of $1 million for individual projects or groups of geographically related projects (a group of projects that are interdependent or interrelated).
   b. b. NPA analysis will include cost benefit analysis that reflects an avoided GHG compliance cost element consistent with a high-cost estimate of future alternative fuels prices. Non-Energy Impacts must be included as part of the NPA analysis.
   c. NPA analysis will include electrification, targeted energy efficiency, targeted demand response, and other alternative solutions.
   d. NPA analysis should look forward five years to allow ample time for evaluation and implementation.
   e. NPA analysis will include an explanation of solutions considered and evaluated including a description of the projected timeline and annual implementation rate for the solutions evaluated, the technical feasibility of the solutions, and the strategy to implement the solutions evaluated.
   f. NPA analysis should include an explanation of the resulting investment selection (either NPA or a traditional investment) including the costs and ranking of the solutions, and the criteria used to rank or eliminate them. i. If a NPA is not selected and the reason is insufficient implementation time, it should include steps the Company will take to perform NPA analysis to provide sufficient implementation time for future projects.
3. Future IRPs should include the results of distribution system planning, including project data and NPA analysis for any proposed traditional investments, and NPA analysis for any proposed NPA.
4. Future IRPs should include a database containing information about feeders, in service dates of pipes, and lowest recent observed pressures.

Modeling and Assumptions Overview



Expected Load Model
Least Cost Resource Solve Model
Risk Model
(differing load future scenarios)
Model / Process
End Use Efficiencies / Stock Rollover
Weather
Scenario Assumptions
Climate Program/Policy Constraints
Current Demand Side Resources
Demand Side Resource Options
Current Supply Side Resources
Supply Side Resource Options
Risk Objectives and Input
Preferred Resource Strategy
Output
End Use Load Forecast
Electric Costs for added customers
CPA
Least Cost Solve /Avoided Costs
IRP

2

Load Assumptions

- PRS load input will rely on current known state policy, codes and requirements
  - WA SBCC will be included in load forecast baseline
  - Line extension program expirations will be included in forecast baseline
    - 2027 end date in Oregon
    - 2024 end date in Washington
- Hybrid heating begins below 40 degrees Fahrenheit
  - Chosen as an average between furnace manufacturer coefficient of performance values (COP)
  - Value is also used by fundamental forecast houses in their electrification evaluations
- The end use model can select higher efficiencies if cost effective or standard at rollover
  - Model will select cost effective pathway (gas or electric) and distribute load
- Scenarios will estimate risk of differing load expectations

Cost Assumptions

All quantifiable current and estimated costs:

- Interstate pipeline transportation
- Storage
- Expected cost of natural gas by supply basin (AECO, Malin, Rockies, Stanfield, Station 2, Sumas)
- Alternative fuels (RNG, Methanation, Hydrogen – all forms, carbon capture)
- Compliance mechanisms to climate programs (Allowances, Offsets, CCIs)
- Social cost of carbon @ 2.5%, where applicable
- Economic non energy impact (NEI) adders
- Energy Efficiency per the CPA
- Demand Response potential costs per the CPA
- New capital distribution projects by area
- Maintaining the LDC
- Electricity cost by area (including distribution, transmission additions)
- Electrification (including efficiencies, costs by area, including distribution and transmission additions)

Output

- An average rate, with power costs, will be provided by scenario
- Emissions by scenario
- A levelized cost by scenario
- A net present value revenue requirement (NPVRR)
- Risks
- Energy Burden

Scenarios

Scenarios – Deterministic & Monte Carlo	Description
PRS	*Our expected case based on assumptions and costs with a least risk and least cost resource selection. This scenario includes all known policies and orders from Idaho, Oregon and Washington. Assumes 4.5 RCP weather.*
High Growth on Gas System	A high case to measure risk of additional customer and meeting our emissions and energy obligations
High Electrification	The highest expected conversions to the electric system. Electric IRP indicates 80% loss by 2045
PRS - Includes CPP	PRS assumptions, but includes the CPP expectations going forward from 2025
No Climate Programs	PRS assumptions with no climate programs
Low Natural Gas Use Case	This scenario will include high electrification, with the 8.5 RCP for weather, high cost of alternative fuels and a high cost of allowances in WA.

*Each scenario will have a rate per class, a cost with power included, emission and energy burden

Scenarios – Deterministic Only

Scenarios – Deterministic Only	Description
Low Alternative Fuel Costs	A scenario to measure resource selection with a lower-than-expected set of Alternative Fuel costs by source
High Alternative Fuel Costs	A scenario to measure resource selection with a higher-than-expected set of Alternative Fuel costs by source
High Natural Gas Prices	Higher than expected prices for natural gas
Average Case Weather	Non climate change projected 20-year history of average daily weather and excludes peak day
High CCA Costs	Considers a high cost for allowances in Washington

 *Each scenario will have a rate per class, a cost with power included, emission and energy burden

Scenarios – Deterministic Only

Scenarios – Deterministic Only	Description
RCP 8.5 Weather	Weather will use the RCP 8.5 future
RCP 6.0 Weather	Weather will use the RCP 6.0 future as the average between RCP 8.5 and 4.5
Resiliency	Supply will be selected to create a resilient system
No New Natural Gas	Restrict customers after line extensions expire in Oregon and Washington to 0 growth
Hybrid Heating	A scenario to include hybrid heating for temperatures below 40 degrees Fahrenheit
Diversified Portfolio	This scenario will include electrification, 25% of supply from RNG, 25% of supply from methanation and 7% from hydrogen all after 2035.
Social Cost of Carbon	A scenario to value resources in all locations using the Social Cost of Carbon @ 2.5% and includes upstream emissions

*Each scenario will have a rate per class, a cost with power included, emission and energy burden

Modeling Risk

- 18 total scenarios
  - Deterministically solve a set of resources to meet variability in the scenarios for a stochastic set of futures
- Run 500 monte carlo futures for the 4 distinct load scenarios to determine risk
- Efficient Frontier may be used to select least cost and least risk solution

Avista CROME High Level Overview

Comprehensive Resource Optimization Model in Excel

Michael Brutocao
Natural Gas Analyst

Timeline: IRP Modeling Software

<u>Prior to 2023</u>

SENDOUT®

<u>2023 IRP</u>

PLEXOS®

<u>2025 IRP</u>

Avista

CROME

High Level Overview

Select scenario-specific data

INPUTS AND ASSUMPTIONS

Avista CROME

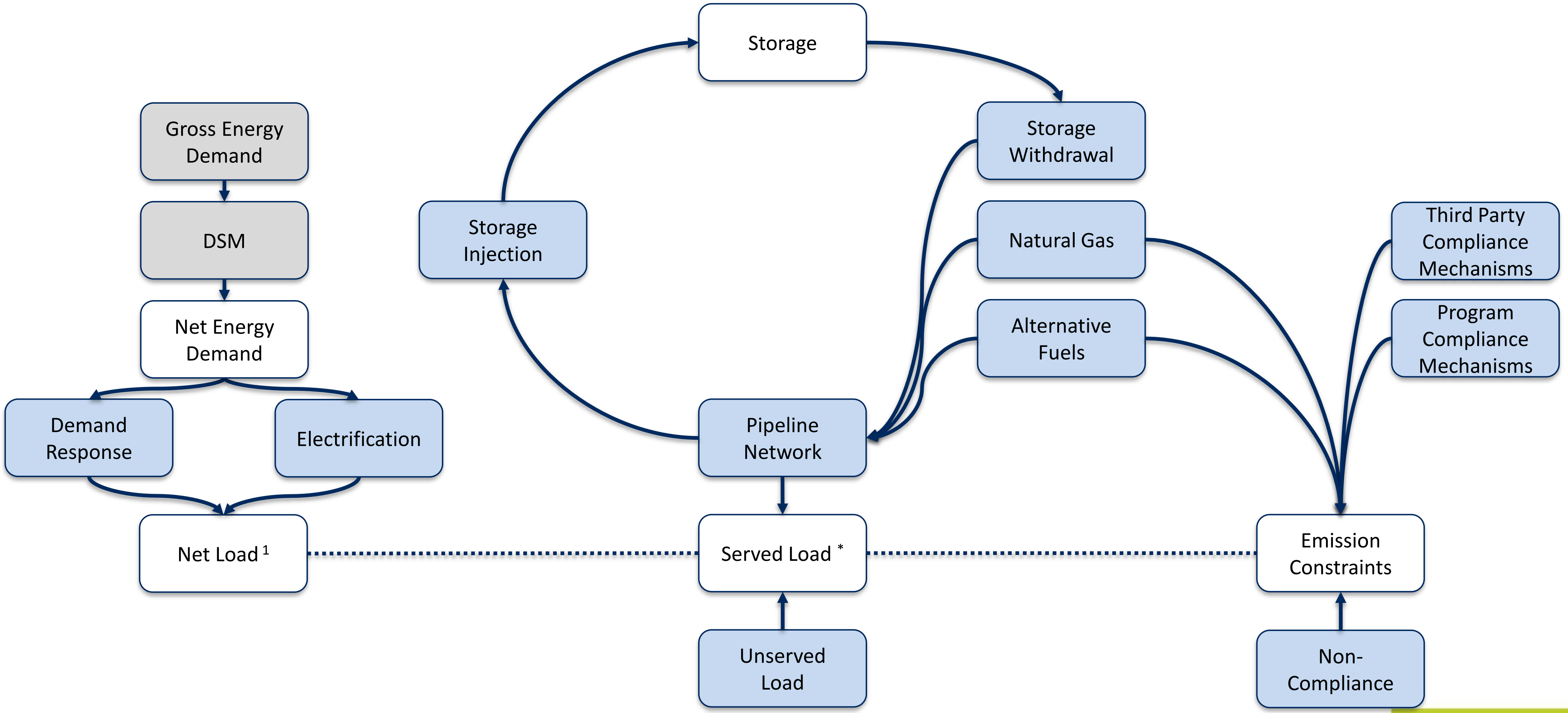
REPORTS

- Inputs and assumptions are stored here.
- Data is prepared for CROME.

- Inputs, assumptions, and constraints are brought together.
- Decision points are optimized to produce least-cost solution.

- CROME solution data updates templates for summary statistics and graphics.

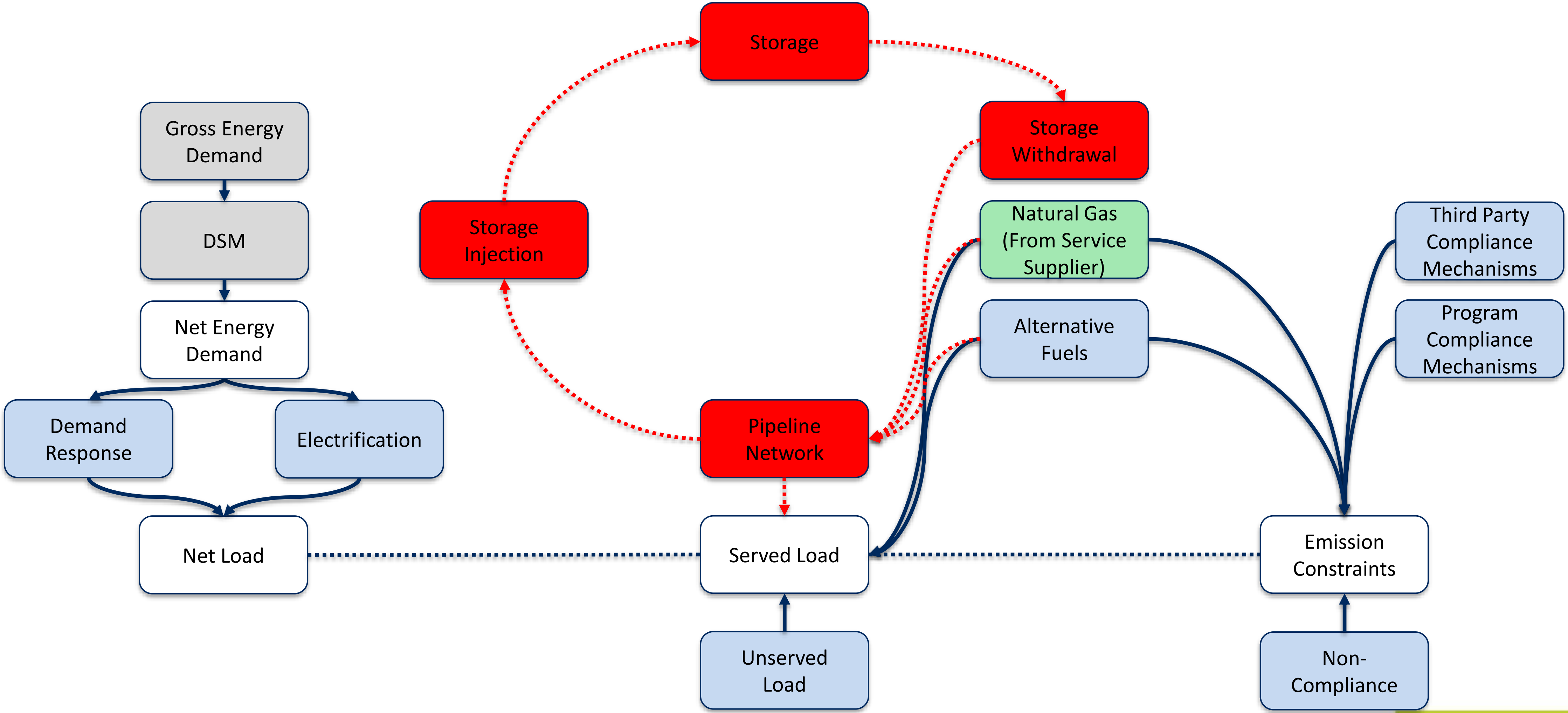
Solving for Residential, Commercial, and Industrial Loads



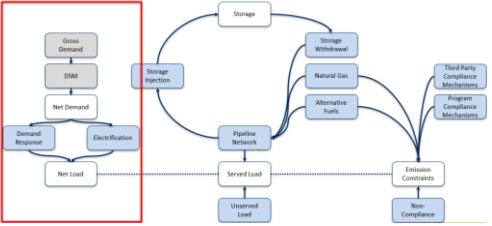
* NEI cost consideration

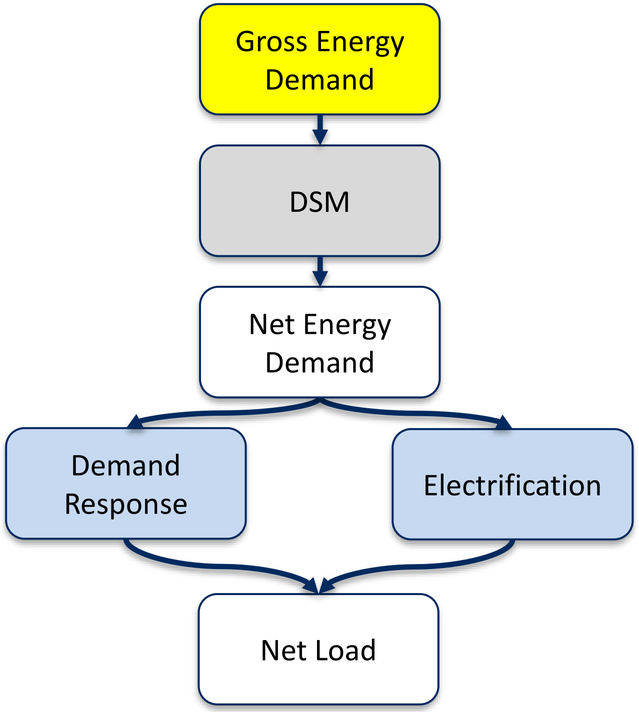
[1] Cost of expected distribution projects

Solving for Transport Customer Loads



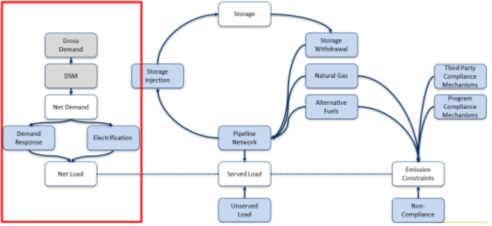
NET LOAD

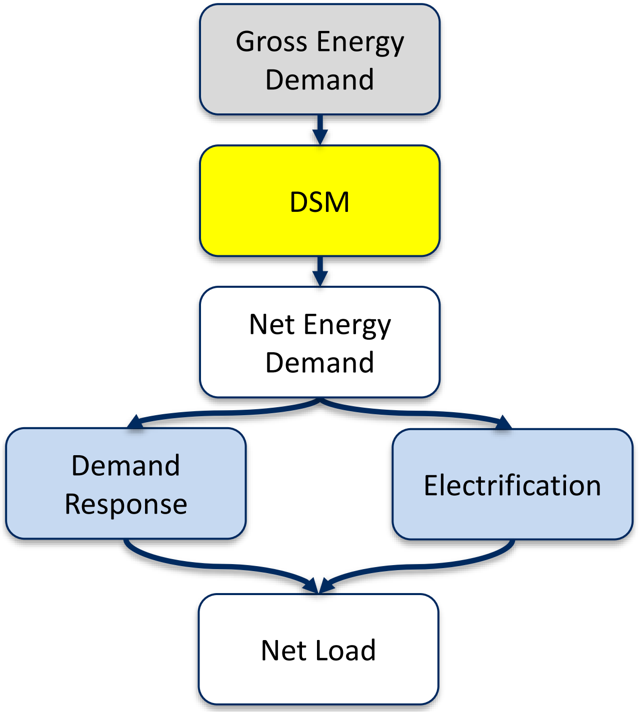




Gross Demand

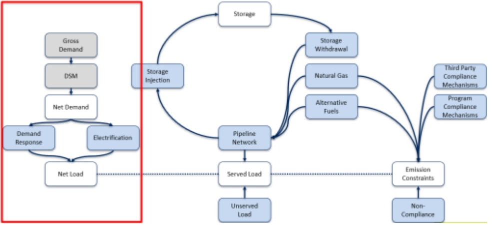
Considerations:	Number of customers by end-use
	Base use per customer
	Heating use per customer
	Weather
Optimization Decision:	N/A
Points:	All modeled areas and customer classes
Frequency:	Daily

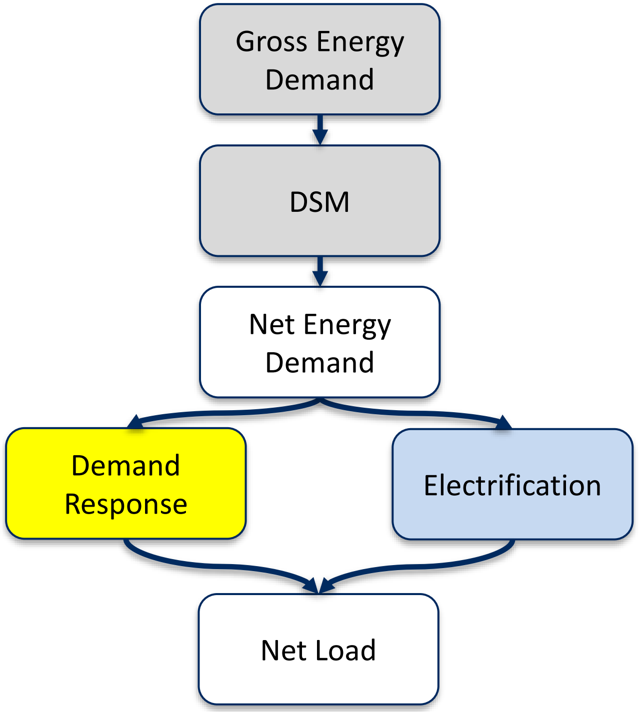




Demand Side Management

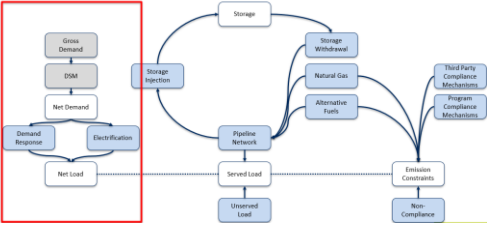
Considerations:	Avoided cost by area and customer class Number of customers by end-use CPA from AEG/ETO
Inputs:	UCT (ID), TRC (WA, OR)
Points:	All modeled areas and customer classes
Frequency:	Daily

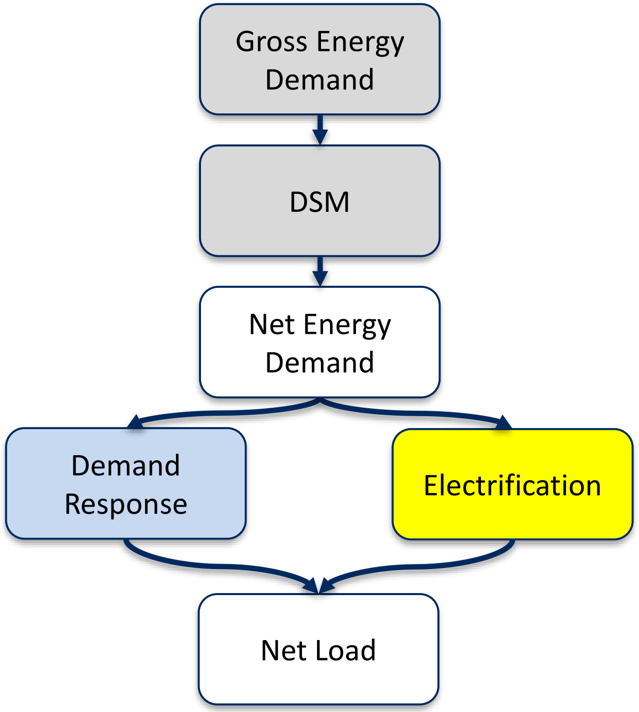




Demand Response

Considerations:	Cost
	Available “supply” by program, area and customer class
Optimization Decision:	Quantity “purchased”
Decision Points:	All modeled areas and customer classes
Decision Frequency:	Daily





Electrification

Considerations: Cost

Available “supply”*

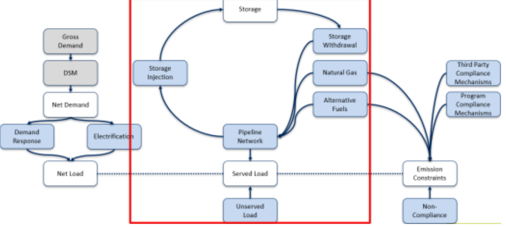
Optimization Decision: Quantity “purchased”

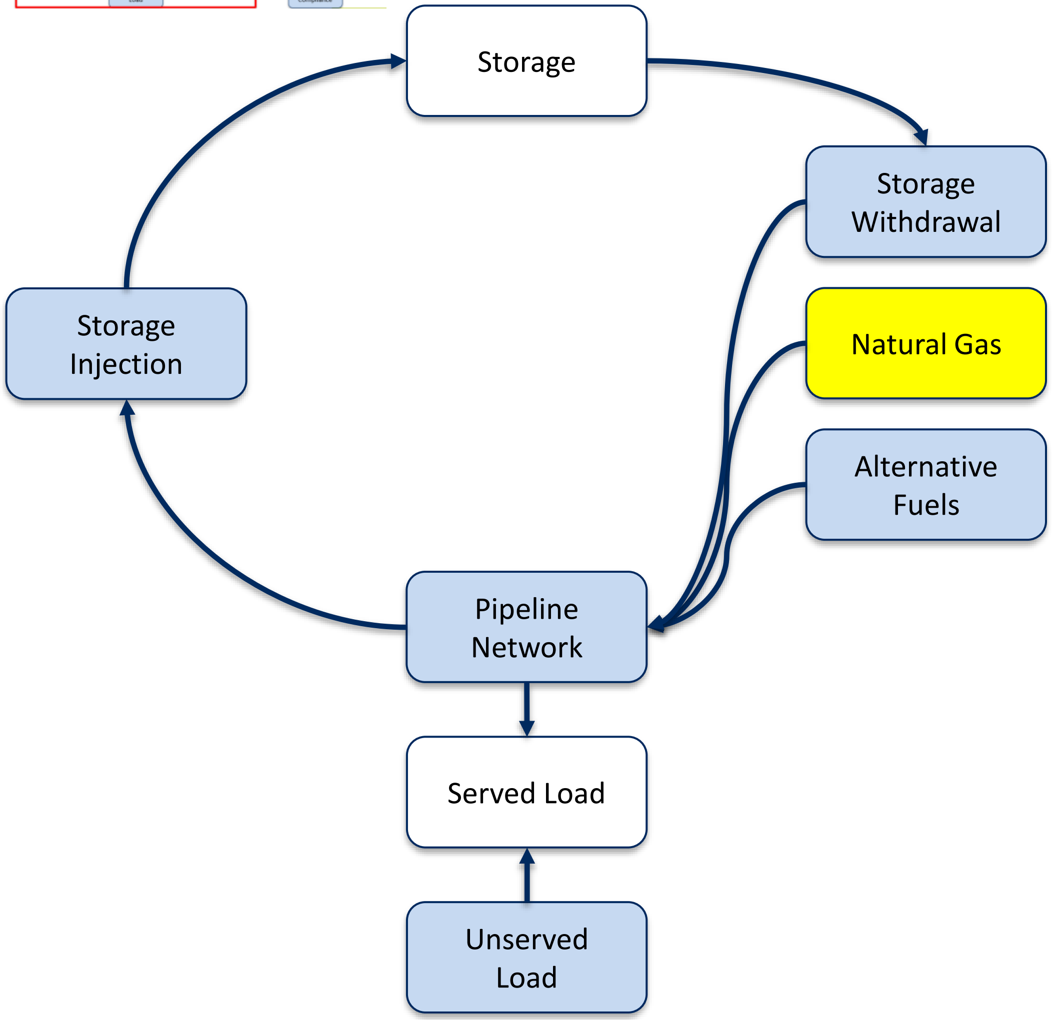
Decision Points: Residential and commercial classes (OR, WA)

Decision Frequency: Annual

* This is constraining the optimization decision

SERVED LOAD





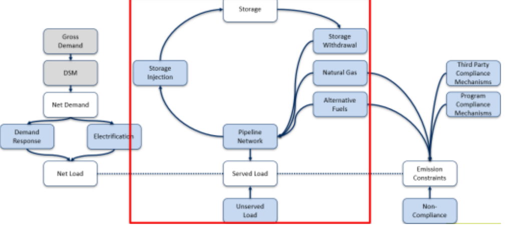
Natural Gas

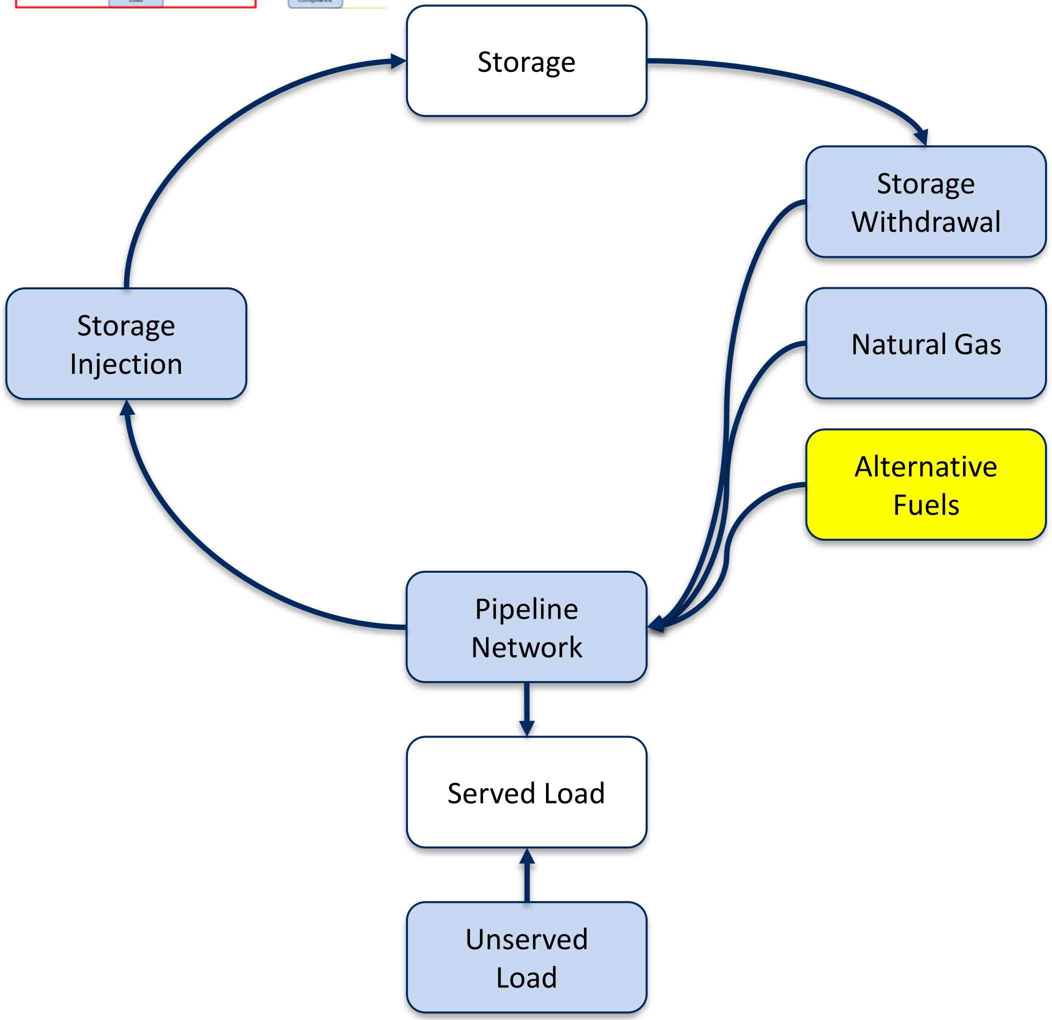
Considerations: Cost

Optimization Decision: Quantity purchased

Decision Points: AECO, Malin, Rockies, Stanfield, Station 2, Sumas

Decision Frequency: Daily





Alternative Fuels

Considerations: Cost

Available supply *

Max blend percent *1

Optimization Decision: Quantity purchased

Decision Points: Hydrogen (7 forms)

RNG (5 forms)

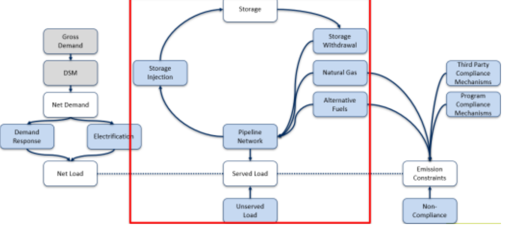
Synthetic methane (3 forms)♣

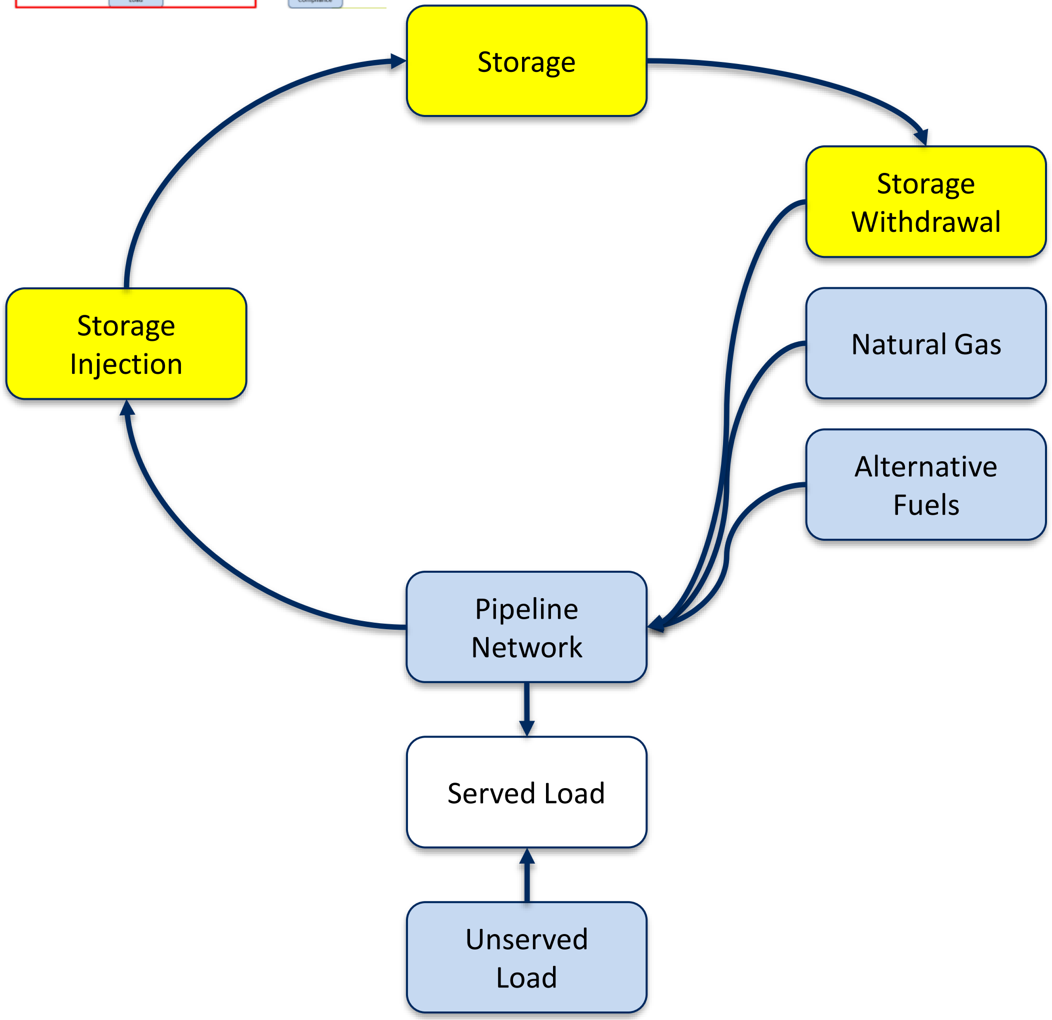
Decision Frequency: Annual

* This is constraining the optimization decision

1 A daily constraint on the volume of hydrogen blended into pipeline

♣ Model decision frequency to be determined by alternative fuel study results

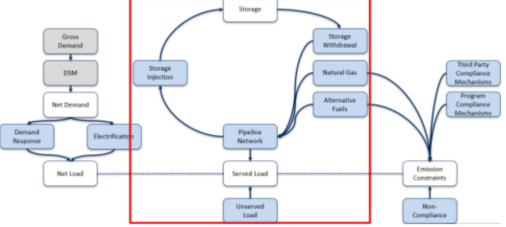


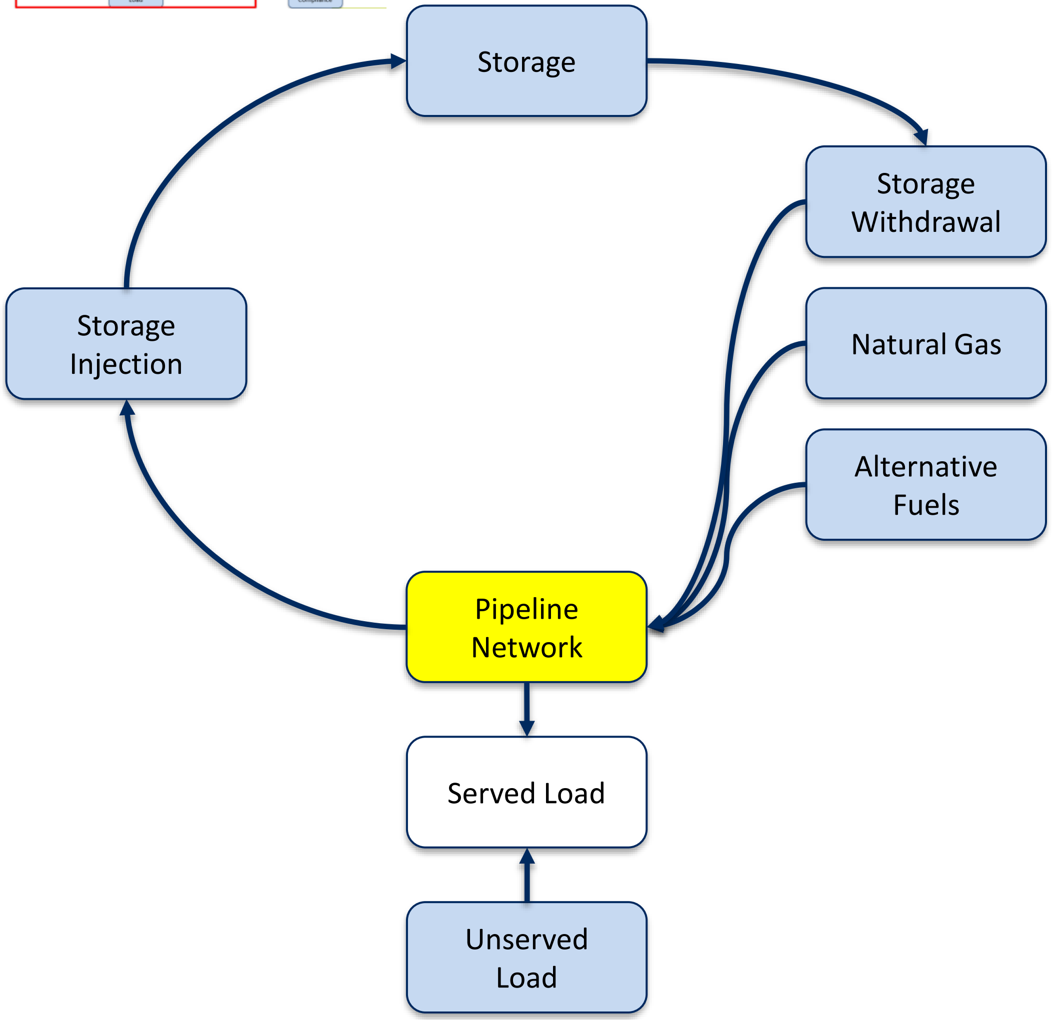


Storage

Considerations:	Min/max volume *
	Max daily injection/withdrawal *
	Capital & overhead
	Carrying rate
Optimization Decision:	Quantity injected/withdrawn
Decision Points:	Jackson Prairie
Decision Frequency:	Daily

* This is constraining the optimization decision

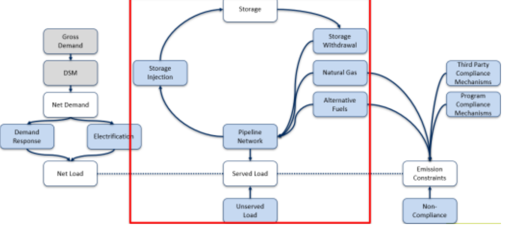


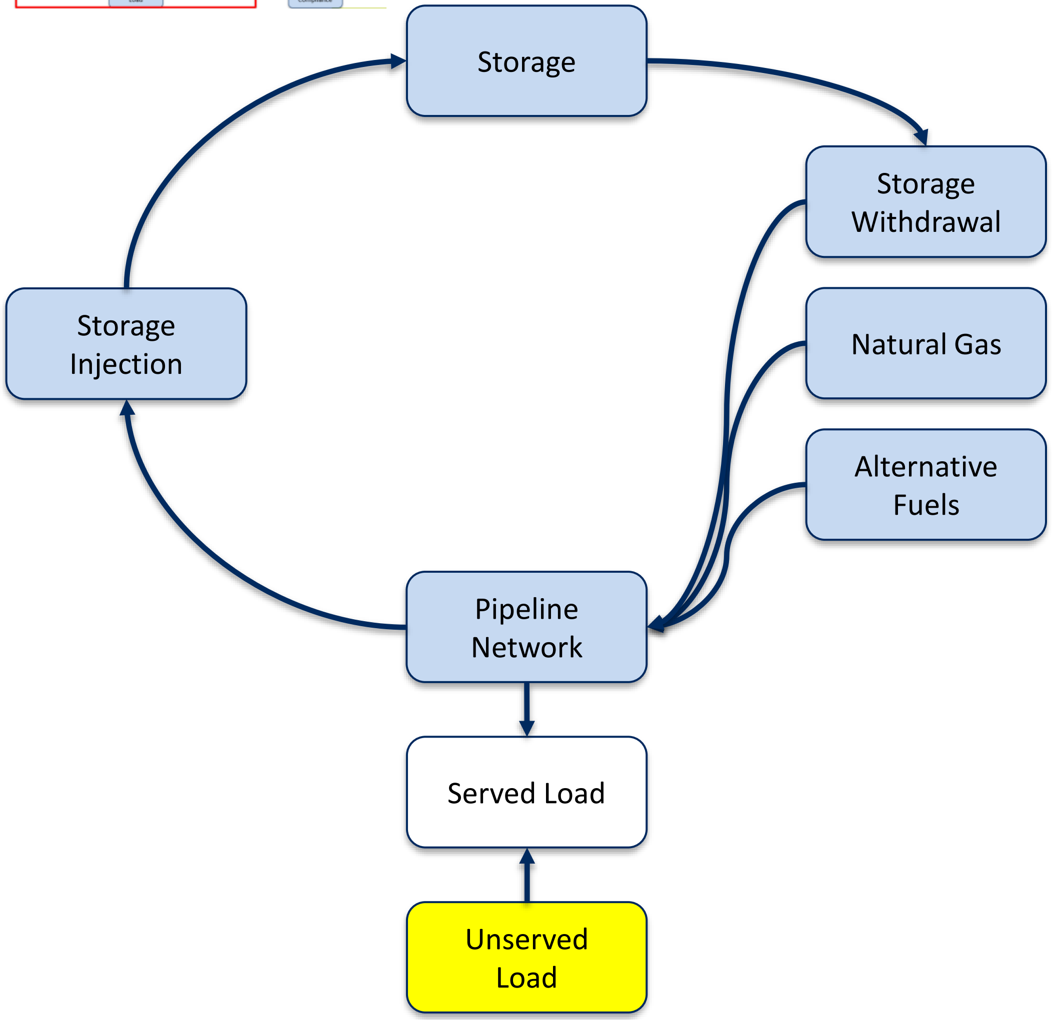


Pipeline Network

Considerations:	Flow capacity *
	Reservation rate
	Variable rate (flow charge)
	Fuel loss
Optimization Decision:	Segment flow
Decision Points:	All pipeline segments in network
Decision Frequency:	Daily

* This is constraining the optimization decision





Unserved Load

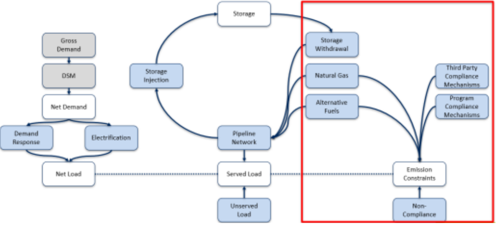
Considerations: Cost

Optimization Decision: Quantity unserved

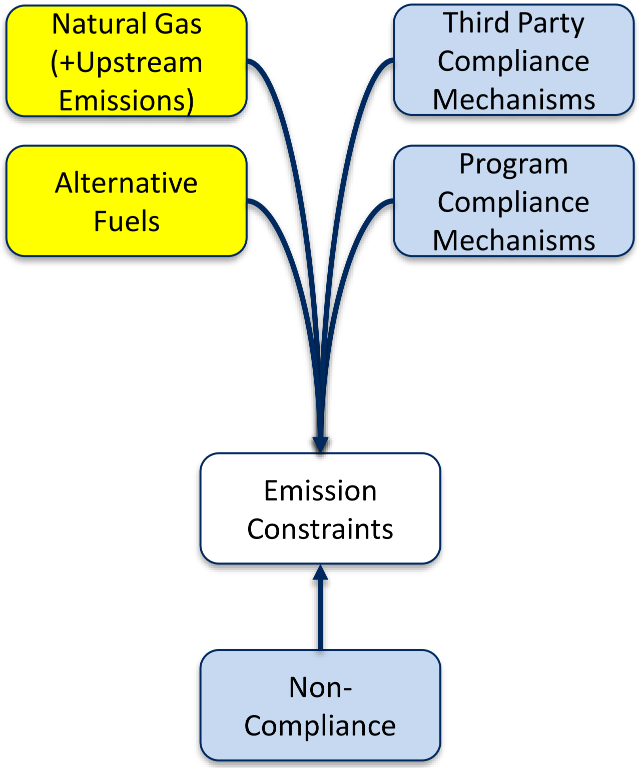
Decision Points: All modeled areas and customer classes

Decision Frequency: Daily

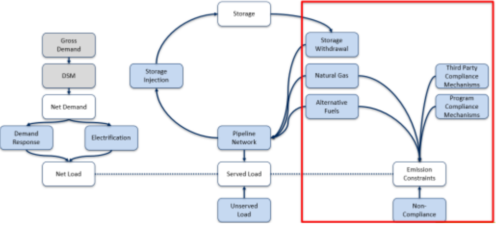
EMISSIONS

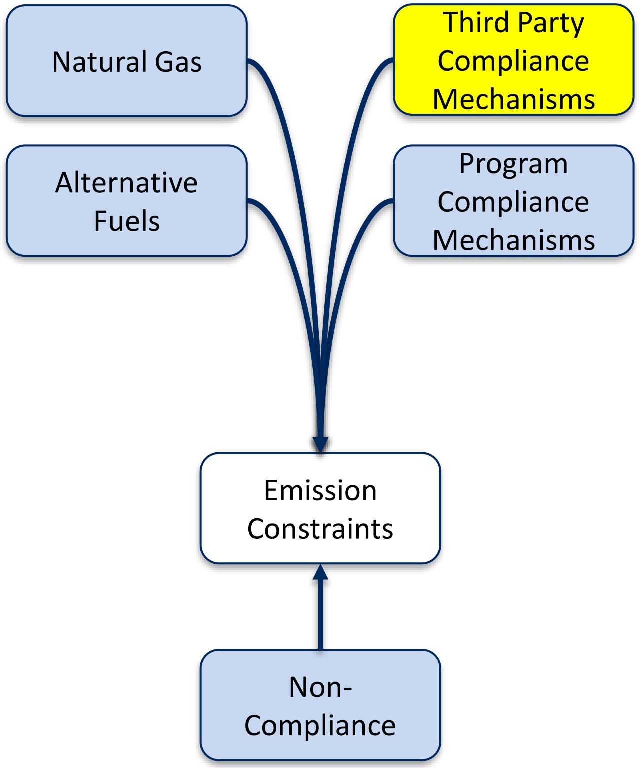


Natural Gas & Alternative Fuels



Considerations:	Carbon emissions
Optimization Decision:	Quantity purchased
Decision Points:	Same as in served
Decision Frequency:	Annual, daily





Third Party Compliance Mechanisms

Considerations: Cost

Available supply *

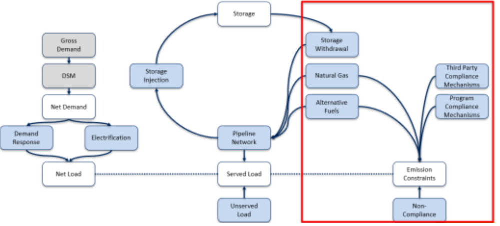
Optimization Decision: Quantity purchased

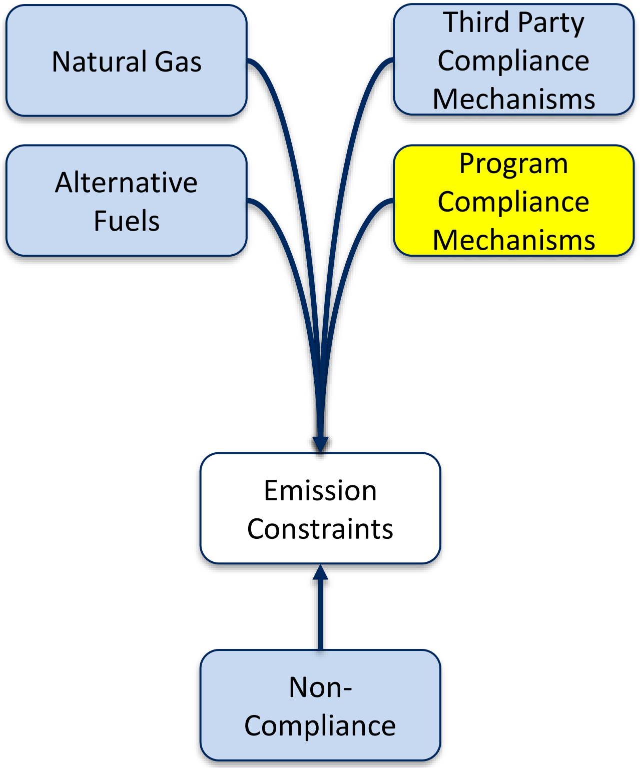
Decision Points: Renewable thermal credits (3 forms)

Carbon capture (4 forms)

Decision Frequency: Annual

* This is constraining the optimization decision





Program Compliance Mechanisms

Considerations: Cost

Available supply *

Optimization Decision: Quantity purchased

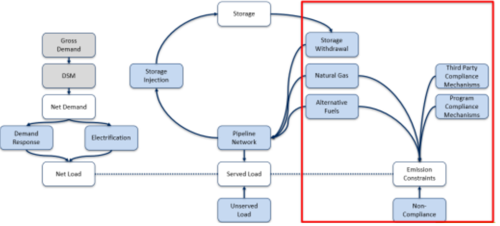
Decision Points: Allowances (CCA)

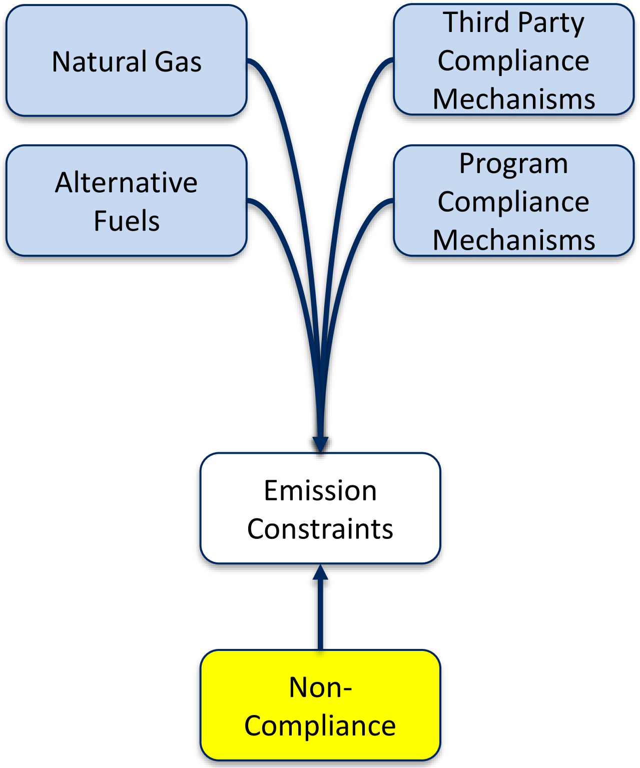
Offsets (CCA)

CCIs (prior CPP)

Decision Frequency: Annual

* This is constraining the optimization decision





Non-Compliance

Considerations:	Cost
Optimization Decision:	Quantity
Decision Points:	Climate Commitment Act Prior Climate Protection Program
Decision Frequency:	Compliance period, annual (CCA)

2025 Natural Gas Integrated Resource Plan
Technical Advisory Committee Meeting No. 4 Agenda
Wednesday, June 5, 2024
Virtual Meeting

Topic	Time (PTZ)	Staff
Feedback from prior TAC	9:00	Tom Pardee
Distribution System Modeling	9:10	Terrence Browne
OPUC Recommendation on NPA	10:10	OPUC Staff
Targeted Energy Efficiency	10:35	ETO
Weather Futures and Peak Planning	11:00	Tom Pardee
TAC feedback	11:50	All

Microsoft Teams meeting
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Click here to join the meeting
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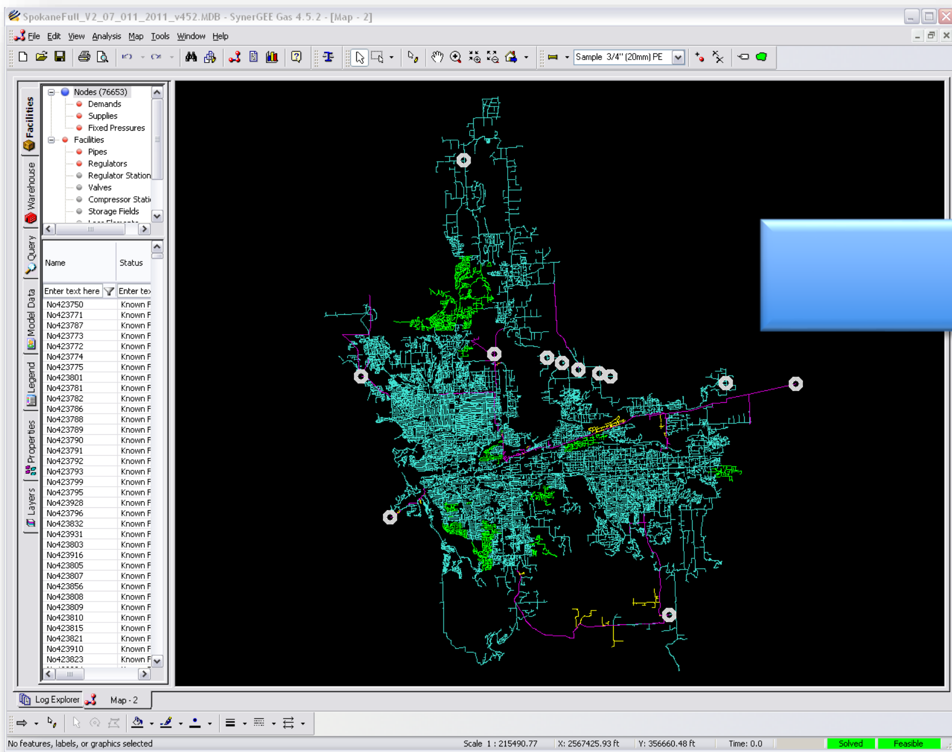
Distribution System Planning

Terrence Browne PE, Principal Gas Planning Engineer

Natural Gas Technical Advisory Committee
June 5, 2024

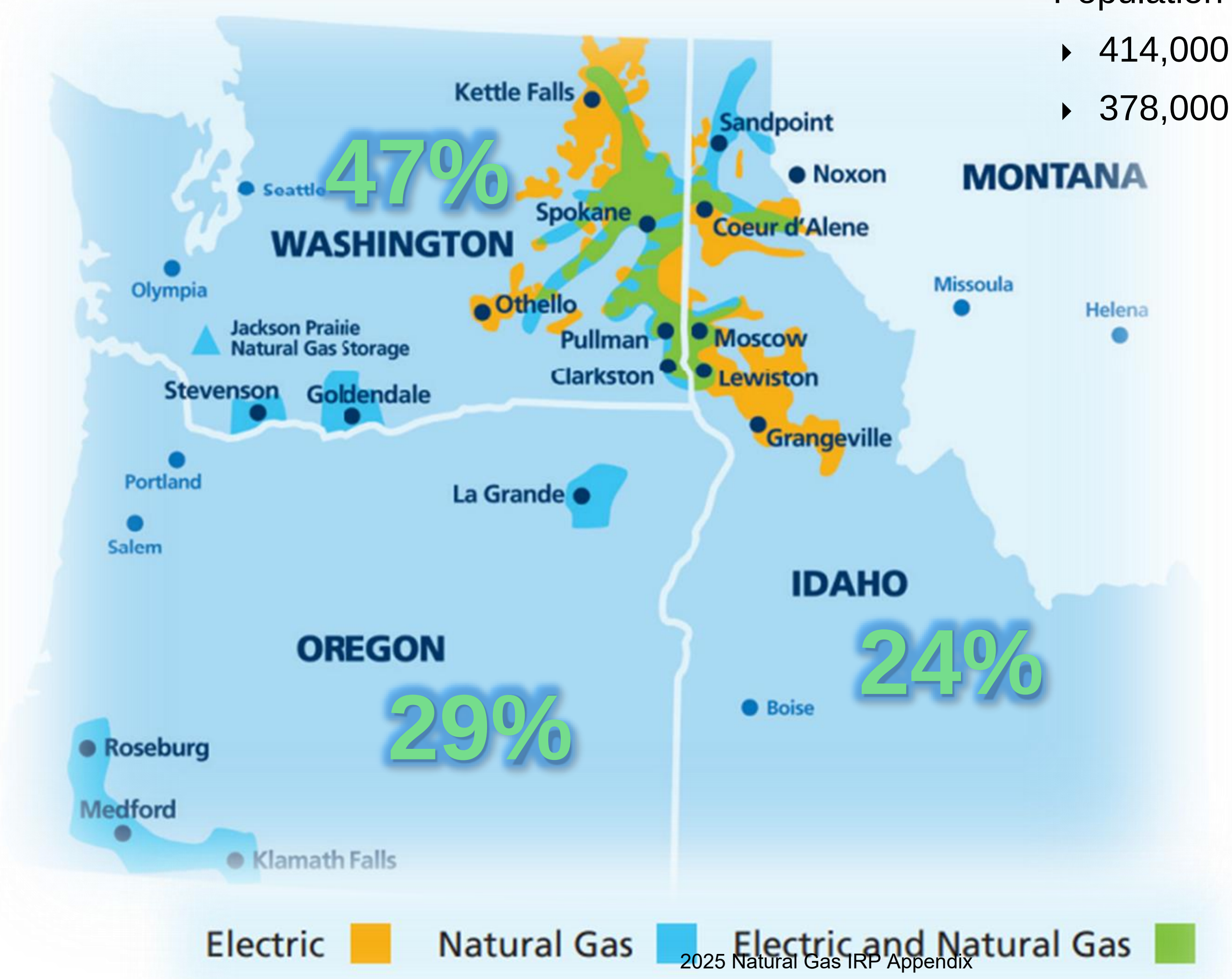
Mission

- Using technology to plan and design a safe, reliable, and economical distribution system



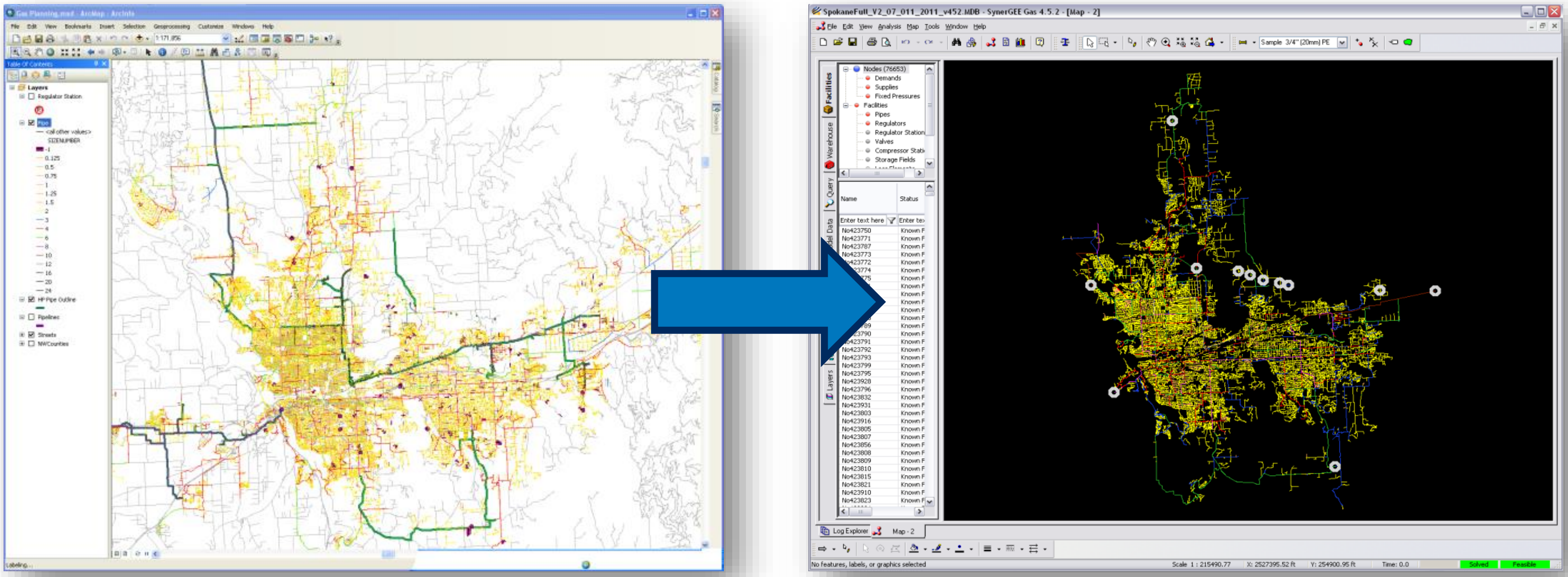
Service Territory and Customer Overview

- Serves electric and natural gas customers in eastern Washington and northern Idaho, and natural gas customers in southern and eastern Oregon
  - Population of service area 1.7 million
    - 414,000 electric customers
    - 378,000 natural gas customers

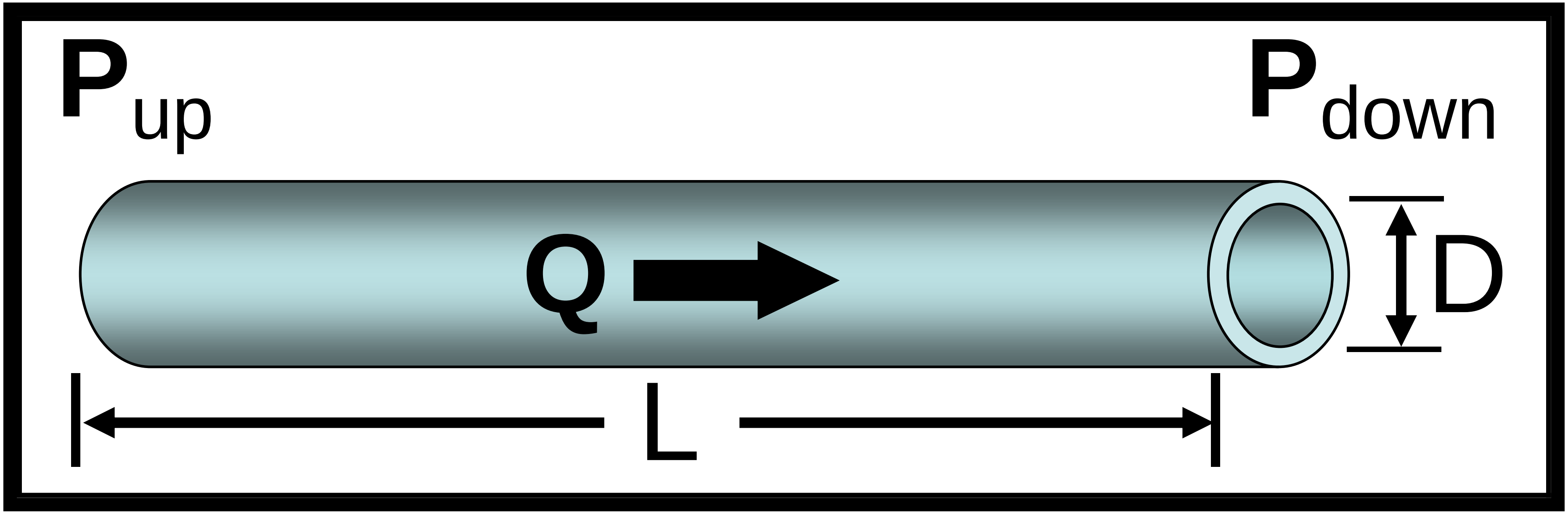


Our Planning Models

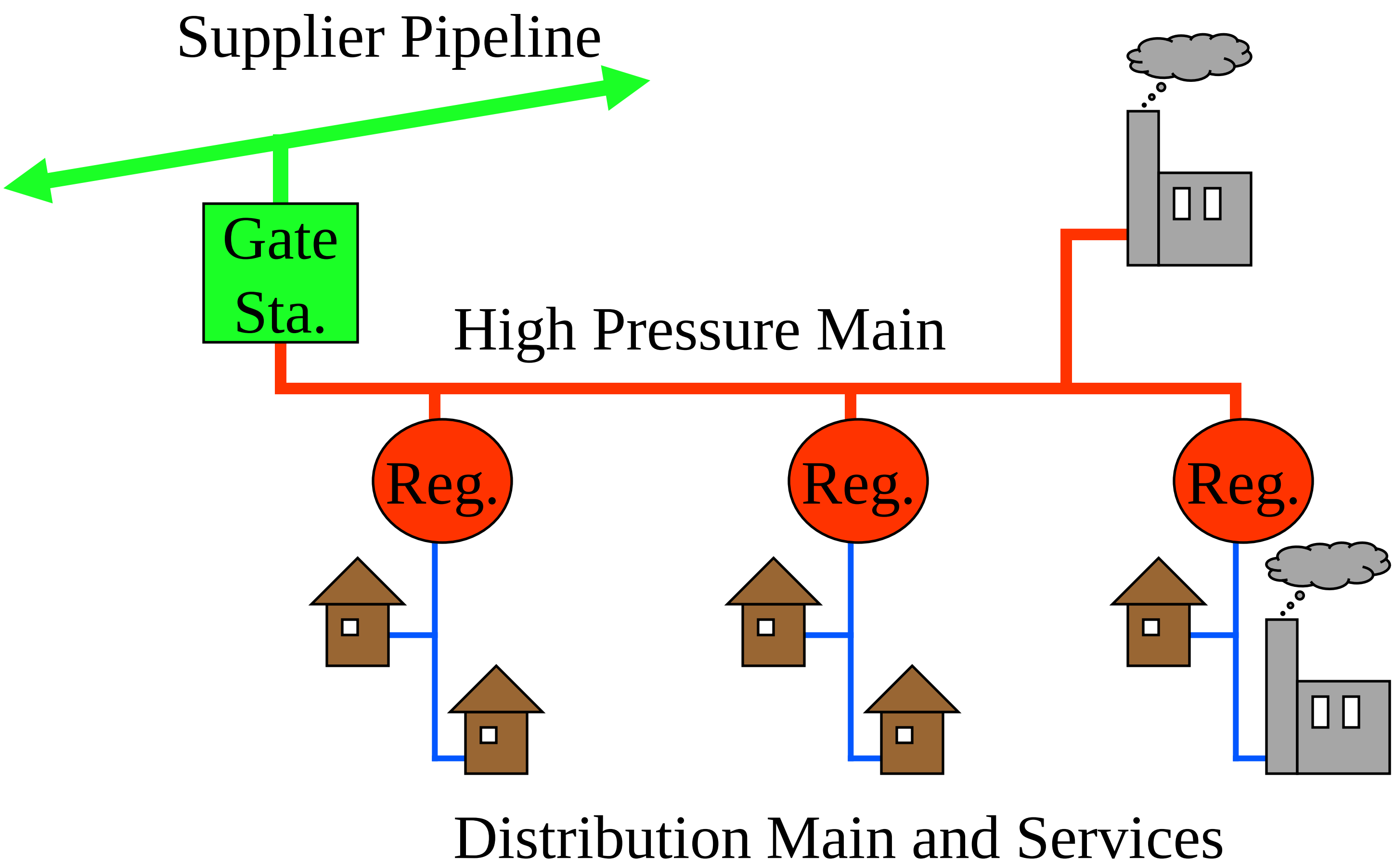
- 8,000 miles of distribution main
- 120 cities
- 40 load study models



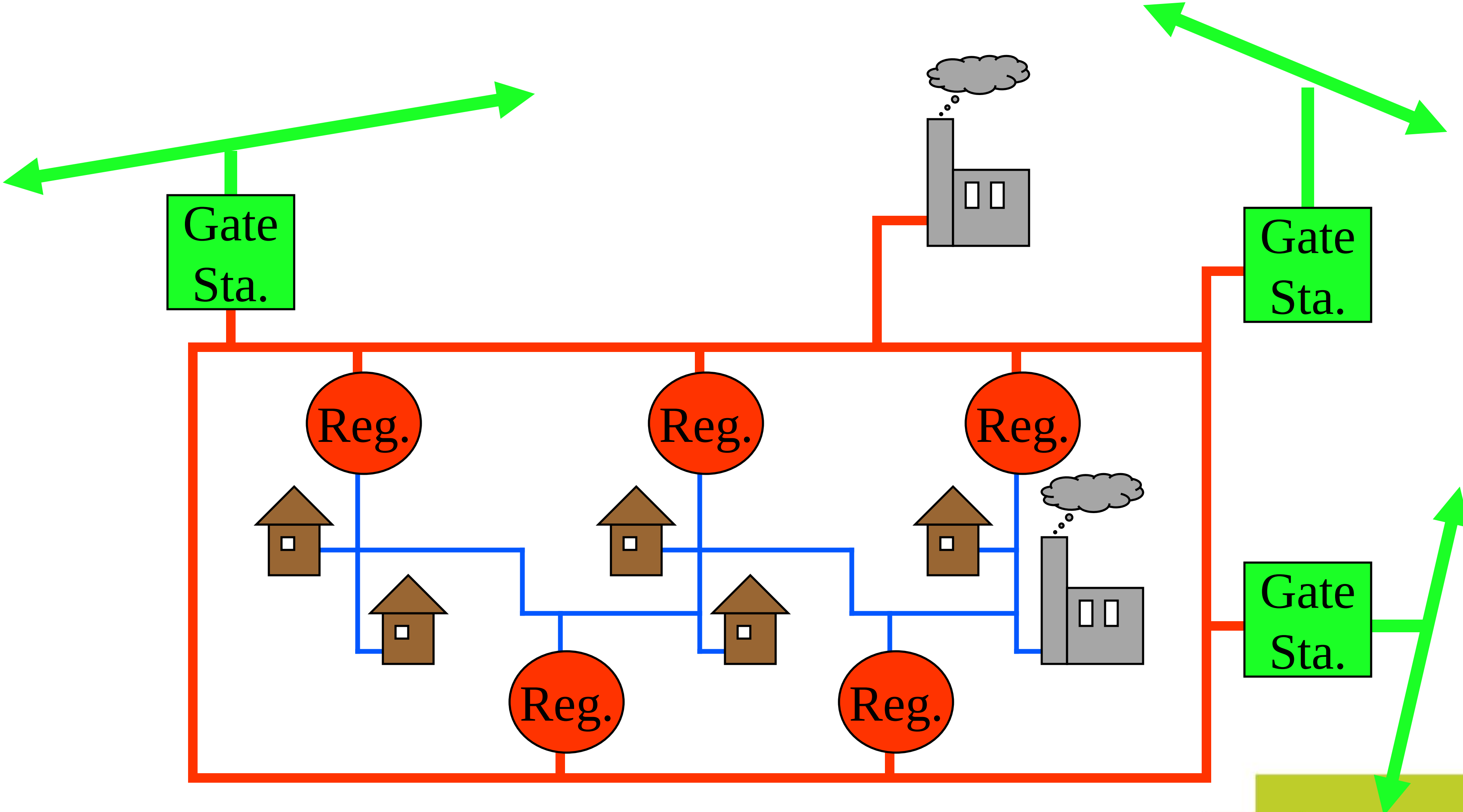
5 Variables for Any Given Pipe



Scope of Gas Distribution Planning

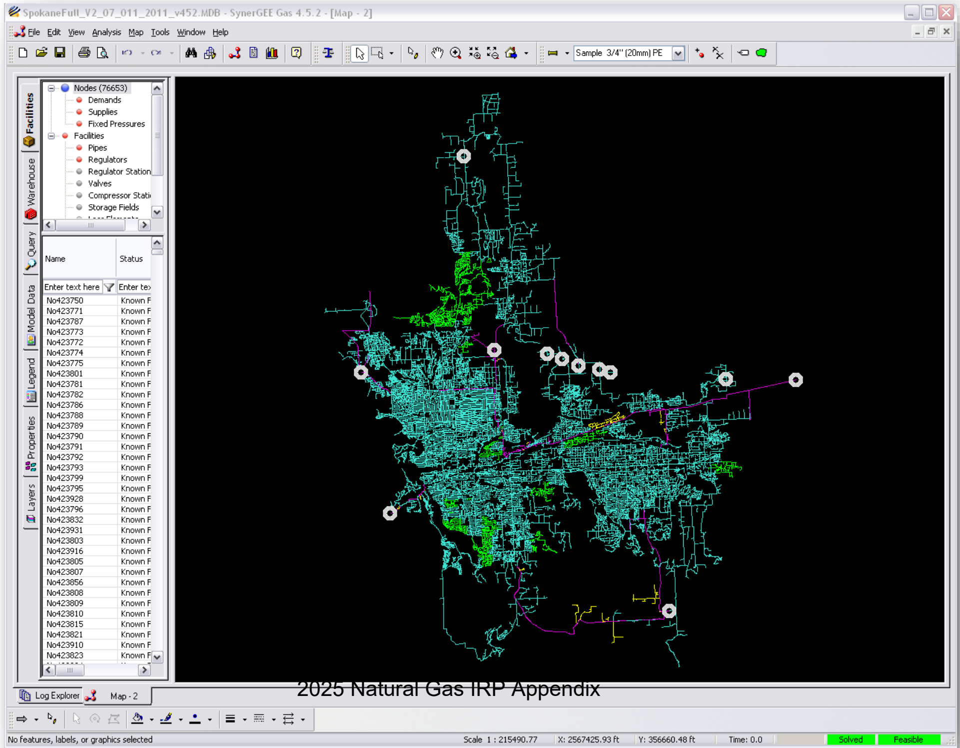


Scope of Gas Distrib. Planning cont.



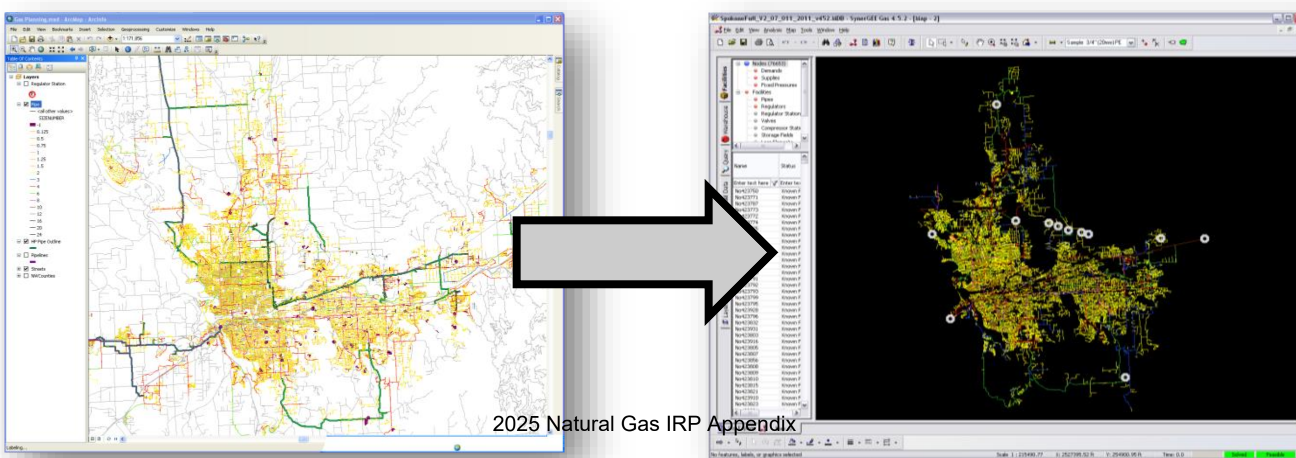
SynerGi (SynerGEE, Stoner) Load Study

- Simulate distribution behavior
- Identify low pressure areas
- Test reinforcements against future growth/expansion
- Measure reliability



Creating a Pipeline Model

- Elements
  - Pipes, regulators, valves
  - Attributes: Length, internal diameter, roughness
- Nodes
  - Sources, usage points, pipe ends
  - Attributes: Flow, pressure



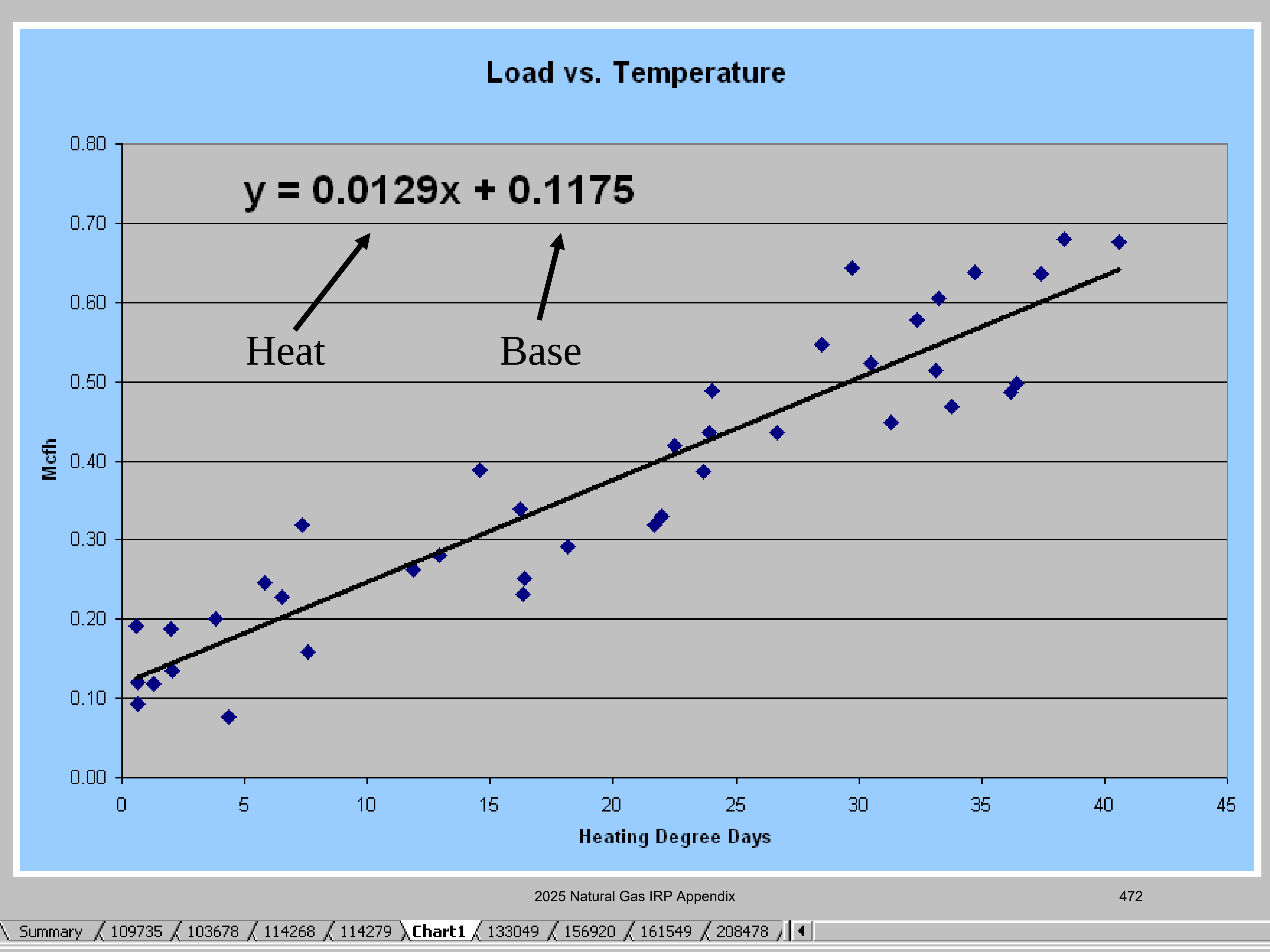
Estimating Customer Usage

- Gathering Data
  - Days of service
  - Degree Days
  - Usage
  - Name, Address, Revenue Class, Rate Schedule…

Estimating Customer Usage cont.

- Degree Days
  - Heating (HDD)
  - Cooling (CDD)
- Temperature - Usage Relationship
  - Load vs. HDD's
  - Base Load (constant)
  - Heat Load (variable)
  - High correlation with residential

Avg. Daily Temperature ('Fahrenheit)	Heating Degree Days (HDD)	Cooling Degree Days (CDD)
85		20
80		15
75		10
70		5
65	***0***	***0***
60	5	
55	10	
50	15	
45	20	
40	25	
35	30	
30	35	
25	40	
20	45	
15	50	
10	55	
5	60	
4	61	
0	65	
-5	70	
-10	75	
-15	80	



Load vs. Temperature
y = 0.0129x + 0.1175
Heat
Base
Mcfh
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
0
5
10
15
20
25
30
35
40
45
Heating Degree Days
Summary
109735
103678
114268
114279
Chart1
133049
156920
161549
208478

Monitoring Our System

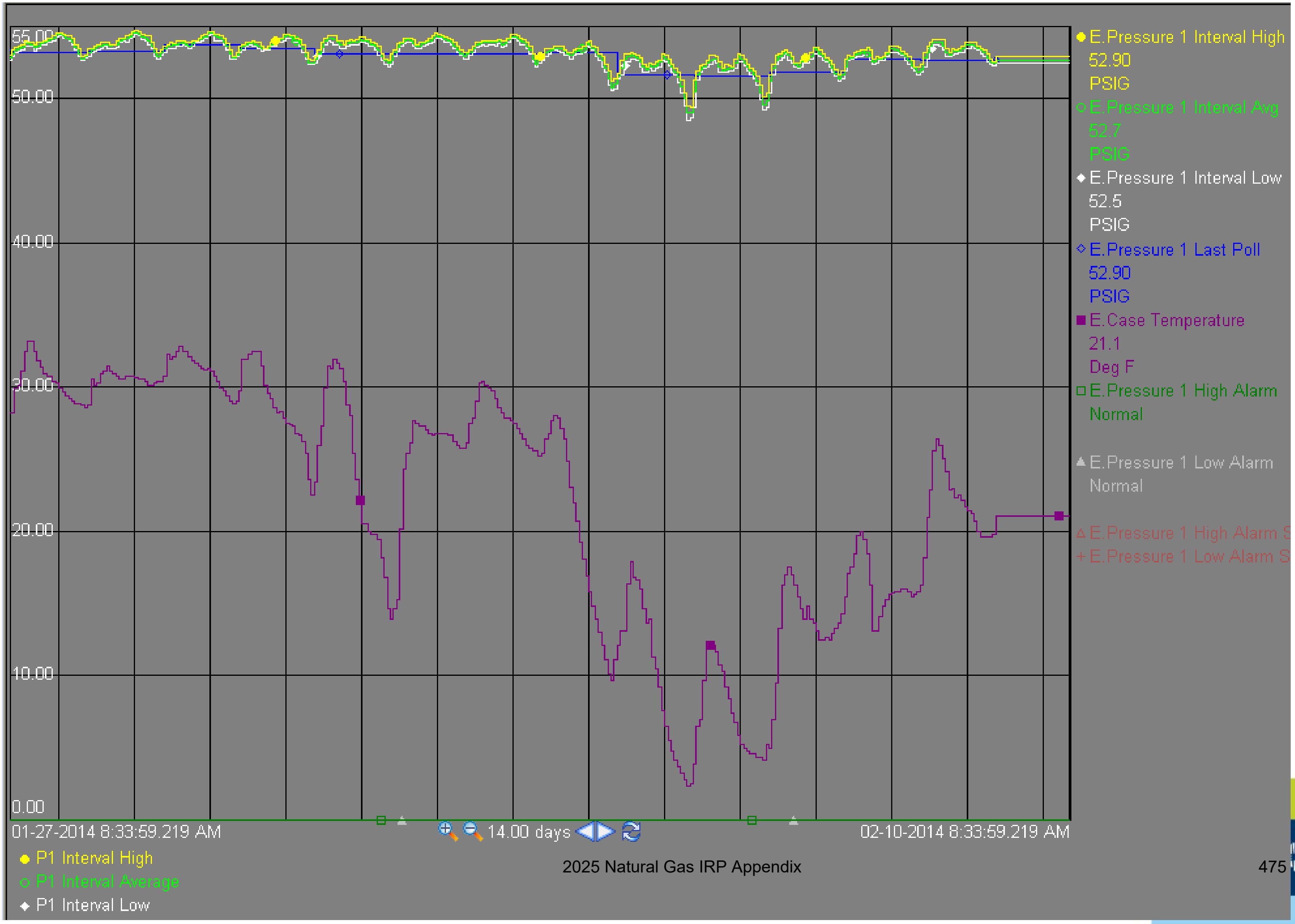
- Electronic Pressure Recorders
  - Daily Feedback
  - Real time if necessary
- Validates our Load Studies

Validating Model

- Simulate recorded condition
- Electronic Pressure Recorders
  - Do calculated results match *field* data?
- Gate Station Telemetry
  - Do calculated results match *source* data?
- Possible Errors
  - Missing pipe
  - Source pressure changed
  - Industrial loads

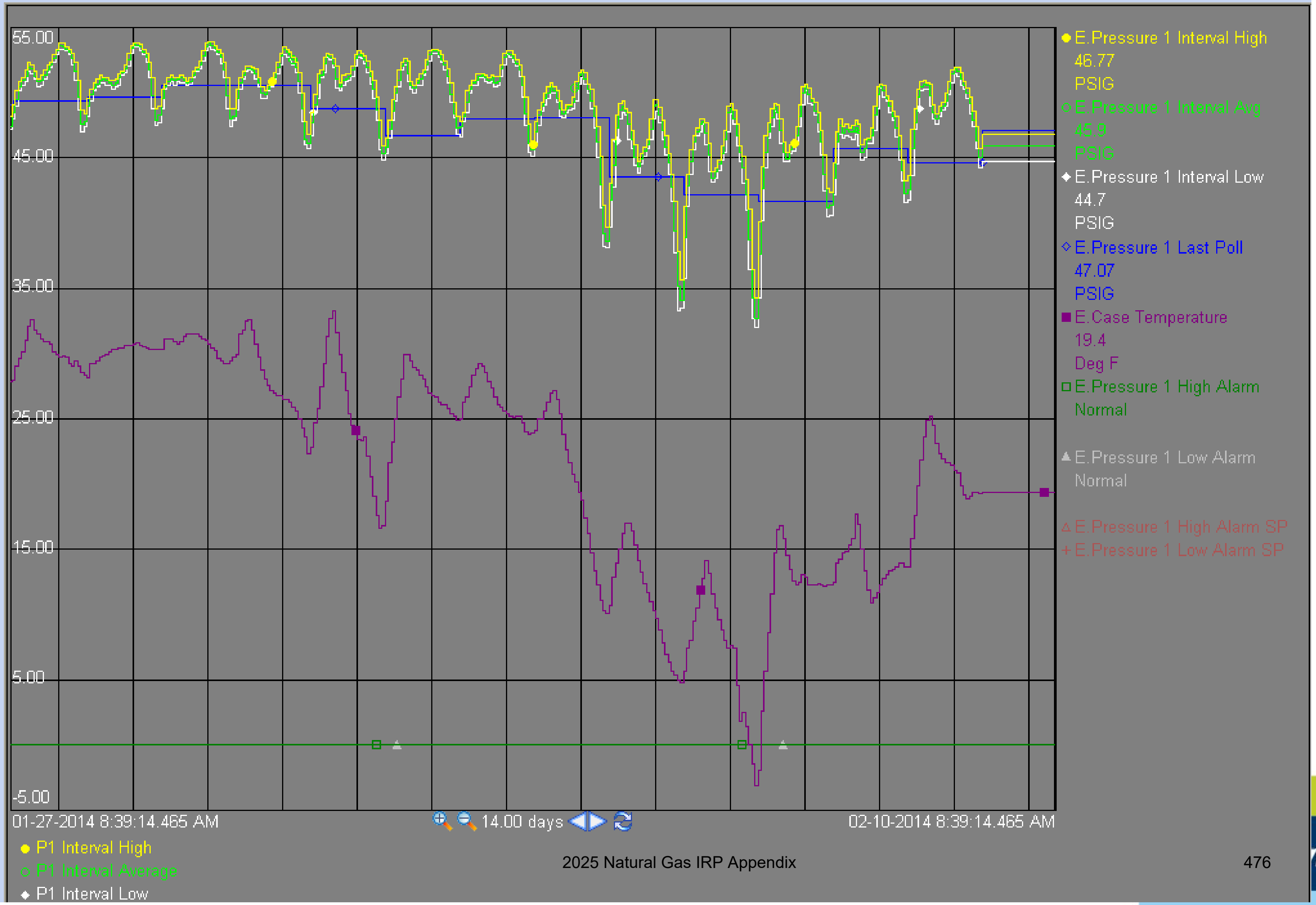
St Dominic's Girls School, W. 20274 Riverview Dr. Liberty Post Falls ID

Post Falls State Line



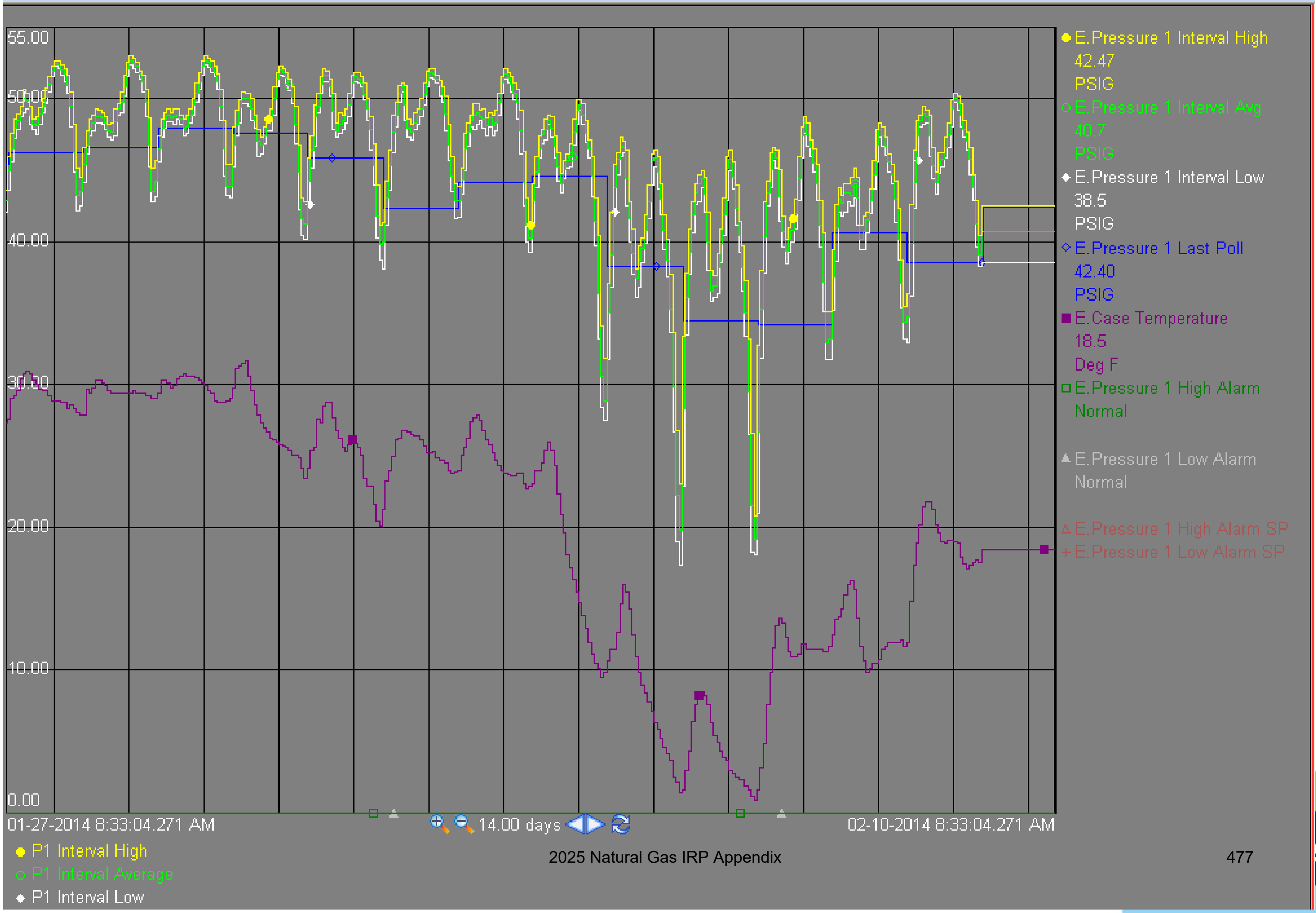
2362 E Bozanta, Hayden Lake ID

Hayden Lake



E. 3203 Crestwood Ct ,Hayden Lake ID

South Hayden Lake



Planning Criteria – 2023

- Reliability during design HDD
  – Spokane **76 HDD** *(avg. daily temp. -11' F)*
  – Medford **49 HDD** *(avg. daily temp. 16' F)*
  – Klamath Falls **72 HDD** *(avg. daily temp. -7' F)*
  – La Grande **72 HDD** *(avg. daily temp. -7' F)*
  – Roseburg **46 HDD** *(avg. daily temp. 19' F)*

- Maintain minimum of 15 psig in system at all times
  – 5 psig in lower MAOP areas
  – 3 psig in Medford 6 psig systems

Fixes and Reinforcements

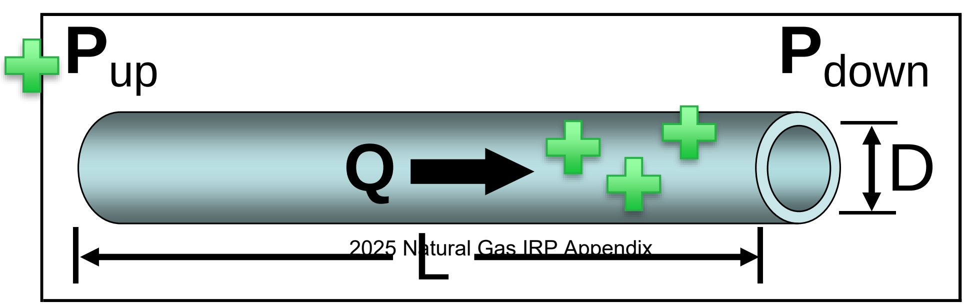
- Identify Low Pressure Areas
  - Number of feeds
  - Proximity to source
- Looking for Most Economical Solution
  - Length (minimize)
  - Construction obstacles (minimize)
- Lead Times:
  - Design and engineering; 12 months
  - Real estate, permits, and environmental; 6-24 months
  - Material ordering and delivery; 3-6 months

Non-Pipe Alternatives (NPAs)

- System Pressure Uprates
- Conservation
- Electrification

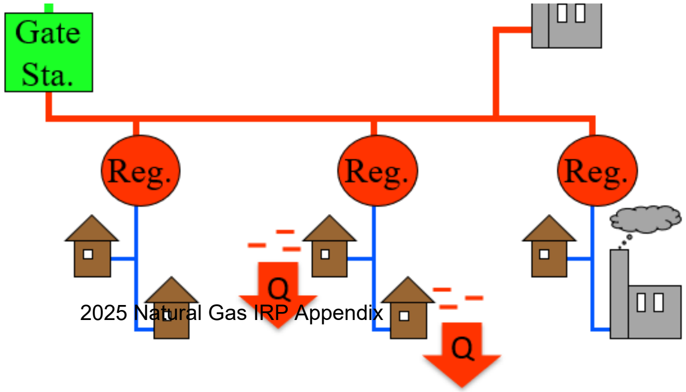
NPA: System Pressure Uprates

- Objective
  - Raise source pressure to increase capacity
- Process
  - Deep dive into records
  - Series of leak surveys
- Challenges
  - Remaining opportunities?
- Lead time
  - 6-12 months



NPA: Conservation

- Objective
  - Reduce customer demand on distribution
- Process
  - Targeted Load Management (TLM) programs
    - Identify opportunities and energy efficiency potential
    - Implement energy efficiency measures
- Challenges
  - Minimal benefits realized at distribution locations
  - More effective on supply side
- Lead time
  - 3-5 years



NPA: Conservation

- Results of Energy Trust TLM analysis (Oct 5th 2023)

Avista TLM: Total Potential and Program Activity

Area	Utility Target Goal	Total Efficiency Resource	Historic Annual Average
Medford	691	479	11
Sutherlin	121	158	2

peak hour therms

three-year total efficiency resource; cost-effective achievable potential

- Resource assessment modelling results demonstrate there is not enough peak reduction to meet AVI load reduction targets.
  - The Medford AVI target is **144%** of resource potential.
  - The Sutherlin AVI target is **77%** of resource potential.
- Program history shows the targets are 60x greater than a typical year of program activity.

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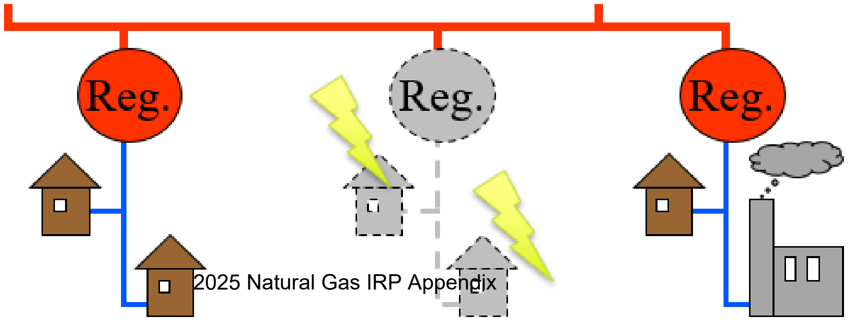
peak hour therms
assumes three-year TLM project
29 years needed to achieve targets at NWN pilot rate

- NWN Pilot achieved 4% of resource potential in two years of enhanced incentives.
  - ➢ Generalizing to a three-year project this equates to roughly 12% of Avista's targets.
- NWN Pilot nearly doubled historical acquisition.
  - ➢ This would result in about 9% of Avista's targets in a three-year period.

NPA: Electrification

- Objective
  - Eliminate customer demand on distribution
- Process
  - Identify customers in deficient areas
  - Transition to electric appliances/load
- Challenges
  - Transition may be expensive (cost of appliances)
  - Limited capacity and infrastructure of electric utility
    - Who pays for upgrade
- Lead time
  - 1-?? years



Areas Currently Monitoring for Low Pressure and Proposed Solutions*

- Medford 6 psig system, OR
- Airway Heights, WA
- South Hill Spokane, WA
- Schweitzer Resort, ID
- Moscow, ID
- *Notes:
  - List not comprehensive
  - projects are subject to change and will be reviewed on a regular basis

City Gate Stations Currently Monitoring and Proposed Solutions*

- Sutherlin, OR: *rebuild/enhance in 2024+*
- Malin, OR: *observe, rebuild/enhance in 2025+*
- Medford, OR: *work with pipeline to increase capacity*
- Rathdrum – Chase, ID: *rebuild/enhance in 2024+*
- Pullman, WA: *work with pipeline to increase capacity*
- *Notes:
  - List not comprehensive
  - projects are subject to change and will be reviewed on a regular basis

Questions and Discussion

Mission

Using technology to plan and design a safe, reliable, and economical distribution system

Avista 2025 Gas IRP TAC 4

STAFF'S PROPOSAL FOR NON PIPE ALTERNATIVES

Nick Sayen
Senior Utility Analyst
June 5, 2024

Oregon Public Utility Commission

Staff's Proposal

….Staff expects the Company to update its distribution system planning practices and IRP processes to include:

- *Guidance from Attachment A to Staff's Report in Order No. 23-023;*
- *Direction provided by Order No. 23-281;*
- *Practices agreed to through Stipulation Item 21 in Order No. 23-384; and*
- *Several of the extensions of Stipulation Item 21 suggested by Climate Advocates.*

Specific elements of Staff's expectation are included in Attachment C. ***Staff emphasizes this expectation does not include significant, new concepts.*** *With the exception of three items (2e., 2f., and 3) all of these practices have already been included in Commission Orders. Staff's expectation* ***simply assembles these concepts into a more cohesive package****.*

Staff's Second Errata Final Comments on 2023 IRP (Docket No. LC 81), page 45, https://edocs.puc.state.or.us/efdocs/HAC/lc81hac326154032.pdf

Attachment C

1. Future distribution system planning should identify the rationale for projects as either Safety/General System Reliability, or Customer Growth/Reliability Related to Growth.
    a. When proposing growth-driven projects in IRPs the utility should be prepared to present project data on: relationship to CPP compliance strategy, modeling and verified measurement, local load forecast, and assessment of alternatives through the NPA framework.

Attachment C

The Company should update its DSP practices and IRP processes to include:

1. Future distribution system planning should identify the rationale for projects as either Safety/General System Reliability, or Customer Growth/Reliability Related to Growth.
    a. When proposing growth-driven projects in IRPs the utility should be prepared to present project data on: relationship to CPP compliance strategy, modeling and verified measurement, local load forecast, and assessment of alternatives through the NPA framework.

2. Future distribution system planning should include an NPA framework in Oregon. The framework should include:
    a. NPA analysis will be performed for supply-side resources (these include but are not limited to all resources upstream of Avista's distribution system and city gates, and supply-side contracts) and for distribution system reinforcements and expansion projects that exceed a threshold of $1 million for individual projects or groups of geographically related projects (a group of projects that are interdependent or interrelated).
    b. NPA analysis will include cost benefit analysis that reflects an avoided GHG compliance cost element consistent with a high-cost estimate of future alternative fuels prices. Non-Energy Impacts must be included as part of the NPA analysis.
    c. NPA analysis will include electrification, targeted energy efficiency, targeted demand response, and other alternative solutions.
    d. NPA analysis should look forward five years to allow ample time for evaluation and implementation.
    e. NPA analysis will include an explanation of solutions considered and evaluated including a description of the projected timeline and annual implementation rate for the solutions evaluated, the technical feasibility of the solutions, and the strategy to implement the solutions evaluated.
    f. NPA analysis should include an explanation of the resulting investment selection (either NPA or a traditional investment) including the costs and ranking of the solutions, and the criteria used to rank or eliminate them.
        i. If a NPA is not selected and the reason is insufficient implementation time, it should include steps the Company will take to perform NPA analysis to provide sufficient implementation time for future projects.
3. Future IRPs should include the results of distribution system planning, including project data and NPA analysis for any proposed traditional investments, and NPA analysis for any proposed NPA.
4. Future IRPs should include a database containing information about feeders, in service dates of pipes, and lowest recent observed pressures.

Oregon Public Utility Commission

Attachment C

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Thank you

Nick Sayen

Senior Utility Analyst

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Oregon Public Utility Commission

Targeted Load Management Overview

Energy Trust and Avista

June 2024

Energy Trust of Oregon

Agenda

- What is TLM at Energy Trust?
- TLM Process Phases
- Program Implementation Strategies
- Prior TLM Examples- Medford and Sutherlin

What is TLM at Energy Trust?

A range of planning, program and community services:

- Market intelligence and characterization
- Resource potential analysis
- Program design and delivery strategies
- Customer and community engagement

Objectives:

- Determine whether targeted energy efficiency can meet local utility system needs
- Deliver benefits to utility and local communities

Targeted Load Management Process Phases

*Could include funding beyond current PPC funds

Program Implementation Strategies

Previous TLM efforts included:

- **Increased incentives**: maximum based on cost effectiveness, and max allowed based on localized avoided costs
- **Increased Trade Ally (TA) engagement**: training, participation agreements, single point of contact support, incentive form assistance
- **Increased Trade Ally Business Development Funds**: to subsidize and support TA sponsored marketing efforts
- **Increased Marketing**: local newspapers, social media, tabling at local events, TLM landing page
- **Increased Customer outreach and engagement**: proactive contact with large commercial and industrial customers

Avista TLM Analysis:
Medford and Sutherlin

Avista TLM: Load Forecast Composition

Customer Segment	**Medford**	**Sutherlin**
Residential	62%	64%
Commercial	37%	25%
Industrial	1%	10%

- The load forecast and premise IDs identified in each TLM area are primarily residential with some commercial and industrial.
  - ➢ This load breakdown was used as input to the resource assessment model

Avista TLM: Total Potential and Program Activity

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- Program history shows the targets are 60x greater than a typical year of program activity.

Thank you!

Adam Shick, Planning Manger
adam.shick@energytrust.org

Spencer Moersfelder, Director of Planning and Evaluation
spencer.moersfelder@energytrust.org

Willa Perlman, Planning Project Manager

willa.perlman@energytrust.org

Supplemental Slides

Resource Assessment Overview

What is a resource assessment?

- Estimate of energy efficiency resource potential at a range of costs that is achievable over a defined number of years
- Identifies opportunities for energy efficiency measures within a territory based on existing conditions of building stock

What is it used for?

- The purpose is to help Energy Trust and utilities strategically plan future investments in both demand side and supply side resources
- Provides a cost-effective resource estimate of annual and peak savings
- For localized efforts, it helps inform a go/no-go decision

Is the locational potential enough to meet utility targets?

Avista TLM: Forecast Using NWN Pilot Results

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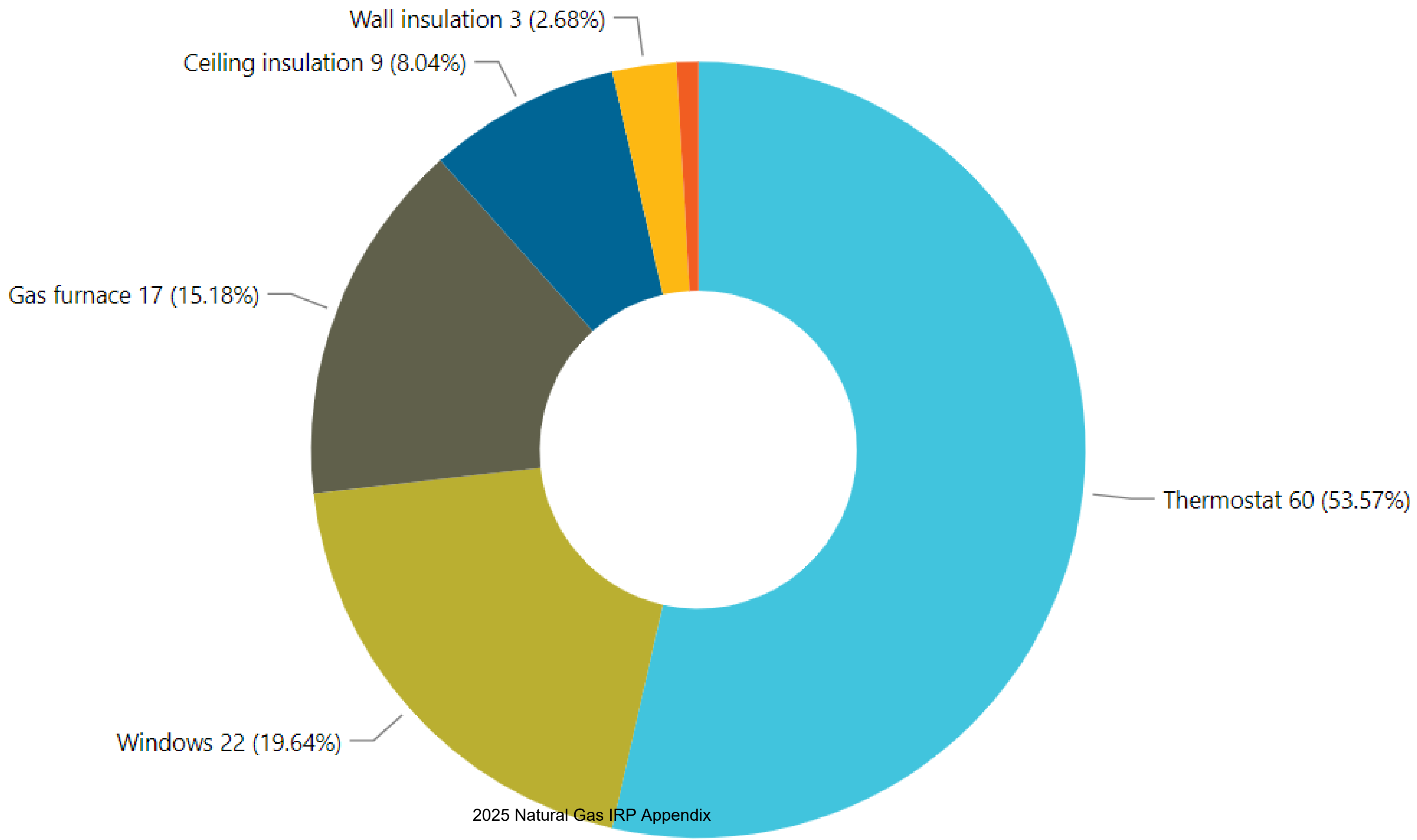
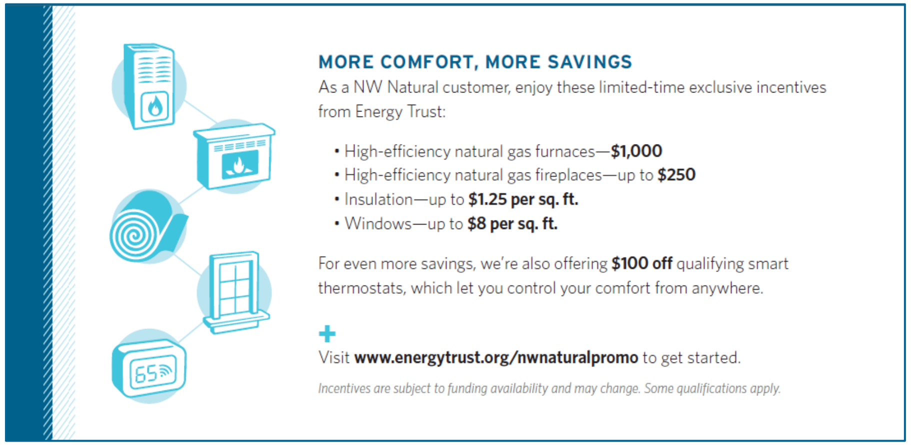
Past TLM Example: Gas efficiency measure mix



Past TLM examples: Marketing materials

TLM – Residential bill insert



TLM – Commercial Postcard

Phase/ Aspect	Identify constrained areas and utility needs	Analyze resource potential (one or many sites)	Develop program planning and strategies to meet localized needs	Go/No-Go decision with Energy Trust and utility partner	Build out budget and strategies for annual ETO budget	TLM Implementation
Energy Trust	Collaborates with utility partner to understand various utility needs (e.g., peak demand, flexible load, carbon)	Use Resource Assessment (RA) Model to estimate potential in local areas	Use existing suite of measures/offers mapped to each TLM area need; Consider local community needs for design and delivery	**Joint decision needed for Energy Trust's budget cycle**	Owns the program delivery strategy and implementation plan	Lead all aspects of implementation for EE and distributed RE (for electrics)
Utility Partner	Analyzes grid needs and grid constraints, typically through IRP (historical) and new processes like DSP or CEP	Provides data on specific feeder(s) and any market verticals; Provides localized avoided costs estimates	Collaborate on Distributed Energy Resources (DERs) beyond EE, including DR/flex load, storage, EVs		Agrees to overall play through 1) overall budget process; 2) any additional funding	Collaborate in key areas – regional account management/ outreach, CBAIGs, marketing
Community	*Potential to further automate early analysis with feeder data and RA model;* ***Establish project leads with decision-making authority at each utility***	*Consider ETO Neighborhood Reports and/or Market Characterization Reports at this stage*	*To network with community partners early and often*	*Consider how both Energy Trust and utilities represent insights from community engagements*	*Demonstrate input via existing channels: Advisory Councils, outreach/ community networks*	*Share insights of "how this is impacting communities"*

Additional Program Delivery Strategies

- Fixed Price Promotions
- Community Partner Funding (CPF) promotions
- Community Based Organization (CBO) engagement
- Income qualified offers
- No-cost offerings (incentive covers full cost of measure)
- Direct Install offerings: Energy Trust coordinates install and pays full cost of measure
- Introduction of new measures such as: duct sealing and duct insulation

Weather

Avista 2025 IRP

TAC 5 – June 5th, 2024

Tom Pardee

Weather Forecasts

Data by Planning Region

- Klamath Falls
- La Grande
- Medford
- Roseburg
- Spokane

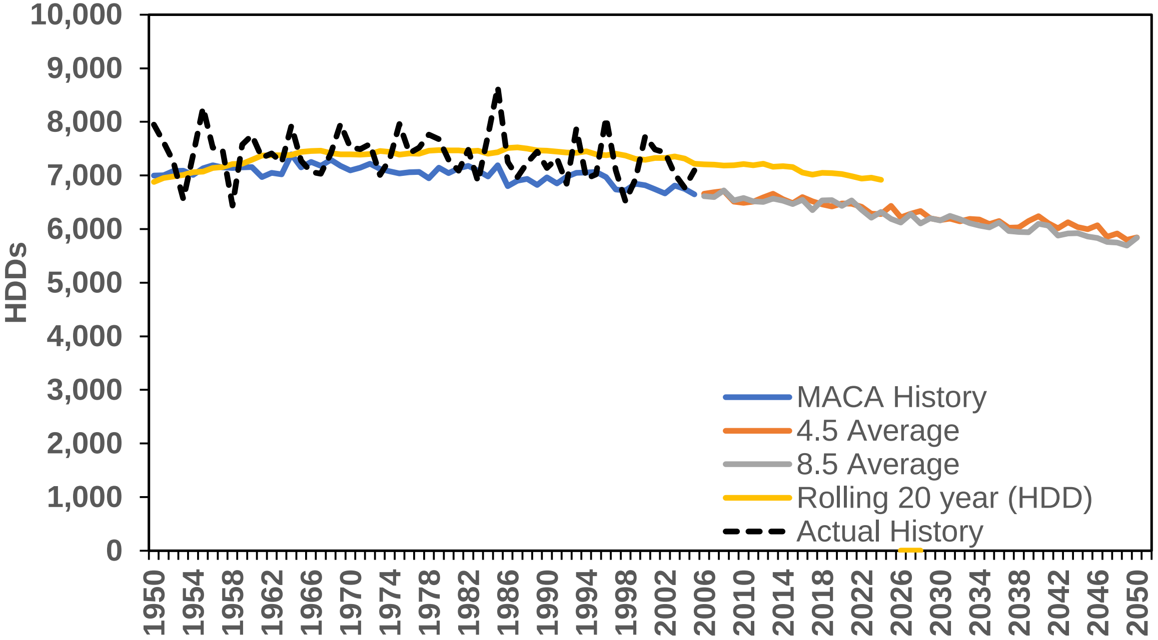
MACA 4.5 data[1]

- Multivariate Adaptive Constructed Analogs (MACA)
- Median HDD values of available studies by planning region
  - HDD calculated from Average of Min/Max by study
- Trended HDDs from 2026 – 2045
- Rolling 20-year blend (historic and MACA HDDs)

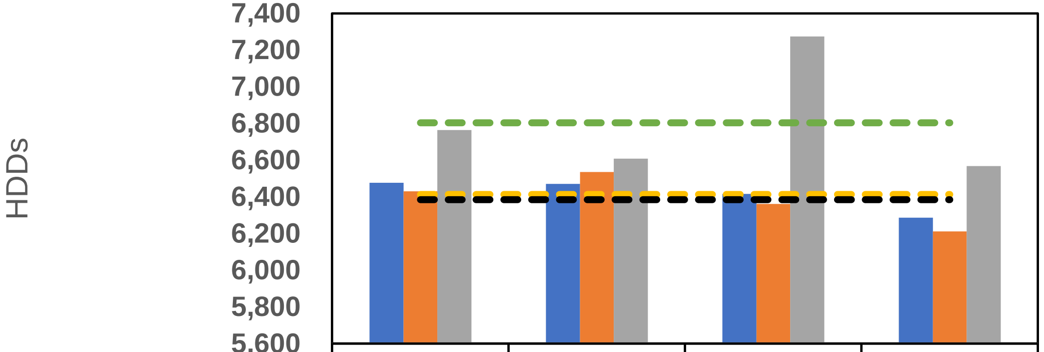
1MACA Statistical Downscaling Method (northwestknowledge.net)

MACA versus Actual Weather (Spokane)

Weather Comparison

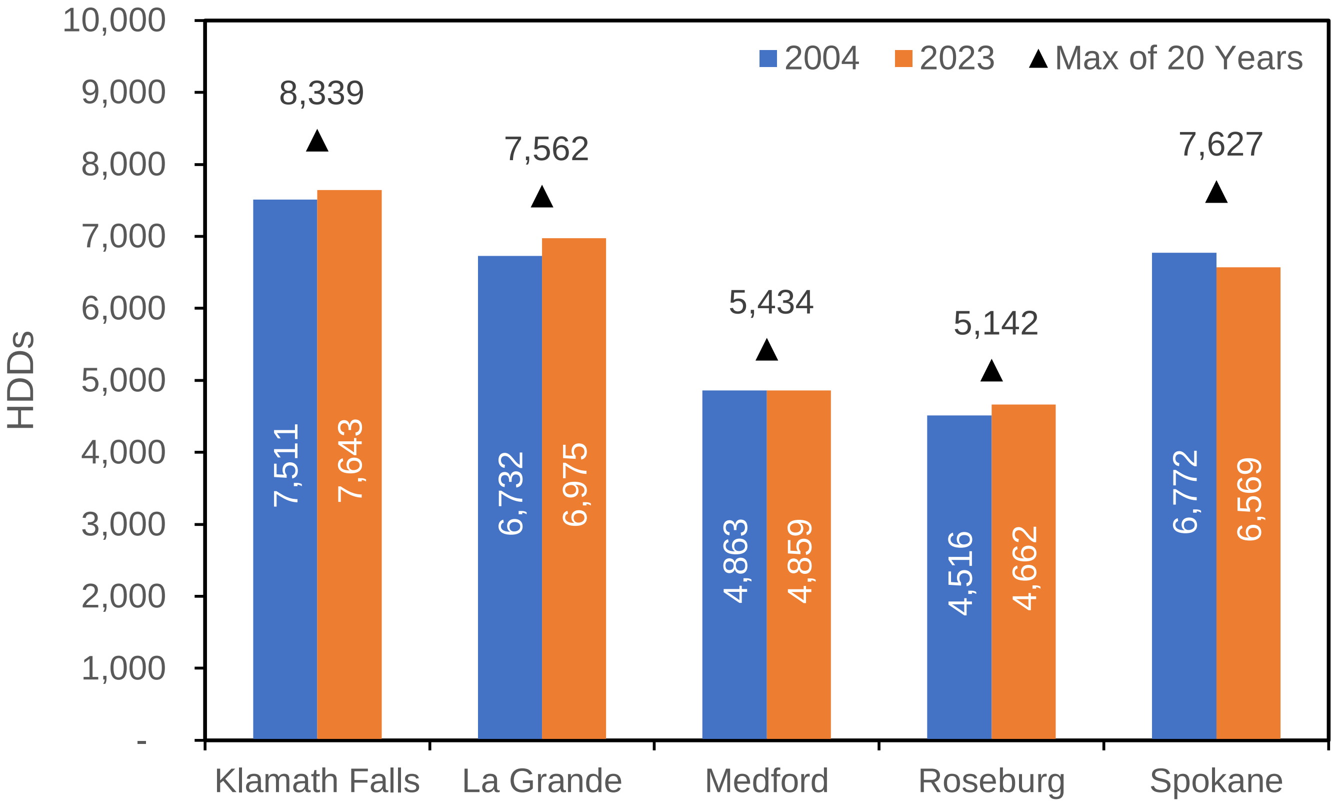


2020 – 2023 Comparison

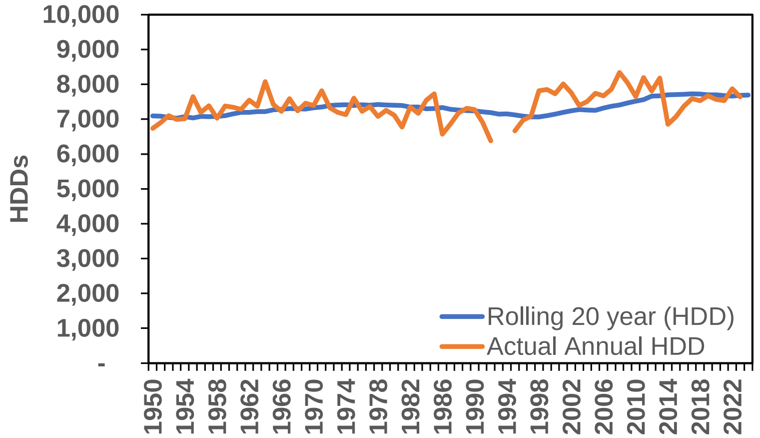


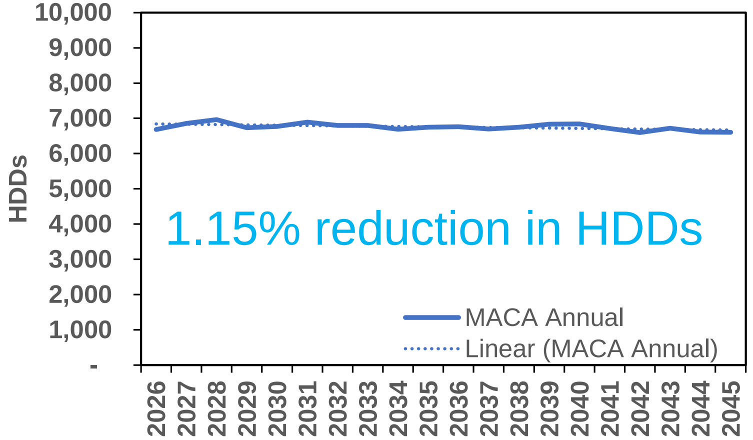
	2020	2021	2022	2023
4.5 Median	6,477	6,471	6,416	6,288
8.5 Median	6,431	6,535	6,361	6,213
Actual History	6,766	6,609	7,276	6,569
Average 4.5	6,413	6,413	6,413	6,413
Average 8.5	6,385	6,385	6,385	6,385
Average History	6,805	6,805	6,805	6,805

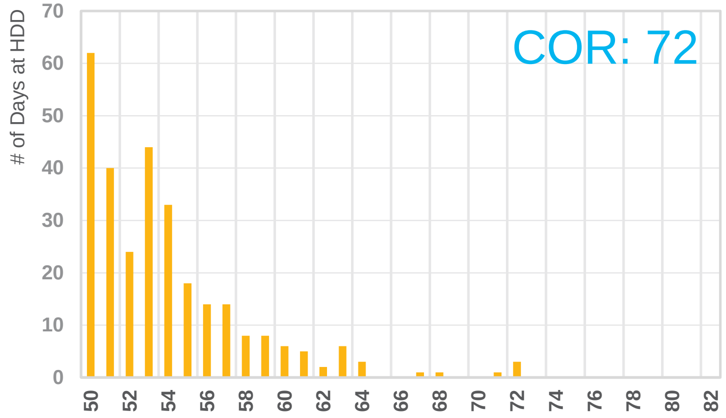
Weather History Comparison



Klamath Falls
Weather History and 4.5 MACA







Weather History

20 Year rolling HDD daily average of 7,695 HDDs (2004-2023)

4.5 MACA

Trended reduction in HDDs from 2026 to 2045

Peak HDDs

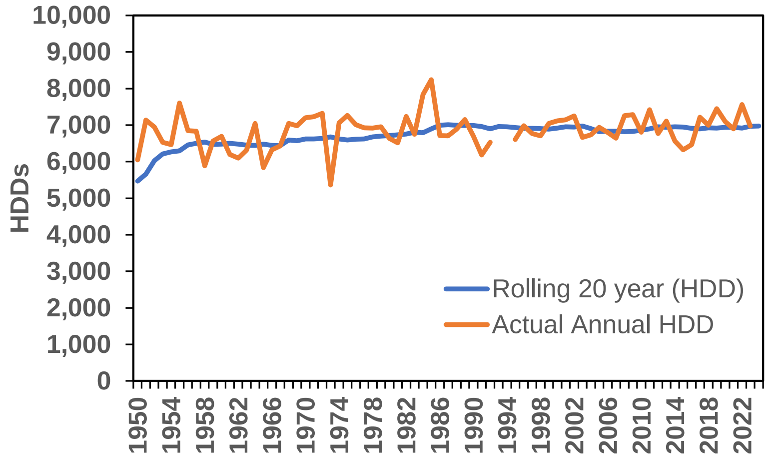
Coldest on Record Dates:

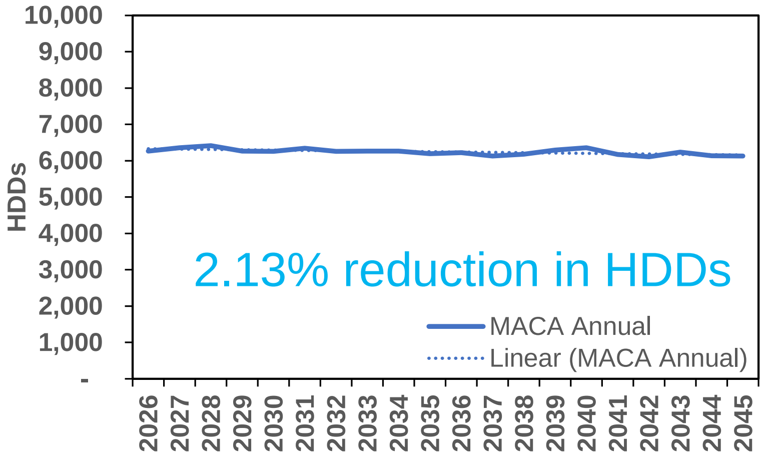
12/21/1990

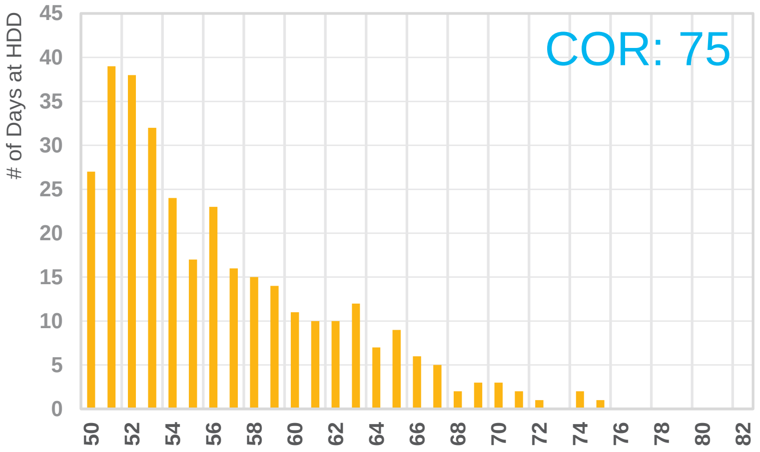
12/8/2013

1/6/2017

La Grande
Weather History and 4.5 MACA







Weather History

20 Year rolling HDD daily average of 6,978 HDDs (2004-2023)

4.5 MACA

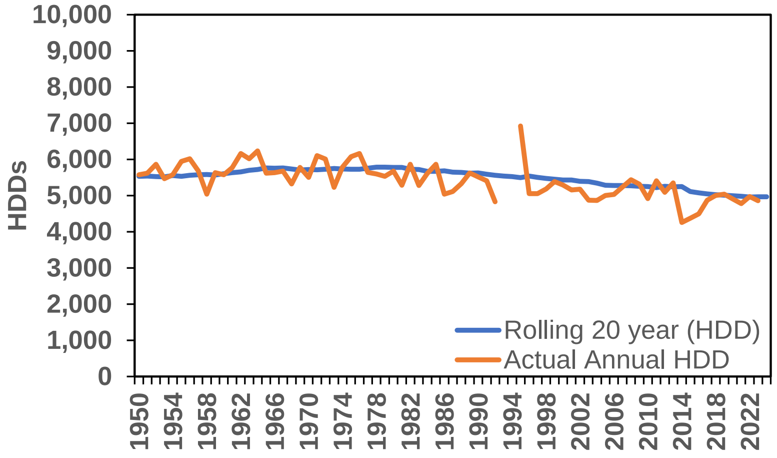
Trended reduction in HDDs from 2026 to 2045

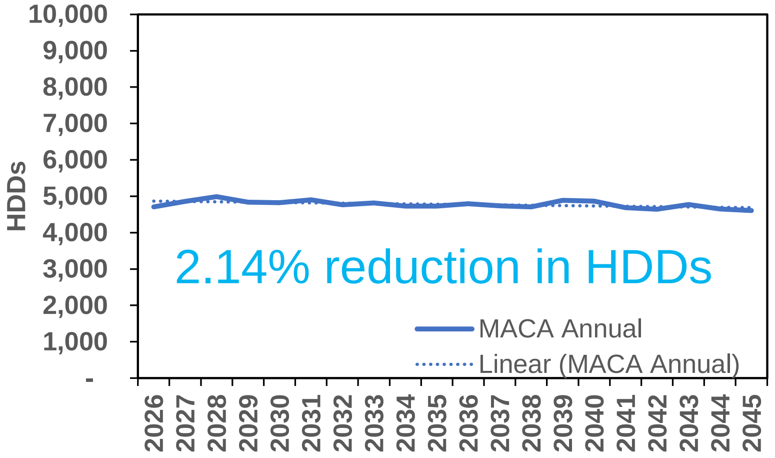
Peak HDDs

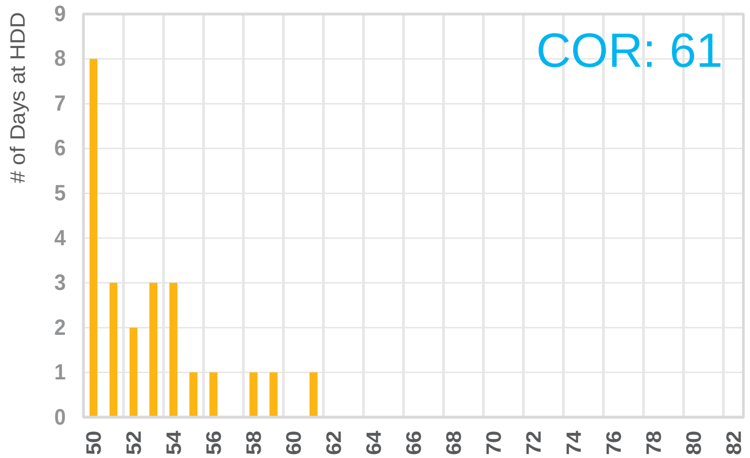
Coldest on Record Dates:

1/31/1996

Medford
Weather History and 4.5 MACA







Weather History

20 Year rolling HDD daily average of 4,965 HDDs (2004-2023)

4.5 MACA

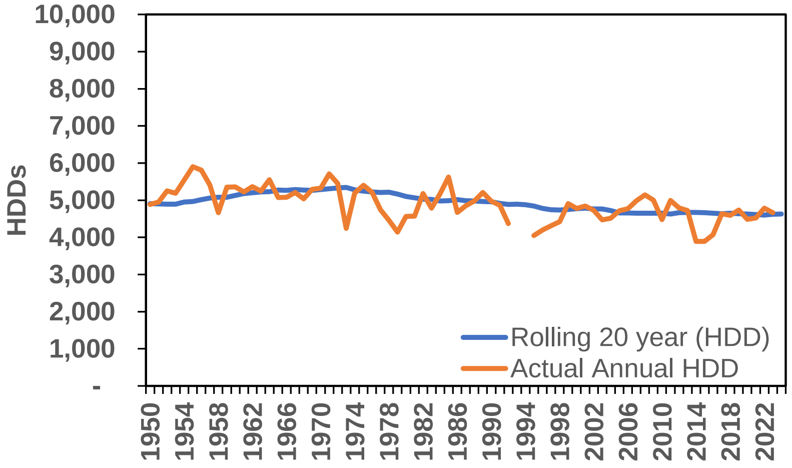
Trended reduction in HDDs from 2026 to 2045

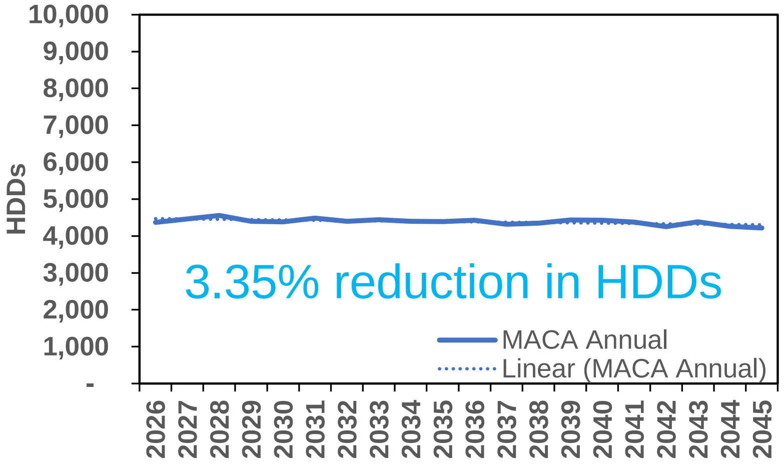
Peak HDDs

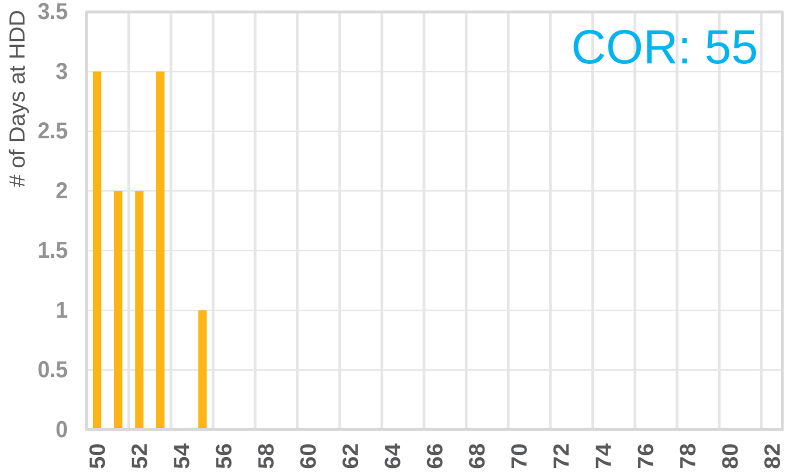
Coldest on Record Dates:

12/9/1972

Roseburg
Weather History and 4.5 MACA







Weather History

20 Year rolling HDD daily average of 4,627 HDDs (2004-2023)

4.5 MACA

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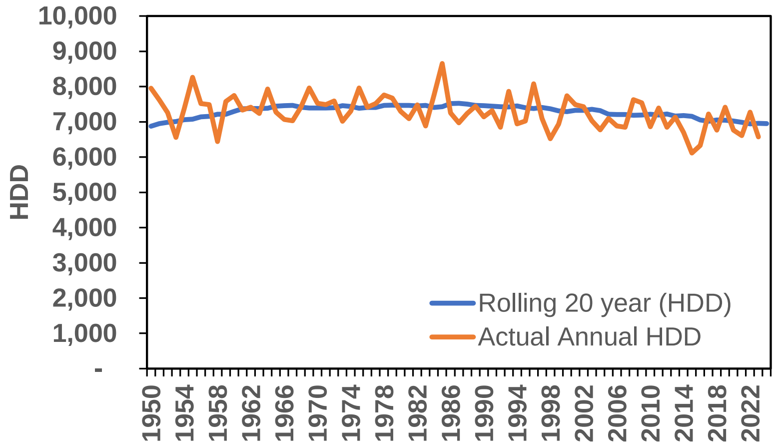
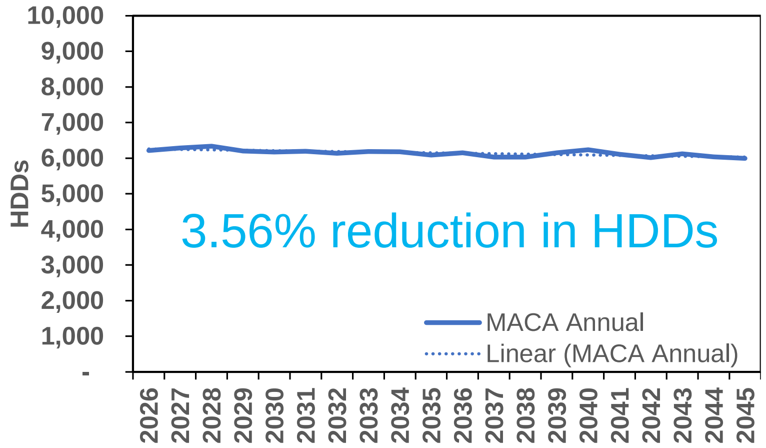
Peak HDDs

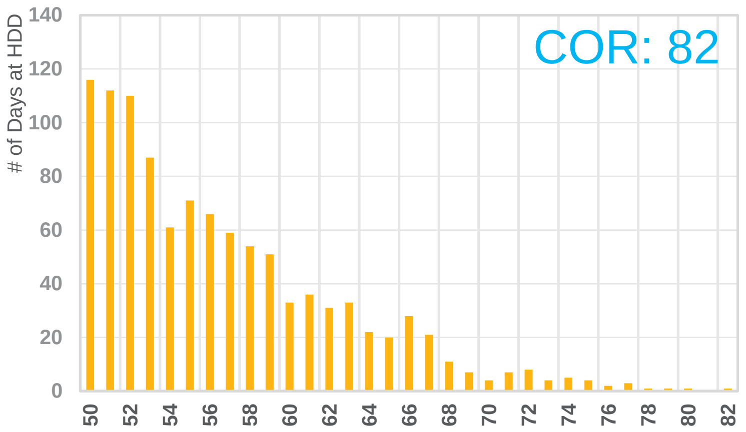
Coldest on Record Dates:

12/22/1990

Spokane
Weather History and 4.5 MACA







Weather History

20 Year rolling HDD daily average of 6,946 HDDs

(2004-2023)

4.5 MACA

Trended reduction in HDDs from 2026 to 2045

Peak HDDs

Coldest on Record Dates:

12/30/1968

Peak Day Options

99% Probability

Weather futures are higher than coldest on record and drastically increases the peak day for each area

Max daily temp across all weather futures

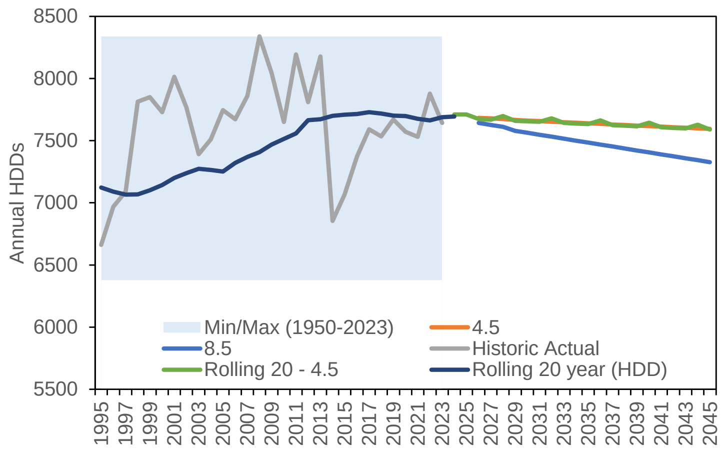
Coldest on Record (COR)

Some coldest on record temps have not occurred in recent history

COR less decrease in HDDs

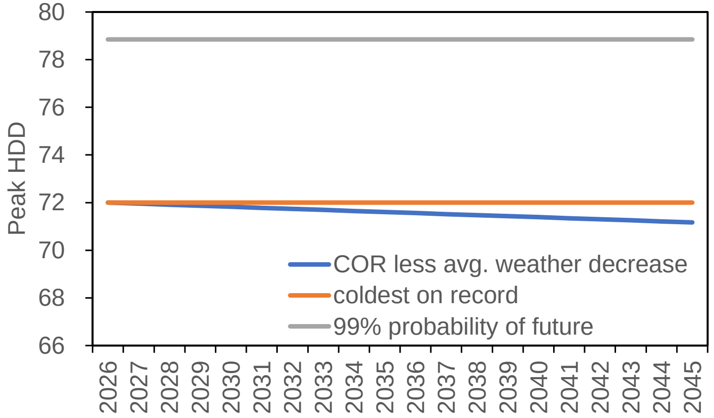
Uses a coldest on record less the average decrease in temps from 2026 - 2045

Klamath Falls



4.5 MACA

- **4.5 Median of future weather studies**
- **20 year rolling average (historic + forecast)**

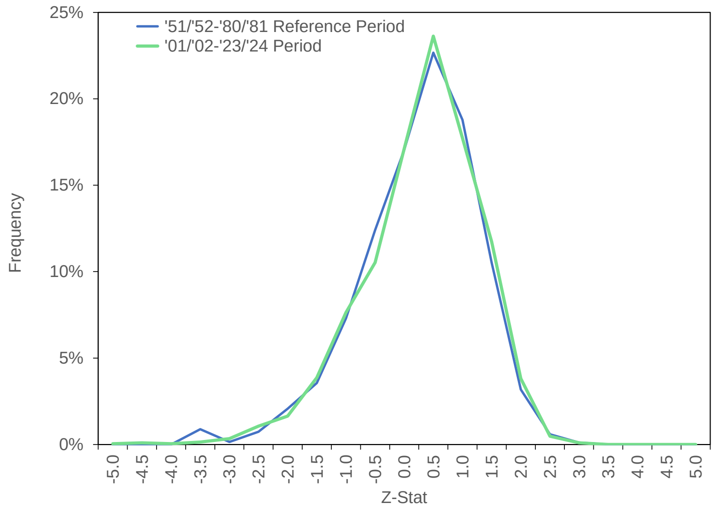


Peak

Coldest on Record less average forecasted annual decrease (2026-2045)

2025 IRP: 71 HDD peak planning

(89% probability in MACA 4.5)



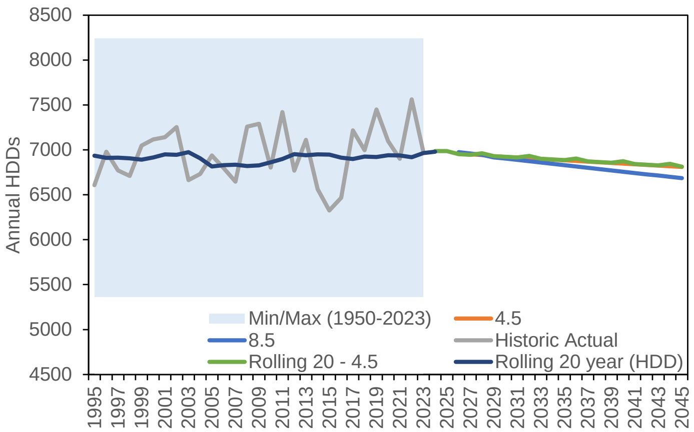
Historic Weather Comparison

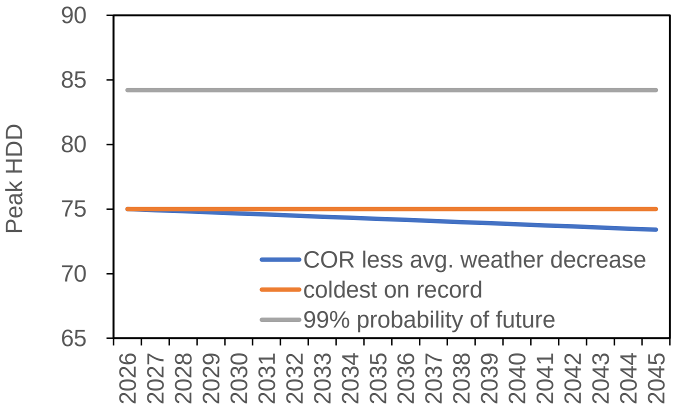
1951 – 1981 Winters (Dec, Jan, Feb)

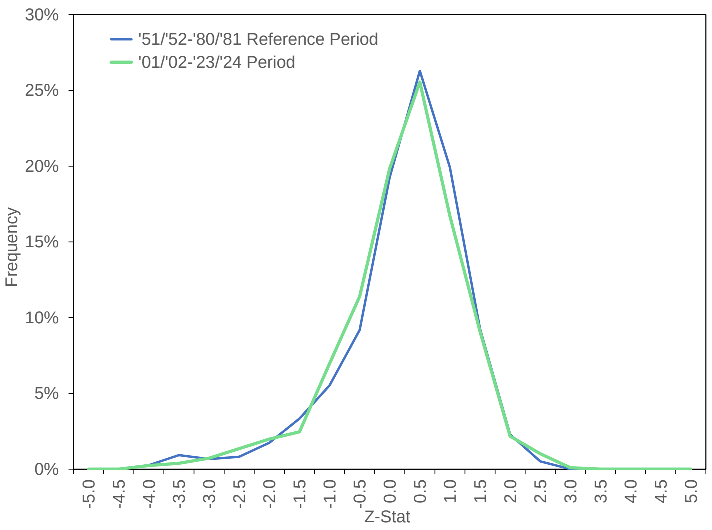
Compared to:

2001 – 2023 Winters (Dec, Jan, Feb)

La Grande







4.5 MACA

- **4.5 Median of future weather studies**
- **20 year rolling average (historic + forecast)**

Peak

Coldest on Record less average forecasted annual decrease (2026-2045)

2025 IRP: 73 HDD peak planning

(69.5% probability in MACA 4.5)

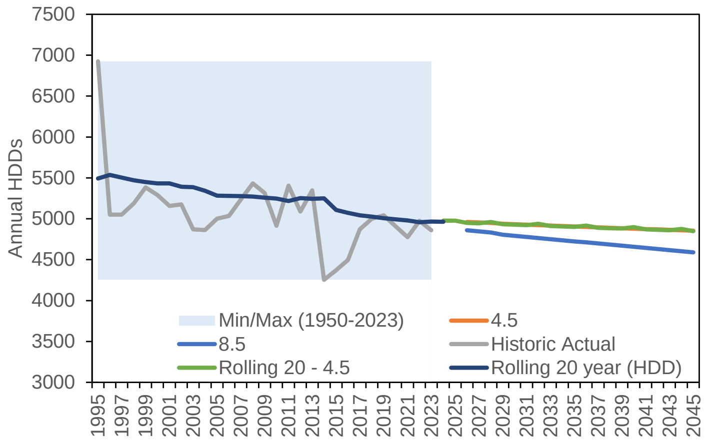
Historic Weather Comparison

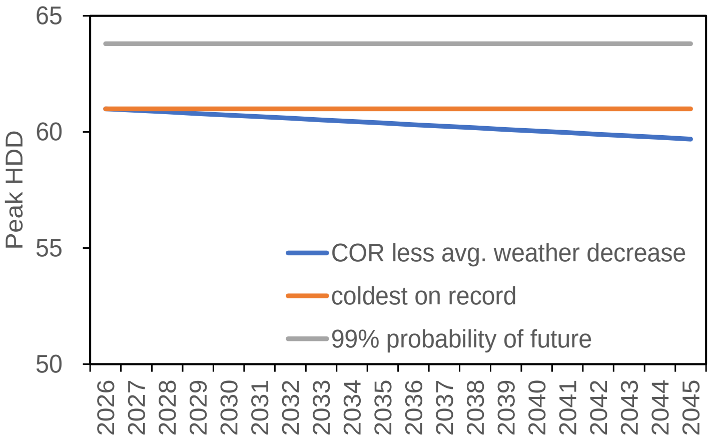
1951 – 1981 Winters (Dec, Jan, Feb)

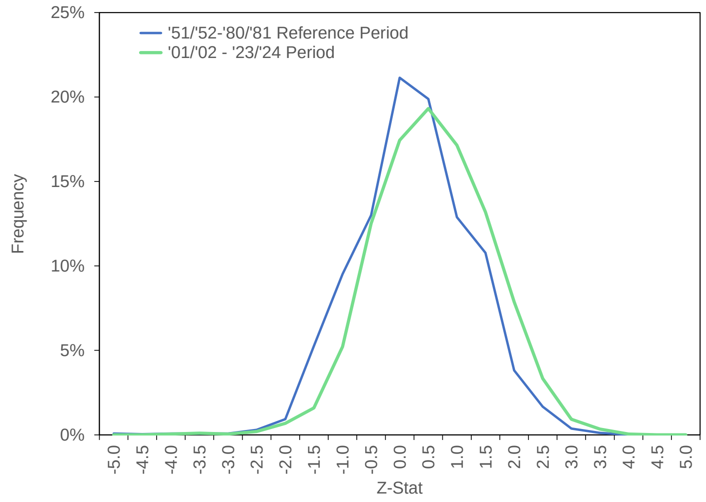
Compared to:

2001 – 2023 Winters (Dec, Jan, Feb)

Medford







4.5 MACA

- 4.5 Median of future weather studies
- 20 year rolling average (historic + forecast)

Peak

Coldest on Record less average forecasted annual decrease (2026-2045)

2025 IRP: 60 HDD peak planning

(96% probability in MACA 4.5)

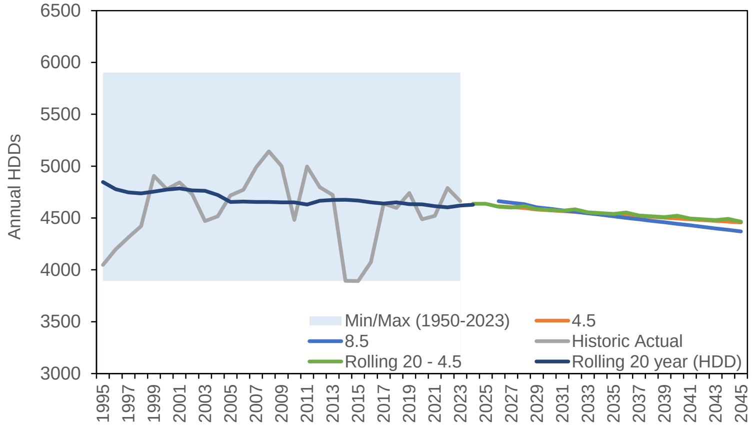
Historic Weather Comparison

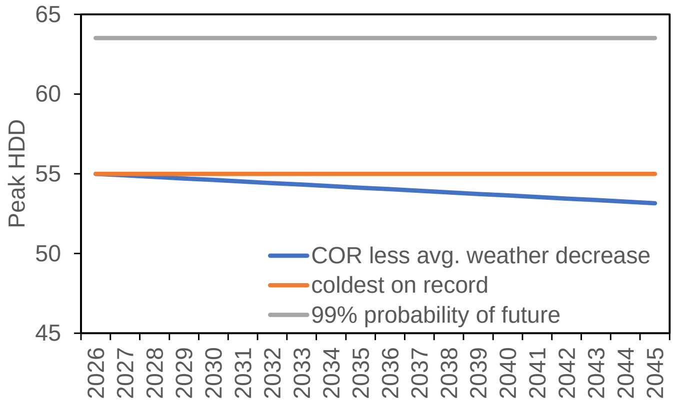
1951 – 1981 Winters (Dec, Jan, Feb)

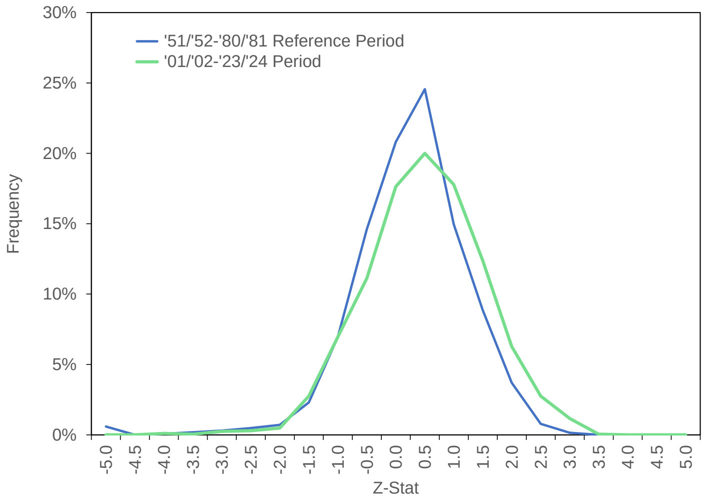
Compared to:

2001 – 2023 Winters (Dec, Jan, Feb)

Roseburg







4.5 MACA

- **4.5 Median of future weather studies**
- **20 year rolling average (historic + forecast)**

Peak

Coldest on Record less average forecasted annual decrease (2026-2045)

2025 IRP: 53 HDD peak planning

(75.5% probability in 4.5 MACA)

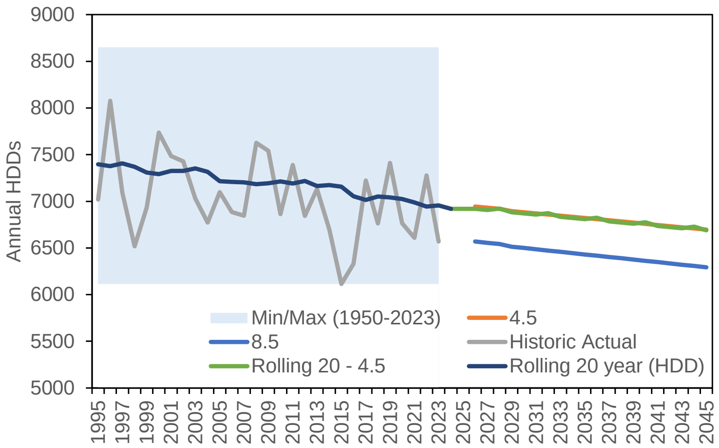
Historic Weather Comparison

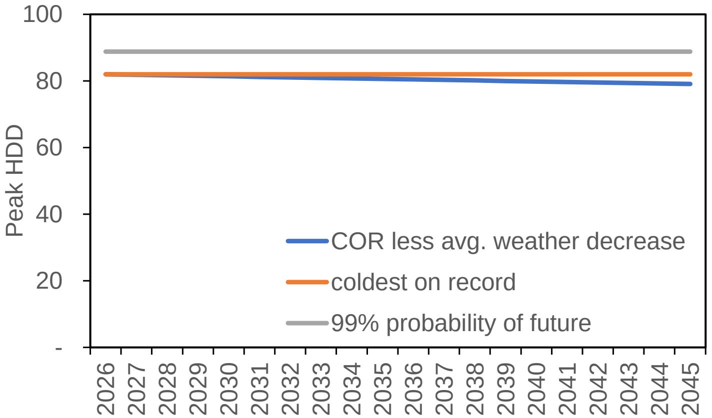
1951 – 1981 Winters (Dec, Jan, Feb)

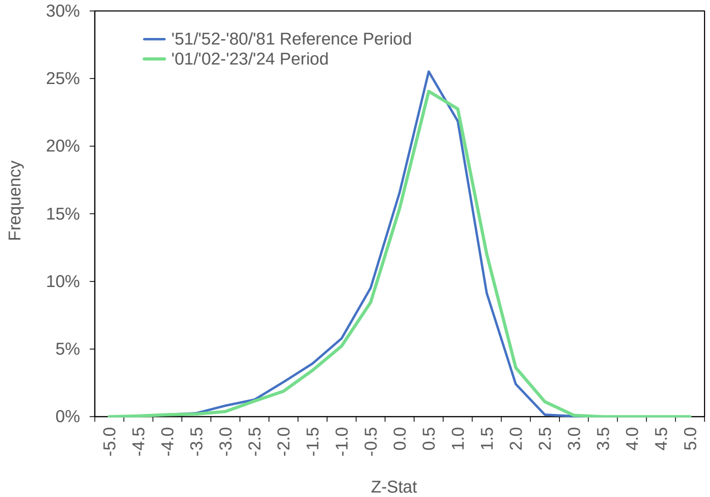
Compared to:

2001 – 2023 Winters (Dec, Jan, Feb)

Spokane







4.5 MACA

- 4.5 Median of future weather studies
- 20 year rolling average (historic + forecast)

Peak

Coldest on Record less average forecasted annual decrease (2026-2045)

2025 IRP: 79 HDD peak planning

(80% probability in MACA 4.5)

Historic Weather Comparison

1951 – 1981 Winters (Dec, Jan, Feb)

Compared to:

2001 – 2023 Winters (Dec, Jan, Feb)

*Weather used for Idaho and Washington

Summary

- MACA 4.5 weather median futures trended from 2026 – 2045 by planning area and combine with historical actual data into a rolling 20-year average
- Peak Planning: coldest on record less average decrease in HDDs from 2026 - 2045

2025 Natural Gas Integrated Resource Plan

Technical Advisory Committee Meeting No. 5 Agenda

Wednesday, June 26, 2024

Virtual Meeting

Topic	Time (PTZ)	Staff
Feedback from prior TAC	10:30	All
Current Avista Resources	10:40	Justin Dorr
Greenhouse Gas Emissions & Pricing	11:15	Tom Pardee
TAC feedback	11:50	All

Microsoft Teams meeting

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Supply Side Resources

Justin Dorr

Manager of Natural Gas Resources

Interstate Pipeline Resources

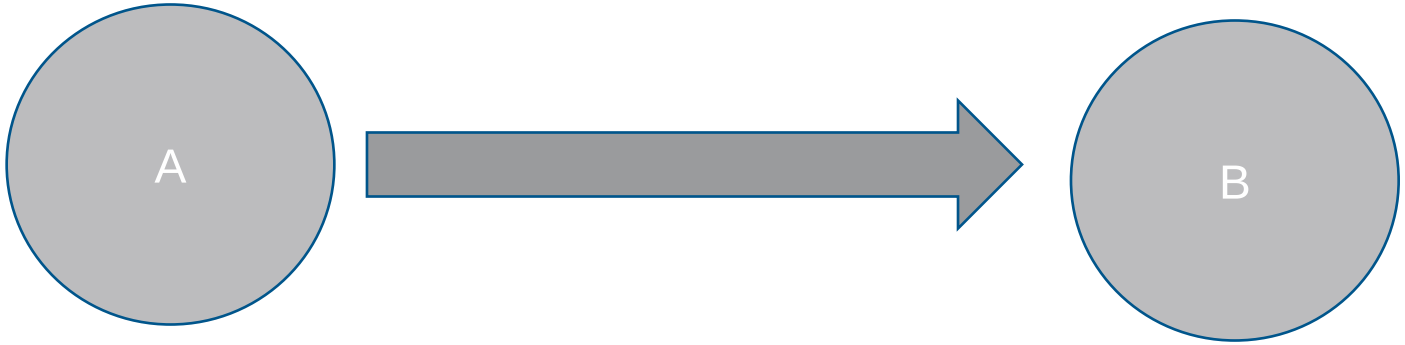
- The Integrated Resource Plan (IRP) brings together the various components necessary to ensure proper resource planning for reliable service to utility customers.

- One of the key components for natural gas service is interstate pipeline transportation. Low prices, firm supply and storage resources are meaningless to a utility customer without the ability to transport the gas reliably during cold weather events.

- Acquiring firm interstate pipeline transportation provides the most reliable delivery of supply.

Pipeline Contracting

Simply stated: The right to move (transport) a specified amount of gas from Point A to Point B



Contract Types

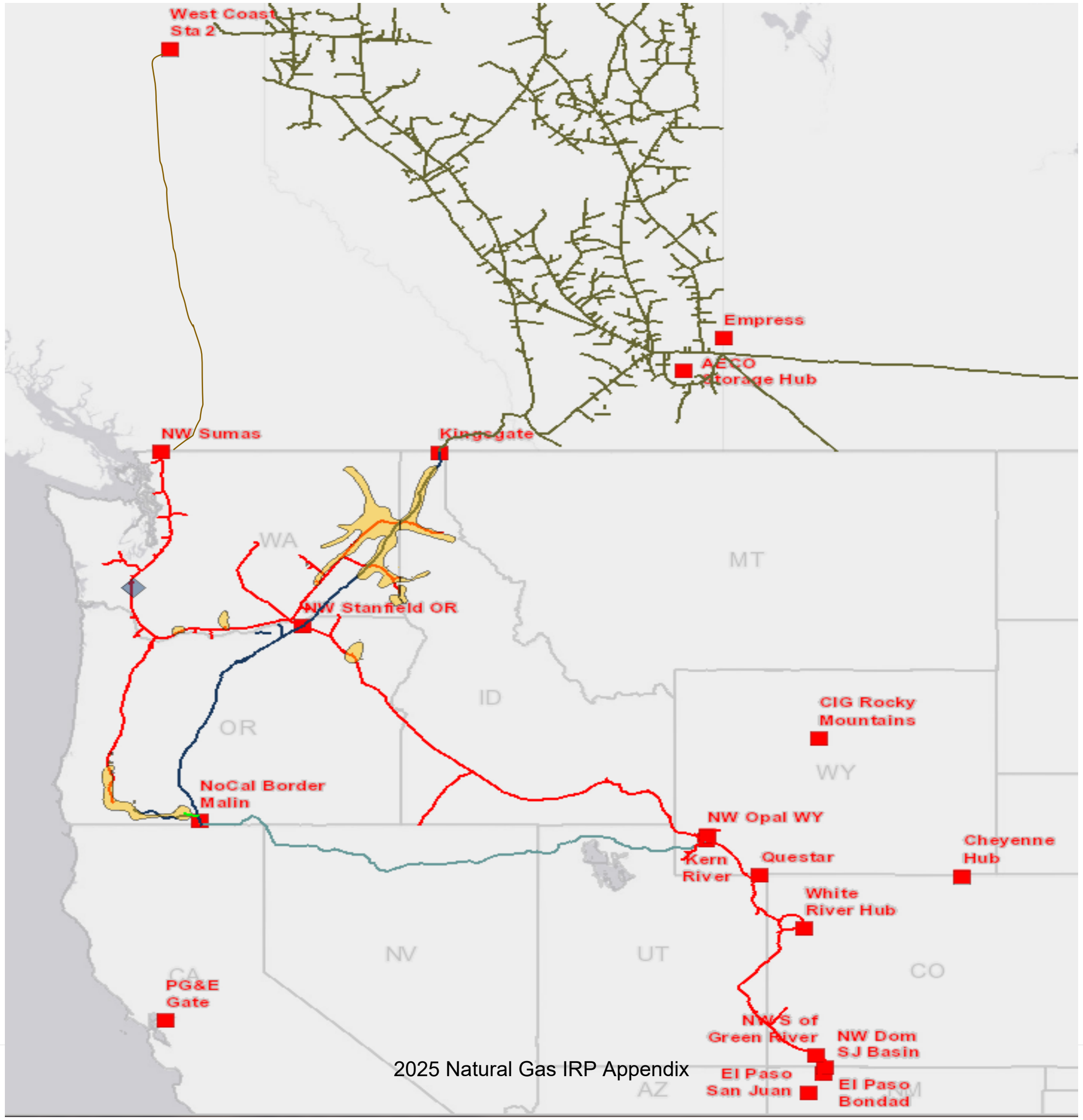
- Firm transport
  - Point A to Point B
  - Kingsgate to Malin
- Alternate firm
  - Point C to Point D
  - Kingsgate to Stanfield
- Seasonal firm
  - Point A to Point B but only in winter
- Interruptible
  - Maybe it flows, maybe it doesn’t

Pipeline Rate Design

- Mileage Rate (GTN)
  - Distance between receipt and delivery determines price
  - Plus variable charges (variable, fuel, commodity)

- Postage Stamp (NWP)
  - 1 mile from receipt to deliver same price as 1000 miles
  - Plus variable charges (variable, fuel, commodity)

Pipeline Overview



Avista's Transportation Contract Portfolio

Avista holds firm transportation capacity on 6 interstate pipelines:

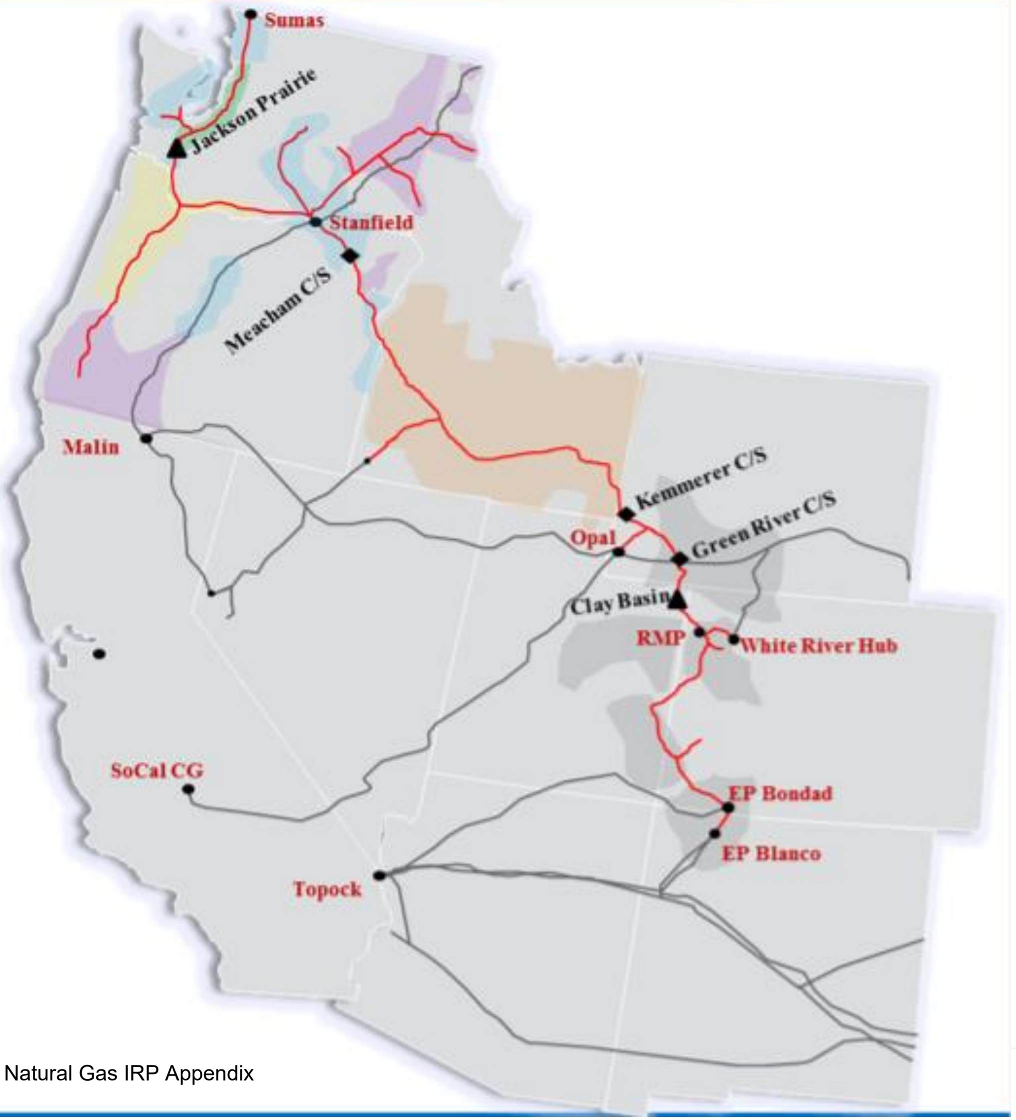
Pipeline	Expirations	Base Capacity Dth	Current Rate
Williams NWP	2025-2042	285,000	$0.3725/MMBtu
Westcoast (Spectra)	2026	10,000	$0.5770/ GJ
TC- NGTL	2025-2046	146,500	$0.1994/ GJ
TC- Foothills	2025-2046	144,300	$0.1448/GJ
TC- GTN	2025-2035	142,000-96,000	$0.0004297/Mile
TC- Tuscarora	2026	200	$0.23064/MMBtu

*1 MMBTU = 1.055056 GJ

1) Pipe reservations and modeling are only for LDC customers
2) Pipe reservations and model explicitly DO NOT CONSIDER electric side of business.

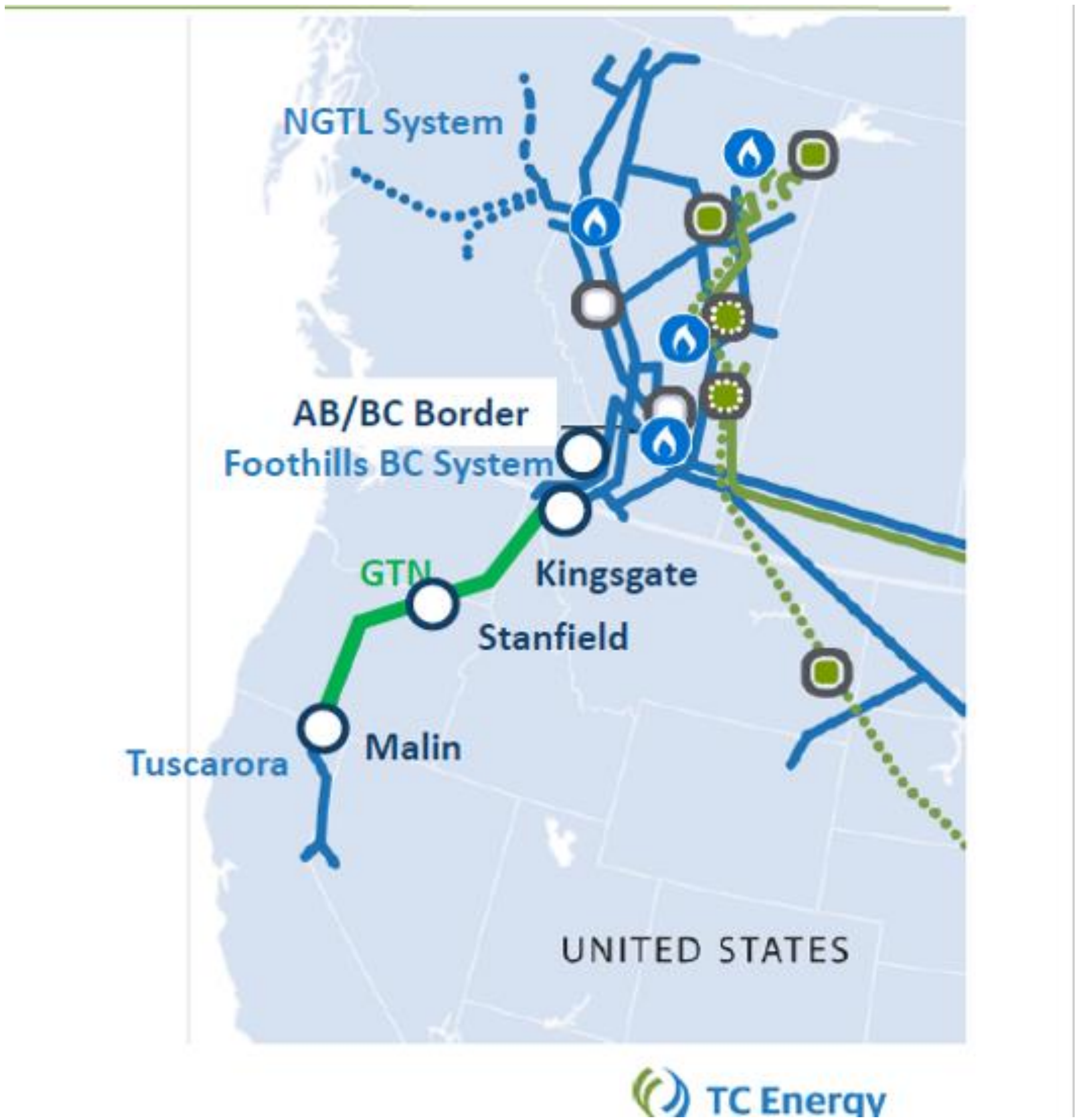
Northwest System – Strategically Located

- Low-cost, primary service provider in the Pacific Northwest
  - 3,900-mile system with 3.8 Bcf/d peak design capacity
  - ~120 Bcf of access to storage along pipeline, with high injection and deliverability capability in market area
- Bi-directional design
  - Provides flexibility (Rockies to market and Sumas to market)
  - Cheapest supply drives flow patterns
  - Provides operational efficiencies through displacement
- Supply and market flexibility
  - 65 receipt points totaling 11.6 Bcf/d of supply from Rockies, Sumas, WCSB, San Juan, emerging shales
  - 366 delivery points totaling 9.7 Bcf/d of delivery capacity



GTN Overview

- Transports WCSB* and Rox natural gas to ID, WA, OR, and CA
- Approximately 1,377 miles of pipe
- Kingsgate best efforts receipt capability of approx. 2.87 Bcfd and throughput capacity of approx. 2 Bcfd through Station 14.

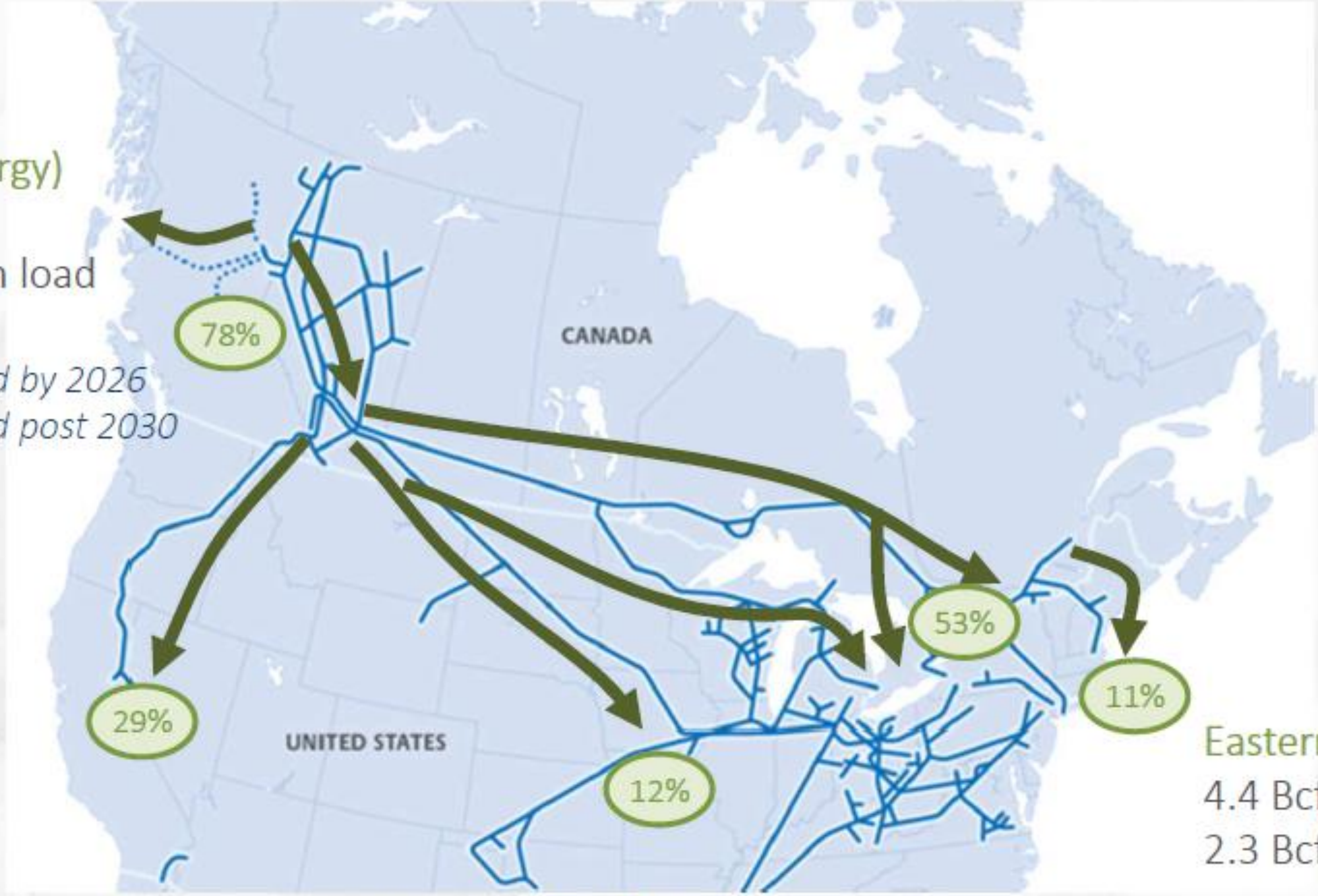


*WCSB – Western Canadian Sedimentary Basin

AVISTA

WCSB gas is competitive in key markets

WCSB (78% TC Energy)
18 Bcf/d supply
8 Bcf/d intra basin load
10 Bcf/d export
2 Bcf/d LNG projected by 2026
4 Bcf/d LNG projected post 2030



U.S. Northeast
7 Bcf/d market
0.7 Bcf/d via TC

Pacific
9 Bcf/d market
2.5 Bcf/d via TC

Eastern Canada
4.4 Bcf/d market
2.3 Bcf/d from WCSB via TC

Chicago (Mid-West)
13 Bcf/d end use market
1.5 Bcf/d from WCSB via TC

FOR DISCUSSION PURPOSES ONLY | APRIL 2024

Flow data based on 2023 Calendar year

TC Energy

Storage – A Valuable Asset

- Peaking resource
- Improves reliability
- Enables capture of price spreads between time periods
- Enables efficient counter cyclical utilization of transportation (i.e., summer injections)
- May require transportation to service territory
- In-service territory storage offers most flexibility

Avista's Storage Resources

Washington and Idaho
Owned Jackson Prairie

- 7.7 Million Dth of Capacity with approximately 346,000 Dth/d of deliverability

Oregon

Owned Jackson Prairie

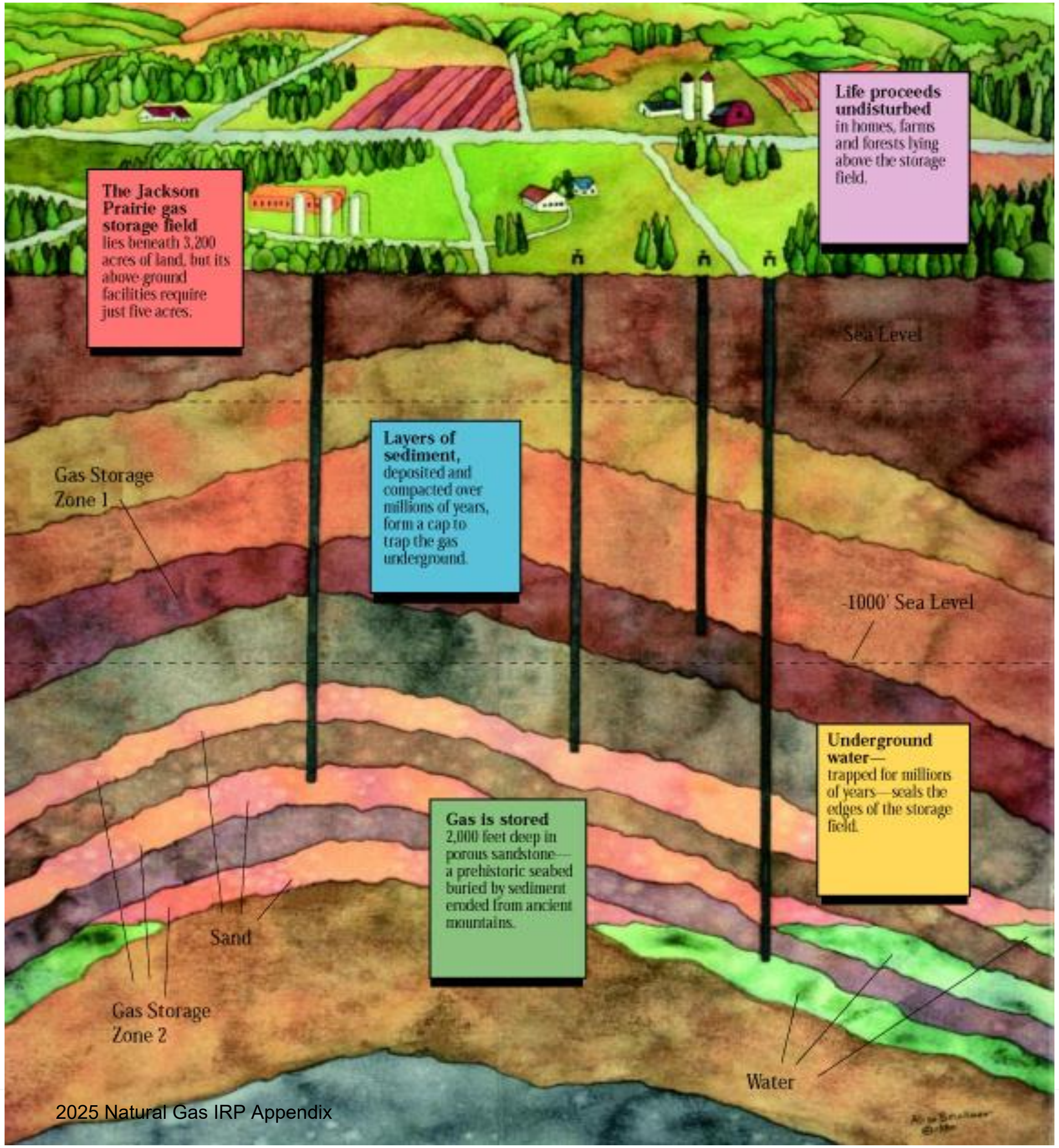
- 823,000 Dth of Capacity with approximately 52,000 Dth/d of deliverability

Leased Jackson Prairie

- 95,565 Dth of Capacity with approximately 2,654 Dth/d of deliverability

The Facility

- Jackson Prairie is a series of deep, underground reservoirs – basically thick, porous sandstone deposits.
- The sand layers lie approximately 1,000 to 3,000 feet below the ground surface.
- Large compressors and pipelines are employed to both inject and withdraw natural gas at 54 wells spread across the 3,200-acre facility.



Jackson Prairie Energy Comparisons

1.2 Bcf per day (energy equivalent)

- 10 coal trains with 100 - 50 ton cars each
- 29 - 500 MW gas-fired power plants
- 13 Hanford-sized nuclear power plants
- 2 Grand Coulee-sized hydro plants (biggest in US)

45 Bcf of stored gas

- 12” pipeline 11,000,000 miles long (226,000 miles to the moon)
- 1,400 Safeco Fields (Baseball Stadiums)
- Average flow of the Columbia River for 2 days
- Cube - 3,550 feet on a side

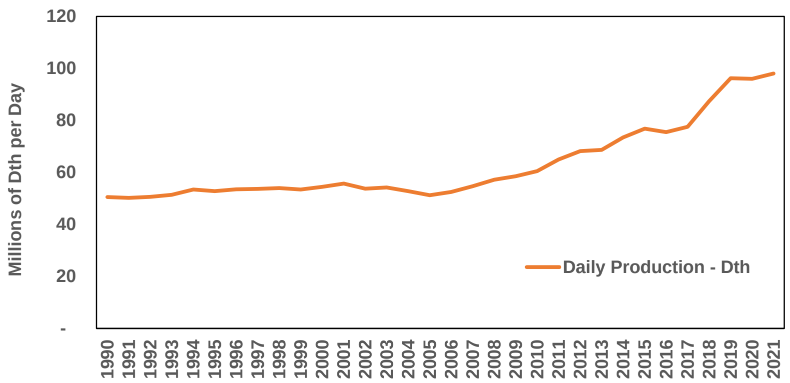
Green House Gas Assumptions and Climate Pricing

2025 Avista Gas IRP

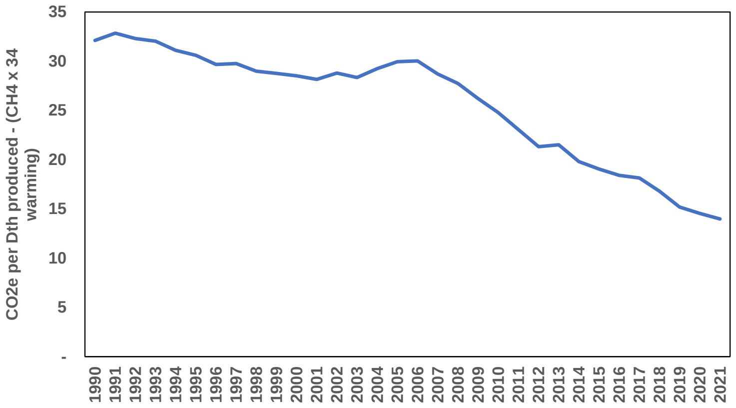
June 26, 2024

Greenhouse Gas Assumptions

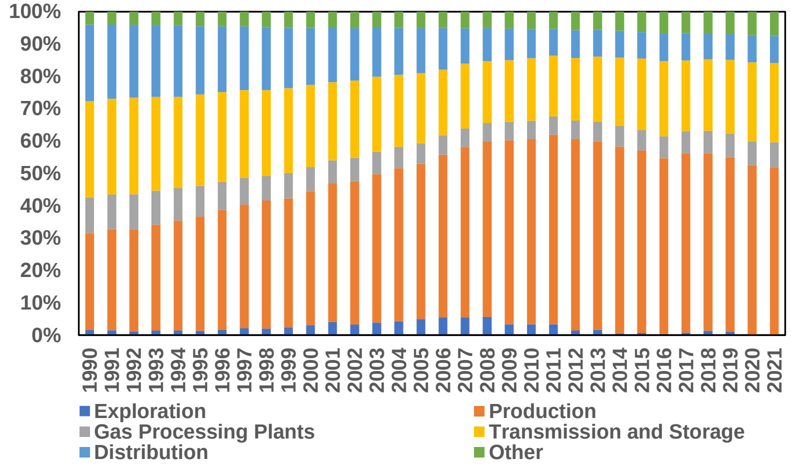
CH4 emissions (kt) for Natural Gas Systems (EIA)



Production



CO2e of CH4 per Dth



CH4 by Major Category

Source: 2023 ghgi annex tables – EIA - Table 3.6-1: CH4 Emissions (kt) for Natural Gas Systems, by Segment and Source, for All Years

Total Emissions for natural gas (combustion, upstream and LDC)

Fuel Emission Rates in lbs GHG per unit of natural gas combusted in lbs & CO_2e lbs - 100 year GWP	lb GHG/mmbtu	lb CO_2e/mmbtu
Combustion		
CO_2	116.88	116.88
CH_4	0.0022	0.0748
N_2O	0.0022	0.6556
Total Combustion		118
Upstream		
CH_4	0.422	14.35
Total		132

*NWPCC – 2021 Power Plan with updated average actual Avista basin purchases for prior 5 years

**Includes LDC L&U estimate of 0.8%

Use of Upstream Emissions in 2025 IRP

1

Evaluation of energy efficiency in OR and WA

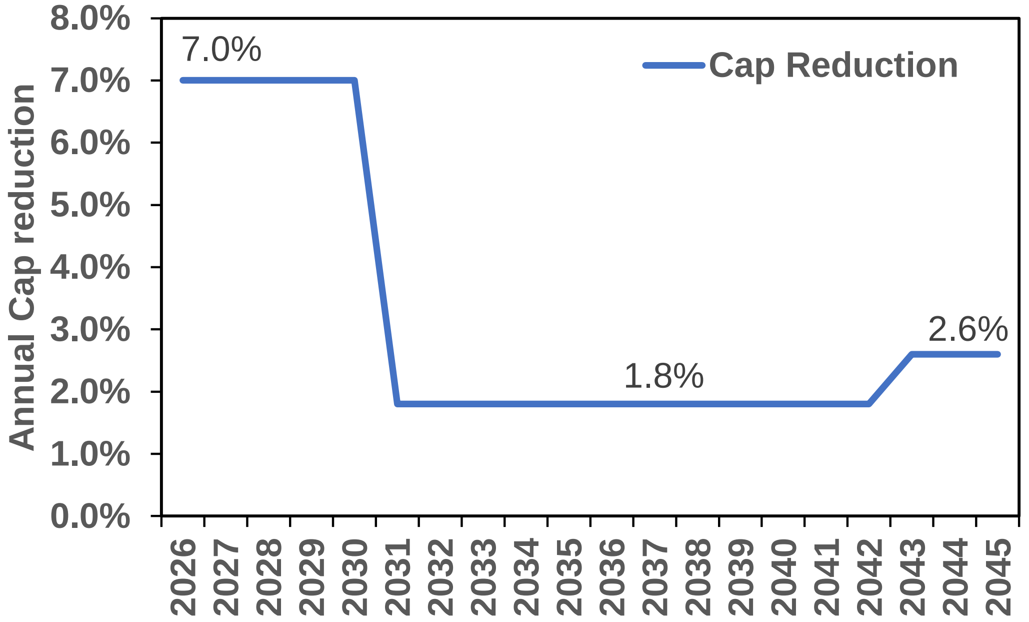
2

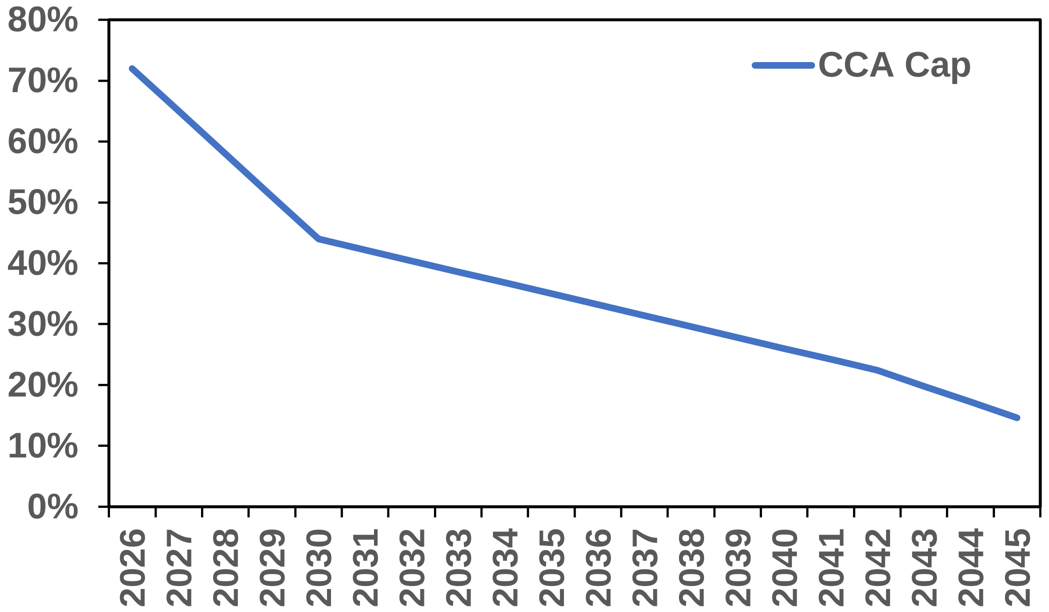
SCC scenario in all jurisdictions

3

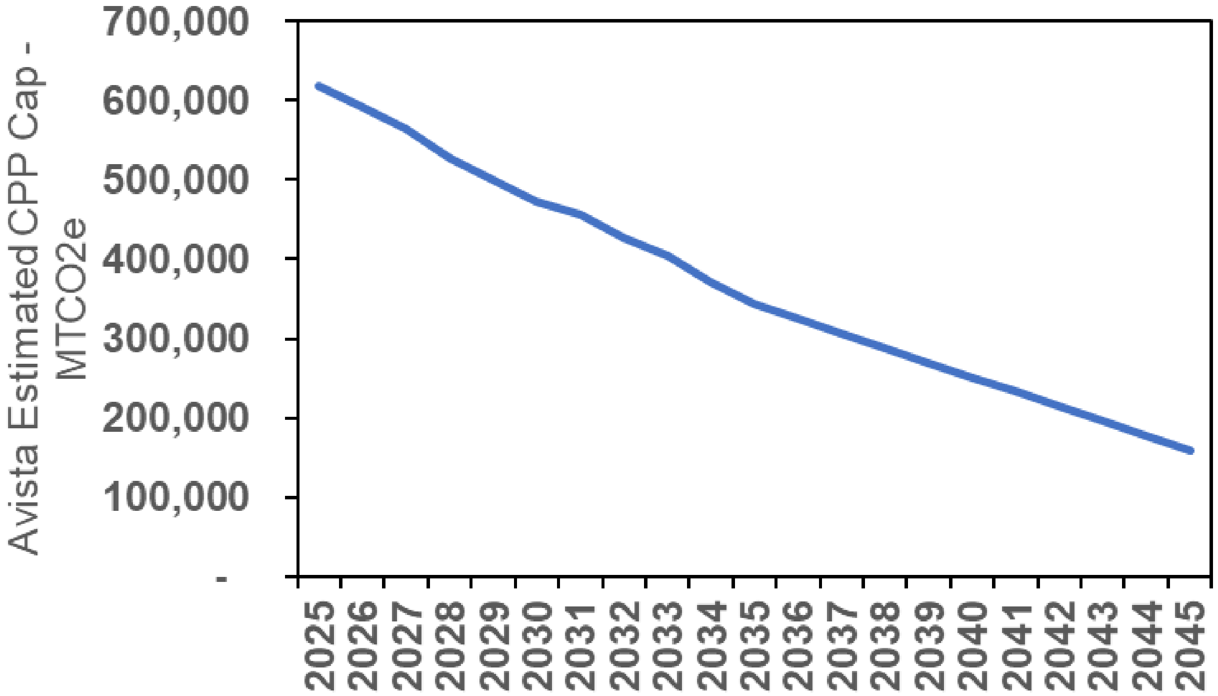
CCA and CPP do not account for upstream emissions in program requirements

Climate Commitment Act (CCA) Cap

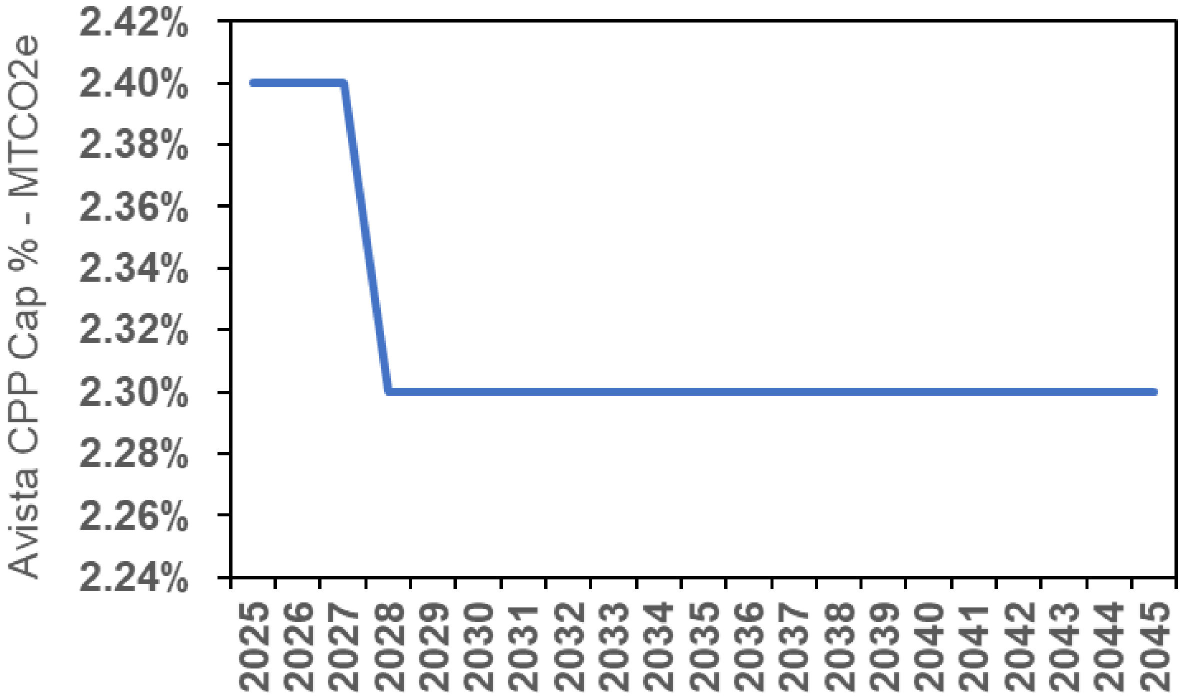




Climate Protection Plan (CPP) Cap



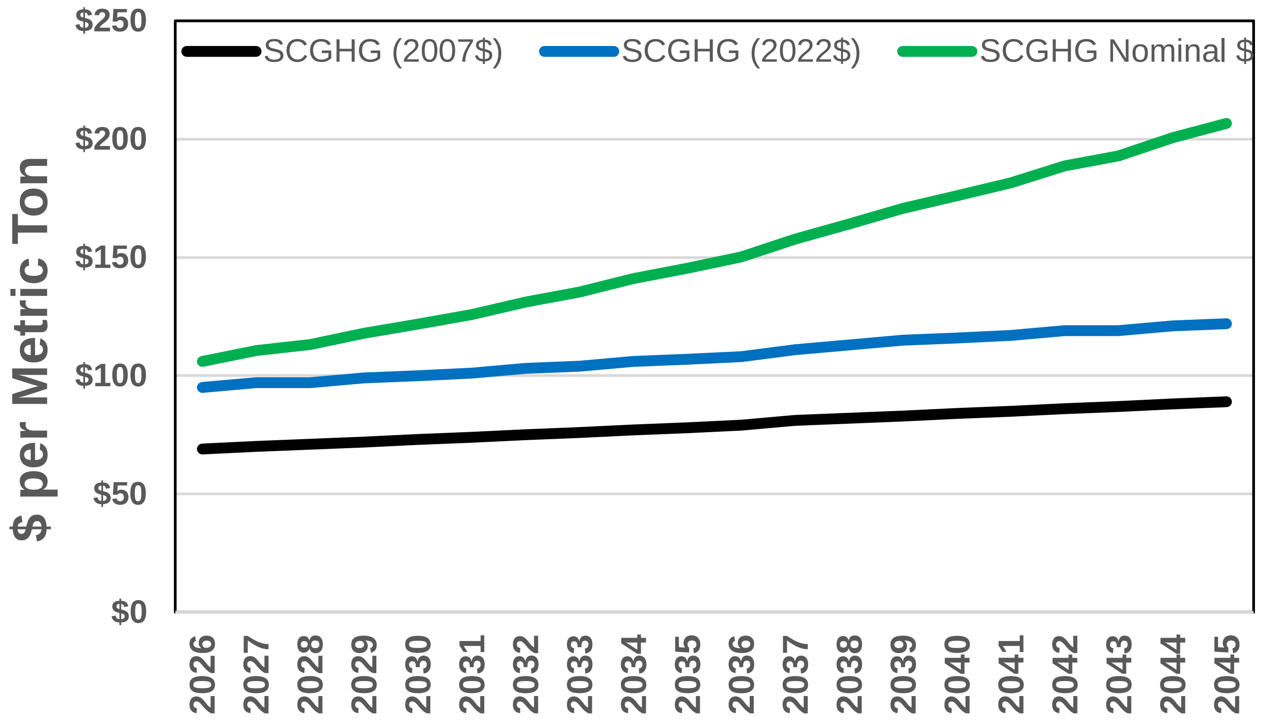
*RAC Draft Rules – June ‘24 – Tables 2 & 4



*RAC Draft Rules – June ‘24 – Table 4

Climate Pricing

Social Cost of Carbon (SCC) at 2.5%

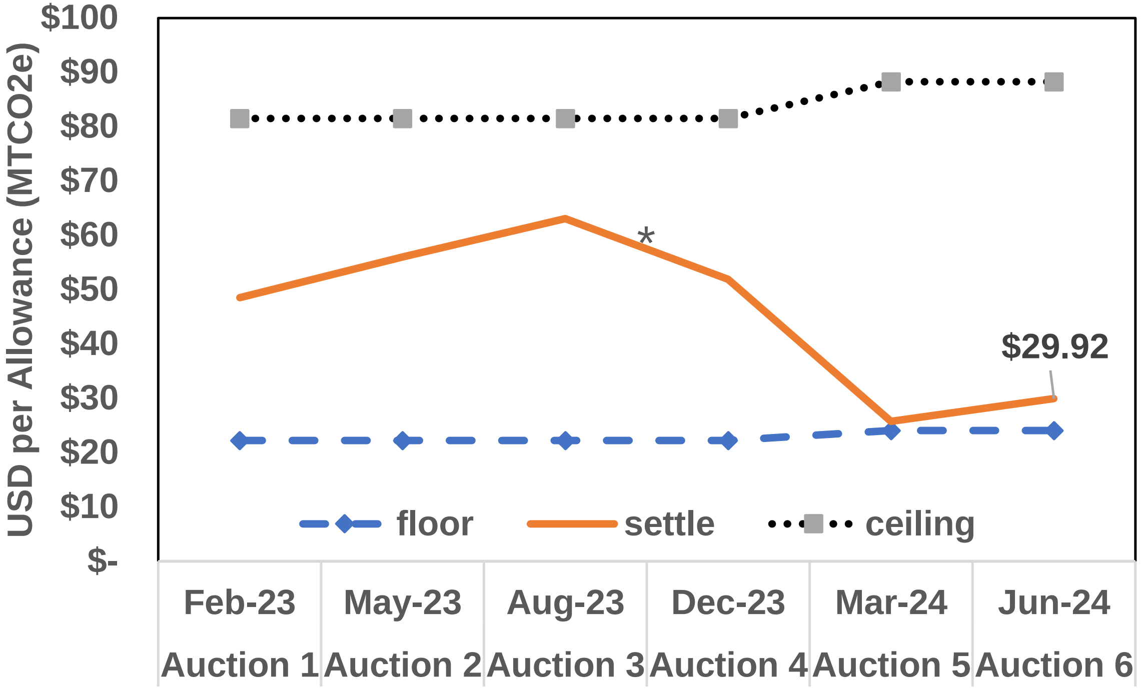


- SCC @ 2.5% will be used for Energy Efficiency CPA in OR and WA
- SCC scenario will utilize SCC @ 2.5% as a resource selection criteria and is added to the price of emissions to each Dth of natural gas for all jurisdictions

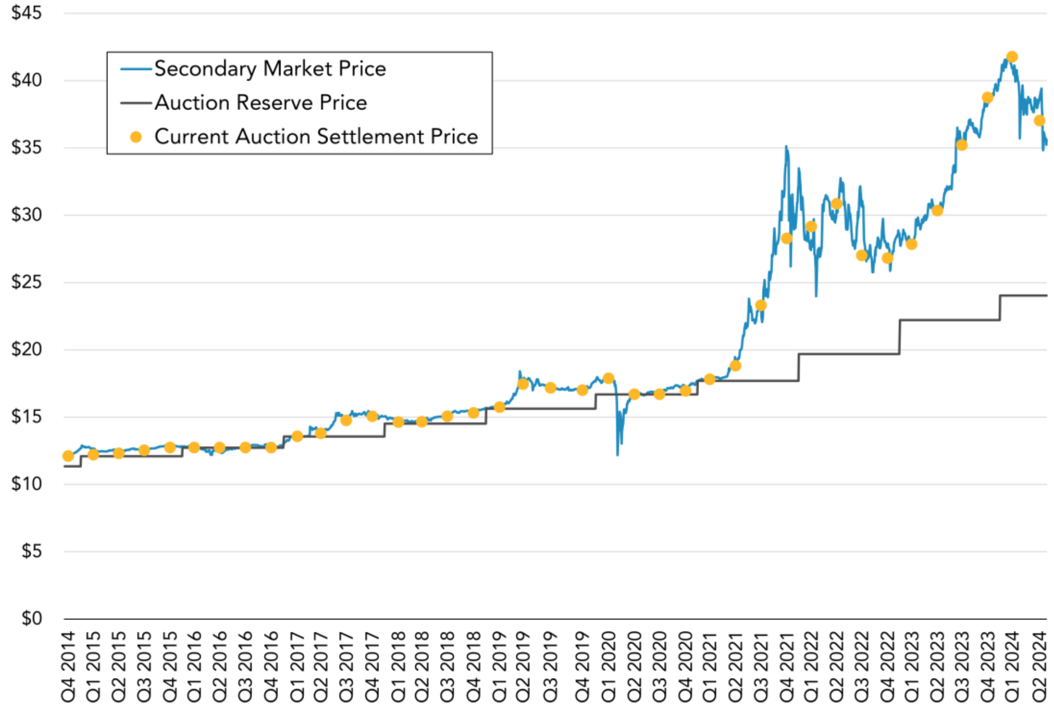
Source: https://www.utc.wa.gov/regulated-industries/utilities/energy/conservation-and-renewable-energy-overview/clean-energy-transformation-act/social-cost-carbon

Allowance Prices

CCA



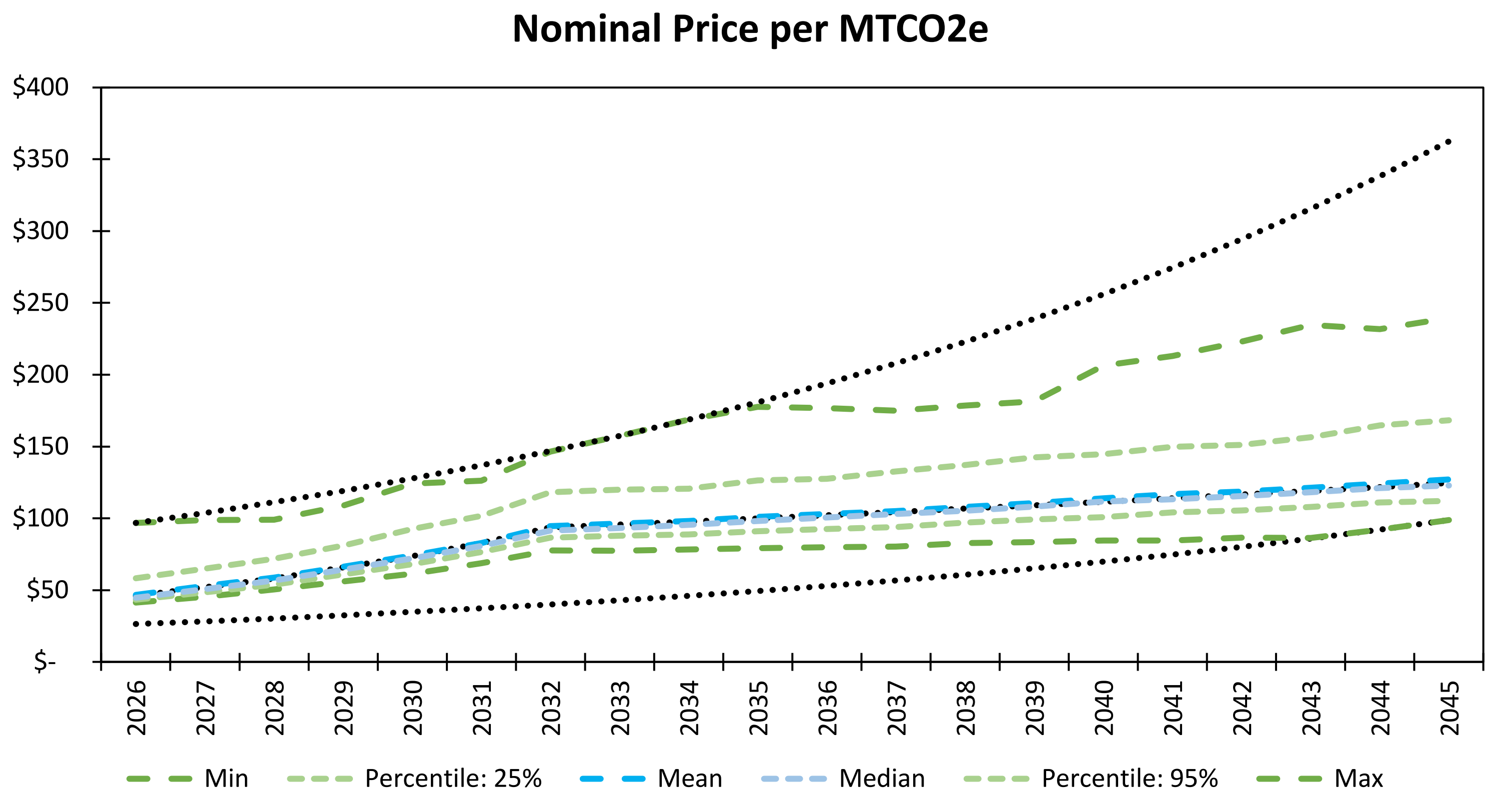
California - Québec



*Nov. 3rd Announcement to pursue linkage to CA Cap and Trade

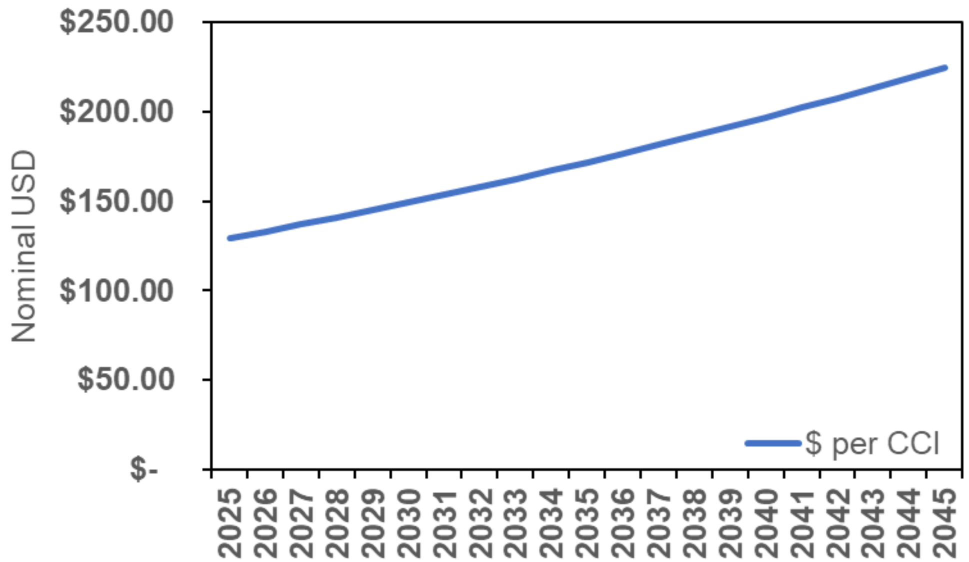
Cap-and-Trade Program Data Dashboard | California Air Resources Board

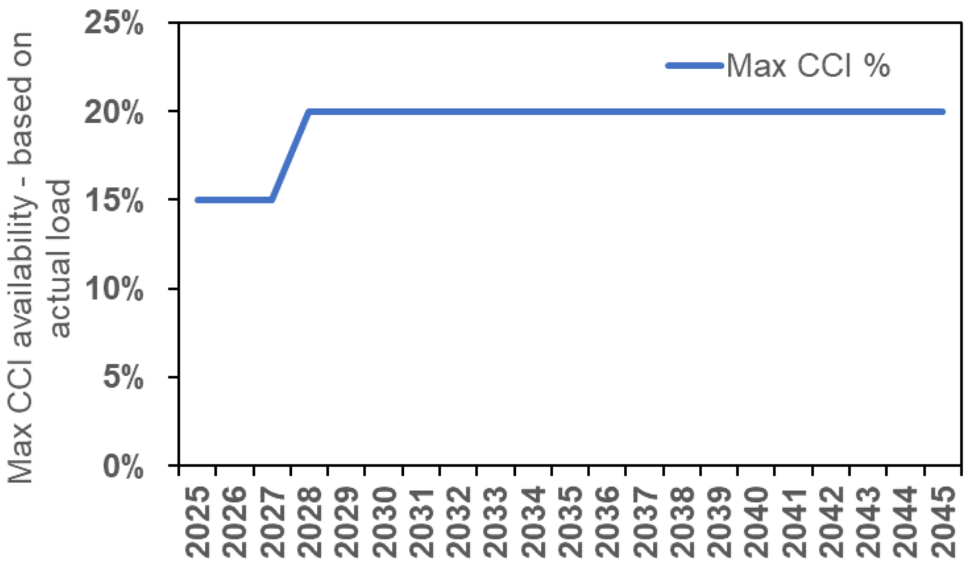
Allowance Price Estimate



*300 stochastic 20-year draws

Community Climate Investments (CPP)

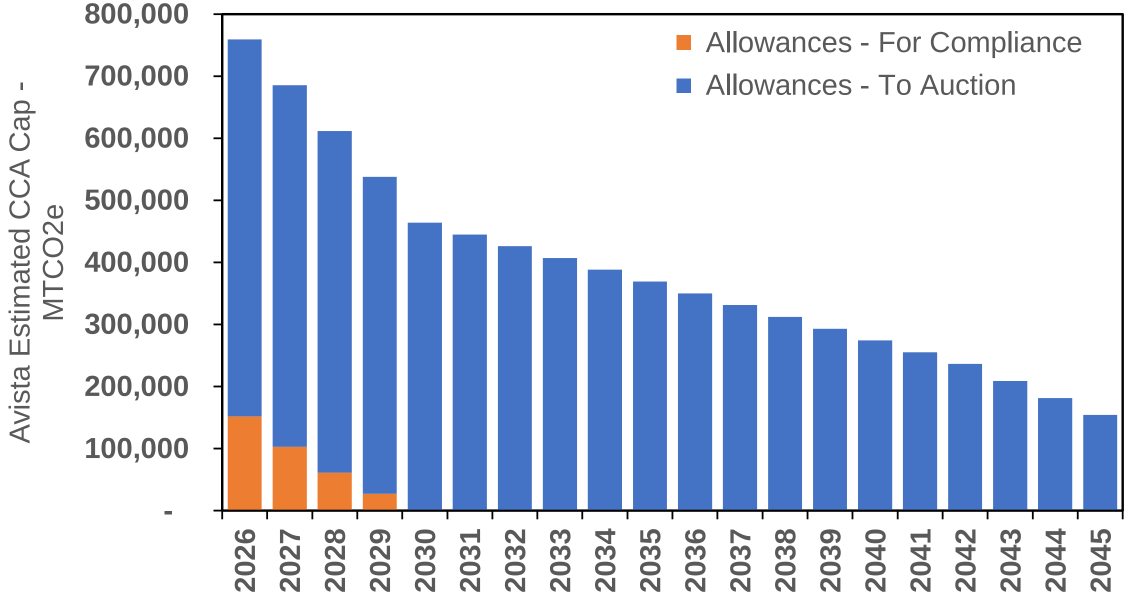




Use of Pricing in 2025 Gas IRP

- SCC @ 2.5% will be used for Energy Efficiency CPA in OR and WA
  - SCC scenario will utilize SCC @ 2.5% as a resource selection criteria and is added to the price of emissions to each Dth of natural gas
- CCA pricing for the allowance market will be used to evaluate program compliance in Washington
  - All cases except SCC scenario
- CPP pricing will be used to evaluate the use of CCIs for program compliance in Oregon (Most recent draft rules available at the time of modeling)
  - All cases except SCC scenario

CCA Summary



Allowances - For Compliance
Allowances - To Auction
Avista Estimated CCA Cap - MTCO2e
800,000
700,000
600,000
500,000
400,000
300,000
200,000
100,000
-
2026
2027
2028
2029
2030
2031
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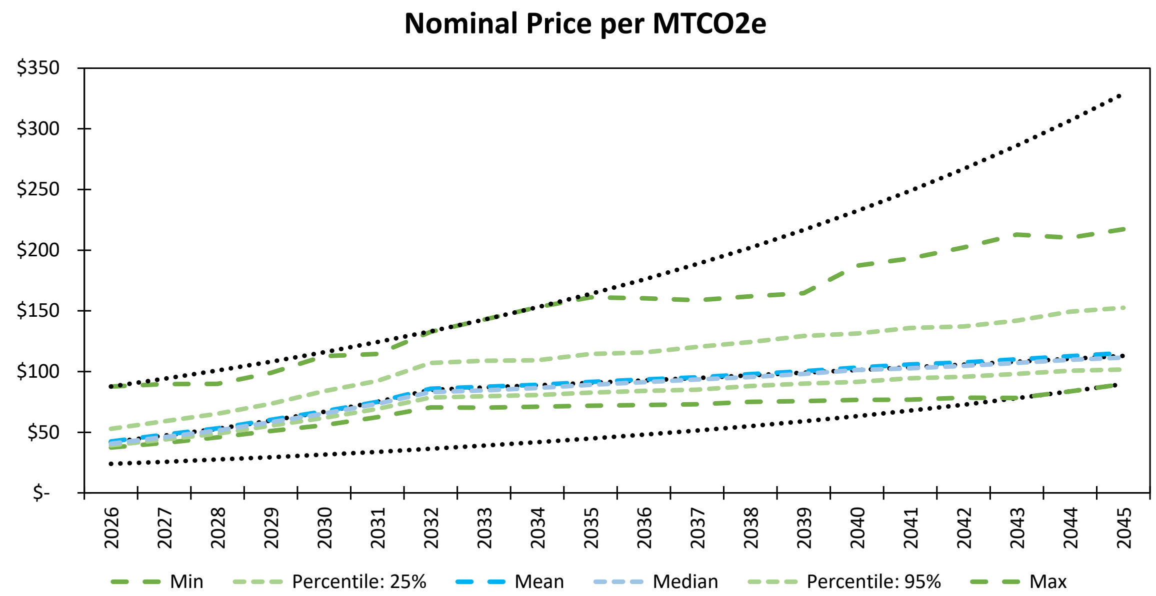
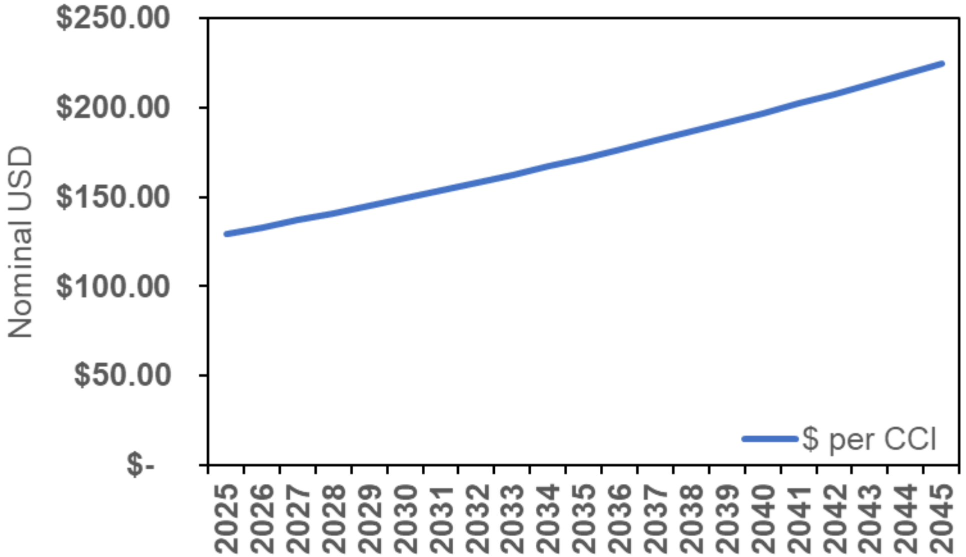
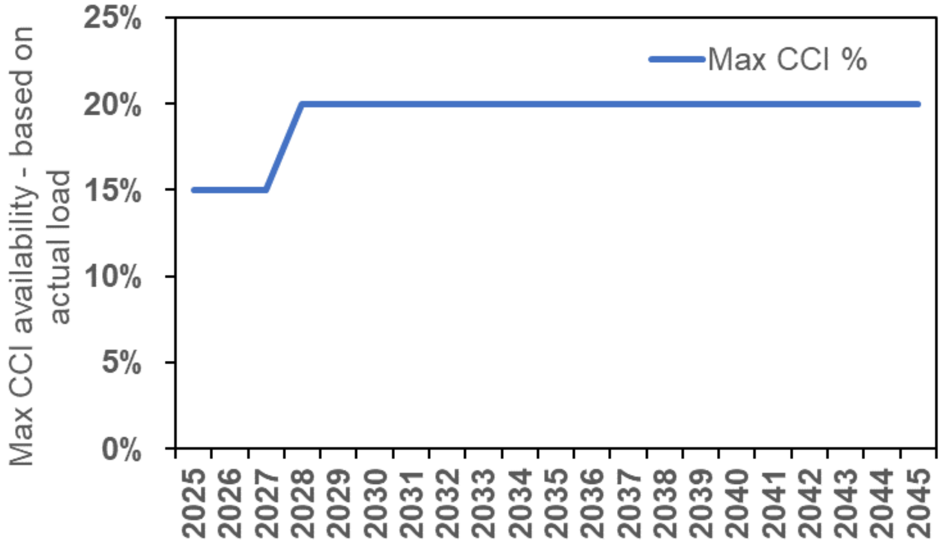
2042
2043
2044
2045

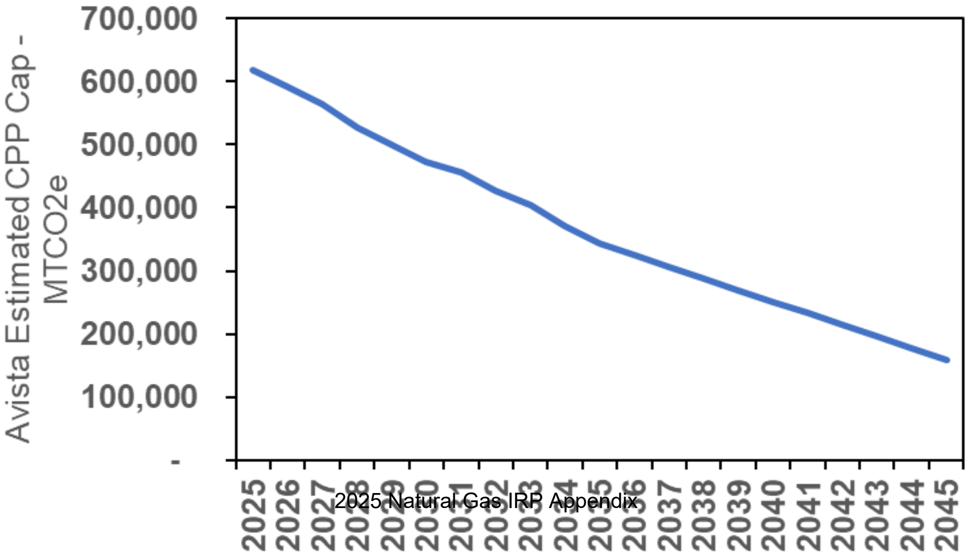


Nominal Price per MTCO2e
$350
$300
$250
$200
$150
$100
$50
$-
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2041
2042
2043
2044
2045
Min
Percentile: 25%
Mean
Median
Percentile: 95%
Max

CPP Summary*







*2025 IRP values will be updated based on RAC process and changes

Updated TAC Schedule

TAC 6: Wed. 17 July 2024: 10:30 am to 12:00 pm (PTZ)
- Feedback from prior TAC (10 min.)
- Load Forecast – AEG (80 min.)

TAC 7: Wed. 21 Aug. 2024: 10:30 am to 12:00 pm (PTZ)
- Feedback from prior TAC (10 min.)
- Natural Gas Market Overview and Price Forecast (40 min.)
- Avoided Costs Methodology (30 min.)

TAC 8: Wed. 25 Sept. 2024: 10:30 am to 12:00 pm (PTZ)
- Feedback from prior TAC (10 min.)
- Heat Pump COP (30 min.)
- Electrification (40 min.)

TAC 9: Wed. 30 Oct. 2024: 10:30 am to 12:00 pm (PTZ)
- Feedback from prior TAC (10 min.)
- NEI Study (30 min.)
- New Resource Options Costs and Assumptions (40 min.)

TAC 10: Wed. 18 Dec. 2024: 9:00 am to 12:00 pm (PTZ)
- All assumptions review (20 min.)
- Conservation Potential Assessment (AEG) (30 min.)
- Demand Response Potential Assessment (AEG) (20 min.)
- Conservation Potential Assessment (ETO) (30 min.)
- Scenario Results (20 min.)
- Scenario Risks (20 min.)
- PRS Overview of selections and risk (20 min.)
- Per Customer Costs by Scenario (10 min.)
- Cost per MTCO2e by Scenario (10 min.)

AEG
APPLIED ENERGY GROUP

Avista Energy Natural Gas Forecasting

Prepared for Avista Energy TAC Meeting July 2024

Background

AEG has worked with Avista for multiple Conservation Potential Assessments going back to 2010

As part of the CPA, AEG creates a baseline projection at the segments and end use level, which provides granular insight changes in individual technology classes and populations

Now Avista is using AEG's LoadMAP^{TM} end use model directly to inform its official load forecast, including effects of state energy codes, potential electrification and market trends in a clear and direct manner.

Major Modeling Inputs and Sources

Avista foundational data

- Avista power sales by schedule
- Current and forecasted customer counts
- Retail price forecasts by class

Survey data showing presence of equipment

- Avista: Residential customer survey conducted in 2013
- NEEA: Residential and Commercial Building Stock Assessments (RBSA 2016 and CBSA 2019)
- US Energy Information Administration: Residential, Commercial, and Manufacturing Energy Consumption Surveys (RECS 2020, CBECS 2018, and MECS 2015)

Technical data on end-use equipment costs and energy consumption

- Regional Technical Forum workbooks
- Northwest Power and Conservation Council's 2021 Power Plan workbooks
- US Department of Energy and ENERGY STAR technical data sheets
- Energy Information Administration's Annual Energy Outlook/National Energy Modeling System data files

State and Federal energy codes and standards

- Washington State Energy Code
- Idaho Energy Code
- Federal energy standards by equipment class

Market trends and effects

- RTF market baseline data
- Annual Energy Outlook purchase trends (in base year)

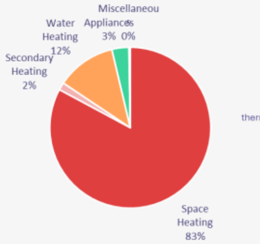
Forecast Process

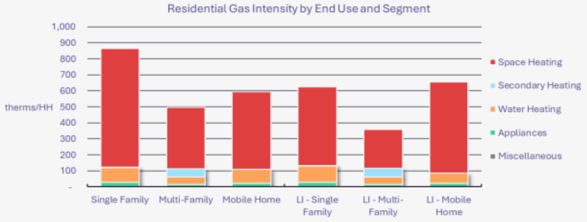
Market Characterization

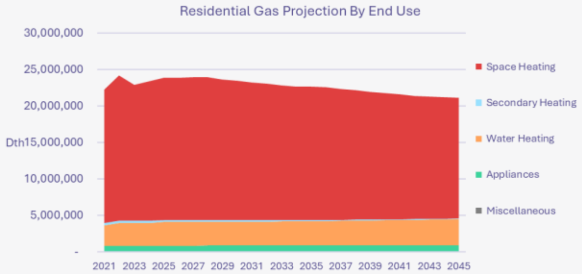
- Segmentation
- End Use and Technology List
- Allocate electric loads & calibrate

Run Baseline Projection (Annual)

- Customer Forecast
- Stock Turnover
- Purchase Decisions





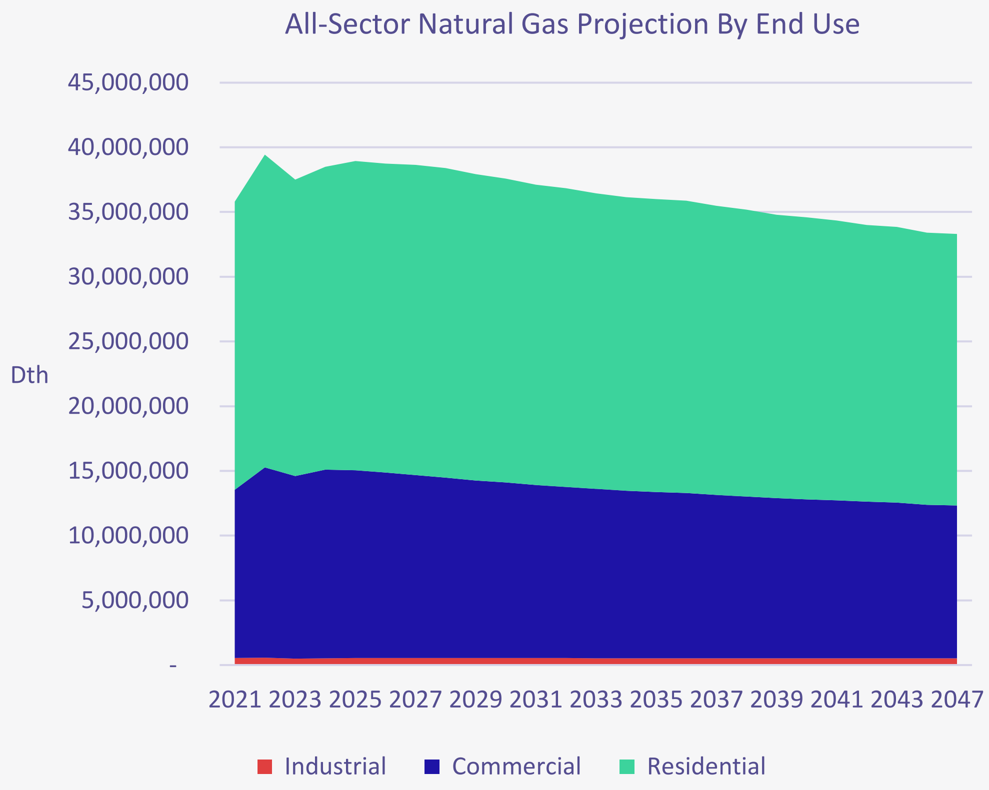


Existing vs New Buildings

- Modeling tracks existing building stock separately from new code-compliant buildings
  - Buildings also undergo renovation at a rate consistent with the DOE's National Energy Modeling System, converting them into code-compliant structures
- Presence of equipment in new buildings is adjusted to comply with energy codes where applicable
  - For example, all new residential structures are assumed to use electric or dual-fuel heat pumps for space heating, which dramatically lowers gas loads in new construction

System Total Load Forecast

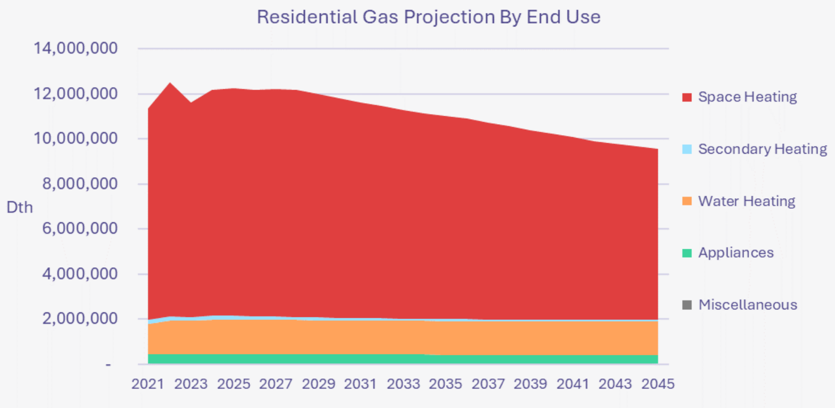
WA + ID + OR, Excludes Transport

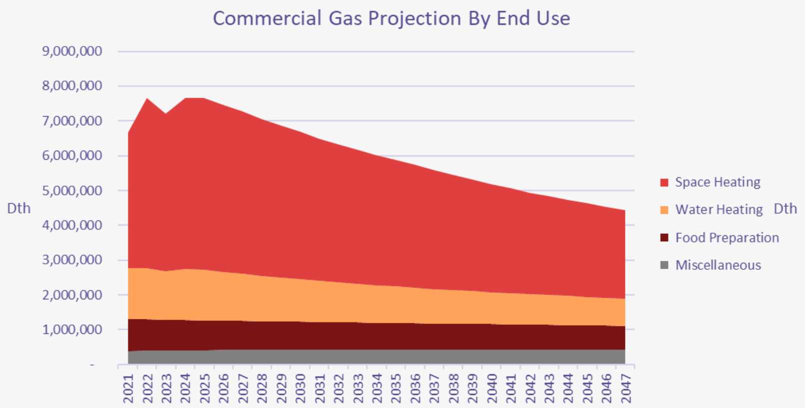


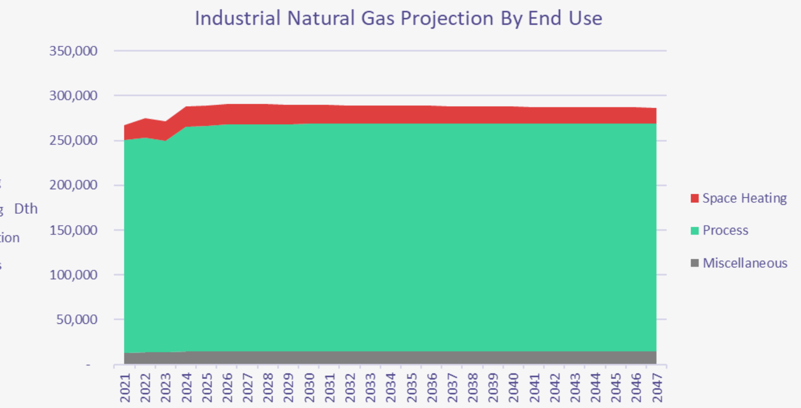
- A combination of electrification, building codes, and natural efficiency cause overall gas loads to decline by 7% across the forecast period
- Washington has a much stronger downward trend in isolation, offset by growth in Idaho (see next slides)
- Includes:
  - Projected heating degree days according to climate trends in Avista's territory
  - Market efficiency impacts (such as customers installing HE furnaces on their own), which are saving 42 million therms in the forecast period compared to minimum codes & standards

Washington Sector-Level Forecasts

- WA Residential declines 15.8% as residential space heat electrifies (or converts to dual-fuel systems) either in natural equipment replacement cycles or to comply with state energy code
- Commercial declines for the same reason, however the decline is steeper as commercial space tends to turn over faster compared to residential spaces (and therefor is under pressure to become code compliant when new occupants move in)
- Industrial loads do not have the electrification opportunity that res and com space heating do and are minimally affected by the code requirements. Loads are generally flat.

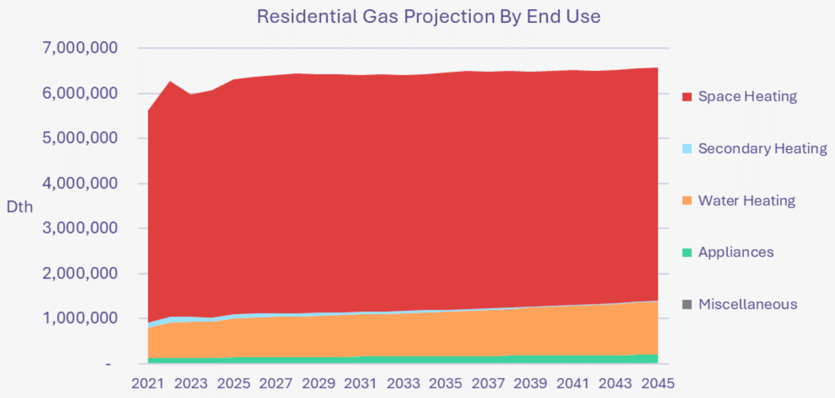


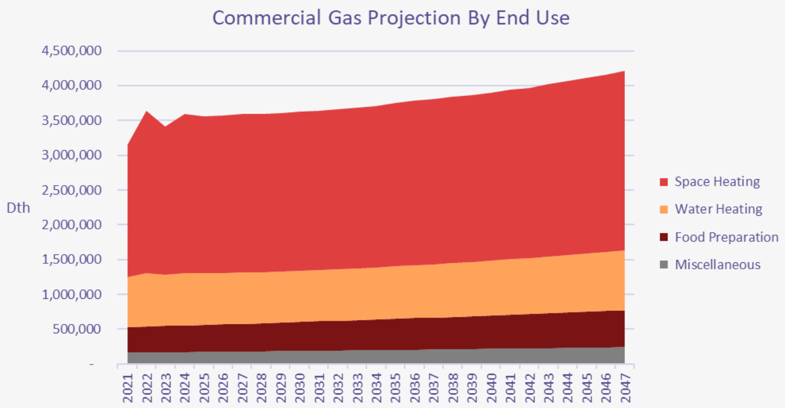


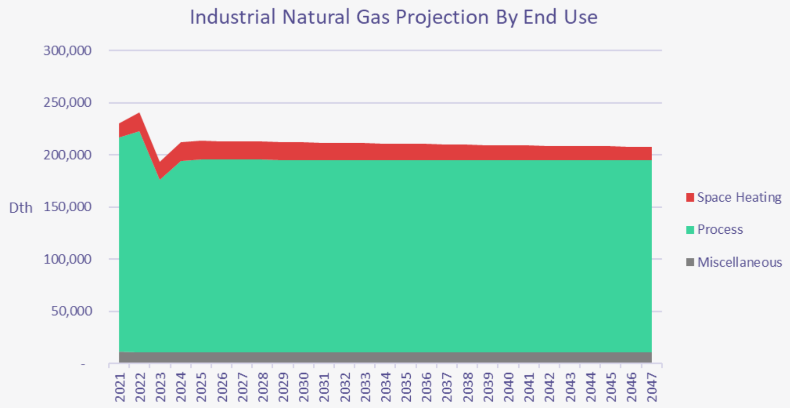


Idaho Sector-Level Forecasts

- ID gas loads do not have the same downward pressure as WA.
- While building shells improve in efficiency as older stock is renovated, customer growth continues to increase the use of natural gas in the forecast.

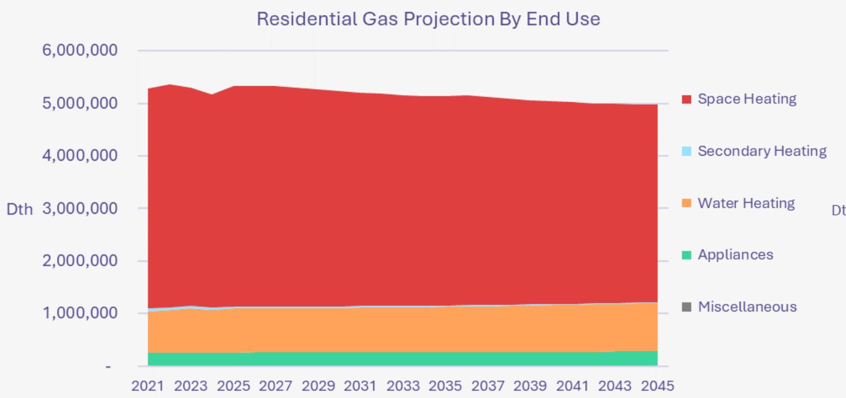


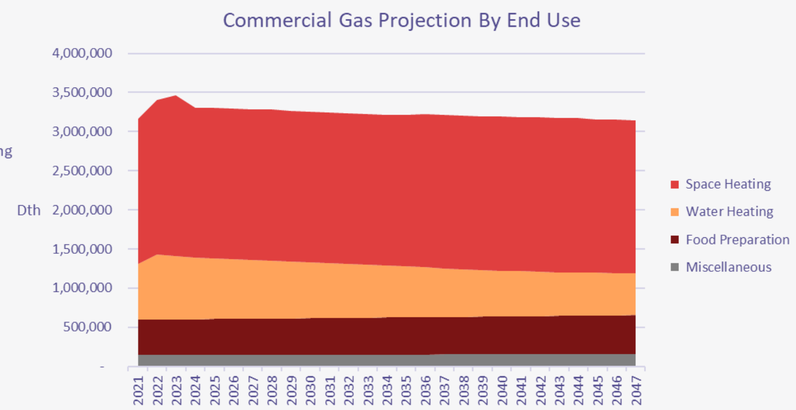


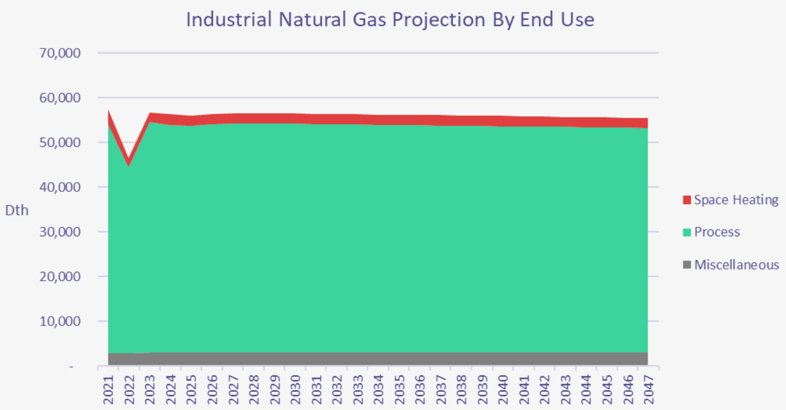


Oregon Sector-Level Forecasts

- Oregon has relatively stable natural gas loads, as building stock improvements keep pace with modest customer growth and lead to reductions in overall gas use



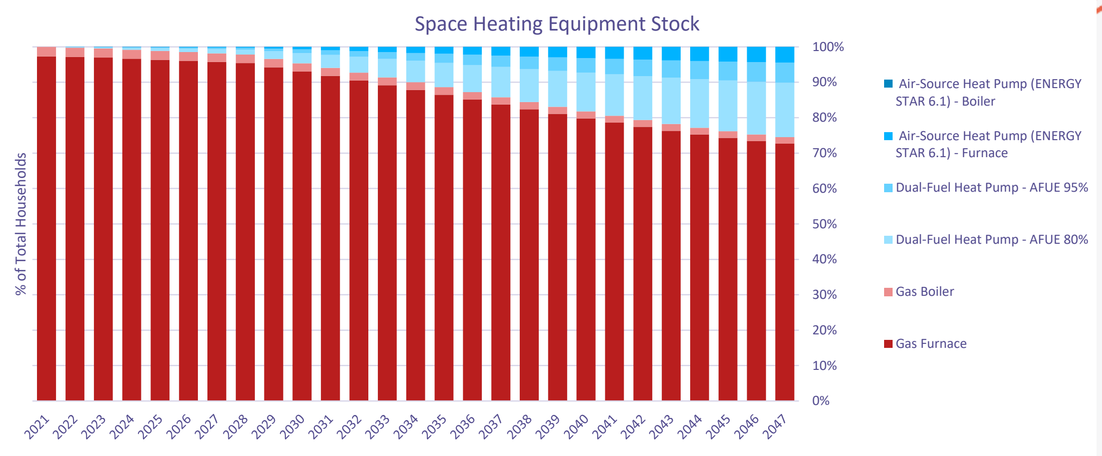




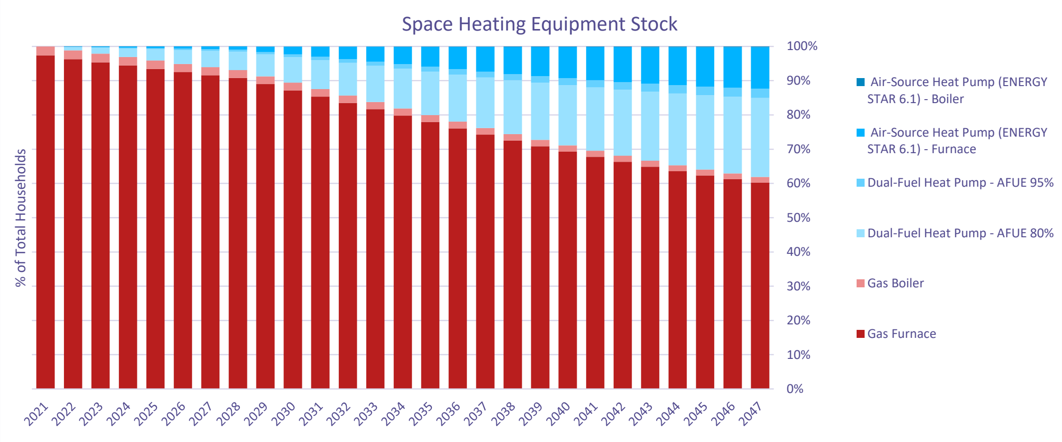
Electrification Decision Modeling

- Gas customers were modeled the same way as the electric market, with the option to replace existing gas space or water heating equipment with electric alternatives, using purchase decision logic copied from the US DOE's National Energy Modeling System.
- Conversion costs include the possibility of a panel upgrade and associated labor. The model compares the lifetime cost of ownership including up front costs and associated lifetime fuel costs.
- As data on customer electrification is not readily available*, electrification purchases were seeded with a value ¼ that of dual-fuel heat pump installations, which do have documented market shares for WA and ID.

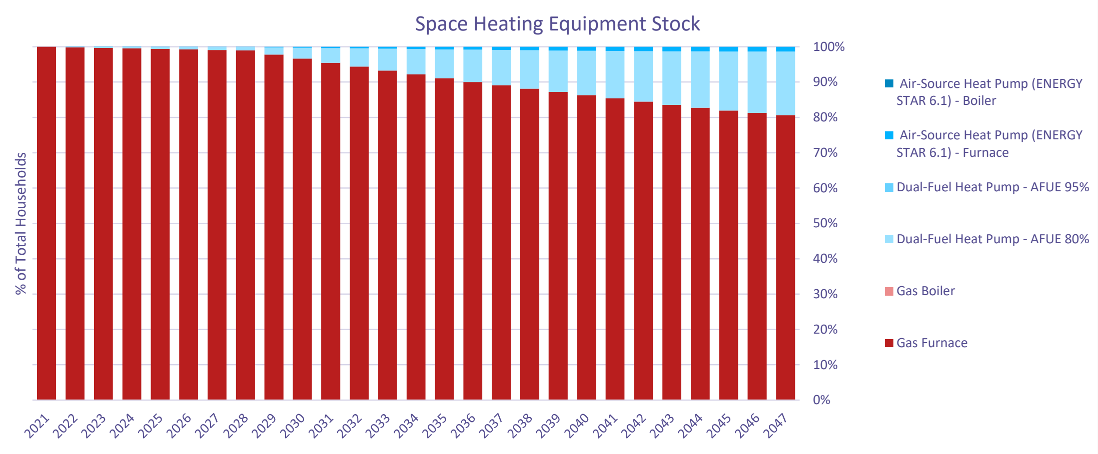
Washington Residential Gas Heating Market Transformation



Oregon Residential Gas Heating Market Transformation



Idaho Residential Gas Heating Market Transformation



Thank You.

Phone: 631-434-1414

APPLIED ENERGY GROUP

2025 Gas Integrated Resource Plan
Technical Advisory Committee Meeting No. 7 Agenda
Wednesday, August 21, 2024
Virtual Meeting

Topic	Time (PTZ)	Staff
Feedback from prior TAC	10:30	All
Natural Gas Market Overview	10:40	Tom Pardee
Natural Gas Price Forecast	11:20	Michael Brutocao
Avoided Cost Methodology	11:30	Tom Pardee

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Natural Gas Market Overview

2025 Gas IRP – TAC 7

Tom Pardee

Wood Mackenzie does not warrant or represent that the Information is appropriate or sufficient for your purposes and has not taken into account the purposes for which you are preparing the Document or using the Information and you acknowledge and agree that if you use or rely upon the Information for any purpose then you shall do so entirely at your own risk;

Key macro and oil assumptions

Macro assumptions

Geopolitics

- Sanctions and bans on Russian exports remain in place through to 2030 but ease thereafter with 'normality' re-established from 2035.
- While we continue to see an increase in bilateral conflicts, as per the recent events between Iran and Israel, we do not assume an escalation to a multilateral conflict in the region. We assume the war and the Red Sea transit issues end before Q4 2024.

Macroeconomic outlook

- Inflation continues to decline; interest rates loosen in 2024
- Global economy to hold steady in 2024 but weakness in Europe and China provide recession risk.
- Geopolitical tensions increase as China and the G7 compete for ties with non-OECD and BRICS+
- Global GDP growth of 2.2% (CAGR), 2028 to 2050

Energy transition

- Energy and environmental policy continue to focus on CO_2 reduction, but countries fail to achieve net zero targets.
- Global temperature rise to around 2.5 °C compared to pre-industrial levels.

Gas and LNG assumptions

US LNG pause

- The Biden administration's pause on granting new non-FTA approvals for US LNG projects lasts until the end of 2024 and is relaxed in 2025 after the elections.
- Existing and under-construction projects are not impacted.
- Some projects with existing non-FTA approval that are set to expire before the expected commissioning could proceed to FID in 2024. Consensus is emerging that non-FTA extensions will be granted if the project can provide a reasonable explanation for delayed FID since the first approval. We assume one project sourcing gas from the US will take FID in 2024.

Russian gas and LNG supply

- Pipe exports to the EU decline further after 2024 as the Russia-Ukraine transit contract expires. New pipelines to China, including the Far East (2028) and Power of Siberia 2 (2033) pipelines, continue to develop.
- Western sanctions create issues for Russian LNG – we have risked the production profile of the existing and under-construction projects and assume no new Russian LNG FIDs for the foreseeable future.
- Sanctions-related issues with ice-class LNG shipping restrict the use of the Northern Sea Route to Asia. The European Parliament passed rules allowing EU governments to restrict Russian LNG imports, but until a formal ban is in place, we assume imports continue.

Energy policies and implications for gas

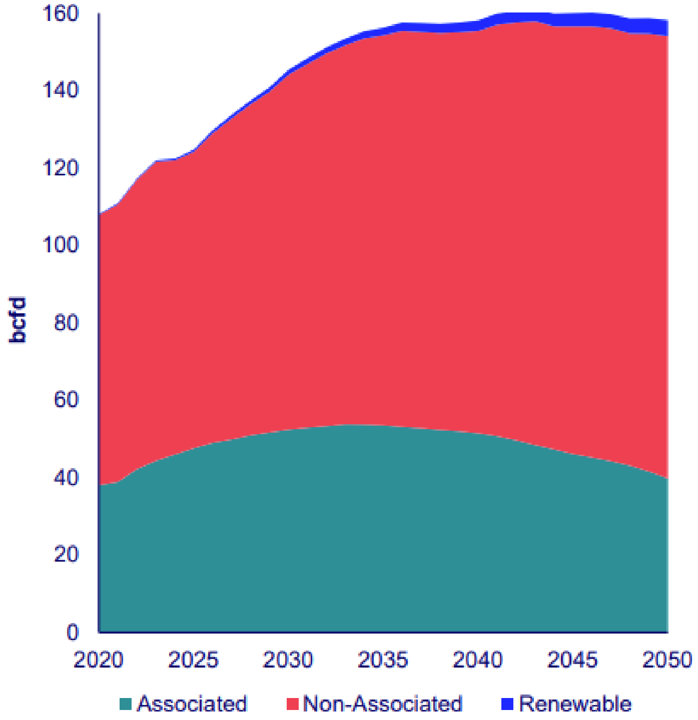
- Europe: gas demand continues to decline in line with Fit-for-55 targets, but the EU fails to achieve RePowerEU targets. Some decarbonisation initiatives, like electrification of heating, face challenges.
- US: IRA supports renewables development, but scaling up to ambitions remains tough, resulting in resilient gas demand.
- Asia: after stagnating in the near term, gas demand returns to growth in key emerging markets, reaching 15.4% of regional primary demand by 2050 versus about 11% in 2024.

Wood Mackenzie

North America natural gas at a glance

Gas market expands by over 30% until early 2040s to reach over 160 bcfd

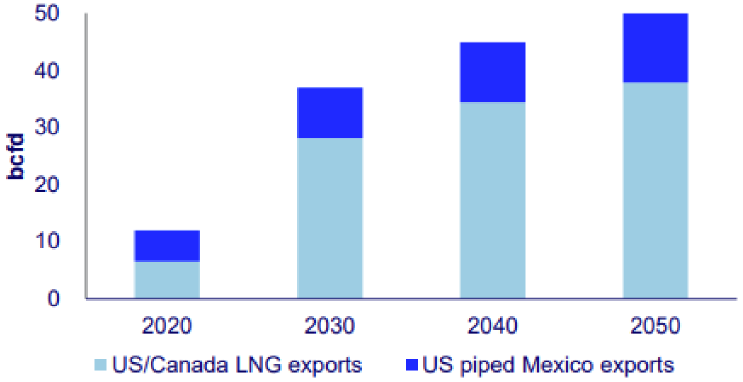
Associated supply growth accelerates but peaks by mid-2030s



Source: Wood Mackenzie

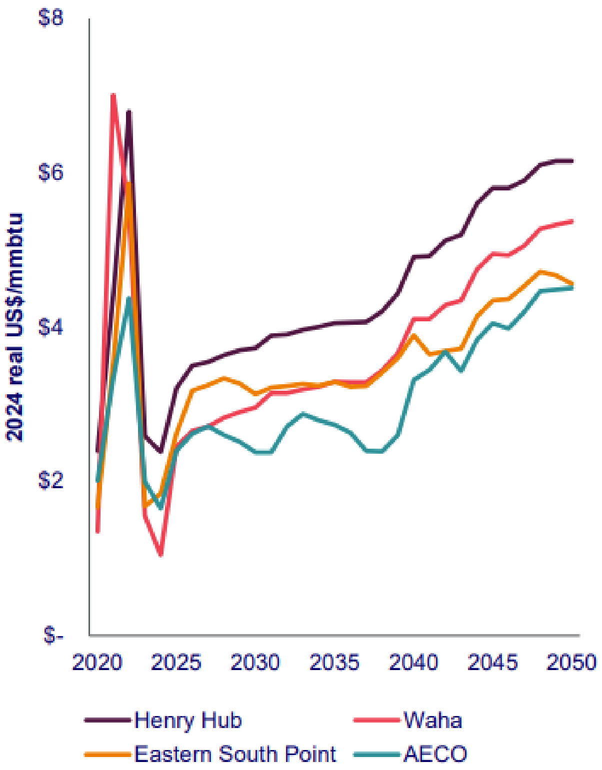
Wood Mackenzie

LNG exports triple by 2050 despite near term delays in the US



Stronger power load growth supports resilient domestic gas demand

Henry Hub gas prices reach $6/mmbtu by late 2040s



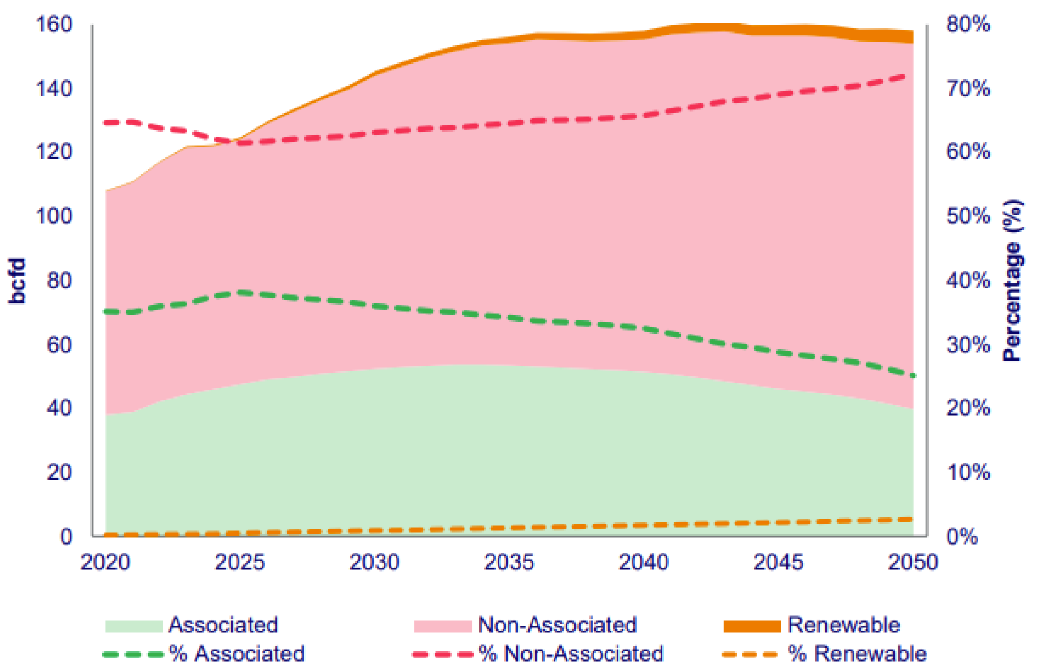
AVISTA

Supply

North America gas supply grows yearly by an average of 3.3 bcfd until the mid-2030s before stabilizing near 160 bcfd through 2050

Permian associated gas is the largest growth region over the next five years; however, the Haynesville is the largest growth area over the next ten years; Post-2040 there is a greater call on non-associated gas sources

North America gas by type



Renewable

RNG production grows tenfold between 2023 and 2050 supported by low carbon policies, such as the Low Carbon Fuel Standard (LCFS), Renewable Fuel Standard (RFS) and the Inflation Reduction Act (IRA), and ample resources of landfill and dairy biogas feedstock. Still, in the long term, RNG supply will be a modest 3% of the total North America natural gas supply.

Non-Associated

Softer near-term gas prices negatively impact short term non-associated gas supply growth. However, growing demand in the medium term will need to be met by growth from non-associated regions. Gulf Coast, Western Canada and the Northeast will grow by a combined 24 bcfd by 2035 from current levels. Haynesville could deliver 11 bcfd of growth by 2035. Continued Northeast supply growth is needed to meet demand in the long term.

Associated

Strong oil prices support liquids-focused drilling activity, bringing large volumes of low-cost associated gas to market. This temporarily delays some non-associated gas growth until later in the forecast. Associated gas growth is fueled by the Permian and Western Canada. The Permian accounts for 80% of associated gas growth by 2035, adding 8 bcfd from 2024 levels, followed by 11% coming from WCSB adding 1 bcfd.

[No Title]

Source: Wood Mackenzie

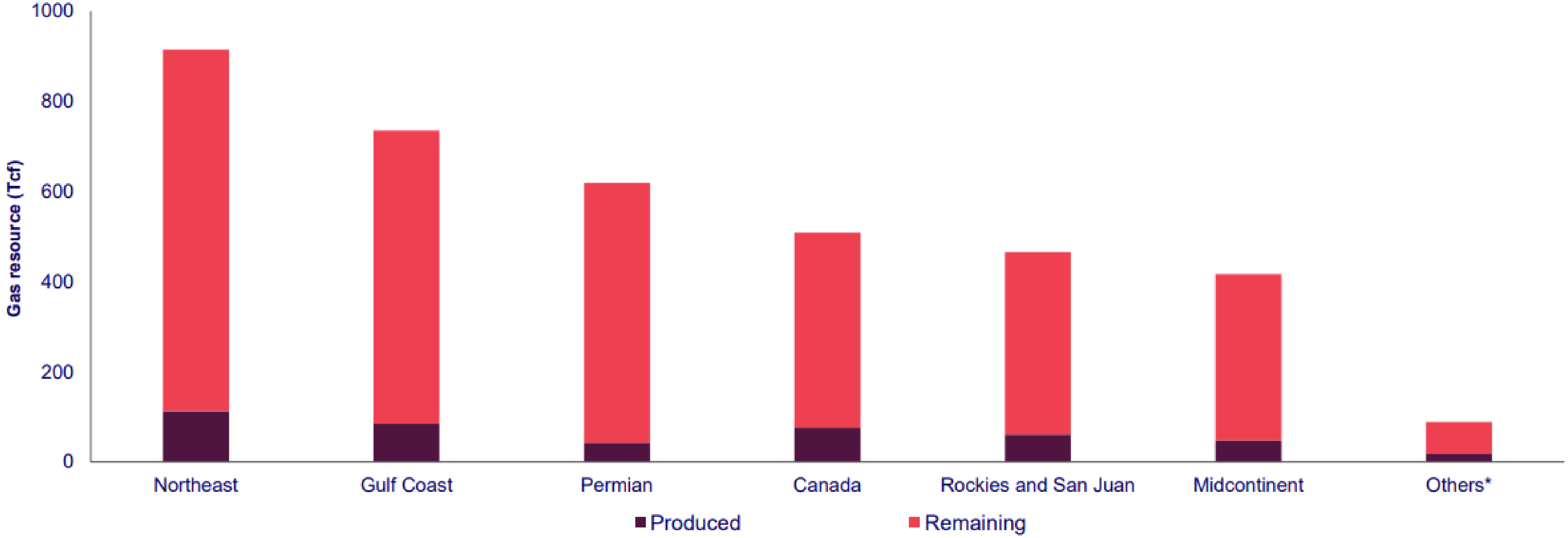
Wood Mackenzie

Supply

North America has significant gas resource available for development

In addition to commodity prices, factors such as demand, well economics, infrastructure, regulations, emissions considerations and investor sentiment will dictate how much resource is ultimately produced

Remaining gas resource for key regions



Source: Wood Mackenzie

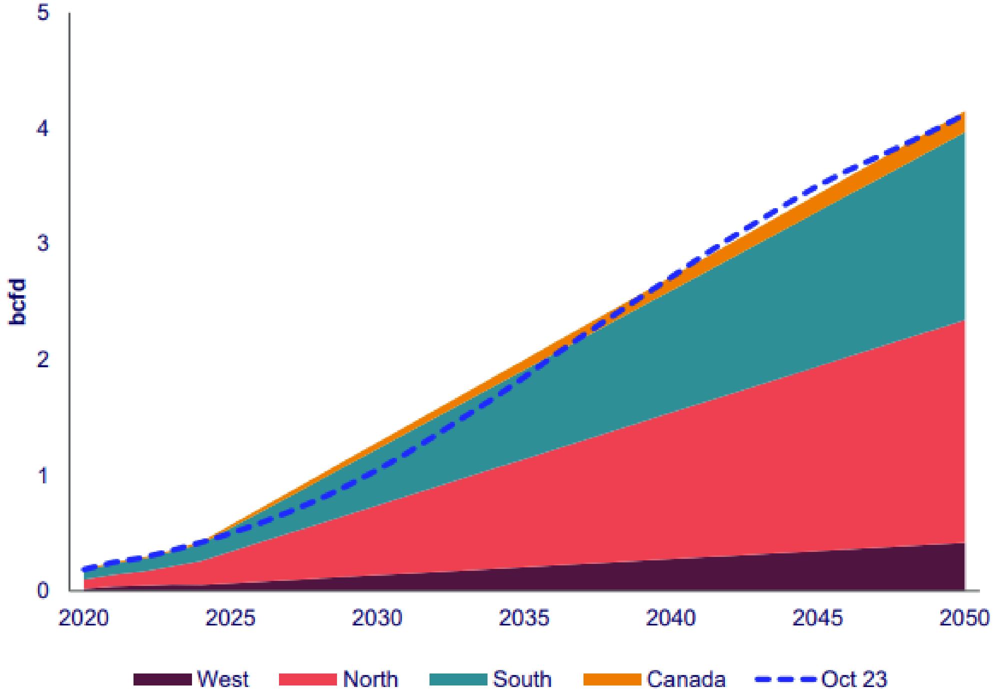
*Others: Fort Worth, West Coast

Wood Mackenzie

With appropriate technology development and policy frameworks, North America renewable natural gas (RNG) production will grow to over 4 bcfd by 2050

RNG production capacity has doubled since 2020, and more projects are expected to come online in the long term supported by ample landfill and dairy farm resources

RNG production forecast by region



Canada	British Columbia, Quebec and Ontario lead RNG production as local utilities and government aggressively commit to net carbon-zero targets and stakeholders capitalize on credits from the Clean Fuel Standard. RNG producers invest in development of new feedstock types and technologies that take advantage of local resources.
US Gulf Coast	RNG production in Texas benefits from proximity to LNG export facilities. Major players in the industry look at RNG to decarbonize shipments to oversees markets with aggressive emission reduction targets. Landfill gas sites dominate the supply mix in the region, but producers also invest in large farm projects in the area to utilize environmental credits available in the transport sector.
US Northeast	More RNG facilities come online as utilities and states seek to fulfill GHG emission reduction goals, which are one of the most aggressive in the nation. Ohio, Pennsylvania and Indiana are among top five states with highest RNG production in our forecast, benefiting from large landfill projects and dairy RNG potential.
US Pacific	Pioneering the nation with its progressive low-carbon policies, the west leads in new dairy project developments until the late 2020s. California remains the top RNG producer in our forecast, but we expect demand will transition from fueling NGVs to fulfilling LDC and industrial sector.

Source: Wood Mackenzie, Argonne National Laboratory RNG Database, IEA Outlook for biogas and biomethane

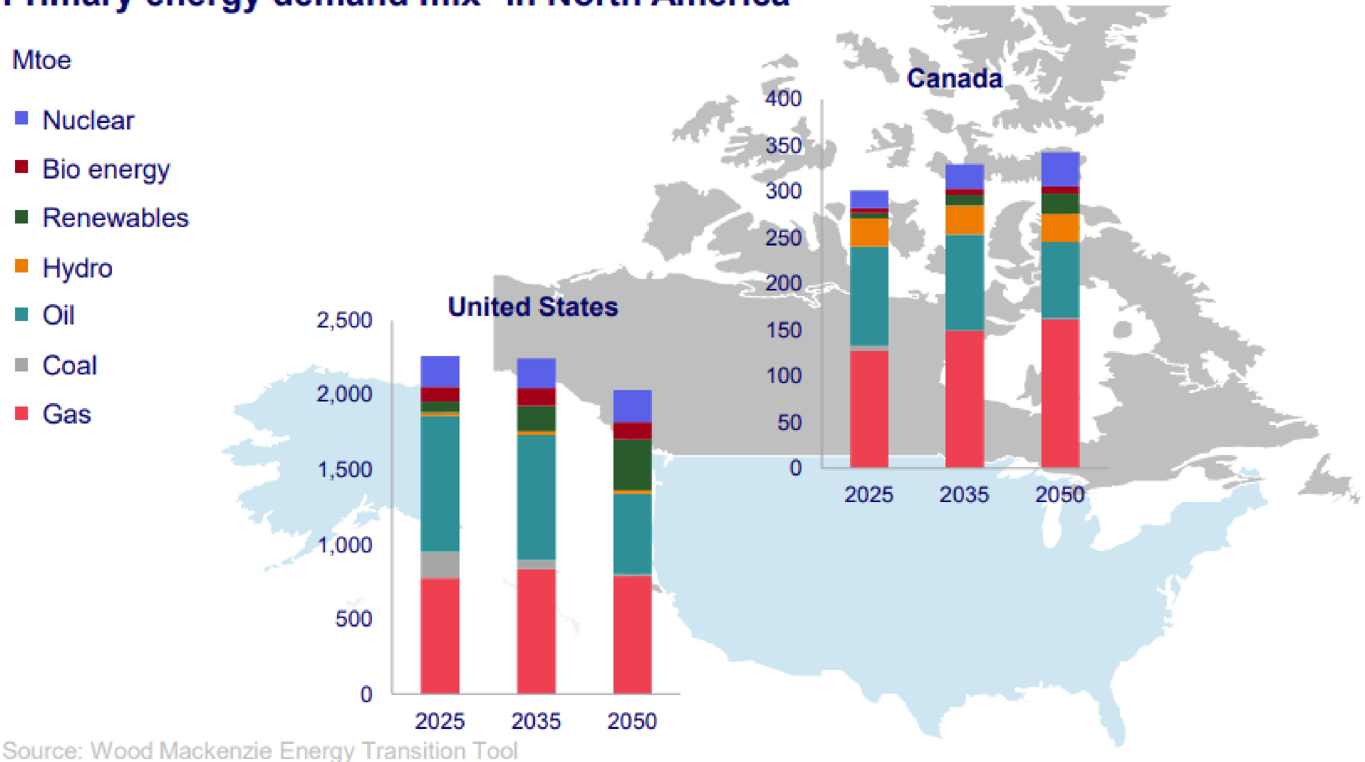
Wood Mackenzie

Demand

Gas plays a pivotal role in the energy transition with its market share in the energy mix growing by 5% from 2025 to 2050 at the expense of coal and oil

Gas represents about 40% of North American total energy demand in 2050

Primary energy demand mix* in North America



Canada	• Gas demand continues to climb throughout the decades with the emergence of blue hydrogen developments and new industrial opportunities • The near elimination of coal and decrease in oil demand is driven by switching to gas for power and continued expansion of renewables. • New technologies including large scale CCS projects create an environment for reduced emissions, allowing expansion in demand.
United States	• Gas demand grows at a CAGR of 0.7% between 2025 and 2035, driven primarily by growth in blue hydrogen and industrial sectors. • Between 2035 and 2050, the CAGR drops to -0.4% due to the energy transition, such as gas displacement from low-carbon hydrogen in the industrial sector and building electrification in the LDC sector. • Gas remains resilient in the power sector and supports more robust load growth through the 2030s, but rising renewable generation erodes gas demand in the 2040s albeit at a more gradual rate compared to the previous outlook.

Source: Wood Mackenzie Energy Transition Tool

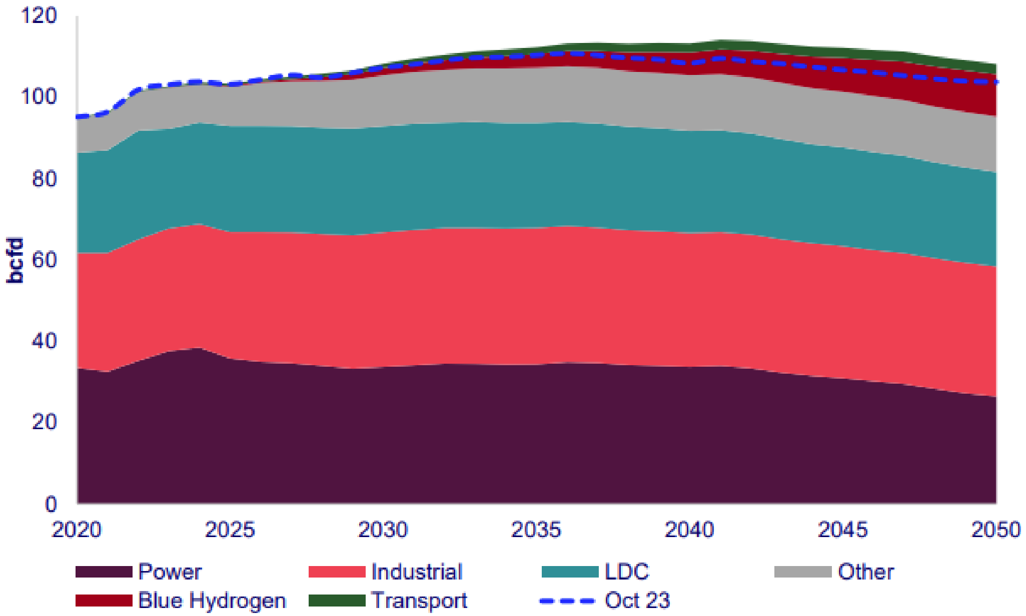
*Gas is based on Wood Mackenzie 2024 North America gas strategic planning outlook. Other commodities are based on Wood Mackenzie's 2023 commodity strategic planning outlook

Wood Mackenzie

North America domestic gas demand will continue to rise well into the 2040s

Gas use in the power sector continues to be resilient, driven by the retirement of coal-fired plants in the near term and sustained power demand growth stemming from data centers and industry reshoring in the long term

North America gas demand by sector



Source: Wood Mackenzie

Wood Mackenzie's "Other Demand" matches the EIA definition, which is lease and plant fuel and pipeline losses. It is the gas used within the industry, where the two biggest components to its growth are supply (the more supply the more L&P fuel) and LNG exports.

Wood Mackenzie

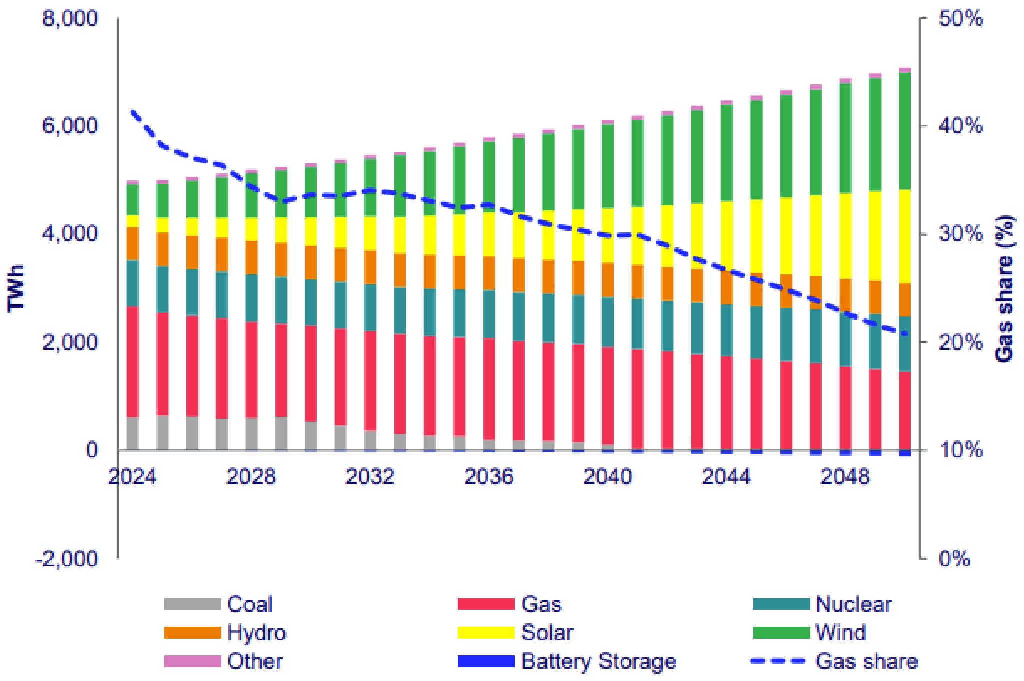
Transport	Transportation demand includes the consumption of natural gas in vehicles and small-scale bunkers. We expect the demand to grow from 0.4 bcfd in 2024 to 2.5 bcfd in 2050. This growth will be bolstered by widespread adoption of RNG, substantial funding and tax credit from the IRA for the US market, as well as recent technological advancements in gas engines for heavy-duty trucks.
Blue hydrogen	North America will lead blue hydrogen supply with over 56% of global production by 2050, requiring 10.4 bcfd of gas demand. The momentum is highly concentrated in the US as the Production Tax Credit announced under the IRA remains one of the market's most robust financial support mechanisms for low-carbon hydrogen. Three of the seven hubs selected by the DoE in 2023 to receive US$7 billion in funding will be blue hydrogen hubs and help drive growth.
Other	With rising gas production and LNG exports, we expect other demand to grow by 4.3 bcfd between 2024 and 2050.
LDC (residential and commercial)	We expect the combined demand for residential and commercial sectors to peak at 26.2 bcfd in the early 2030s. The subsequent decline can be attributed to the displacement of demand by hydrogen and the ongoing building electrification. In this update, we see potential upside risks from slower adoption of building electrification, influenced by preemptive US legislation and reduced heat pump sales.
Industrial	Industrial demand will reach 30.3 bcfd in 2024 and peak at 33.54 bcfd by 2035. We expect over 50 new industrial projects in the US and Canada to be commissioned between 2024 and 2031 to facilitate this expansion. Over the long term, North American industrial demand will decline to 31.9 bcfd by 2050. This is due to replacing grey hydrogen with low-carbon hydrogen in the ammonia, refining, and methanol sectors.
Power	Although gas demand in the power sector will decrease by 8% over the next decade, the decline is much more gradual compared to our previous update, as gas' share in the power market will stay close to 30% by 2040. Stronger power load growth from data centers used for AI, cloud computing, digitization and industry reshoring – particularly the semiconductor industry – requires gas to help support the grid as solar and wind continue to face transmission constraints.

Demand

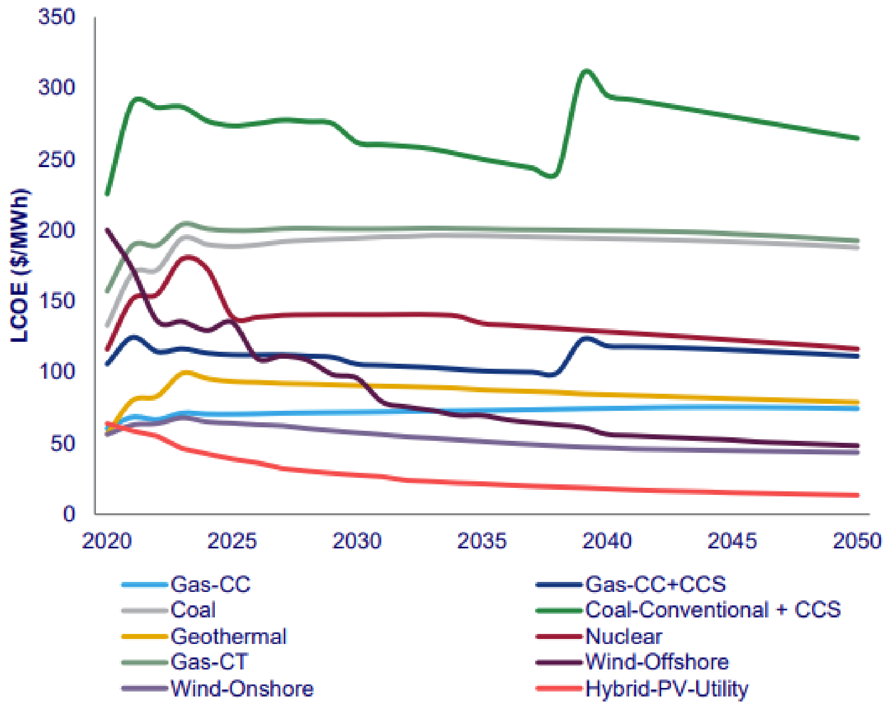
Compared to prior outlook, North America sees about 5% higher overall power loads from data center buildout and re-shoring of semiconductor industry

Decline of gas share in power stack is much slower as renewables see limited growth from challenges with interconnection queues and transmission bottlenecks

North America power generation by type



Levelized cost of energy (LCOE)



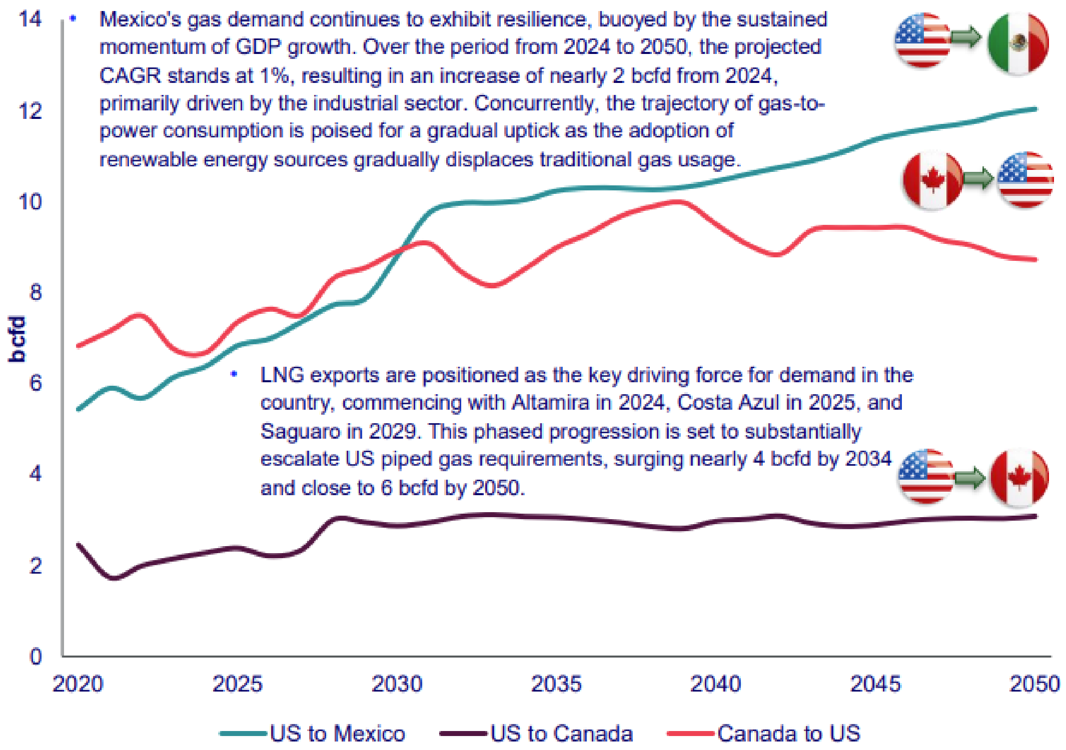
Source: Wood Mackenzie

Market balances and trade flows

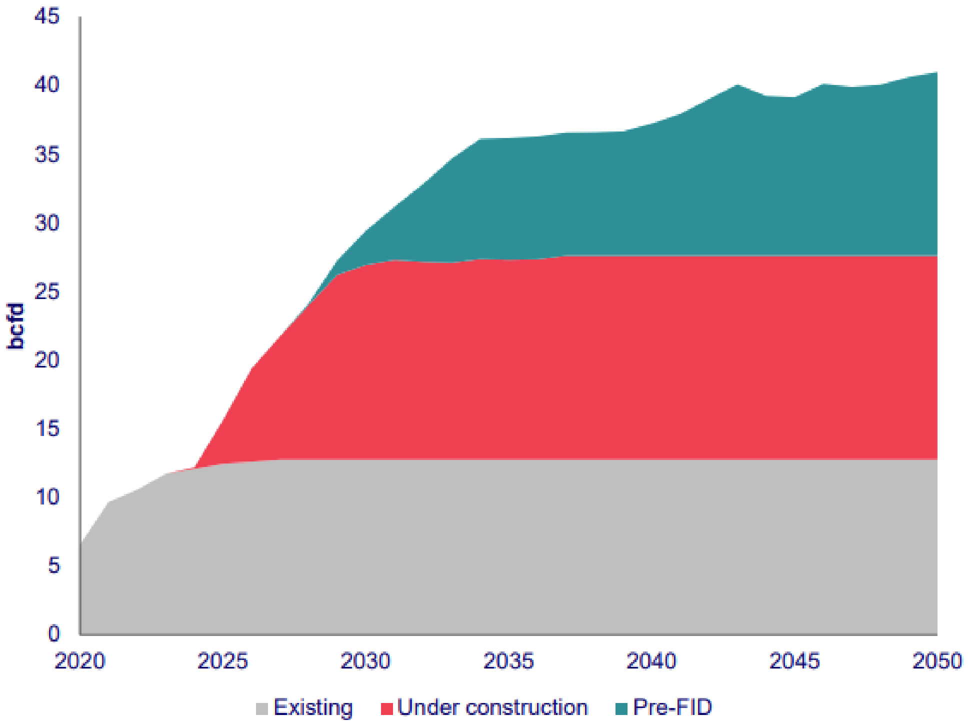
US exports to Mexico almost double by 2050 as west coast Mexican LNG exports gain momentum while indigenous production declines

The Biden administration's DOE non-FTA permit approval pause delays some US LNG projects in the near term but the prospect for more pre-FID North America LNG remains bright

North American piped trade flows



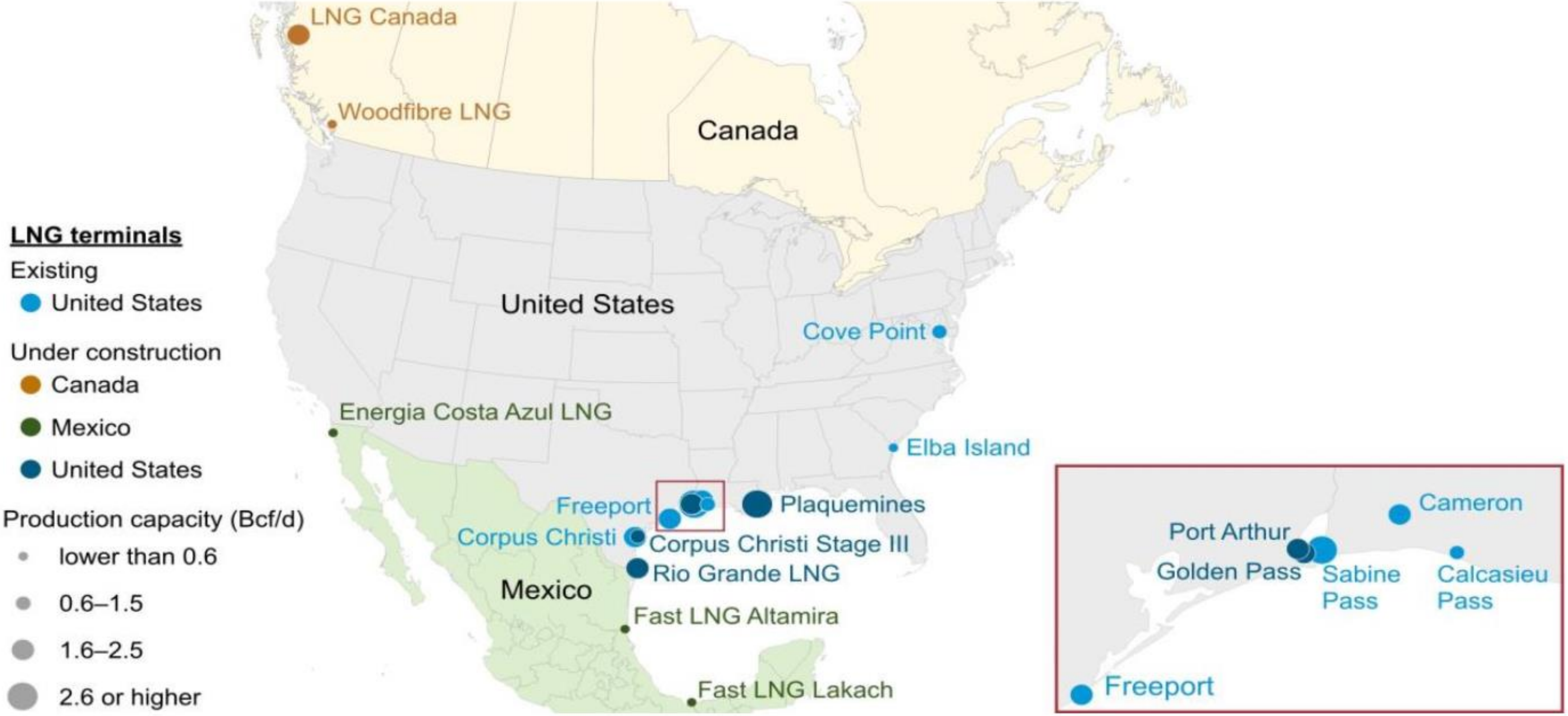
North American LNG exports



Source: Wood Mackenzie

Wood Mackenzie

North America liquefied natural gas export facilities, existing and under construction (2016–2027)



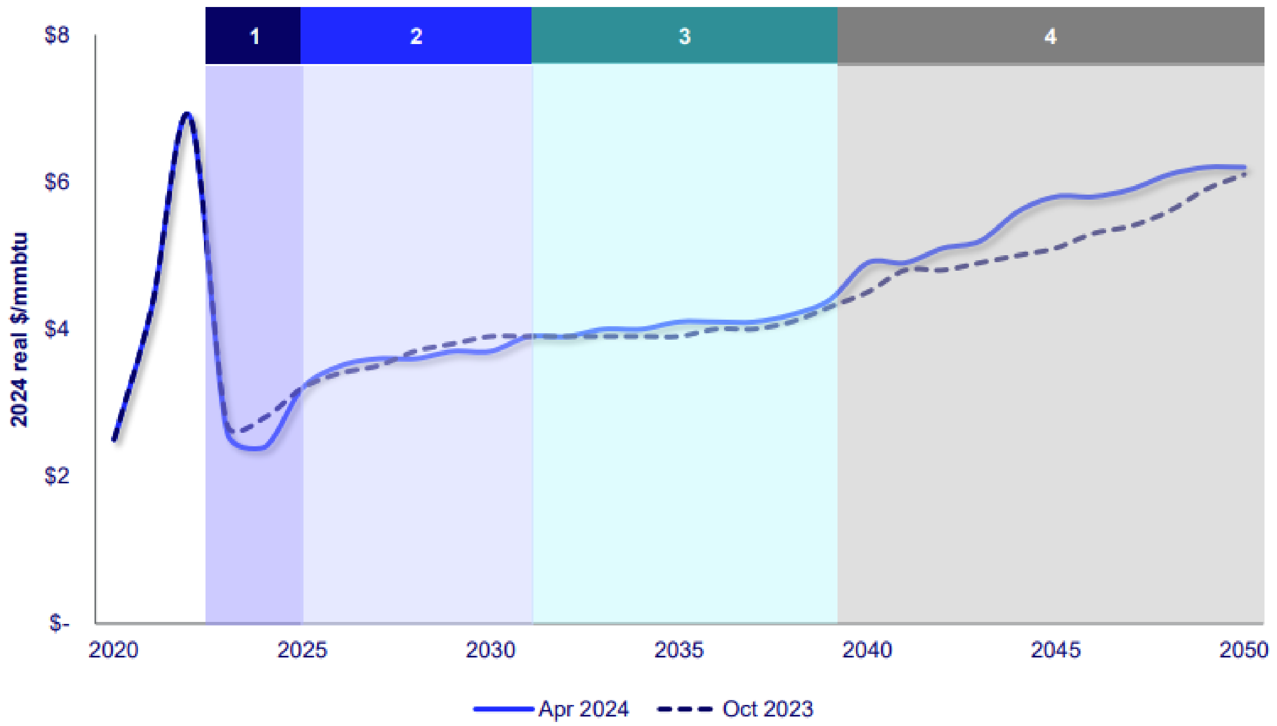
Data source: U.S. Energy Information Administration, *Liquefaction Capacity File*, and trade press
Note: Bcf/d=billion cubic feet per day. Map current as of October 2023.

Price & margin outlook

Henry Hub prices reach $6/mmbtu by late 2040s

Henry Hub prices rebound to $3.50/mmbtu by 2026 with rising LNG exports and restraints from non-associated producers on supply growth

Gas price outlook



Source: Wood Mackenzie

1 **(2024-2025)**
Bloated storage inventory pressures prices to the downside, but LNG project ramp-ups begin to tilt the market to balance, especially with near-term production curtailments.

2 **(2026-2031)**
North America LNG exports increase substantially with delayed US projects but also from accelerated Canadian and Mexican projects. Despite higher associated supply led by higher oil prices, restraints from non-associated producers could prevent the market from becoming oversupplied again.

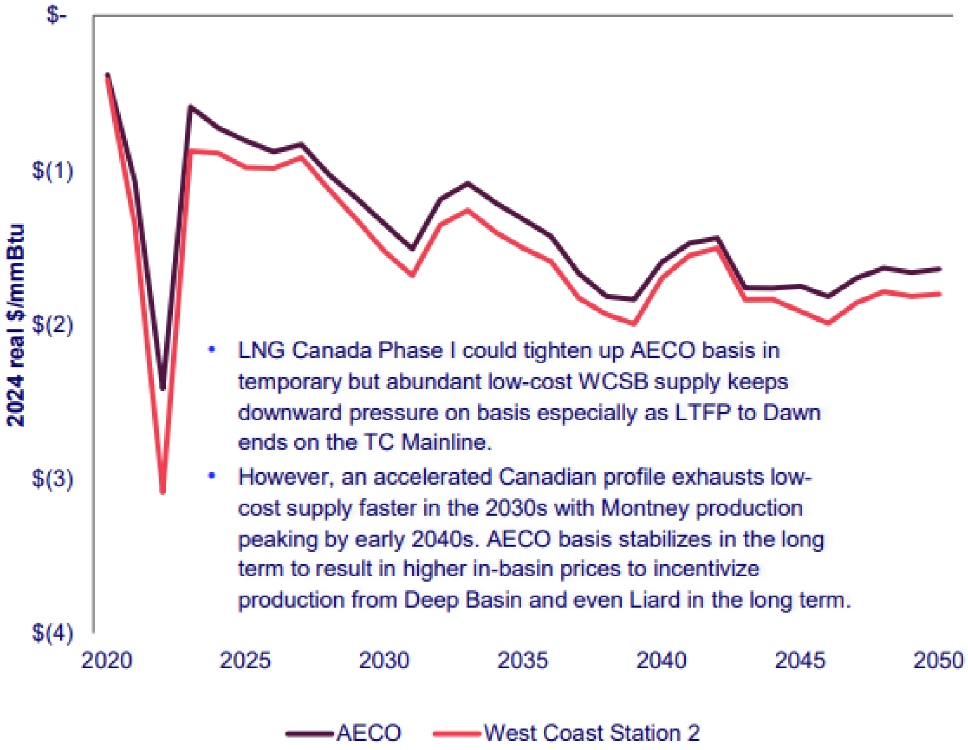
3 **(2032-2038)**
Market expansion continues with more US LNG exports and domestic demand growth – notably from a more resilient power sector. Henry Hub prices stabilizes through sustained growth in the associated supply until mid-2030s and a Haynesville production rebound.

4 **(2039-2050)**
The size of the gas market peaks by the early 2040s and declines in associated and Haynesville production put significant upward pressure on Henry Hub prices especially with demand resiliency in the power sector. Production from legacy gas basins increases to moderate Henry Hub prices from spiking up.

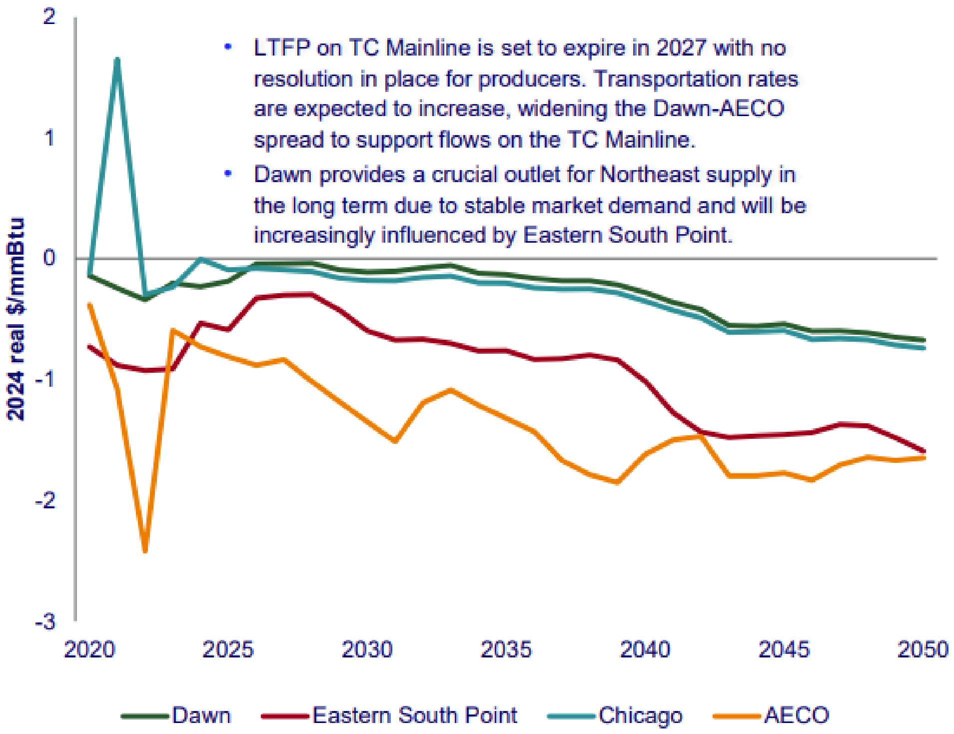
AECO weakens in the long term as WCSB still requires piped exports to clear marginal supply despite new LNG exports

Supply competition intensifies for Eastern Canada in the long term with stable market demand and the Northeast wins out with widening Eastern South Point-Dawn spread

Western Canada



Eastern Canada



Source: Wood Mackenzie

Price risks

North American gas prices

Prices upside (+)

- Early termination of US DOE's non-FTA export permitting pause to result in more US LNG FIDs

- Restrained spending by non-associated producers
- Pipeline development delays in the Haynesville

- Continued re-shoring of power-intensive industries and data center growth

- CCS and blue hydrogen emerge as mainstream technologies

2024 — **2035** — **2050**

Prices downside (-)

- Economic concerns in Europe or Asia impacting LNG demand

- Intensified LNG supply competition with Non-North America LNG projects reaching FIDs or return of Russian exports to Europe

- Energy transition picks up pace to replace gas demand with electrification or green hydrogen adoption

- Upstream exploration success and efficiency gains in second tier or legacy gas basins

Strength of the impact on price

Low — High

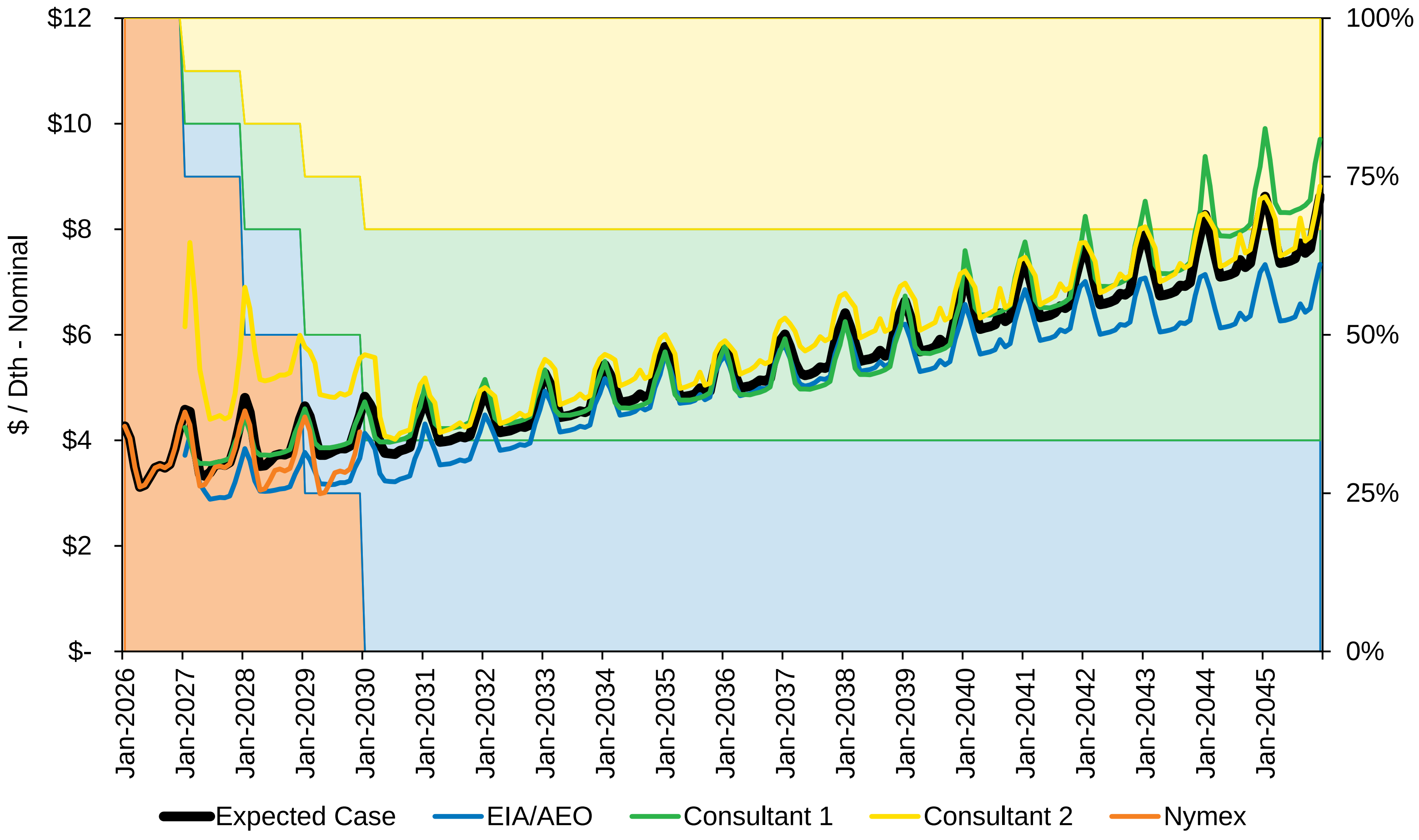
Source: Wood Mackenzie

Wood Mackenzie

Natural Gas Market Price Forecast

Michael Brutocao, Natural Gas Supply Analyst
Technical Advisory Committee Meeting No. 7
August 21, 2024

Henry Hub Expected Case Price Forecast



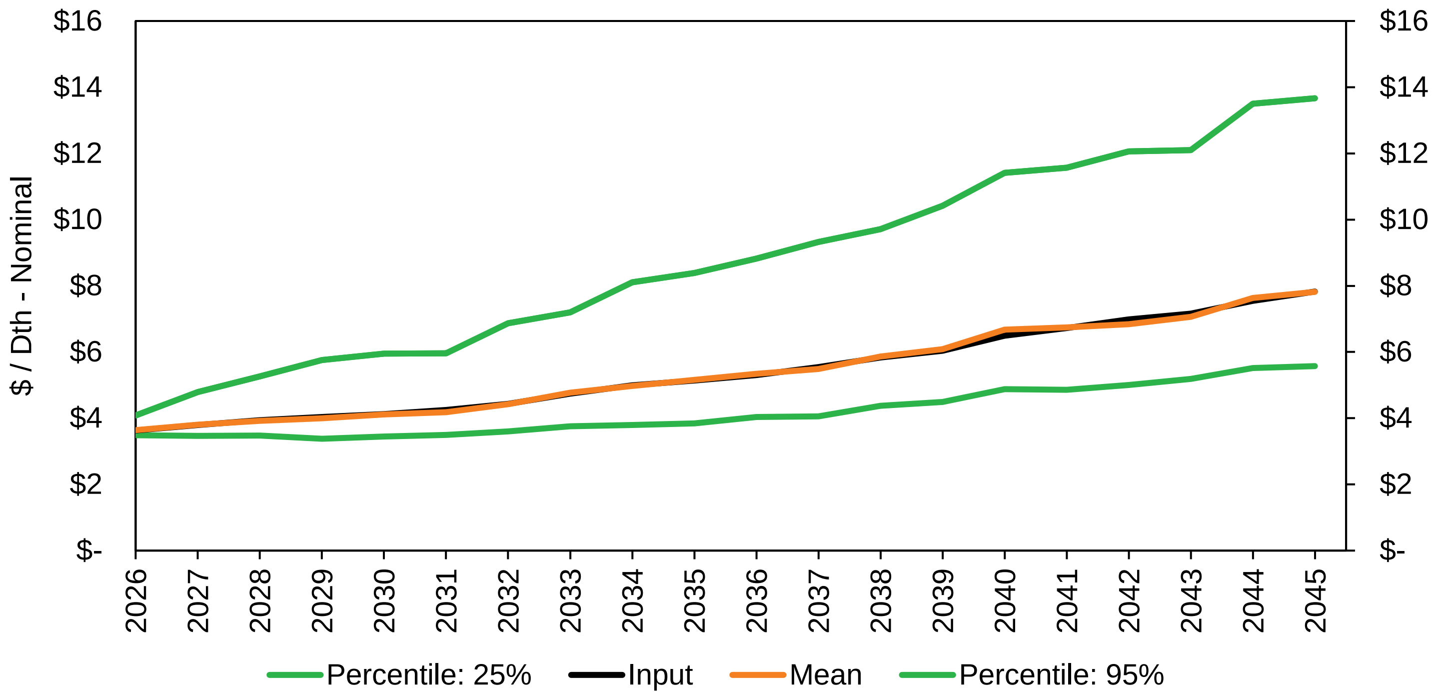
- Levelized Price: $4.95
- Data Sources
  - NYMEX forward market prices on August 5, 2024
  - Annual Energy Outlook 2023
  - Consultants 1 & 2 monthly price forecast
- Methodology
  - Average price of forecasts
  - Decreasing blend of NYMEX

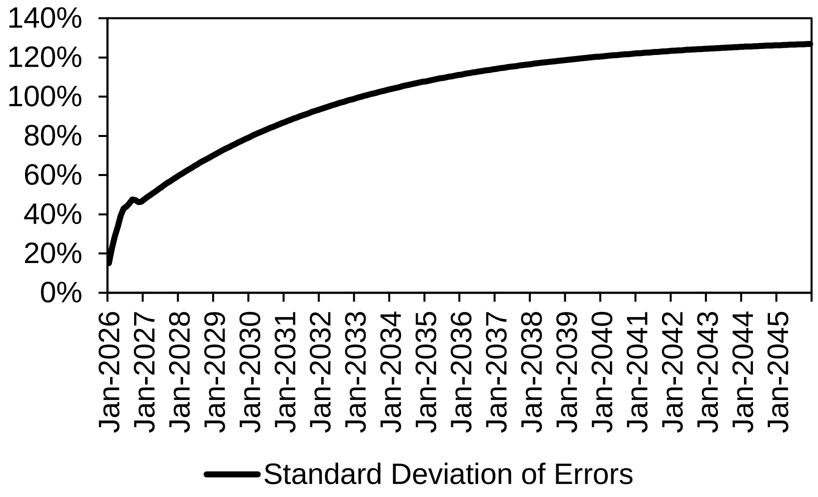
	NYMEX	Other
2026	100%	0%
2027	75%	25%
2028	50%	50%
2029	25%	75%
2030 - 2045	0%	100%

Annual Energy Outlook 2023 – Natural Gas Spot Price at Henry Hub

Henry Hub Stochastic Price Forecast

- Stochastic Inputs
  - Expected Case Forecast
    - Data Source: See previous slide
  - Autocorrelation (94.31%)
    - Data Source: Historical monthly prices at Henry Hub
  - Standard Deviation of Errors
    - Data Source: Historical daily NYMEX forward market prices
    - Data Source: Historical monthly prices at Henry Hub

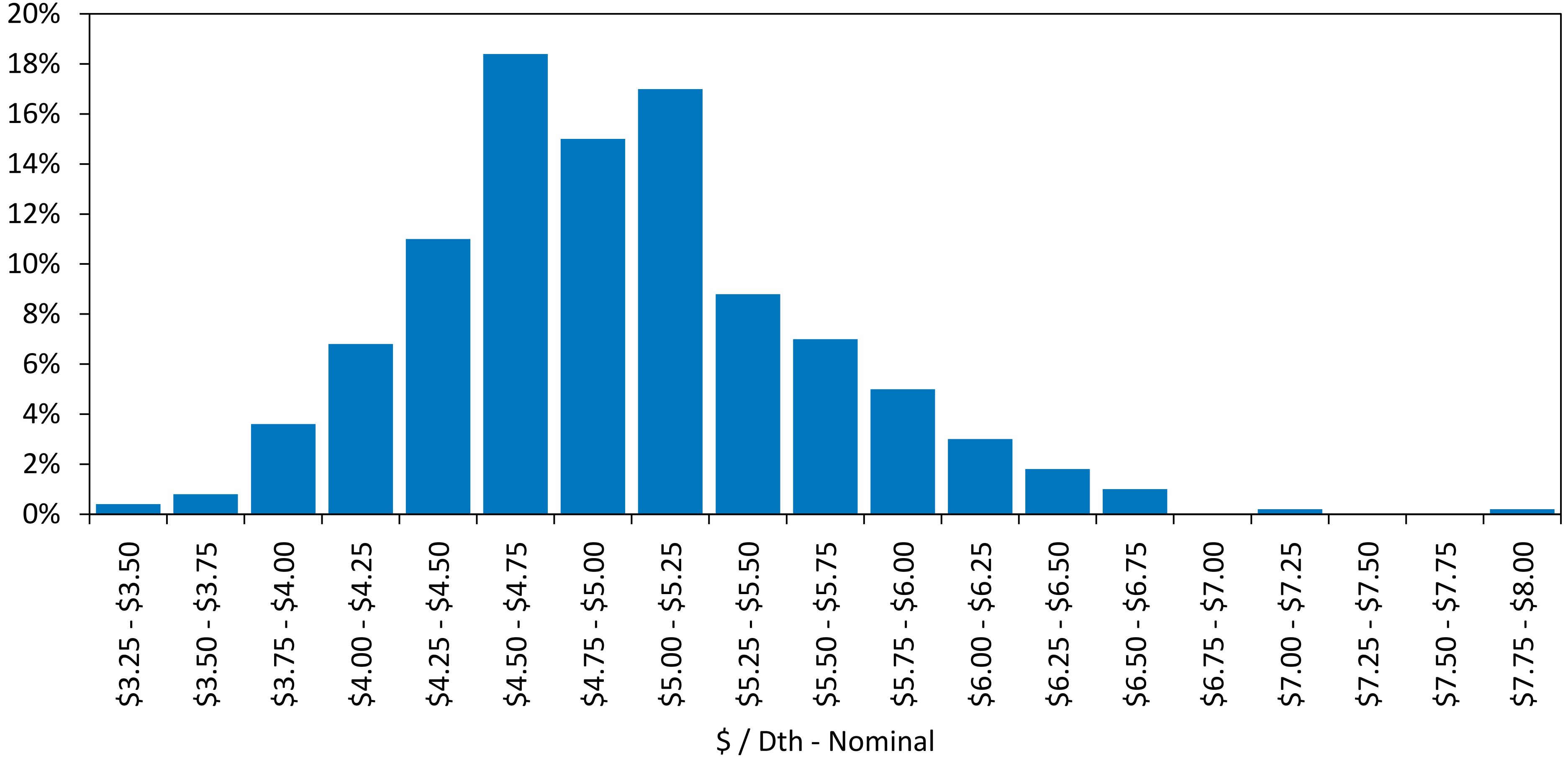




- Methodology
  - Start from Expected Case Forecast
  - Perform adjustment for Autocorrelation to prior month
  - Randomly draw from prices with lognormally distributed standard deviation of errors

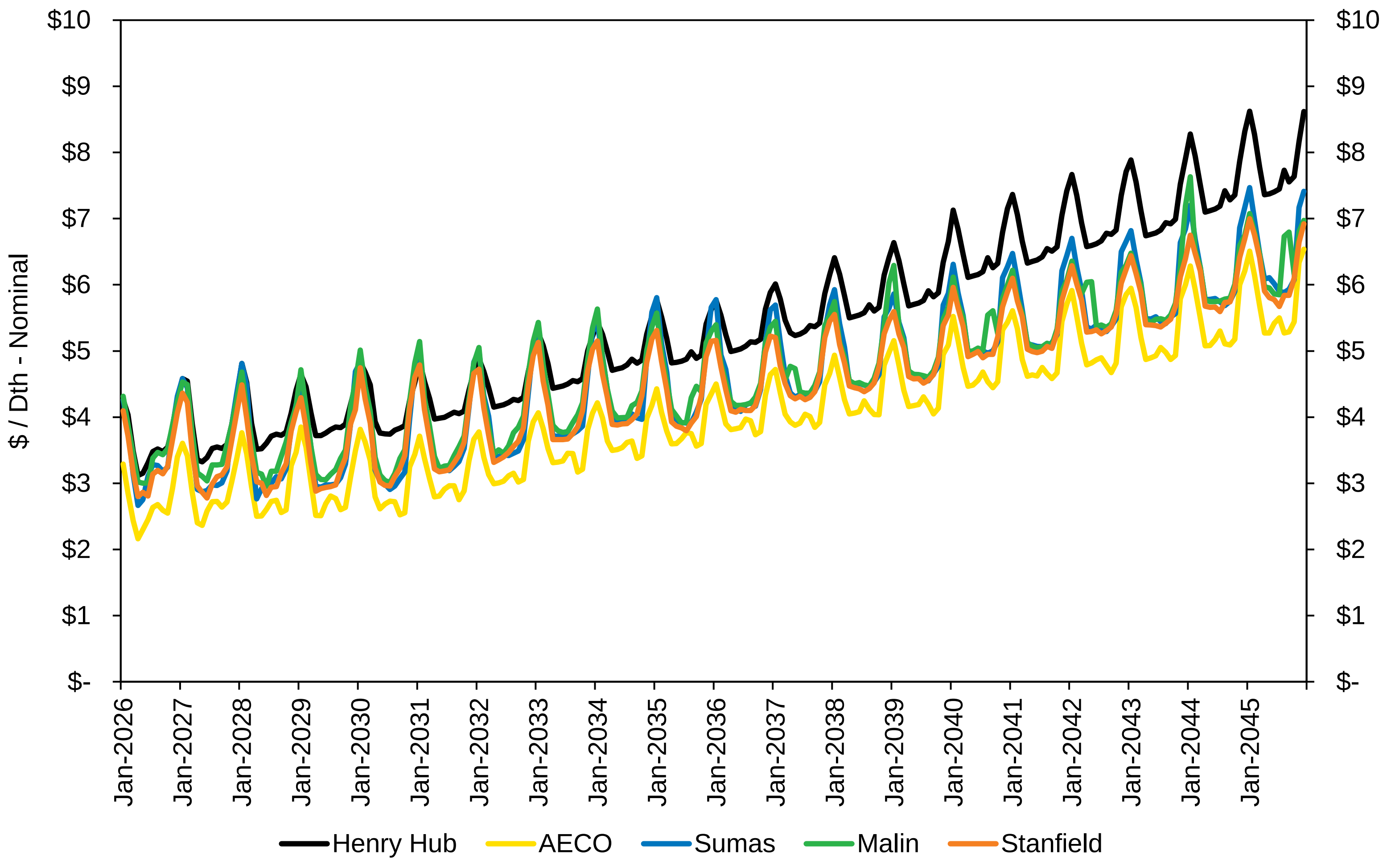
Historical Monthly prices at Henry Hub

Henry Hub Stochastic Price Forecast - Levelized



Data Source: Consultant 2 percent basis price differential to Henry Hub forecast

All Basins Expected Case Price Forecast



Levelized Prices

Henry Hub	$4.95
AECO	$3.67
Sumas	$4.30
Malin	$4.38
Stanfield	$4.21

Data Source: Consultant 2 percent basis price differential to Henry Hub forecast

Avoided Cost Methodology

2025 Gas IRP – TAC 7

EE Rules guidance - Idaho

- Include commodity, Interstate transport costs and current policy and distribution component, if measurable to avoid, in the avoided cost calculation
  - The distribution component calculation once determined must be presented to the Commission for approval and included in the IRP DSM avoided cost calculation. (CASE NO. INT.G.22-03)

EE Rules guidance - Oregon

OAR 860-030-0007
Gas Utility Avoided Costs

- **(1)** Investor-owned gas utilities shall file a proposed avoided-cost method and draft avoided costs with their integrated resource plans pursuant to Order No. 89-507. The avoided-cost method filed should be appropriate for determining the cost effectiveness of weatherization measures from the gas utility's perspective.
- **(2)** A gas utility may propose, or the Commission may require a gas utility to file the data described in OAR 860-030-0007 (Gas Utility Avoided Costs)(1) during the two-year period between filing integrated plans pursuant to Order No. 89-507 to reflect significant changes in circumstances, such as acquisition of a major block of resources. Such a revision will become effective 90 days after filing.
- **(3)** At least every two years, the gas utility must file with the Commission the data described in section (1) of this rule.
- Current Elements in UM 1893 from the companies most recently acknowledged IRP
    - Global Inputs (Discount rate, inflation rate, NWPCC 10% adder, system peak coincident day/hour factor)
    - Commodity & Transport (Gas commodity and transportation/storage costs)
    - Environmental Compliance (environmental compliance cost)
    - Infrastructure Capacity (forecast of distribution system capital costs)
    - Risk Reduction (a value for commodity risk)
    - End Use Profiles (end use profile by source and customer class)

EE Rules guidance - Washington

Gas companies—Conservation targets.

(1) Each gas company must identify and acquire all conservation measures that are available and cost-effective. Each company must establish an acquisition target every two years and must demonstrate that the target will result in the acquisition of all resources identified as available and cost-effective. The cost-effectiveness analysis required by this section must include the costs of greenhouse gas emissions established in RCW **80.28.395**. The targets must be based on a conservation potential assessment prepared by an independent third party and approved by the commission. Conservation targets must be approved by order by the commission. The initial conservation target must take effect by 2022.

(2) The commission may require a large combination utility as defined in RCW **80.86.010** to incorporate the requirements of this section into an integrated system plan established under RCW **80.86.020**.

[**2024 c 351 s 17**; **2019 c 285 s 11**.]

NOTES:

Findings—Intent—Effective date—2024 c 351: See notes following RCW **80.86.010**.

Findings—2019 c 285: "(1) The legislature finds and declares that:

(a) Renewable natural gas provides benefits to natural gas utility customers and to the public; and

(b) The development of renewable natural gas resources should be encouraged to support a smooth transition to a low carbon energy economy in Washington.

(2) It is the policy of the state to provide clear and reliable guidelines for gas companies that opt to supply renewable natural gas resources to serve their customers and that ensure robust ratepayer protections." [**2019 c 285 s 12**.]

RCW 80.28.380: Gas companies—Conservation targets. (wa.gov)

Standard Cost Effectiveness Tests

Total Resource Cost

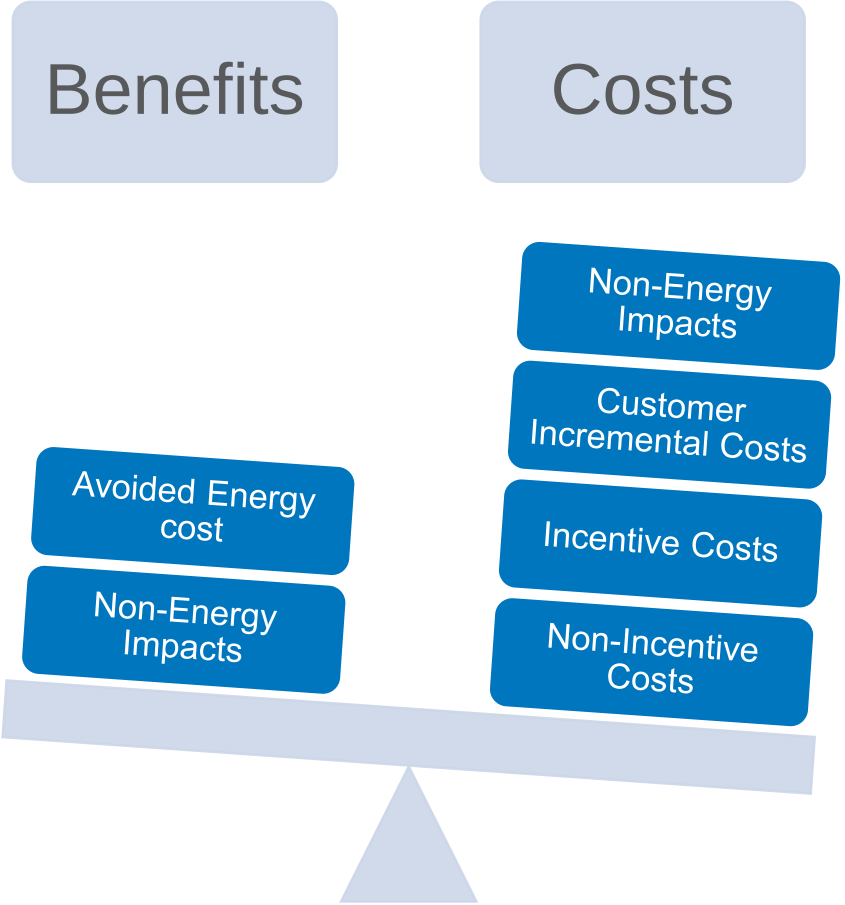
- Measures the cost to all involved
- Societal in nature
- Adjusting incentive does not impact TRC

Utility Cost Test

- Considers the impact to the utility
- Determines if programs are deferring capital investments
- We can adjust incentive to impact UCT*

*Adjusting incentives too much in pursuit of UCT may reduce participant enthusiasm

Cost Effectiveness Items



	TRC	UCT
Benefit Components		
Avoided Cost of Utility Energy	$	$
Value of Non-Utility Energy Savings	$	
Non-Energy Impacts	$	
Reduced Retail Cost of Energy		
Cost Components		
Customer Incremental Cost	$	
Utility Incentive Cost		$
Utility Non-Incentive Cost	$	$
Imported Funds (tax credits, federal funding etc)	($)	
Reduced Retail Revenues		

Idaho - Avoided Costs Input (Res, Com, Ind)

Commodity

- Natural Gas
- Hydrogen
- Methanation
- RNG

Interstate Pipeline Contracts***

- Variable Costs
- Fuel Costs
- Reservation costs

Local Distribution

- If capital costs are forecast
- Valued at peak hour

*Interstate Pipelines include GTN, NWP, NIT, Foothills, West Coast
**Storage costs from JP are excluded. Facility will need to be maintained (reliability, safety, operability) regardless of use.
***Local Distribution is excluded from interruptible customers of any class

Oregon and Washington - Avoided Costs Input (Res, Com, Ind)

Commodity
- Natural Gas
- Hydrogen
- Methanation
- RNG

Interstate Pipeline Contracts*
- Variable Costs
- Fuel Costs
- Reservation costs

Local Distribution***
- If capital costs are forecast
- Valued at peak hour

Carbon Adder
- Include Upstream Emissions
- CPP (OR)
- SCC @ 2.5% (WA)

NWPCC 10%

NEI

*Interstate Pipelines include GTN, NWP, NIT, Foothills, West Coast
**Storage costs from JP are excluded. Facility will need to be maintained (reliability, safety, operability) regardless of use.
***Local Distribution is excluded from interruptible customers of any class

Oregon and Washington - Avoided Costs Input (Transport**)

Commodity
- Natural Gas
- Hydrogen
- Methanation
- RNG

Interstate Pipeline Contracts*
- Variable Costs
- Fuel Costs
- Reservation costs

Local Distribution****
- If capital costs are forecast
- Valued at peak hour

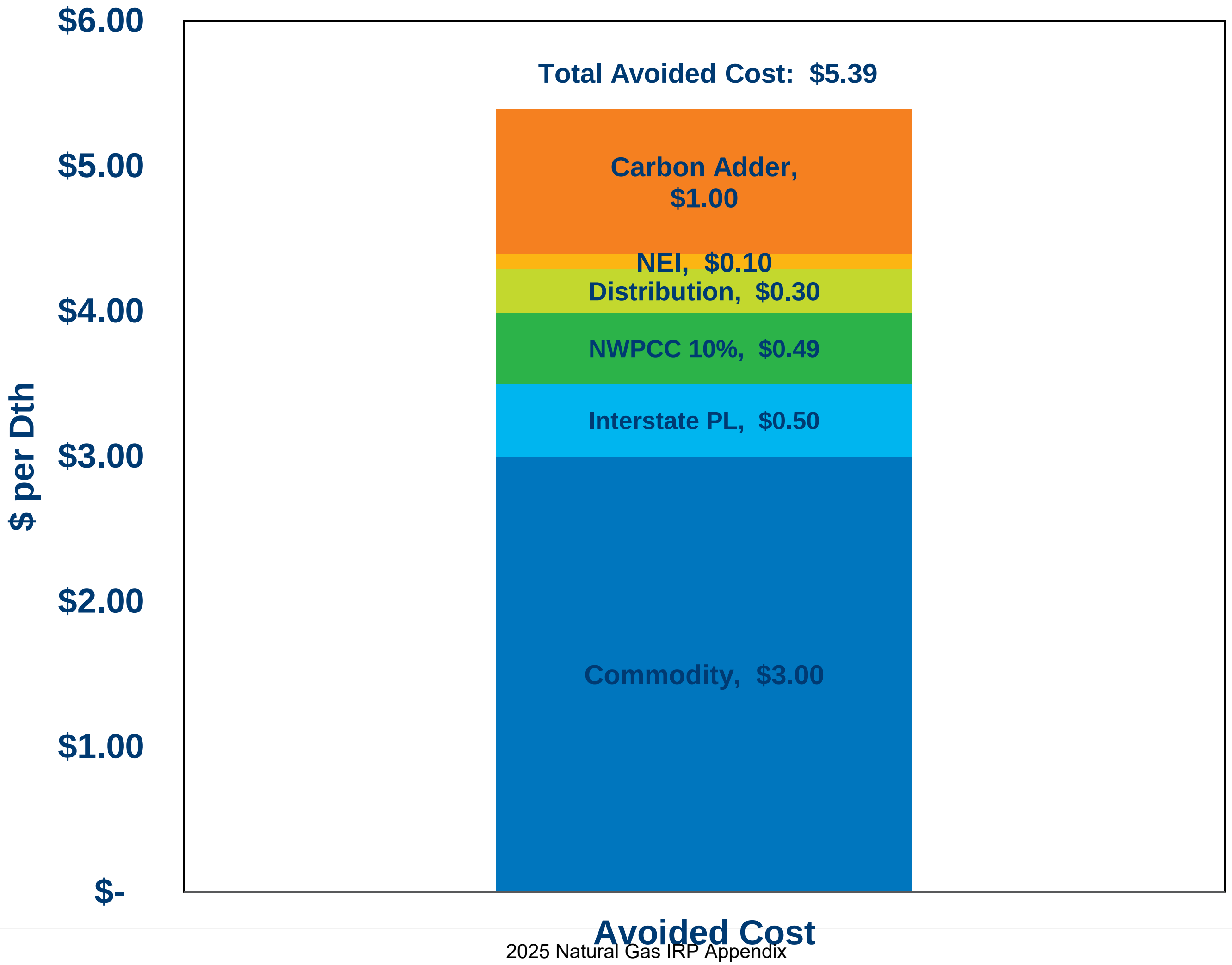
Carbon Adder
- Include Upstream Emissions
- CPP (OR)
- SCC @ 2.5% (WA)

NWPCC 10%

NEI

*Interstate Pipelines include GTN, NWP, NIT, Foothills, West Coast (Avista contract costs as estimate)
**Only transport suppliers included in Avista's CCA and CPP obligations
***Storage costs from JP are excluded. Facility will need to be maintained (reliability, safety, operability) regardless of use
****Local Distribution is excluded from interruptible customers of any class

Avoided Cost (example only)



2025 Gas Integrated Resource Plan
Technical Advisory Committee Meeting No. 8 Agenda
Wednesday, September 25, 2024
Virtual Meeting

Topic	Time (PTZ)	Staff
Feedback from prior TAC	10:30	All
Heat Pump Efficiency	10:40	Tom Pardee
Electrification Costs	11:20	Tom Pardee

Microsoft Teams Need help?

Join the meeting now

Meeting ID: 232 105 574 200
Passcode: JmeAyM

Dial in by phone

+1 509-931-1514,,62195212# United States, Spokane
Find a local number
Phone conference ID: 621 952 12#
For organizers: Meeting options | Reset dial-in PIN

Heat Pump Efficiency

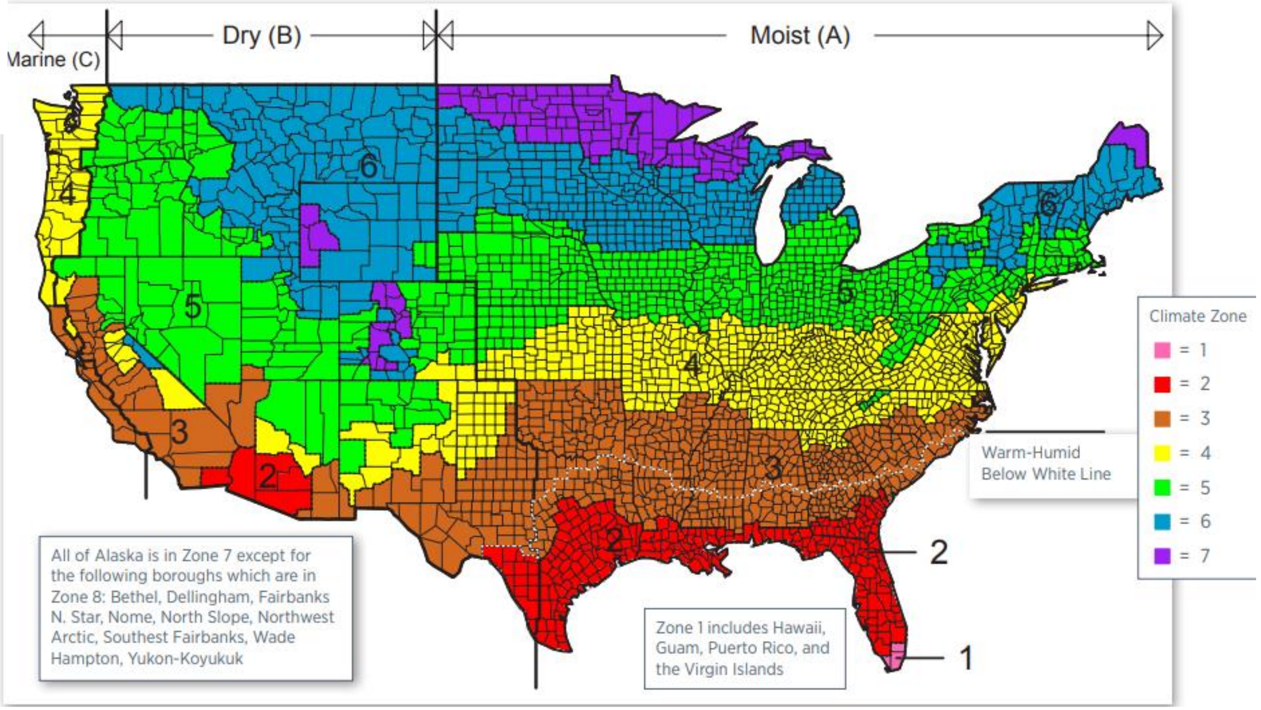
September 25, 2024

Climate Zones

- Avista LDC territory comprises 3 climate zones
  - Climate Zone 4: Roseburg, Medford
  - Climate Zone 5: La Grande, Spokane
  - Climate Zone 6: Northern WA and ID

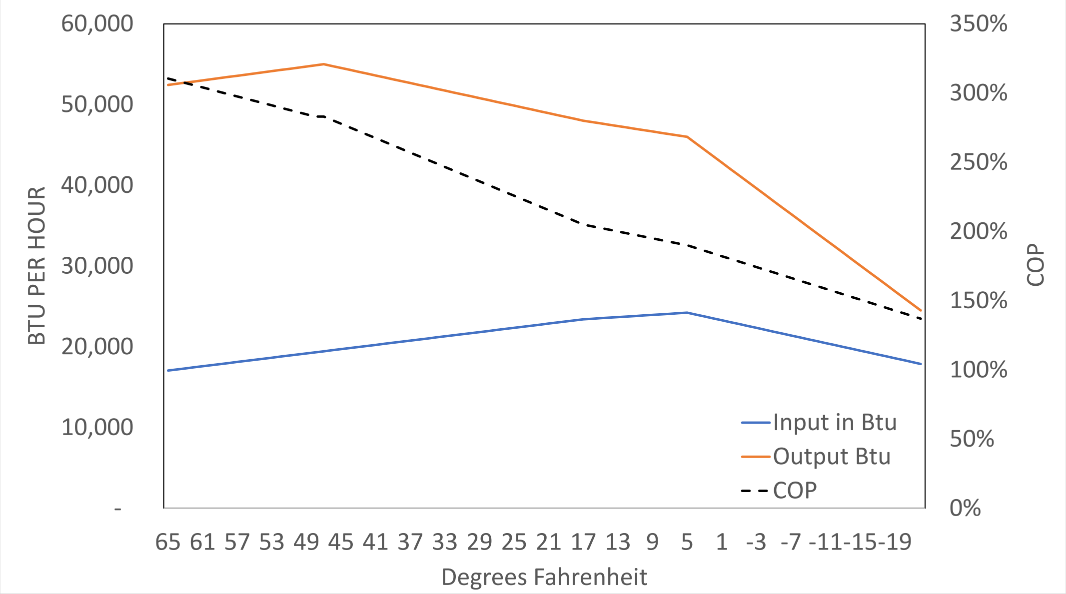
- Climate zones help determine sizing of heat pumps and furnaces

Zone	btu needed per sq. ft
1	35
2	40
3	45
4	50
5	55
6	60



Basic Calculation Considerations of Heat Pumps

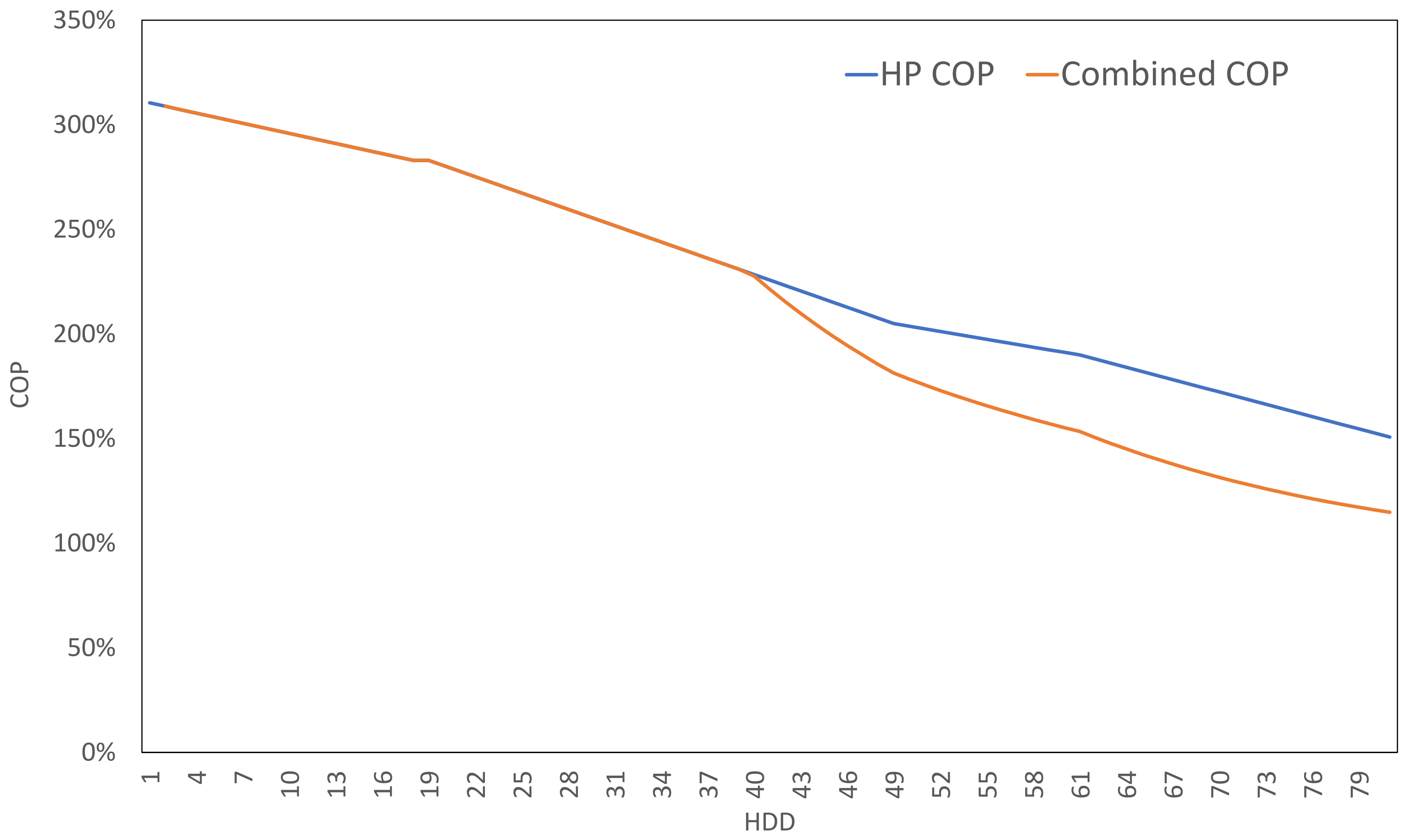
- Output Btu
- Input Btu
- Temperature in Fahrenheit
- Coefficient of Production
- Climate zone
- House size
- Ducted Heat Pump



ASHP (neep.org)

1. Heat pumps need a higher air flow rate to provide the same amount of heat from a furnace
2. Higher air flow requires bigger ducts

COP including auxiliary



Assumes 100% efficient electric furnace as auxiliary backup heat

Detailed Calculation and Considerations

- **Cubic foot of heating volume (L x W x H) of structure**
- Exposure to elements (shade, direct exposure)
- Window glaze (double pane, single pane)
- Room type (kitchen, hall, bedroom)
- **Desired temperature increase**
  - **(desired temperature change) x (cubic feet of space) x.080713 (lbs of air per cubic foot)**
- **Auxiliary space heating (back up type) – Electric @ 100% efficiency**
- **Rates of electricity (kWh) vs. gas (therm)**
- **Efficiency of heat pump**

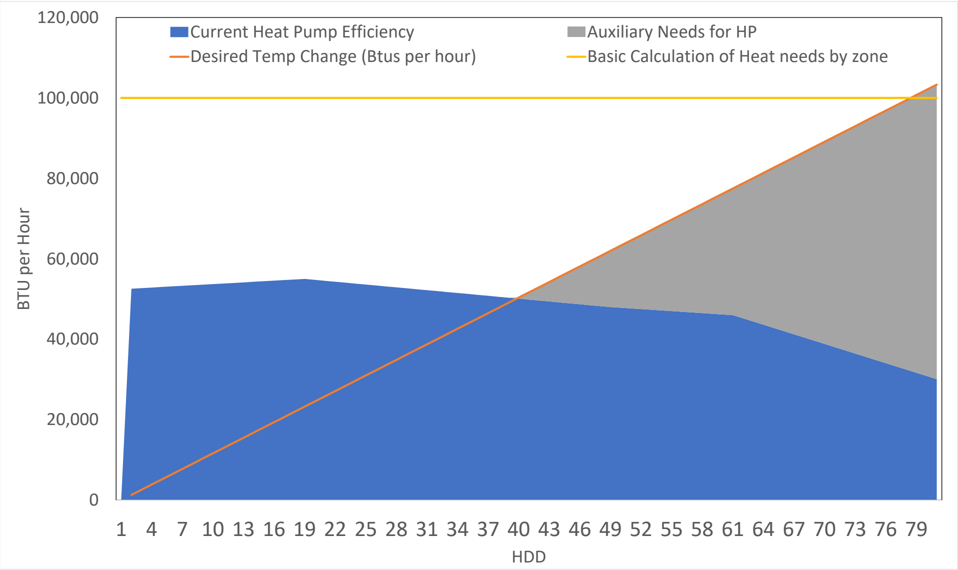
Takeaway: a lot of variability for heat needs depending on home size, location, efficiency, shell and climate

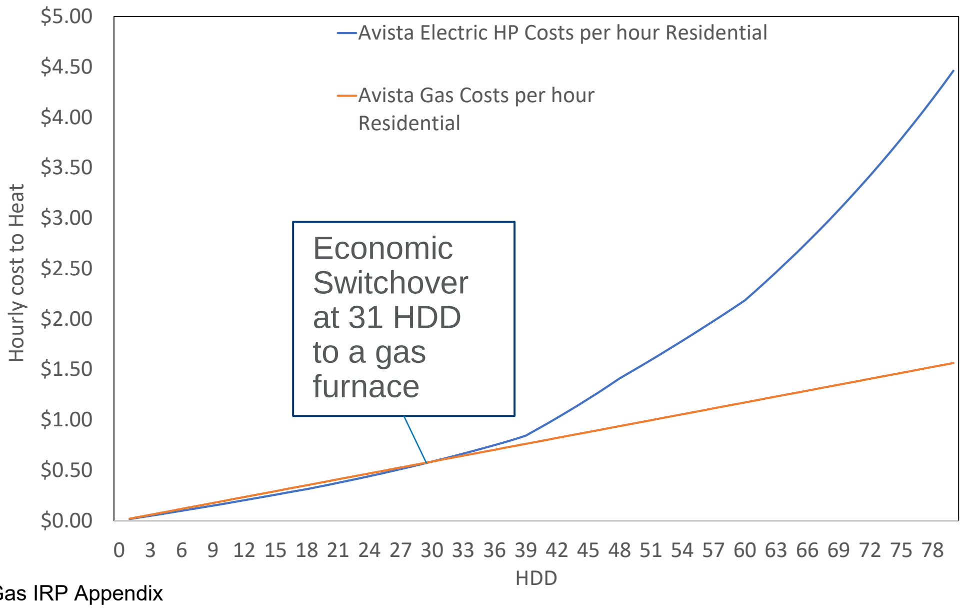
Rates of Energy

- The energy rate (kWh or therm) has a great deal of impact on overall costs with switchover temperature
- Although heat pumps provide a great deal of savings of btus, when colder weather occurs the efficiency declines (COP)

Oregon Example

- Avista 2024 Rate per therm: $1.26
- 2024 Res Rate per kWh:$0.13 (blended PAC and City of Ashland)
- 2000 sq. ft. house
- Climate zone 4
- Gas furnace efficiency: 80%

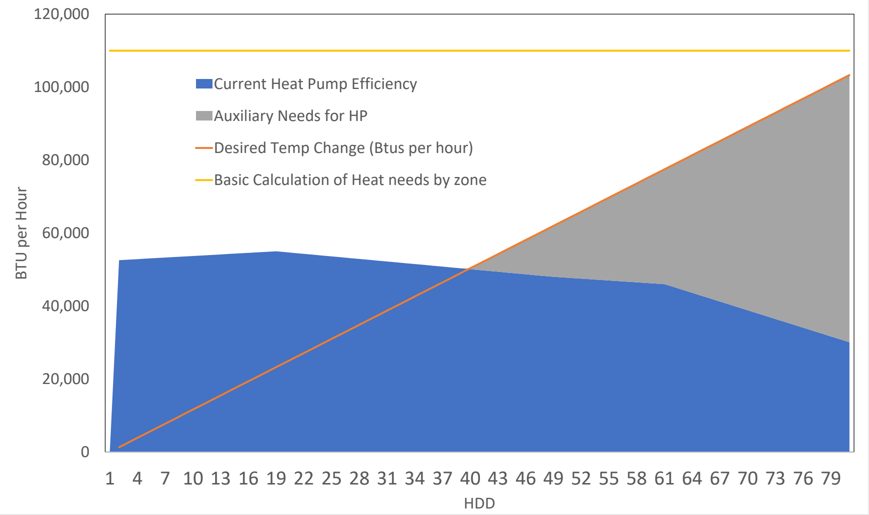


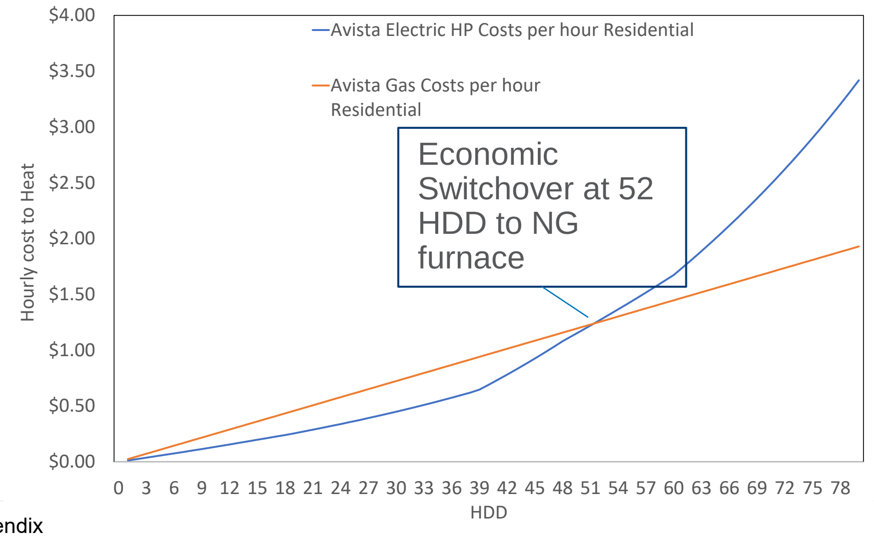


*does not assume a lock out temp on heat pump

Washington Example

- Avista 2024 Rate per therm: $1.556
- Avista 2024 Res Rate per kWh: $0.11582
- 2000 sq. ft. house
- Climate zone 5
- Gas furnace efficiency: 80%

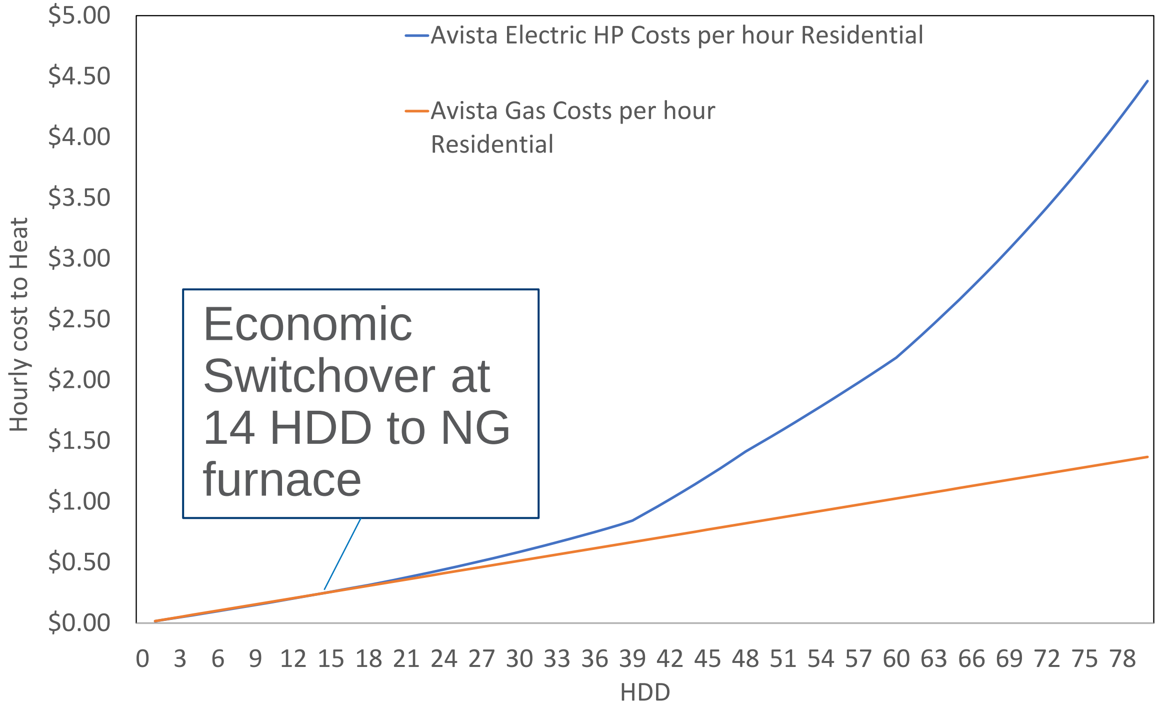




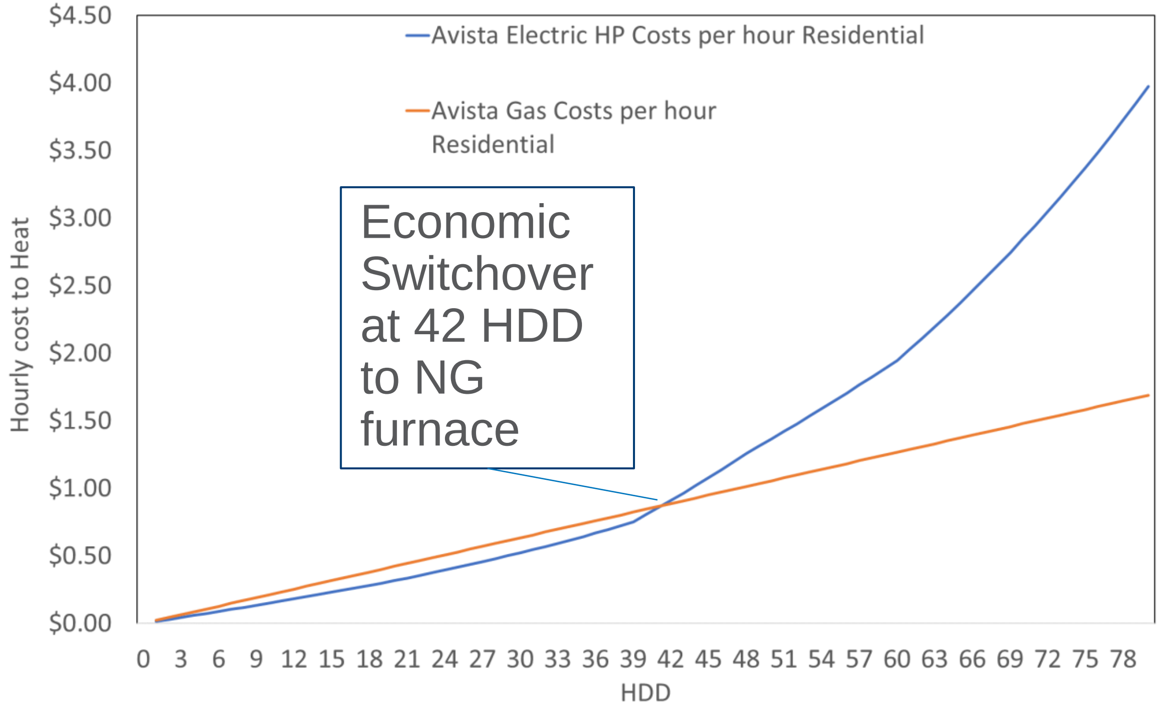
*does not assume a lock out temp on heat pump

Current Rates with a 95% efficient NG furnace

Oregon



Washington



*Same assumptions as previous slide, just efficiency of NG furnace changed

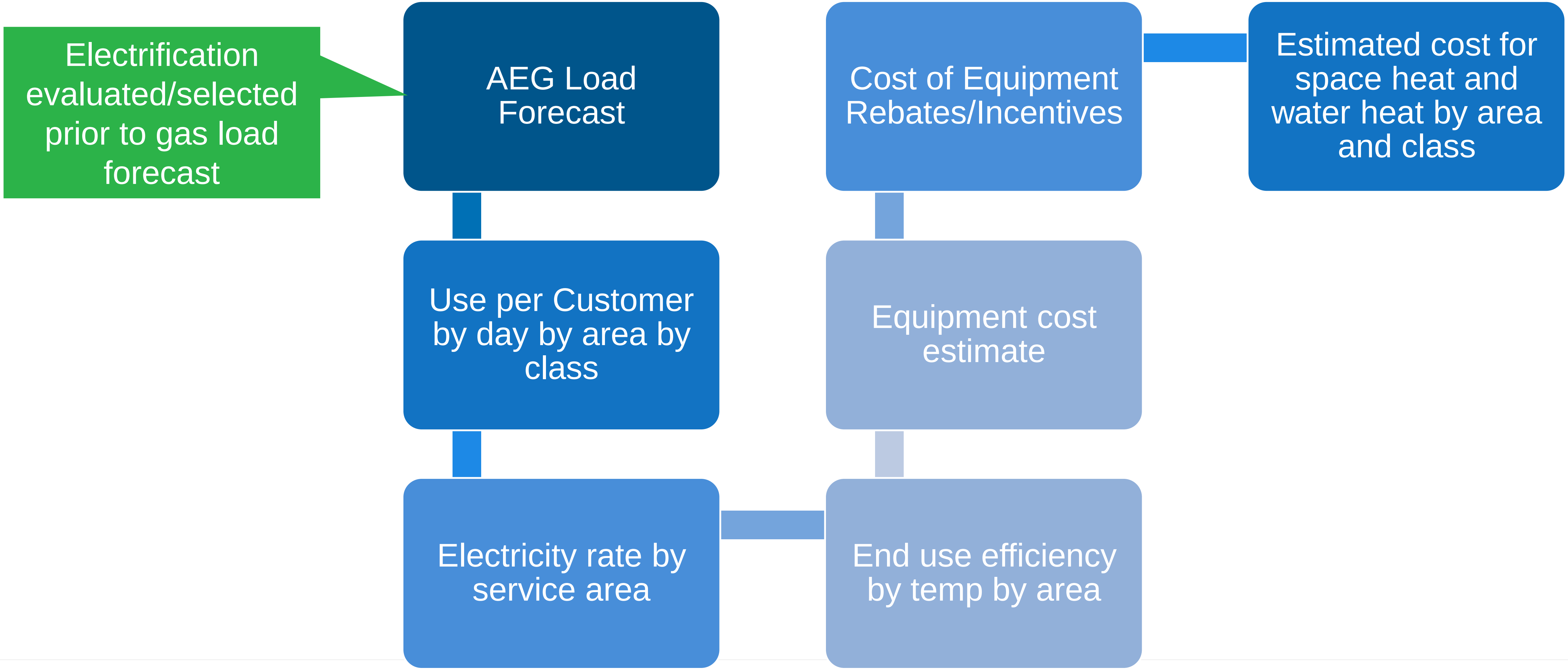
Summary

- Heat pumps may be a good alternative depending on climate zone, house size and insulation as a primary source of heating
  - This is magnified in areas of low electricity rates
- Heat pump life cycle is generally less than half of expected life cycle of a gas/electric furnace (Additional capital)
- Heat pumps provide additional benefits like cooling that may be considered when switching to or replacing a furnace
- Costs of energy and rates may alter the use of heat pumps for space heating, regardless of efficiency
- Defrost cycles in extreme weather may affect the usability during these cold events
- Costs:
  - depending on the customer type, heavy incentives may be available to help convert to heat pumps
  - If one commodity goes up or down more significantly than the other, the economic switchover temperature will change
  - There are thousands of different heat pumps, costs and related efficiencies so an industry estimate will be used as the assumed price of installation

Electrification Costs

Oregon and Washington

High Level Diagram of Process



Electrification Costs in the CROME Model

- Provides a price elastic response to higher gas costs and compliance to the CCA and CPP
  - Customers were electrified in the end use model prior to the final gas load forecast
- Once a unit is chosen at any point in time within the analysis, it is removed for the remainder of the forecast timeframe
- If electrification is chosen, a program decision and methodology will need to occur as well as a verified cost estimate to electrify:
  - Does Avista pay all costs or partially with electric provider?
  - How do costs get recovered?
  - Do all classes pay for these costs?
  - Trying to model costs and benefits, but not who pays (TRC test in EE)

Clean Energy Targets

Oregon Clean Energy Targets

- Oregon
- In 2021 Oregon State Legislature passed the Clean Energy Targets bill. This bill requires Portland General Electric, PacifiCorp and Electricity Service Suppliers to reduce greenhouse gas emissions from the electricity they provide. The bill also created targets for these companies to reduce the greenhouse gas emissions from electricity sold in Oregon to:

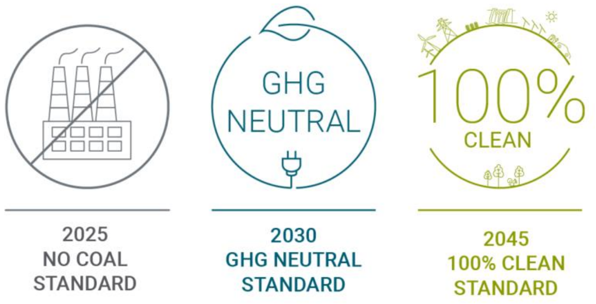
- 80 percent below baseline emissions levels by 2030;

- 90 percent below baseline emissions levels by 2035; and

- 100 percent below baseline emissions levels by 2040

Department of Environmental Quality : Oregon Clean Energy Targets : Action on Climate Change : State of Oregon

Washington Clean Energy Targets



- **CETA applies to all electric utilities serving retail customers in Washington and sets specific milestones to reach a 100% clean electricity supply.**

- The law requires utilities to phase out coal-fired electricity from their state portfolios by 2025.

- By 2030, their portfolios must be greenhouse gas emissions neutral, which means they may use limited amounts of electricity generated from natural gas if it is offset by other actions.

- By 2045, utilities must supply Washington customers with electricity that is 100% renewable or non-emitting with no provision for offsets.

[CETA Overview - Washington State Department of Commerce]

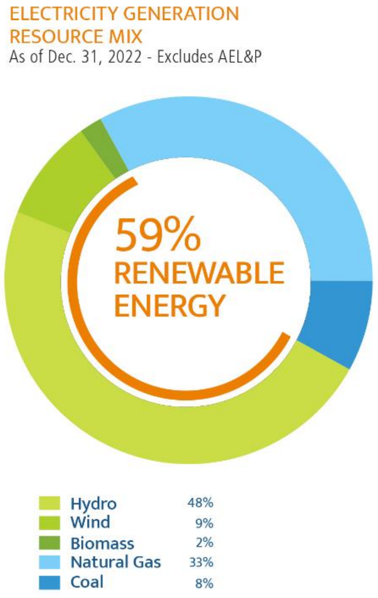
Electric Rates

Electric Rate assumptions

- Current Rates for each provider and inflated to 2026 $ then increased by estimated rate impact for Avista’s electric $ per kWh from Washington territory
  - The resource mix of Avista as compared to Pacific Power is much cleaner so the impacts to Pacific Power would likely be greater than the estimate
    - Pacific Power may use the clean resources from its portfolio to comply with Oregon Clean Energy Targets
- Power provided by BPA is assumed as clean energy and currently in compliance with clean goals
  - BPA does not have any excess power to sell in the event electric loads increase for these electric providers, but for this analysis it is assumed rates will increase by 3% YOY

Washington Electric Provider Rates

- Washington rates are weighted by # of customers for each provider.
- These providers are Avista (81%), Inland Power (10%), Modern Electric (5%) and VERA water and power (4%)

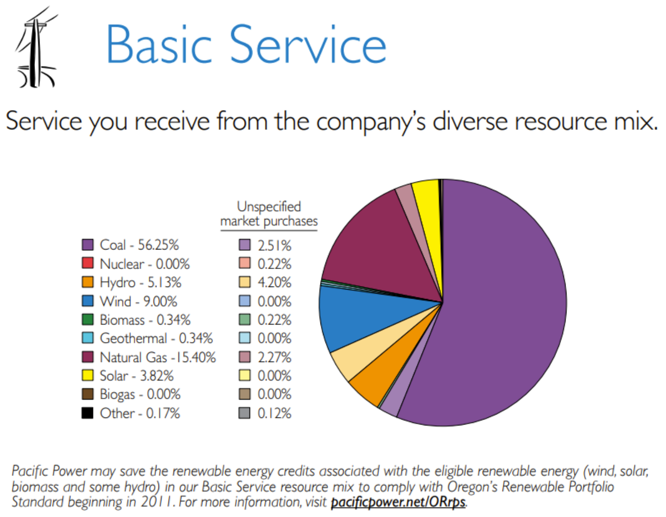


	VERA	Modern	Inland	Avista	Est.Total E. Wash electric customers with crossover from natural gas territory
WA	13,000	16,000	32,000	254,065	315,065
% of Total Customers	4%	5%	10%	81%	
Current Rates as of June 2024					
Res	$ 0.07	$ 0.06	$ 0.07	$ 0.09	
Com	$ 0.07	$ 0.06	$ 0.07	$ 0.14	
Large Com	$ 0.06	$ 0.06	$ 0.06	$ 0.09	
Weighted Average					**Total Estimated Rate**
Res	$ 0.003	$ 0.003	$ 0.007	$ 0.073	$ 0.086
Com	$ 0.003	$ 0.003	$ 0.007	$ 0.111	$ 0.125
Large Com	$ 0.003	$ 0.003	$ 0.006	$ 0.073	$ 0.085

[About Our Energy Mix (myavista.com)](myavista.com)

Oregon Electric Provider Rates

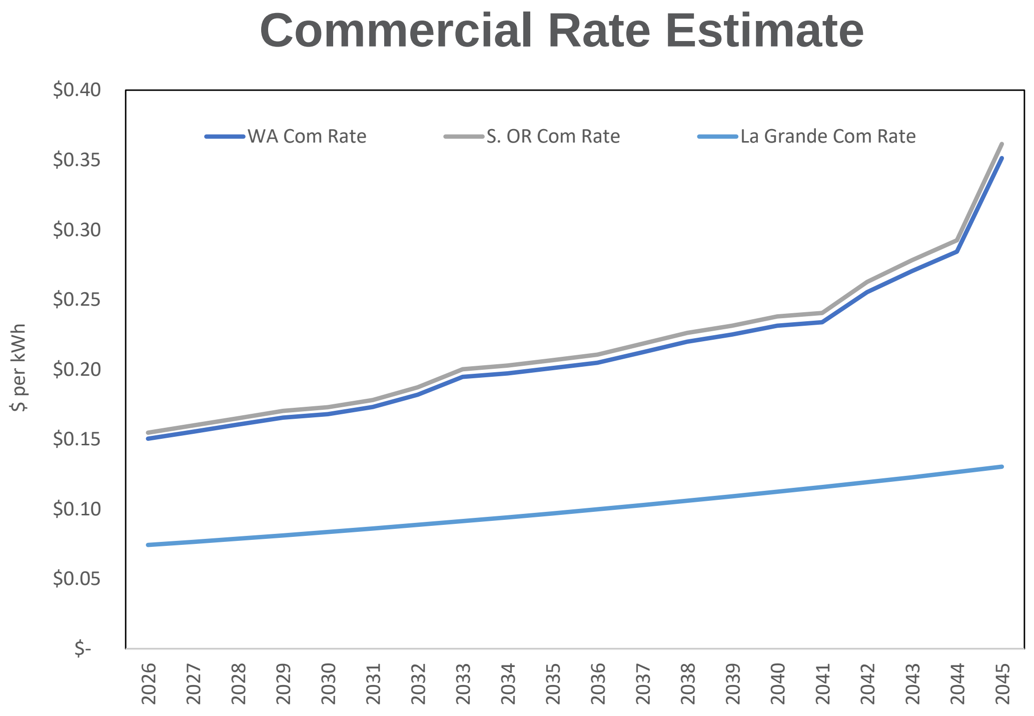
- Southern Oregon rates are weighted by # of customers from each electric provider.
- These providers are the City of Ashland (12%) and Pacific Power (88%)
- La Grande has a single electric provider. Oregon Trail Electric rates are increased by 3% YOY rather than the yearly increase to meet emissions goals
    - Current Res kWh rate is $0.068 and Com $0.07

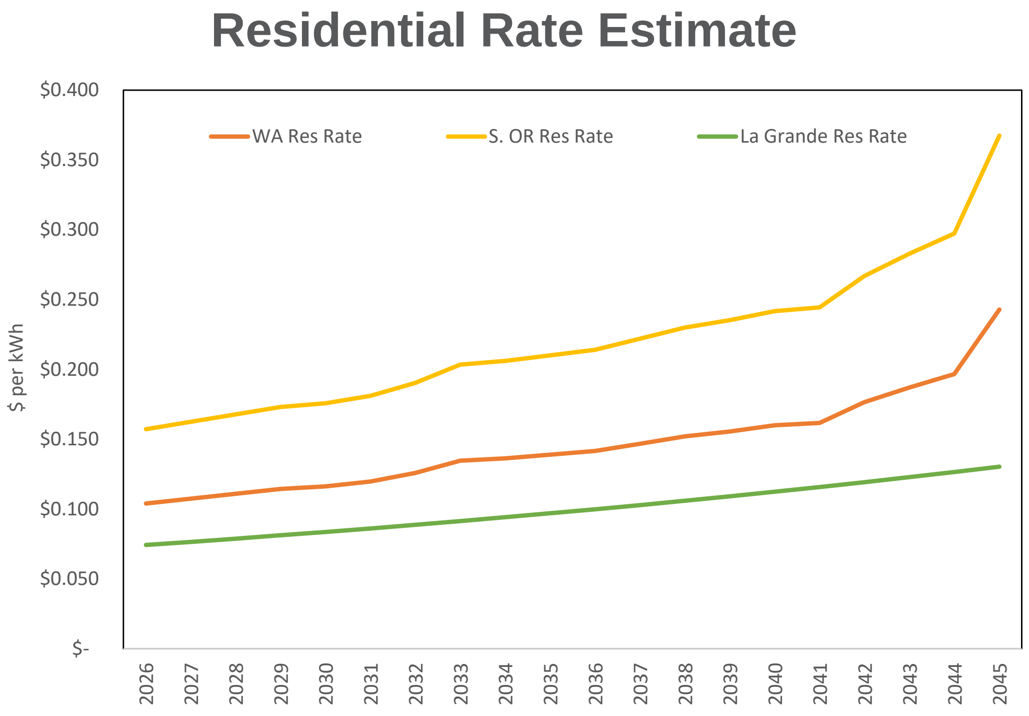


	City of Ashland	Pacific Power	Total Avista Gas Customers S. Oregon
Customers	11,000	83,601	94,601
% of Total Customers	12%	88%	
Current Rates as of June 2024 ($/kWh)			
Res	$ 0.08	$ 0.14	
Com	$ 0.09	$ 0.13	
Large Com	$ 0.09	$ 0.09	
Weighted Average			**Total Estimated Rate**
Res	$ 0.01	$ 0.12	$ 0.13
Com	$ 0.01	$ 0.12	$ 0.13
Large Com	$ 0.01	$ 0.08	$ 0.09

[OR Labeling Insert Large Business.pdf (pacificpower.net)]

Electric Rate forecast





Equipment Costs and Rebates/Credits

Equipment Costs

- Assumes a 3-ton ducted heat pump is needed for space heat (2,000 sq. ft. house)
- Full electrification cost for all appliances is assumed at $13,162 (2024 $)*
  - 3-ton ducted heat pump $5,993
  - Heat pump water heater $3,528
  - Electric Range $2,038
  - Electric Dryer $1,602
- Costs are assumed less incentives (IRA) and have a 5-year payback period in the form of an average monthly payment (annuity) at 3% interest
- Assumes a 20-year lifespan for all equipment (Heat pumps average between 10-15 years on average)

*Electrifying Buildings – December 2022 rmi.org

IRA Rules

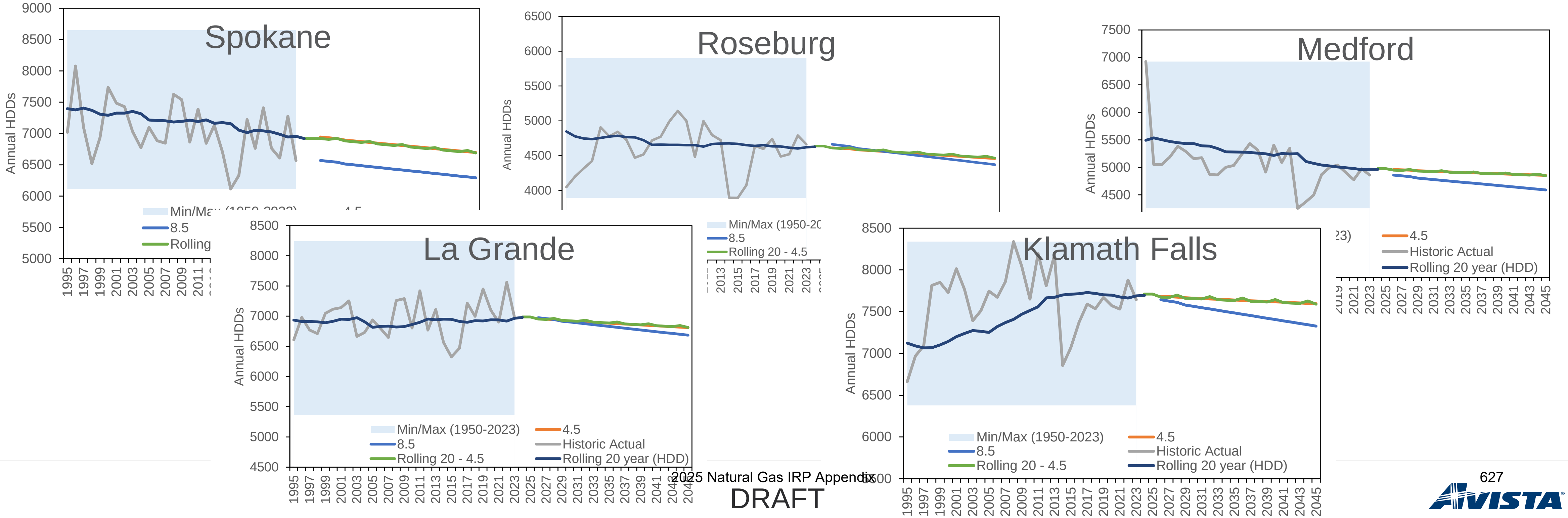
- Depending on income level, rebates for these home efficiency upgrades can be as much as 100% of the costs, up to $14,000

Type of Home Energy Project	Maximum Allowed Rebate Amount Per Household Below 80% Area Median Income (AMI)	Maximum Allowed Rebate Amount Per Household Above 80% Area Median Income (AMI)
Home Efficiency Project with at least 20% predicted energy savings	80% of project costs, up to $4,000*	50% of project costs, up to $2,000 (maximum of $200,000 for a multifamily building)
Home Efficiency Project with at least 35% predicted energy savings	80% of project costs, up to $8,000*	50% of project costs, up to $4,000 (maximum of $400,000 for a multifamily building)
Home Electrification Project Qualified Technologies (only households with an income below 150% AMI are eligible)	100% of project costs up to technology cost maximums**; up to $14,000	50% of project costs, up to technology cost maximums*; up to $14,000 (households with incomes above 150% AMI are not eligible)

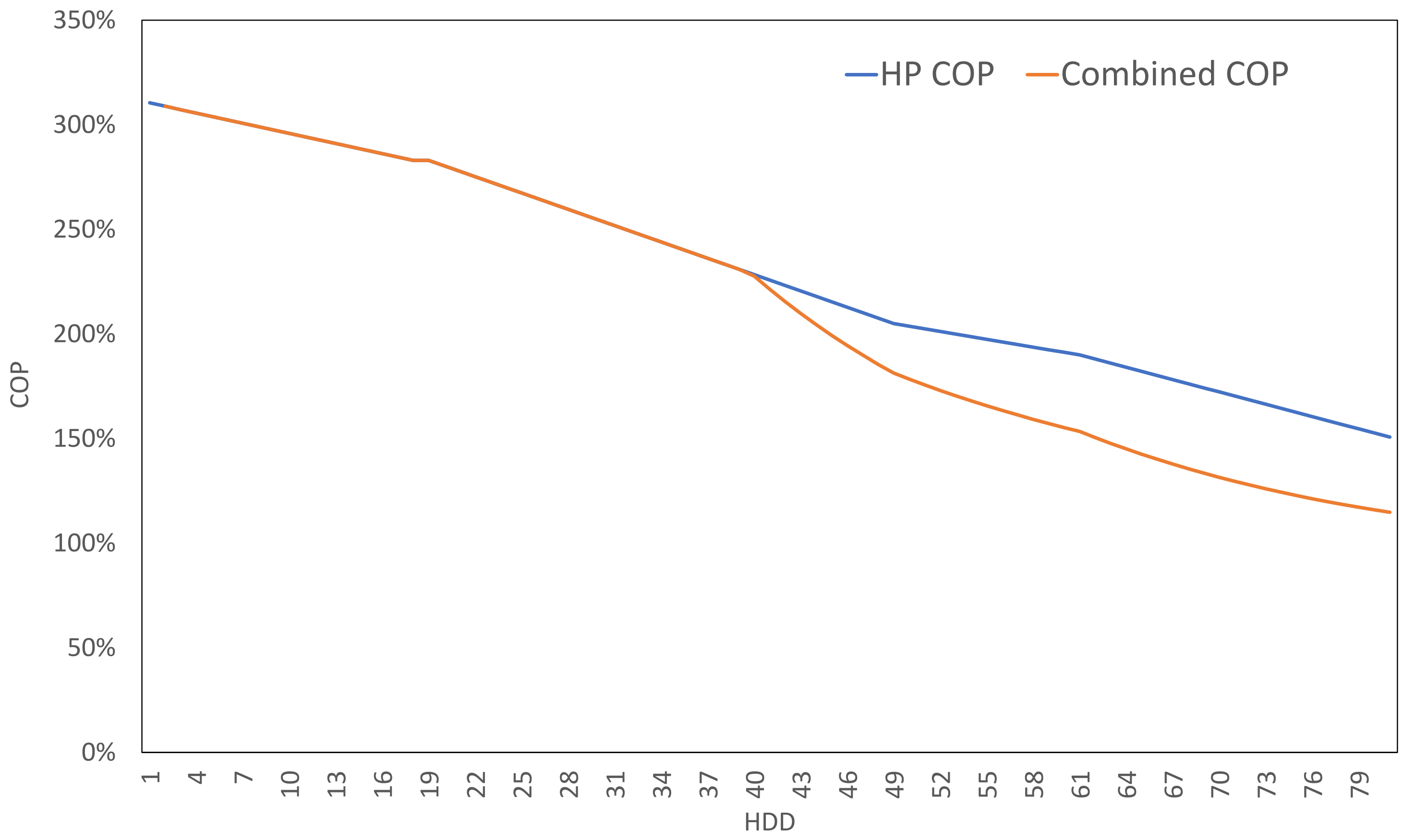
Input

Weather

- RCP 4.5 weather is used at a daily level to estimate energy needs by planning region.
- This is then rolled up to an average monthly level by end use

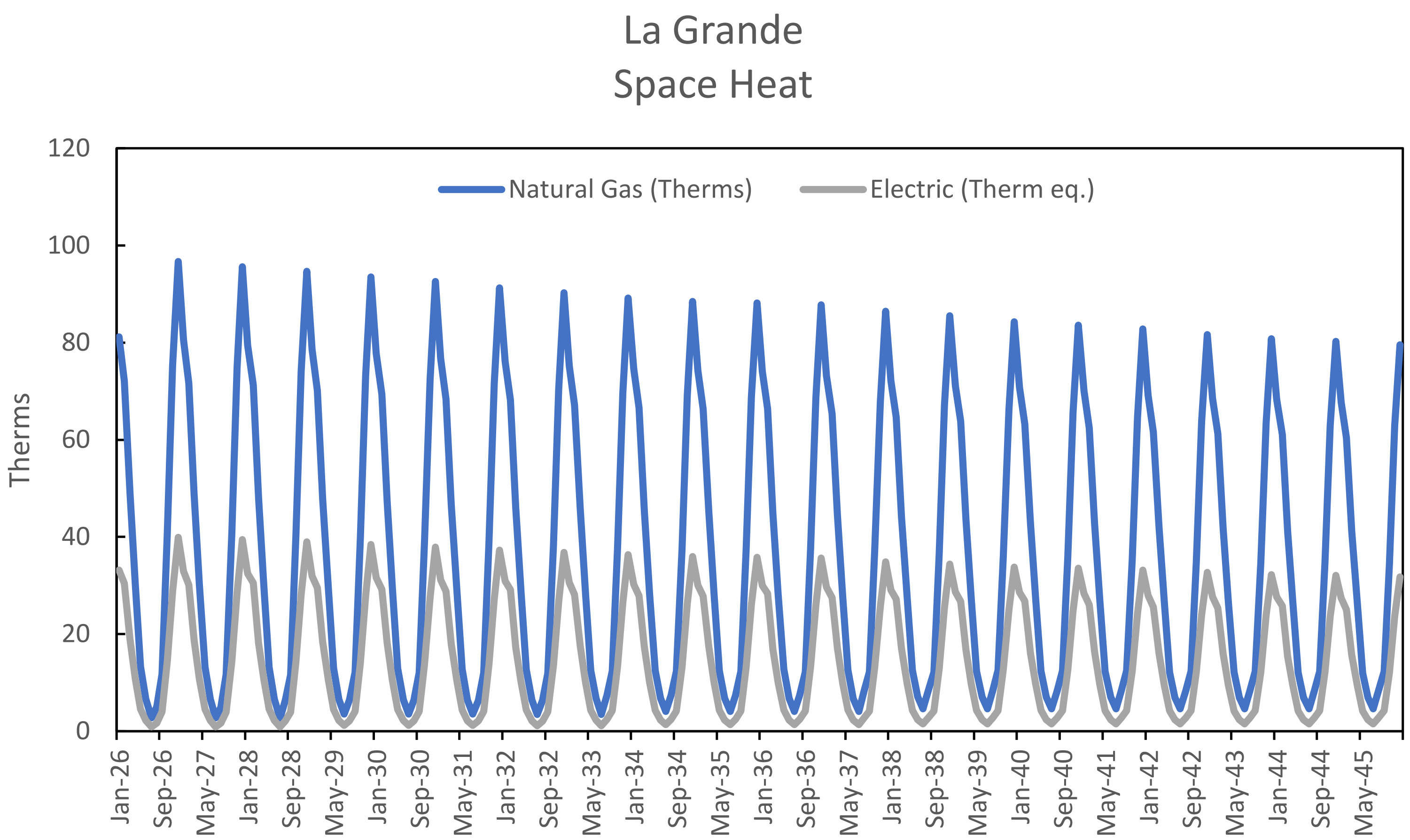


COP including auxiliary

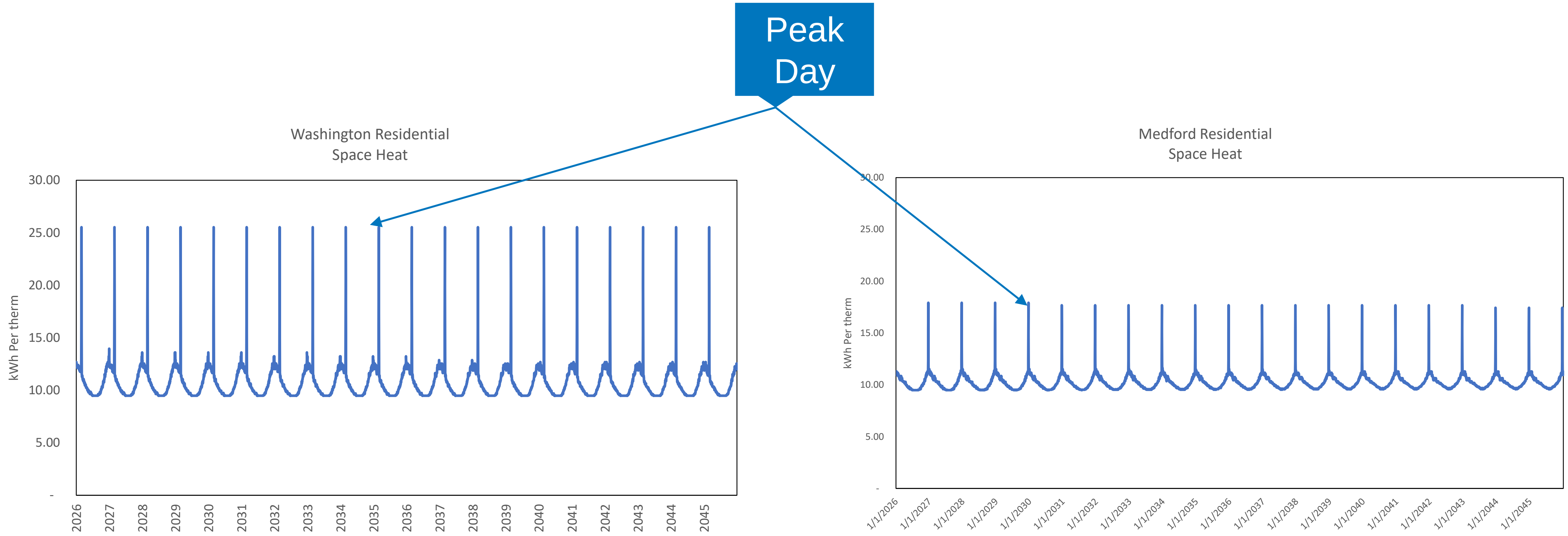


Assumes 100% efficient electric furnace as auxiliary backup heat

Use per customer



Daily Conversion to kWh



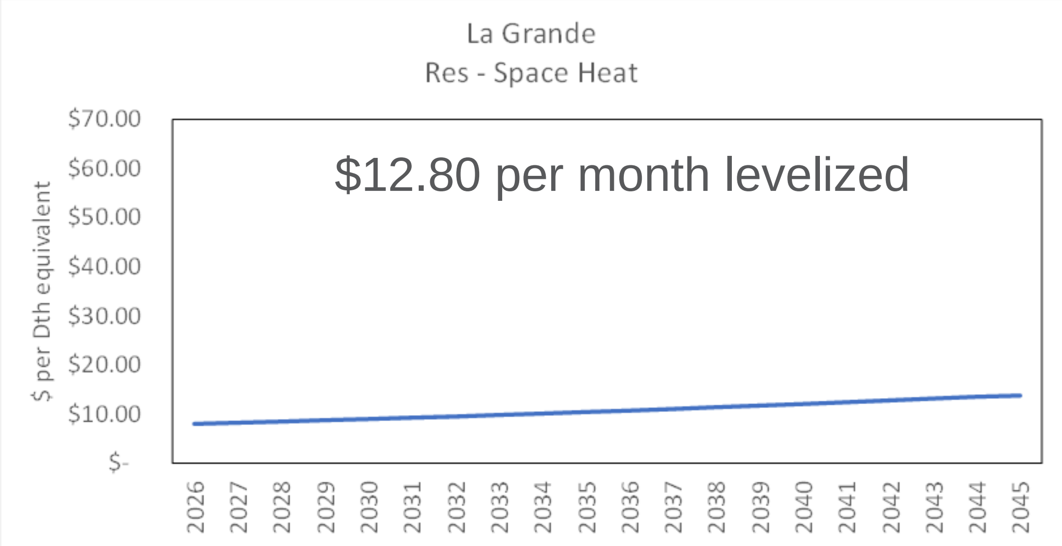
*29.3 kWh per therm of energy

Electrification Cost Estimates

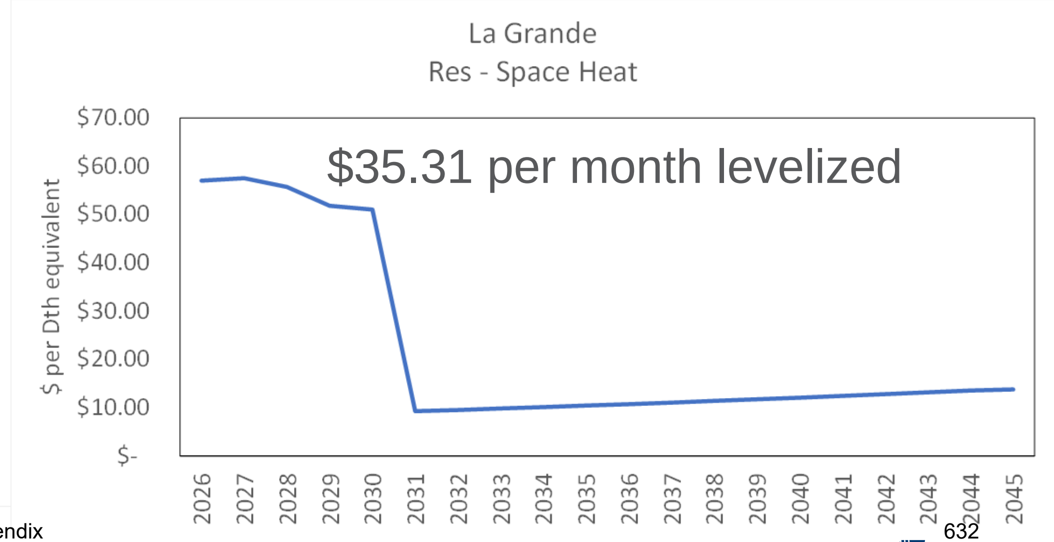
Levelized Cost

- Calculated at 20 year increments
- Includes inflation adjustment for each year
- Current cost of capital is included in levelized costs
    - (6.71% OR, 6.51% WA)
- This is done each year from 2026-2045 to estimate costs for space heating with heat pumps, heat pump water heater, and other (range, dryer)

Example with No Equipment Costs:
Levelized beginning in 2026

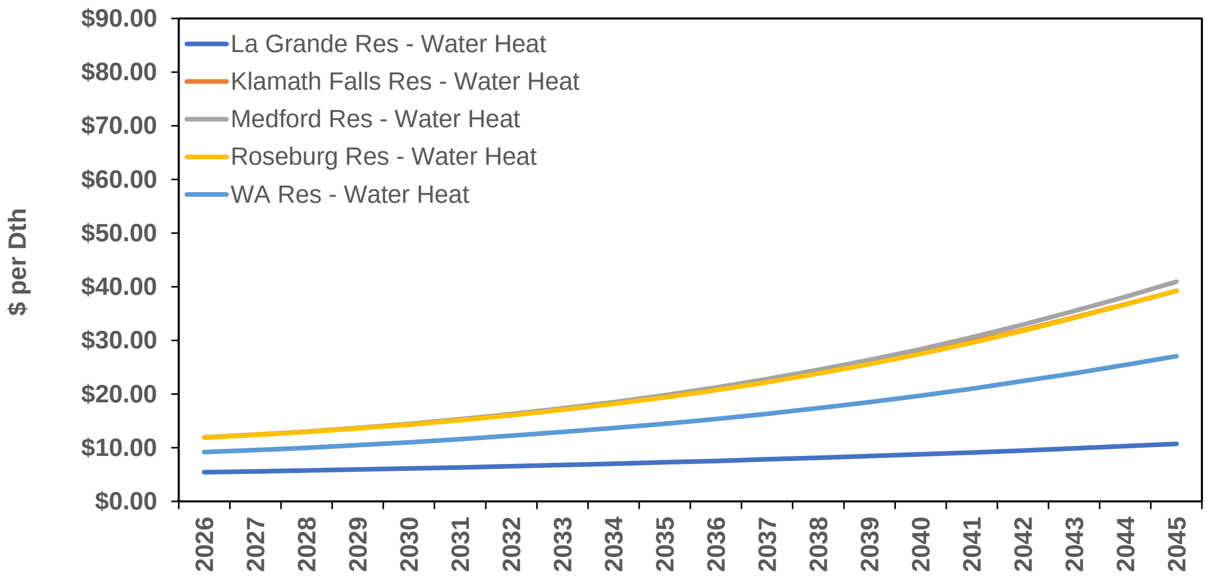


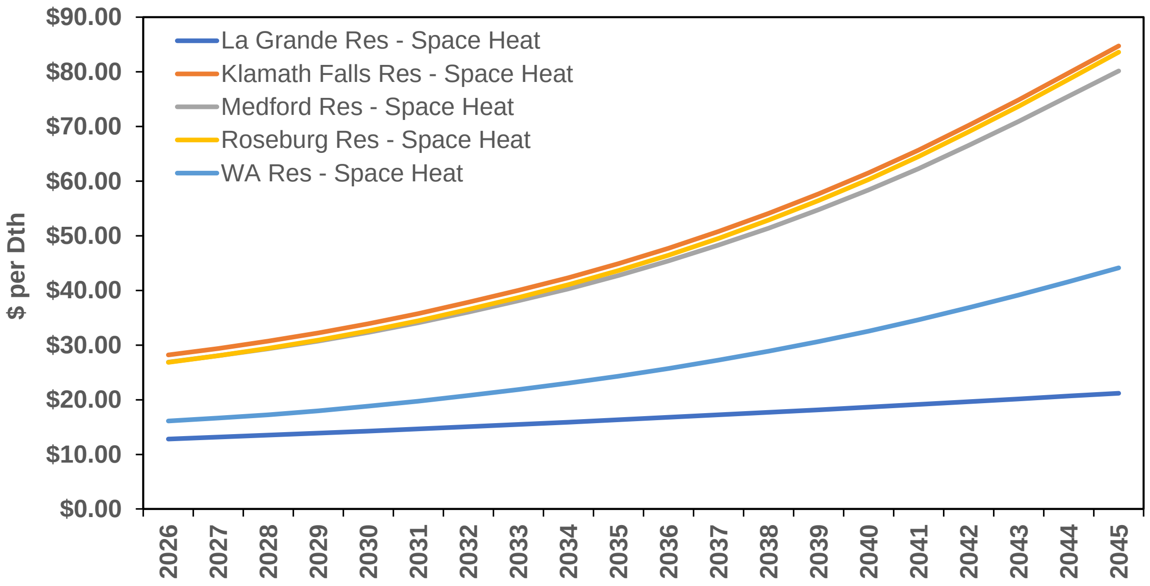
Example with equipment costs:
20 year levelized cost beginning in 2026



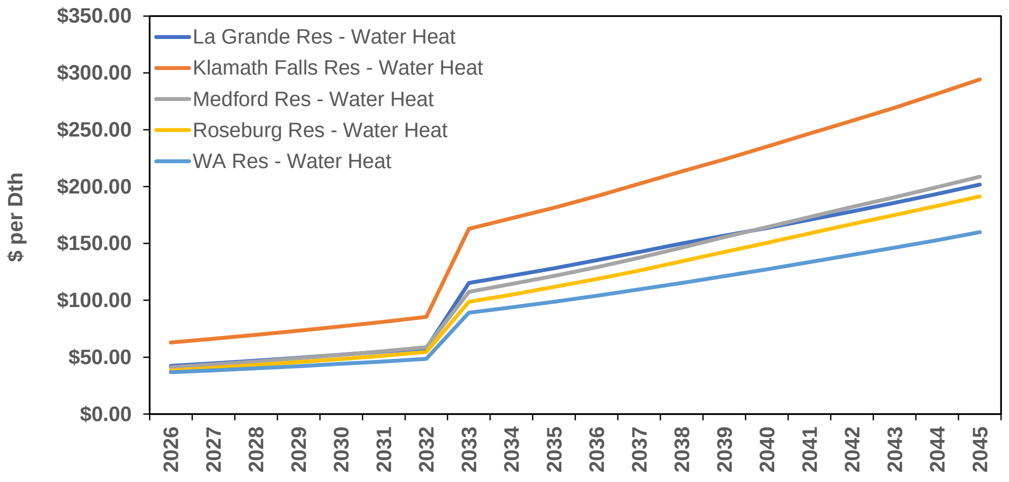
Cost without equipment costs

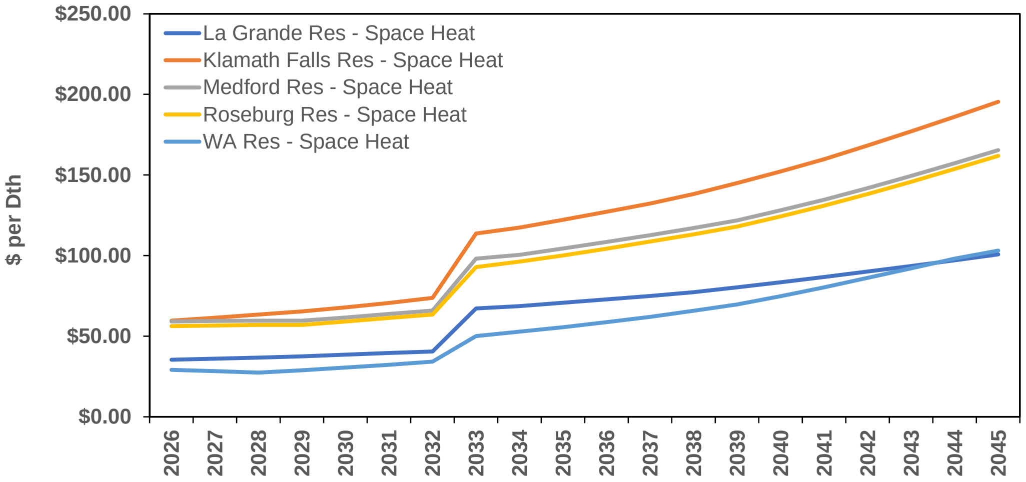
- Per customer, per month, per end use, without appliance cost

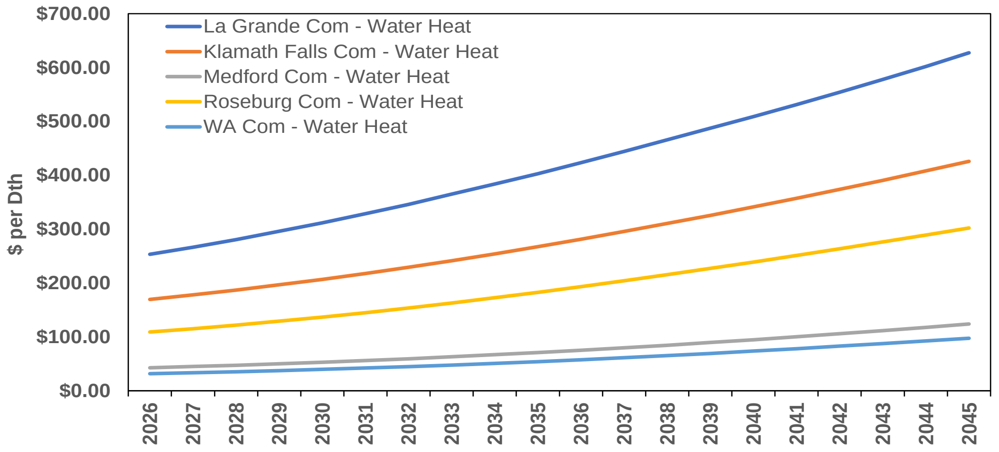


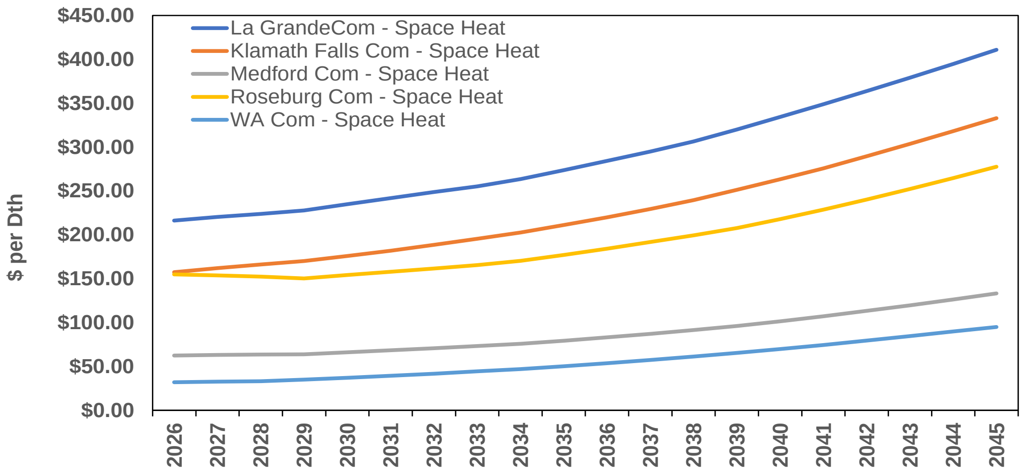


Cost with equipment costs









Questions and/or Feedback?

TAC 9 – 2025 Avista Gas IRP

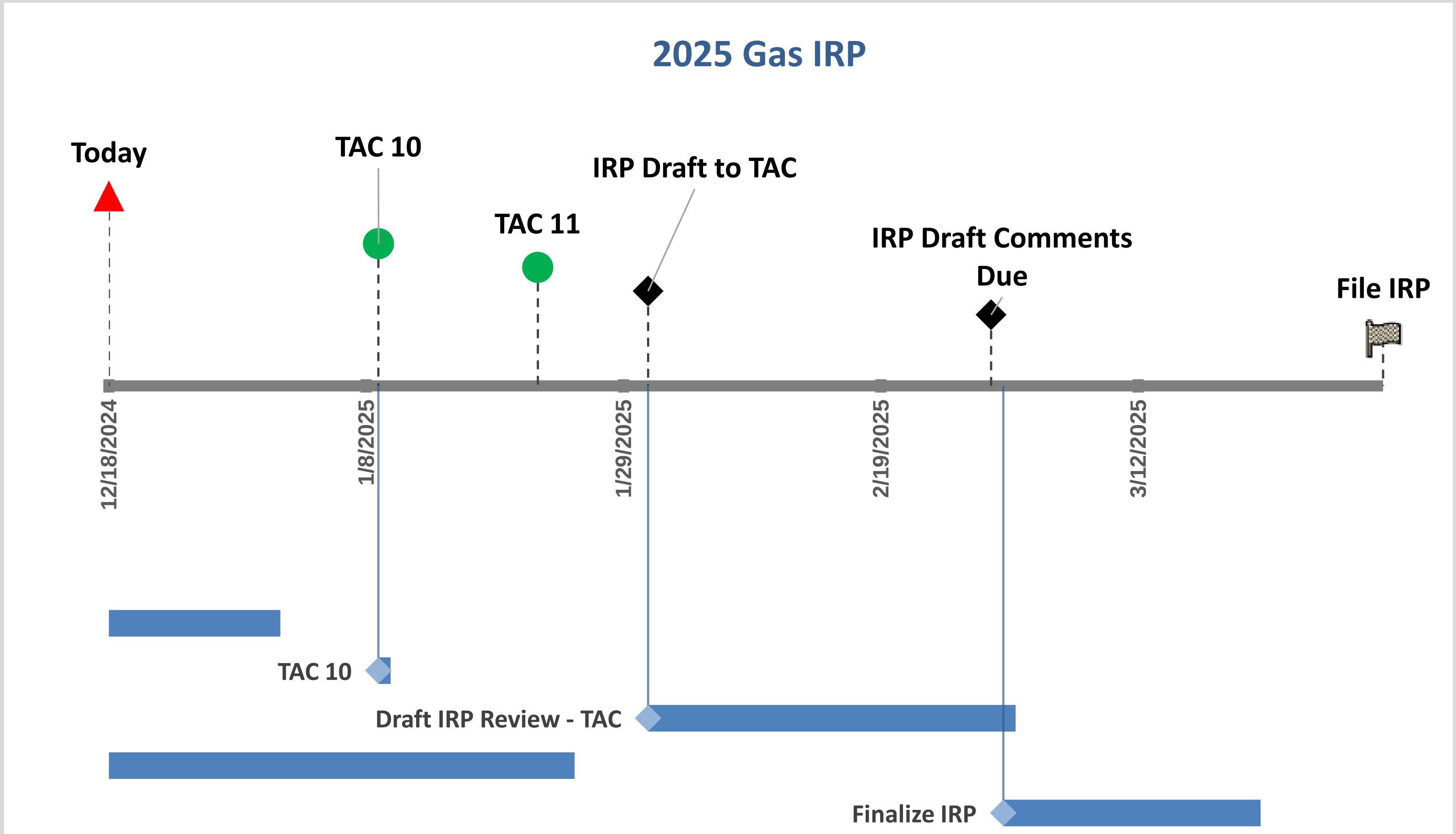
December 18, 2024

Agenda

- Peak Day
- NEI
- Alternative Fuel Prices
- Alternative Fuels Technical Potential Volumes (ICF)
- Daily Modeled Volumes
- All Resource Options

2025 Avista IRP Timeline

Date	Milestone
12/18/2024	Today
11/19/2024	TAC 9
1/9/2025	TAC 10
1/22/2025	TAC 11
1/31/2025	IRP Draft to TAC
2/28/2025	IRP Draft Comments Due
4/1/2025	File IRP

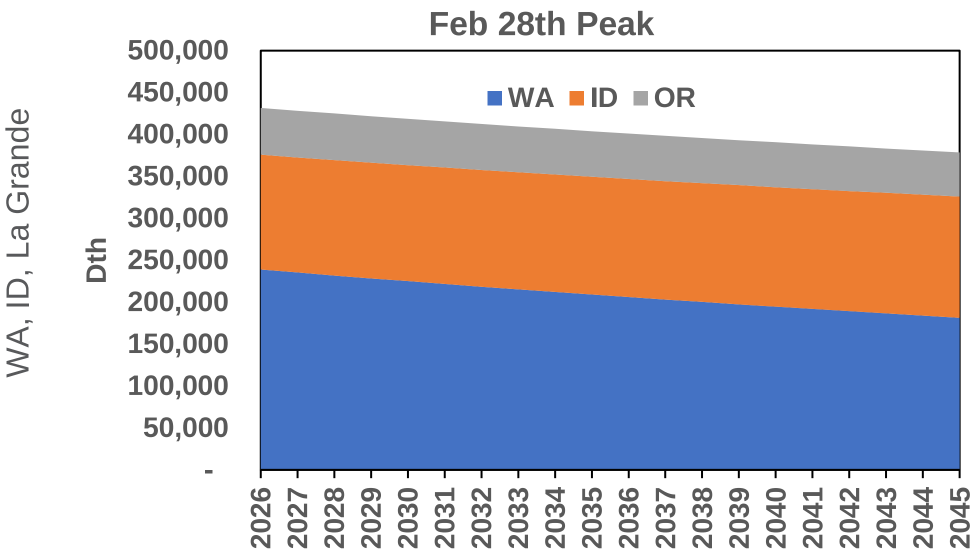


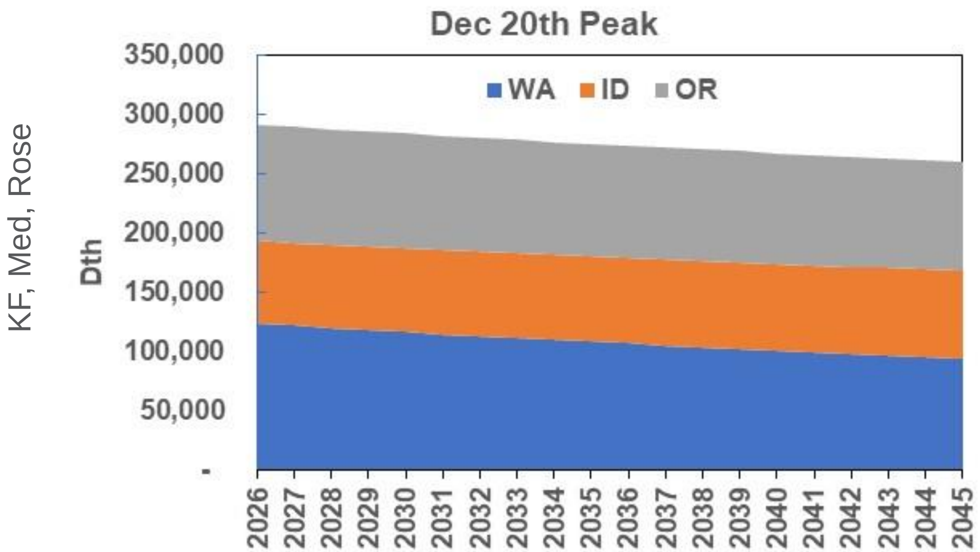
Peak Day

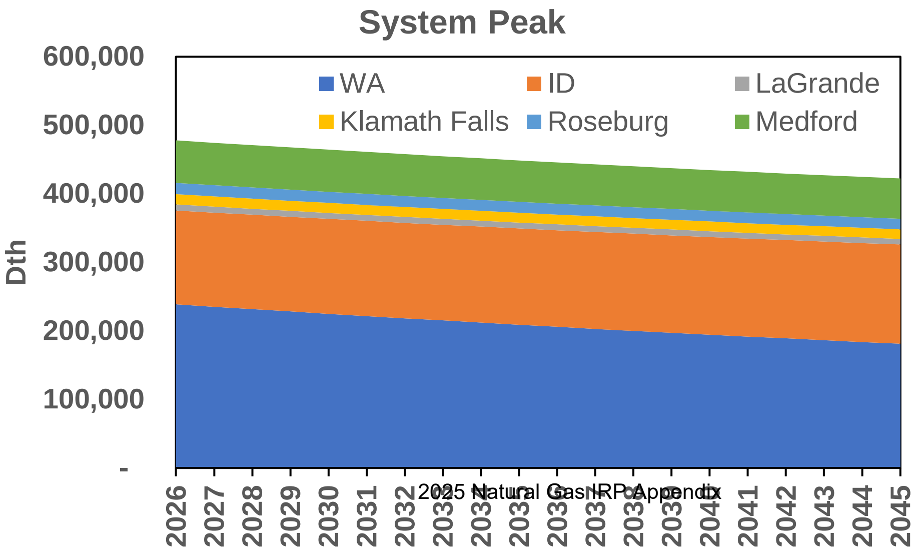
Peak Day Calculation

- Used the 2026-2045 average growth rate from Load Forecast (AEG) to adjust peak day with carbon intensity (efficiency of use per customer)
- Expected customer counts from Load Forecast (AEG)
- Use 75th percentile of historical winters HDD (2004-2023) for area nonpeak days on Dec 20th and Feb 28th by area
- HDD peak days by area:
  - La Grande 73 HDD
  - Klamath Fall 71 HDD
  - Medford 60 HDD
  - Roseburg 53 HDD
  - Spokane 79 HDD

Peak Day Calculation







NEI

NEI* - example

Inputs into IMPLAN
for capital requirement:

1. State facility would reside: Oregon
2. LFG CapEX - $16.4M
3. Pipeline Cost - $2.0M

Economic Indicators by Impact

Impact	Employment	Labor Income	Value Added	Output
1 - Direct	107.00	$4,186,318.69	$5,885,714.97	$18,488,622.00
2 - Indirect	26.91	$2,125,567.06	$3,456,331.04	$6,831,637.92
3 - Induced	29.02	$1,776,491.76	$3,170,463.10	$5,297,434.49
Totals	162.93	$8,088,377.52	$12,512,509.12	$30,617,694.40

Direct	Initial effects to a local industry or industries due to the activity or policy being analyzed
Indirect	Effects stemming from business to business purchases in the supply chain taking place in the region
Induced	Effects in the region stemming from household spending of income, after removal of taxes, savings, and commuters

Taxes

Impact	Sub County General	Sub County Special Districts	County	State	Federal	Total
1 - Direct	$ 78,676	$ 124,057	$ 48,363	$ 336,474	$ 900,835	$ 1,488,405
2 - Indirect	$ 52,120	$ 82,183	$ 32,266	$ 187,818	$ 504,647	$ 859,034
3 - Induced	$ 42,267	$ 66,647	$ 26,681	$ 160,234	$ 436,411	$ 732,240
Total Impact	$ 173,062	$ 272,886	$ 107,310	$ 684,526	$ 1,841,894	$ 3,079,679

*Also Including Safety Incidents and Carbon Monoxide Poisoning

Alternative Fuel Prices

Alternative Fuel Prices Inputs

Model Restriction

- Selection for any physical products will not be available in the model until 2030

- Average prices above $75 per Dth will not be modeled

Capital Costs

- Equipment
- Pipeline Costs
- Installation and Owners Costs

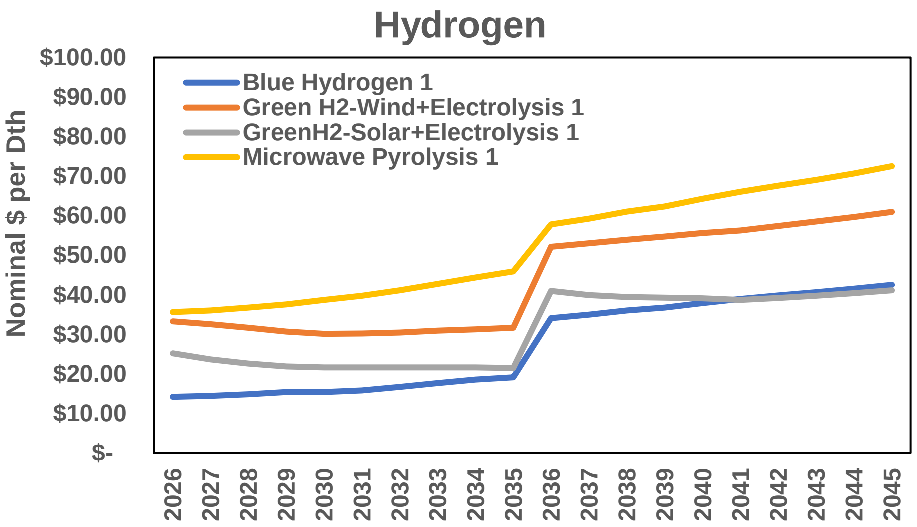
O&M – Fixed and Variable

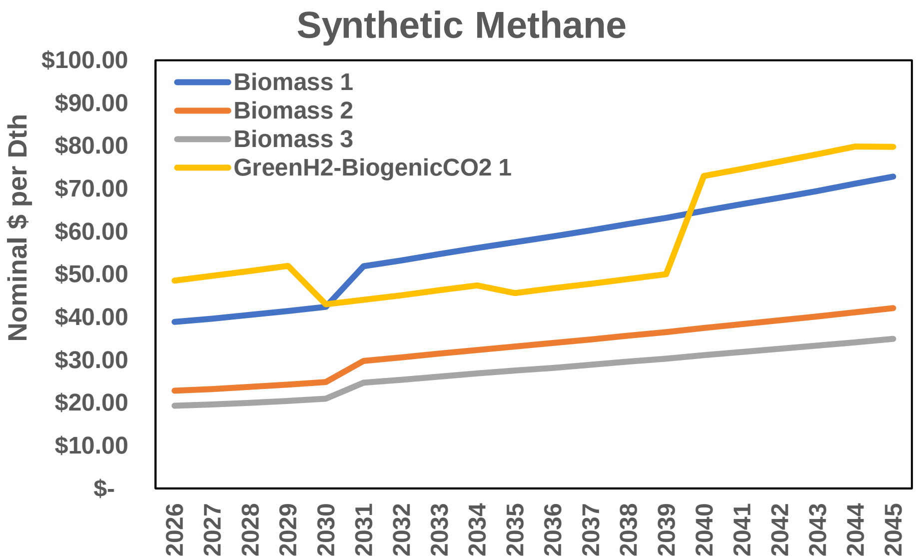
- Electricity rates
- Gas rates

Prices

- Expected prices are broken down between northwest and national technical potential (ICF)
  - All prices consider Inflation Reduction Act (IRA) incentives where applicable
  - These prices assume a first mover access to alternative fuels
  - Prices are averaged between two distinct groupings Northwest and National to reduce model inputs
  - Hydrogen (H2) & Synthetic Methane (SM) prices will be treated as a purchase gas agreement where Avista would sign a term contract, each year, with the producer for these prices through the forecast.
  - Renewable Natural Gas assumes a proxy ownership with costs levelized over 20 years
  - Renewable Thermal Credit (RTC) is a production cost plus, where prices cover all costs
    - These exclude Investment Tax Credit (ITC) or Production Tax Credit (PTC) and consider a higher capital rate
  - Prices are nominal and levelized for each reference year

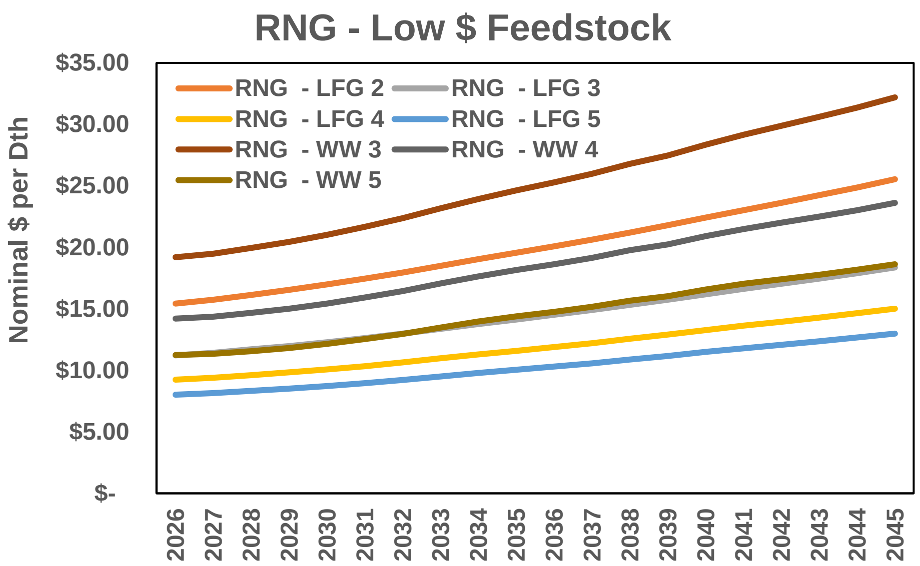
Hydrogen (H2) and Synthetic Methane (SM)

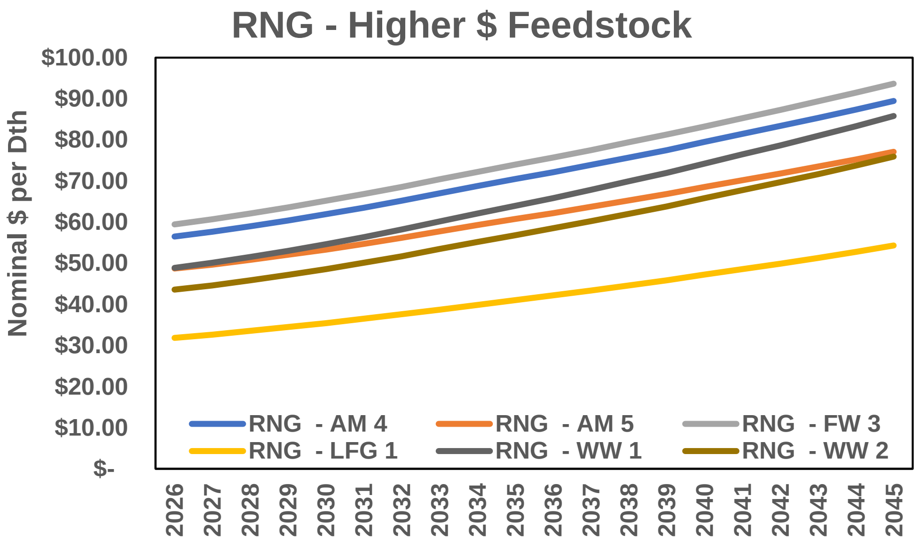




ICF levelized the Section 45V tax credit over 20 years. Since hydrogen projects must be under construction by the end of 2032 to qualify for 45V credits, the 45V tax credits were modeled until 2035 as a conservative estimate assuming every new hydrogen facility beginning construction after 2032 may not 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.

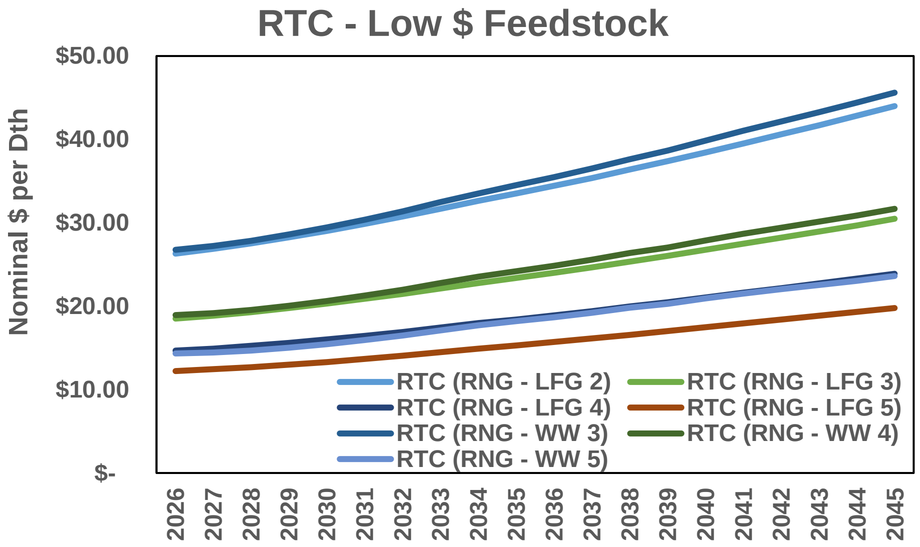
Renewable Natural Gas (RNG)

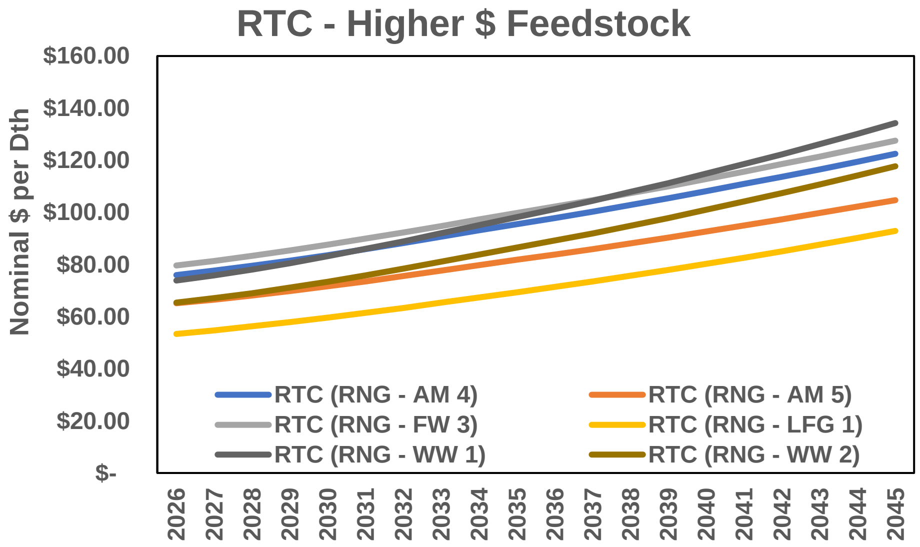




*Blend of national and NW estimated costs for RNG facilities
**Includes ITC/PTC until 2030

Renewable Thermal Certificate (RTC)

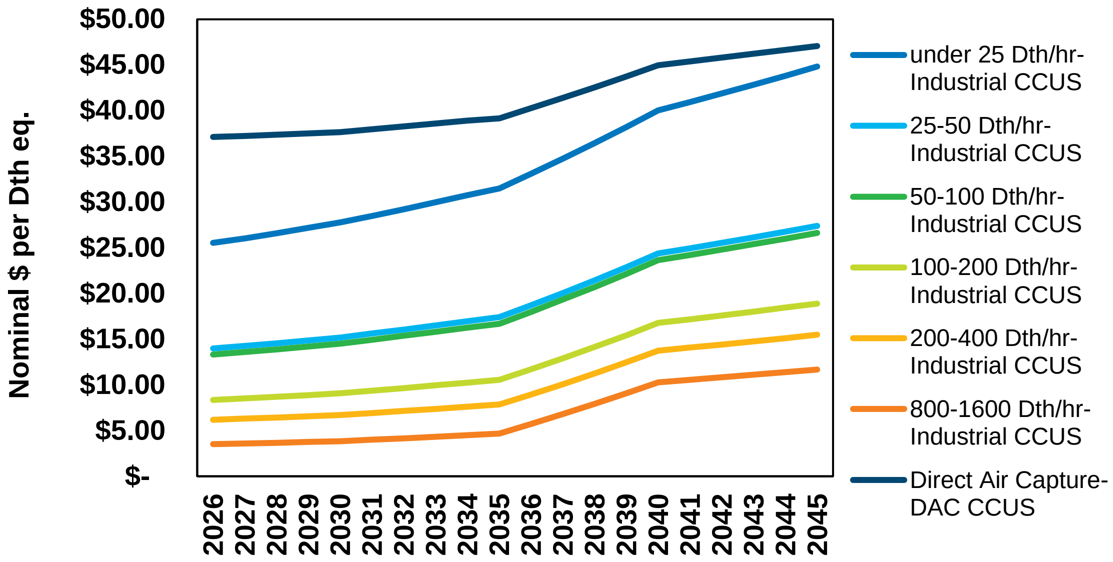


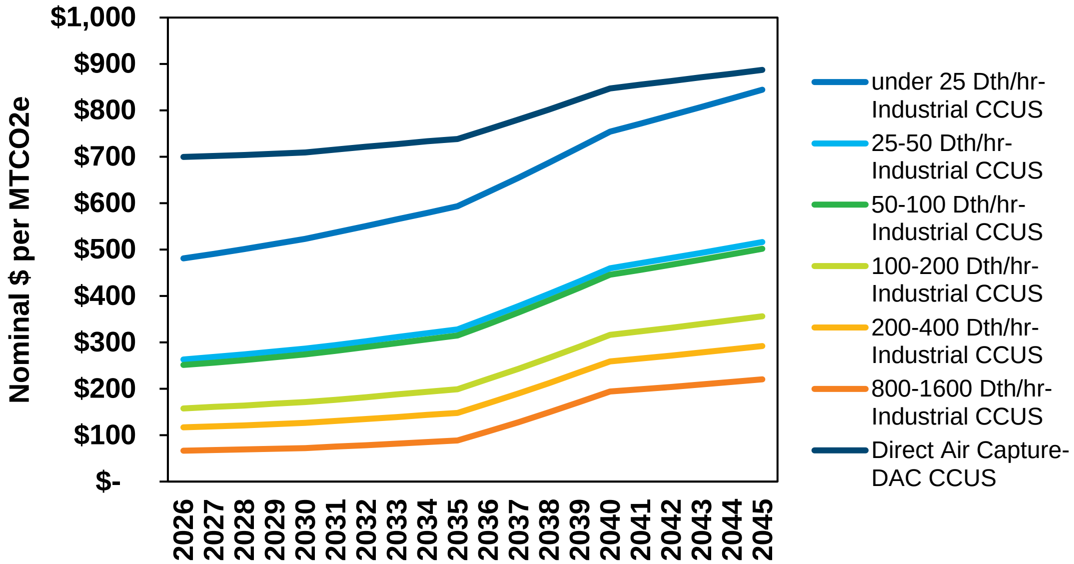


1-No ITC, considers price from producer to create RTC and cover costs (production prices)

2-Not tied to market actual prices

Carbon Capture, Utilization and Storage (CCUS)





*Avista specific high-volume customers

**Includes ITC/PTC to 2030

Alternative Fuels Technical Potential Volumes (ICF)

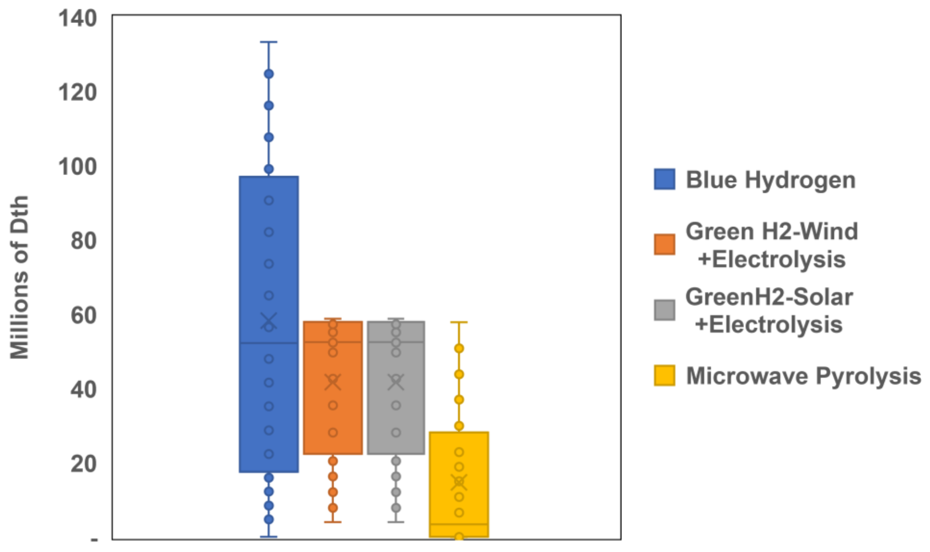
Volumes

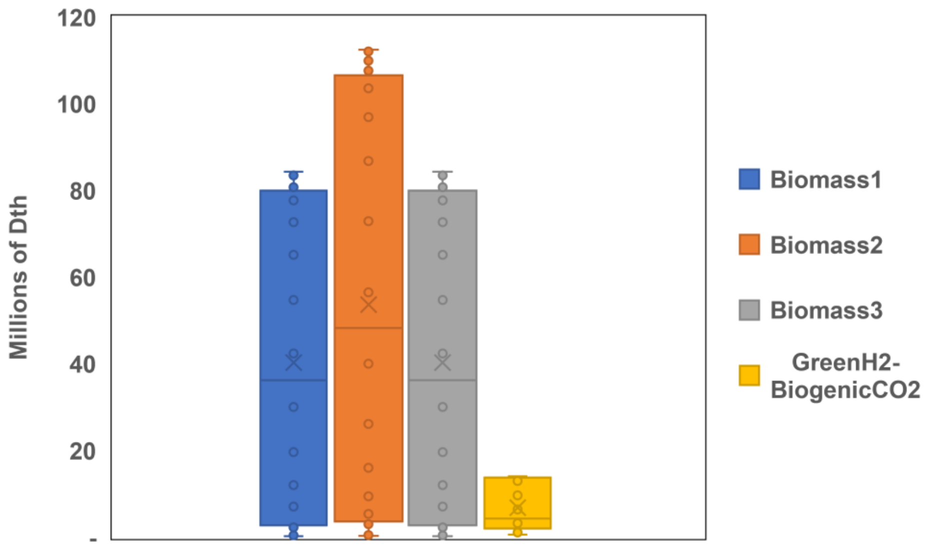
- Expected volumes are broken down between Northwest and national technical potential
  - These volumes assume a first mover access to alternative fuels
  - Weighted by US population for states where some form of climate policy is in place or demand is expected
  - Modeled potential volumes are from Avista's weighted share in only the Northwest for RNG, H2, SM
  - Broken out by 2023 number of meters between LDCs in Oregon and Washington

Company	2023 # of Meters	Share
AVA	379,223	15.831%
CNG	316,929	13.231%
NWN	799,250	33.366%
PSE	900,000	37.572%
Total NW	2,395,402	100.000%

*Renewable Energy Technical Potential - The renewable energy technical potential of a technology is its achievable energy generation given system performance, topographic, environmental, and land-use constraints.

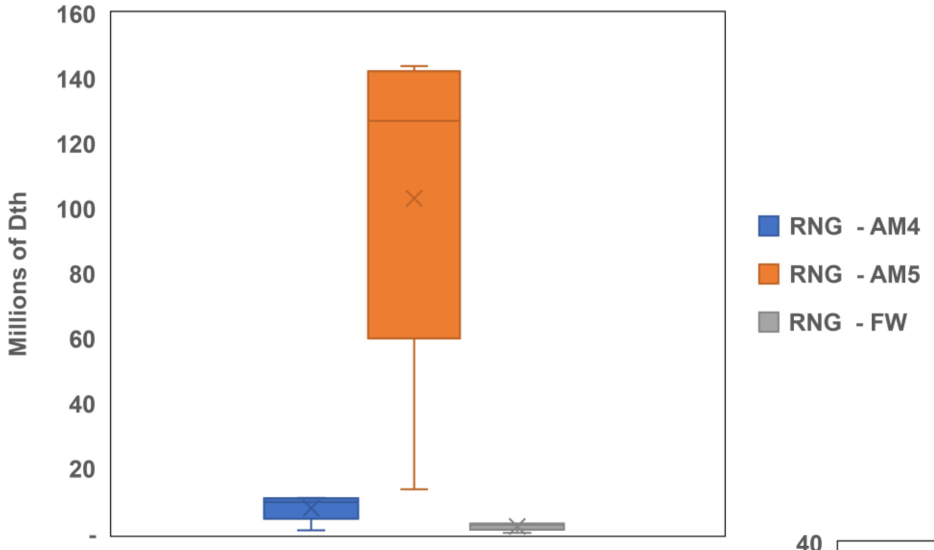
H2 and SM – Avista's share
Technical Potential Volumes (2026-2045)

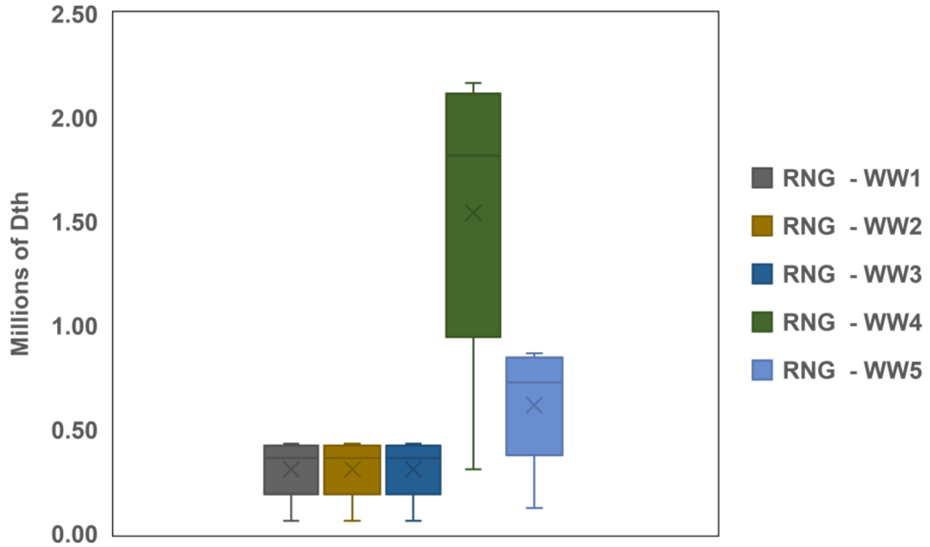


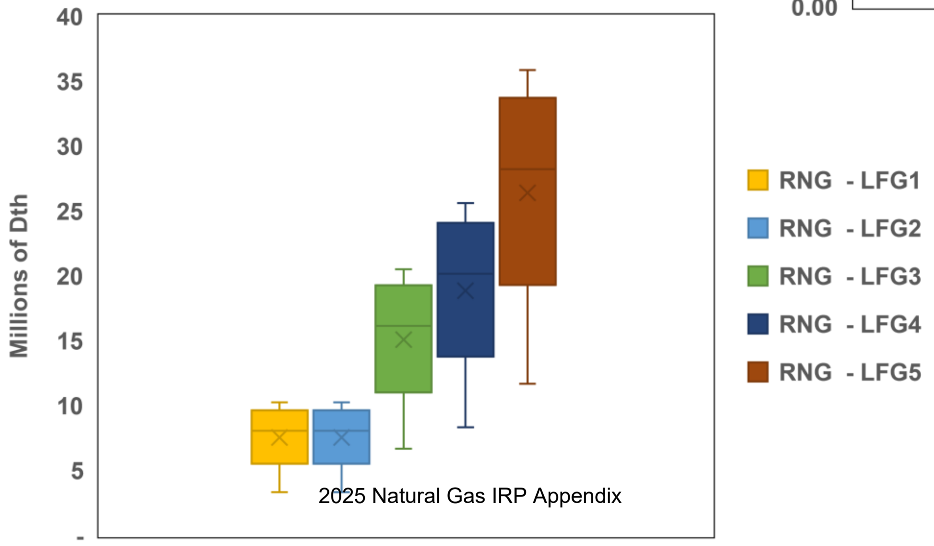


*H2 will be limited by volume to 20%
**No volumes will be available until 2030

RNG – Avista's Share
Technical Potential Volumes (2026-2045)

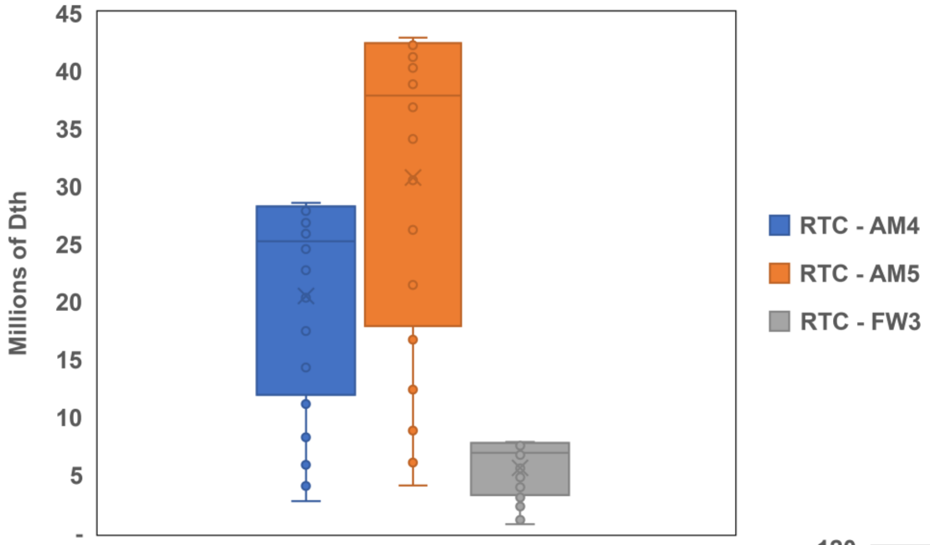


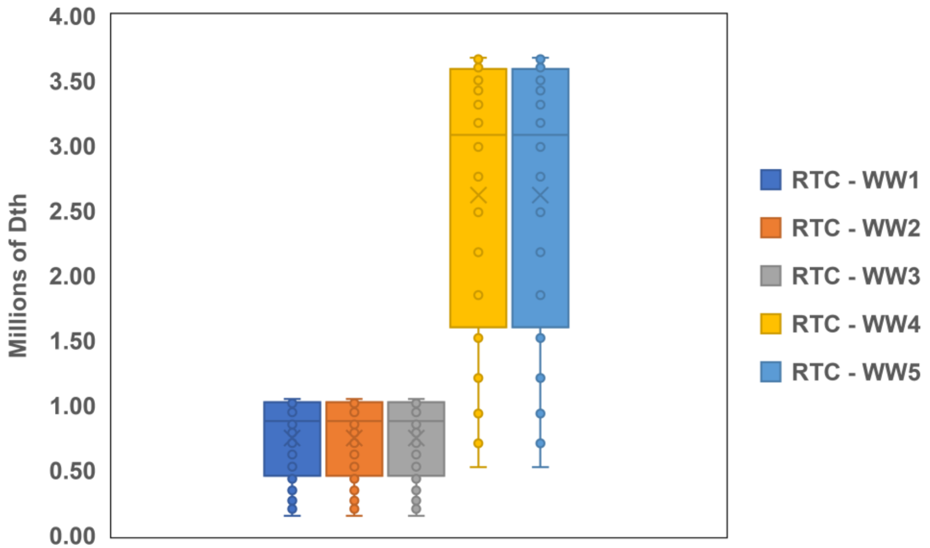


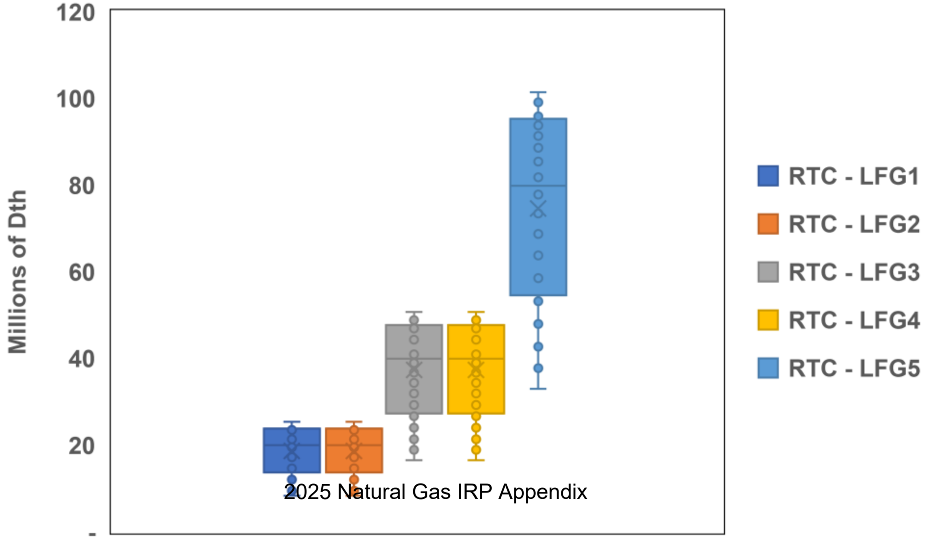


*Quantities not available until 2030

RTC* – Avista's Share
Technical Potential Volumes (2026-2045)

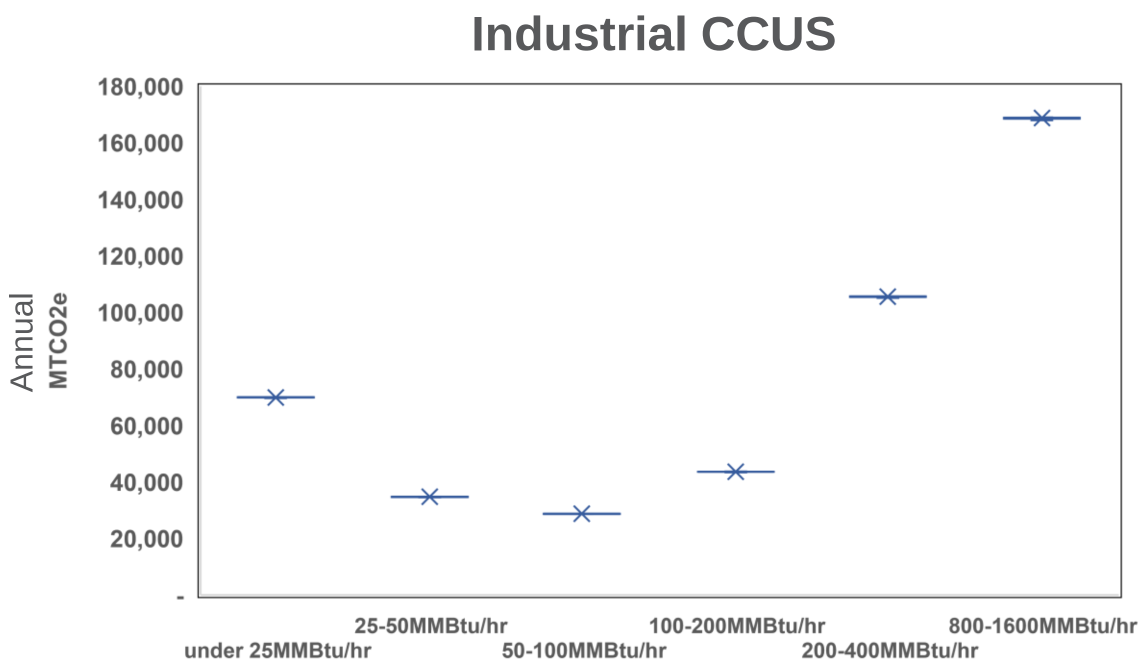


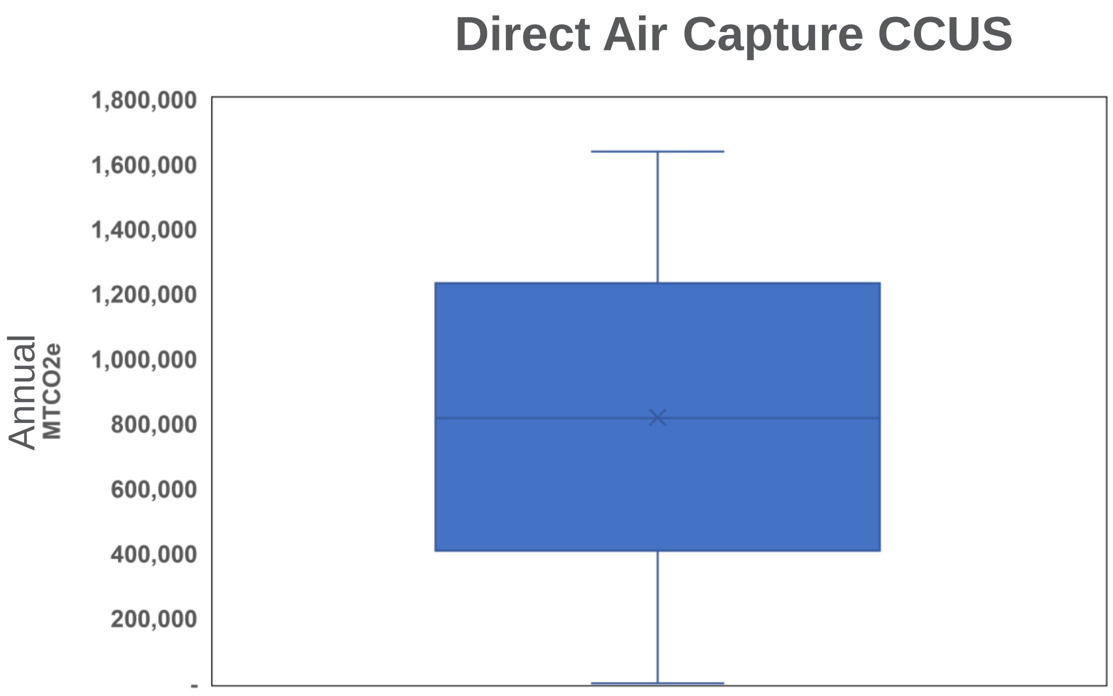




*Quantities are available to the model in 2026

CCUS

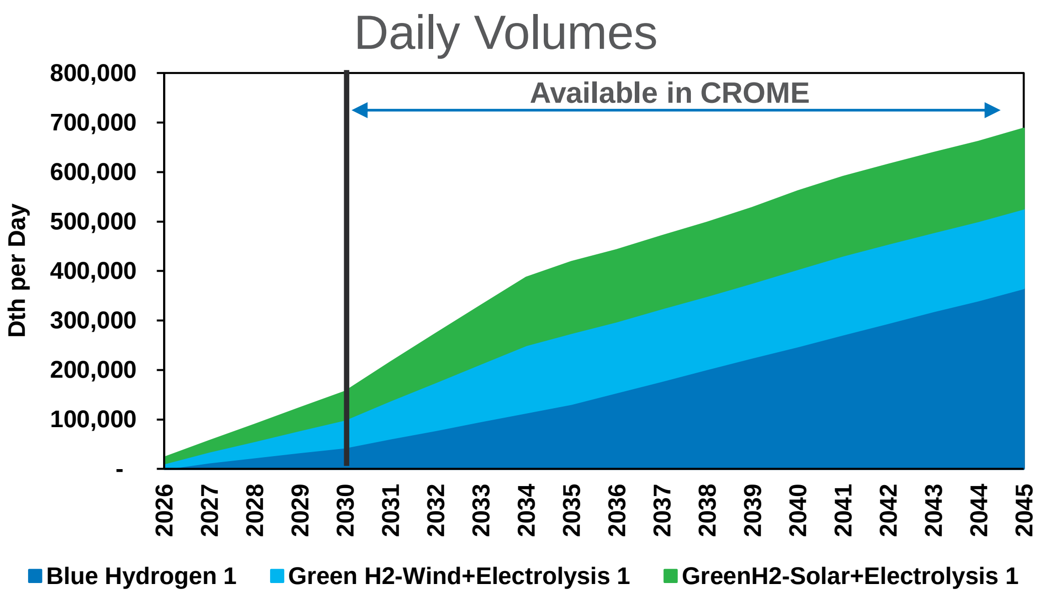


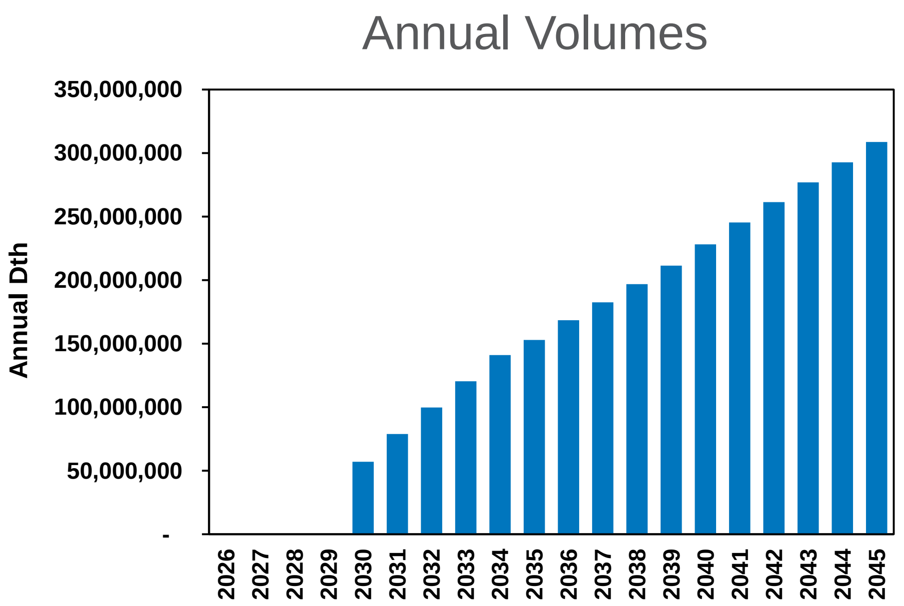


*Years 2025-2045
**No Volumes will be available until 2030

Daily Modeled Volumes

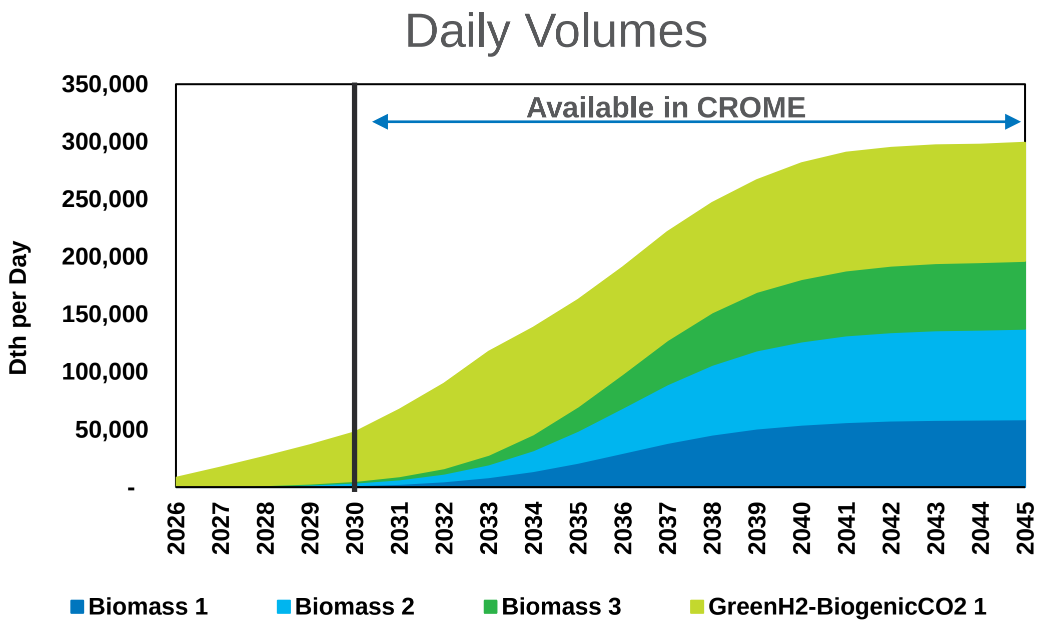
H2 – Modeled Volumes

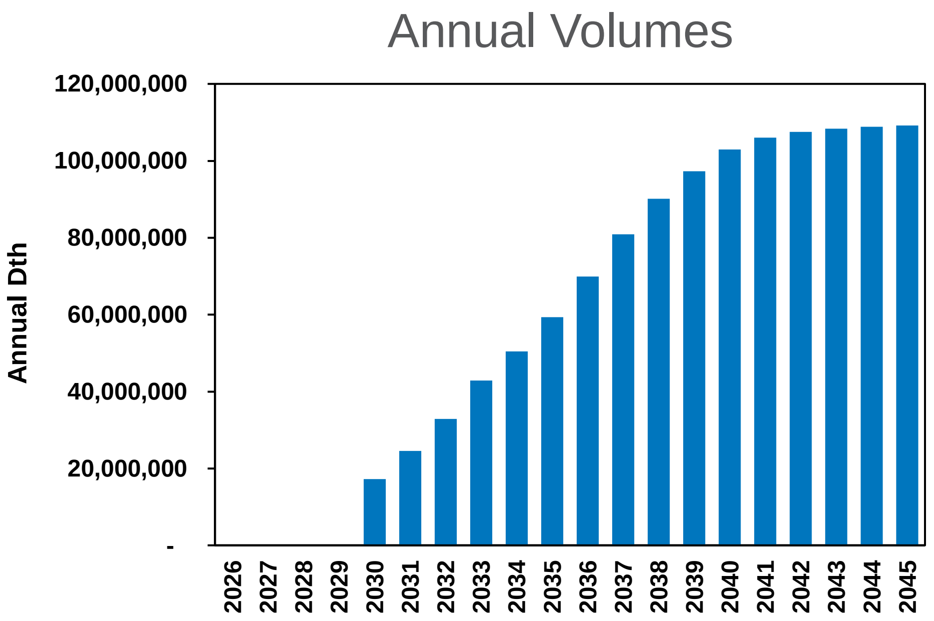




*H2 will be limited by volume to 20% regardless of availability
**No volumes will be available until 2030

SM – Modeled Volumes

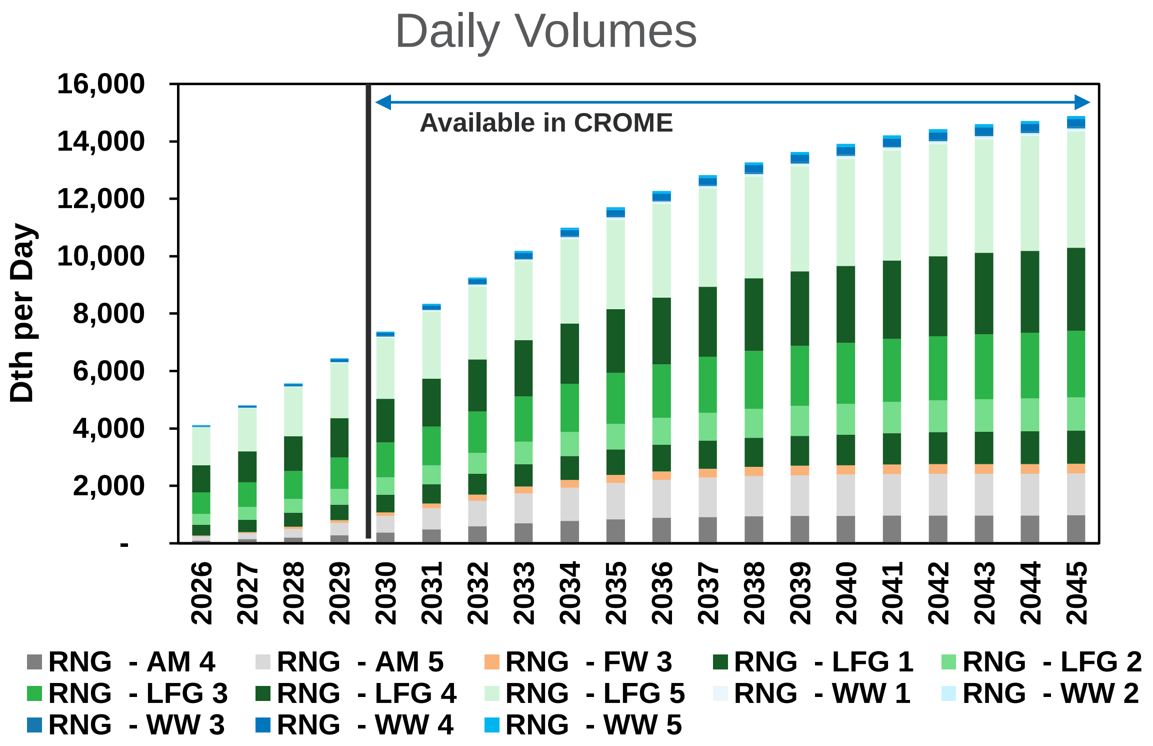


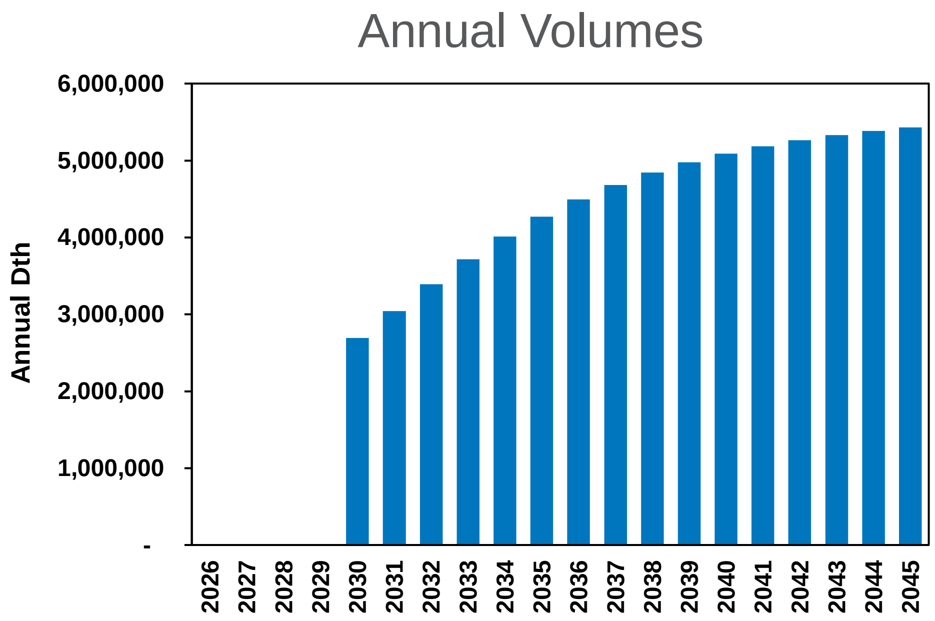


*SM is limited to NW Technical Potential availability & Avista share based on # of LDC meters

**No volumes will be available until 2030

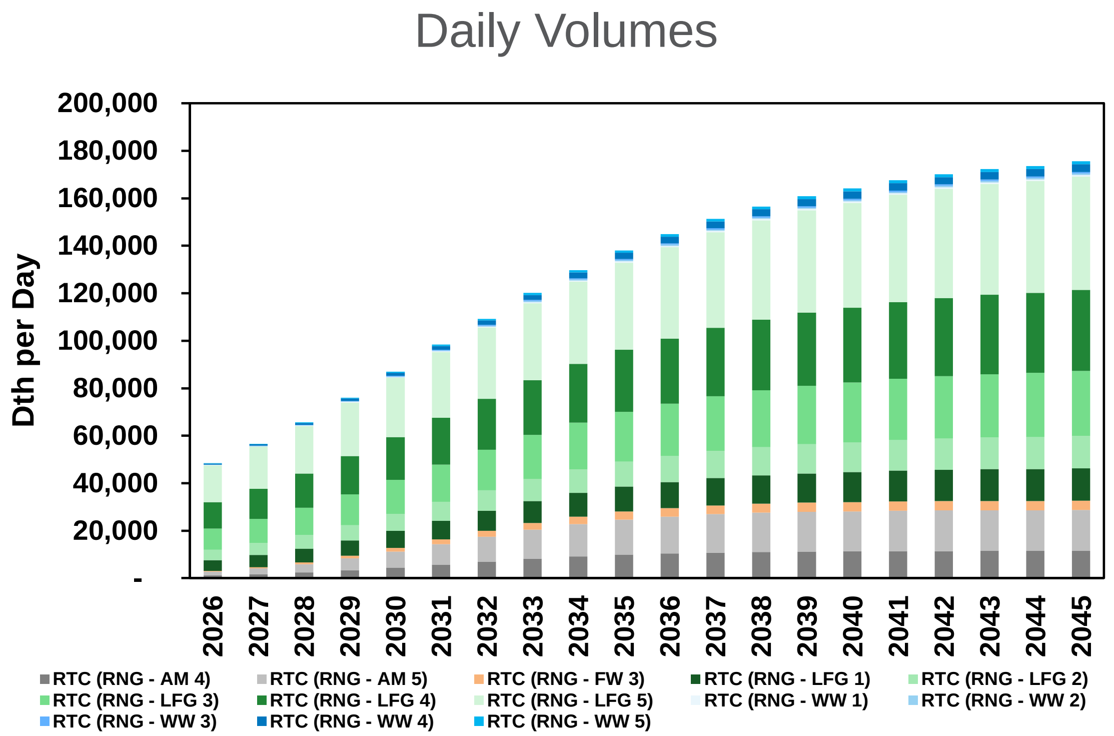
RNG – Modeled Volumes

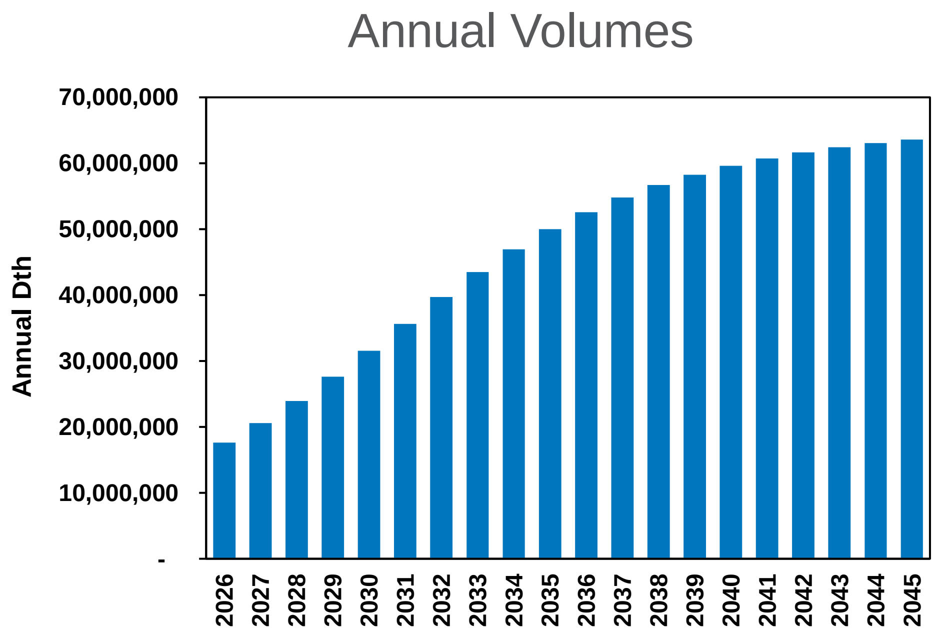




*Quantities not available until 2030
**RNG volumes are limited to NW technical potential availability to allocate 1.5MM Dth between RNG type
***Removal of high priced RNG prior to modeling (AM1-3, FW1-2)

RTC – Modeled Volumes

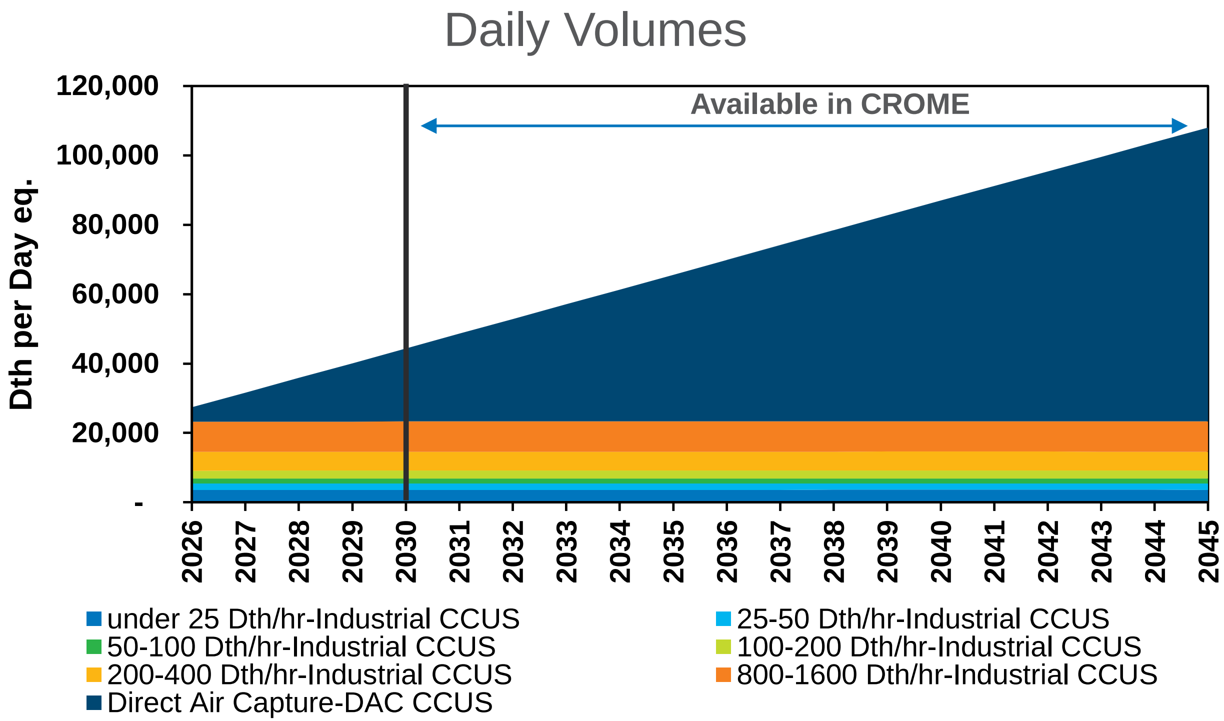


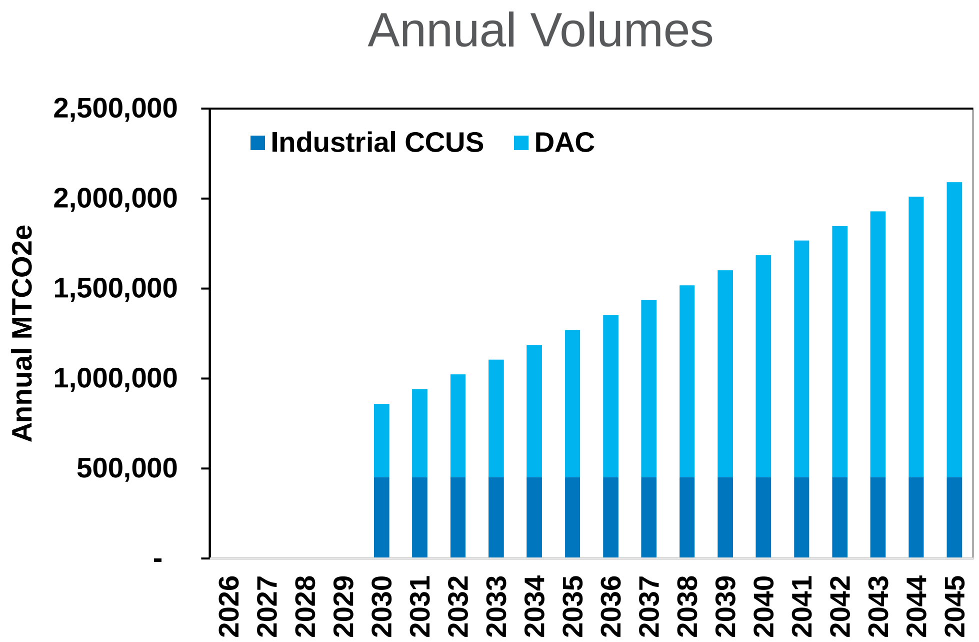


*Quantities are available to the model in 2026
**RTCs are limited to National availability & Avista share and allocated by RTC type with 2024 Avista RFP volumes
***Removal of high priced RTCs prior to modeling (AM1-3, FW1-2)

AVISTA

CCUS



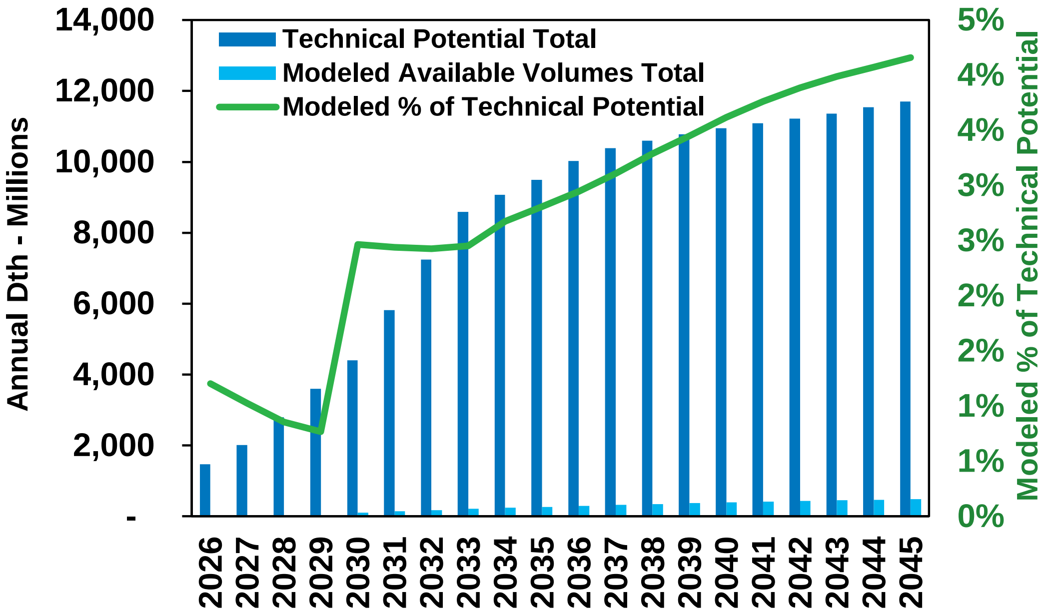


*No Volumes will be available until 2030

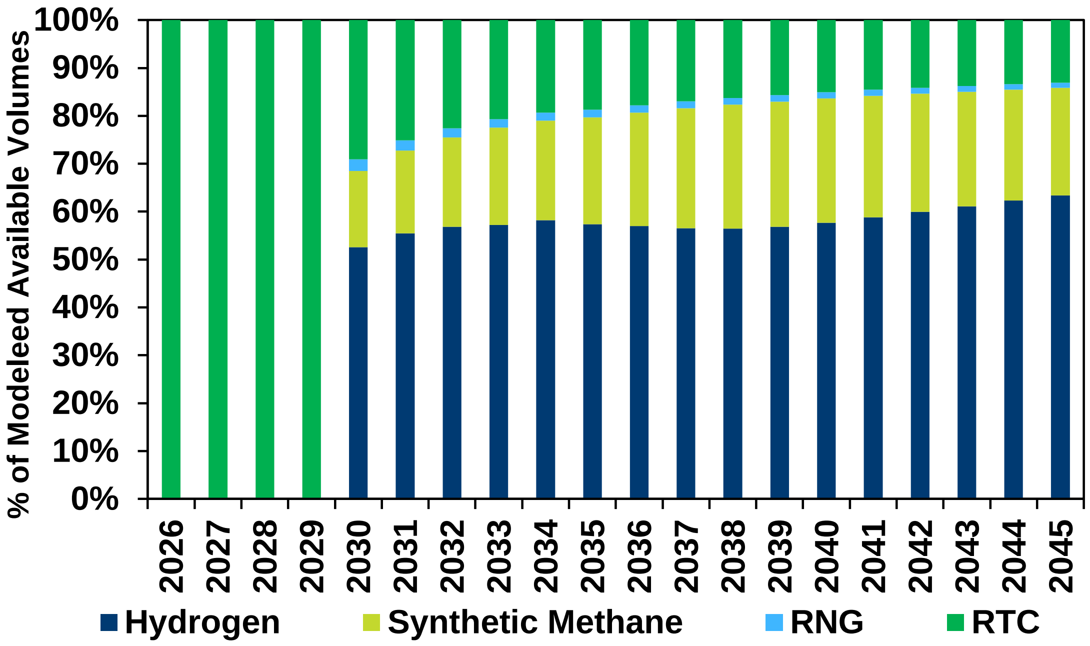
**CCUS “Industrial” is based on Avista specific high-volume customers

Annual - Modeled Volumes vs. Technical Potential Volumes

% of Modeled Volumes vs. Technical Potential**



% of Modeled Total Volumes in CROME by Type*



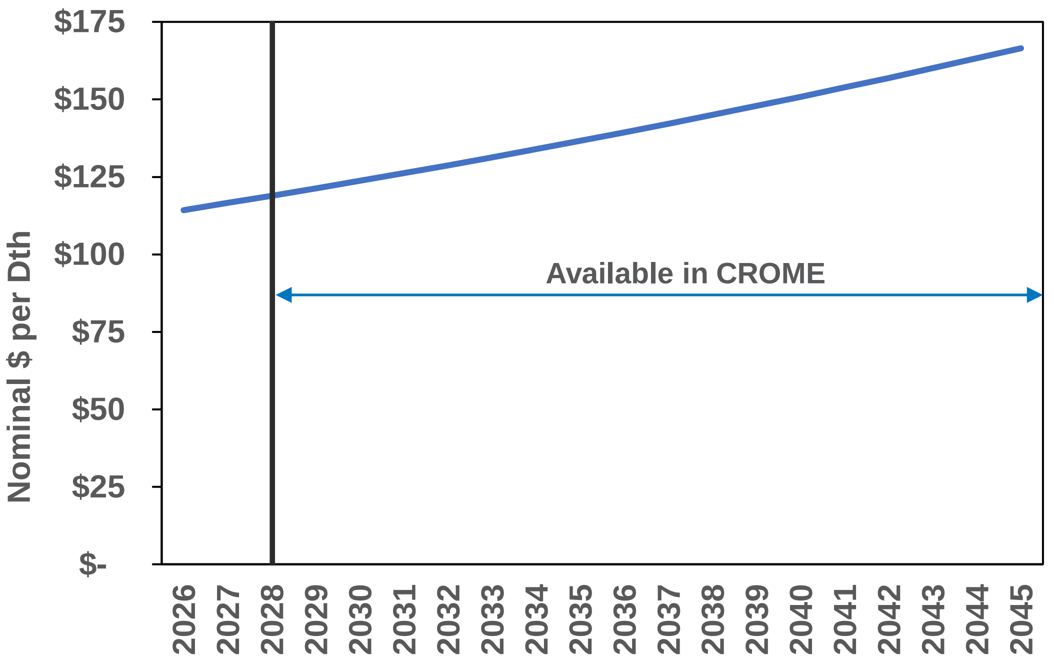
*Excludes CCUS

**Technical Potential Volumes are from ICF and weighted to % share of LDC # of customers for National and NW volumes, meaning this would be Avista's share of those volumes

All Resource Options

Propane Storage

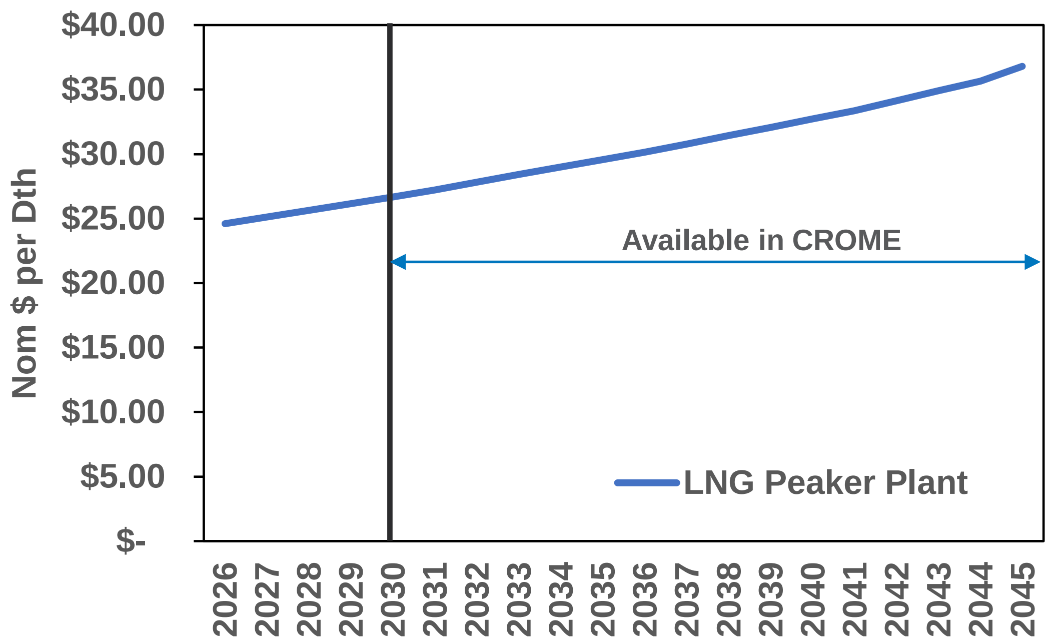
- CapEX - $14.7MM (20 Year Asset Life)
- Plant Size – 30M Dth (1 cycle)
- Pipeline - $2MM
- Installation + Owners costs – 5% of capital cost
- Delivery Cost - $0.33 per gallon of Propane
- Plant electricity and air injection
- Siting, permitting and build - 2 years
- Propane costs per gallon are included in estimated nominal $ per Dth



*Cycling of plant reduces overall cost per Dth
**No volumes will be available until 2028

Liquified Natural Gas (LNG) Peak Storage

- CapEX - $200MM (50 Year Asset Life – Avista Rev. Req)
- Plant Size – 1.037MM Dth
- Max volume per day – 103,700Dth
- Pipeline - $2MM
- Utility Interconnect - $3.12MM
- Installation + Owners costs – 30% of capital
- Liquefaction Costs
- Days of peak supply – 10
- Liquefier capacity per day – 7,000 Dth
- Siting, permitting and build - 4 years
- Gas commodity costs included in CROME and combined with estimated nominal $ per Dth



*Cycling of plant reduces overall cost per Dth
**No volumes will be available until 2030

Constraints of Resource options in CROME

Resource Type	Volumetric Restriction	First Year of Availability
Allowances	10% of Market per program rules (CCA)	2026
Community Climate Investments	15% (2025-2027), 20% 2028+ (CPP)	2026
Demand Response	CPA from AEG for potential	2026
Electrification	No constraints, up to total energy demanded on LDC by area/class/year	2026
Energy Efficiency	CPA from AEG and ETO	2026
Renewable Thermal Credit	NW Technical Potential (ICF)	2026
Propane Storage	30,000 Dth	2028
Hydrogen	NW Technical Potential to Avista (ICF) & 20% by volume	2030
Synthetic Methane	NW Technical Potential to Avista (ICF)	2030
Renewable Natural Gas	NW Technical Potential (ICF) for allocation of 1.5MM Dth Total Availability	2030
Liquified Natural Gas	1 Bcf Total & 0.1 Bcf Daily W/D	2030
Carbon Capture, Utilization and Storage	Constraints to Avista high volume customers (ICF)	2030

Remaining TAC Meetings

TAC 10 – (January 9th)

- Conservation Potential Assessment (AEG)
- Demand Response Potential Assessment (AEG)
- Conservation Potential Assessment (ETO)
- Dual Fuel Pilot Program – Oregon (ETO)
- Deterministic Results
- Alternative Fuel Final Results - Questions

TAC 11 – (January 22nd)

- Risks and costs by scenario
- Preferred Resource Selection
- Non-Energy Impacts
- Emissions by Scenario
- Energy Burden
- Average Rates
- Net present value revenue requirement (NPVRR)
- Action Items

*Draft will be released on or before January 31, 2025

TAC 10 – 2025 Avista Gas IRP

Edited Alternative Fuel Volumes

January 9, 2025

Alternative Fuel Prices

Alternative Fuel Prices Inputs

Model Restriction

- Selection for any physical products will not be available in the model until 2030
- Average prices above $75 per Dth will not be modeled

Capital Costs

- Equipment
- Pipeline Costs
- Installation and Owners Costs

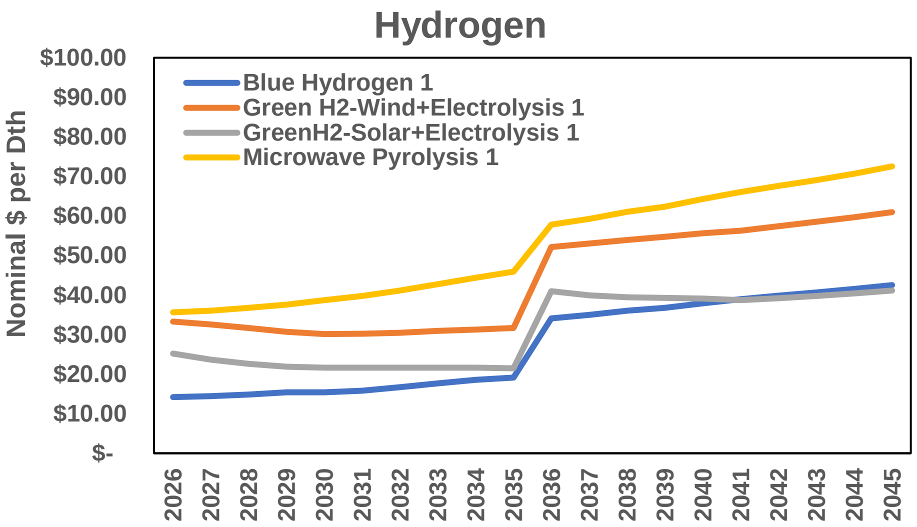
O&M – Fixed and Variable

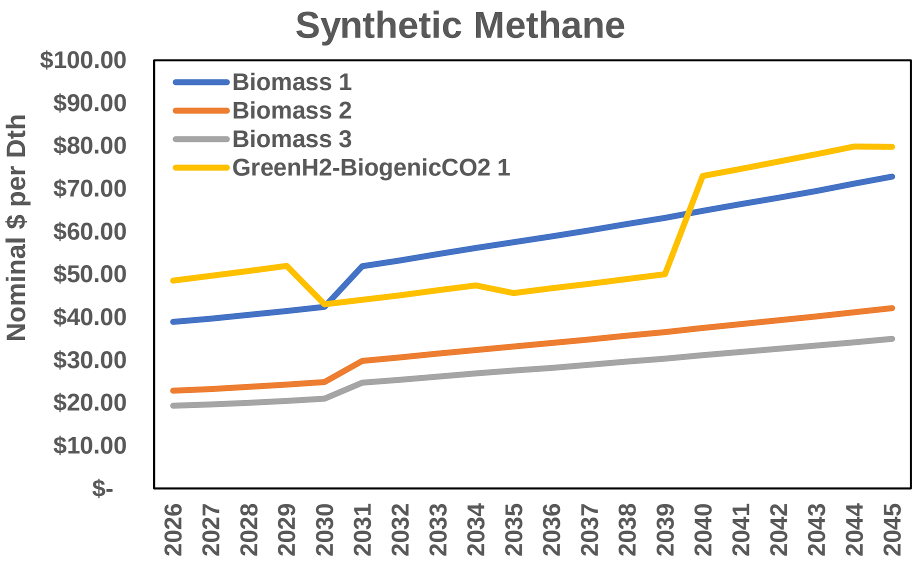
- Electricity rates
- Gas rates

Prices

- Expected prices are broken down between northwest and national technical potential (ICF)
  - All prices consider Inflation Reduction Act (IRA) incentives where applicable
  - These prices assume a first mover access to alternative fuels
  - Prices are from the Northwest for each alternative fuel and National for Renewable Thermal Credits (RTC)
  - Hydrogen (H2) & Synthetic Methane (SM) prices will be treated as a purchase gas agreement where Avista would sign a term contract, each year, with the producer for these prices through the forecast.
  - Renewable Natural Gas (RNG) assumes a proxy ownership with costs levelized over 20 years
  - RTC considers a production cost plus, where prices cover all costs
    - These exclude Investment Tax Credit (ITC) or Production Tax Credit (PTC) and consider a higher capital rate
  - Prices are in nominal dollars

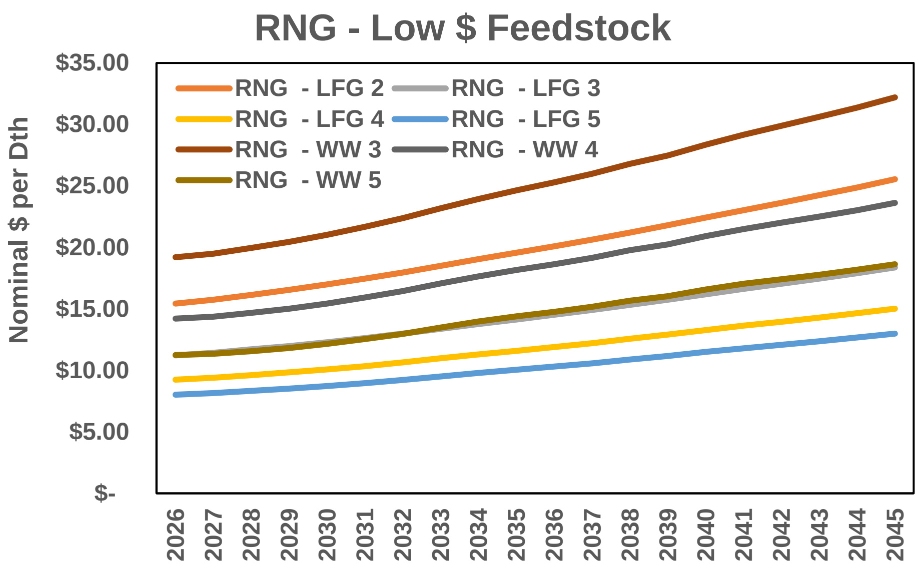
Hydrogen (H2) and Synthetic Methane (SM)

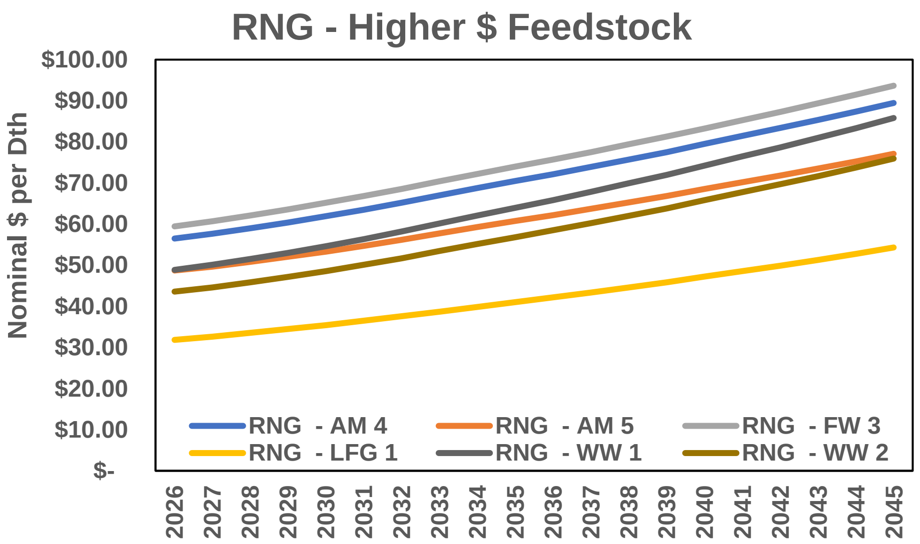




ICF levelized the Section 45V tax credit over 20 years. Since hydrogen projects must be under construction by the end of 2032 to qualify for 45V credits, the 45V tax credits were modeled until 2035 as a conservative estimate assuming every new hydrogen facility beginning construction after 2032 may not 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.

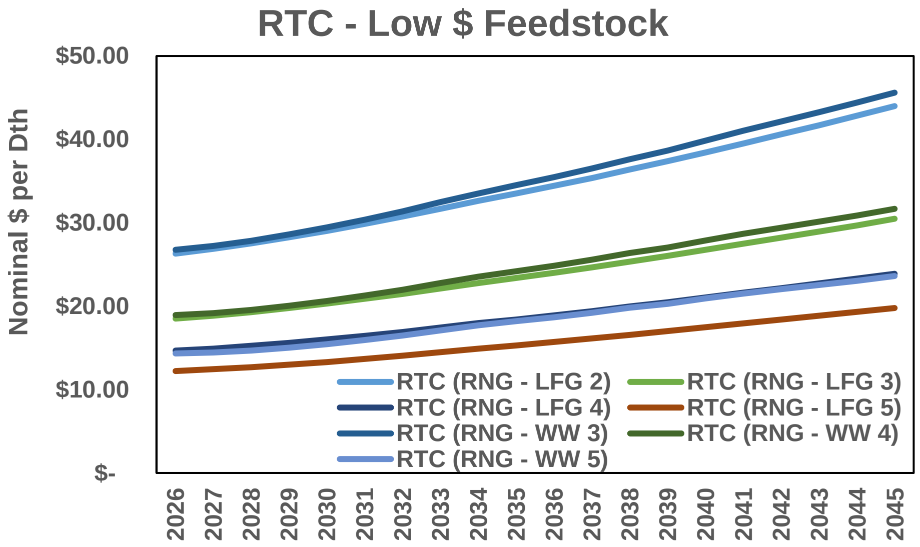
Renewable Natural Gas (RNG)

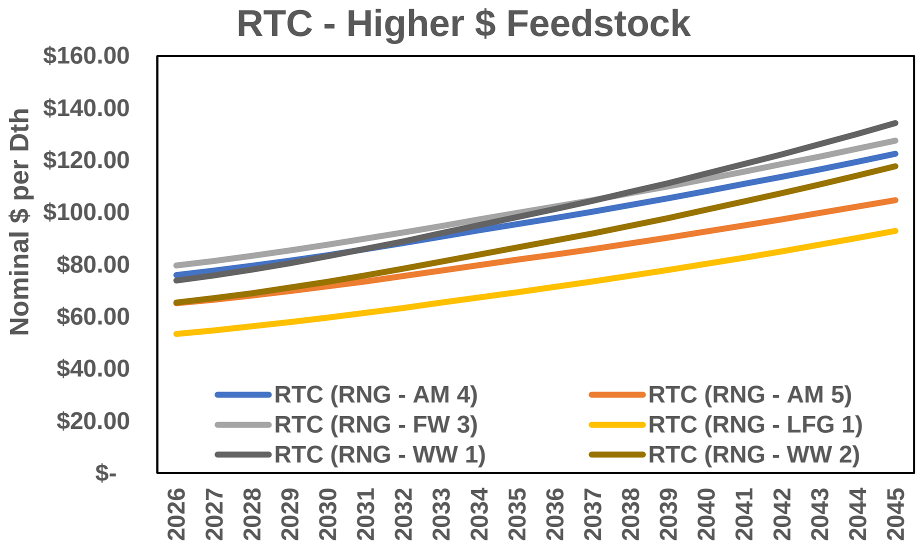




*Blend of national and NW estimated costs for RNG facilities
**Includes ITC/PTC until 2030

Renewable Thermal Certificate (RTC)

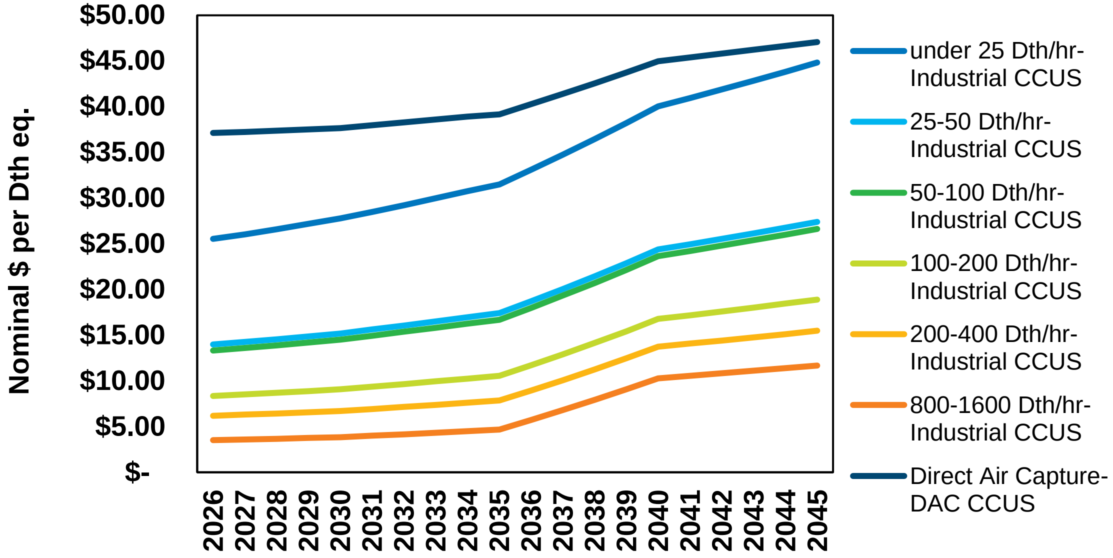


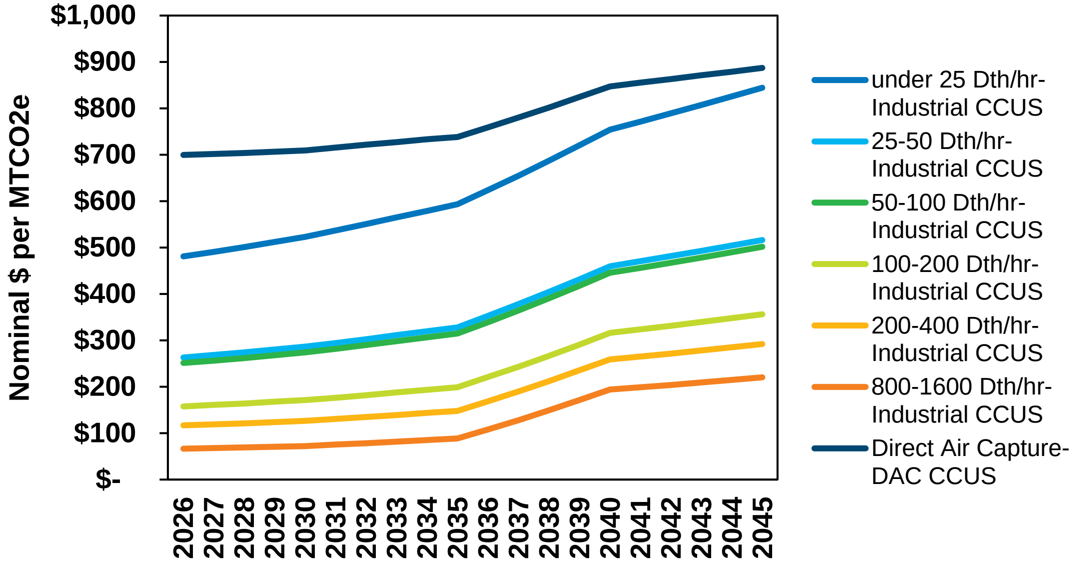


1-No ITC, considers price from producer to create RTC and cover costs (production prices)

2-Not tied to market actual prices

Carbon Capture, Utilization and Storage (CCUS)





*Avista specific high-volume customers

**Includes ITC/PTC to 2030

Alternative Fuels Technical Potential Volumes (ICF)

Updated Technical Potential Volumes

- Total Technical Potential Volumes have been updated from the final version of TAC 9 (12/18/2024)

- These volumes were overestimated based on interpretations of math provided by ICF
  - Clarification was given by ICF on January 3rd and Impacted deterministic runs
    - The "output Excel files list a unit of 1x10e9 Btu for various resources. This is equivalent to billion Btu. If one were to enter 1x10E9 into an Excel file, you will get 10 billion (10,000,000,000). However, this is because the number should be interpreted as $1x10^9$. The "e" is meant to stand for "exponent" whereas entering the sequence 10E9 in Excel is interpreted as 10×10^9."
  - The good news is the final number matched closely to those Avista adjusted for estimated volumes, so now all volumes for alternative fuels are from ICF study directly
  - These deterministic alternative scenarios will be reviewed along with final content in TAC 11
  - The deterministic PRS will be discussed further in TAC 10

Volumes

- Expected volumes are broken down between Northwest and National technical potential
  - These volumes assume a first mover access to alternative fuels
  - Weighted by US population for states where some form of climate policy is in place or demand is expected
  - Modeled physical potential volumes are from Avista's weighted share in the Northwest and intended to represent all volumes available to Avista in the United States
    - RTC are the only National potential volumes considered and assumes physical pipeline accessibility to meet CCA and CPP program rules
    - Broken out by 2023 number of meters between LDCs in Oregon and Washington

Company	2023 # of Meters	Share
AVA	379,223	15.831%
CNG	316,929	13.231%
NWN	799,250	33.366%
PSE	900,000	37.572%
Total NW	2,395,402	100.000%

*Renewable Energy Technical Potential - The renewable energy technical potential of a technology is its achievable energy generation given system performance, topographic, environmental, and land-use constraints.

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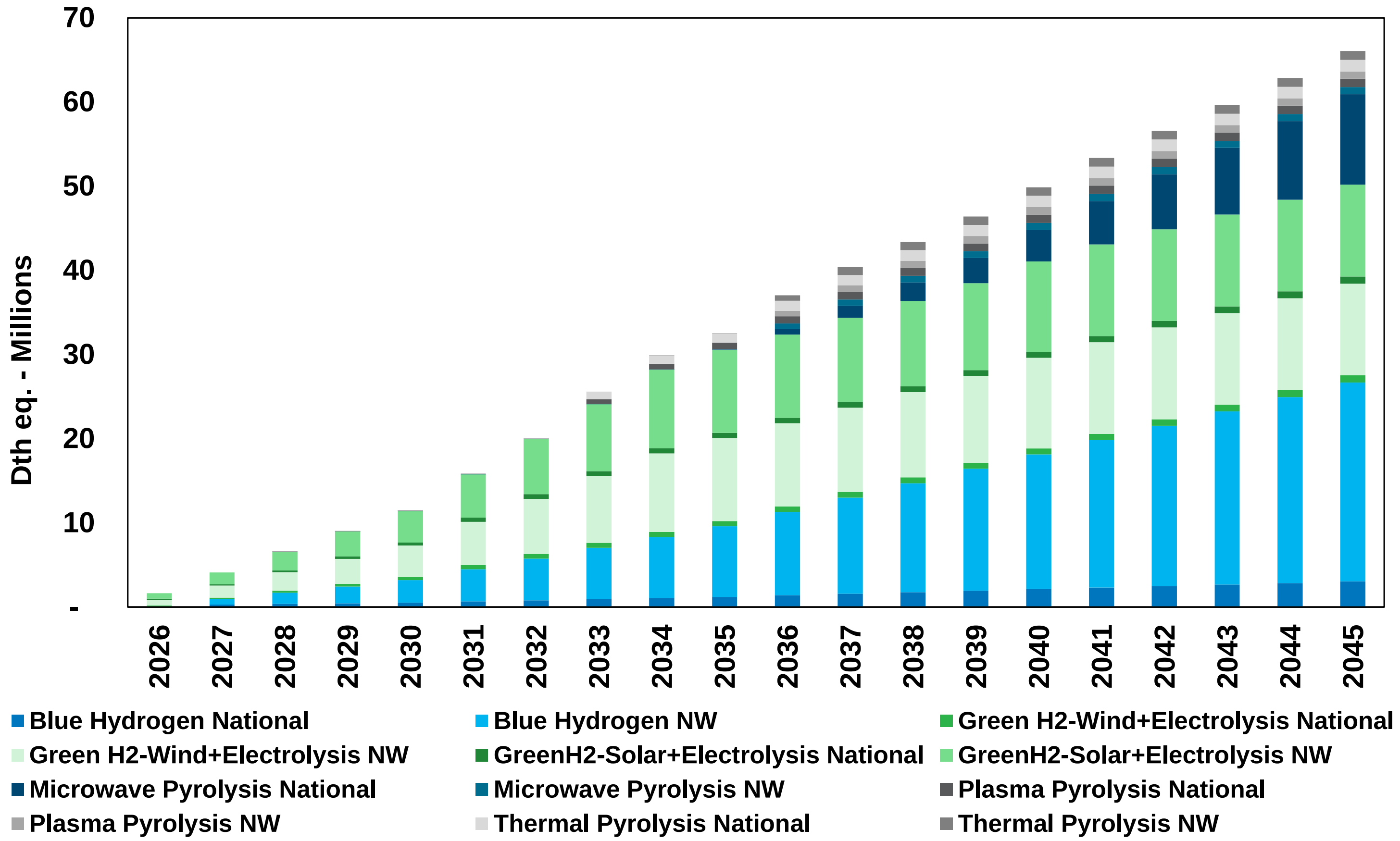
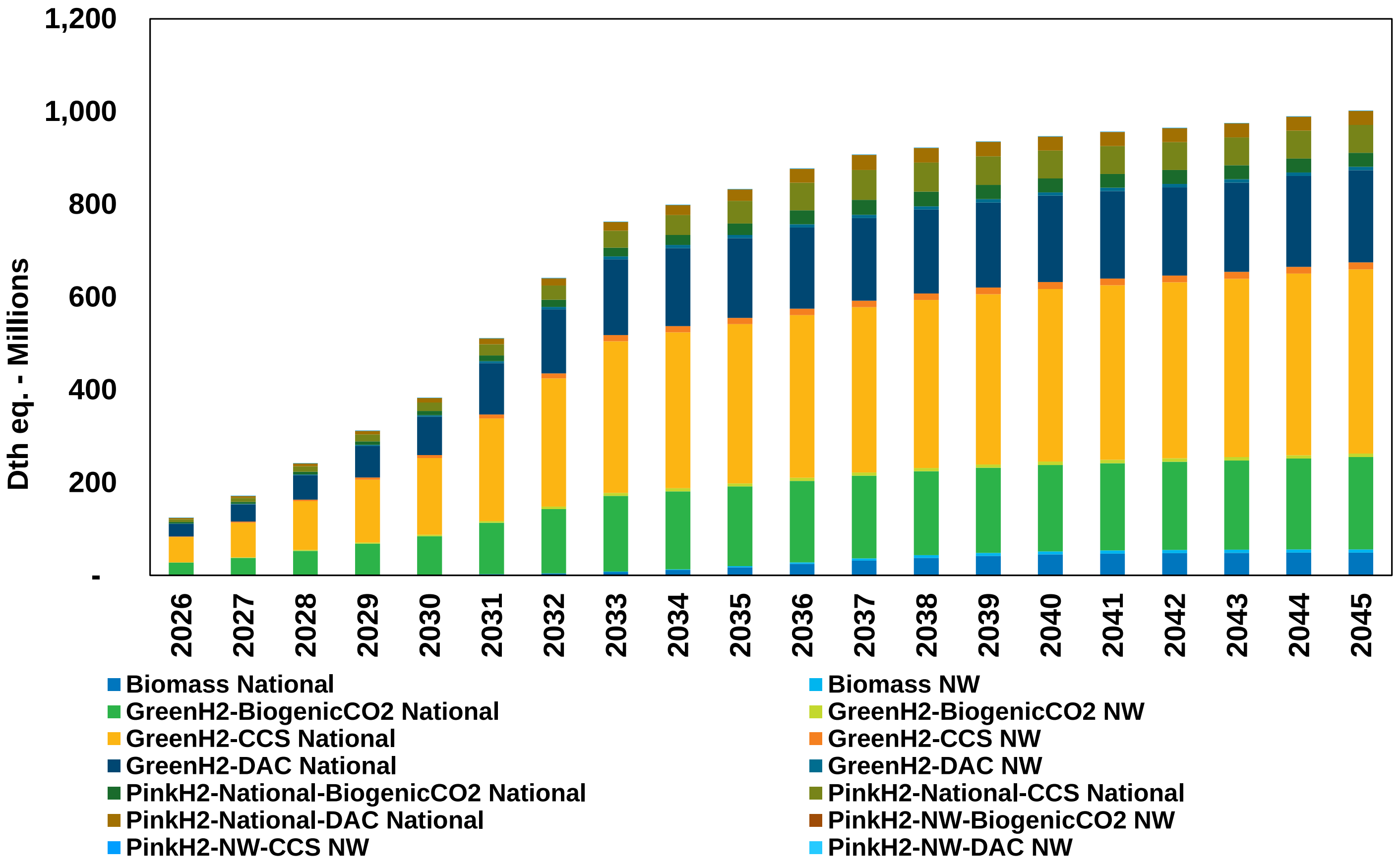
Hydrogen – Avista's Share
Technical Potential Volumes (2026-2045)



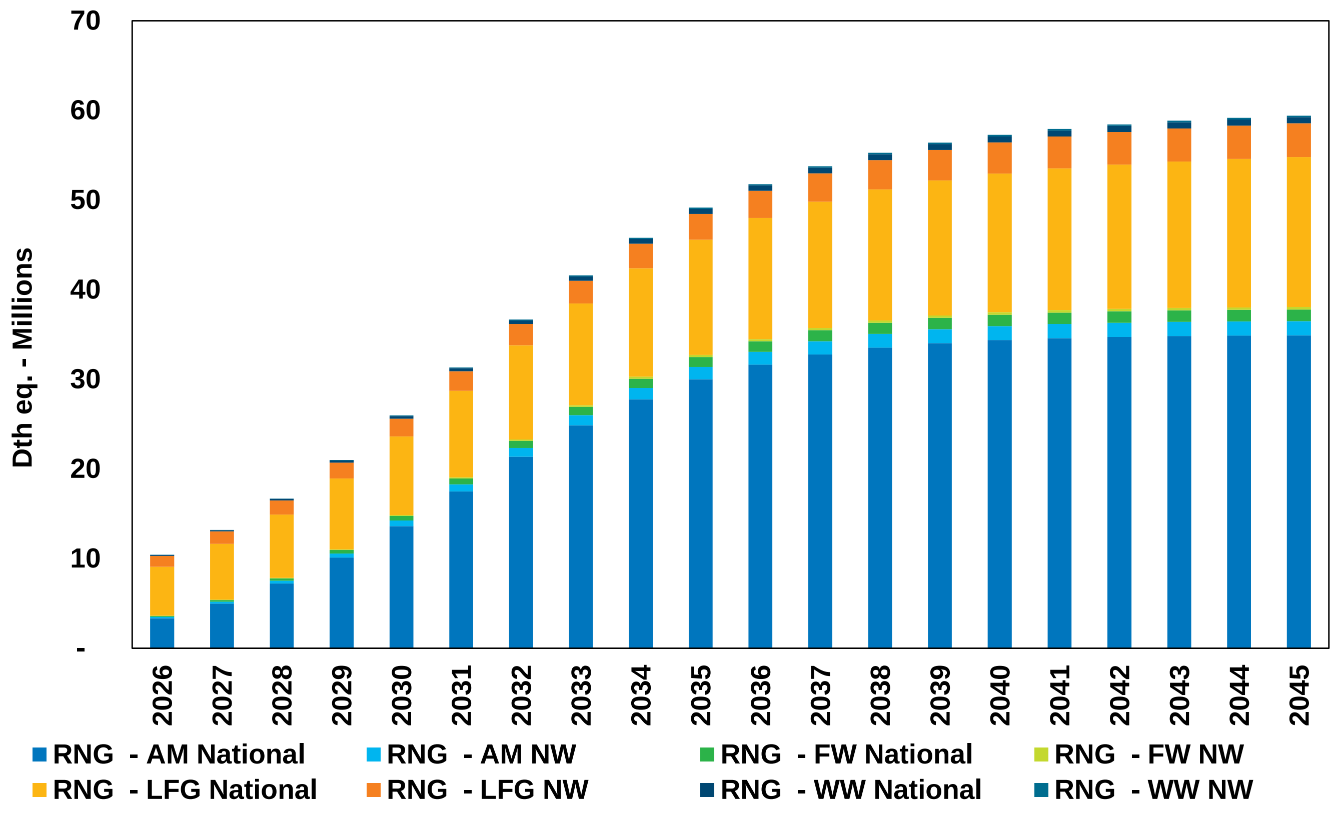
*H2 will be limited by volume to 20%
**No volumes will be available until 2030

Synthetic Methane – Avista's Share Technical Potential Volumes (2026-2045)



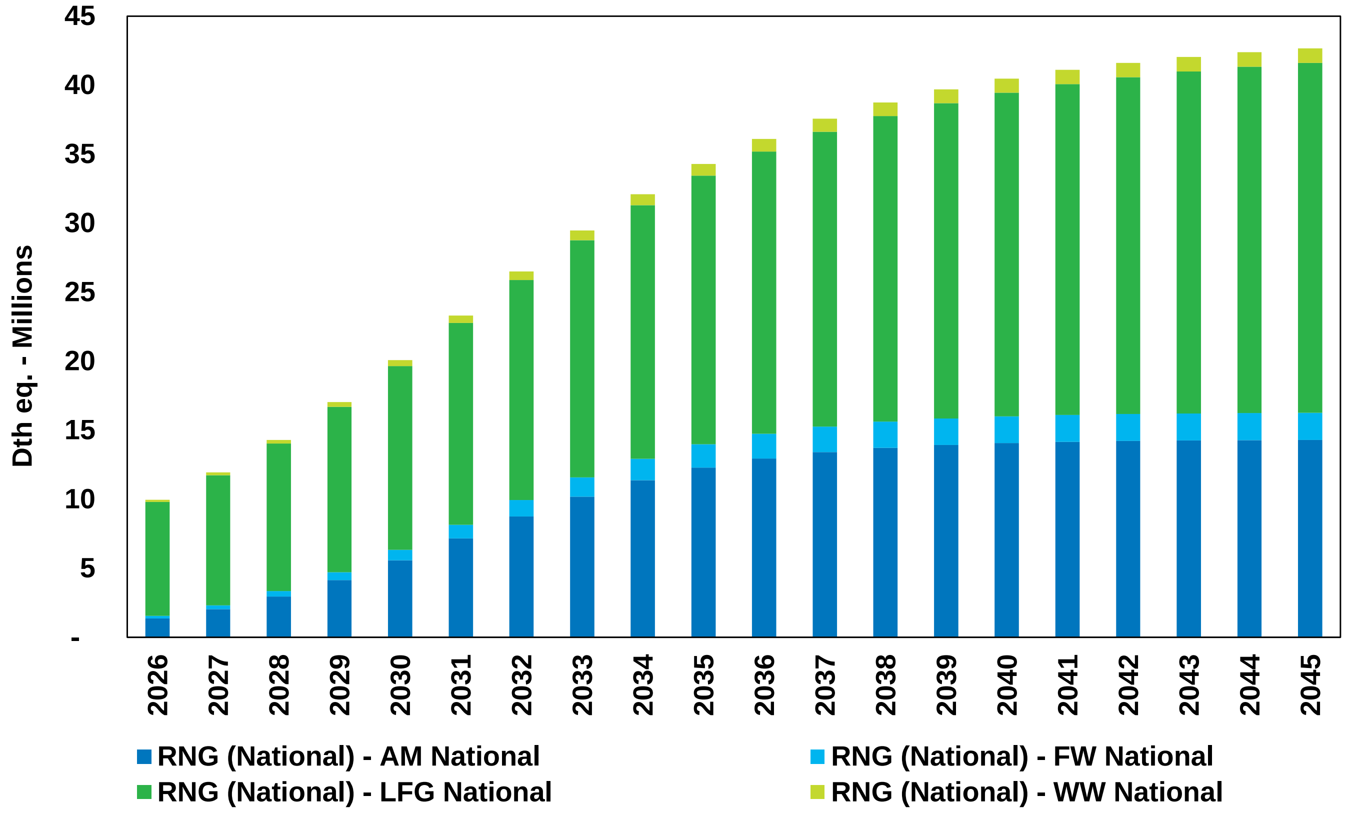
*No volumes will be available until 2030

Renewable Natural Gas – Avista's Share Technical Potential Volumes (2026-2045)



*No volumes will be available until 2030

Renewable Thermal Certificate – Avista's Share Technical Potential Volumes (2026-2045)



*Volumes are available to the model in 2026

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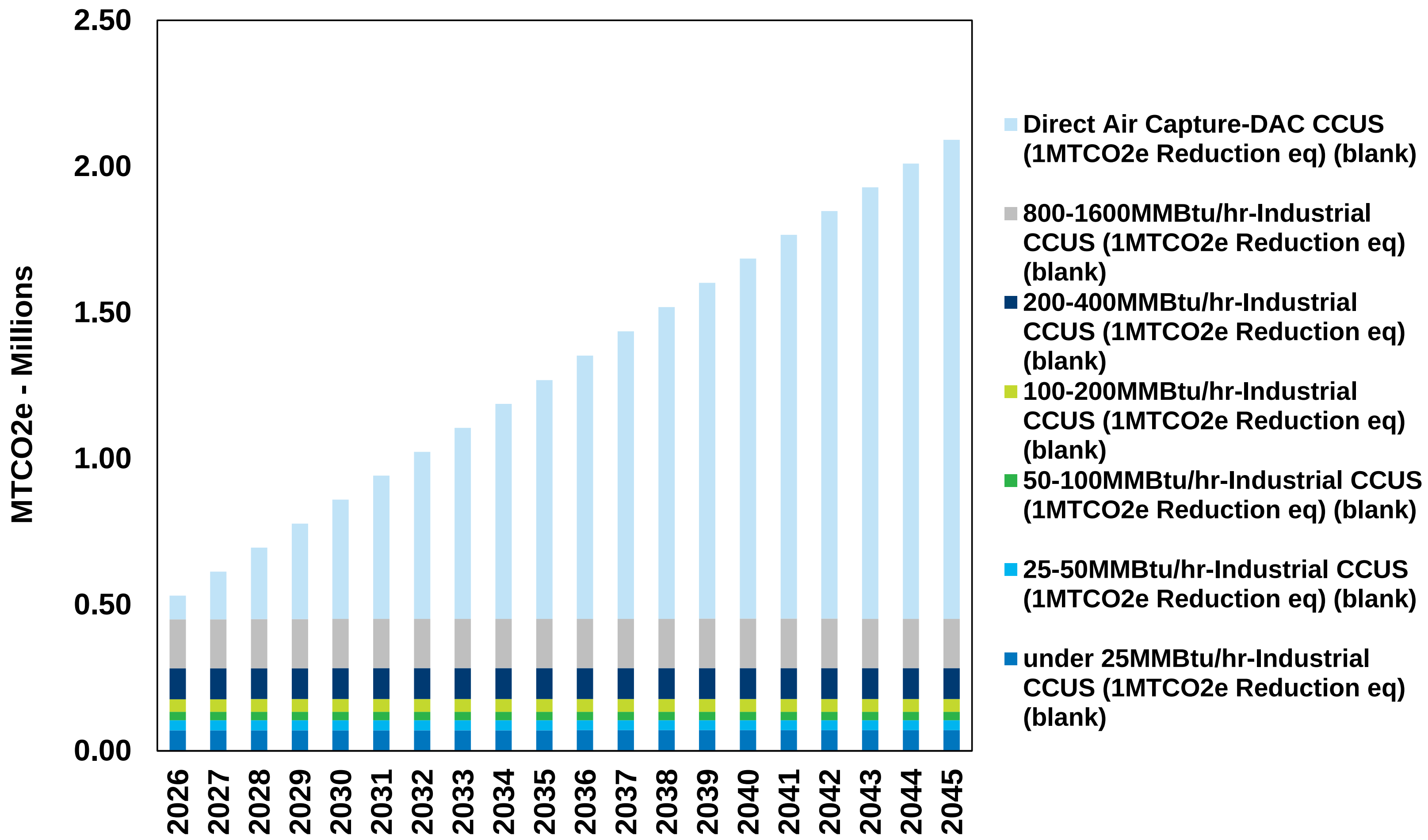
CCUS (2026-2045)

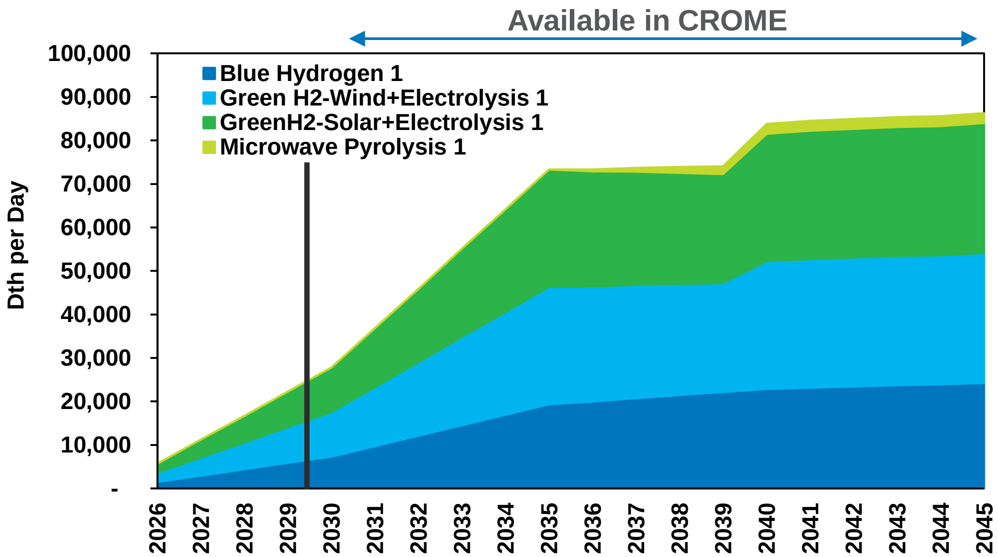


*Years 2025-2045
**No Volumes will be available until 2030

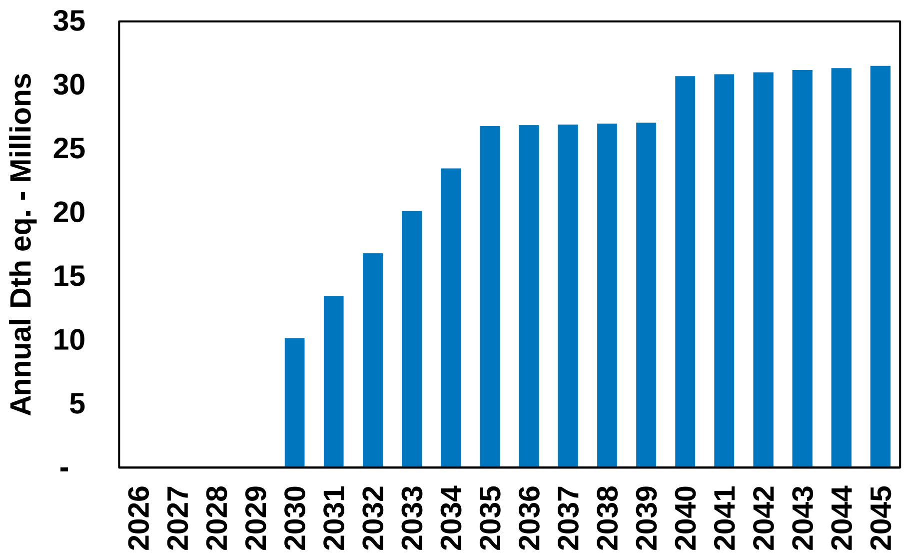
Daily Modeled Volumes

H2 – Modeled Volumes NW Only

Daily Volumes

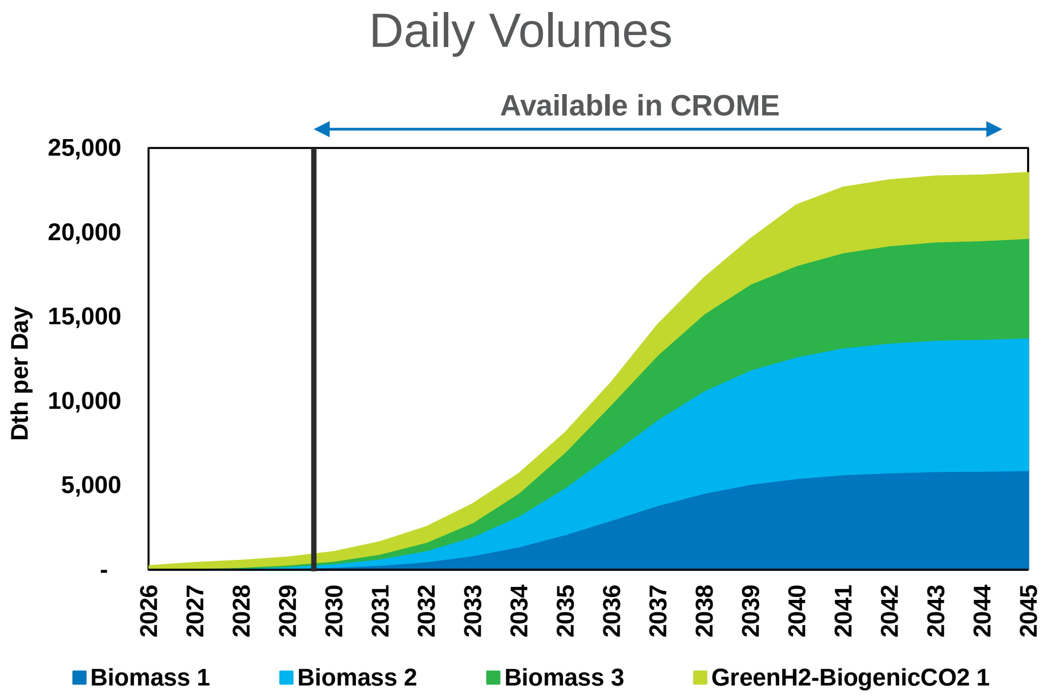


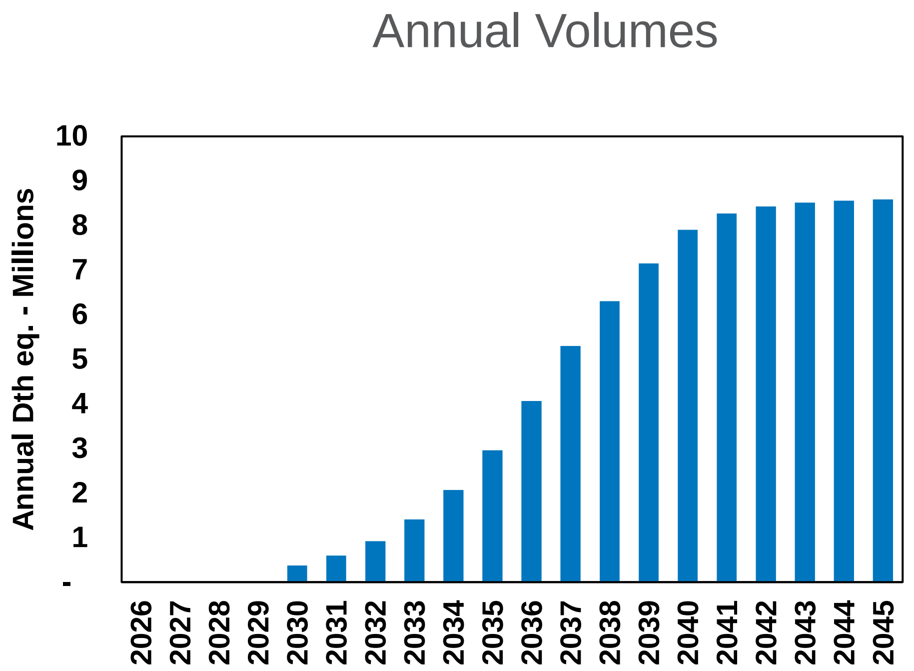
Annual Volumes



*H2 will be limited by volume to 20% regardless of availability
**No volumes will be available until 2030

SM – Modeled Volumes NW Only

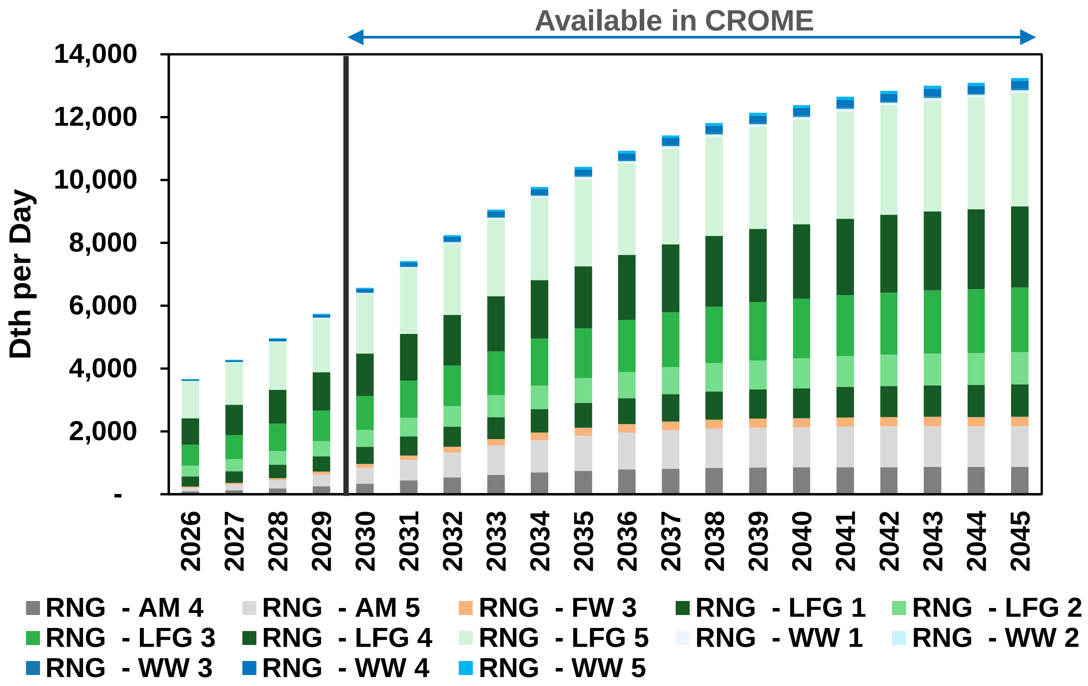




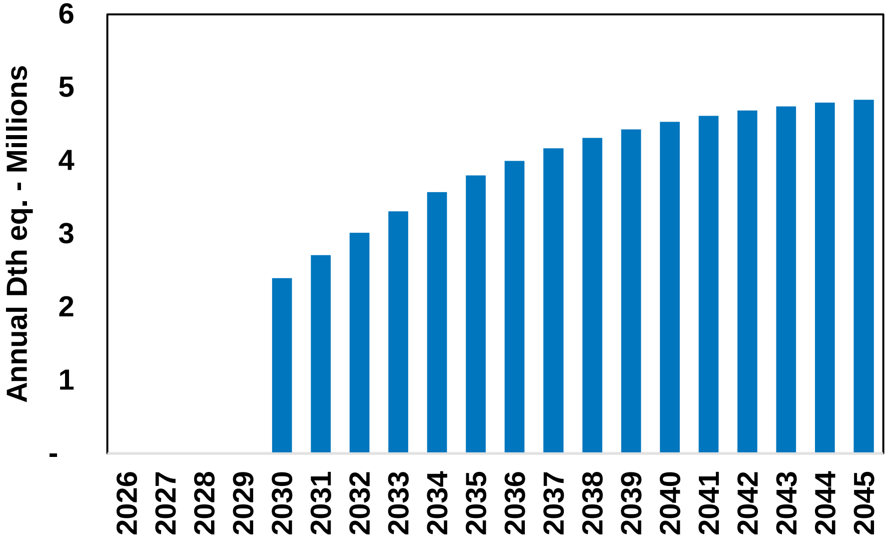
*SM is limited to NW Technical Potential availability & Avista share based on # of LDC meters
**No volumes will be available until 2030

RNG – Modeled Volumes NW Only

Daily Volumes



Annual Volumes

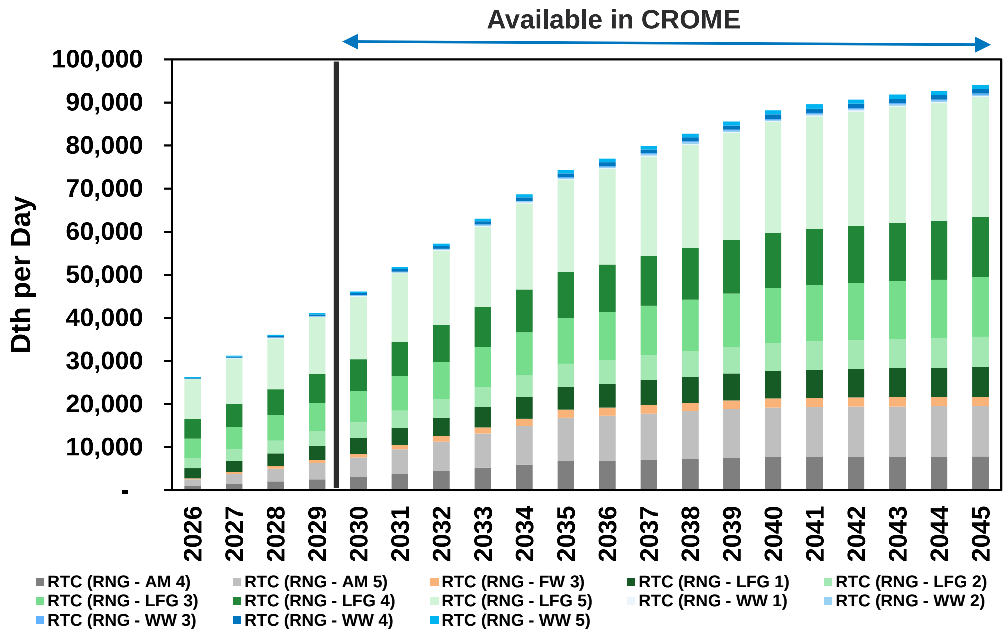


*Quantities not available until 2030

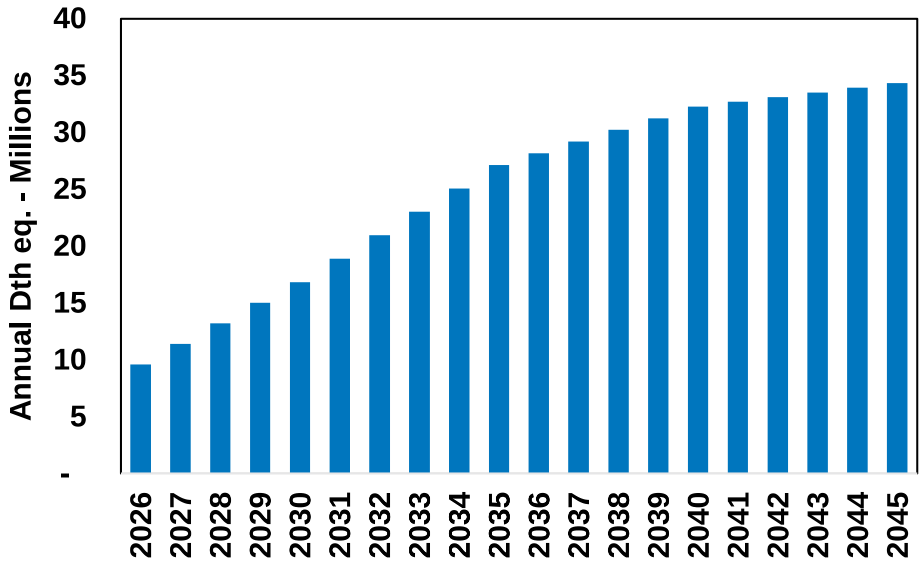
**Removal of high priced RNG prior to modeling (AM1-3, FW1-2)

RTC – Modeled Volumes NW Only

Daily Volumes



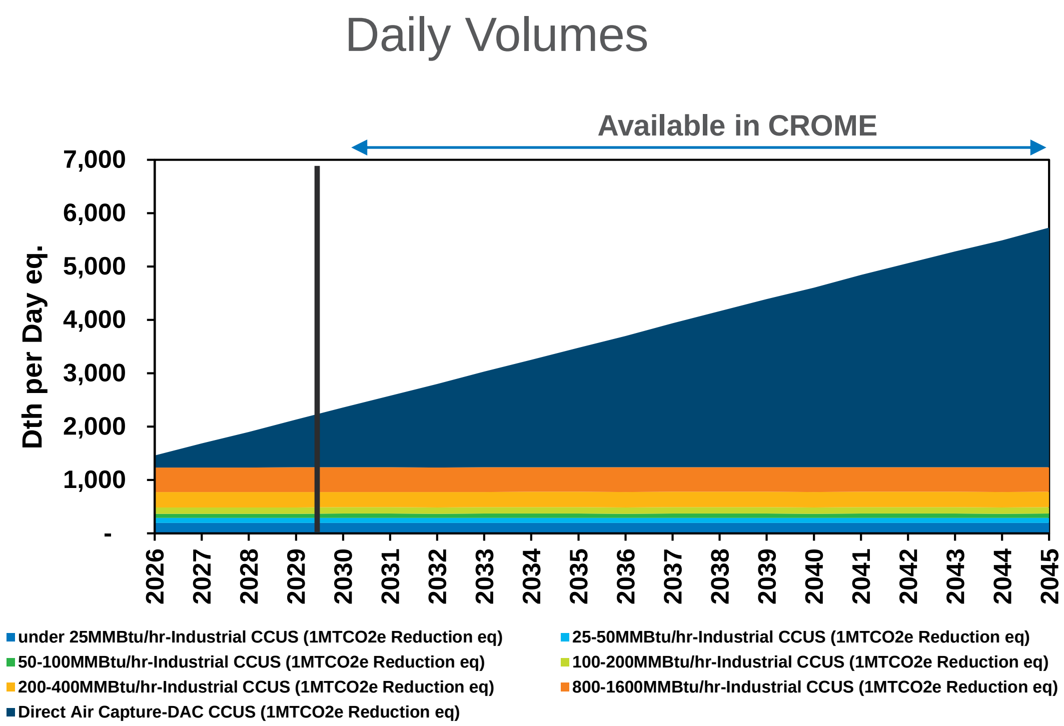
Annual Volumes

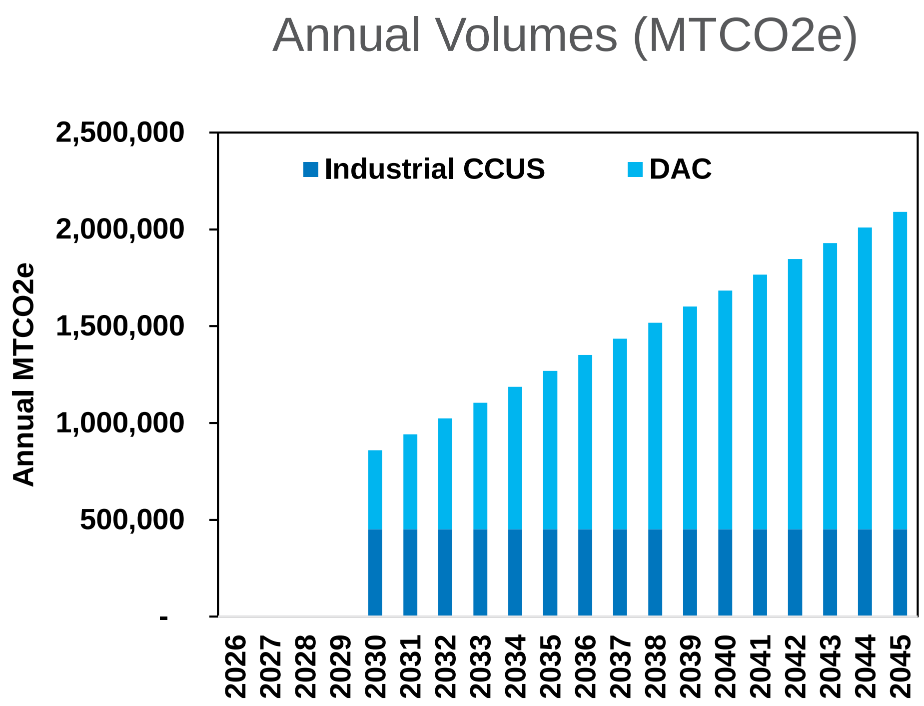


*Quantities are available to the model in 2026

**Removal of high priced RTCs prior to modeling (AM1-3, FW1-2)

CCUS
NW Only



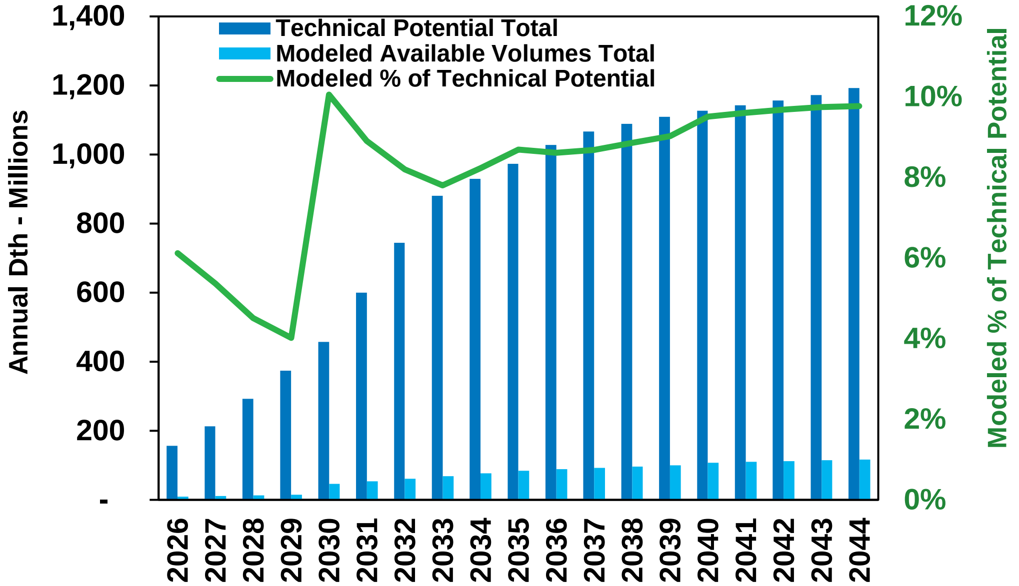


*No Volumes will be available until 2030

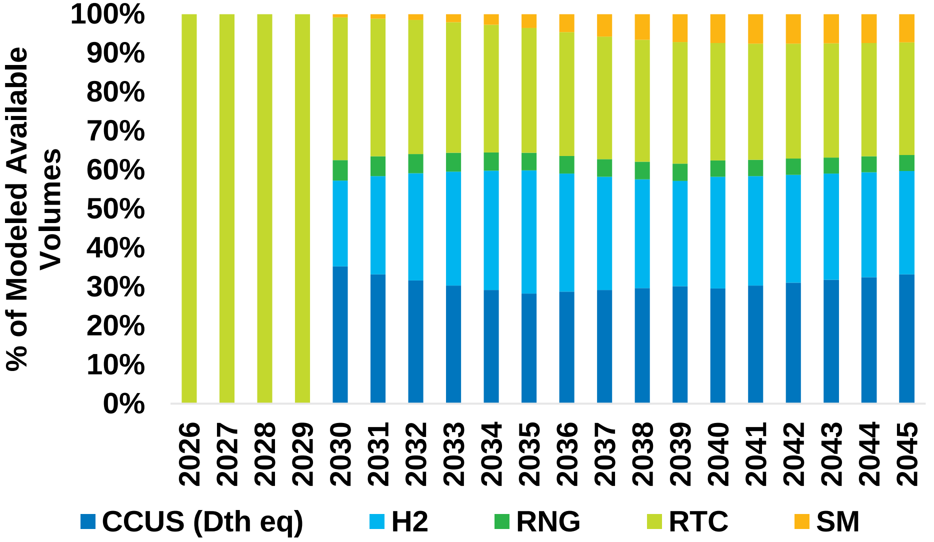
**CCUS "Industrial" is based on Avista specific high-volume customers

Annual - Modeled Volumes vs. Technical Potential Volumes

% of Modeled Volumes vs. Technical Potential**



% of Modeled Available Volumes in CROME by Type*

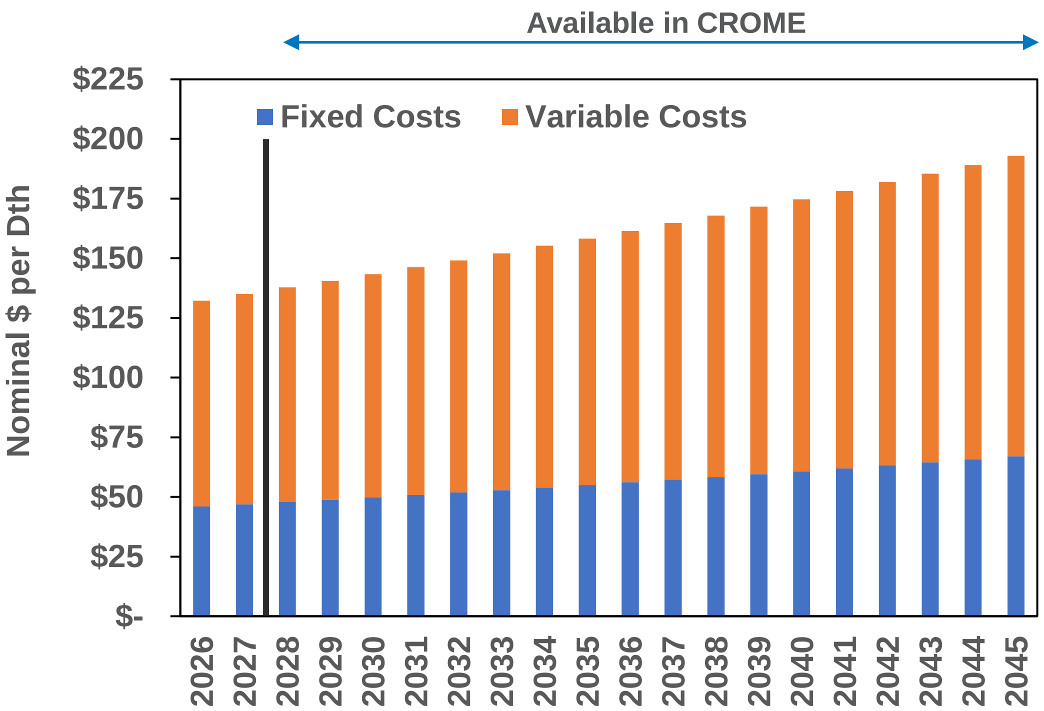


*Technical Potential Volumes are from ICF and weighted to % share of LDC # of customers for National and NW volumes, meaning this would be Avista's share of those volumes

Other Supply Side Resource Options

Propane Storage

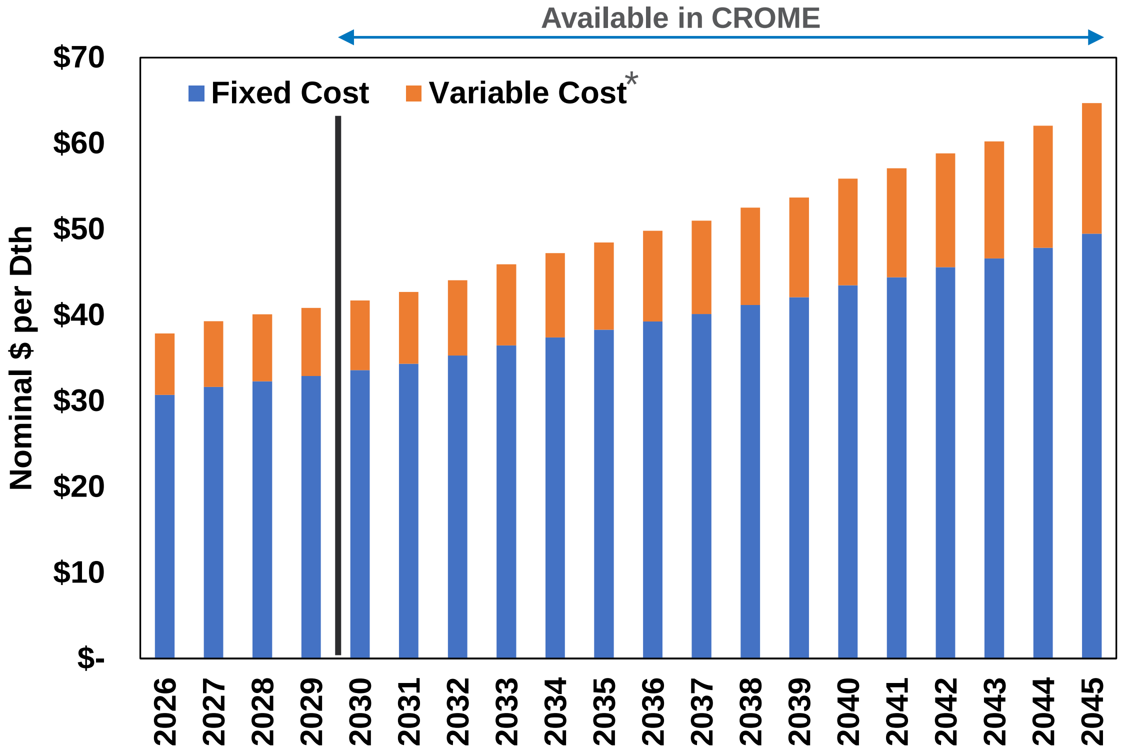
- CapEX - $14.7MM (20 Year Asset Life)
- Plant Size – 30M Dth (1 cycle)
- Installation + Owners costs – 5% of capital cost
- Delivery Cost is included
- Plant electricity and air injection
- Siting, permitting and build - 2 years
- Propane costs per gallon are included in estimated nominal $ per Dth – Variable Costs



*Cycling of plant reduces overall cost per Dth
**No volumes will be available until 2028

Liquified Natural Gas (LNG) Peak Storage

- CapEX - $200MM (50 Year Asset Life – Avista Rev. Req)
- Plant Size – 1 Bcf
- Max volume per day – 103,700Dth
- Pipeline - $2MM
- Utility Interconnect - $3.12MM
- Installation + Owners costs – 30% of capital
- Liquefaction Costs
- Days of peak supply – 10
- Liquefier capacity per day – 7,000 Dth
- Siting, permitting and build - 4 years
- Gas commodity costs included in CROME and combined with estimated nominal $ per Dth



*Example only as costs are modeled directly in CROME

*Cycling of plant reduces overall cost per Dth
**No volumes will be available until 2030

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Constraints of Resource options in CROME

Resource Type	Volumetric Restriction	First Year of Availability
Allowances	10% of Market per program rules (CCA)	2026
Community Climate Investments	15% (2025-2027), 20% 2028+ (CPP)	2026
Demand Response	CPA from AEG for potential	2026
Electrification	No constraints, up to total energy demanded on LDC by area/class/year	2026
Energy Efficiency	CPA from AEG and ETO	2026
Renewable Thermal Credit	NW Technical Potential (ICF) – Avista Share (16%)	2026
Propane Storage	30,000 Dth	2028
Hydrogen	NW Technical Potential (ICF) & Avista Share (16%) & 20% by volume	2030
Synthetic Methane	NW Technical Potential (ICF) & Avista Share (16%)	2030
Renewable Natural Gas	NW Technical Potential (ICF) & Avista Share (16%)	2030
Liquified Natural Gas	1 Bcf Total & 0.1 Bcf Daily W/D	2030
Carbon Capture, Utilization and Storage	Constraints to Avista high volume customers (ICF)	2030

AEG

APPLIED ENERGY GROUP

Avista Energy Natural Gas CPA Draft Results

Prepared for Avista Energy TAC Meeting 1/9/2025

Overview

- Introduction
- Methodology Overview
- WA & ID Conservation Potential Assessment
  - Energy Efficiency
  - Demand Response
- Oregon Low-Income Energy Efficiency Potential Study
- OR-WA Transport Customer Energy Efficiency Potential Study

CPA Objectives

- Assess a broad set of technologies to identify long-term energy efficiency and demand response potential in Avista's Washington and Idaho service territories to support:
  - Integrated Resource Planning
  - Portfolio target-setting
  - Program development
- Provide information on costs and seasonal impacts of conservation to compare to supply-side alternatives
- Use methodology consistent with the Northwest Power and Conservation Council, while recognizing differences between electricity and natural gas.
- Understand differences in energy consumption and energy efficiency opportunities by sector, and for Residential, by income level
- Ensure transparency into methods, assumptions, and results

Methodology Overview for Washington & Idaho CPA

AEG Modeling Approach

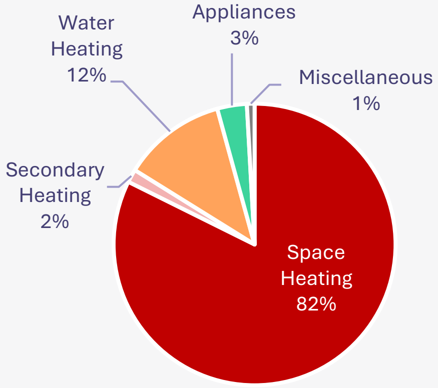
Market Characterization
- Baseline studies
- Utility data
- Secondary data

Identify Demand-Side Resources
- EE equipment
- EE measures
- Emerging tech.

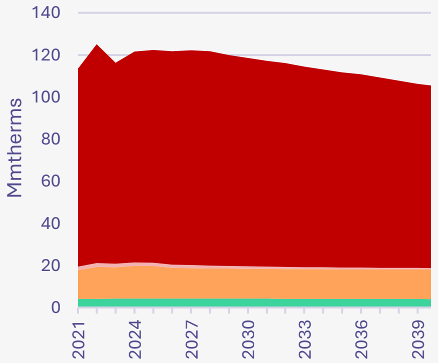
Baseline Projection
- Utility forecasts
- Standards and building codes

Potential Estimation
- Technical
- Achievable Tech.
- Economic Achiev.

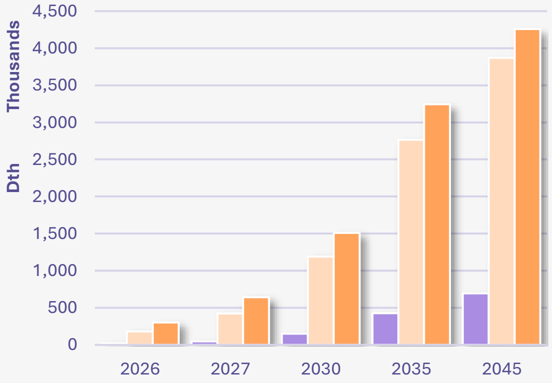
Residential Gas Usage by End Use



Natural Gas Projection by End Use



Cumulative Natural Gas Savings



Major Modeling Inputs and Sources

Avista foundational data

- Avista gas sales by schedule
- Current and forecasted customer counts
- Retail price forecasts by class

Survey data showing presence of equipment

- Avista: Residential customer survey conducted in 2013
- NEEA: Residential and Commercial Building Stock Assessments (RBSA 2016 and CBSA 2019)
- US Energy Information Administration: Residential, Commercial, and Manufacturing Energy Consumption Surveys (RECS 2020, CBECS 2018, and MECS 2015)

Technical data on end-use equipment costs and energy consumption

- Regional Technical Forum workbooks
- Northwest Power and Conservation Council's 2021 Power Plan workbooks
- US Department of Energy and ENERGY STAR technical data sheets
- Energy Information Administration's Annual Energy Outlook/National Energy Modeling System data files

State and Federal energy codes and standards

- Washington State Energy Code
- Idaho Energy Code
- Federal energy standards by equipment class

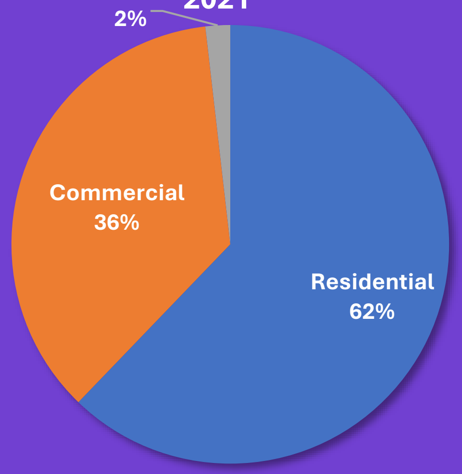
Market trends and effects

- RTF market baseline data
- Annual Energy Outlook purchase trends (in base year)

Market Characterization

- The first step in the CPA process is to define energy-consumption characteristics in the base year of the study (2021).
- AEG incorporates Avista's actual consumption and customer counts to develop "Control Totals" – values to which the model will be calibrated.
- Market characterization is an important step in the CPA process as it grounds the analysis in Avista's data and provides us with enough details to project assumptions forward, developing a baseline energy projection.
- After separating gas consumption into sectors and segments, it is allocated to specific end uses and technologies in the Market Profile (next slide).

Natural Gas Use by Sector 2021

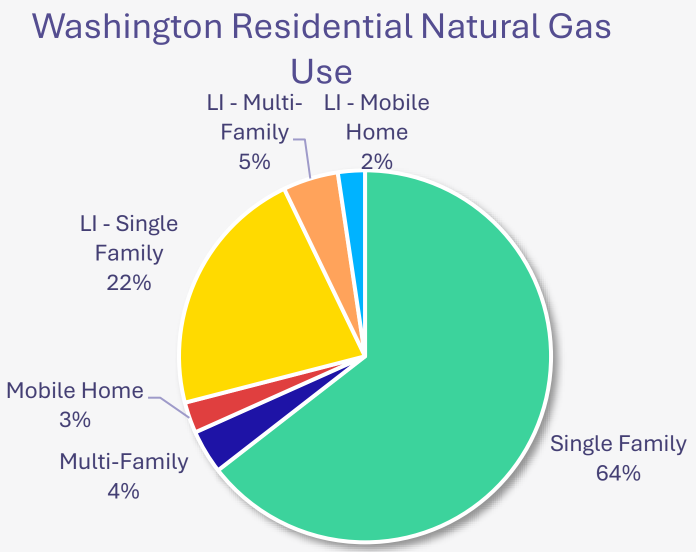


Sector	Accounts	2021 Dth	Segmentation
Residential	237,935	16,973,954	Single Family, Multi-Family, Manufactured Home, and by Income Group within housing type
Commercial	24,454	9,814,874	Office, Retail, Restaurant, Grocery, College, School, Hospital, Lodging, Warehouse, Other
Industrial	194	496,972	Mix of industries from customer data will inform presence of end uses and measure applicability
Total	**262,584**	**27,285,801**	

Energy Market Profile

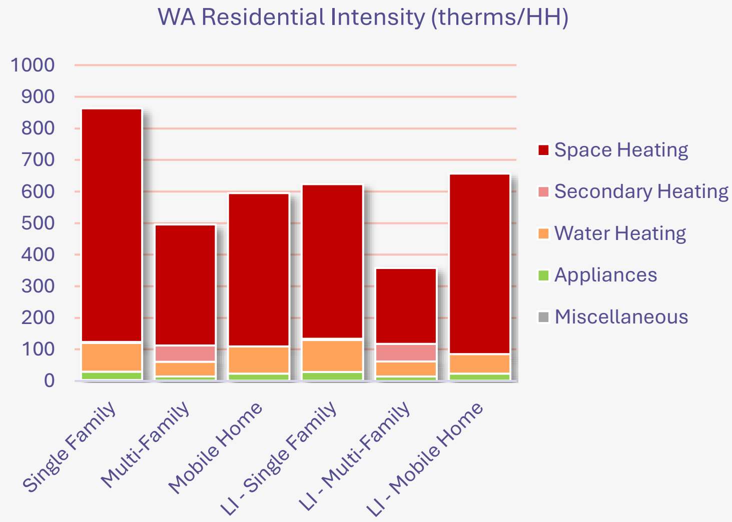
Example – Washington Residential

- Calibrated to Avista's use-per-customer at the household level
- Breaks down energy consumption to the end use and technology level
- Defines the **saturation** (presence of equipment) and the annual consumption of a given technology where it is present **(Unit Energy Consumption – UEC)**
  - Data taken from NEEA's RBSA / CBSA surveys, US DOE Annual Energy Outlook, and Avista's 2013 GenPop Survey



Single Family Profile

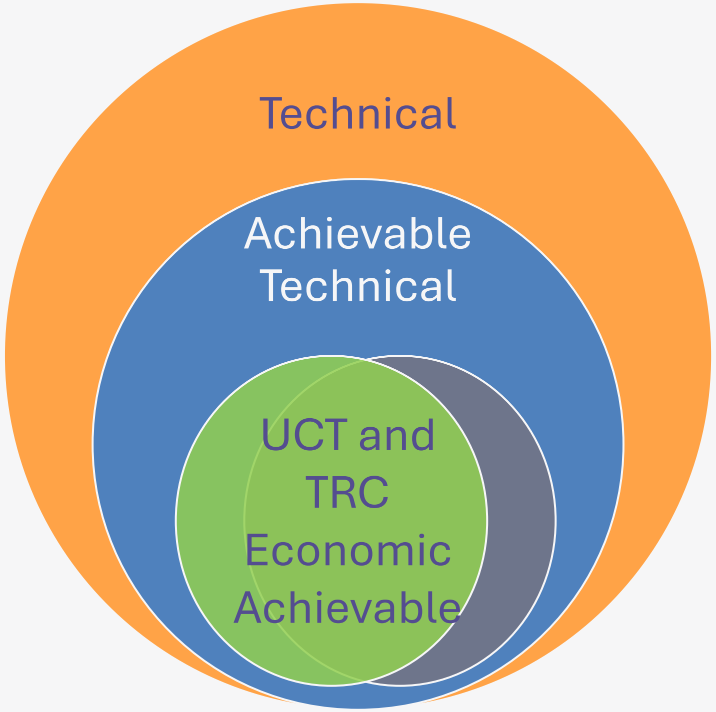
End Use	Technology	Saturation	UEC (therms)	Intensity (therms/HH)	Usage (Dth)
Space Heating	Furnace	85%	646	548	8,648,686
	Boiler	2%	432	10	160,215
Secondary Heating	Fireplace	5%	110	6	88,017
Water Heating	Water Heater (<= 55 Gal)	55%	145	80	1,258,802
	Water Heater (> 55 Gal)	0%	52	0	162
Appliances	Clothes Dryer	28%	22	6	97,826
	Stove/Oven	59%	28	17	260,523
Miscellaneous	Pool Heater	1%	106	1	15,120
	Miscellaneous	100%	1	1	14,482



Estimating Energy Efficiency Potential

We estimate three levels of potential. These are standard practice for CPAs in the Northwest:

- **Technical**: everyone chooses the most efficient option when equipment fails regardless of cost.
- **Achievable Technical** is a subset of technical that accounts for achievable participation within utility programs as well as non-utility mechanisms, such as regional initiatives and market transformation.
- **Achievable Economic** is a subset of achievable technical potential that includes only cost-effective measures. Tests considered within this study were the UCT for Idaho and TRC for Washington.



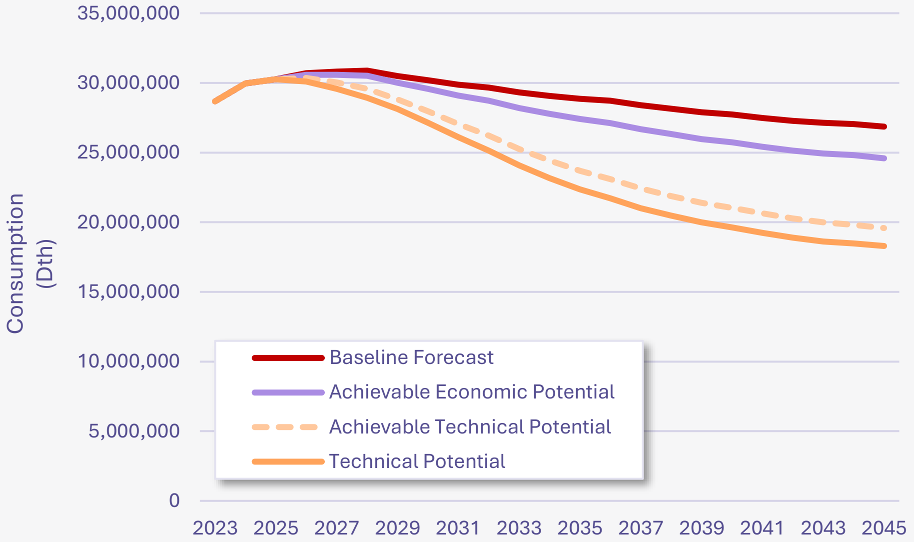
Measure Ramp Rates

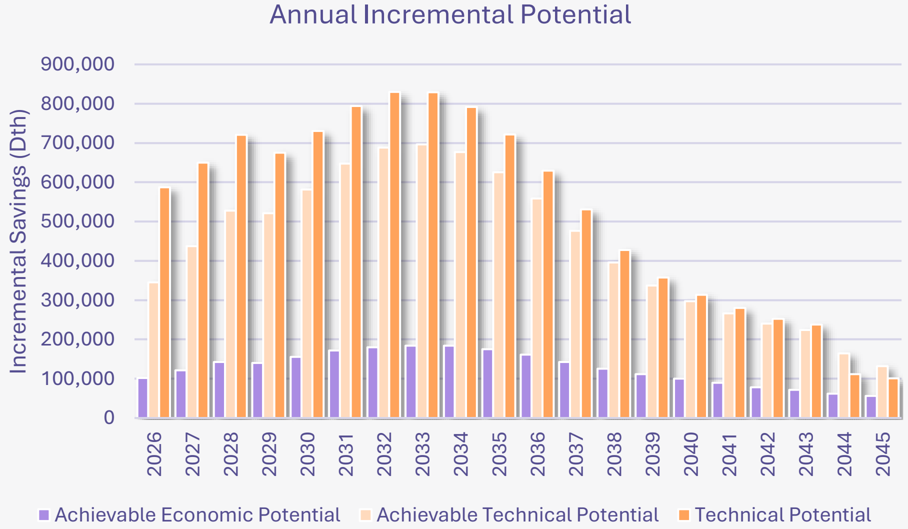
- For this study, AEG adapted the 2021 Power Plan ramp rates for use in a natural gas CPA.
- All measures "ramp up" over time to a maximum of 85% adoption
  - In the 2021 plan, some electric measures have had their maximum achievability increased beyond 85%. None of those specific measures apply to natural gas, and AEG has not increased the achievability for any measures in this study.
  - Power Council's ramp rates include potential realized from outside of utility DSM programs, including regional initiatives and market transformation.
  - A cost-effectiveness screen is applied to equipment measures to address very high-cost measures before ramp rates are applied, consistent with Council methodology.
- AEG considered Avista's recent program achievement when assigning ramp rates to reflect differences between electric and natural gas markets.

Draft Potential Results (All Sectors)

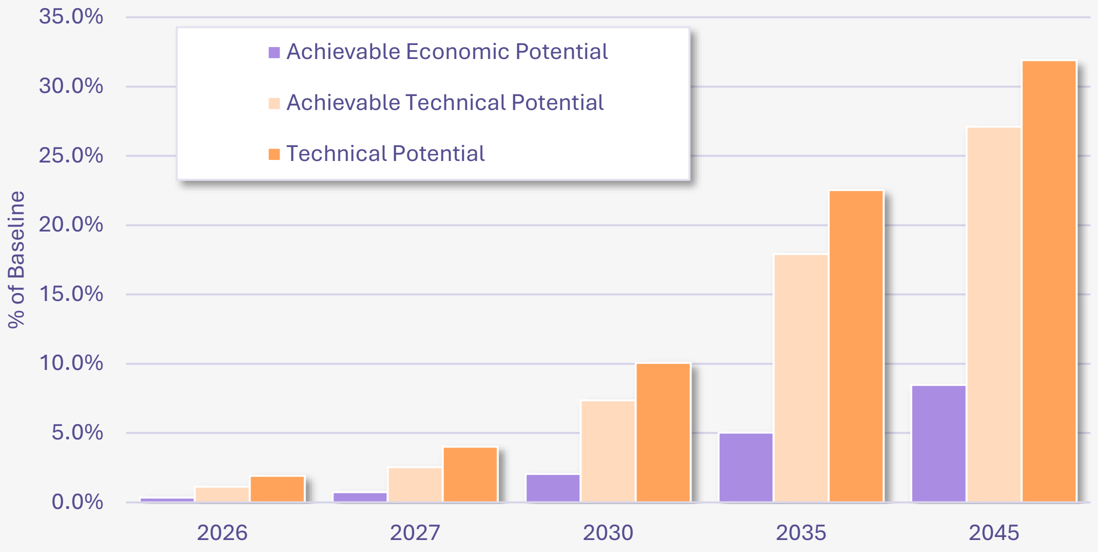
Summary Results (All Sectors, WA & ID Combined)

- Cumulative Achievable Technical Potential reaches 7,280,599 Dth, or 27.1% of the reference baseline by the end of the 20-year study period
- Cumulative Achievable Economic Potential reaches 2,273,359 Dth, or 8.5% of the baseline over the study period





Summary Results Continued

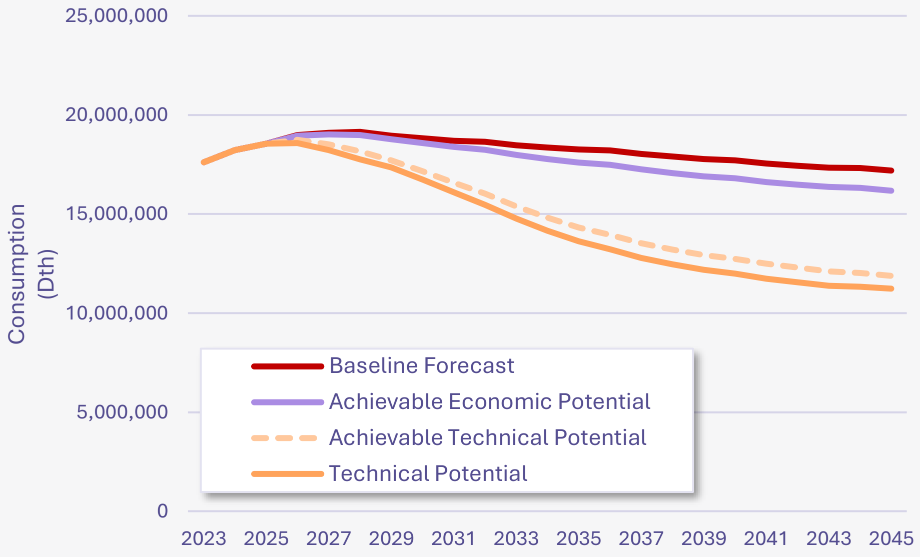


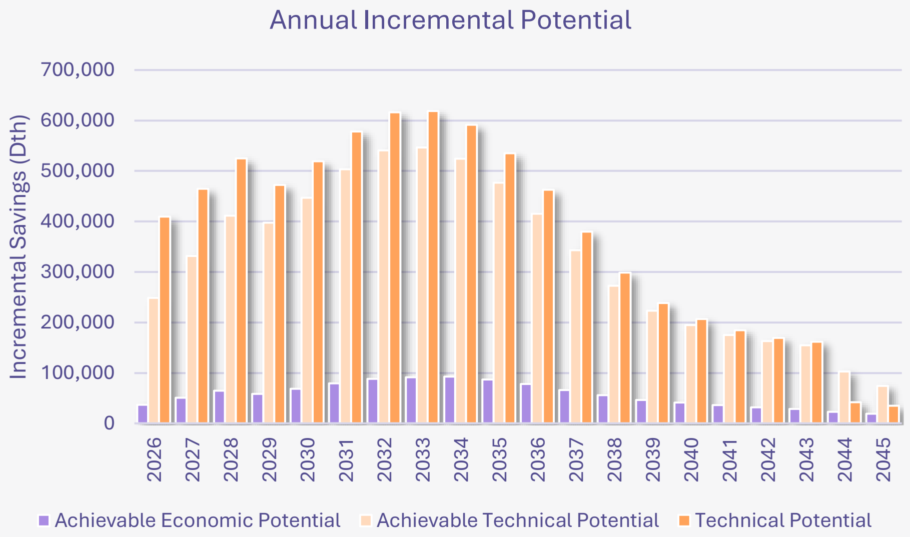
Summary of Energy Savings (Dth), Selected Years	2026	2027	2030	2035	2045
Reference Baseline (Dth)	**30,694,608**	**30,821,229**	**30,189,317**	**28,865,919**	**26,858,182**
Cumulative Savings (Dth)					
Achievable Economic	101,956	224,167	618,329	1,452,725	2,273,359
Achievable Technical	345,378	781,698	2,223,030	5,169,004	7,280,599
Technical Potential	587,137	1,236,115	3,038,374	6,504,292	8,570,562
Energy Savings (% of Baseline)					
Achievable Economic	0.3%	0.7%	2.0%	5.0%	8.5%
Achievable Technical	1.1%	2.5%	7.4%	17.9%	27.1%
Technical Potential	1.9%	4.0%	10.1%	22.5%	31.9%
Incremental Savings (Dth)					
Achievable Economic	101,954	121,649	155,584	175,424	56,357
Achievable Technical	345,371	437,413	581,629	625,774	131,572
Technical Potential	587,129	650,476	730,576	721,826	100,708

Draft Residential Potential Results

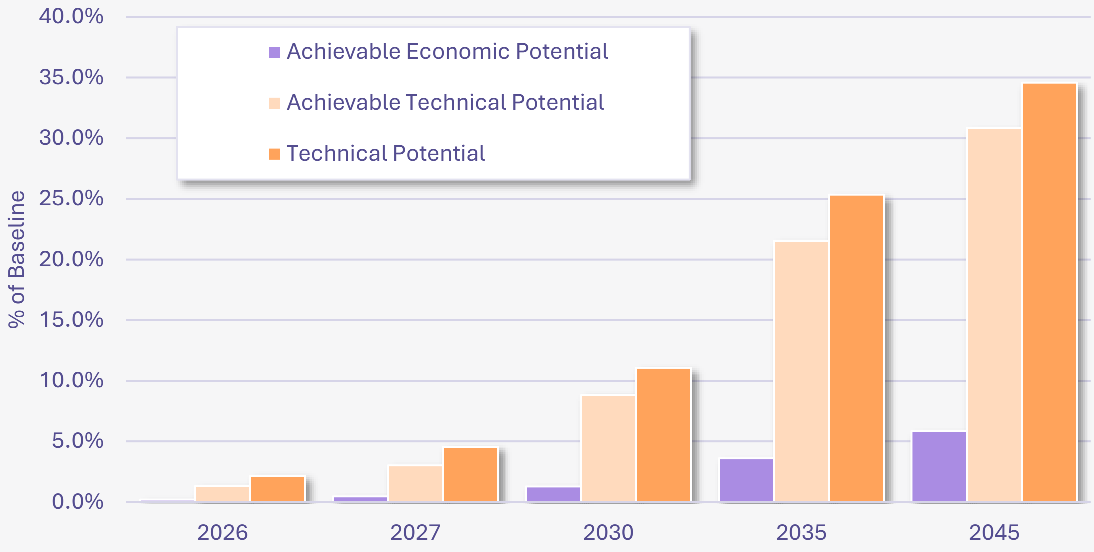
Residential Summary Results (WA & ID Combined)

- Cumulative Achievable Technical Potential reaches 5,299,926 Dth, or 30.8% of the reference baseline by the end of the 20-year study period
- Cumulative Achievable Economic Potential reaches 1,010,061 Dth, or 5.9% of baseline over the study period





Summary Results Continued



Summary of Energy Savings (Dth), Selected Years	2026	2027	2030	2035	2045
Reference Baseline (Dth)	**18,987,239**	**19,099,846**	**18,823,213**	**18,249,556**	**17,185,408**
Cumulative Savings (Dth)					
Achievable Economic	36,948	87,781	242,714	657,590	1,010,061
Achievable Technical	248,509	578,806	1,656,795	3,928,342	5,299,926
Technical Potential	409,851	872,234	2,083,457	4,625,799	5,945,955
Energy Savings (% of Baseline)					
Achievable Economic	0.2%	0.5%	1.3%	3.6%	5.9%
Achievable Technical	1.3%	3.0%	8.8%	21.5%	30.8%
Technical Potential	2.2%	4.6%	11.1%	25.3%	34.6%
Incremental Savings (Dth)					
Achievable Economic	36,948	50,917	68,500	87,033	19,293
Achievable Technical	248,509	331,903	446,884	476,864	74,182
Technical Potential	409,851	464,676	519,371	534,862	34,879

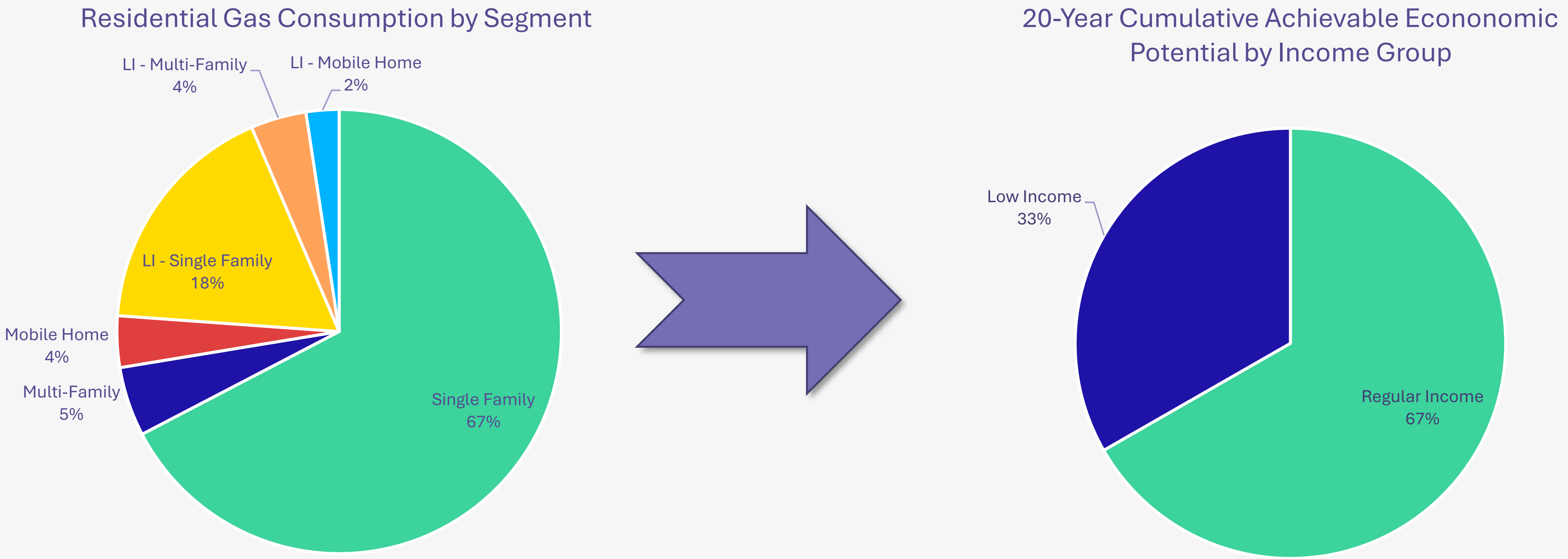
Residential Top Measures (Achievable Economic)

Rank	**Idaho** – Achievable Economic UCT Potential	2045 Achievable Economic Potential (Dth)	% of Total Savings
1	Connected Thermostat - ENERGY STAR (1.0)	71,555	22.6%
2	Insulation - Ceiling Installation	69,252	21.9%
3	Furnace	44,423	14.1%
4	ENERGY STAR Home Design	29,219	9.2%
5	Clothes Washer - CEE Tier 2	16,871	5.3%
6	Home Energy Reports	16,867	5.3%
7	Water Heater - Faucet Aerators	15,641	5.0%
8	Water Heater - Low-Flow Showerheads	14,319	4.5%
9	Building Shell - Air Sealing (Infiltration Control)	9,099	2.9%
10	Windows - Low-e Storm Addition	6,015	1.9%
	Subtotal	**293,261**	**92.8%**
	Total Savings in Year	**315,968**	**100.0%**

Rank	**Washington** – Achievable Economic TRC Potential	2045 Achievable Economic Potential (Dth)	% of Total Savings
1	Furnace	252,172	36.3%
2	Insulation - Ceiling Installation	85,451	12.3%
3	Home Energy Management System (HEMS)	57,291	8.3%
4	Ducting - Repair and Sealing - Aerosol	57,284	8.3%
5	Water Heater (<= 55 Gal)	49,898	7.2%
6	Water Heater - Drainwater Heat Recovery	41,161	5.9%
7	Clothes Washer - CEE Tier 2	25,511	3.7%
8	Home Energy Reports	25,435	3.7%
9	Building Shell - Air Sealing (Infiltration Control)	20,339	2.9%
10	Fireplace	11,915	1.7%
	Subtotal	**626,457**	**90.3%**
	Total Savings in Year	**694,094**	**100.0%**

Residential Potential by Income Group

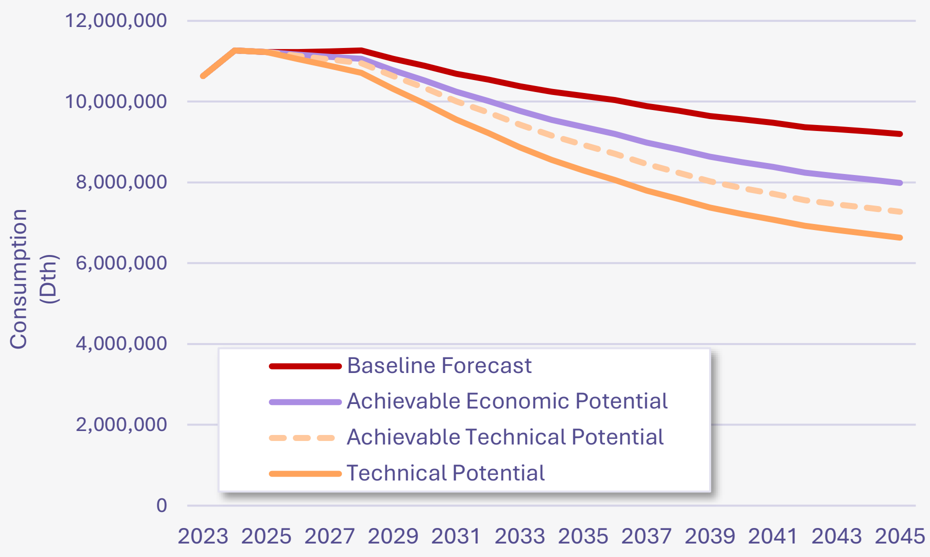
Low-Income potential is proportional to the low-income share of natural gas consumption

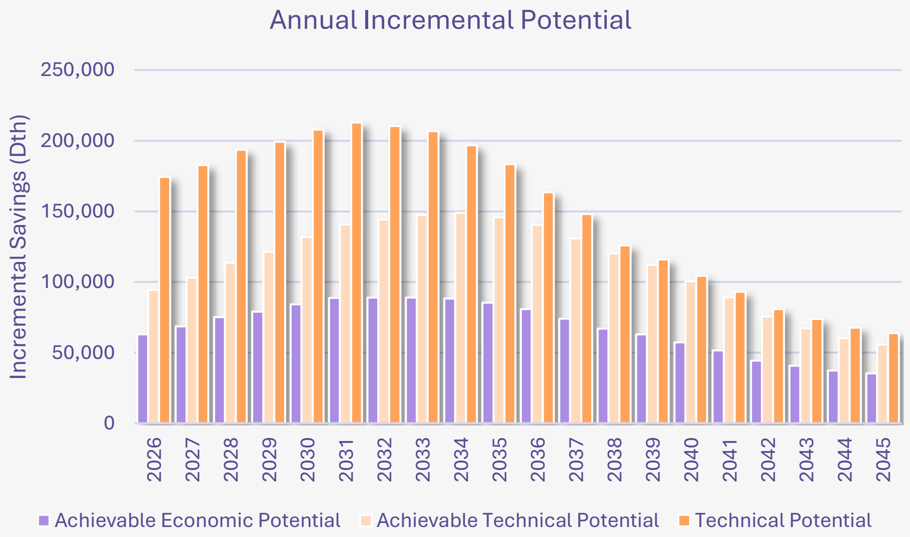


Draft Commercial Potential Results

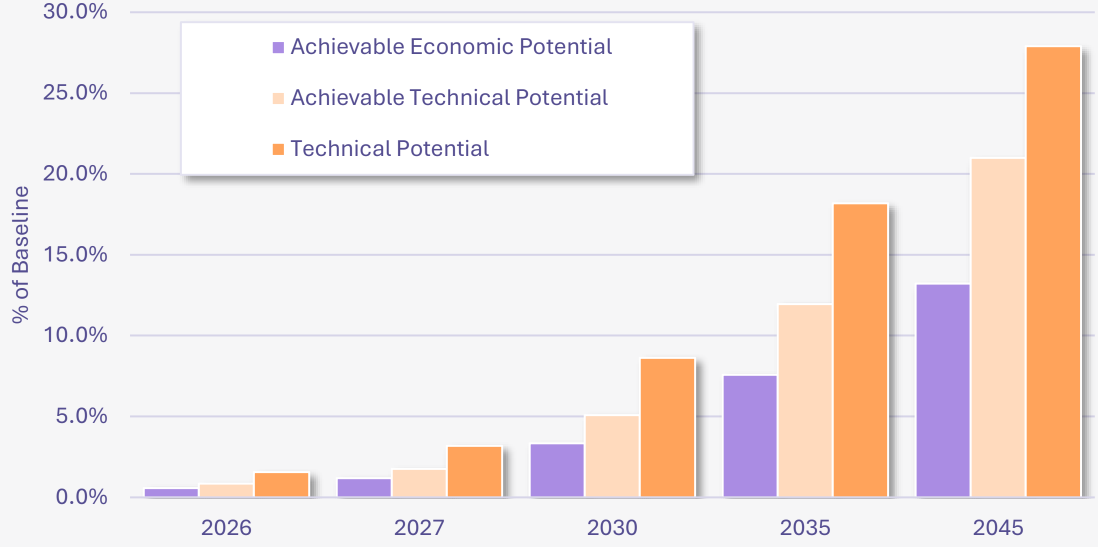
Commercial Summary Results (WA & ID Combined)

- Cumulative Achievable Technical Potential reaches 1,931,836 Dth, or 21% of the reference baseline over the 20-year study period.
- Cumulative Achievable Economic Potential reaches 1,217,146 Dth, or 13.2% of the baseline.





Commercial Summary Results Continued



Summary of Energy Savings (Dth), Selected Years	2026	2027	2030	2035	2045
Reference Baseline (Dth)	**11,229,877**	**11,244,262**	**10,890,299**	**10,142,703**	**9,203,073**
Cumulative Savings (Dth)					
Achievable Economic	62,957	132,246	364,283	768,870	1,217,146
Achievable Technical	94,431	197,967	553,157	1,212,068	1,931,836
Technical Potential	174,326	357,927	939,269	1,844,706	2,567,719
Energy Savings (% of Baseline)					
Achievable Economic	0.6%	1.2%	3.3%	7.6%	13.2%
Achievable Technical	0.8%	1.8%	5.1%	12.0%	21.0%
Technical Potential	1.6%	3.2%	8.6%	18.2%	27.9%
Incremental Savings (Dth)					
Achievable Economic	62,955	68,637	84,298	85,399	35,432
Achievable Technical	94,424	103,018	131,847	145,822	55,739
Technical Potential	174,318	182,798	207,770	183,362	63,935

Commercial Top Measures (Achievable Economic)

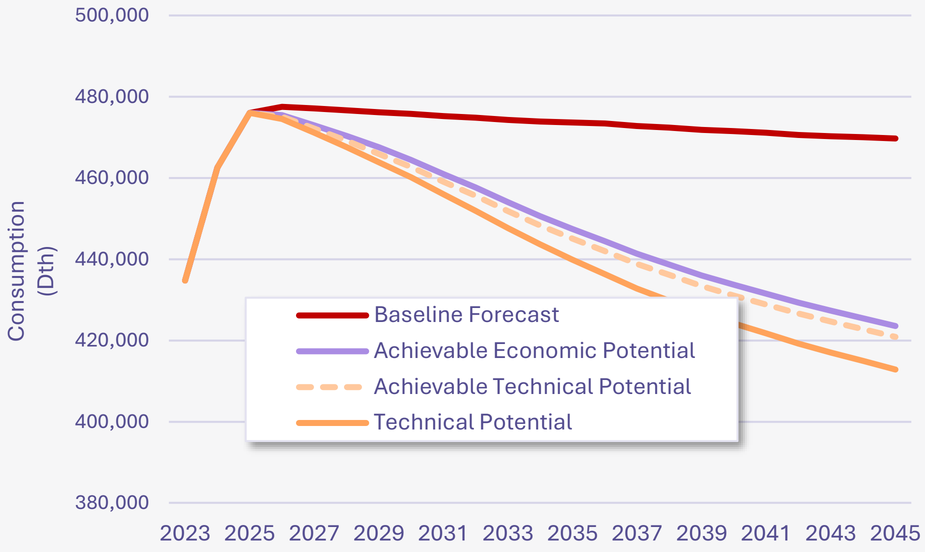
Rank	**Idaho** – Achievable Economic UCT Potential	2045 Achievable Economic Potential (Dth)	% of Total Savings
1	Furnace	55,089	16.1%
2	Fryer	37,786	11.0%
3	HVAC - Energy Recovery Ventilator	30,097	8.8%
4	Water Heater	26,886	7.8%
5	Retrocommissioning	18,855	5.5%
6	Unit Heater	18,435	5.4%
7	Water Heater - Pipe Insulation	16,126	4.7%
8	Boiler	14,536	4.2%
9	Broiler	12,322	3.6%
10	Oven	10,766	3.1%
	Subtotal	**240,898**	**70.3%**
	Total Savings in Year	**342,501**	**100.0%**

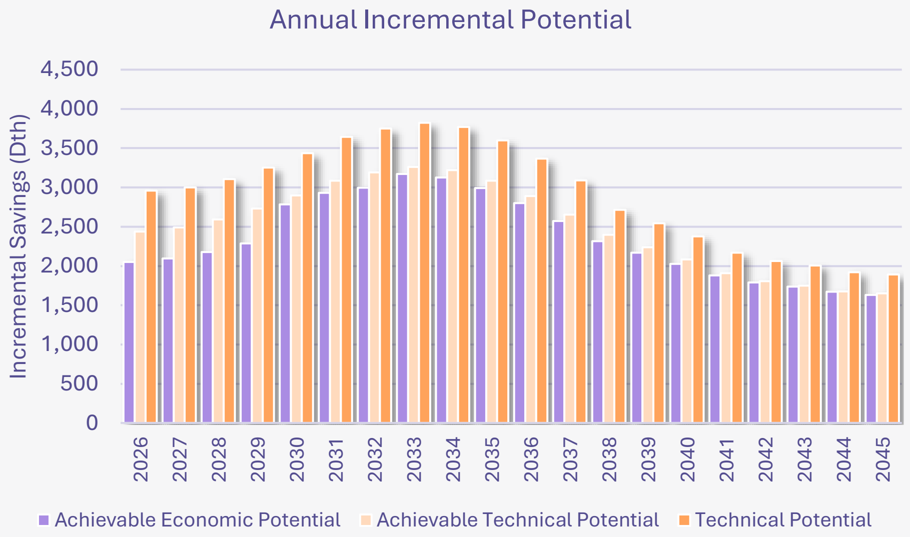
Rank	**Washington** – Achievable Economic TRC Potential	2045 Achievable Economic Potential (Dth)	% of Total Savings
1	Furnace	145,463	16.6%
2	Destratification Fans (HVLS)	76,738	8.8%
3	Ventilation - Demand Controlled	69,390	7.9%
4	HVAC - Energy Recovery Ventilator	64,414	7.4%
5	Strategic Energy Management	44,680	5.1%
6	Water Heater	44,216	5.1%
7	Retrocommissioning	44,020	5.0%
8	Water Heater - Pipe Insulation	33,466	3.8%
9	Broiler	28,854	3.3%
10	Griddle	25,480	2.9%
	Subtotal	**576,719**	**65.9%**
	Total Savings in Year	**874,645**	**100.0%**

Draft Industrial Potential Results

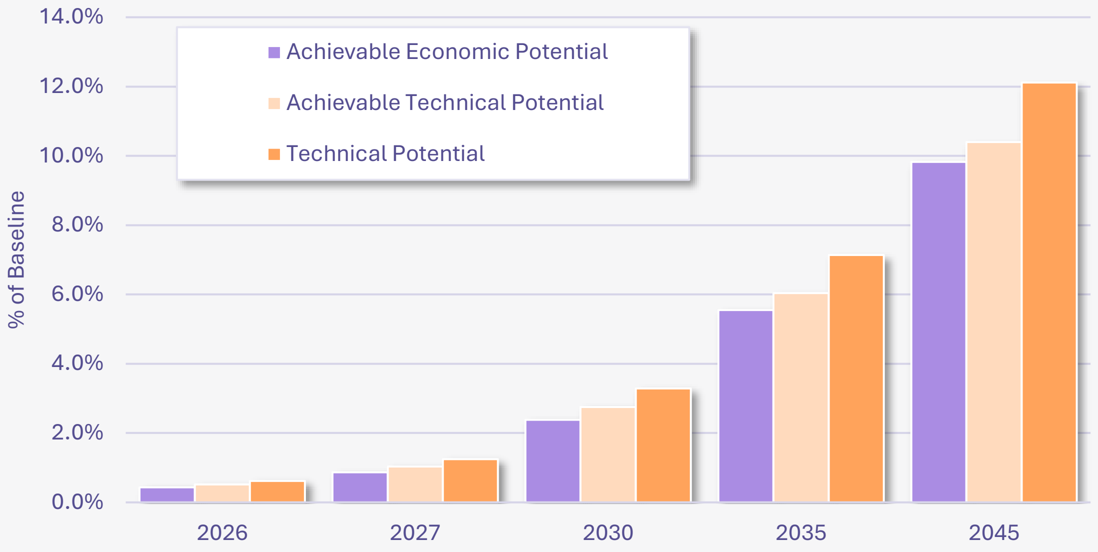
Industrial Summary Results (WA & ID Combined)

- Cumulative Achievable Technical Potential reaches 48,837 Dth, or 10.4% of the reference baseline over the 20-year study period.
- Cumulative Achievable Economic Potential reaches 46,151 Dth, or 9.8% of the baseline.





Industrial Summary Results Continued



Summary of Energy Savings (Dth), Selected Years	2026	2027	2030	2035	2045
Reference Baseline (Dth)	**477,492**	**477,120**	**475,805**	**473,660**	**469,702**
Cumulative Savings (Dth)					
Achievable Economic	2,050	4,141	11,332	26,264	46,151
Achievable Technical	2,439	4,924	13,078	28,594	48,837
Technical Potential	2,960	5,953	15,648	33,786	56,888
Energy Savings (% of Baseline)					
Achievable Economic	0.4%	0.9%	2.4%	5.5%	9.8%
Achievable Technical	0.5%	1.0%	2.7%	6.0%	10.4%
Technical Potential	0.6%	1.2%	3.3%	7.1%	12.1%
Incremental Savings (Dth)					
Achievable Economic	2,050	2,096	2,786	2,992	1,633
Achievable Technical	2,439	2,492	2,899	3,087	1,650
Technical Potential	2,960	3,002	3,435	3,601	1,894

Industrial Top Measures (Achievable Economic)

Rank	**Idaho** – Achievable Economic UCT Potential	2045 Achievable Economic Potential (Dth)	% of Total Savings
1	Process - Heat Recovery	5,697	41.8%
2	Process Boiler - Steam Trap Replacement	1,816	13.3%
3	Process Boiler - Burner Control Optimization	1,347	9.9%
4	Strategic Energy Management	1,012	7.4%
5	Retrocommissioning	915	6.7%
6	Process Boiler - Insulate Steam Lines/Condensate Tank	601	4.4%
7	Process - Insulate Heated Process Fluids	497	3.7%
8	Unit Heater	417	3.1%
9	Destratification Fans (HVLS)	400	2.9%
10	Process Boiler - High Turndown Burner	272	2.0%
	Subtotal	**12,974**	**95.3%**
	Total Savings in Year	**13,615**	**100.0%**

Rank	**Washington** – Achievable Economic TRC Potential	2045 Achievable Economic Potential (Dth)	% of Total Savings
1	Process - Heat Recovery	15,072	46.3%
2	Process Boiler - Steam Trap Replacement	3,931	12.1%
3	Process Boiler - Burner Control Optimization	2,896	8.9%
4	Strategic Energy Management	2,145	6.6%
5	Retrocommissioning	1,942	6.0%
6	Process Boiler - Insulate Steam Lines/Condensate Tank	1,289	4.0%
7	Process - Insulate Heated Process Fluids	1,078	3.3%
8	Process Furnace - Tube Inserts	924	2.8%
9	Destratification Fans (HVLS)	749	2.3%
10	Process Boiler - High Turndown Burner	585	1.8%
	Subtotal	**30,611**	**94.1%**
	Total Savings in Year	**32,536**	**100.0%**

Natural Gas Demand Response

Approach to the Study

Data Collection → Characterize the Market → Develop list of DR Options → Characterize the Options → Estimate Potential

Align with EE Potential Study

- Market Profiles

Secondary Sources

- DR Program Evaluation Reports from other Utilities

Segmentation by Customer Class

- Residential
- Commercial
- Industrial

Program Options

- Behavioral
- DLC Smart Thermostats – BYOT
- Third Party Contracts

Develop Program Assumptions

- Impacts
- Participation
- End Use Saturations
- Costs
- Incentives

Achievable Potential

- Integrated program options without participant overlap

Changes from Previous Study

The following updates were made to the previous study

- Removed all dynamic rate options (TOU, VPP)
  - Level of sophistication required makes these programs difficult to implement for Gas DR
- Removed Water Heating DLC
  - Costly to implement, unlikely to have high participation, low peak impacts
- Limited Smart Thermostat Program to WA only due to AMI availability
- Updated per-customer peak therms – lower compared to previous study
- Updated program assumptions
- Behavioral Program limited to res-only due to vendor limitations

Assumptions

Study Assumptions

- The programs in this study target the peak hour of the peak day (therms)
- Winter only

Program Impact and Cost Assumptions

- Derived Primarily from other Gas DR Programs
  - Smart Thermostat Program based on ConEd Program
  - Third Party Contracts Program based on National Grid Program
- Diverged where gaps in research
  - Customized for Avista's service territory
  - Pulled remaining assumptions from Electric DR Study and scaled-down where appropriate

Advanced Metering Infrastructure (AMI) Assumptions

Some DR Programs Require AMI

- Dynamic Rate and Smart Thermostat Programs require AMI for billing

Washington

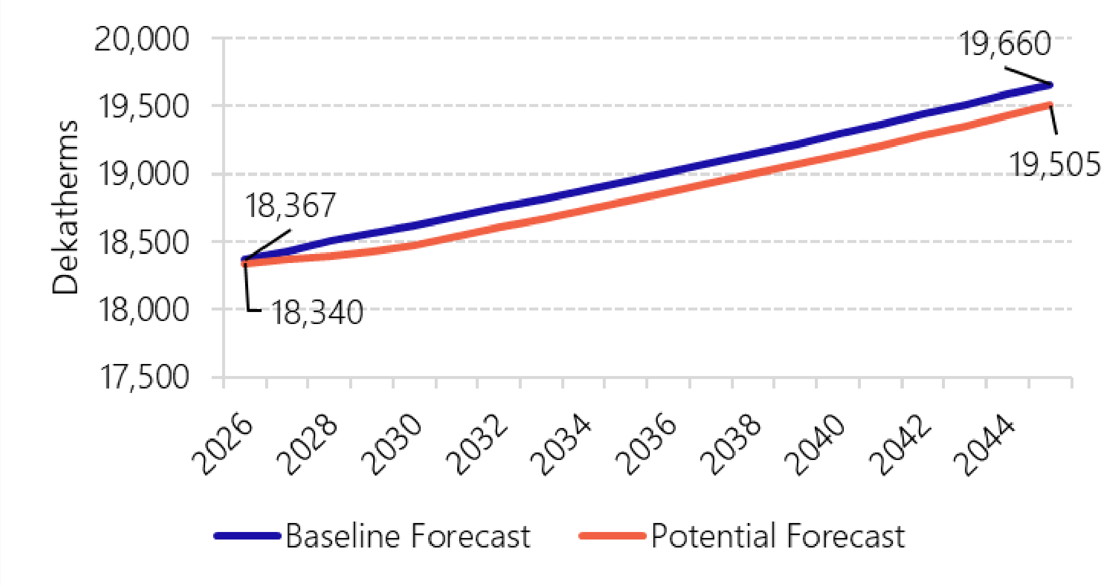
- Used current Avista AMI saturation rates by sector and held constant

Idaho and Oregon

- No AMI Projected

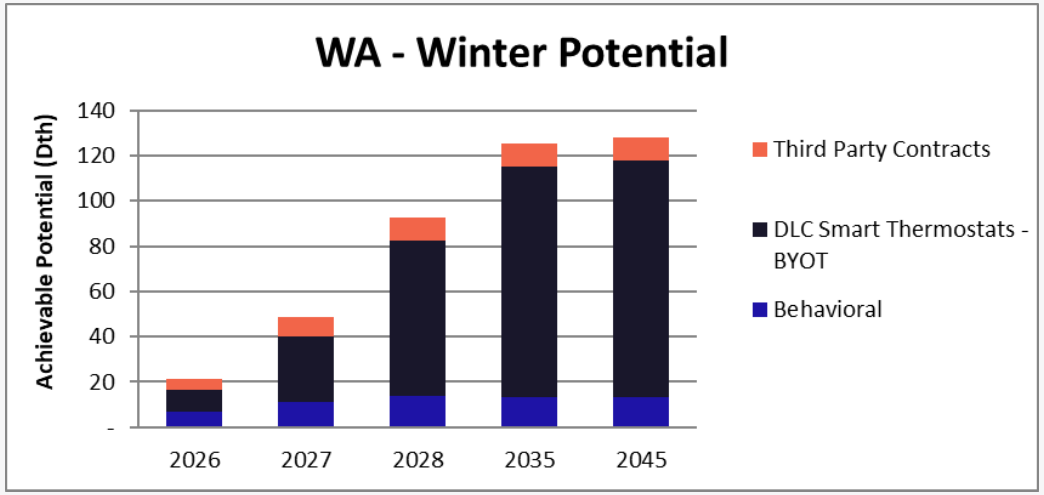
Achievable Potential

Achievable Potential Forecast (All States)



Total Potential	2026	2027	2030	2035	2045
Baseline Forecast (Dth)	**18,367**	**18,428**	**18,623**	**18,946**	**19,660**
Market Potential	26	56	147	150	155
Peak Reduction % of Baseline	0.1%	0.3%	0.8%	0.8%	0.8%
Potential Forecast	**18,340**	**18,372**	**18,476**	**18,795**	**19,505**

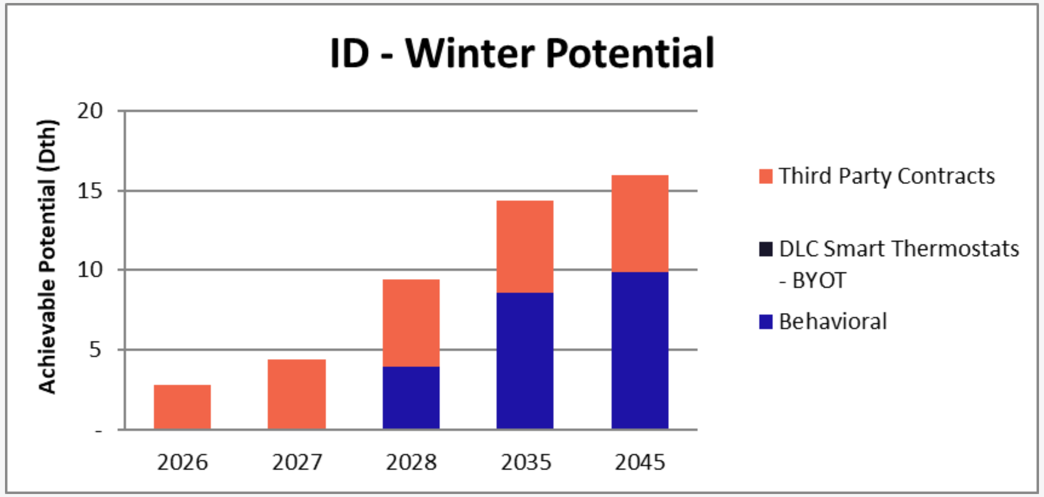
Washington Potential by Program



WA - Winter Potential	2026	2027	2028	2035	2045
Baseline Forecast (Dth)	9,217	9,207	9,193	9,094	8,956
Achievable Potential (Dth)	22	49	93	125	128
Behavioral	7	11	14	13	13
DLC Smart Thermostats - BYOT	10	29	69	102	105
Third Party Contracts	5	8	10	10	10

- Only state with Thermostat potential due to AMI limitations
- Thermostats contribute around 82% of the total potential by 2045
- Potential across all programs ~ 1.4% of WA baseline

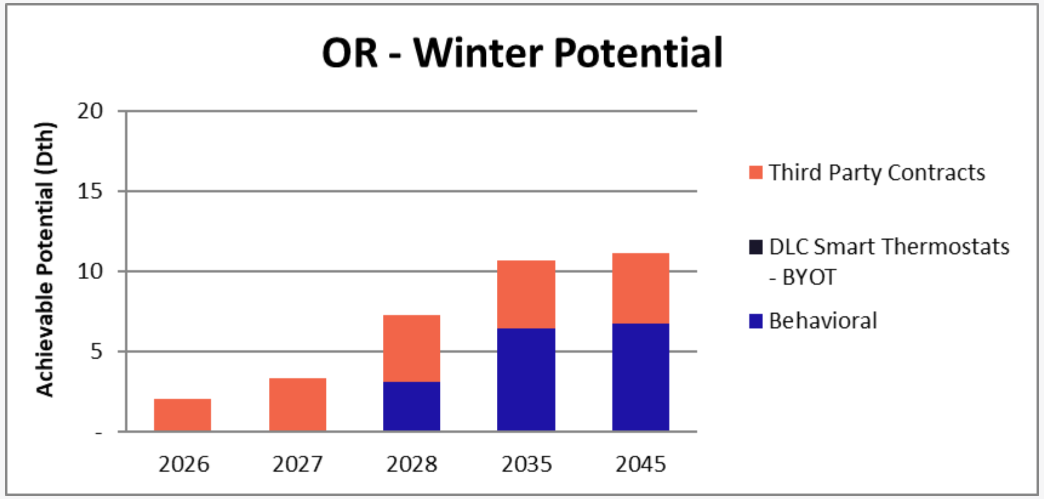
Idaho Potential by Program



ID - Winter Potential	2026	2027	2028	2035	2045
Baseline Forecast (Dth)	5,060	5,115	5,185	5,611	6,288
Achievable Potential (Dth)	3	4	9	14	16
Behavioral	-	-	4	9	10
DLC Smart Thermostats - BYOT	-	-	-	-	-
Third Party Contracts	3	4	6	6	6

- 2028 start date for the Behavioral Program for both ID and OR

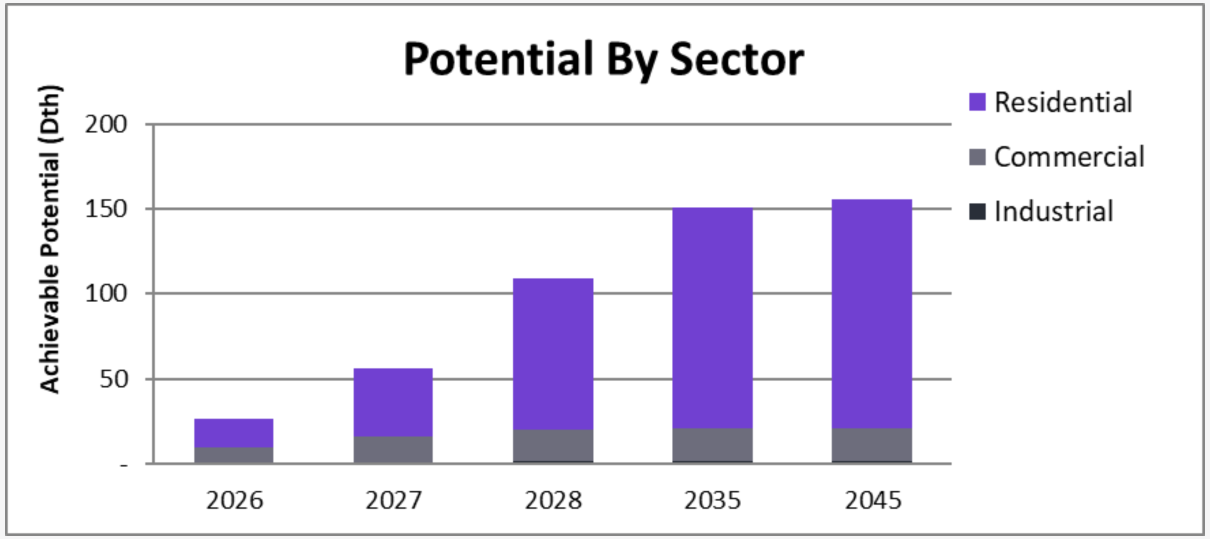
Oregon Potential by Program



OR - Winter Potential	2026	2027	2028	2035	2045
Baseline Forecast (Dth)	4,090	4,107	4,121	4,240	4,416
Achievable Potential (Dth)	2	3	7	11	11
Behavioral	-	-	3	6	7
DLC Smart Thermostats - BYOT	-	-	-	-	-
Third Party Contracts	2	3	4	4	4

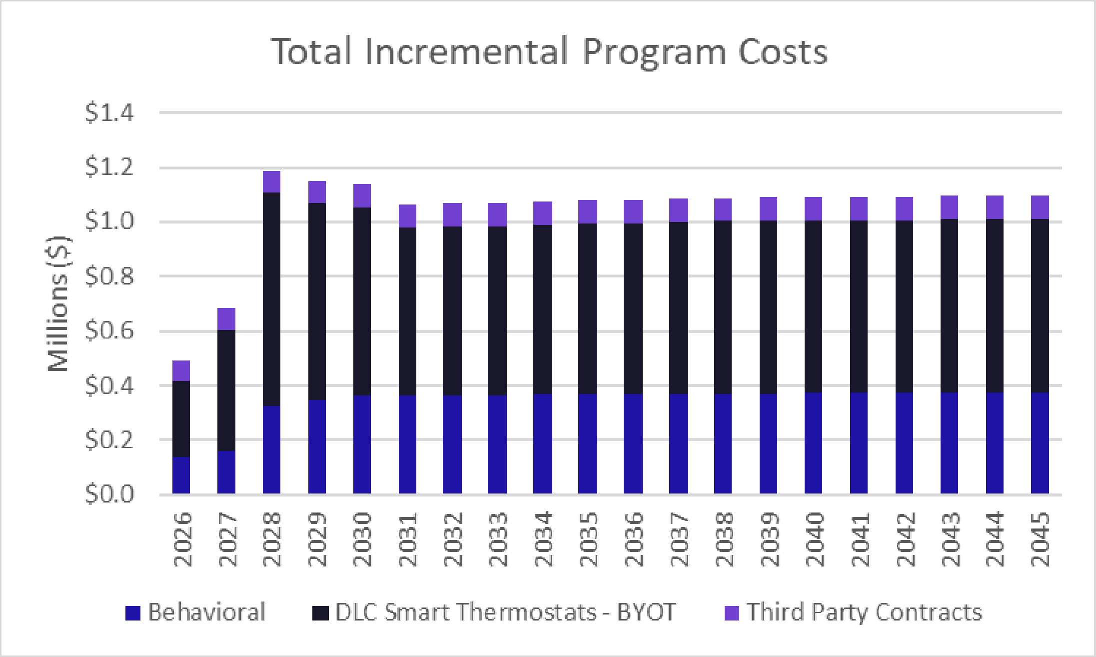
- Lowest potential across all three states due to limited AMI and proportionally low overall baseline Dth

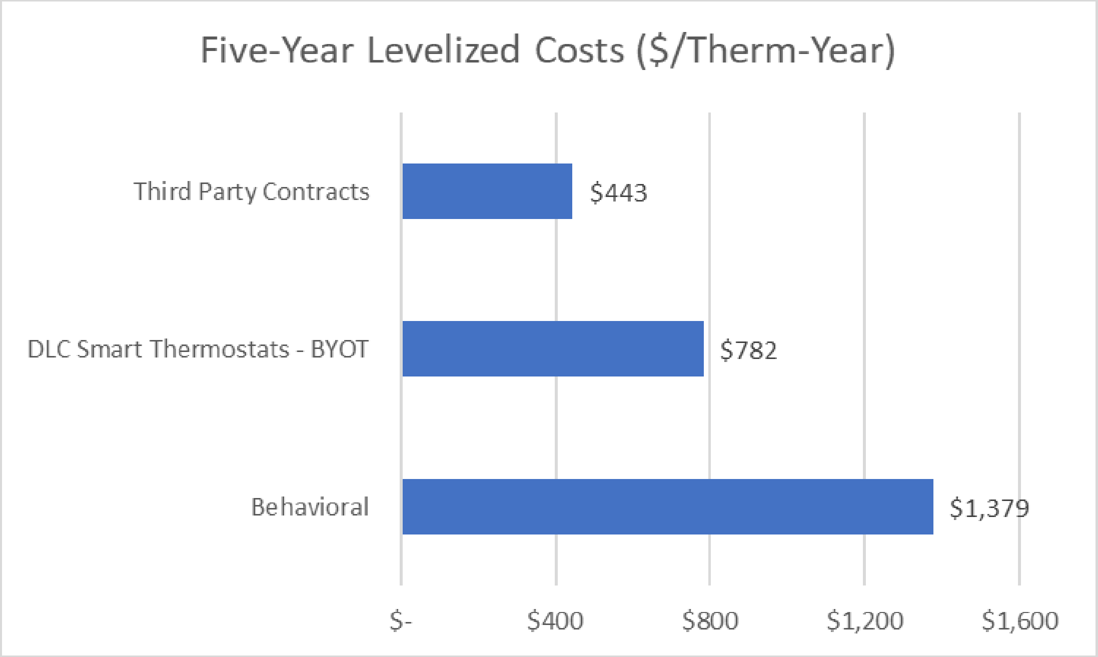
Results by Sector



Potential By Sector	2026	2027	2028	2035	2045
Baseline Forecast (Dth)	18,367	18,428	18,500	18,946	19,660
Achievable Potential (Dth)	26	56	109	150	155
Residential	16	40	89	130	134
Commercial	9	15	19	19	20
Industrial	1	1	1	1	1

Program Costs





Gas DR Key Findings

Natural Gas DR is an emerging resource

- Small number of programs in existence
- Numerous questions surround the applicability and reliability of Gas DR

Program Potential

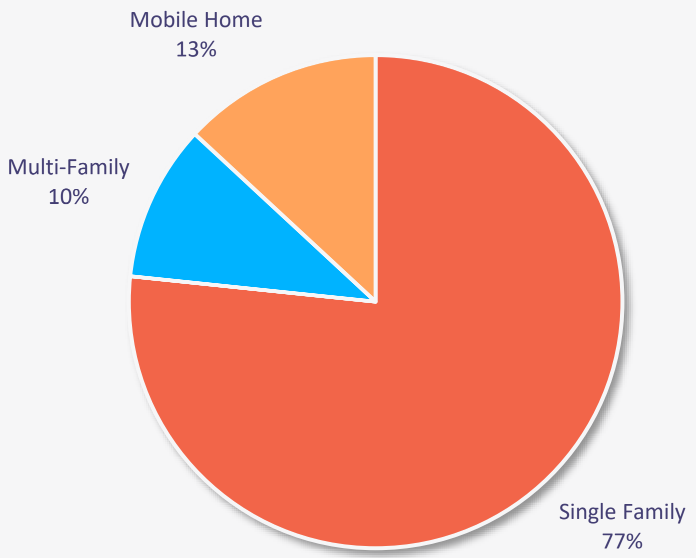
- Smart Thermostats
  - Largest savings potential ~ 82% of potential in WA by 2045
- Third Party Contracts
  - Lowest levelized cost but also lowest potential
    - Small amount of customers
    - Not a lot of discretionary load to reduce

OR Low-Income Energy Efficiency Potential Study

OR Low-Income Customers and Energy Consumption by Home Type

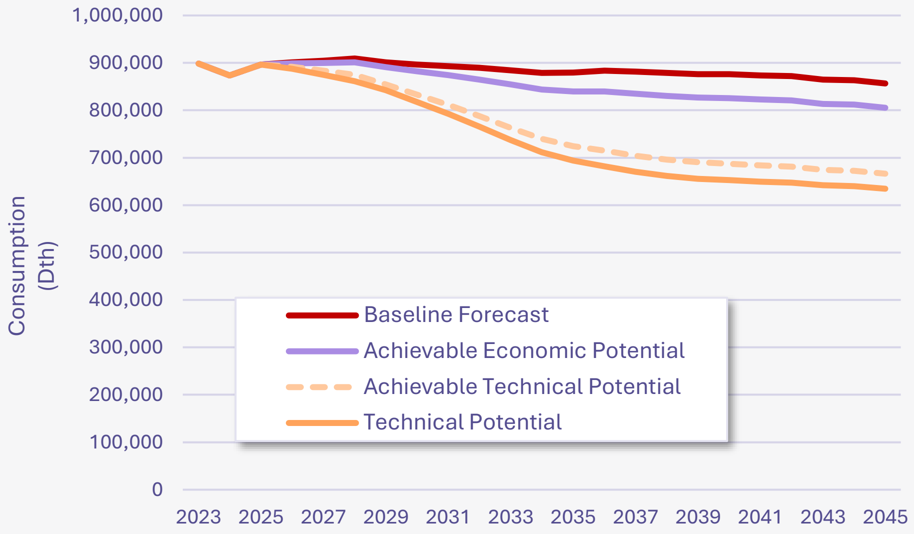
Segment	Households	% of All Homes	Usage (Dth)	Therms / HH
Single Family	12,289	65.0%	622,559	539
Multi-Family	4,428	23.4%	88,679	200
Mobile Home	2,197	11.6%	113,191	515
Total	**18,914**	**100.0%**	**864,429**	**457**

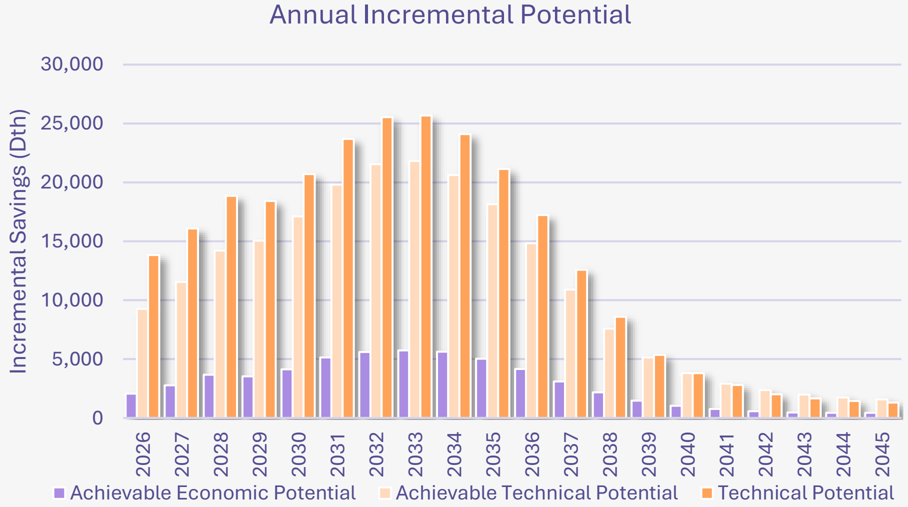
Gas Use by Segment



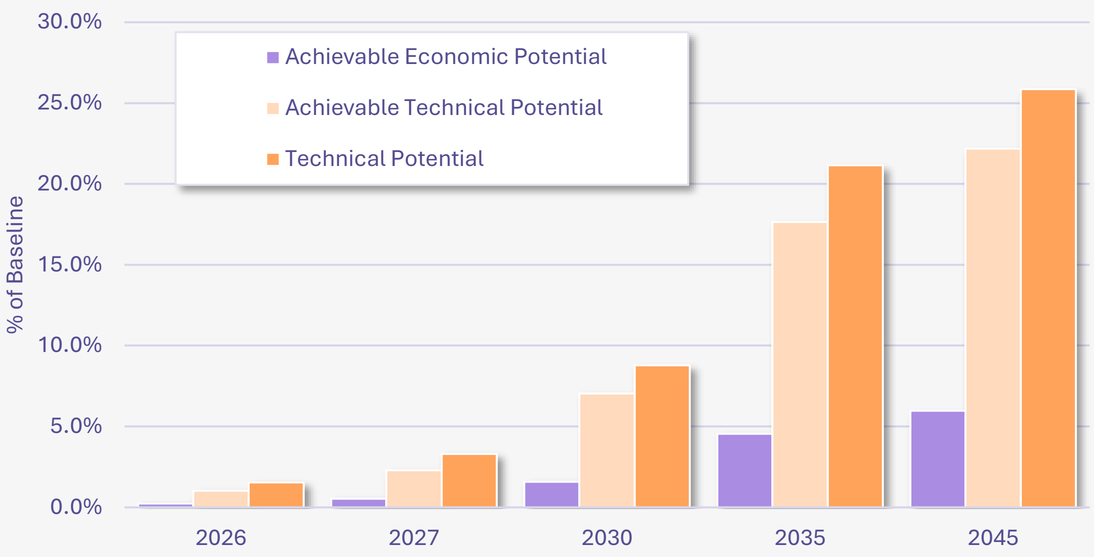
Summary Results (OR Low-Income)

- For Oregon Low-Income Customers, Cumulative Achievable Technical Potential is 189,919 Dth, or 22.2% of the baseline over 20 years
- Cumulative Achievable Economic Potential (TRC) is 51,164 Dth, or 6% of the baseline





Summary Results Continued



Summary of Energy Savings (Dth), Selected Years	2026	2027	2030	2035	2045
Reference Baseline (Dth)	**901,274**	**904,673**	**896,310**	**879,805**	**856,427**
Cumulative Savings (Dth)					
Achievable Economic	2,068	4,856	14,095	39,976	51,164
Achievable Technical	9,275	20,777	63,138	155,234	189,919
Technical Potential	13,847	29,842	78,653	186,112	221,549
Energy Savings (% of Baseline)					
Achievable Economic	0.2%	0.5%	1.6%	4.5%	6.0%
Achievable Technical	1.0%	2.3%	7.0%	17.6%	22.2%
Technical Potential	1.5%	3.3%	8.8%	21.2%	25.9%
Incremental Savings (Dth)					
Achievable Economic	2,068	2,789	4,135	5,032	444
Achievable Technical	9,275	11,566	17,115	18,168	1,580
Technical Potential	13,847	16,090	20,697	21,153	1,329

Top Measures (OR Low-Income)

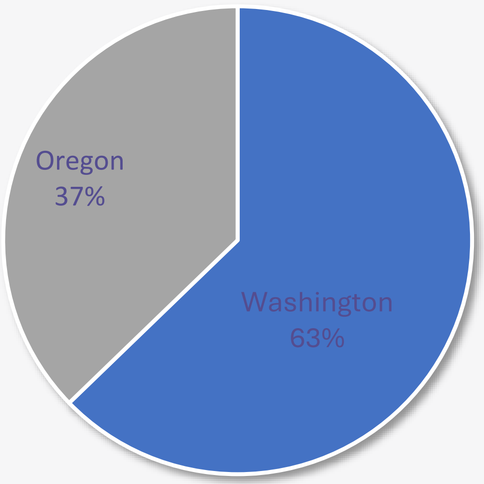
Rank	**Oregon** – Achievable Economic TRC Potential	2045 Achievable Economic Potential (Dth)	% of Total Savings
1	Insulation - Ceiling Installation	7,749	15.1%
2	Insulation - Wall Cavity Upgrade	7,107	13.9%
3	Insulation - Ceiling Upgrade	6,193	12.1%
4	Ducting - Repair and Sealing - Aerosol	4,624	9.0%
5	Building Shell - Air Sealing (Infiltration Control)	3,834	7.5%
6	Furnace	3,297	6.4%
7	Insulation - Floor Upgrade	2,287	4.5%
8	Insulation - Floor Installation	2,254	4.4%
9	Insulation - Ducting	2,073	4.1%
10	Insulation - Wall Sheathing	1,776	3.5%
	Subtotal	**41,196**	**80.5%**
	Total Savings in Year	**51,164**	**100.0%**

OR-WA Transport Customer Energy Efficiency Potential Study

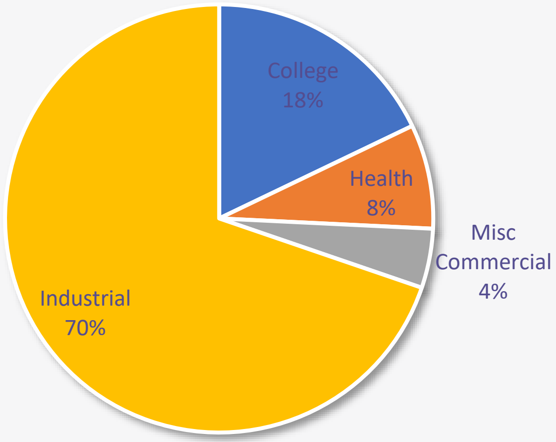
Market Characterization

- Define energy-consumption characteristics in the base year of the study (2021).
- Incorporates Avista's actual consumption and customer counts to develop "Control Totals" – values to which the model will be calibrated.
- Grounds the analysis in Avista data and provides enough detail to project assumptions forward to develop a baseline energy projection.
- After separating gas consumption into sectors and segments, it is allocated to specific end uses and technologies.

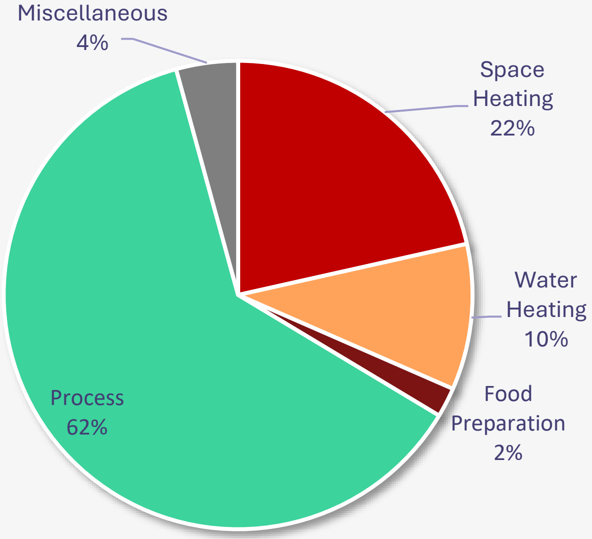
Transport Gas Use by State (2021)



Transport Gas Use by Segment (2021)



Transport Gas Use by End Use (2021)



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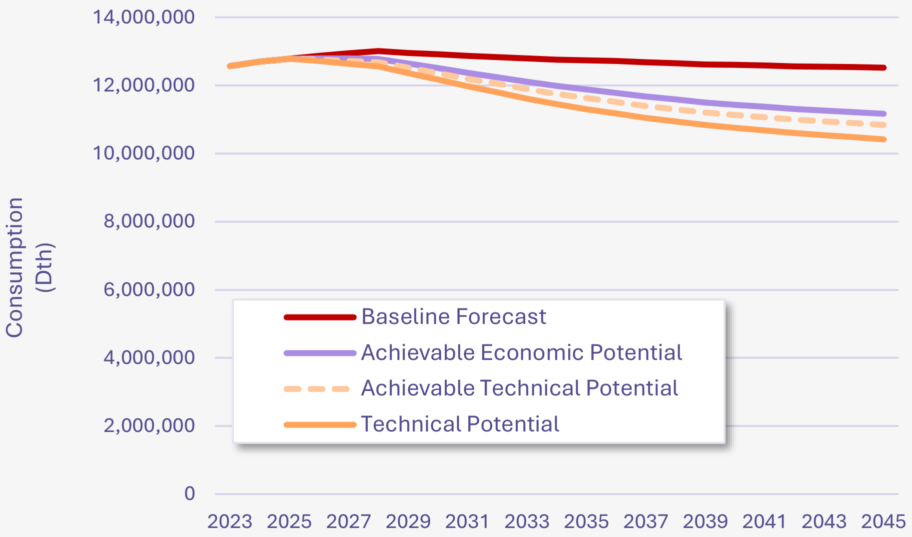
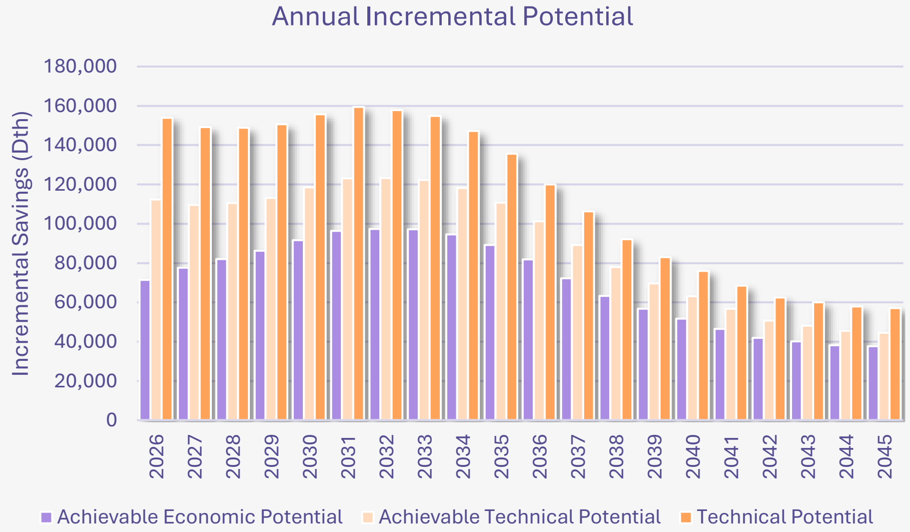
Considerations for this Analysis

- Available potential is largely a function of baseline consumption – segments with the highest baseline consumption are likely to have the highest potential
- Potential studies rely on average information, which may not reflect conditions or opportunities for any single customer
  - This is particularly relevant for this study, where a small number of customers represent a large share of transport load
  - Ramp rates are derived from the Northwest Power and Conservation Council's 2021 Power Plan and reflect expected adoption across a broad set of customers. Actual adoption of energy efficiency for large transport customers may be lumpier based on cycles for implementing large capital projects

Draft Potential Results

Summary Results (All States & Transport Sectors)





Summary of Energy Savings (Dth), Selected Years	2026	2027	2030	2035	2045
Reference Baseline (Dth)	**12,867,931**	**12,940,233**	**12,916,886**	**12,740,100**	**12,521,417**
Cumulative Savings (Dth)					
Achievable Economic	71,410	149,277	405,529	861,783	1,356,513
Achievable Technical	112,359	221,738	553,523	1,111,243	1,681,083
Technical Potential	153,865	302,414	741,338	1,436,433	2,104,270
Energy Savings (% of Baseline)					
Achievable Economic	0.6%	1.2%	3.1%	6.8%	10.8%
Achievable Technical	0.9%	1.7%	4.3%	8.7%	13.4%
Technical Potential	1.2%	2.3%	5.7%	11.3%	16.8%
Incremental Savings (Dth)					
Achievable Economic	71,410	77,638	91,630	89,176	37,661
Achievable Technical	112,359	109,625	118,608	110,727	44,538
Technical Potential	153,865	149,160	155,663	135,624	57,179

Transport Top Measures (All States & Sectors)

Rank	**Oregon** – Achievable Economic TRC Potential	2045 Achievable Economic Potential (Dth)	% of Total Savings
1	Process - Heat Recovery	241,167	50.3%
2	Process Boiler - Burner Control Optimization	42,084	8.8%
3	Retrocommissioning	35,257	7.4%
4	Strategic Energy Management	32,996	6.9%
5	Process Furnace - Tube Inserts	21,174	4.4%
6	Process - Insulate Heated Process Fluids	16,706	3.5%
7	Destratification Fans (HVLS)	10,447	2.2%
8	Gas Boiler - Steam Trap Replacement	10,434	2.2%
9	Process Boiler - High Turndown Burner	9,253	1.9%
10	Process Boiler - Stack Economizer	7,906	1.6%
	Subtotal	**427,423**	**89.1%**
	Total Savings in Year	**479,508**	**100.0%**

Rank	**Washington** – Achievable Economic TRC Potential	2045 Achievable Economic Potential (Dth)	% of Total Savings
1	Process - Heat Recovery	274,917	31.3%
2	Retrocommissioning	70,255	8.0%
3	Ventilation - Demand Controlled	53,105	6.1%
4	Process Boiler - Burner Control Optimization	47,973	5.5%
5	Destratification Fans (HVLS)	39,808	4.5%
6	Water Heater	39,619	4.5%
7	Strategic Energy Management	37,637	4.3%
8	Gas Boiler - Steam Trap Replacement	34,553	3.9%
9	Water Heater - Pipe Insulation	26,232	3.0%
10	Process Furnace - Tube Inserts	23,907	2.7%
	Subtotal	**648,004**	**73.9%**
	Total Savings in Year	**877,004**	**100.0%**

Thank You.

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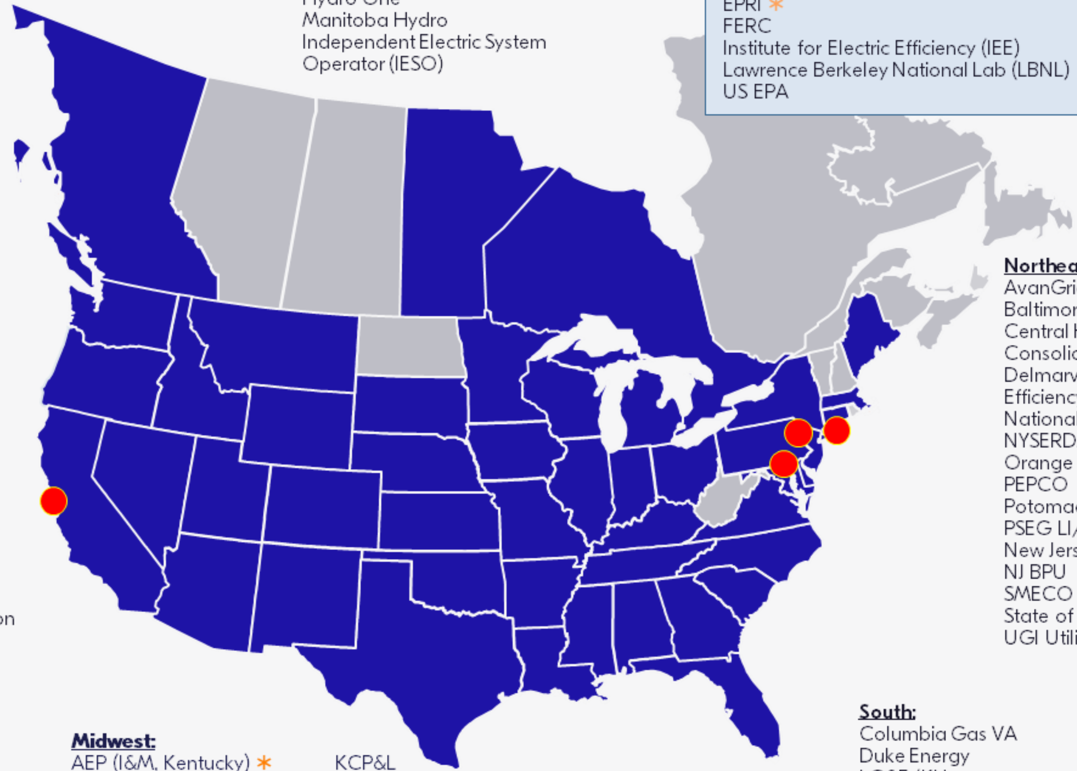
Black Hills Energy *
Cascade Natural Gas *
Chelan PUD
City of Fort Collins
Colorado Electric *
Cowlitz PUD
Energy Trust of OR
Idaho Power *
Inland P&L
Northwest EE Alliance *
Northwest Power & Conservation Council *
Oregon Trail Electric Co-op
PacifiCorp *
PNGC
Portland General Electric
Seattle City Light
Snohomish PUD
Tacoma Power *

Canada:
BC Hydro
Hydro One
Manitoba Hydro
Independent Electric System Operator (IESO)

National:
American Society of Mechanical Engineers (ASME)
EPRI *
FERC
Institute for Electric Efficiency (IEE)
Lawrence Berkeley National Lab (LBNL)
US EPA



Northeast & Mid Atlantic:
AvanGrid (RG&E & NYSEG)
Baltimore Gas & Electric
Central Hudson Electric & Gas *
Consolidated Edison of NY
Delmarva Power
Efficiency Maine *
National Grid
NYSERDA
Orange & Rockland *
PEPCO
Potomac Energy
PSEG LI/LIPA *
New Jersey Natural Gas *
NJ BPU
SMECO
State of Maryland
UGI Utilities

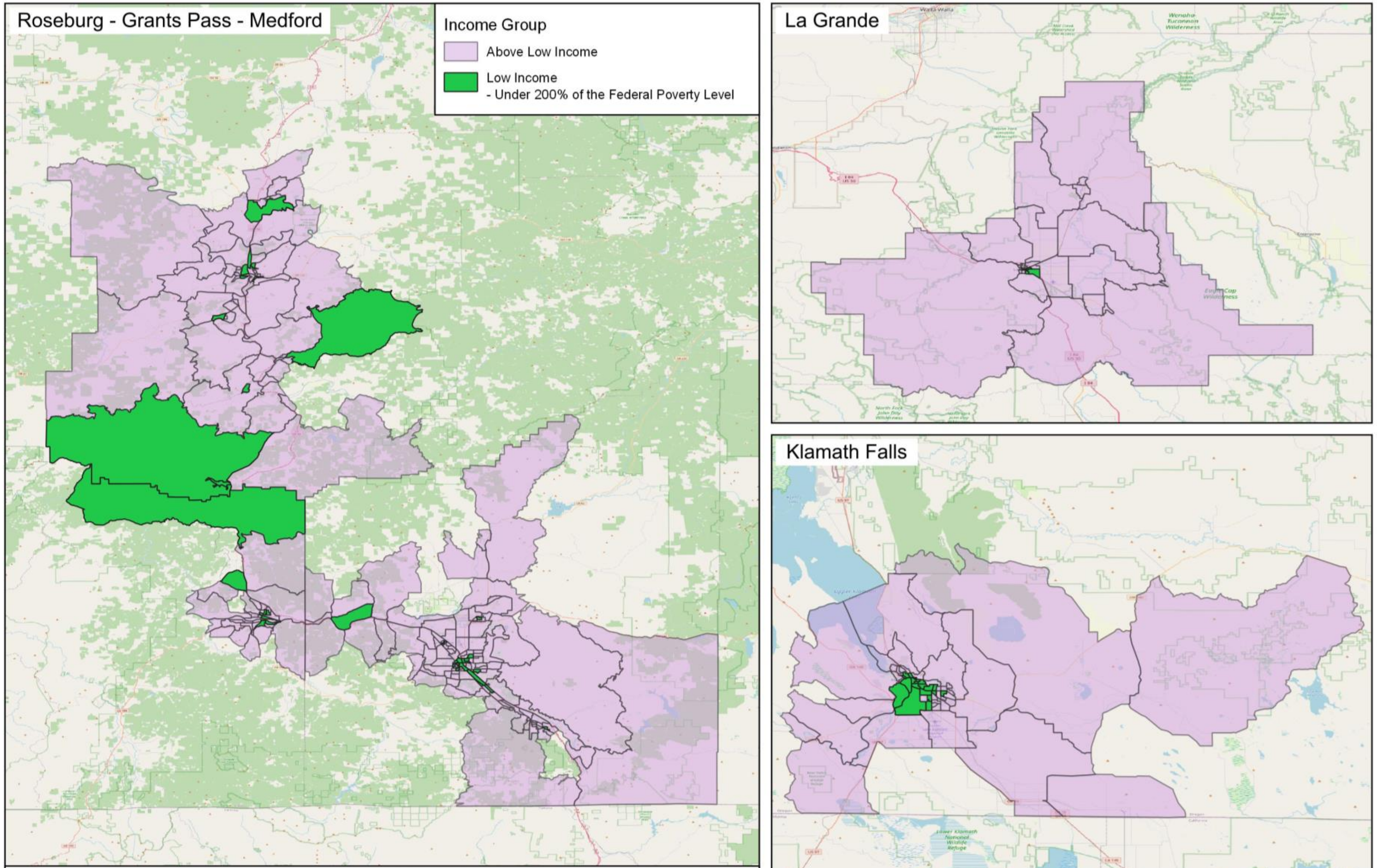
Southwest:
Alameda Municipal Power
Burbank W&P
California Energy Commission
HECO *
LADWP
NV Energy
PNM *
PG&E *
SCE *
SDG&E *
SMUD
State of NM
State of HI *
Tucson Electric Power
Xcel/SPS

Midwest:
AEP (I&M, Kentucky) *
Alliant Energy
Ameren Missouri
Ameren Illinois *
Black Hills Energy *
Citizens Energy
ComEd
Empire District Electric *
First Energy *
Indianapolis P&L
KCP&L
Minnesota Energy Resources *
Midcontinent ISO *
NIPSCO
Omaha Public Power District *
Peoples Gas/North Shore Gas * Spire *
State of Michigan
Sunflower Electric Power Vectren (IN & OH)
Wisconsin PSC

South:
Columbia Gas VA
Duke Energy
LG&E/KU
Oklahoma Gas & Electric (OK and AR) *
South Mississippi Electric Power Association
Southern Company (Services and utilities) *
TVA

States and Provinces in which we've worked
* Current Work
AEG offices
As of May 2021

Income by Region



Source: Census American Community Survey 2019, provides accurate estimates of household median income, household size, and structure type within each block group.

Objectives and Data Sources

- Income group segmentation provides Avista an understanding of where these customers are located, differences in their consumption, and levels of energy efficiency savings opportunities.
  - US Census data provides the basis of household demographics by location
- Detailed surveys like RBSA capture differences in how customers at different income levels use energy, which affects savings potential and cost-effectiveness:
  - Household intensity (therms per home)
  - Building shell
  - Presence of equipment

Gas Customer Intensity by Income Level – RBSA II

Income Class	Responses	Avg. Therms/HH	Δ from Regular
Non-Low-Income	180	636	n/a
Low Income	55	544	-14%

Income Groups by Household Size

HH Size	Low Income Threshold
1	$25,760
2	$34,840
3	$43,920
4	$53,000
5	$62,080
6	$71,160
7	$80,240
8	$89,320

Baseline Projection

The baseline projection is an independent end-use forecast of natural gas consumption at the same level of detail as the market profile.

- "How much energy would customers use in the future if Avista stopped running conservation programs now and in the absence of naturally occurring efficiency?"
  - The baseline projection answers this question

The baseline projection:

Includes	Excludes
• To the extent possible, the same forecast drivers used in the official load forecast, particularly customer growth, natural gas prices, normal weather, income growth, etc. • Trends in appliance saturations, including distinctions for new construction. • Efficiency options available for each technology , with share of purchases reflecting codes and standards (current and finalized future standards) • Expected impact of appliance standards that are "on the books" • Expected impact of building codes, as reflected in market profiles for new construction • Market baselines when present in regional planning assumptions	• Expected impact of naturally occurring efficiency (except market baselines) • **Exception:** RTF workbooks have a market baseline for lighting, which AEG's models also use. • Impacts of current and future demand-side management programs • Potential future codes and standards not yet enacted

Economic Achievable Potential

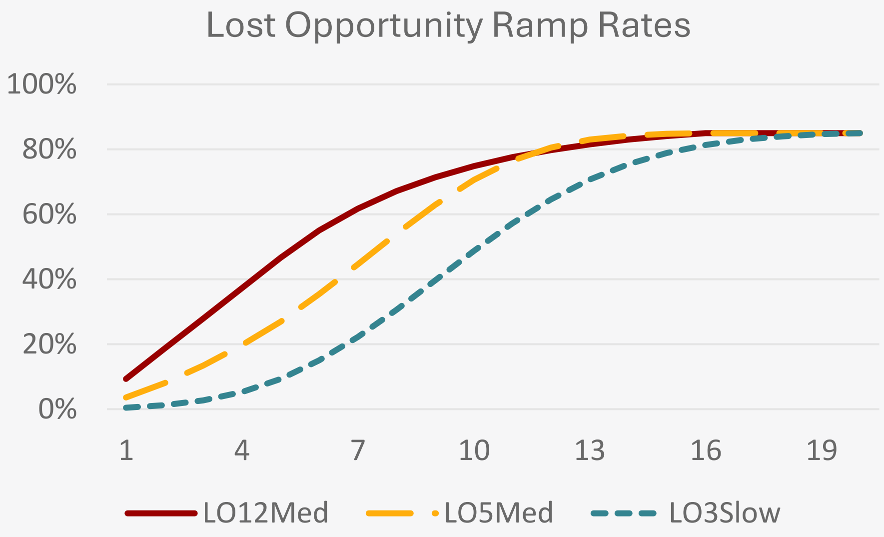
In assessing cost-effective, achievable potential within Avista's territory, AEG considered two perspectives:

- Washington - Total Resource Cost Test (TRC): Assesses cost-effectiveness from the perspective of the utility and its customers. Includes non-energy impacts if they can be quantified and monetized.
- Idaho - Utility Cost Test (UCT): Assesses cost-effectiveness from a utility or program administrator's perspective.

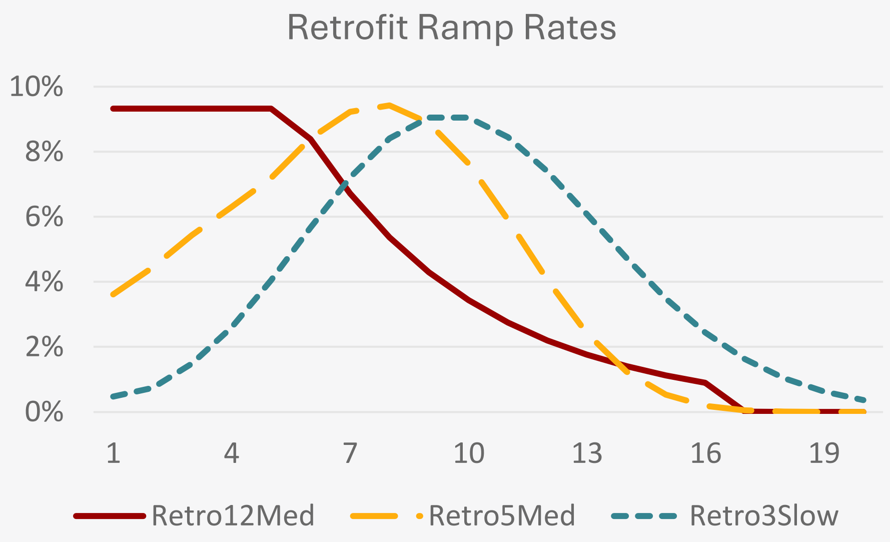
Component	TRC	UCT
Avoided Energy	Benefit	Benefit
Non-Energy Impacts*	Cost/Benefit	
Incremental Cost	Cost	
Incentive		Cost
Administrative Cost	Cost	Cost
10% Conservation Credit	Benefit	

*NEI Categories
- Quantified and monetized non-energy impacts (e.g. water, detergent, wood)
- Projected cost of carbon in Washington
- Heating calibration credit for secondary fuels (12% for space heating, 6% for secondary heating)
- Electric benefits for applicable measures

Council Methodology: Ramp Rate Examples

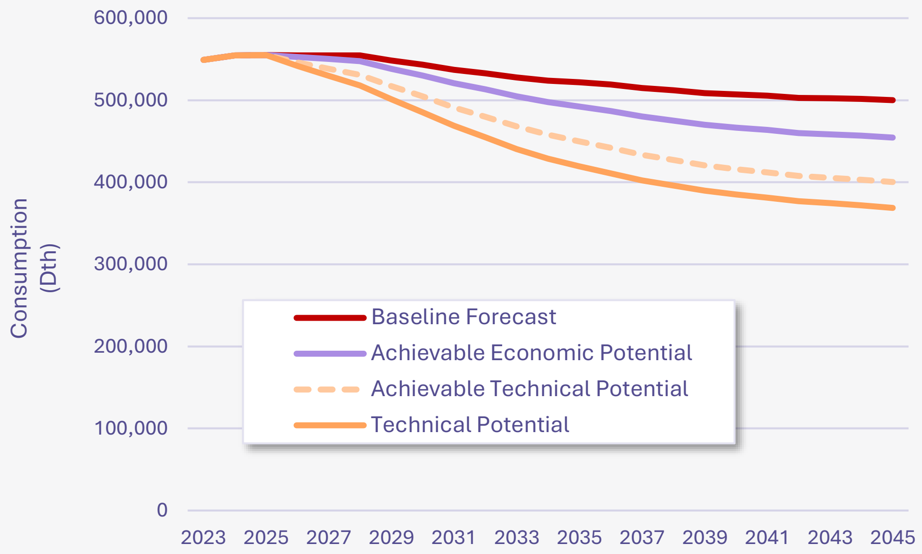


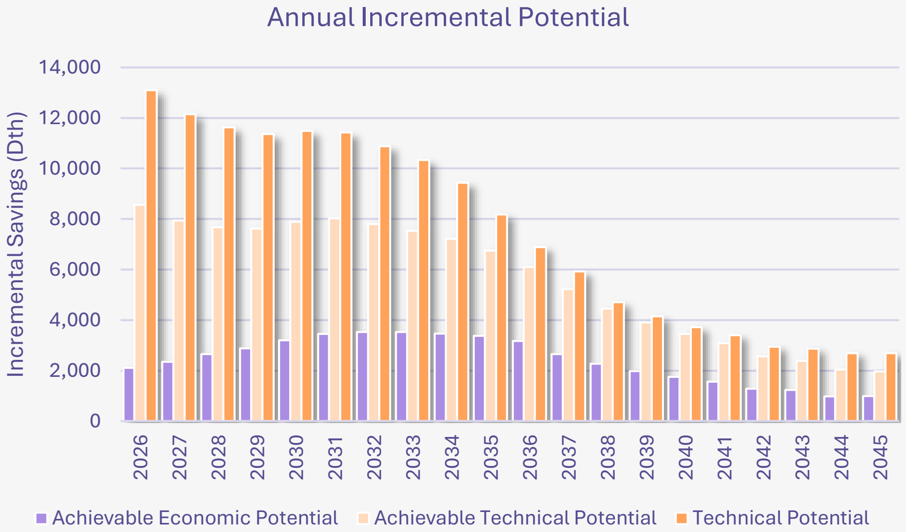
- Describe the % of units assumed to be adopted relative to all units purchased in that year (based on lifetime/turnover)
- Approach their maximum limit over time, but reach that limit at different speeds



- Describe the % of the **total market** that is acquired in each year
- **Add up** to 100% over time, but reach that total at different speeds

Commercial Summary Results (All States)





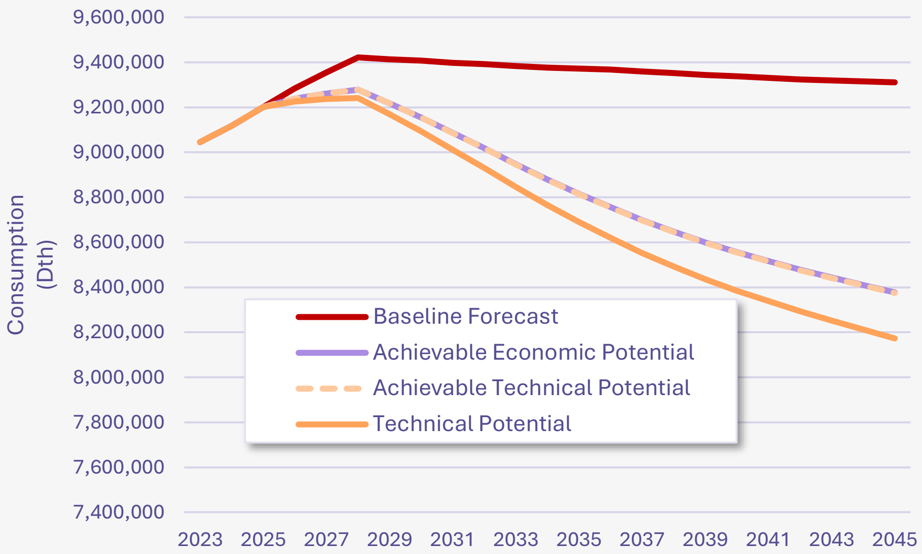
Summary of Energy Savings (Dth), Selected Years	2026	2027	2030	2035	2045
Reference Baseline (Dth)	**3,583,743**	**3,585,198**	**3,509,734**	**3,367,345**	**3,210,679**
Cumulative Savings (Dth)					
Achievable Economic	25,173	55,342	153,330	304,312	422,876
Achievable Technical	66,111	127,768	301,119	552,841	744,546
Technical Potential	95,671	184,390	427,480	753,510	966,787
Energy Savings (% of Baseline)					
Achievable Economic	0.7%	1.5%	4.4%	9.0%	13.2%
Achievable Technical	1.8%	3.6%	8.6%	16.4%	23.2%
Technical Potential	2.7%	5.1%	12.2%	22.4%	30.1%
Incremental Savings (Dth)					
Achievable Economic	25,173	30,211	35,233	28,832	7,585
Achievable Technical	66,111	62,174	62,132	50,182	14,248
Technical Potential	95,671	89,617	86,107	62,781	20,178

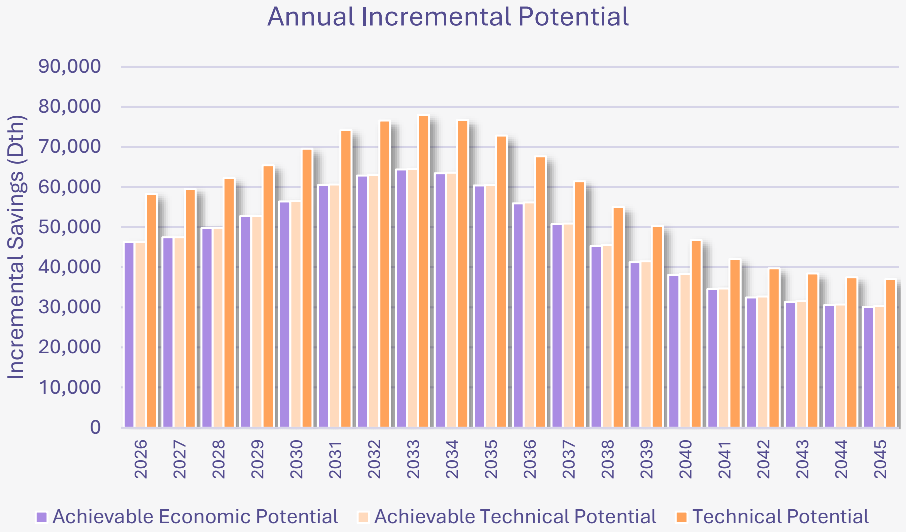
Commercial Transport Top Measures

Rank	**Oregon** – Achievable Economic TRC Potential	2045 Achievable Economic Potential (Dth)	% of Total Savings
1	Gas Boiler - Steam Trap Replacement	10,419	22.8%
2	Water Heater	5,669	12.4%
3	Water Heater - Pipe Insulation	5,443	11.9%
4	Fryer	5,152	11.3%
5	Retrocommissioning	4,886	10.7%
6	Gas Boiler - Thermostatic Radiator Valves	3,405	7.4%
7	Range	3,290	7.2%
8	Gas Boiler - Hot Water Reset	2,682	5.9%
9	Steamer	1,387	3.0%
10	Broiler	880	1.9%
	Subtotal	**43,213**	**94.5%**
	Total Savings in Year	**45,736**	**100.0%**

Rank	**Washington** – Achievable Economic TRC Potential	2045 Achievable Economic Potential (Dth)	% of Total Savings
1	Ventilation - Demand Controlled	52,001	13.8%
2	Water Heater	39,619	10.5%
3	Retrocommissioning	35,455	9.4%
4	Gas Boiler - Steam Trap Replacement	34,537	9.2%
5	Destratification Fans (HVLS)	28,495	7.6%
6	Water Heater - Pipe Insulation	26,232	7.0%
7	Gas Boiler - Thermostatic Radiator Valves	22,070	5.9%
8	Gas Boiler - Insulate Steam Lines/Condensate Tank	17,882	4.7%
9	Gas Boiler - Hot Water Reset	17,382	4.6%
10	Gas Boiler - Stack Economizer	13,625	3.6%
	Subtotal	**287,298**	**76.2%**
	Total Savings in Year	**377,141**	**100.0%**

Industrial Summary Results (All States)





Summary of Energy Savings (Dth), Selected Years	2026	2027	2030	2035	2045
Reference Baseline (Dth)	**9,284,188**	**9,355,036**	**9,407,151**	**9,372,755**	**9,310,738**
Cumulative Savings (Dth)					
Achievable Economic	46,236	93,935	252,199	557,471	933,636
Achievable Technical	46,248	93,970	252,404	558,402	936,537
Technical Potential	58,193	118,024	313,857	682,924	1,137,484
Energy Savings (% of Baseline)					
Achievable Economic	0.5%	1.0%	2.7%	5.9%	10.0%
Achievable Technical	0.5%	1.0%	2.7%	6.0%	10.1%
Technical Potential	0.6%	1.3%	3.3%	7.3%	12.2%
Incremental Savings (Dth)					
Achievable Economic	46,236	47,428	56,397	60,344	30,076
Achievable Technical	46,248	47,451	56,476	60,546	30,290
Technical Potential	58,193	59,543	69,556	72,844	37,001

Industrial Transport Top Measures

Rank	**Oregon** – Achievable Economic TRC Potential	2045 Achievable Economic Potential (Dth)	% of Total Savings
1	Process - Heat Recovery	241,167	55.6%
2	Process Boiler - Burner Control Optimization	42,084	9.7%
3	Strategic Energy Management	32,996	7.6%
4	Retrocommissioning	30,372	7.0%
5	Process Furnace - Tube Inserts	21,174	4.9%
6	Process - Insulate Heated Process Fluids	16,706	3.9%
7	Destratification Fans (HVLS)	10,447	2.4%
8	Process Boiler - High Turndown Burner	9,253	2.1%
9	Process Boiler - Stack Economizer	7,906	1.8%
10	Process Boiler - Steam Trap Replacement	5,882	1.4%
	Subtotal	**417,986**	**96.4%**
	Total Savings in Year	**433,773**	**100.0%**

Rank	**Washington** – Achievable Economic TRC Potential	2045 Achievable Economic Potential (Dth)	% of Total Savings
1	Process - Heat Recovery	274,917	55.0%
2	Process Boiler - Burner Control Optimization	47,973	9.6%
3	Strategic Energy Management	37,637	7.5%
4	Retrocommissioning	34,800	7.0%
5	Process Furnace - Tube Inserts	23,907	4.8%
6	Process - Insulate Heated Process Fluids	19,029	3.8%
7	Destratification Fans (HVLS)	11,312	2.3%
8	Process Boiler - High Turndown Burner	10,562	2.1%
9	Boiler	10,383	2.1%
10	Process Boiler - Stack Economizer	8,994	1.8%
	Subtotal	**479,513**	**95.9%**
	Total Savings in Year	**499,863**	**100.0%**

Energy Efficiency Resource Assessment

Avista 2025 IRP

January 9, 2025

Energy Trust of Oregon

Agenda

- About Energy Trust
- Resource Assessment Model Overview
- Draft Avista 2025 Resource Assessment Results and Deployment Forecast

About us

Independent nonprofit

Serving 2.4 million customers of Portland General Electric, Pacific Power, NW Natural, Cascade Natural Gas and Avista

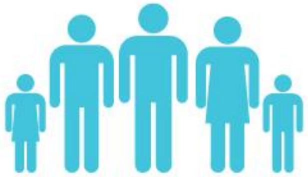
Providing access to affordable energy

Generating homegrown, renewable power

Building a stronger Oregon and SW Washington

Clean and affordable energy since 2002

From Energy Trust’s investment of $2.8 billion in utility customer funds:



825,000 sites transformed into energy efficient, healthy, comfortable and productive homes and businesses

30,000 clean energy systems generating renewable power from the sun, wind, water, geothermal heat and biopower

$13.5 billion in savings over time on participant utility bills from their energy-efficiency and solar investments

42.9 million metric tons of carbon dioxide emissions kept out of our air, equal to removing 11.2 million cars from our roads for a year

Energy Trust Resource Assessment Model Overview

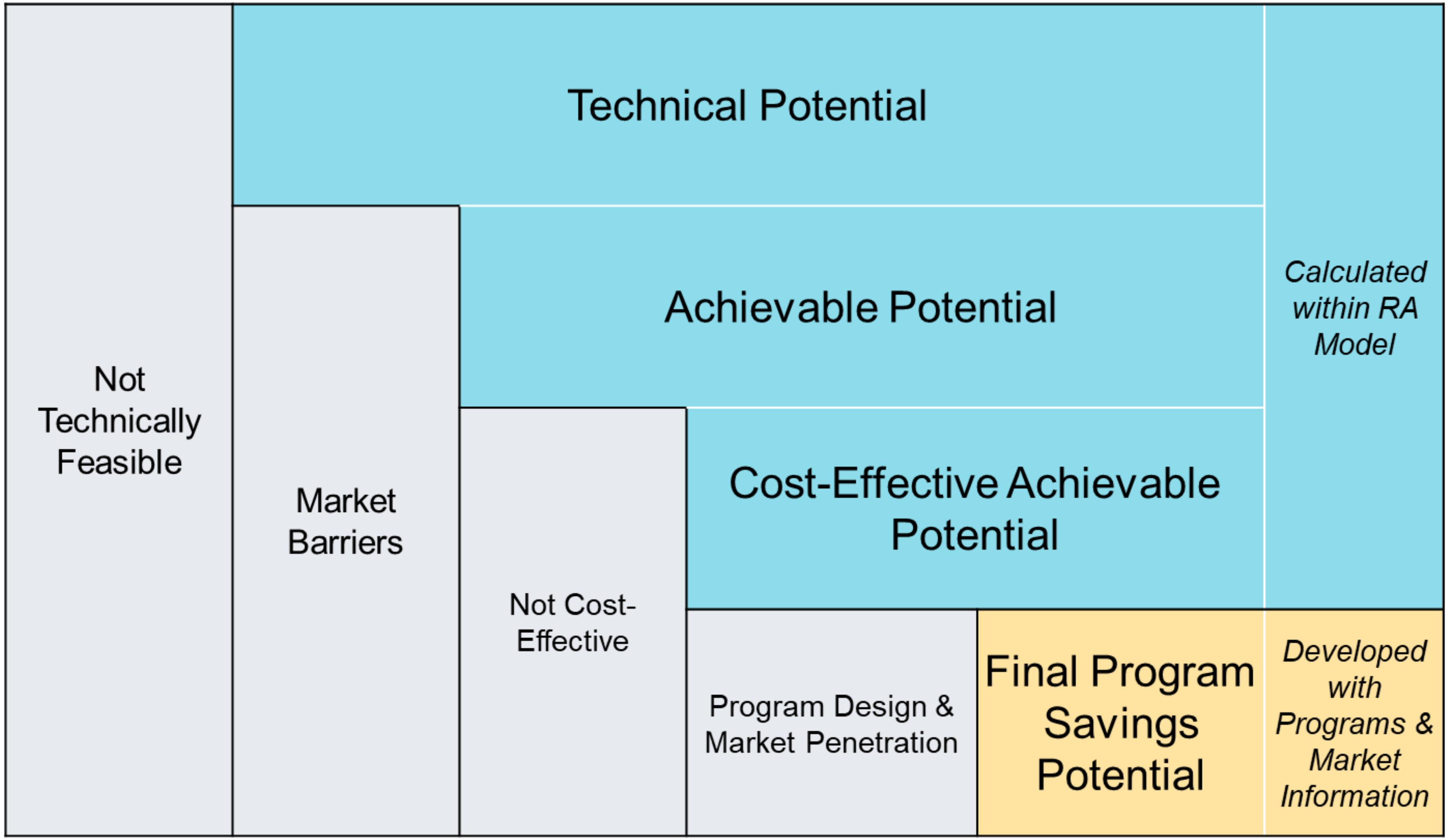
Resource Assessment Model Background

- Estimate of 20-year energy efficiency potential
- "Bottom-up" modeling approach
  - Measure level inputs are scaled to utility level
- Measure inputs
  - Baseline and efficient equipment
  - Measure savings
  - Incremental cost
  - Market data
- Utility inputs
  - Load and customer count/building stock forecast
  - Customer stock demographics
  - Avoided costs

Modeling Updates

- Measure updates
  - Measure savings, incremental cost
  - New measures
  - Emerging technologies
- 2022 Residential Building Stock Assessment (NEEA)
  - Total measure density, technical suitability and baseline initial saturation
  - Heating fuel, water heating fuel splits

Forecasted Potential Types



Cost-Effectiveness Screen

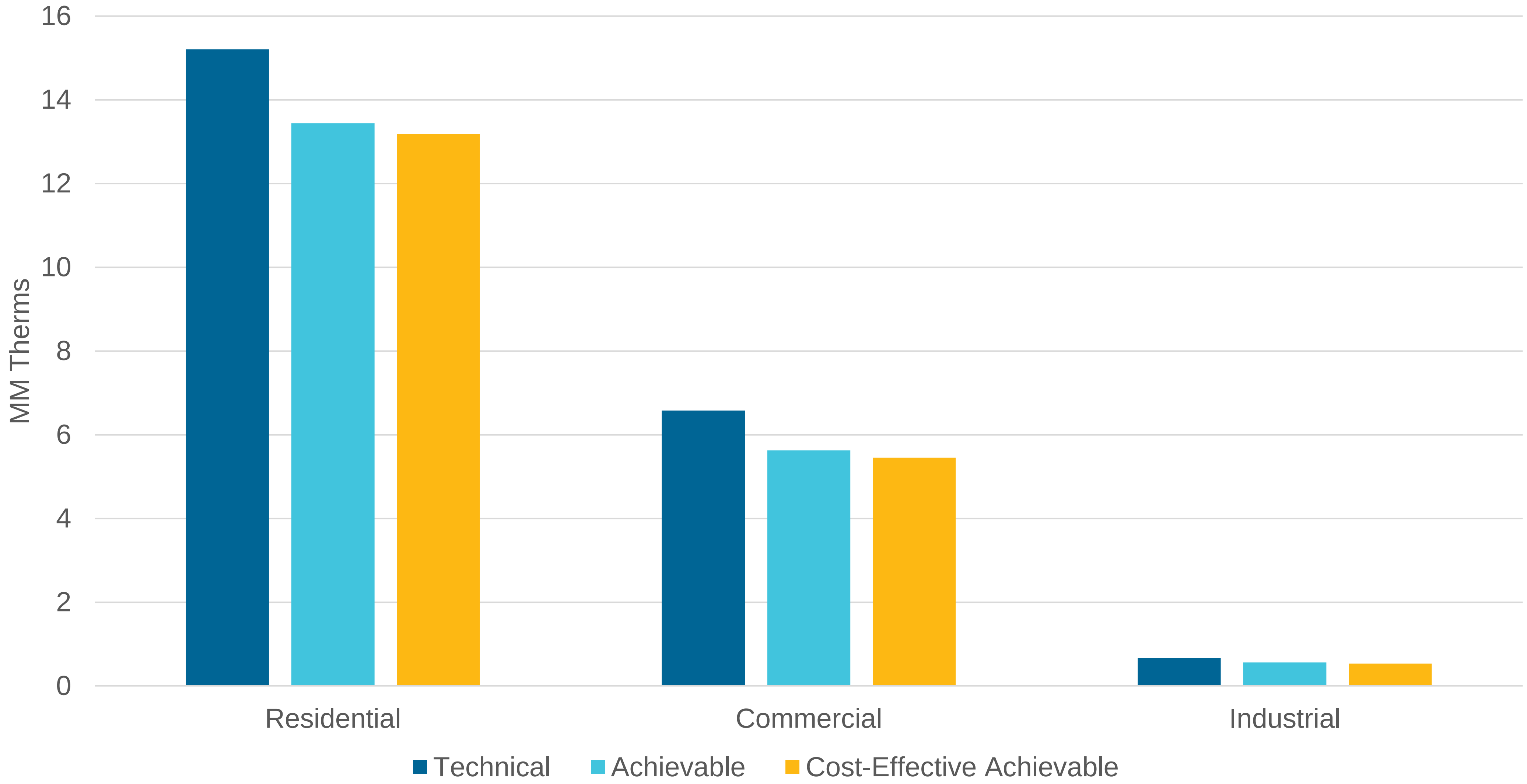
- RA model utilizes the Total Resource Cost (TRC) test to screen measures for cost-effectiveness

$$\mathrm{TRC} = \frac{\textit{Measure Benefits}}{\textit{Total Measure Cost}}$$

- Measure benefits
  - NPV avoided costs per first-year Therm
  - Quantifiable non-energy benefits
- Measure costs
  - The customer cost of installing an efficiency measure (full cost for retrofits, incremental over baseline cost for replacements and new construction)
- Cost-Effectiveness Override
  - Measures under an OPUC exception

Draft Resource Assessment Results
Avista 2025 IRP

Draft Cumulative Potential by Sector and Type



Draft Cumulative Potential by End Use

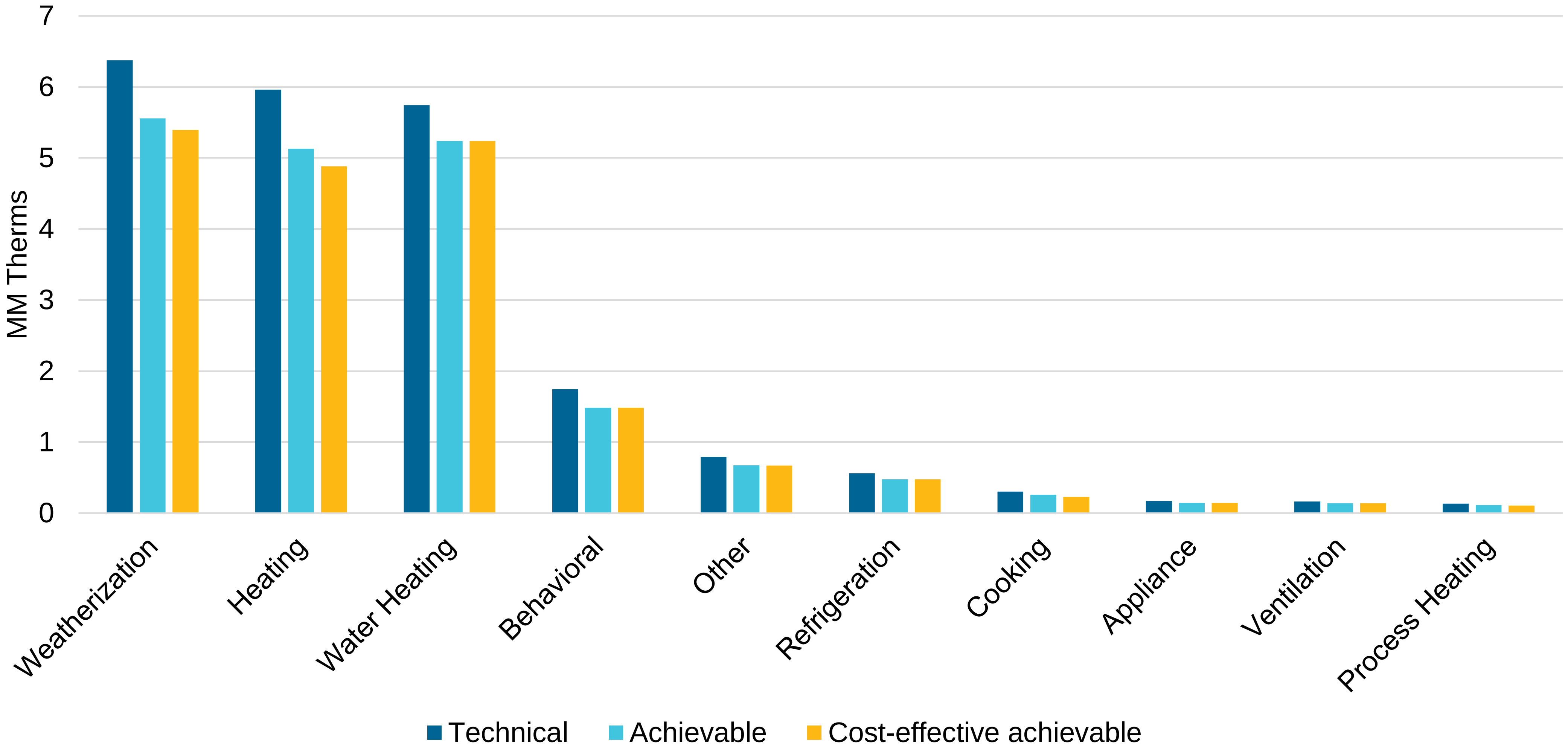


**Chart includes major end uses only and does not add up to total potential*

Draft Results and Deployment

20-year Energy Efficiency Potential (Therms)

Sector	Technical Potential	Achievable Potential	Cost-Effective Achievable Potential	Draft Savings Projection*
Residential	15,204,642	13,442,065	13,179,722	9,012,951
Commercial	6,576,079	5,627,220	5,451,669	4,771,648
Industrial	659,579	560,642	530,695	792,664*
Total	22,440,299	19,629,927	19,162,086	**14,577,215**

Previous IRP – Comparison

2023 IRP Total	27,632,901	22,324,557	21,604,916	15,368,375
% Change	*-19%*	*-12%*	*-11%*	***-5%***

***Draft Projections include exogenous savings. As such, they can exceed the 20-year cost-effective achievable totals**

Draft Avista Deployment, Cost-Effective Achievable Potential

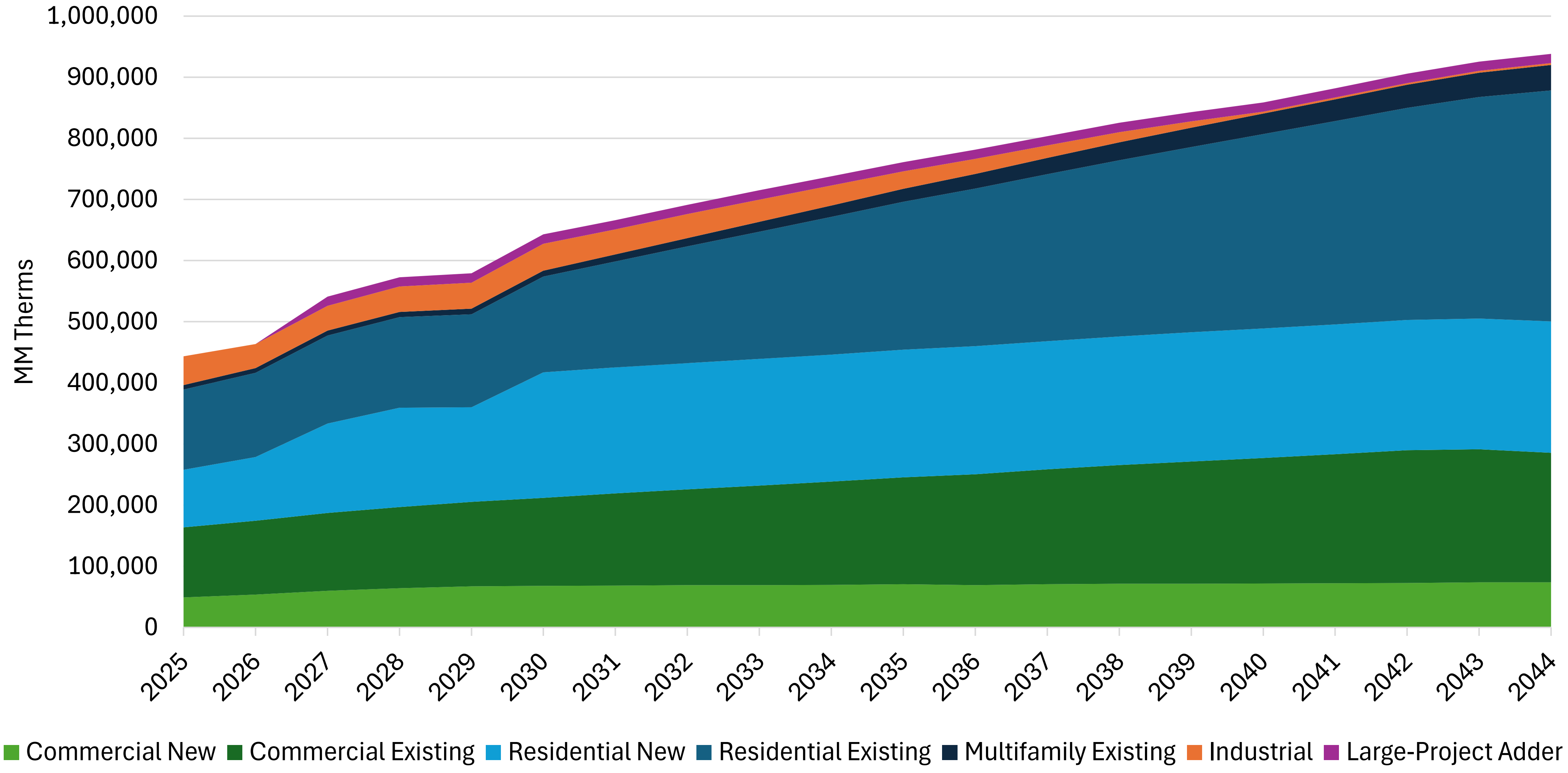
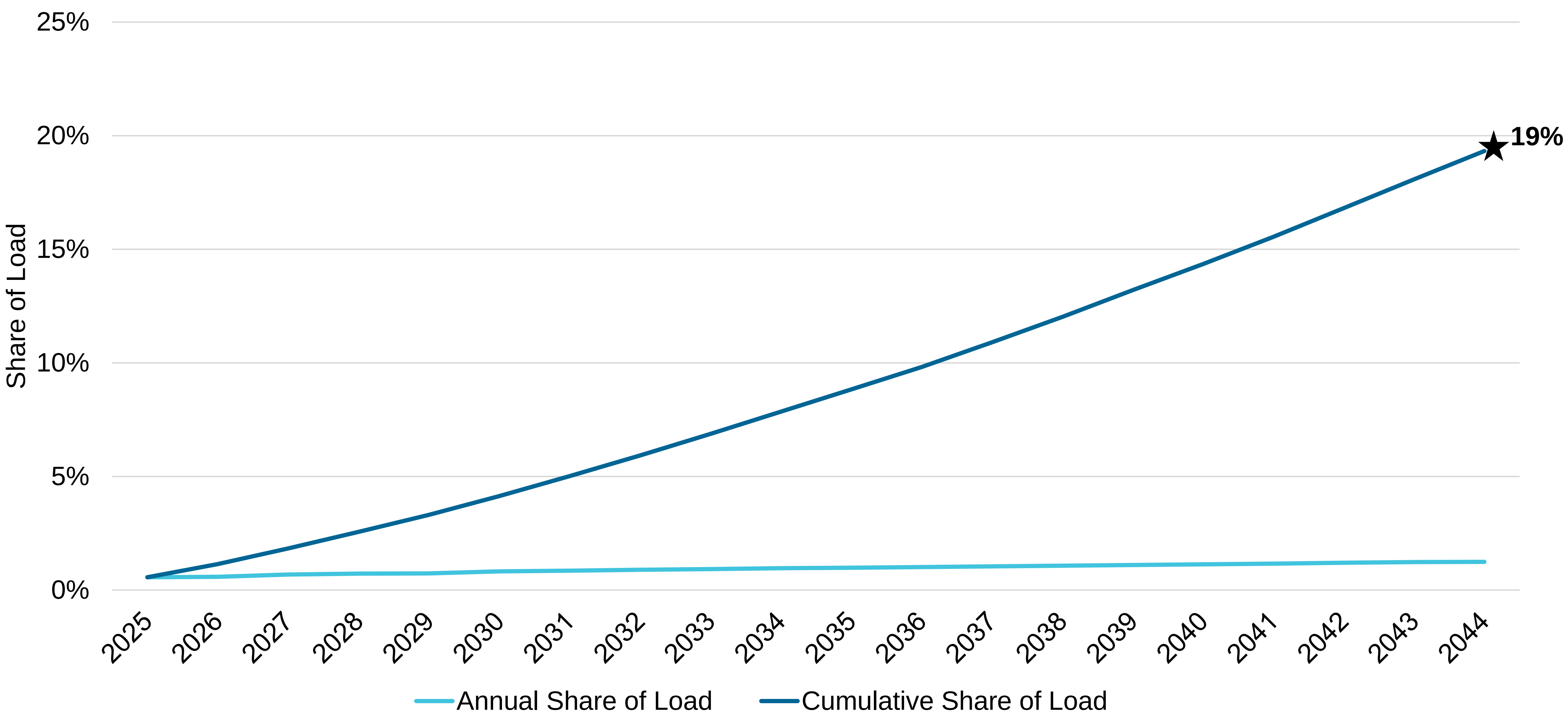


Chart shows total expected efficiency and includes savings from codes and standards. Energy Trust may not claim the entirety of savings depicted above

Draft Deployed Savings Compared to Load Forecast



Average Annual Share of Load Saved: 0.95%

Questions?

Thank you!

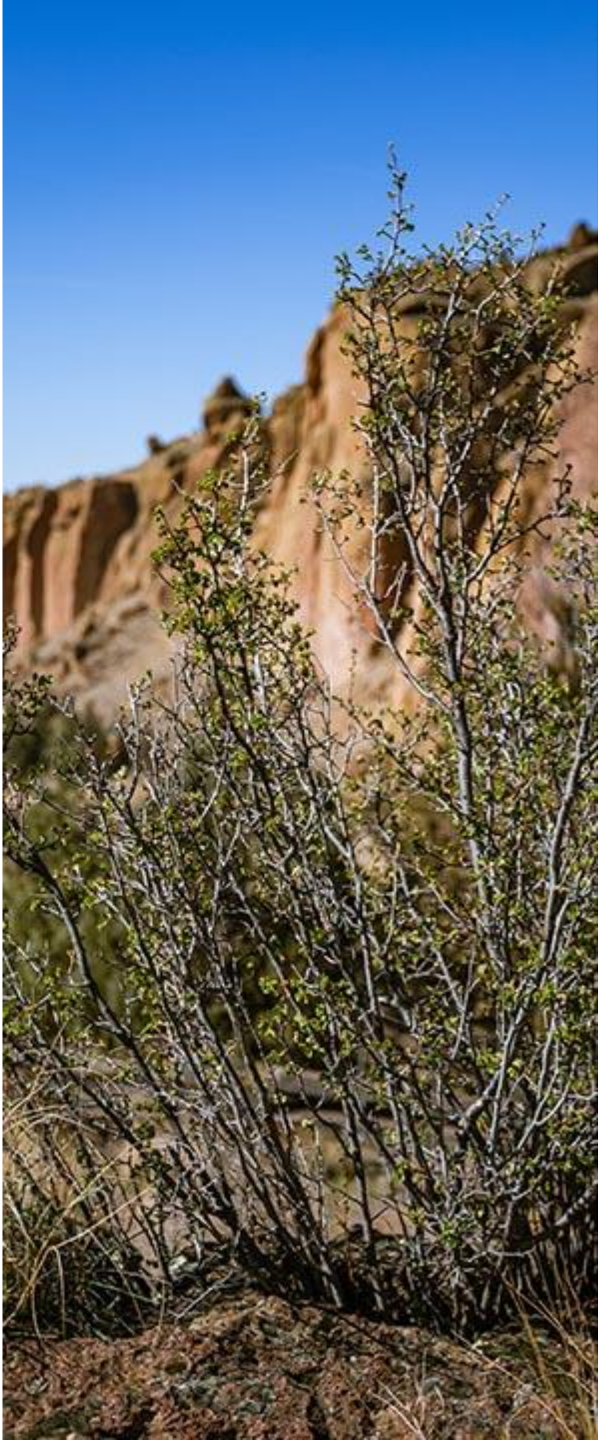
Willa Perlman, Planning Project Manager
willa.perlman@energytrust.org

Dual fuel (Hybrid) Heat Pump Pilot

Avista IRP Meeting

January 9, 2025

EnergyTrust of Oregon



Agenda

- What is Dual Fuel HVAC (Hybrid HVAC)
- Research objectives
- High-level description of pilot design
  - Demographic focus, education and support
  - Home criteria
  - Pilot delivery, installation, quality assurance
  - Technical specifications and utility/geographic scope
- Current Pilot milestones
- Pilot considerations
- Timing
- Next steps

Dual Fuel (Hybrid) HVAC (HHVAC)

Definition of Hybrid (dual fuel) HVAC

- For this pilot, Hybrid HVAC is a dual fuel system where a ducted single-speed heat pump and programmable thermostat are added to an existing gas furnace.
- The pilot application is in single-family homes without air conditioning and with gas furnaces that are five years old on average.
  - Homes have been previously weatherized
  - Homes do not have deferred maintenance that would prohibit successful installation or operation of HVAC system
  - Homes do not need major duct repair
  - Homes do not need major electrical service upgrades such as a new panel or braker box

Research Objectives

Research Objective 1

Determine the <u>utility</u> system costs and benefits of hybrid HVAC system installations.

- Fuel use – gas and electric
- Load/demand – gas and electric
- Carbon intensity – gas, electric and overall

Research Objective 2

Determine the <u>customer</u> costs and benefits of hybrid HVAC system installations.

- Energy costs – gas, electric and overall
- Added cooling value
- Comfort and living conditions
- Backup auxiliary-fuel
- Maintenance and upkeep

Research Objective 3

Determine the costs and process considerations associated with installing Hybrid HVAC systems in low-income households.

- Other necessary infrastructure changes – electric panels, ducts, etc.
- Homes served and homes disqualified
- Geographic regions served well and those we had difficulty serving – customer base size, installation contractors, supply chain
- Cost of installations – Hybrid HVAC system, other infrastructure, Energy Trust costs
- Timeline for installations – customer recruitment to successful implementation and use

Description of Pilot

Pilot Description

- Energy Trust to pay full cost of installs
- Income-qualified households, previously served by low-income weatherization services
- Homes must be weatherized and have a gas furnace no older than ~5 years, and no existing central AC
- House triage and customer education and support provided by Energy Trust staff
- Installation contractors selected through RFQ projects awarded on a rolling basis
- Post install QA provided by Energy Trust in every home

Heat Pump Specifications and Cost

- Heat pump size determined through Manual J, and cooling needs of the home (in alignment with ACCA2 Standard)
- Cross-over temperature
  - Energy Trust will leverage our installation Contractor RFQ to solicit more professional feedback on best practices
    - Goals - avoid customers experiencing no-heat conditions when heat pump switches to defrost mode
    - Follow manufacturer requirements depending on make/model
    - Stay within technical capabilities of equipment selection and controls
- Thermostat selection also to be explored through RFQ
- Cost range between $10,000 - $12,000 (not to exceed $13,000) per home

Geographic Assumptions

- Prioritize overlapping gas and electric territories
- Concentrate efforts regionally to maximize delivery resources
- Leverage utility insights to support customer acquisition

Utility	Units
Pacific Power	20
PGE	20
NW Natural	26
Avista	12
Cascade Natural Gas	12
	90

Gas	Electric	Quantity	Geography
NWN	PGE	50	Portland Metro
AVI	PAC	20	S. Oregon / Klamath
CNG	PAC	20	Central / Eastern

Marketing

Total number of homes included in marketing lists: 2,038 customers

What is the breakdown of these per gas utility?

- AVI - 164 customers
- CNG - 34 customers
- NWN - 1,840 prior Energy Trust gFAF participants

- What is the breakdown of these per electric utility?
  - PGE - 1,530 customers
  - PAC - 508 customers

*Recruitment tactics include emails, postcards, a letter, follow-up phone calls, event tabling.

Installations

Installations Compete

- Avista - 2
- Cascade Natural Gas - 1
- NW Natural - 21

Pilot criteria re-design considerations

- Age of existing furnace
- Presence of central air conditioning (cooling)
- Income qualification requirement

Evaluation

Energy Trust recently completed a solicitation to select a contractor for the first phase of the pilot evaluation.

- This first phase will be focused on the pilot process including successes and places to grow and shift, customer choices and value associated with the system, and an added market assessment with trade allies installing these sorts of systems outside of the Energy Trust pilot in market-rate environments. This work will be conducted by Apex Analytics and Ideal Community Strategies and is expected to be completed in Q4 2025.

- The second phase of the pilot evaluation is expected to begin in Q1 2026. Another public solicitation for a contractor will be conducted to select an evaluation firm to perform an impact analysis, including electric and gas usage, carbon accounting, and peak system impacts observed by installed pilot systems.

Timeline

High Level Project Timeline

May 2023– August 2023
- Implementation planning
- Stakeholder engagement
- Measure development
- Installer recruitment

January 2024 – June 2025
- Customer recruitment
- Site eligibility verification

April 2024- July 2025
- Installations & site treatment
- Post-install verification & QA

July 2025– December 2025?
- Project Evaluation

Thank You

Andrew Shepard

Andrew.shepard@energytrust.org

TAC 10 – 2025 Avista Gas IRP

Edited Alternative Fuel Volumes

January 9, 2025

Alternative Fuel Prices

Alternative Fuel Prices Inputs

Model Restriction

- Selection for any physical products will not be available in the model until 2030

- Average prices above $75 per Dth will not be modeled

Capital Costs

- Equipment
- Pipeline Costs
- Installation and Owners Costs

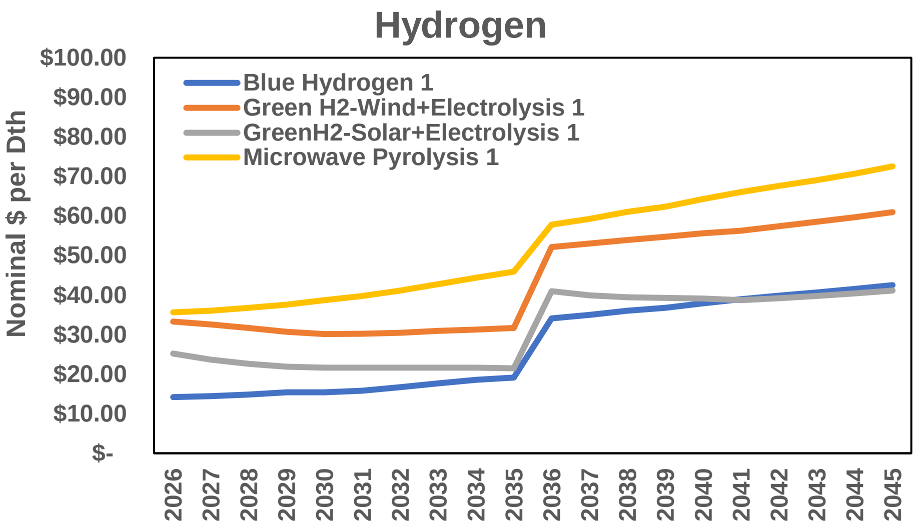
O&M – Fixed and Variable

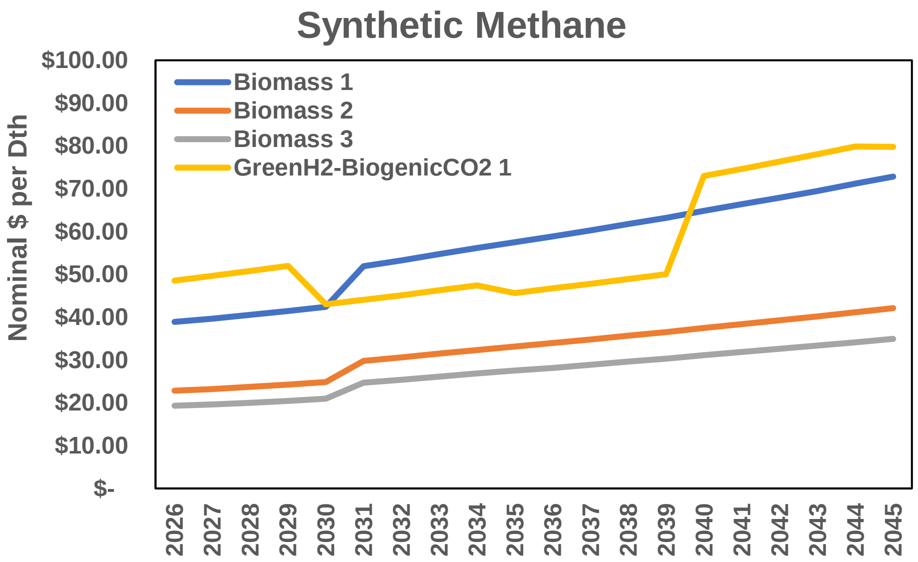
- Electricity rates
- Gas rates

Prices

- Expected prices are broken down between northwest and national technical potential (ICF)
  - All prices consider Inflation Reduction Act (IRA) incentives where applicable
  - These prices assume a first mover access to alternative fuels
  - Prices are from the Northwest for each alternative fuel and National for Renewable Thermal Credits (RTC)
  - Hydrogen (H2) & Synthetic Methane (SM) prices will be treated as a purchase gas agreement where Avista would sign a term contract, each year, with the producer for these prices through the forecast.
  - Renewable Natural Gas (RNG) assumes a proxy ownership with costs levelized over 20 years
  - RTC considers a production cost plus, where prices cover all costs
    - These exclude Investment Tax Credit (ITC) or Production Tax Credit (PTC) and consider a higher capital rate
  - Prices are in nominal dollars

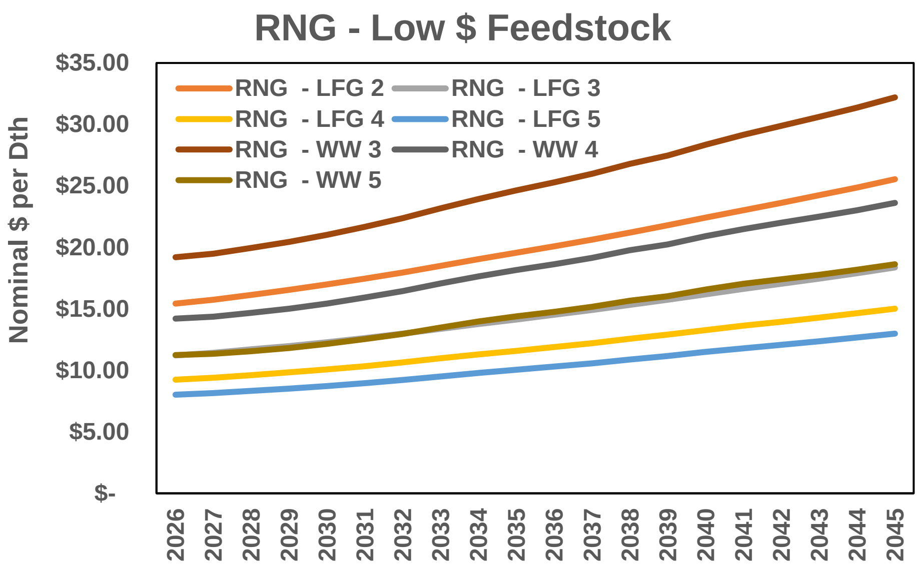
Hydrogen (H2) and Synthetic Methane (SM)

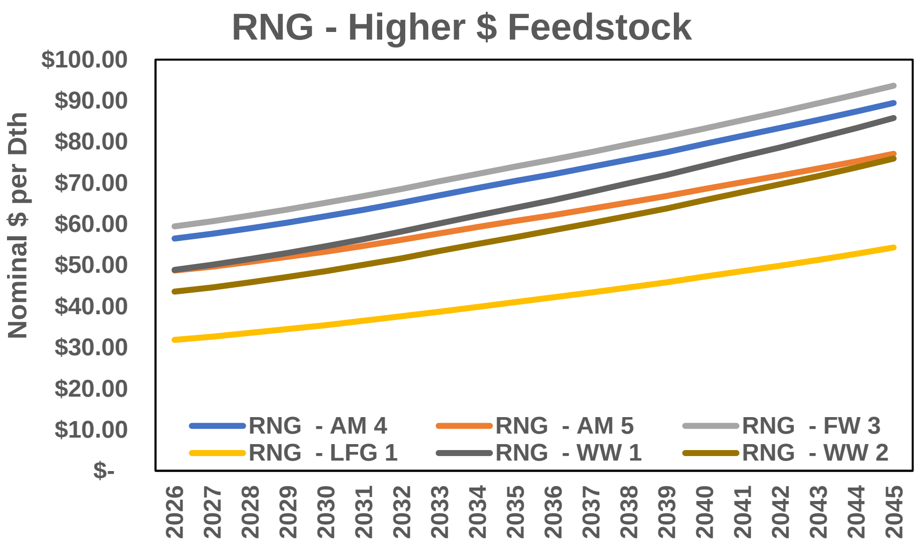




ICF levelized the Section 45V tax credit over 20 years. Since hydrogen projects must be under construction by the end of 2032 to qualify for 45V credits, the 45V tax credits were modeled until 2035 as a conservative estimate assuming every new hydrogen facility beginning construction after 2032 may not 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.

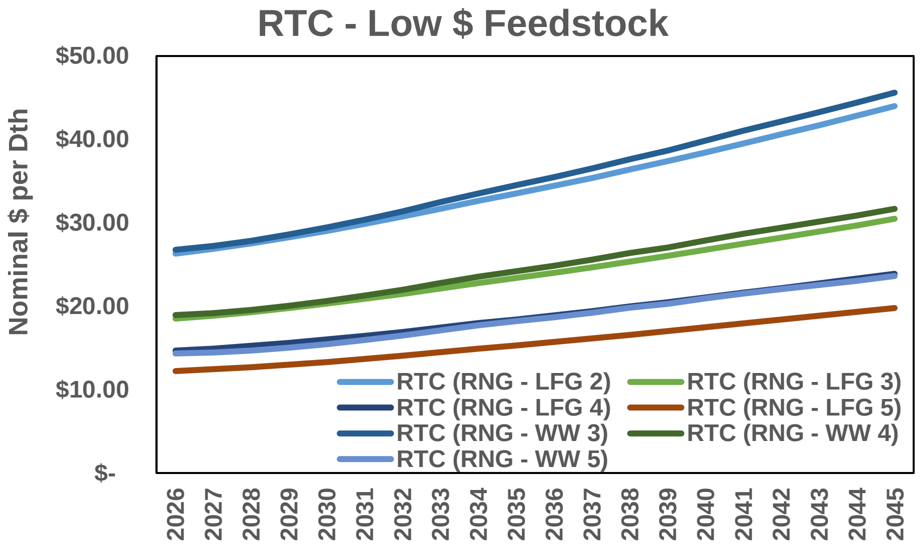
Renewable Natural Gas (RNG)

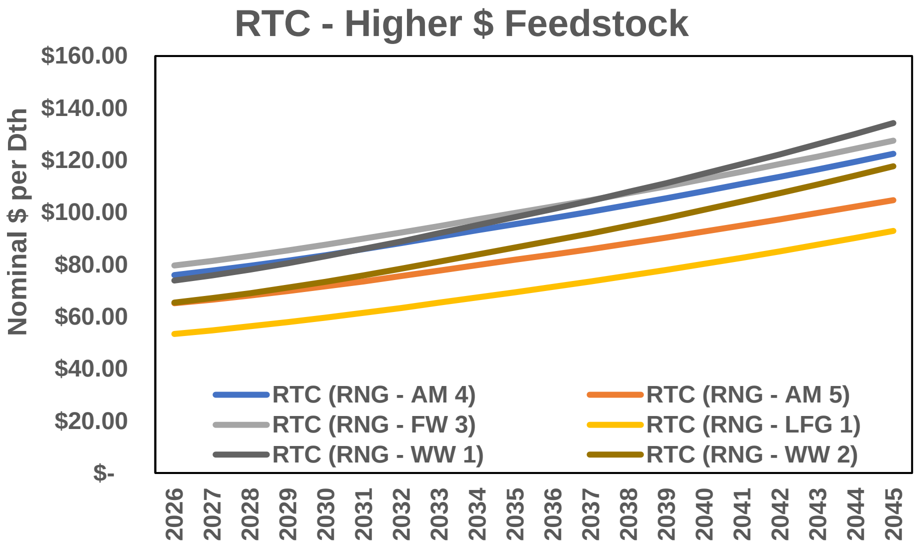




*Blend of national and NW estimated costs for RNG facilities
**Includes ITC/PTC until 2030

Renewable Thermal Certificate (RTC)





1-No ITC, considers price from producer to create RTC and cover costs (production prices)

2-Not tied to market actual prices

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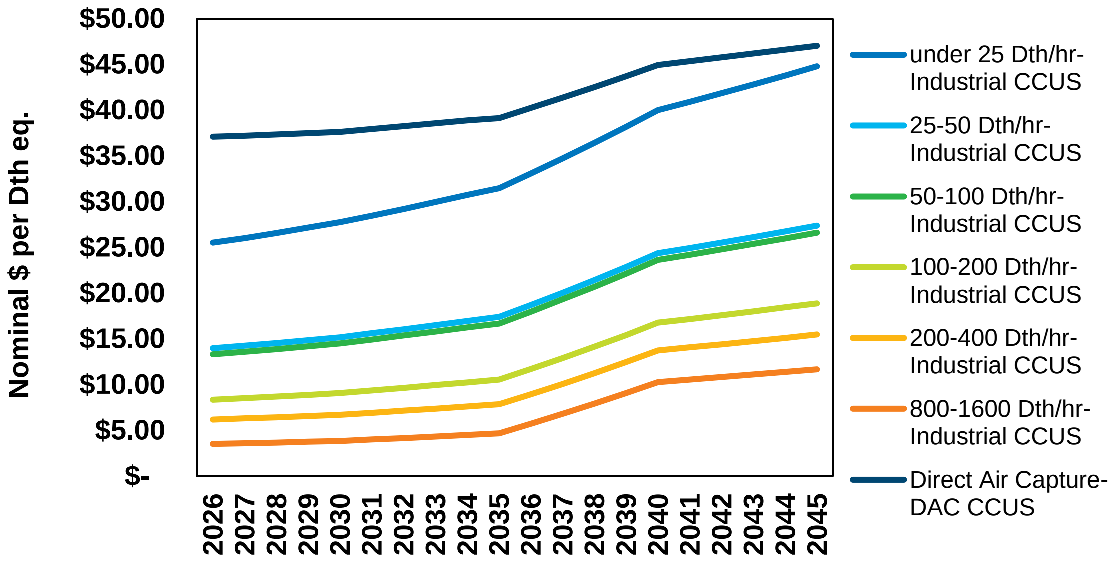
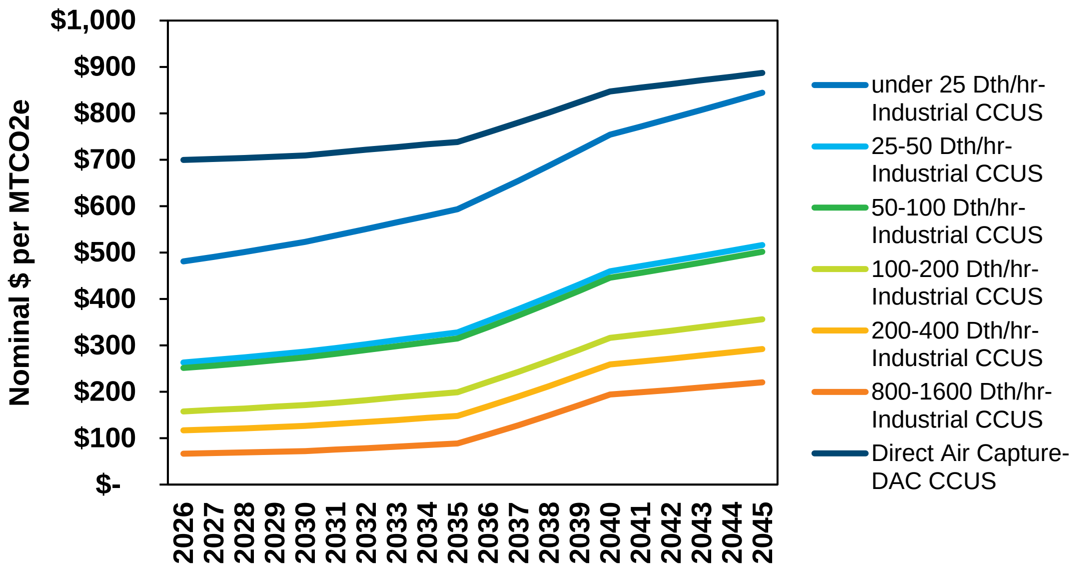
Carbon Capture, Utilization and Storage (CCUS)





*Avista specific high-volume customers

**Includes ITC/PTC to 2030

Alternative Fuels Technical Potential Volumes (ICF)

Updated Technical Potential Volumes

- Total Technical Potential Volumes have been updated from the final version of TAC 9 (12/18/2024)

- These volumes were overestimated based on interpretations of math provided by ICF
  - Clarification was given by ICF on January 3rd and Impacted deterministic runs
    - The "output Excel files list a unit of 1x10e9 Btu for various resources. This is equivalent to billion Btu. If one were to enter 1x10E9 into an Excel file, you will get 10 billion (10,000,000,000). However, this is because the number should be interpreted as 1×10^9. The "e" is meant to stand for "exponent" whereas entering the sequence 10E9 in Excel is interpreted as 10×10^9."
  - The good news is the final number matched closely to those Avista adjusted for estimated volumes, so now all volumes for alternative fuels are from ICF study directly
  - These deterministic alternative scenarios will be reviewed along with final content in TAC 11
  - The deterministic PRS will be discussed further in TAC 10

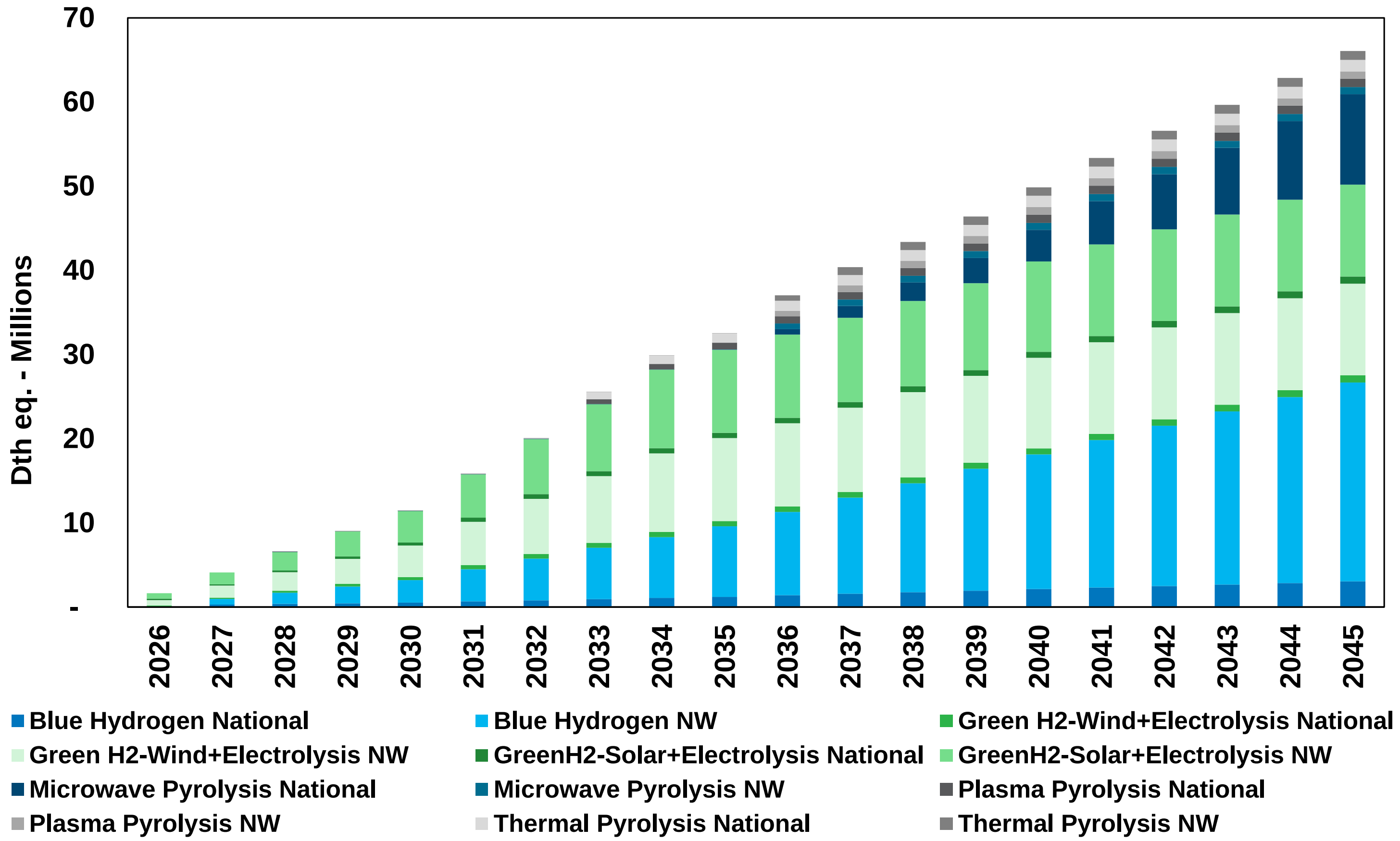
Volumes

- Expected volumes are broken down between Northwest and National technical potential
  - These volumes assume a first mover access to alternative fuels
  - Weighted by US population for states where some form of climate policy is in place or demand is expected
  - Modeled physical potential volumes are from Avista's weighted share in the Northwest and intended to represent all volumes available to Avista in the United States
    - RTC are the only National potential volumes considered and assumes physical pipeline accessibility to meet CCA and CPP program rules
    - Broken out by 2023 number of meters between LDCs in Oregon and Washington

Company	2023 # of Meters	Share
AVA	379,223	15.831%
CNG	316,929	13.231%
NWN	799,250	33.366%
PSE	900,000	37.572%
Total NW	2,395,402	100.000%

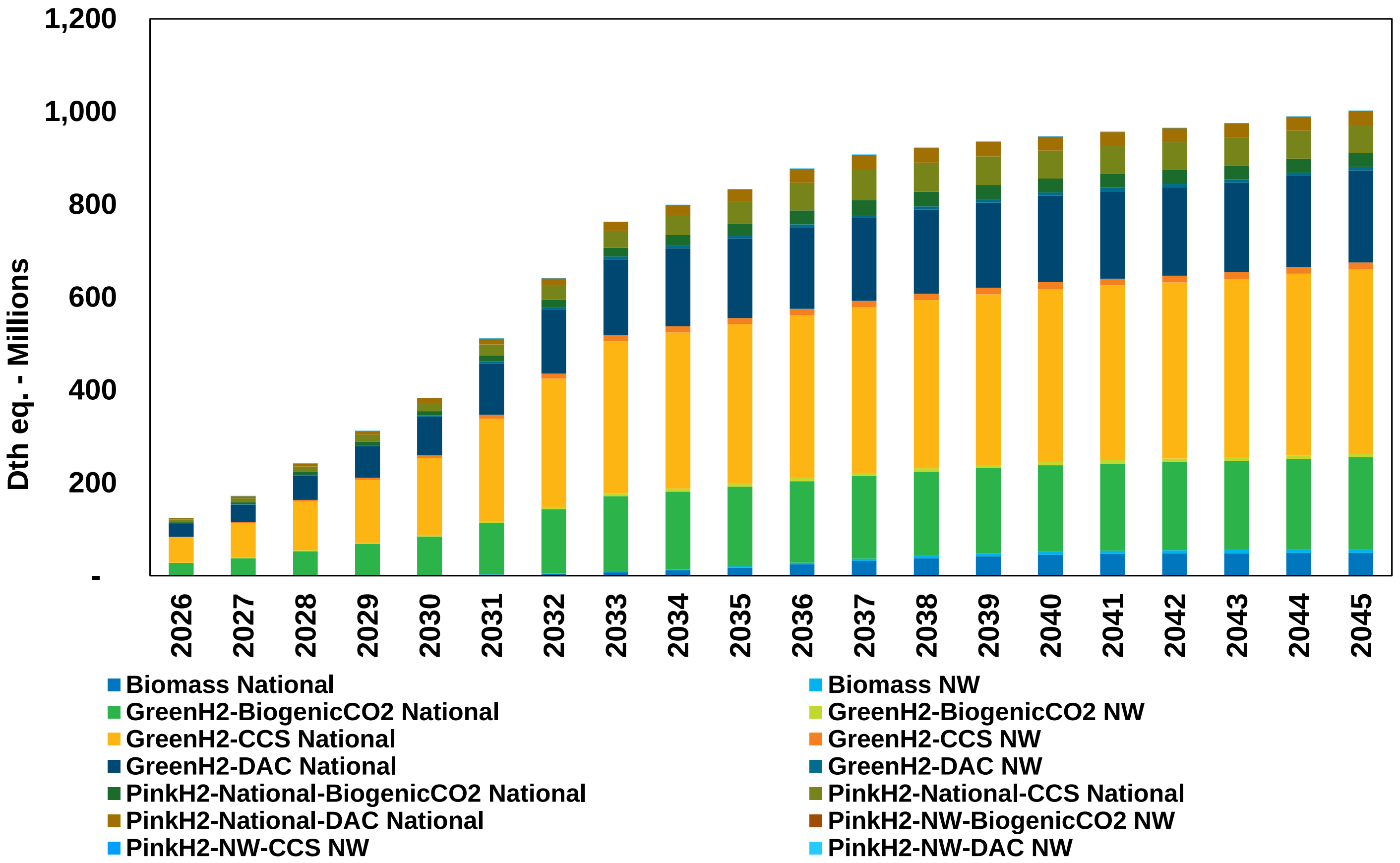
*Renewable Energy Technical Potential - The renewable energy technical potential of a technology is its achievable energy generation given system performance, topographic, environmental, and land-use constraints.

Hydrogen – Avista's Share
Technical Potential Volumes (2026-2045)



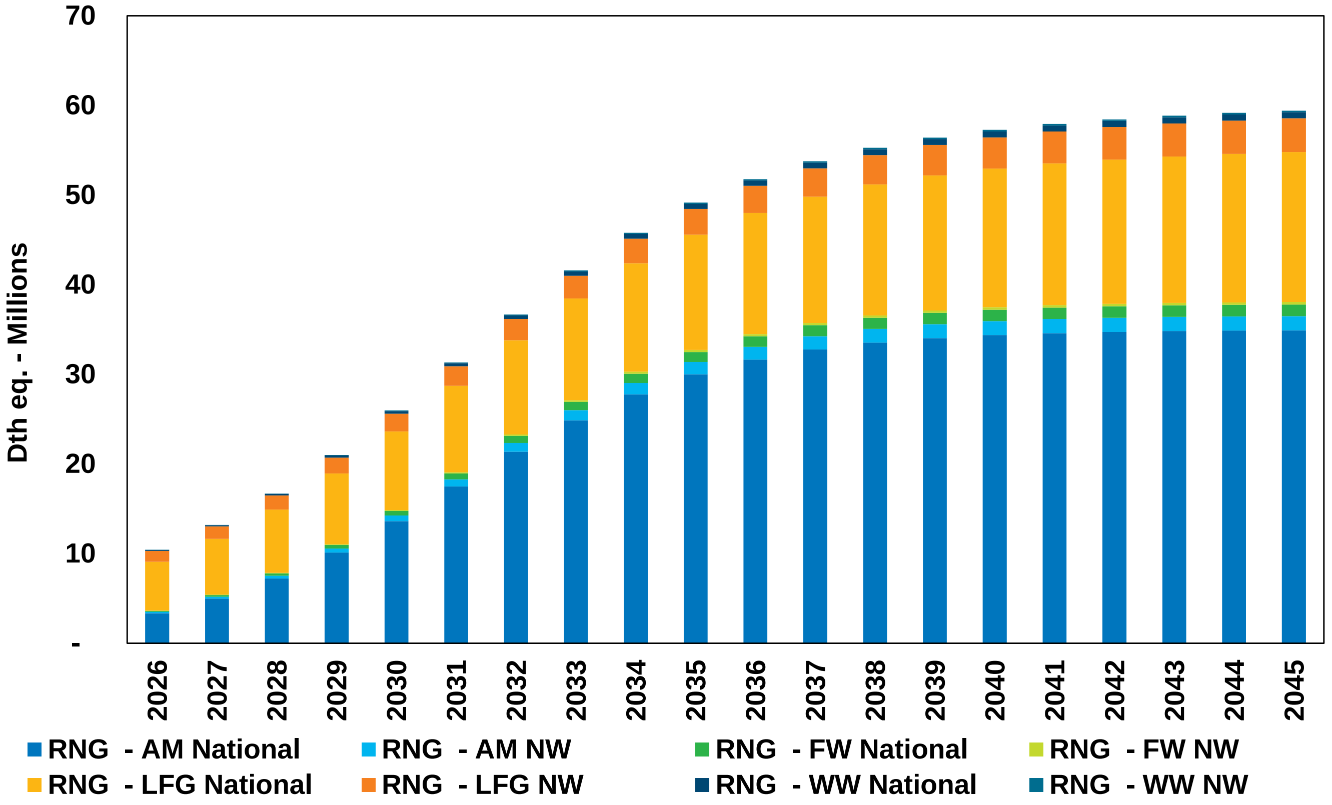
*H2 will be limited by volume to 20%
**No volumes will be available until 2030

Synthetic Methane – Avista's Share Technical Potential Volumes (2026-2045)



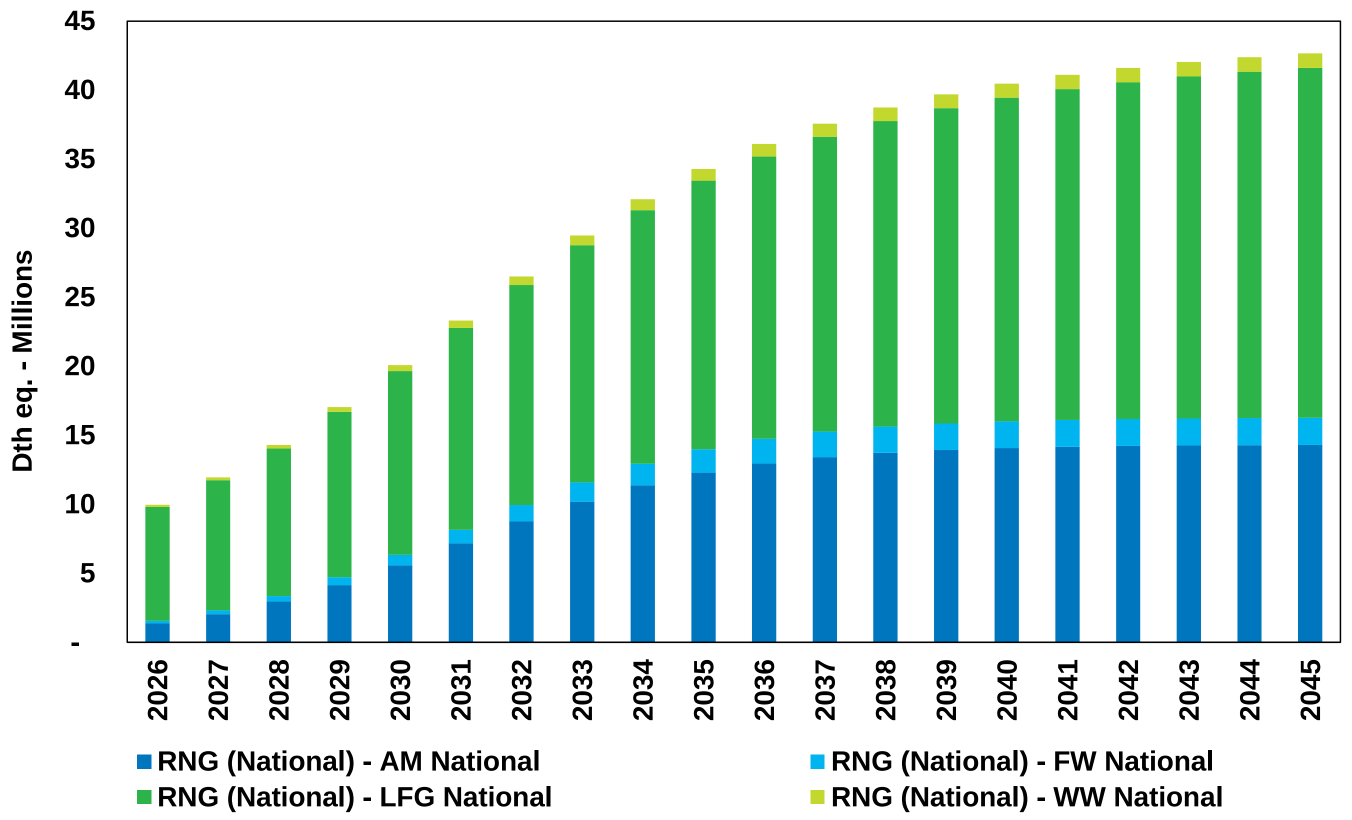
 *No volumes will be available until 2030

Renewable Natural Gas – Avista's Share Technical Potential Volumes (2026-2045)



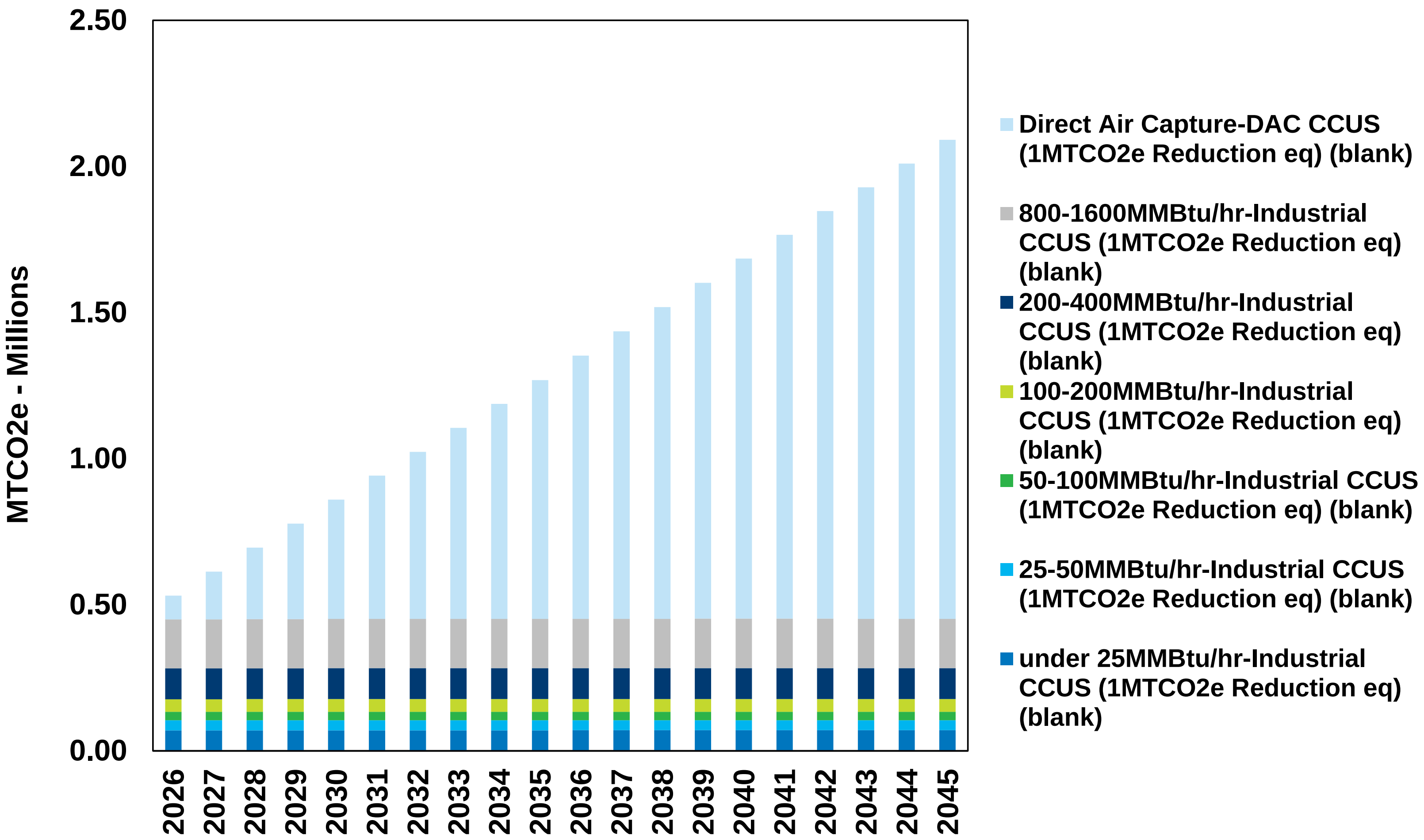
*No volumes will be available until 2030

Renewable Thermal Certificate – Avista's Share Technical Potential Volumes (2026-2045)



*Volumes are available to the model in 2026

CCUS (2026-2045)

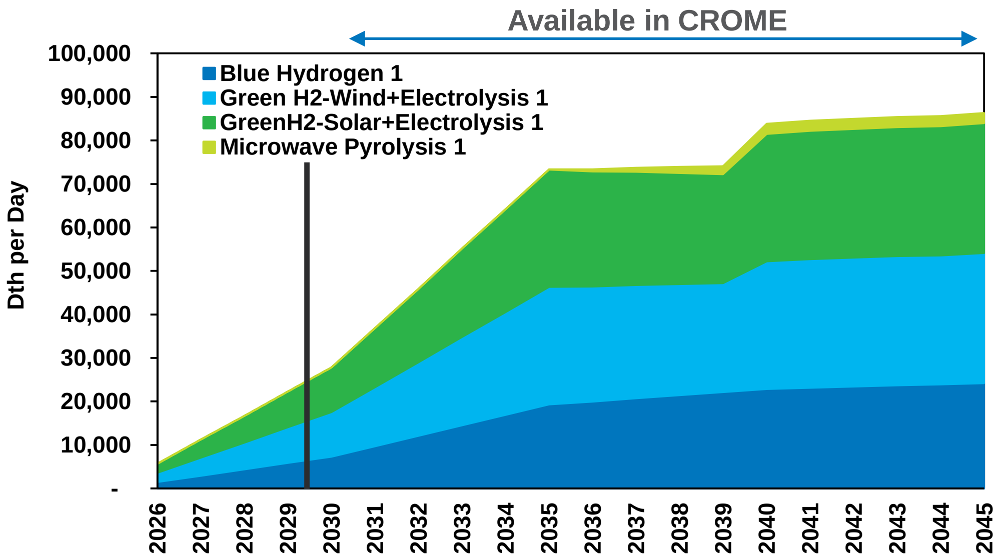


*Years 2025-2045
**No Volumes will be available until 2030

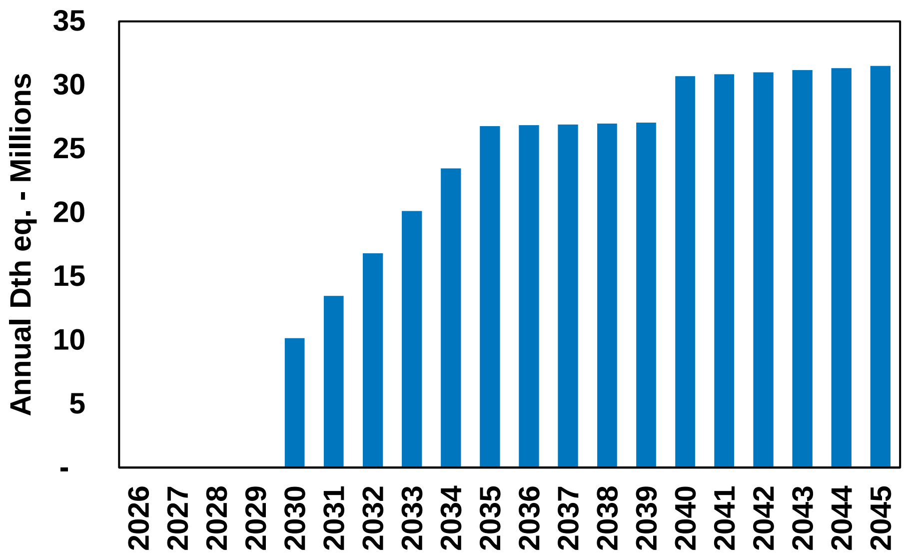
Daily Modeled Volumes

H2 – Modeled Volumes NW Only

Daily Volumes



Annual Volumes

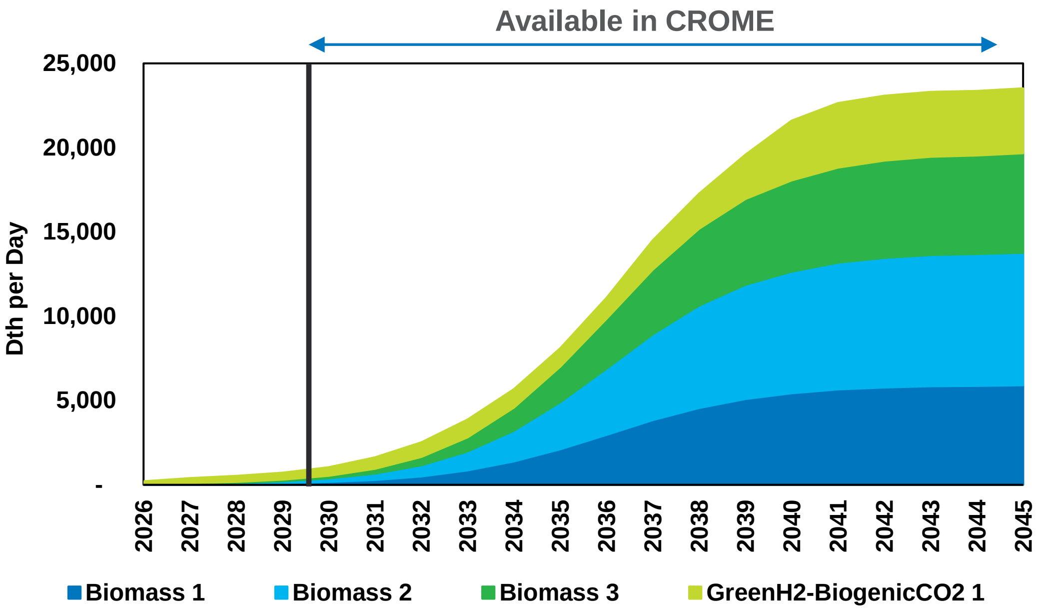


*H2 will be limited by volume to 20% regardless of availability

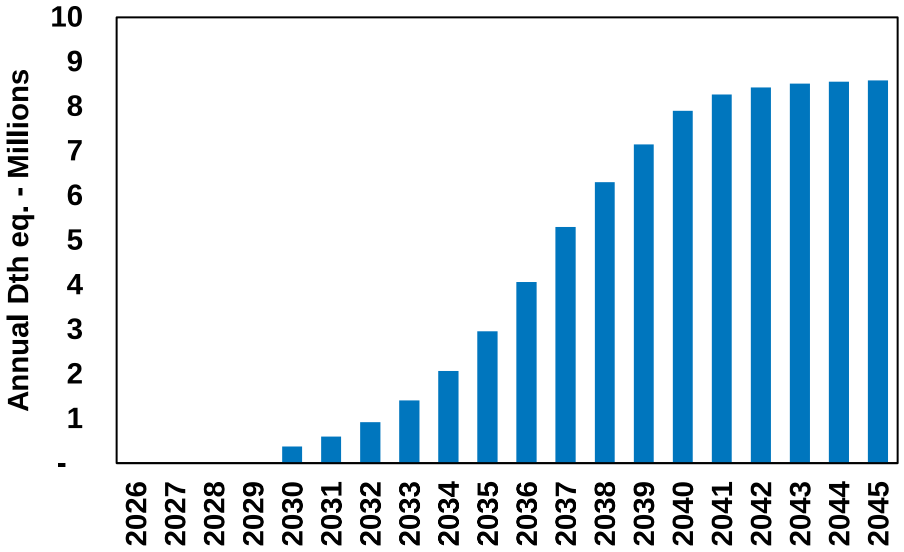
**No volumes will be available until 2030

SM – Modeled Volumes NW Only

Daily Volumes



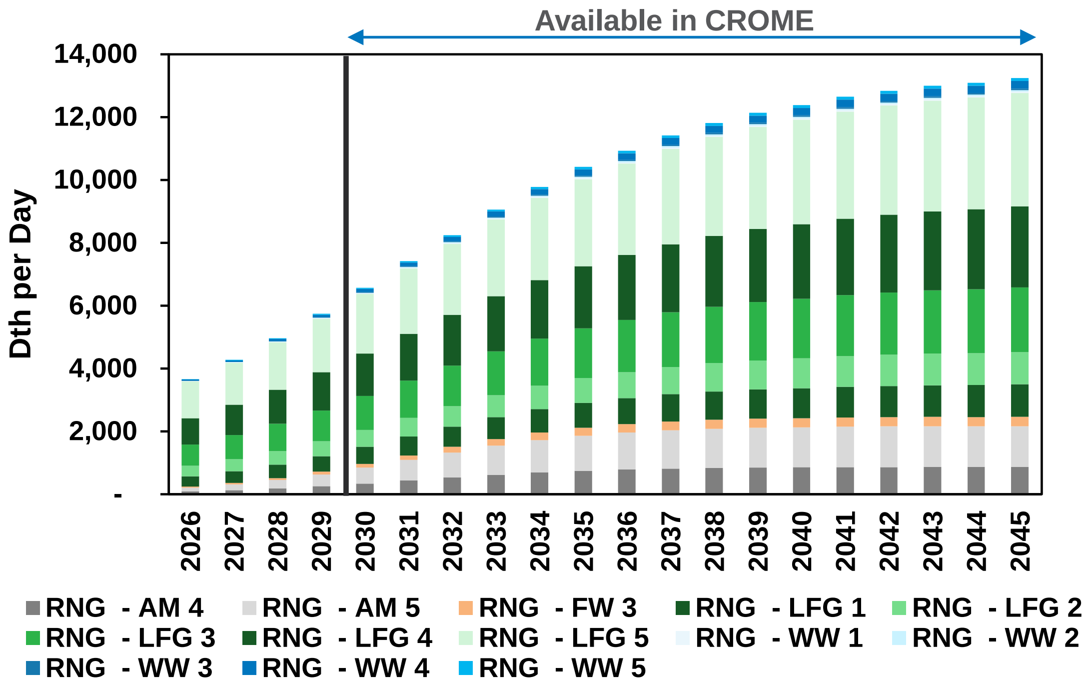
Annual Volumes



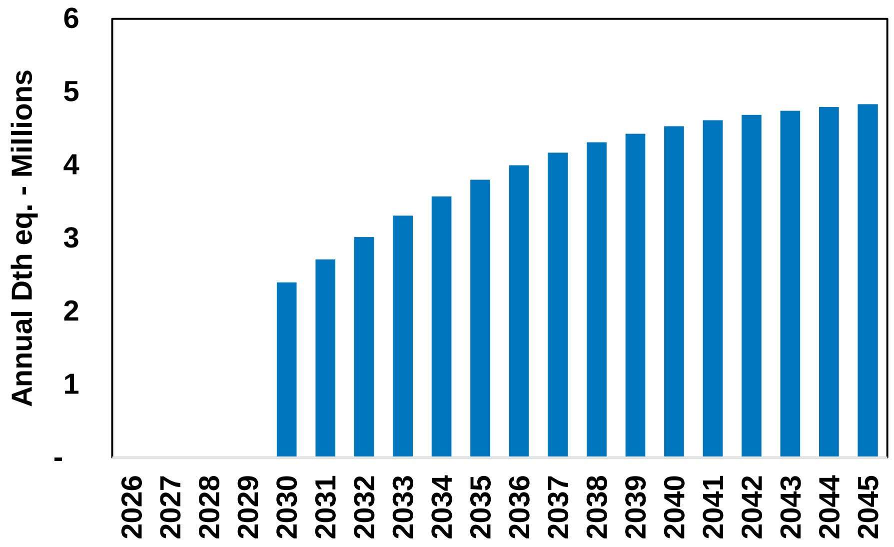
*SM is limited to NW Technical Potential availability & Avista share based on # of LDC meters
**No volumes will be available until 2030

RNG – Modeled Volumes NW Only

Daily Volumes



Annual Volumes



*Quantities not available until 2030

**Removal of high priced RNG prior to modeling (AM1-3, FW1-2)

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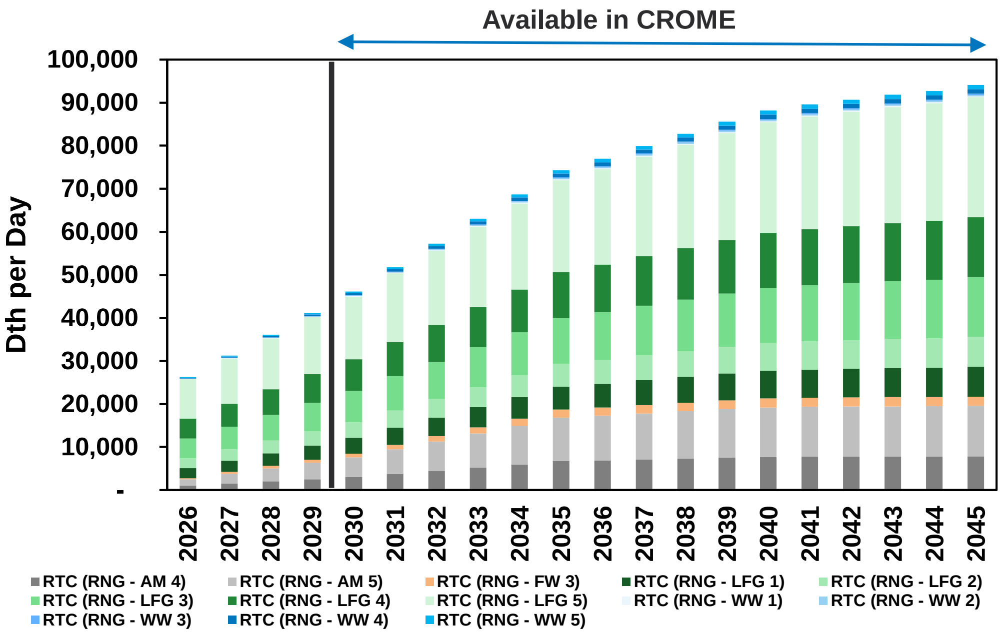
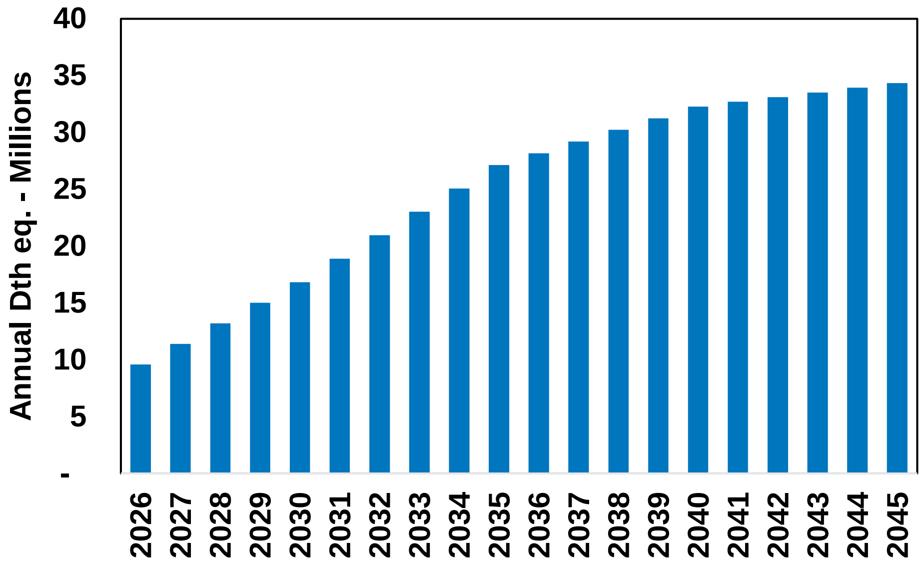
RTC – Modeled Volumes NW Only

Daily Volumes



Annual Volumes

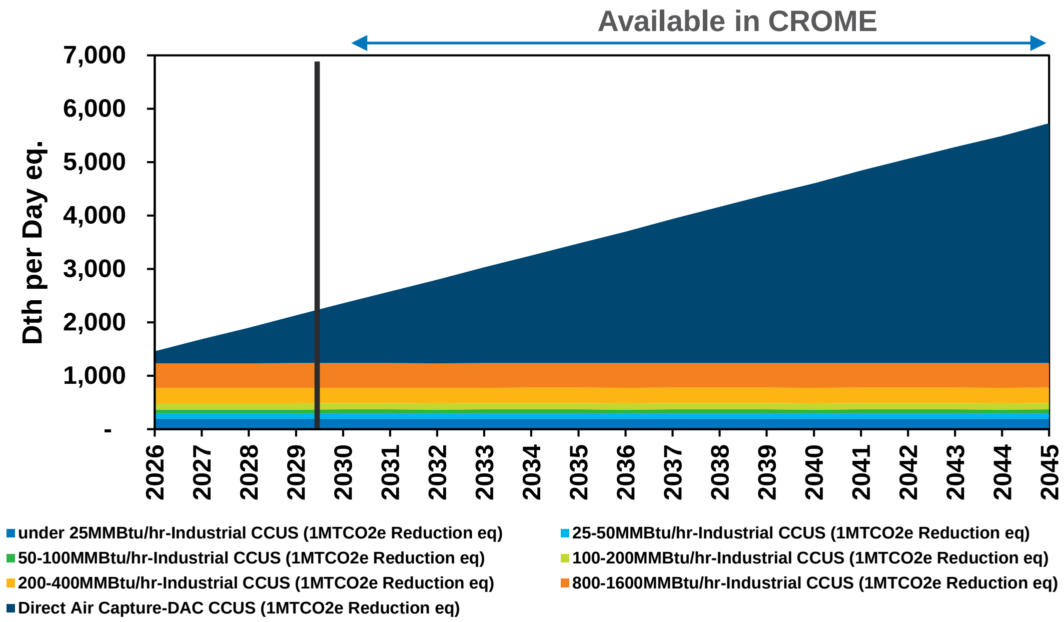


*Quantities are available to the model in 2026

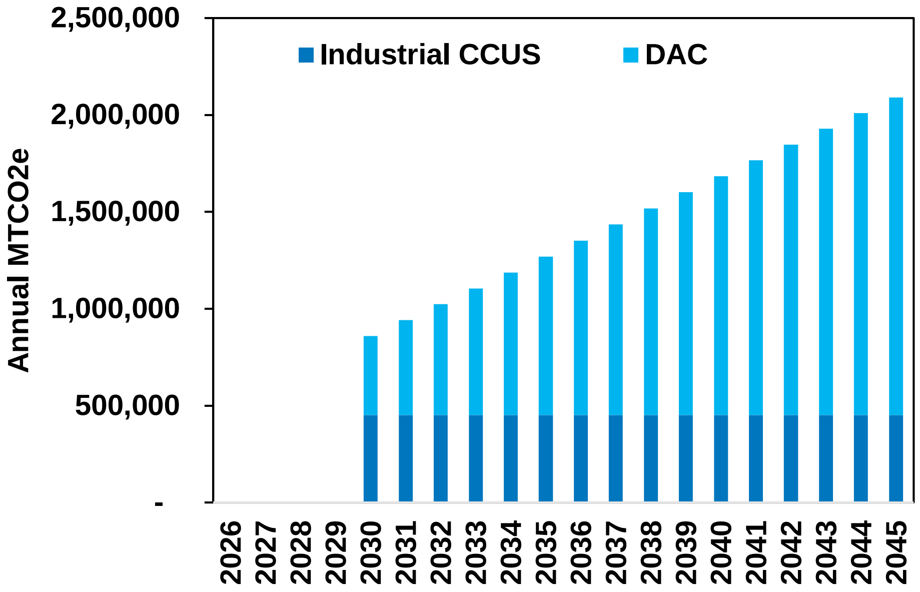
**Removal of high priced RTCs prior to modeling (AM1-3, FW1-2)

CCUS
NW Only

Daily Volumes



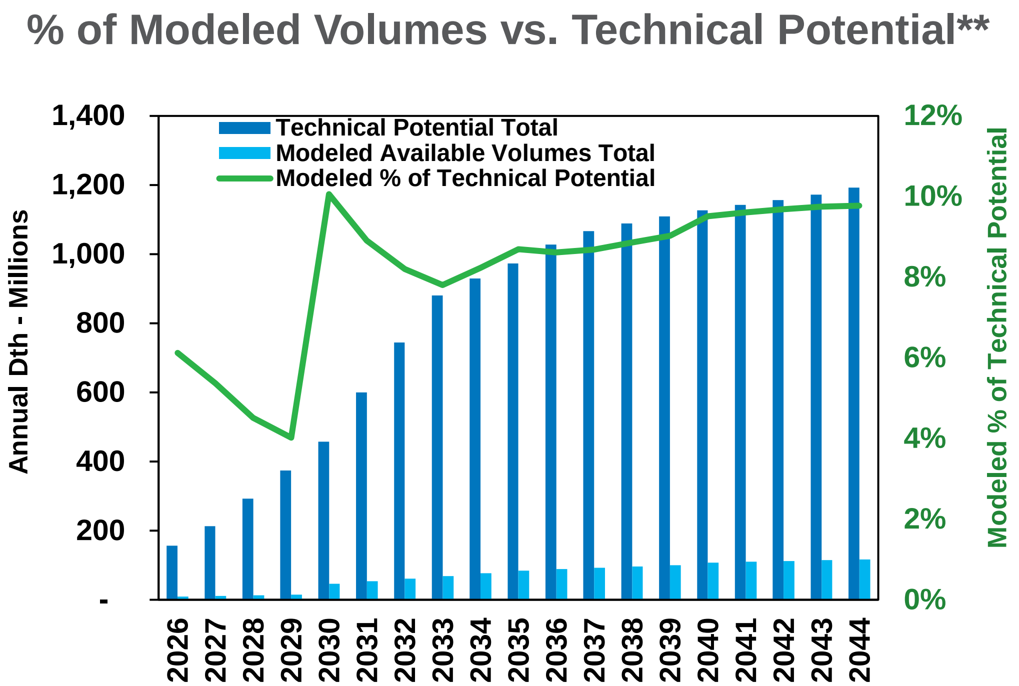
Annual Volumes (MTCO2e)

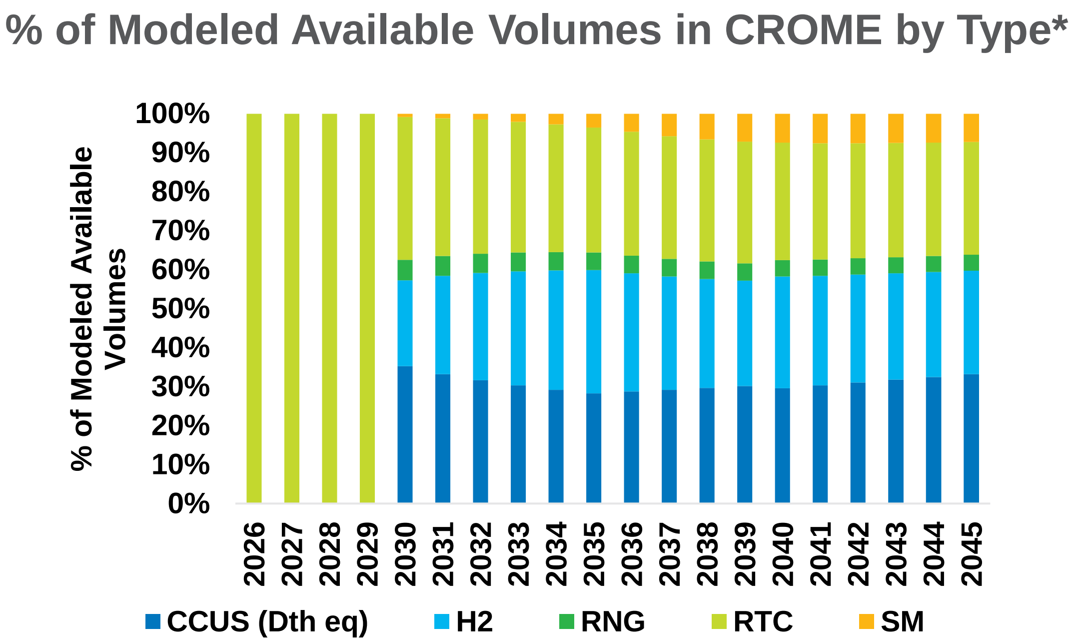


*No Volumes will be available until 2030

**CCUS “Industrial” is based on Avista specific high-volume customers

Annual - Modeled Volumes vs. Technical Potential Volumes





*Technical Potential Volumes are from ICF and weighted to % share of LDC # of customers for National and NW volumes, meaning this would be Avista's share of those volumes

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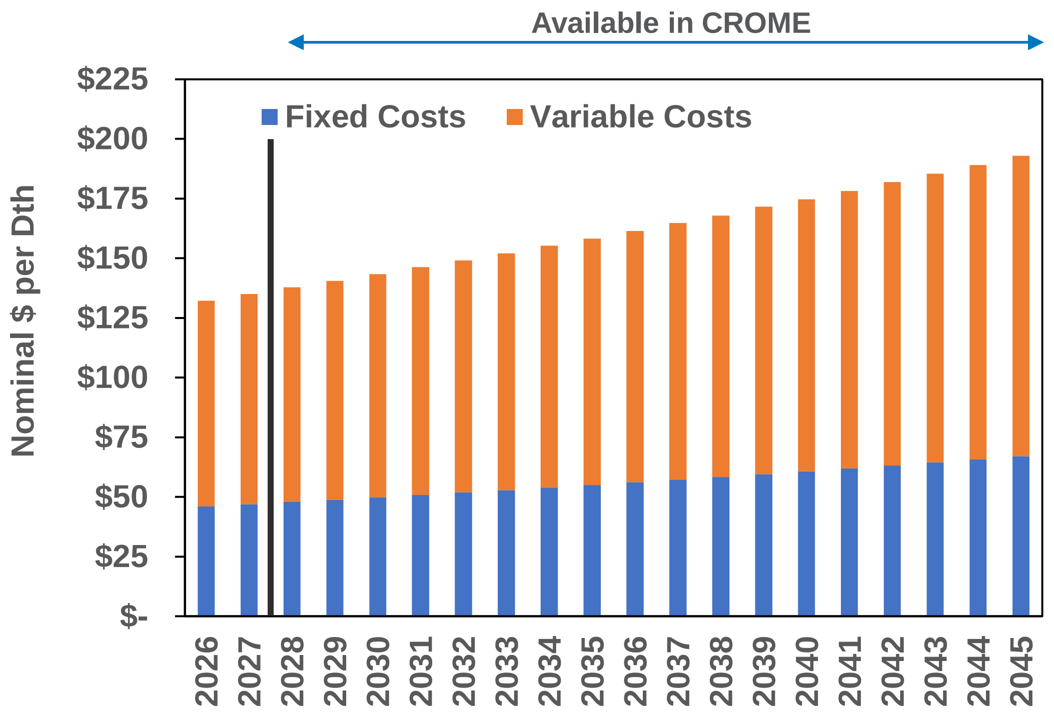
Other Supply Side Resource Options

Propane Storage

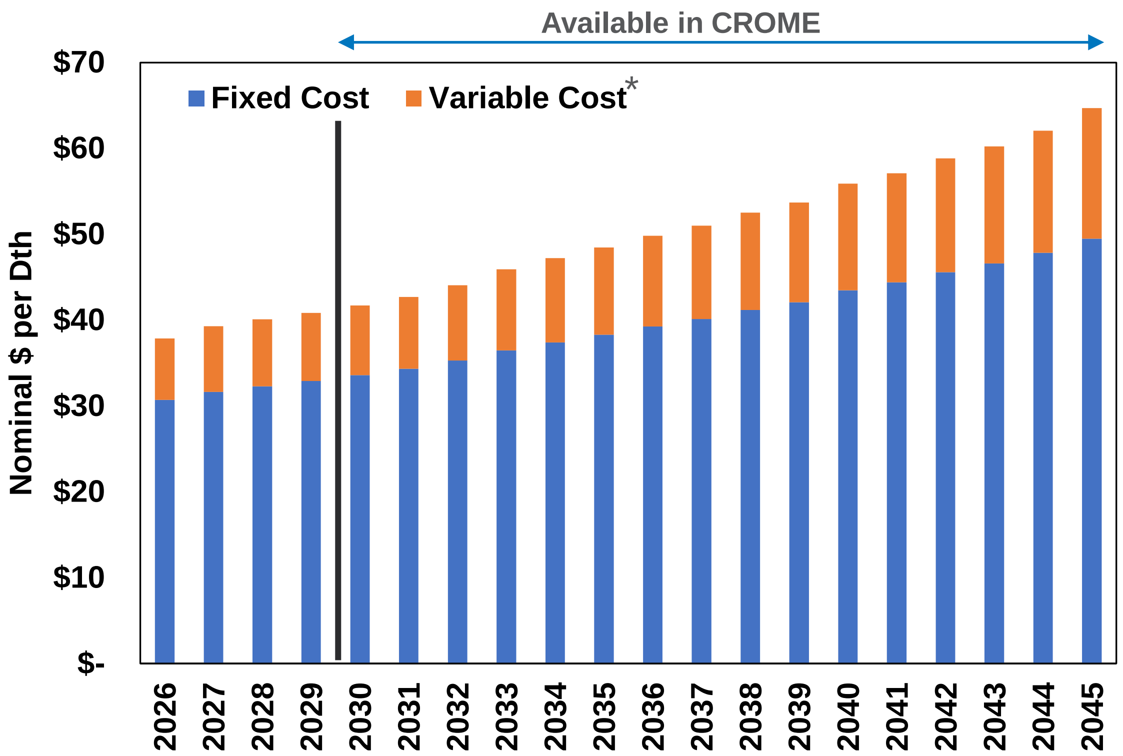
- CapEX - $14.7MM (20 Year Asset Life)
- Plant Size – 30M Dth (1 cycle)
- Installation + Owners costs – 5% of capital cost
- Delivery Cost is included
- Plant electricity and air injection
- Siting, permitting and build - 2 years
- Propane costs per gallon are included in estimated nominal $ per Dth – Variable Costs



*Cycling of plant reduces overall cost per Dth
**No volumes will be available until 2028

Liquified Natural Gas (LNG) Peak Storage

- CapEX - $200MM (50 Year Asset Life – Avista Rev. Req)
- Plant Size – 1 Bcf
- Max volume per day – 103,700Dth
- Pipeline - $2MM
- Utility Interconnect - $3.12MM
- Installation + Owners costs – 30% of capital
- Liquefaction Costs
- Days of peak supply – 10
- Liquefier capacity per day – 7,000 Dth
- Siting, permitting and build - 4 years
- Gas commodity costs included in CROME and combined with estimated nominal $ per Dth



*Example only as costs are modeled directly in CROME

*Cycling of plant reduces overall cost per Dth
**No volumes will be available until 2030

Constraints of Resource options in CROME

Resource Type	Volumetric Restriction	First Year of Availability
Allowances	10% of Market per program rules (CCA)	2026
Community Climate Investments	15% (2025-2027), 20% 2028+ (CPP)	2026
Demand Response	CPA from AEG for potential	2026
Electrification	No constraints, up to total energy demanded on LDC by area/class/year	2026
Energy Efficiency	CPA from AEG and ETO	2026
Renewable Thermal Credit	NW Technical Potential (ICF) – Avista Share (16%)	2026
Propane Storage	30,000 Dth	2028
Hydrogen	NW Technical Potential (ICF) & Avista Share (16%) & 20% by volume	2030
Synthetic Methane	NW Technical Potential (ICF) & Avista Share (16%)	2030
Renewable Natural Gas	NW Technical Potential (ICF) & Avista Share (16%)	2030
Liquified Natural Gas	1 Bcf Total & 0.1 Bcf Daily W/D	2030
Carbon Capture, Utilization and Storage	Constraints to Avista high volume customers (ICF)	2030

PRS

Draft

High Level Modeling Overview

Deterministic Portfolio Optimization – (For All Alternative Scenarios)

- Portfolio solves for 1 future using expected value assumptions/inputs for each data point in the model
- The solve is optimized/valued against constraints:
  - CCA
  - CPP
  - Transport
  - Resource and Volumetric availability

~~Stochastic Portfolio Optimization – (For PRS only)~~

- Portfolio solves for 5 futures simultaneously representing a distribution of choices across varying load profiles, prices and constraints to create the final resource selections
- Avista may test multiple additional futures to arrive at the final PRS

Monte Carlo of a single portfolio – (Selected Scenarios)

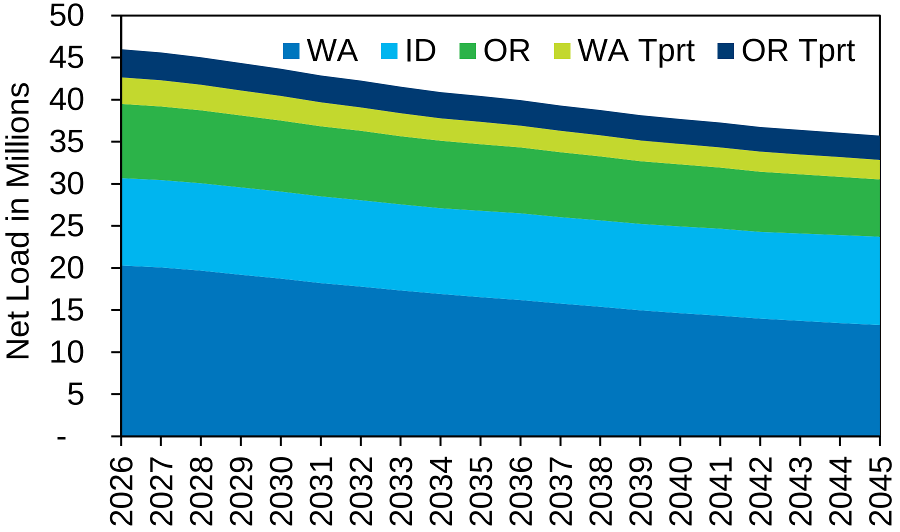
- CROME locks down the resources selected in each portfolio scenario
- A set of 500 Monte Carlo simulations of load, weather, fuel prices and availability
- will be run to measure variation of prices, risk and availability to serving load and meeting required constraints

Monte Carlo portfolio optimization – (PRS Unconstrained)

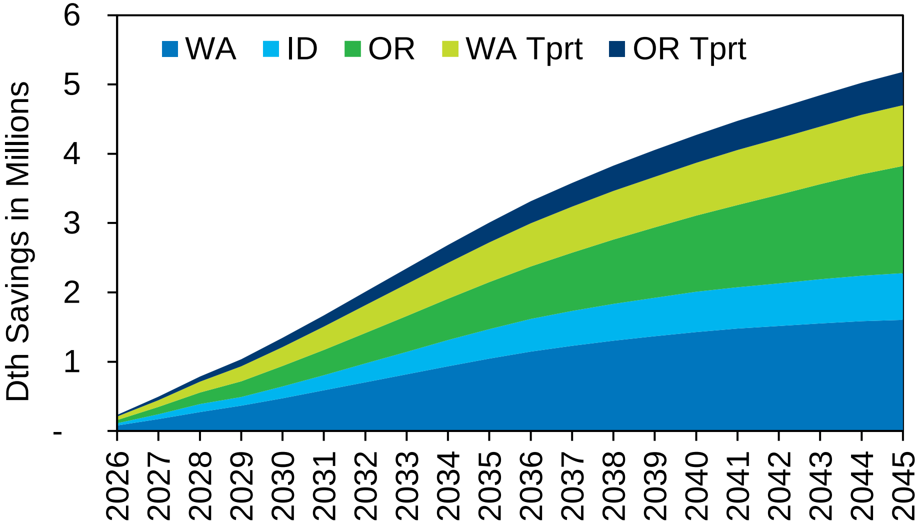
- 500 individual portfolios
- Provide Statistics of 500 portfolio resource selections

Net Load and Energy Efficiency

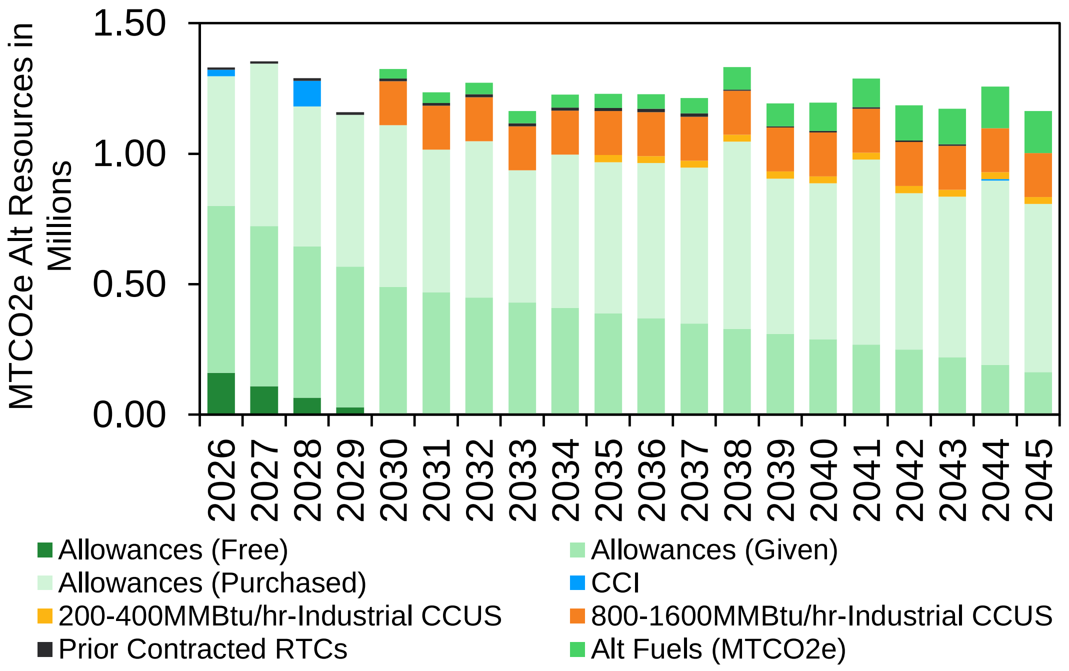
Avg. Net Load After EE

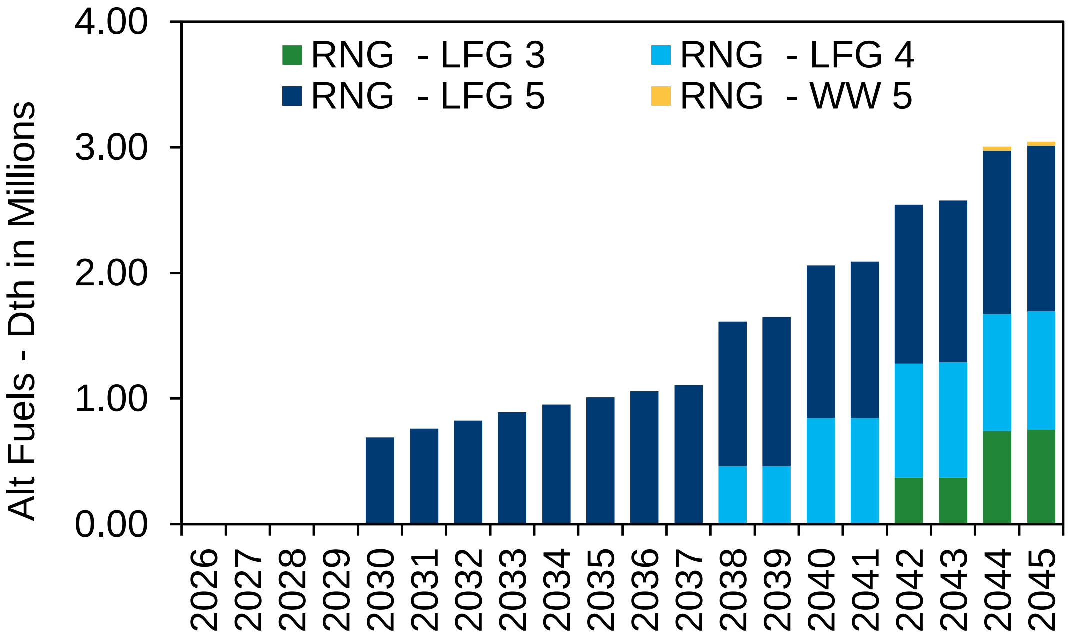


EE Cumulative Reduction

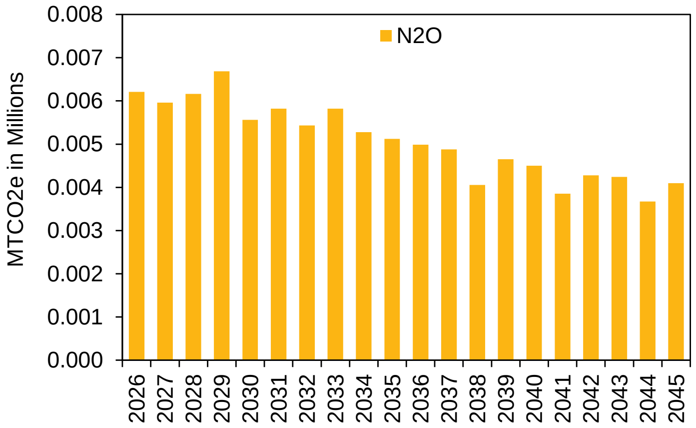


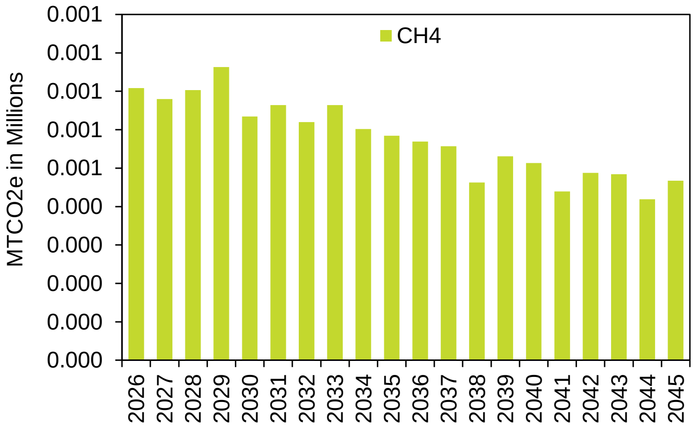
Selected Resources

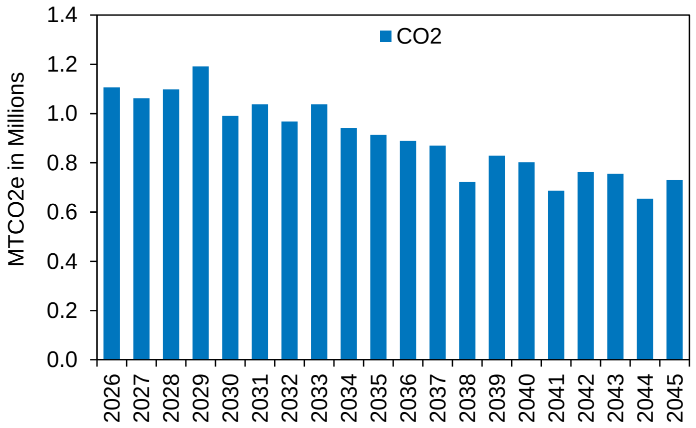


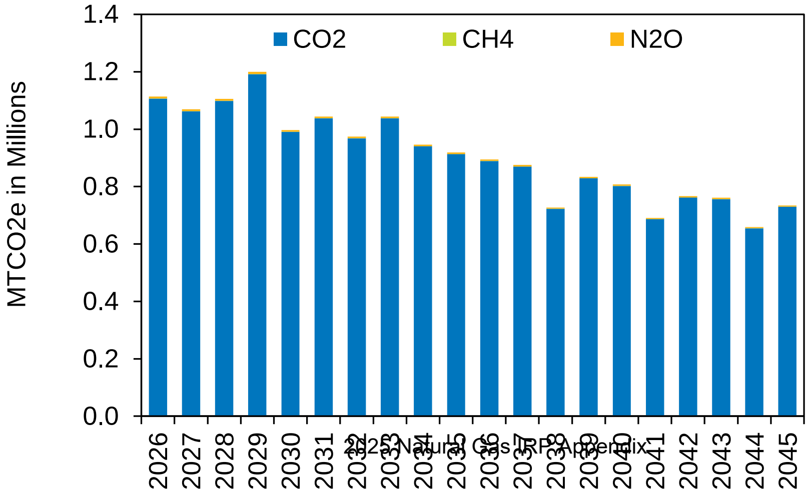


Net Emissions



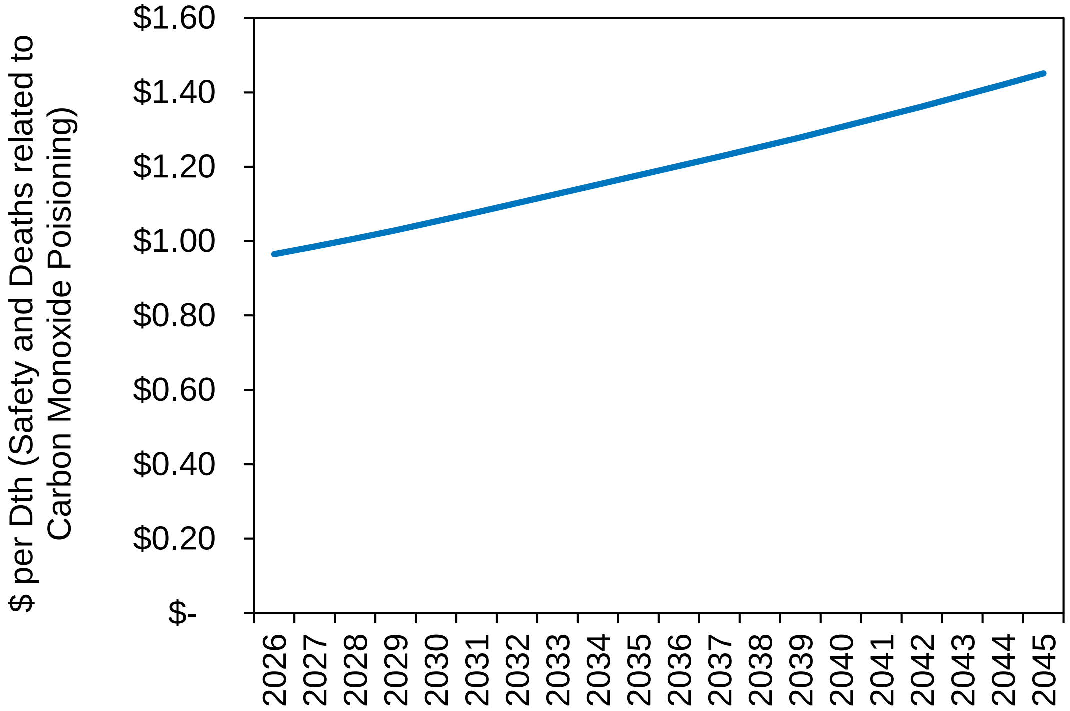




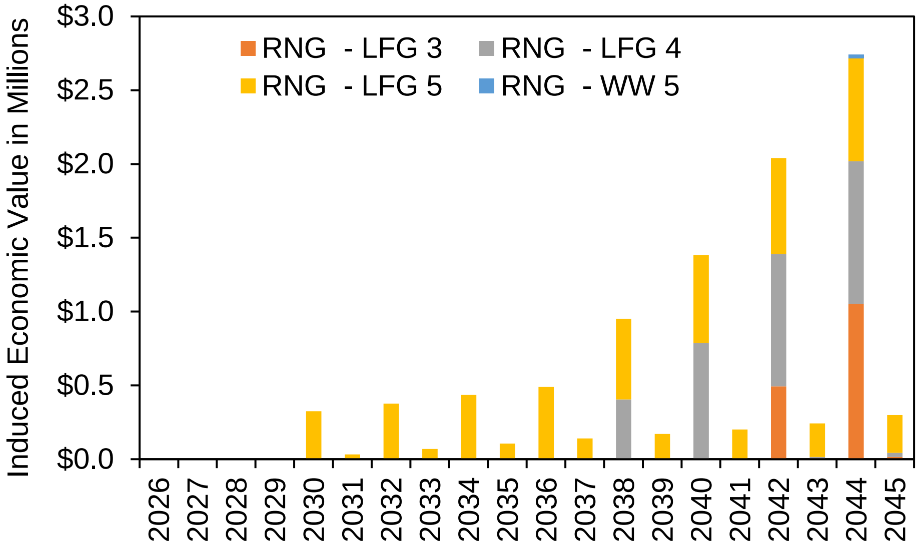


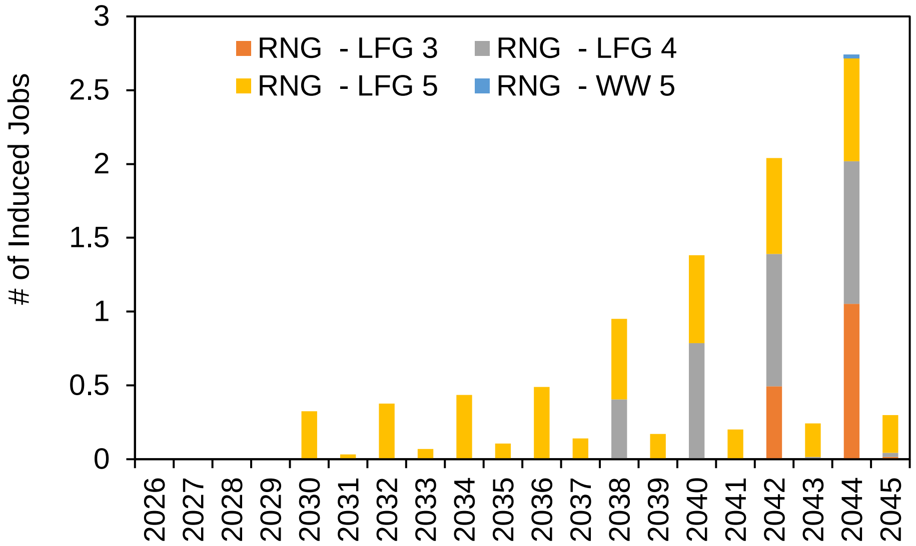
NEI

- Added to the Price of Natural Gas
  - Safety incidents
  - Carbon monoxide poisoning
- Social Cost of Carbon
- Emissions



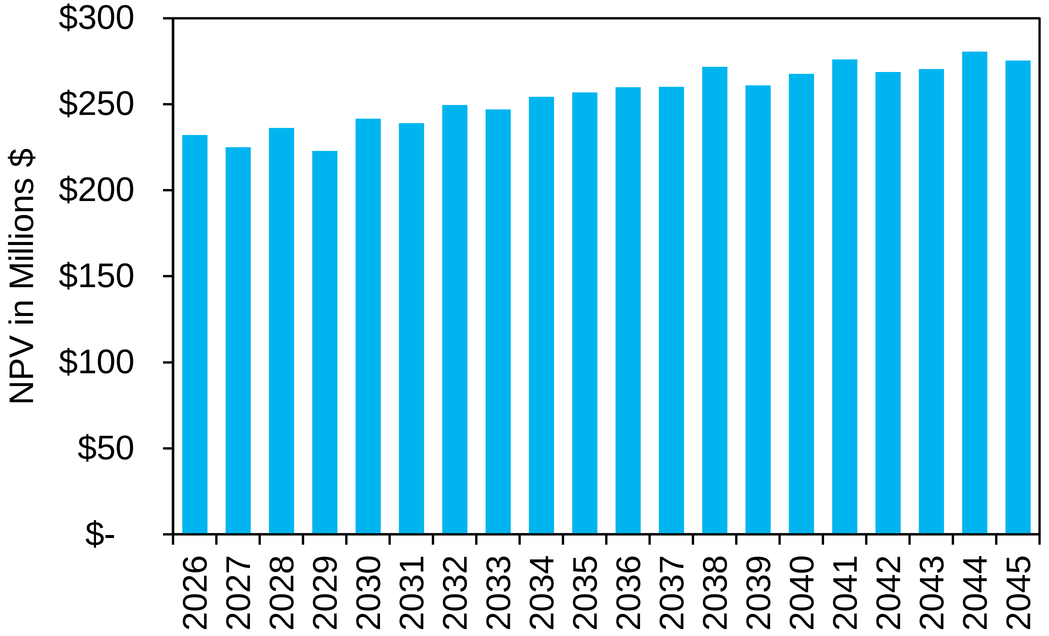
Economic Benefit of RNG Selected

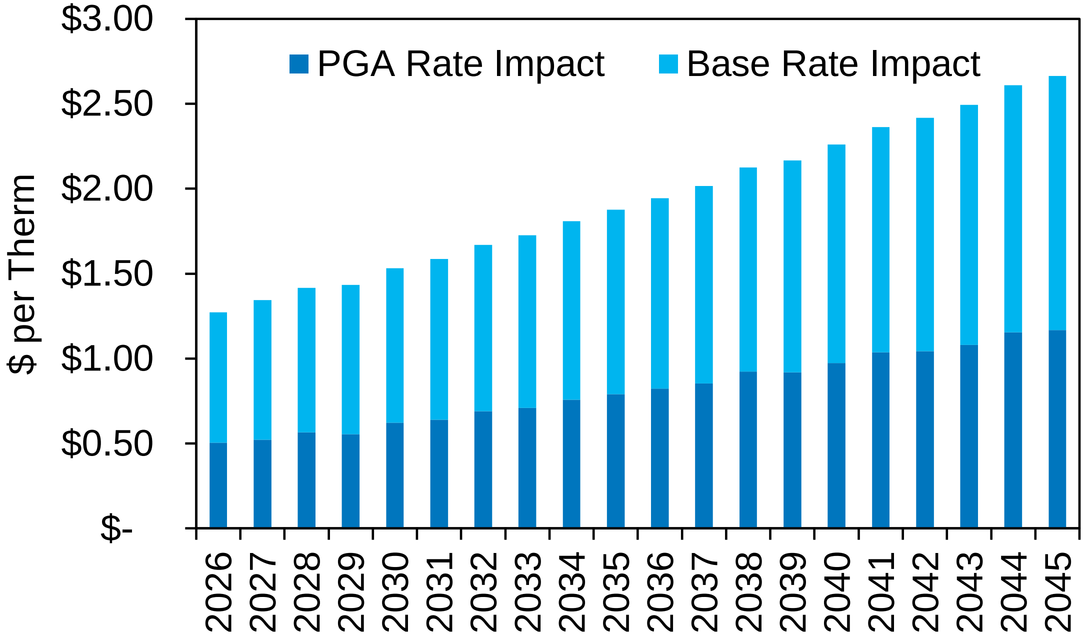




Source: IMPLAN based on selected resources

System Cost and Rate Impact





*Does not include all Tariff Riders

Alternative Scenarios and Sensitivities

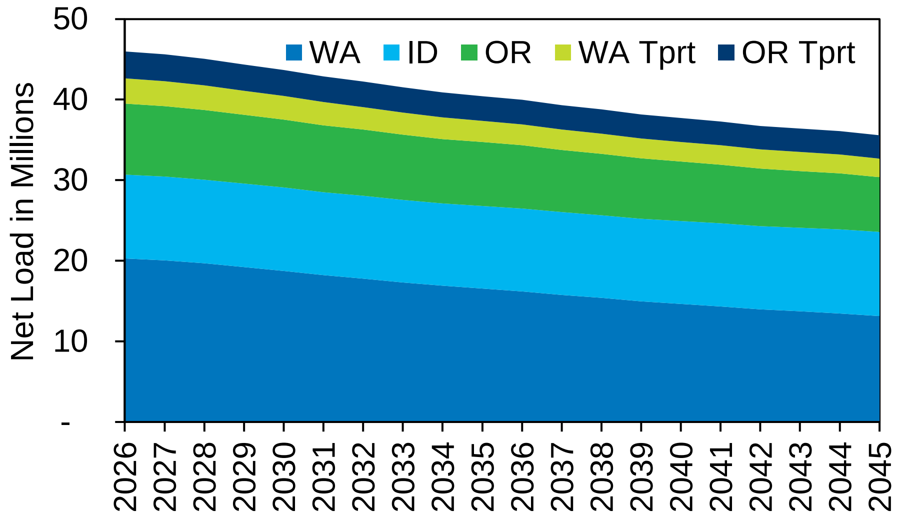
DRAFT

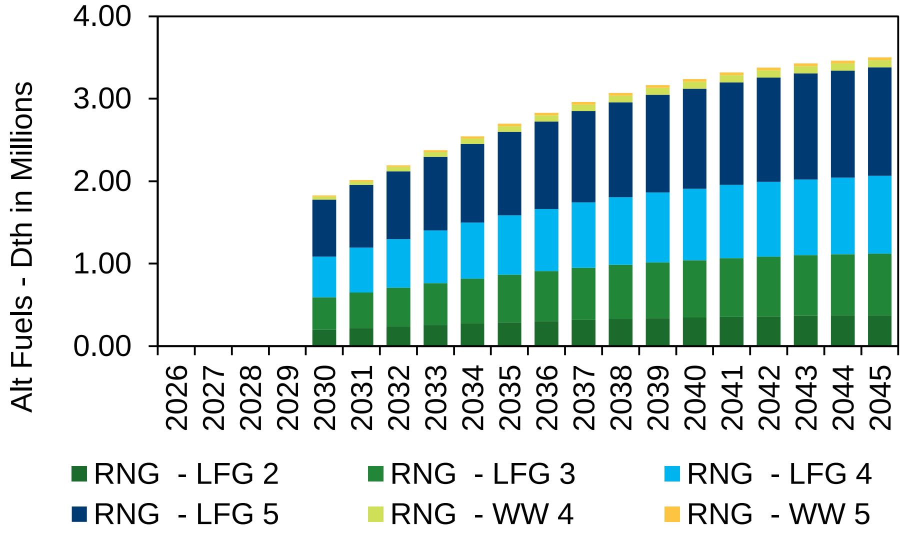
January 22, 2025

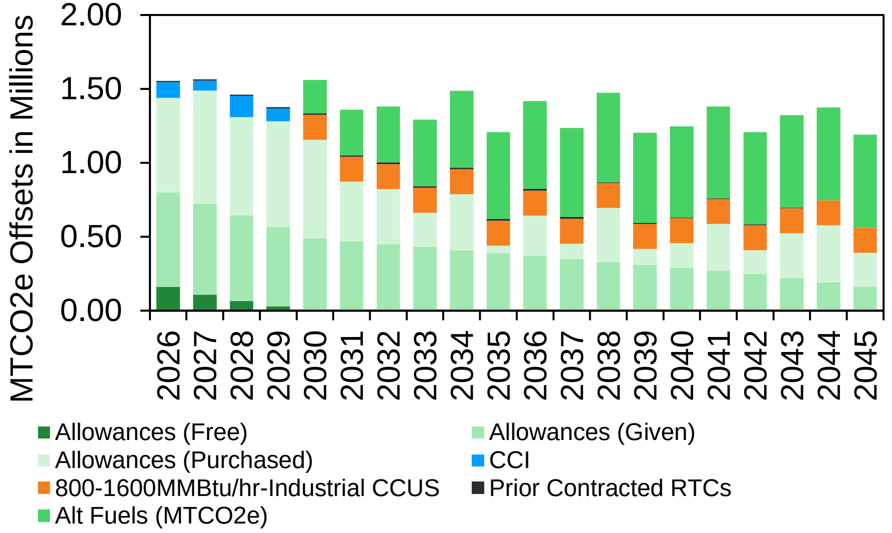
Alternative Scenarios

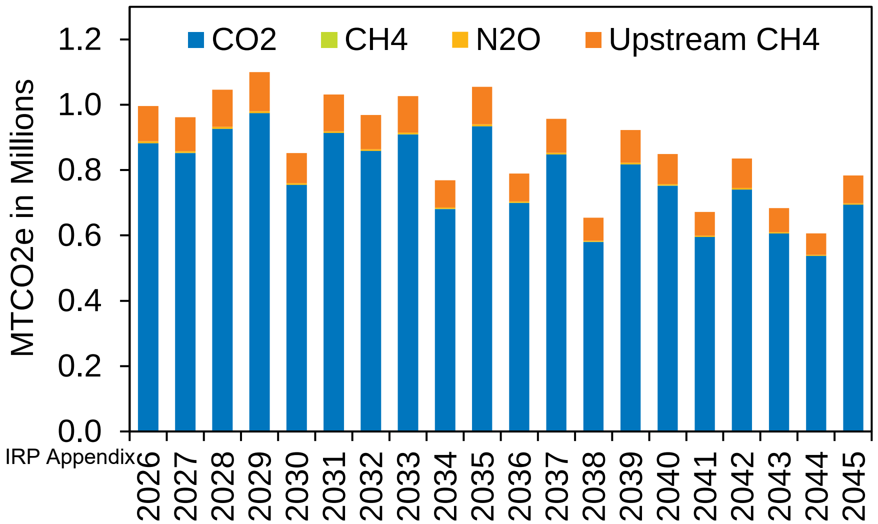
Scenario Description	Changes from PRS
SCC @ 2.5%	SCC in All Jurisdictions

Social Cost of Carbon





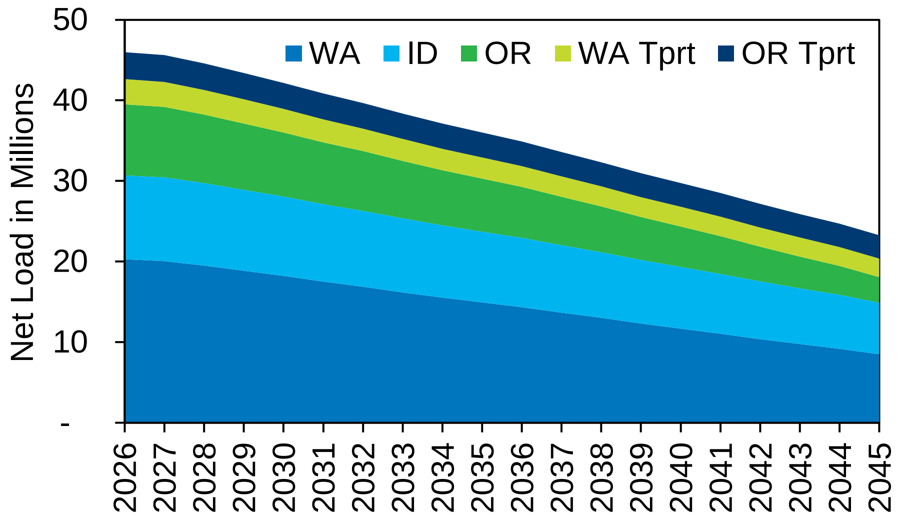


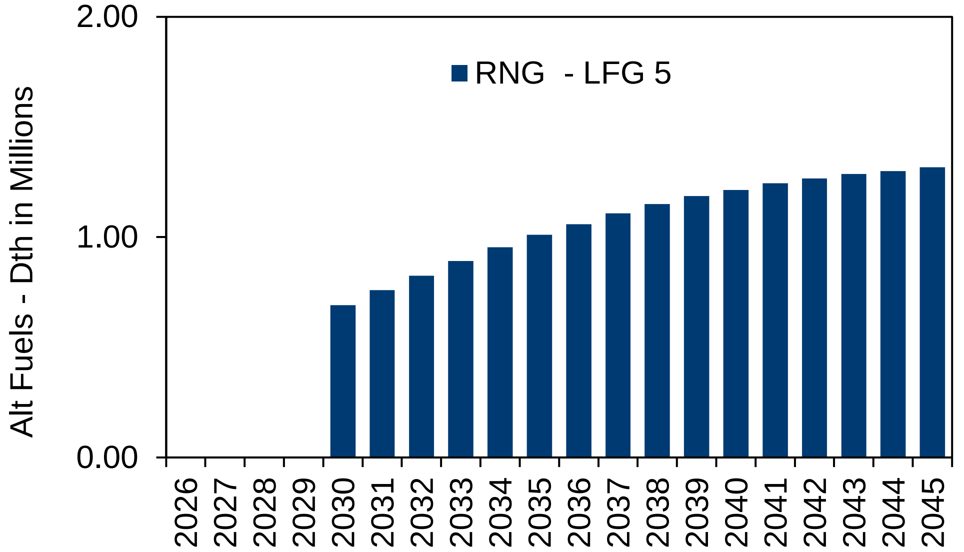


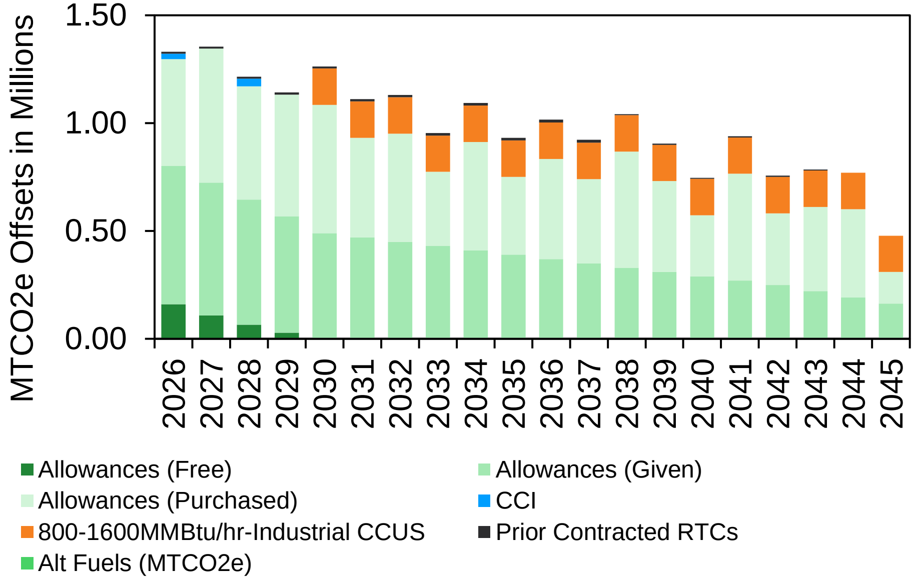
AVISTA

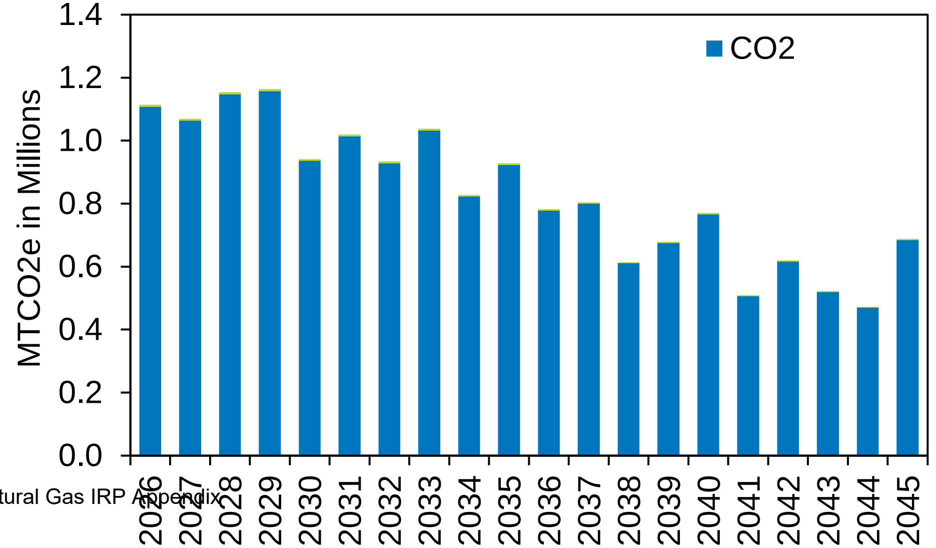
Scenario Description	Changes from PRS
Hybrid Heating from PRS Loads	• **LDC Heating @ 38º F** • **Avista Electric Resources for New Loads (ID/WA)**

Hybrid Heating



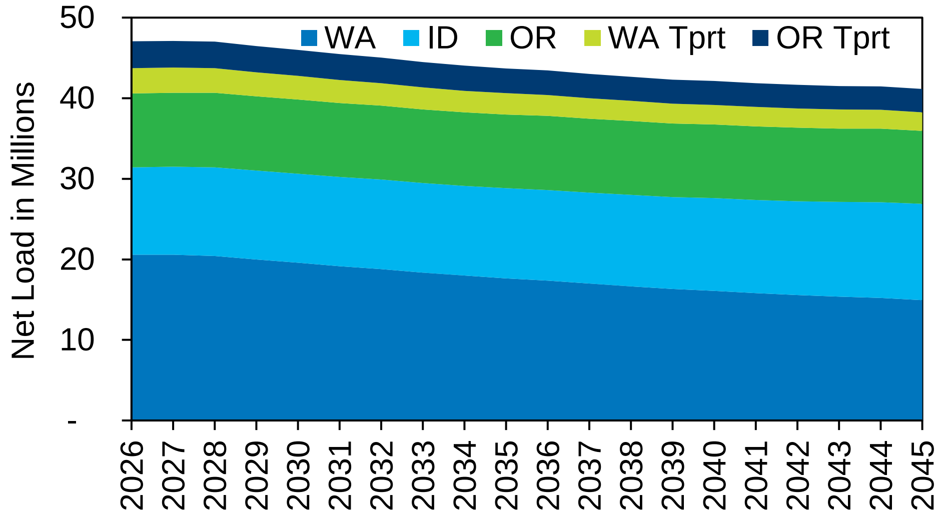


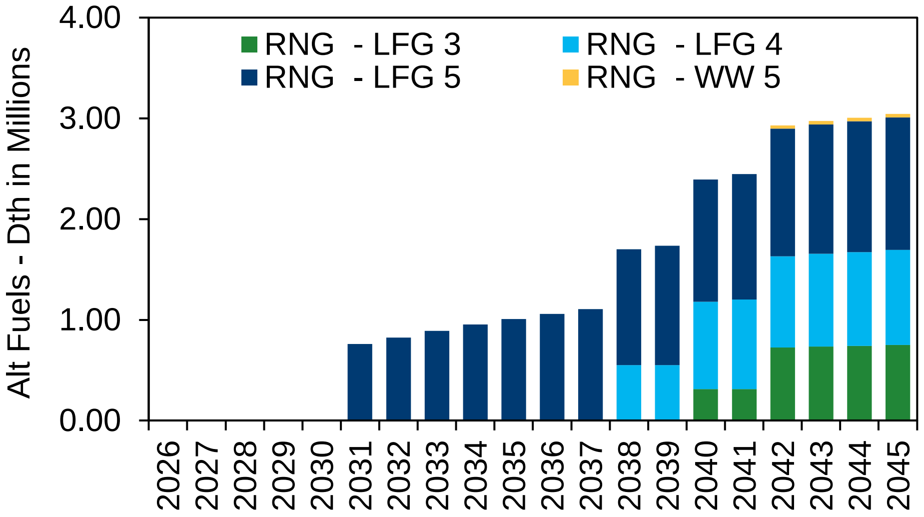


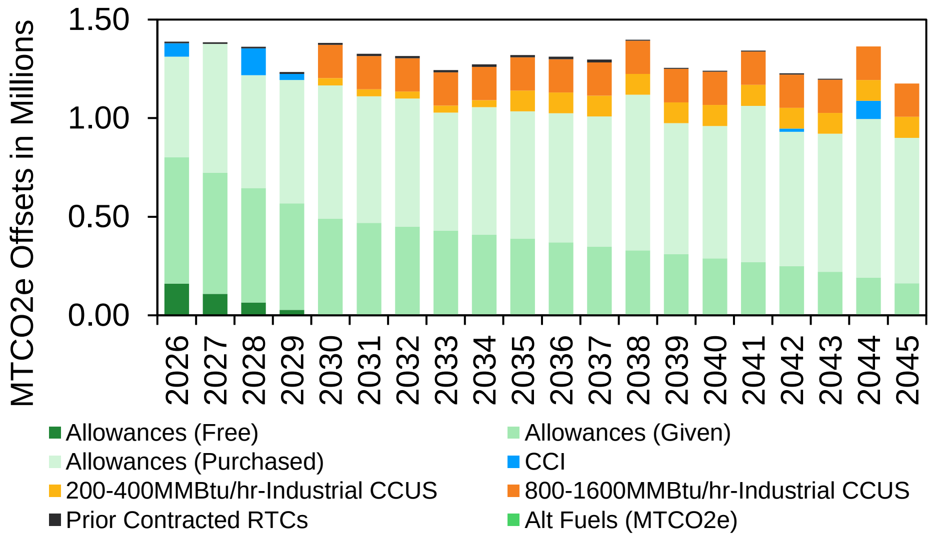


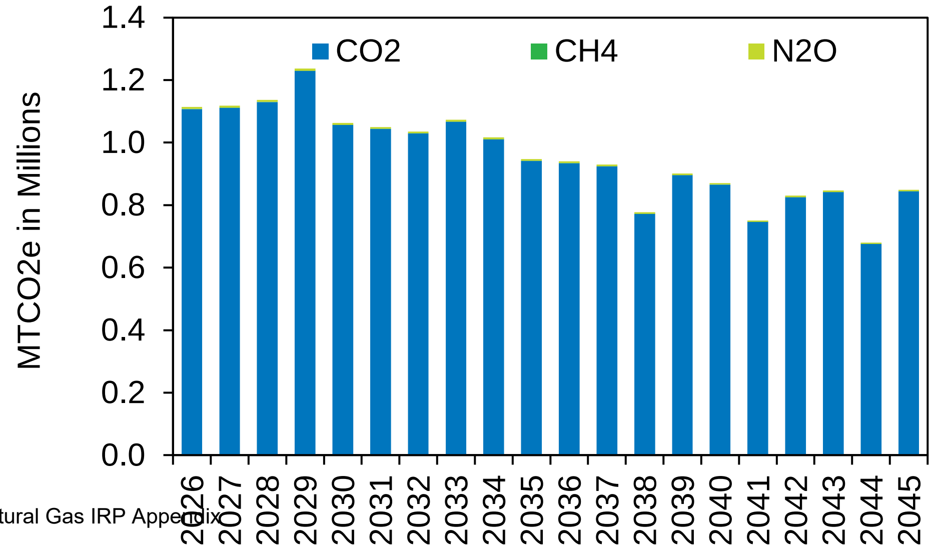
Scenario Description	Changes from PRS
Higher than expected load growth	• High Load Demand

High Growth



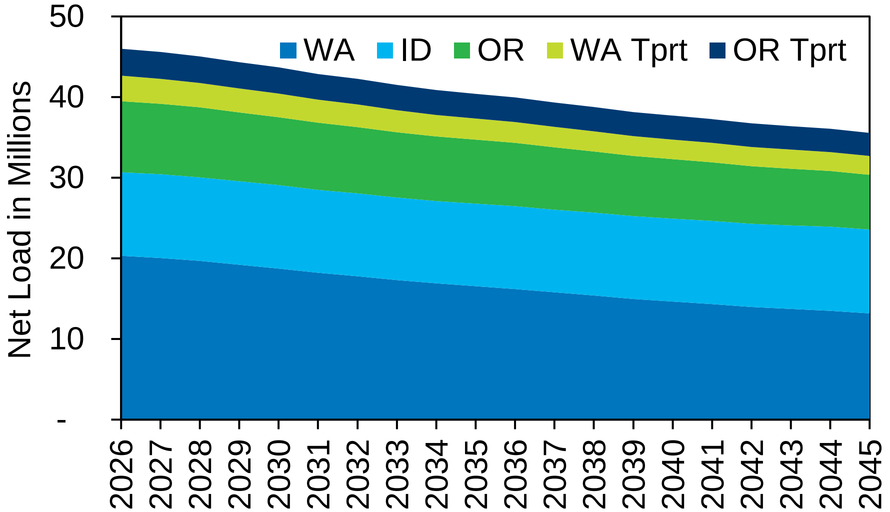


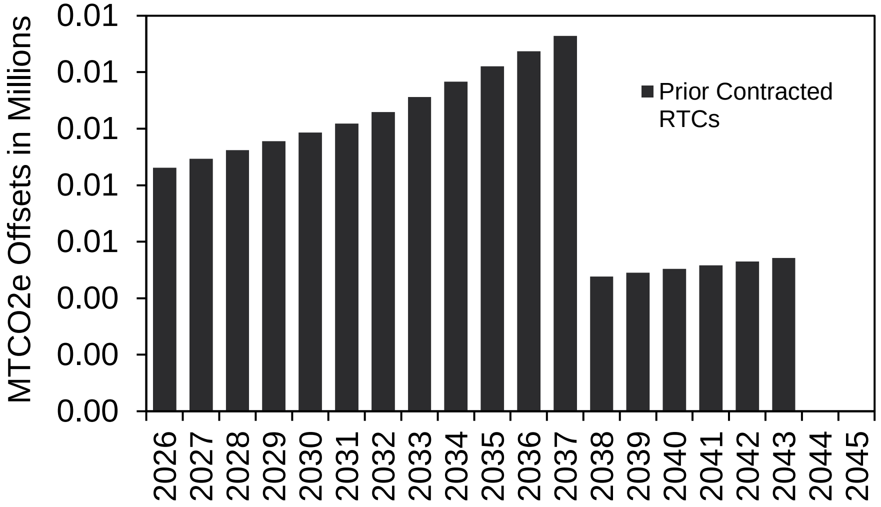


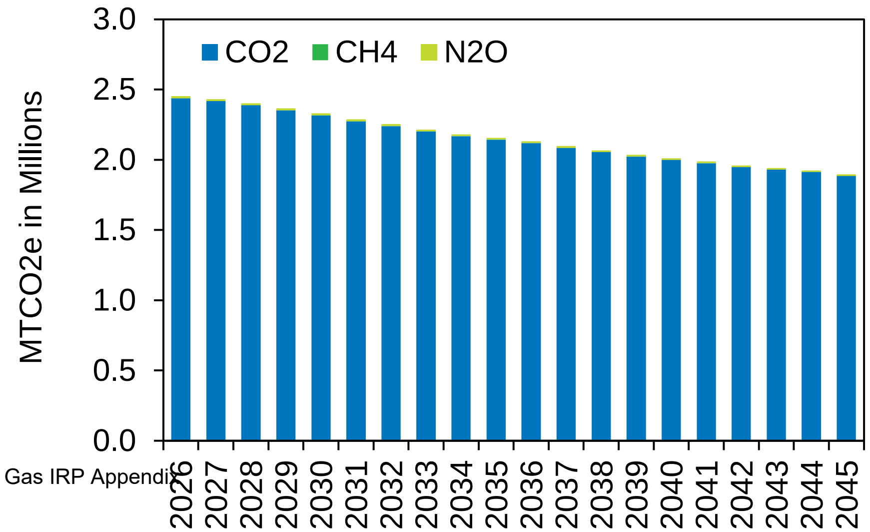


Scenario Description	Changes from PRS
Climate Programs Cost Impact to System	**No Climate Programs (CCA,CPP)**

No Climate Programs

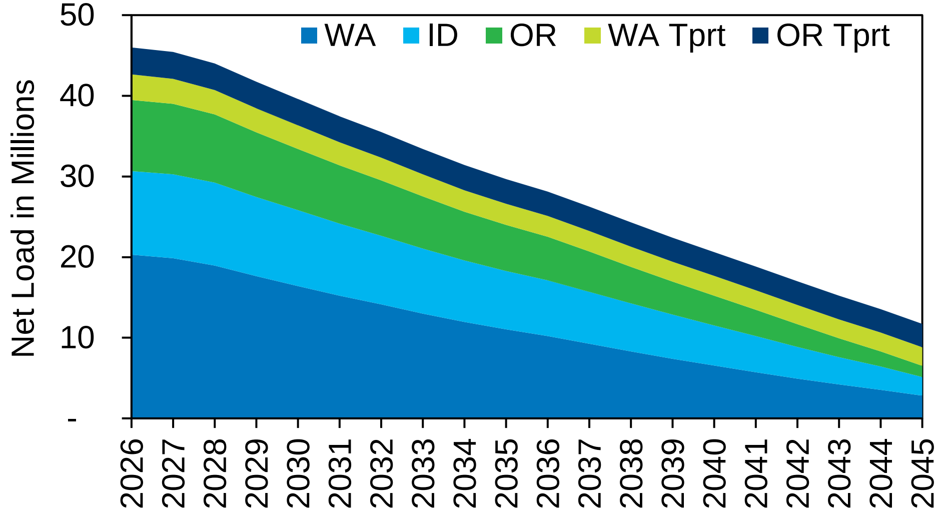


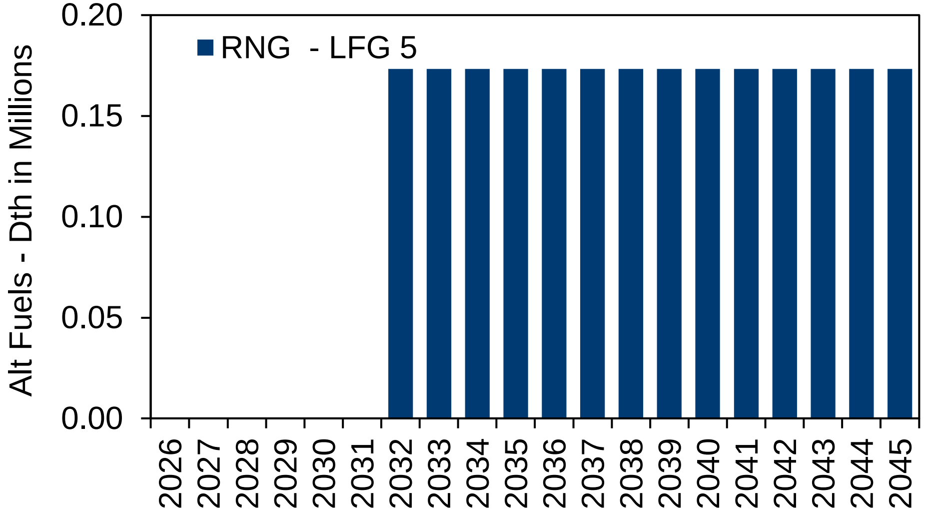


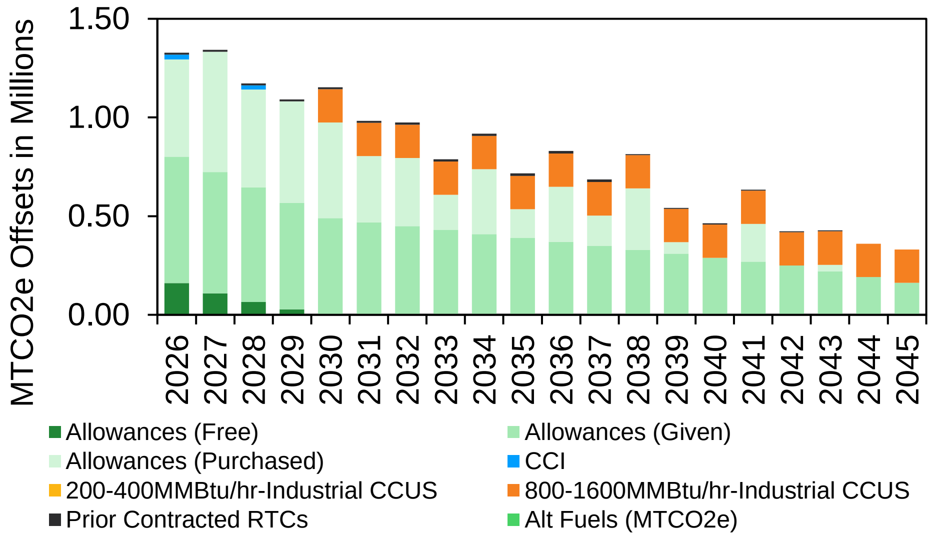


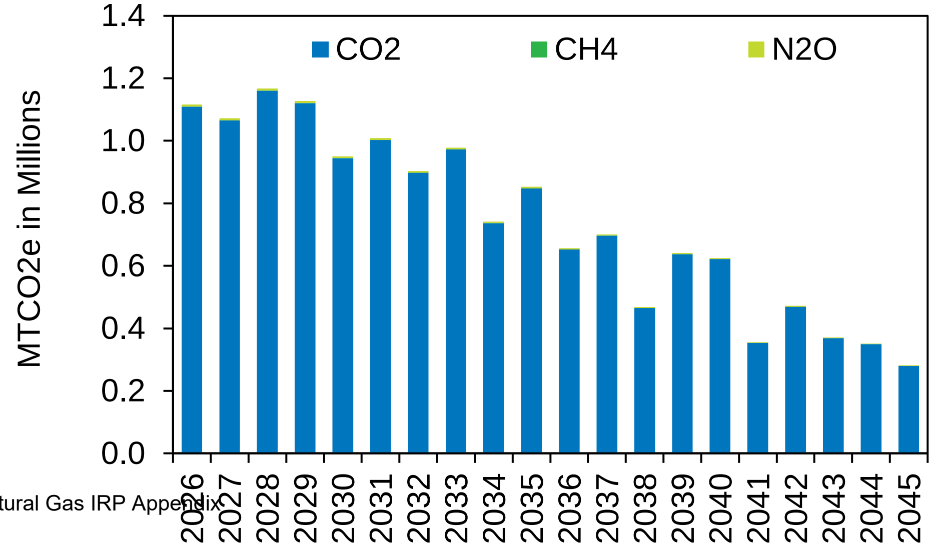
Scenario Description	Changes from PRS
Higher than expected load shift to the power grid	• Lowest Load Demand

High Electrification



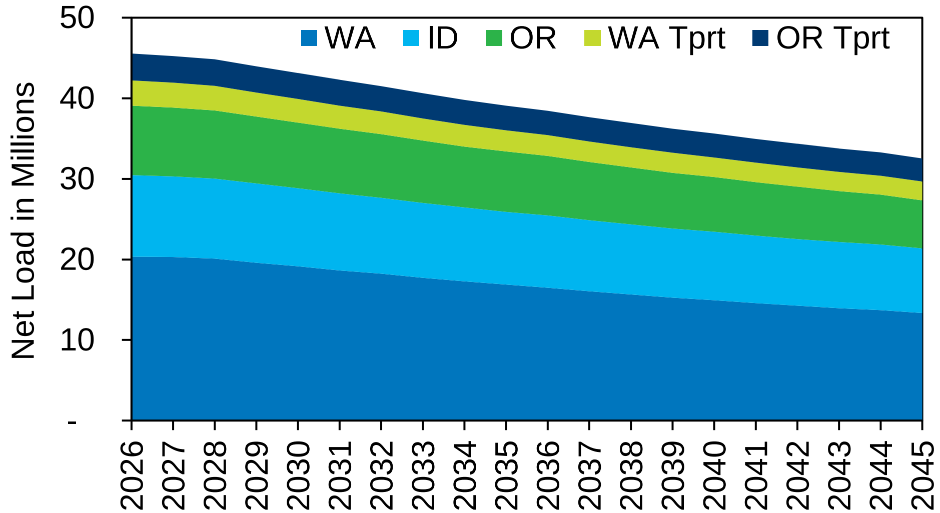


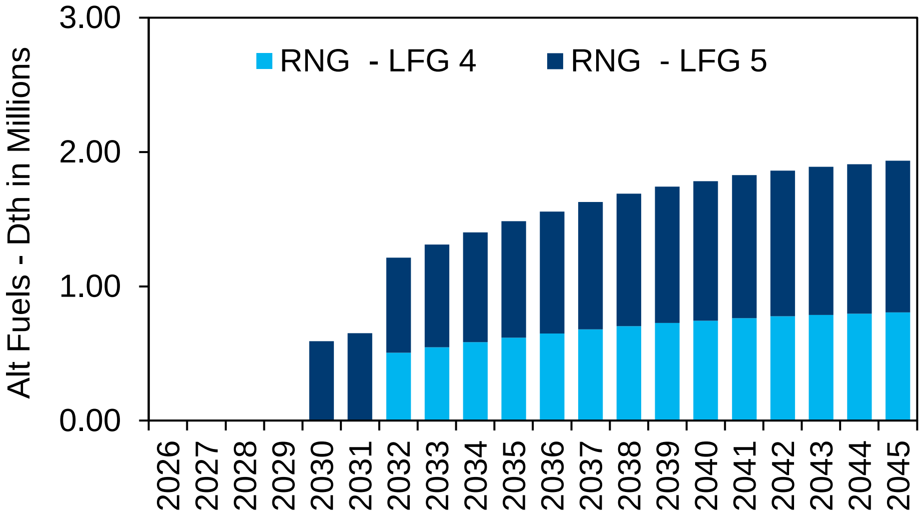


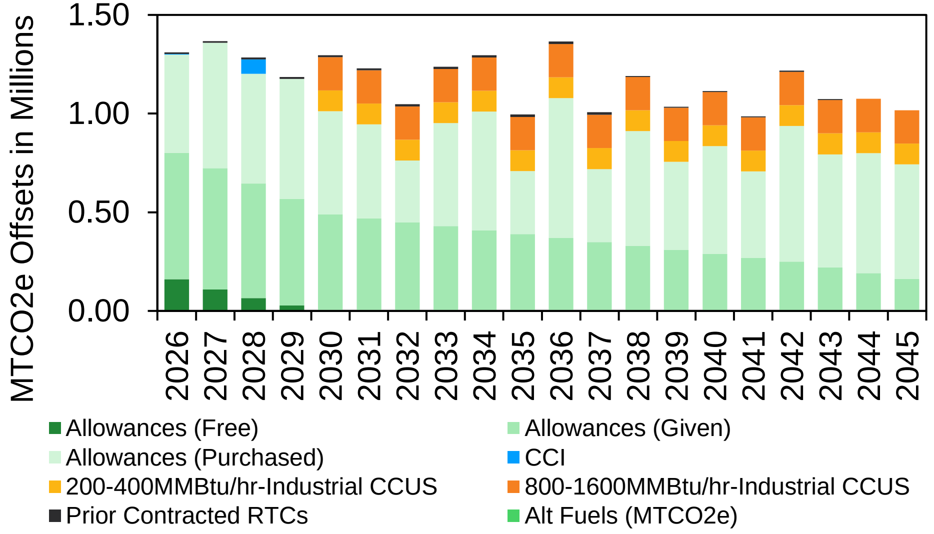


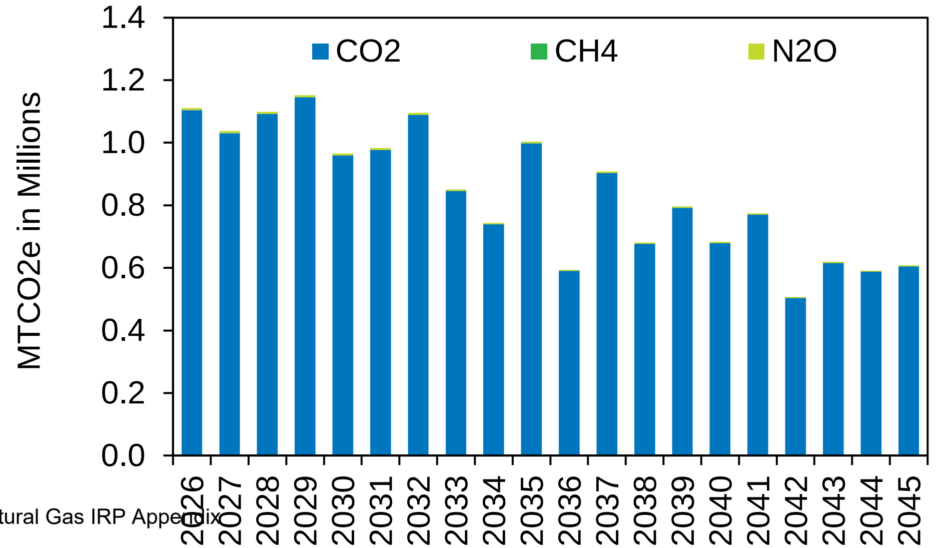
Low Natural Gas Use

Scenario Description	Changes from PRS
Low Natural Gas Use	• **RCP 8.5 Weather** • **95th Percentile of Natural Gas Prices** • **95th Percentile of Allowance Prices** • **Low Alt Fuel Volumes – 5th Percentile** • **High Alt Fuel Prices – 95th Percentile**





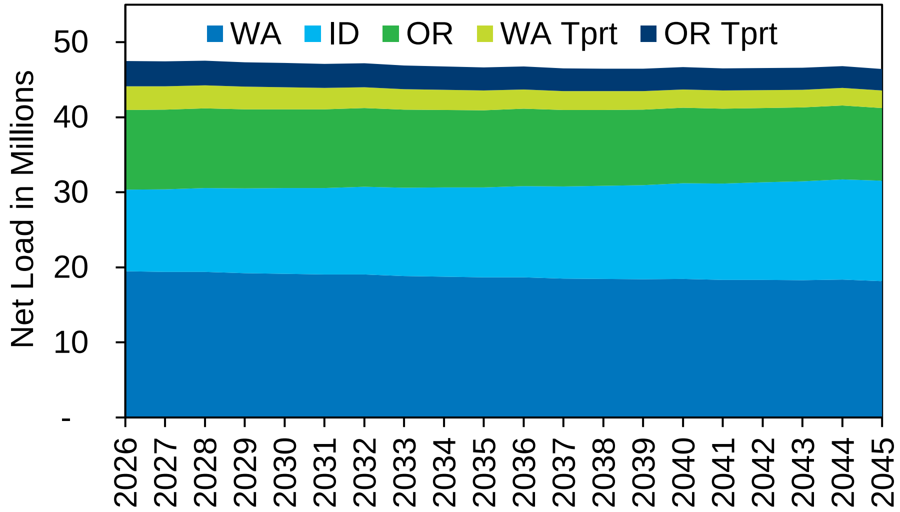


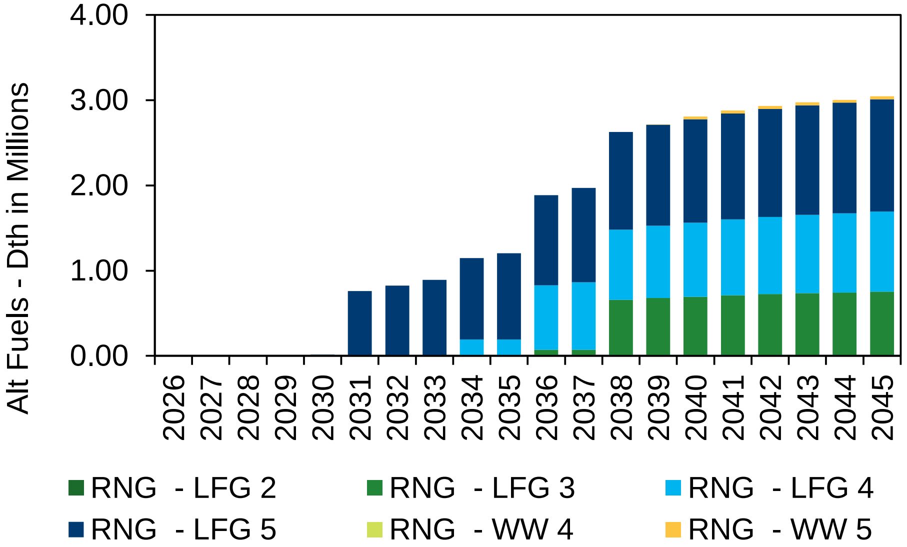


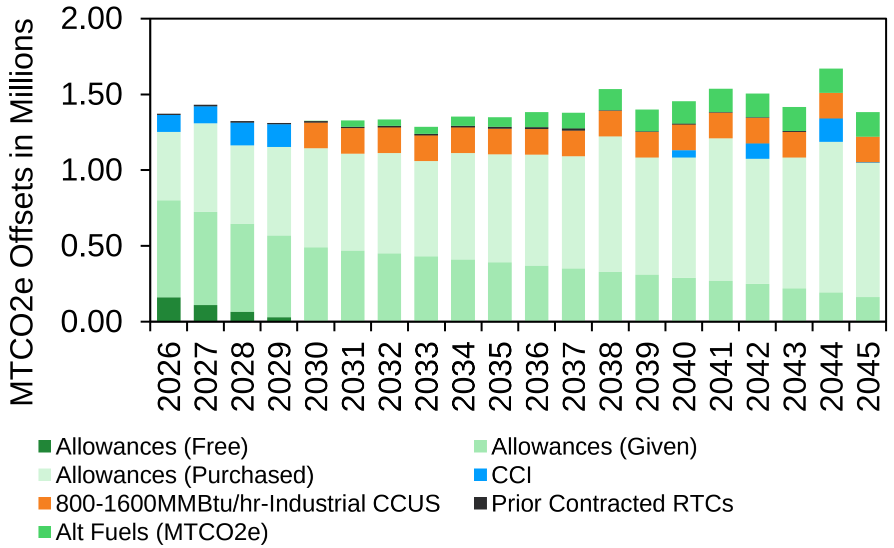
Sensitivity

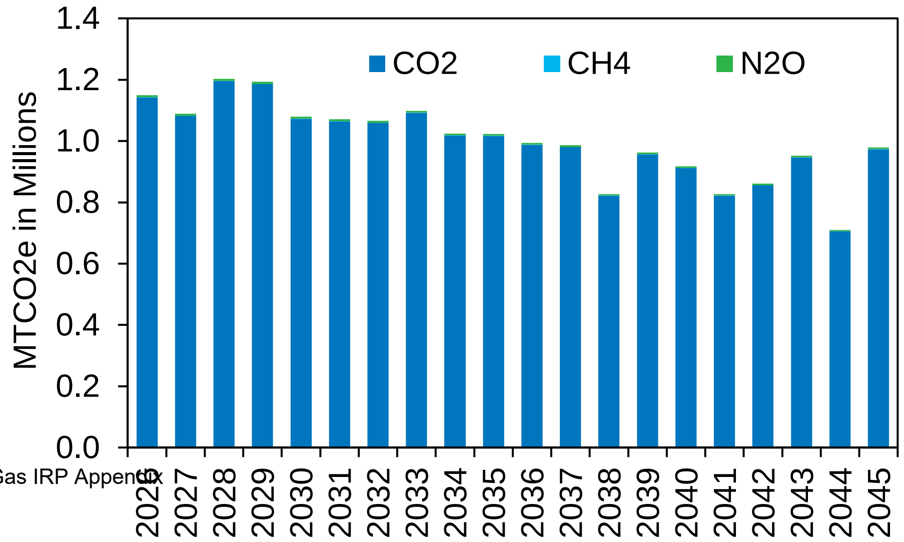
Scenario Description	Changes from PRS
Average Case with Historic Use and 20 Year Rolling Daily Weather	• **3 Year Use Per Customer** • **20 Year Rolling Daily Weather**

Average Case









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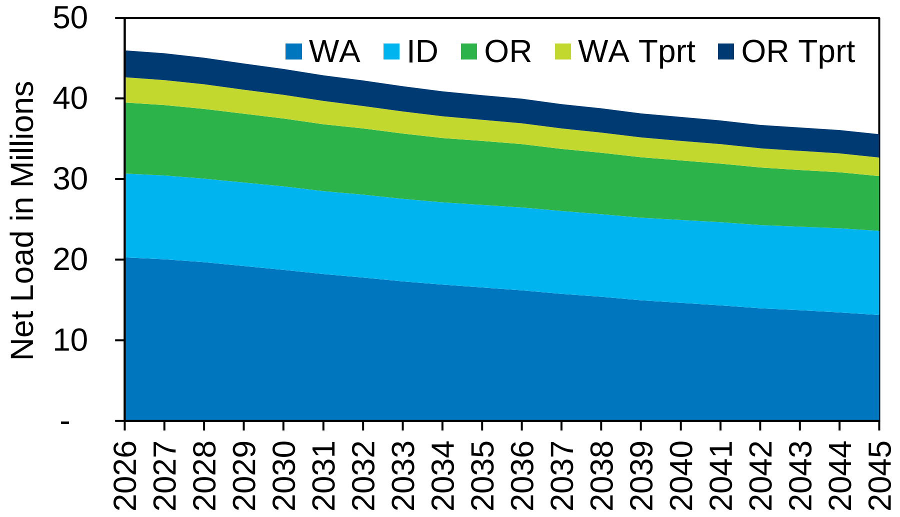
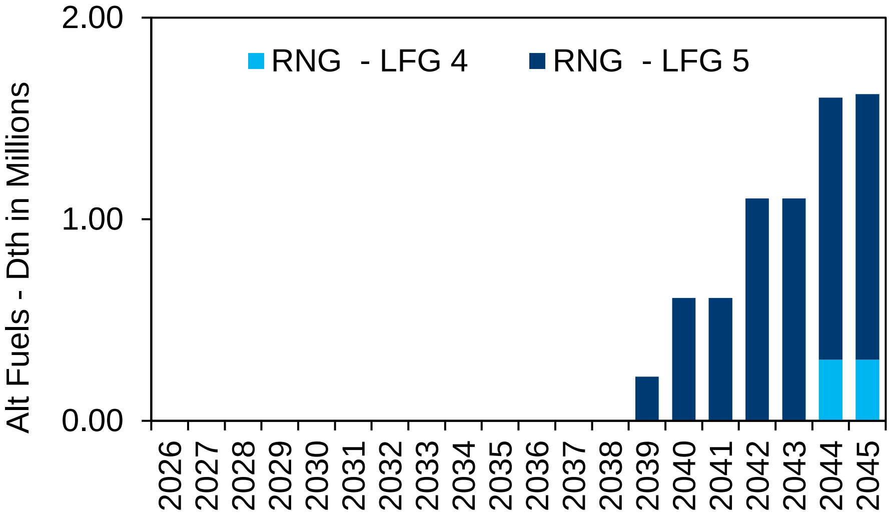
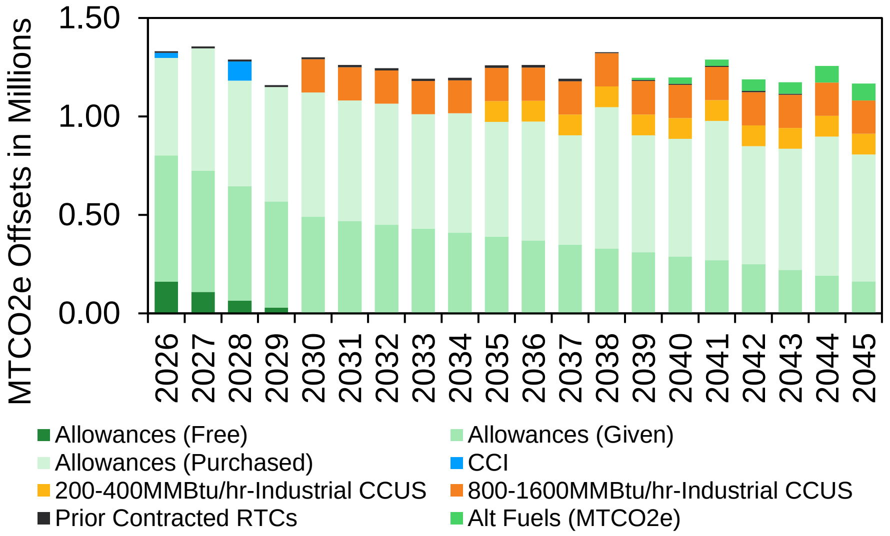
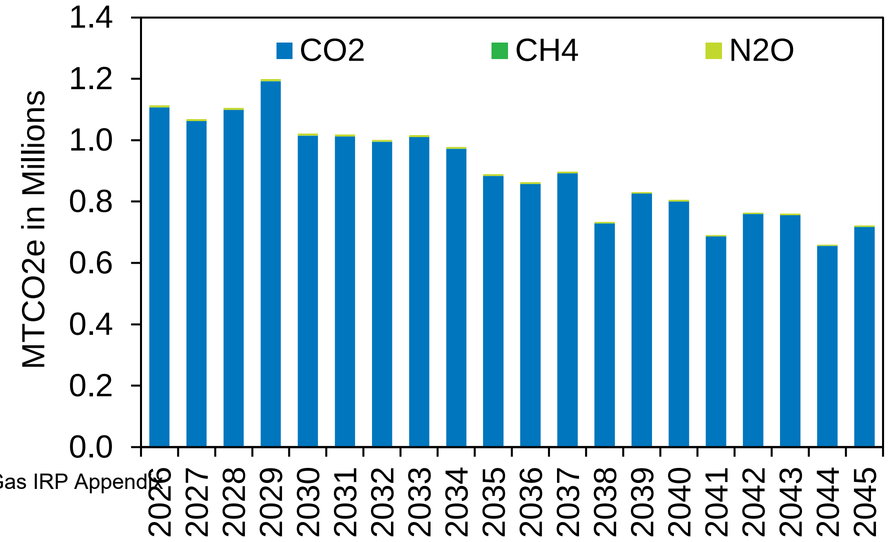
Scenario Description	Changes from PRS
High Cost of Alternative Physical Fuels	• **High Prices of RNG,SM,H2**

High Alternative Fuel Costs



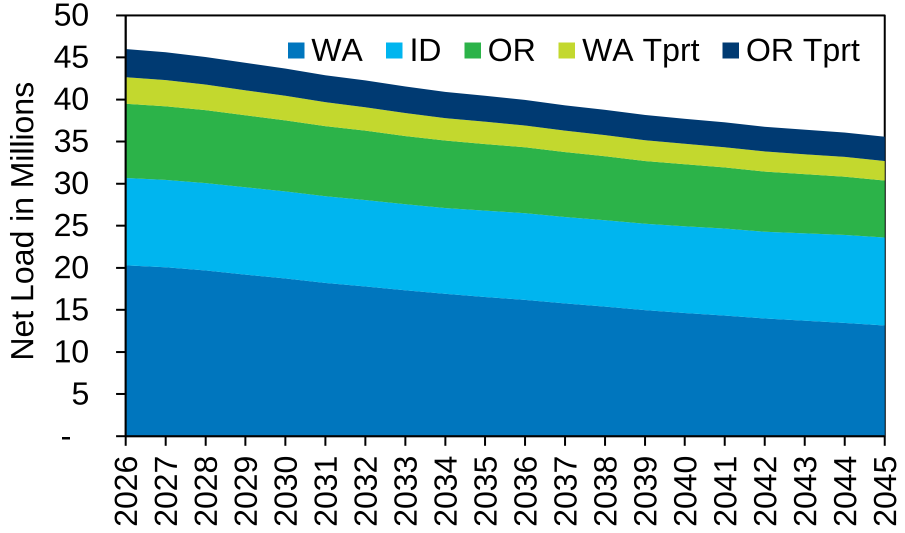


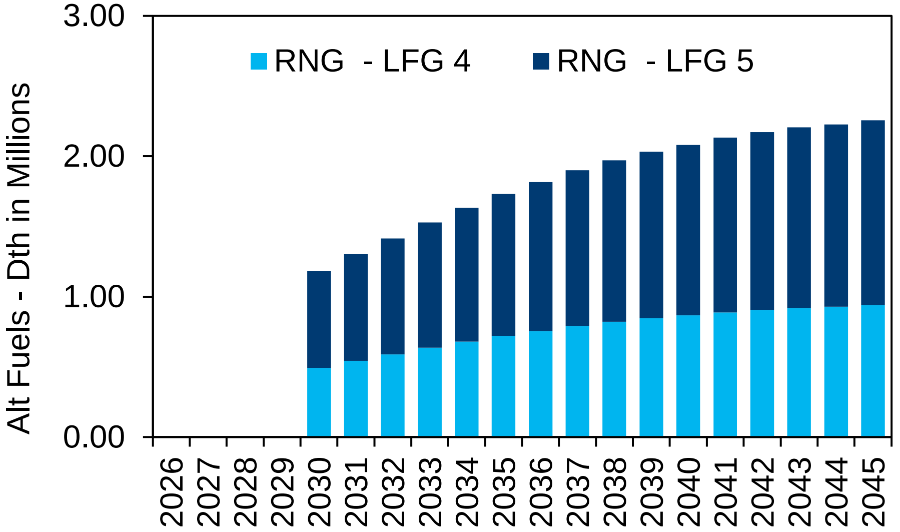


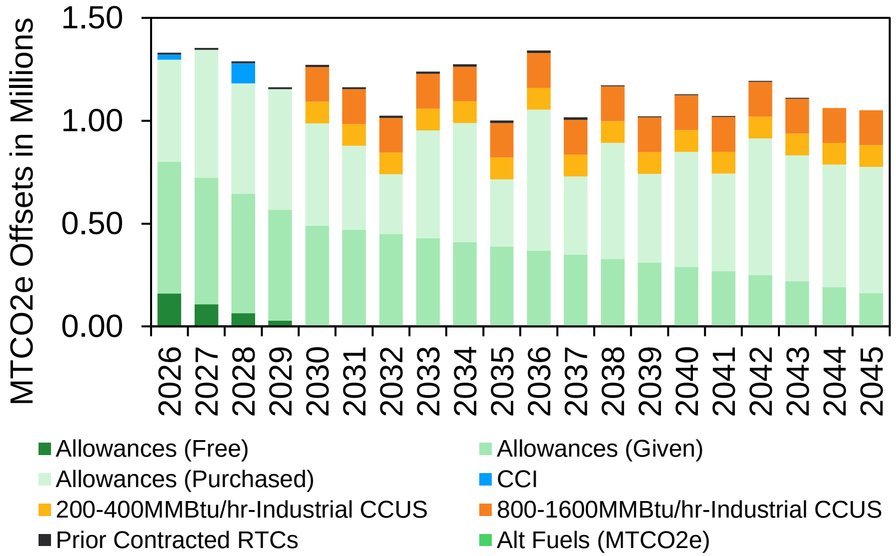


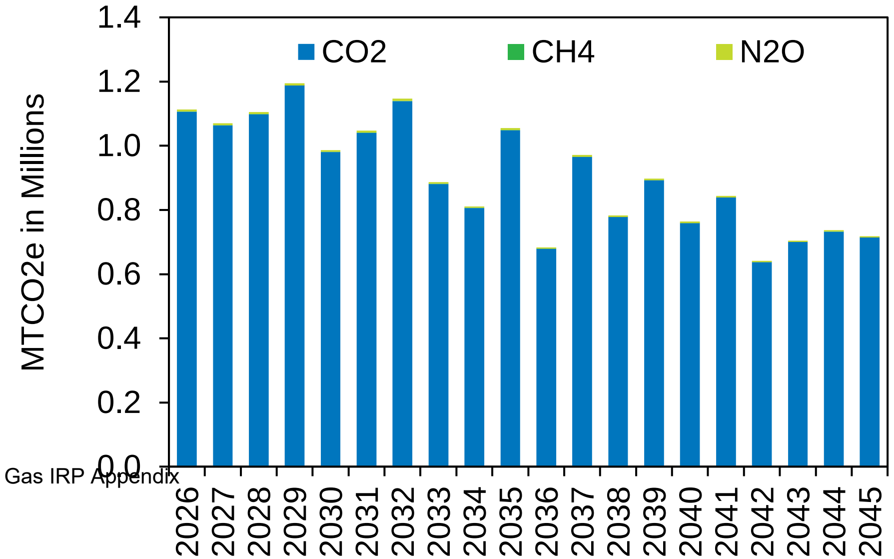
Scenario Description	Changes from PRS
High Costs of CCA Allowances	• **95th Percentile of Expected CCA Costs**

High CCA Costs



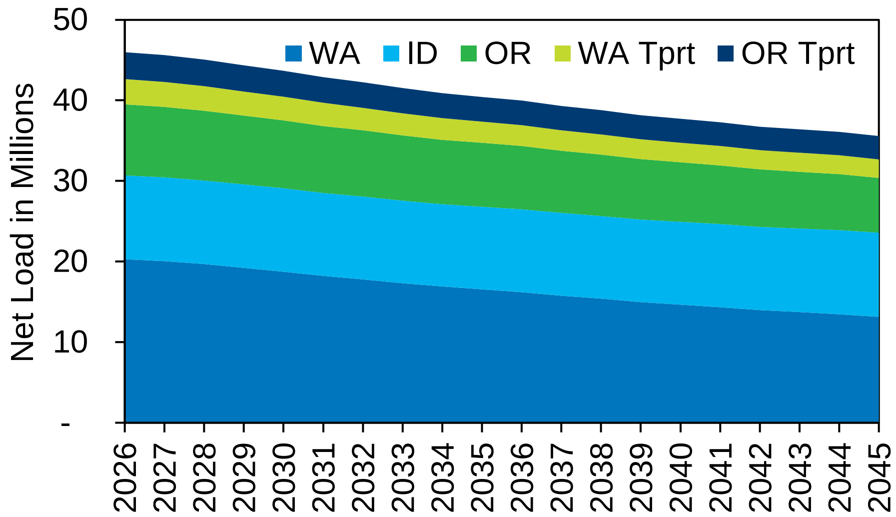


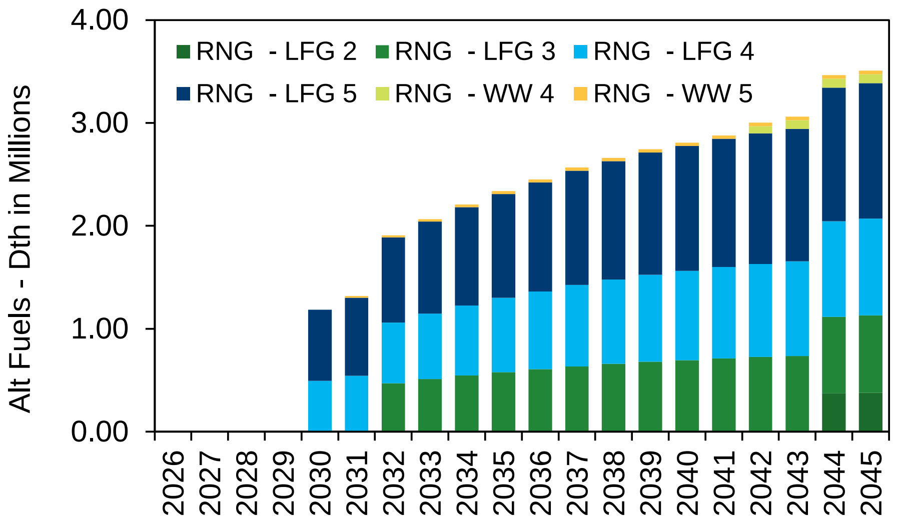


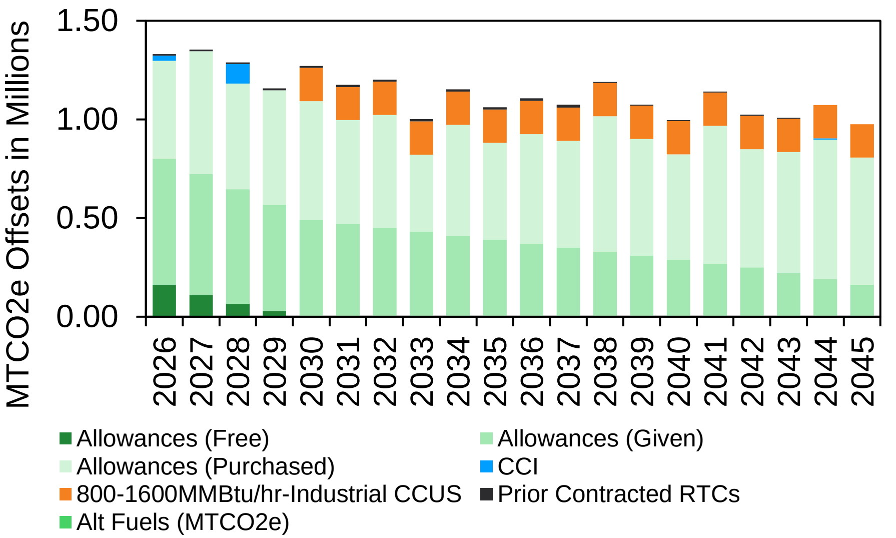


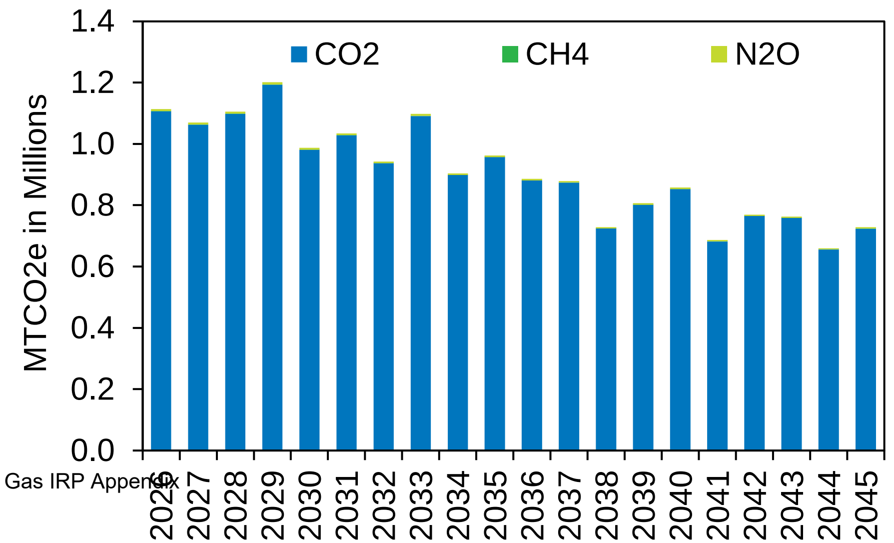
Scenario Description	Changes from PRS
High Costs of Natural Gas	• **95th Percentile of Stochastic Prices**

High Natural Gas Prices



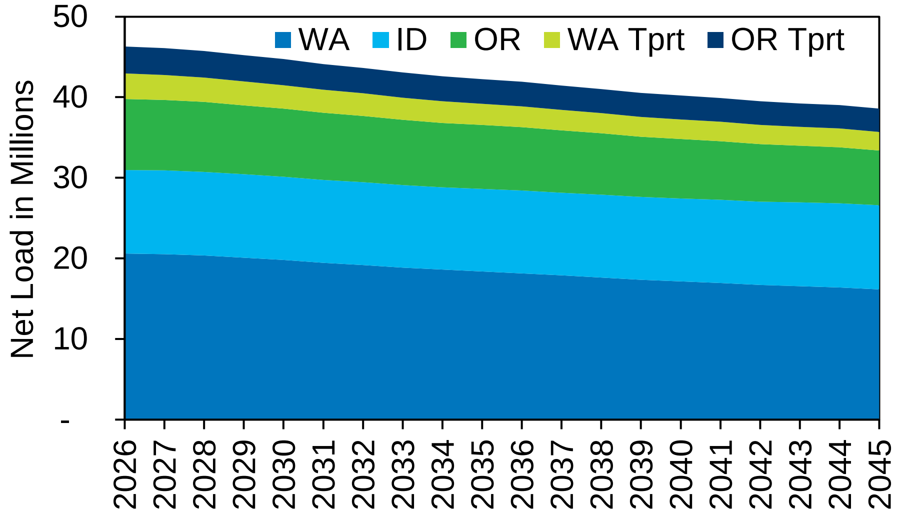


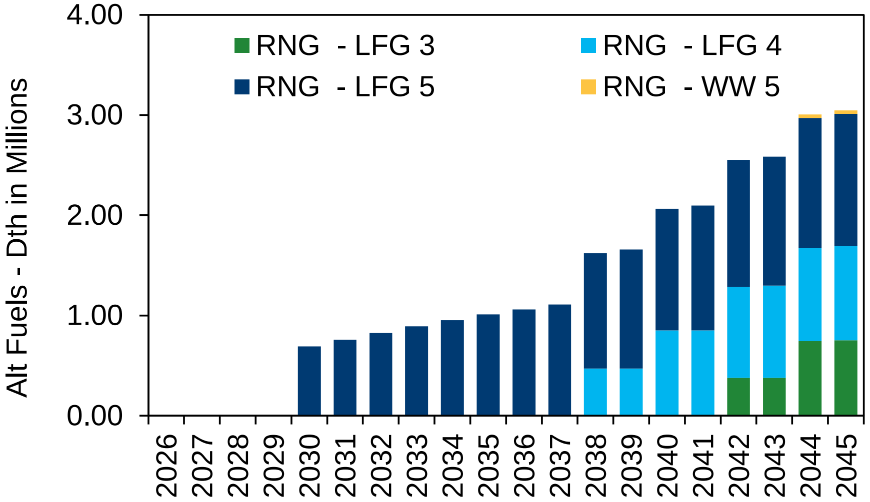


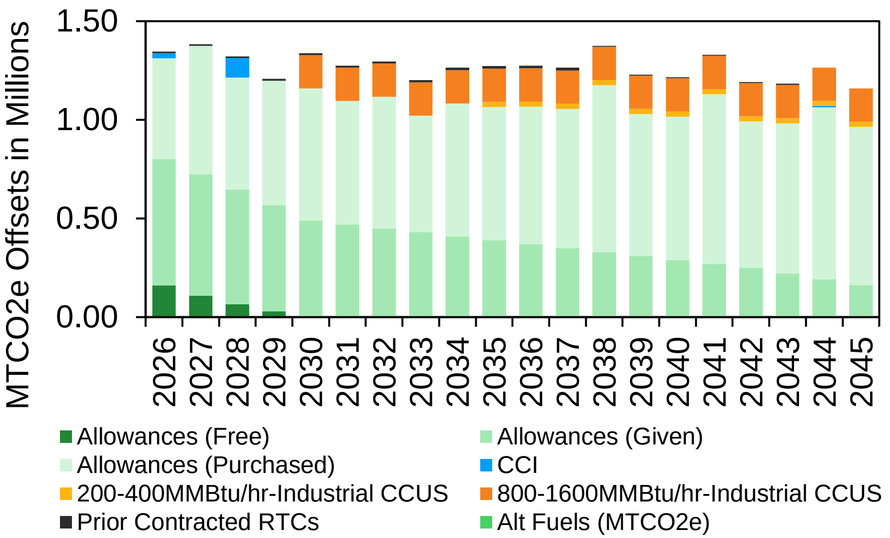


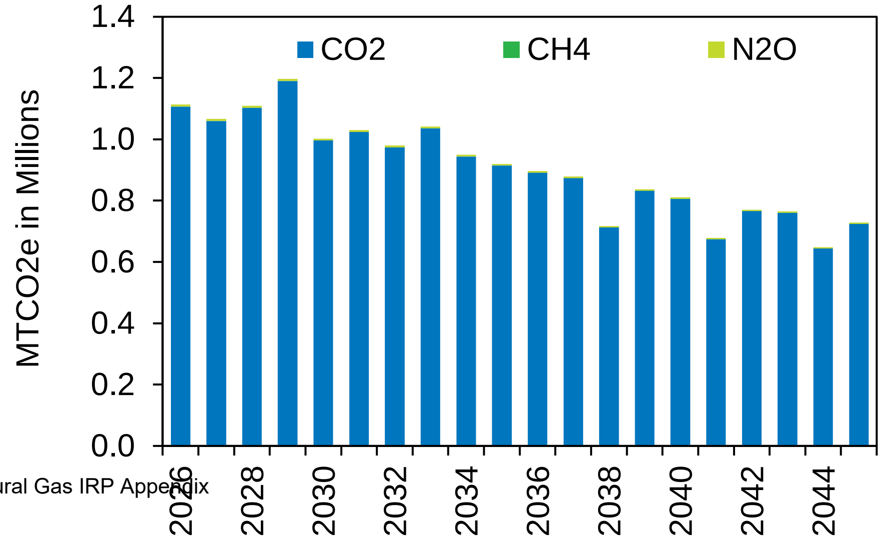
Scenario Description	Changes from PRS
Higher Loads for WA-Com	• Adjusts Loads to Estimate Changes to WA State Building Codes

Initiative 2066



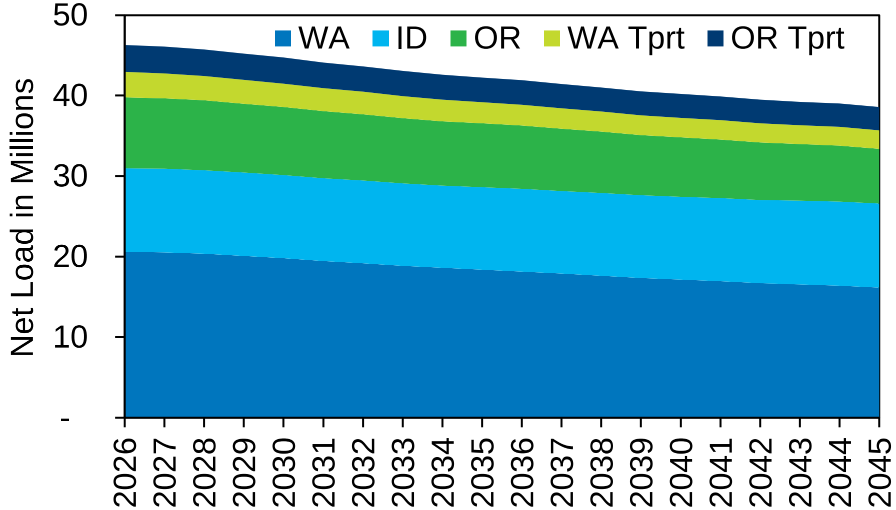


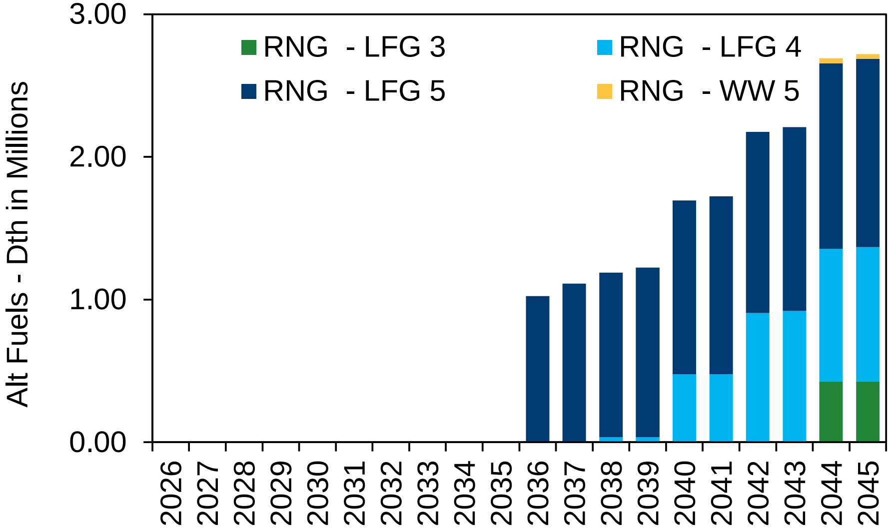


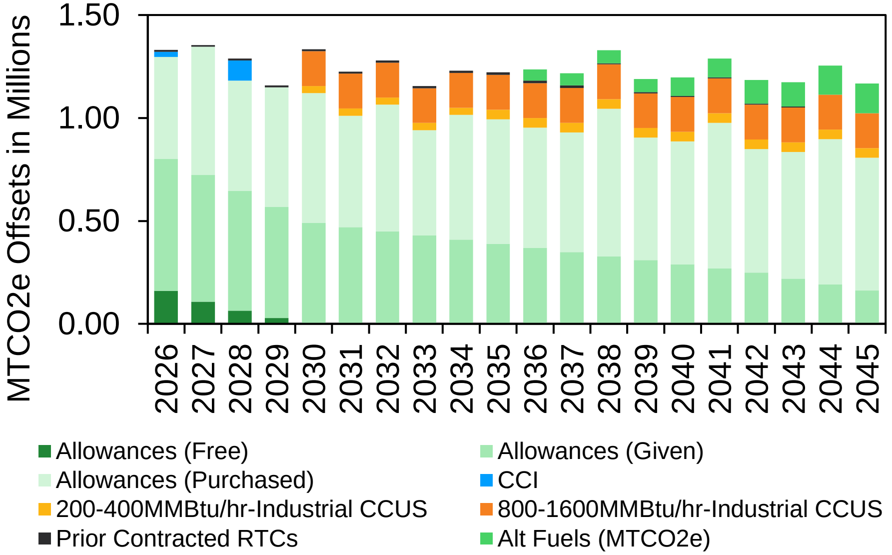


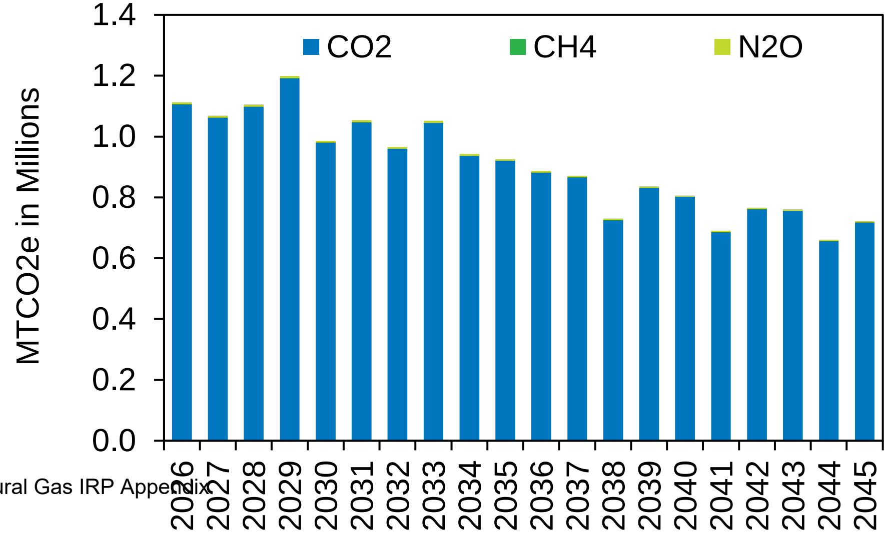
Scenario Description	Changes from PRS
Lower Costs of Alt Fuels	• 5th Percentile Costs for RNG, SM, H2

Low Alternative Fuel Costs



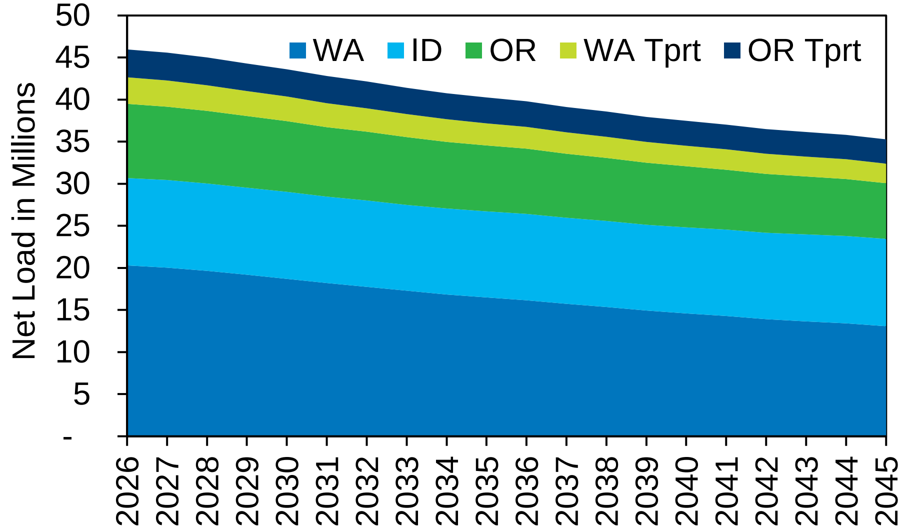


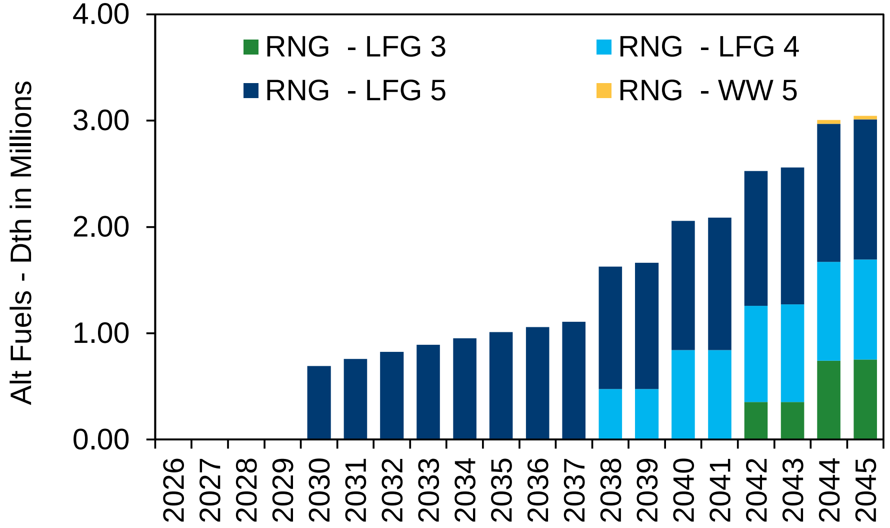


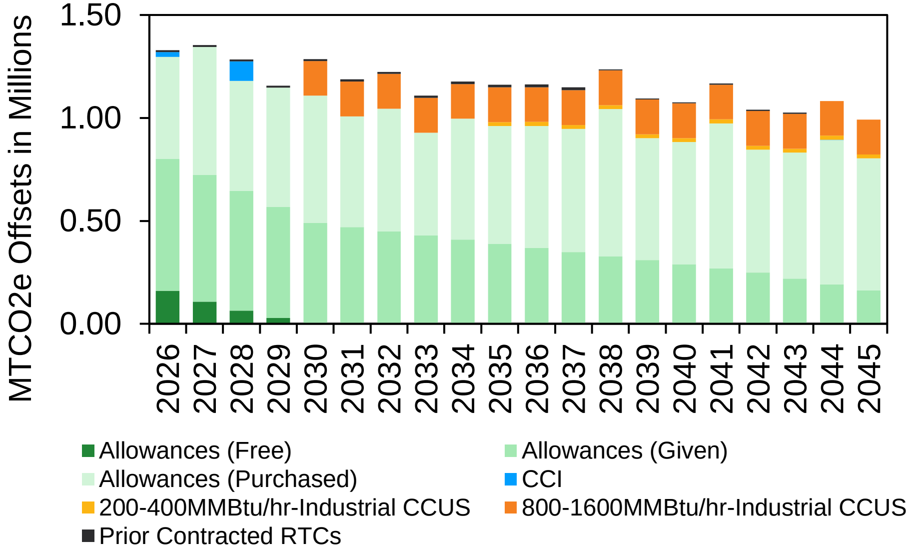


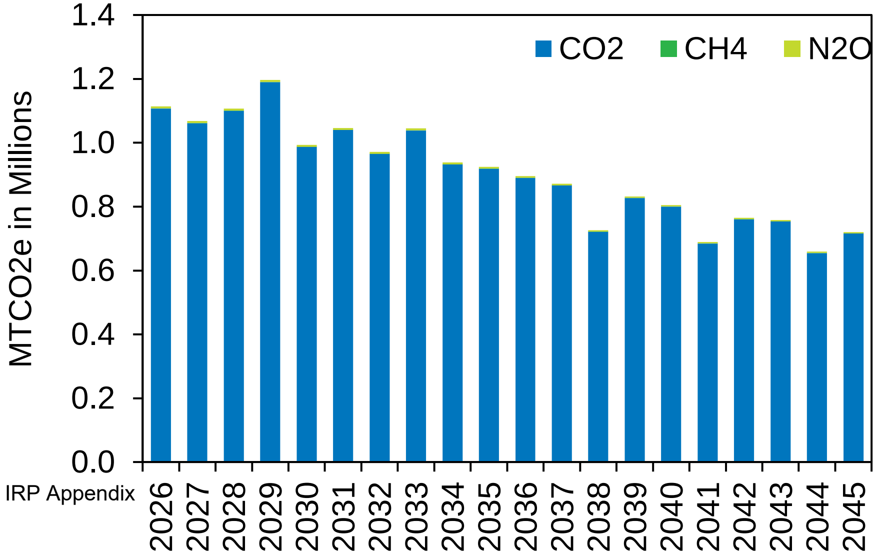
Scenario Description	Changes from PRS
Expected Futures Using 6.5 Weather Futures	• 6.5 Weather Futures

RCP 6.5



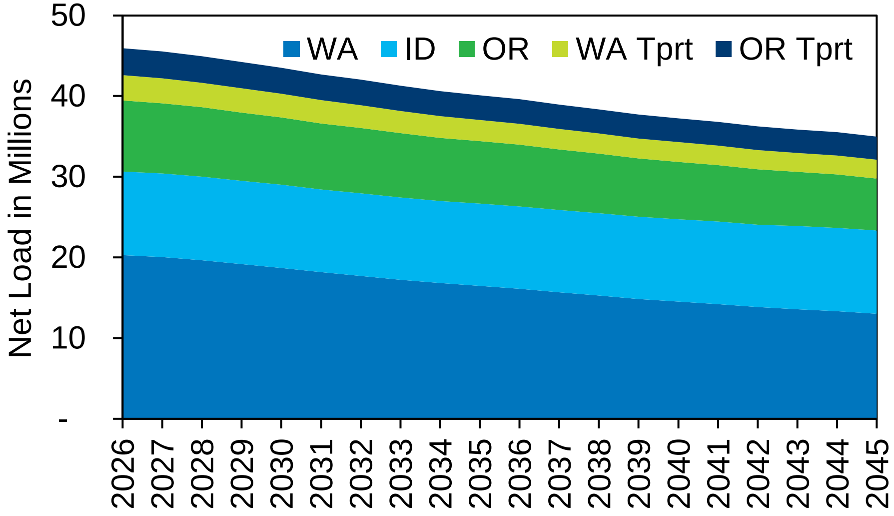


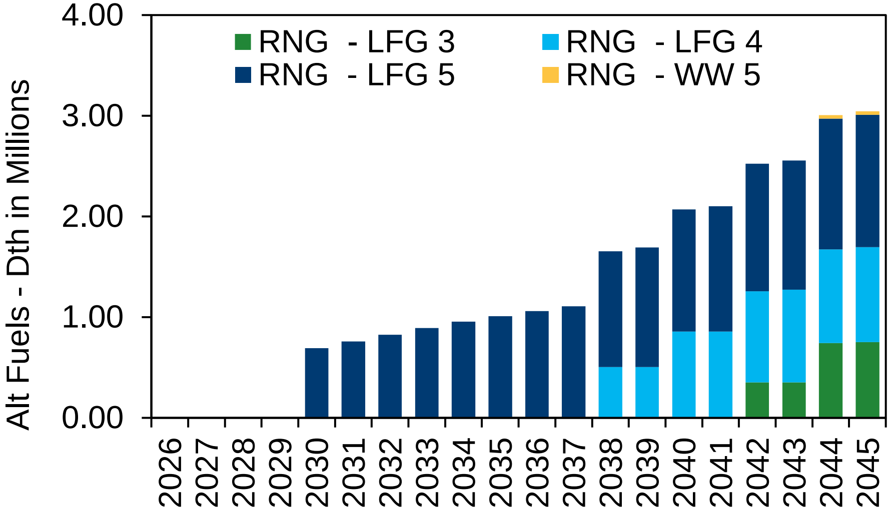


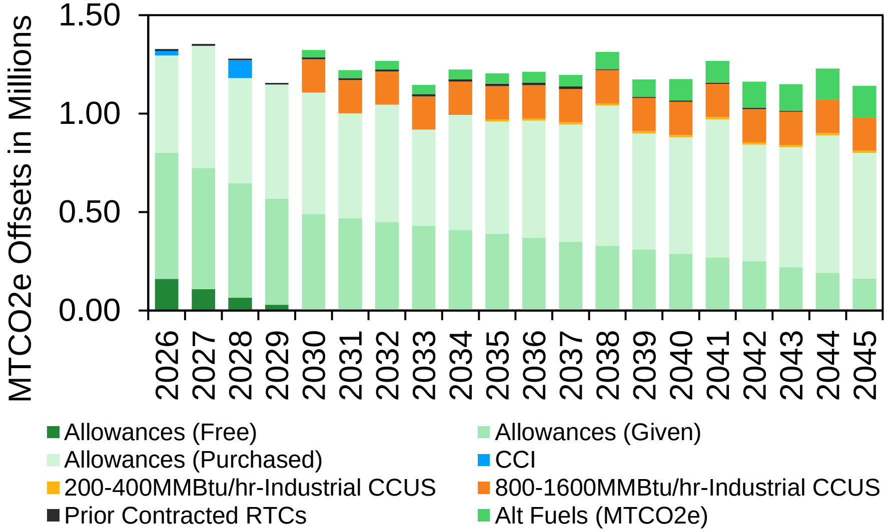


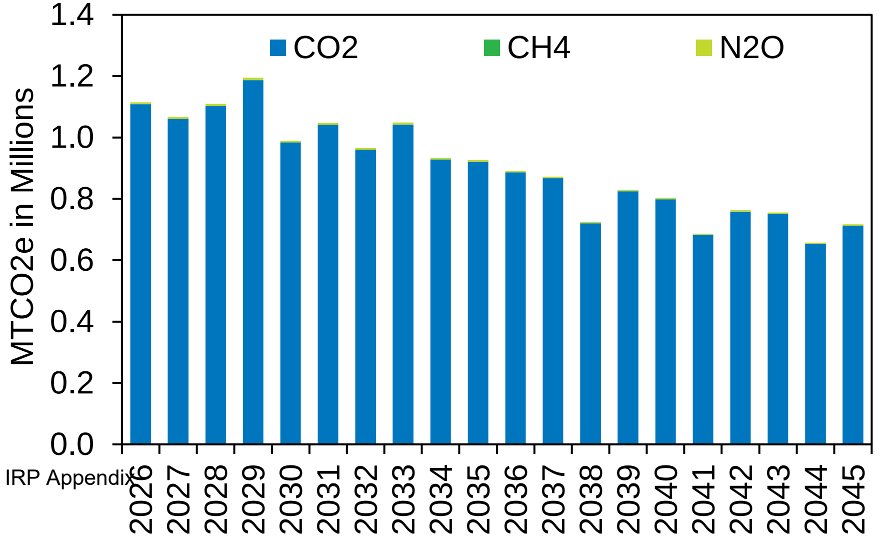
Scenario Description	Changes from PRS
Expected Futures Using 8.5 Weather Futures	• **8.5 Weather Futures**

RCP 8.5



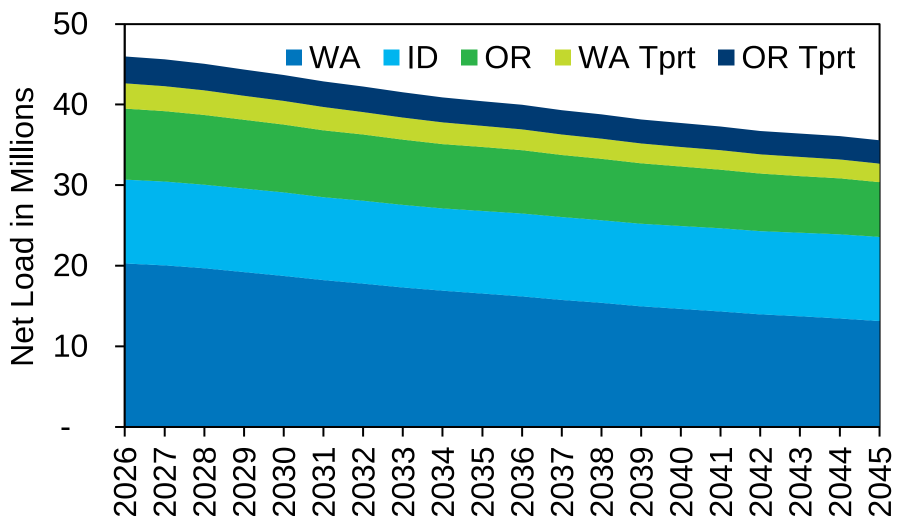


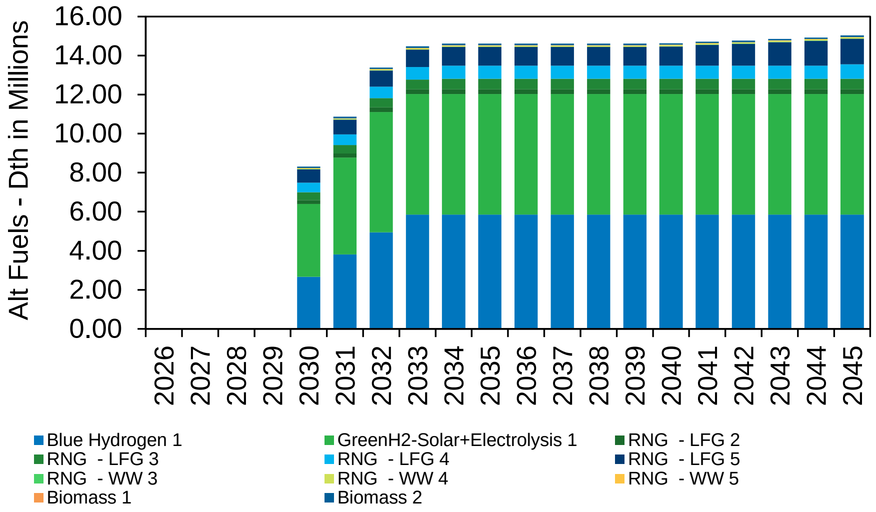


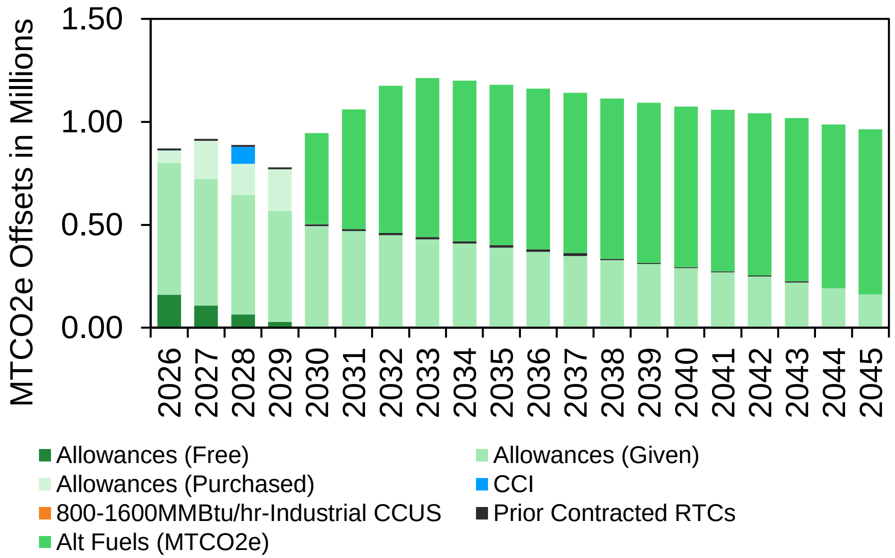


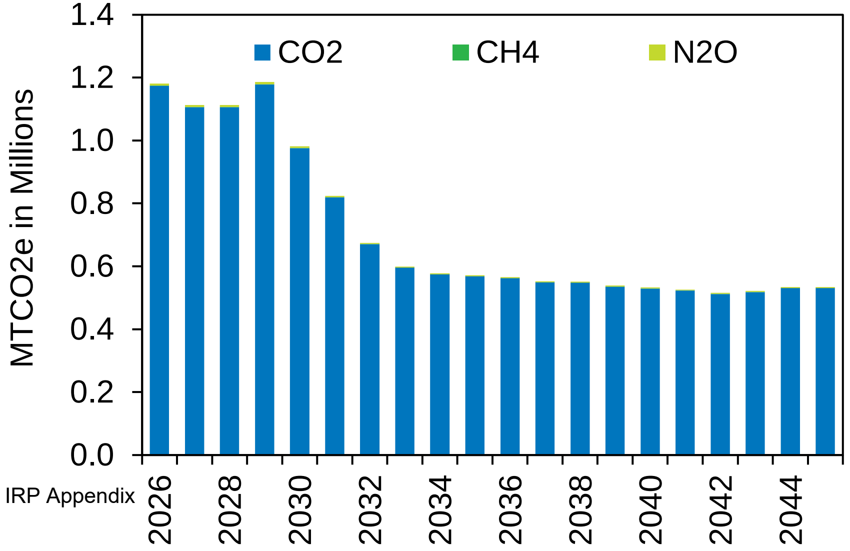
Scenario Description	Changes from PRS
Expected Futures Using 6.5 Weather Futures	• **Western Natural Gas Resources unavailable in Winter (Sumas,St2,JP)**

Resiliency

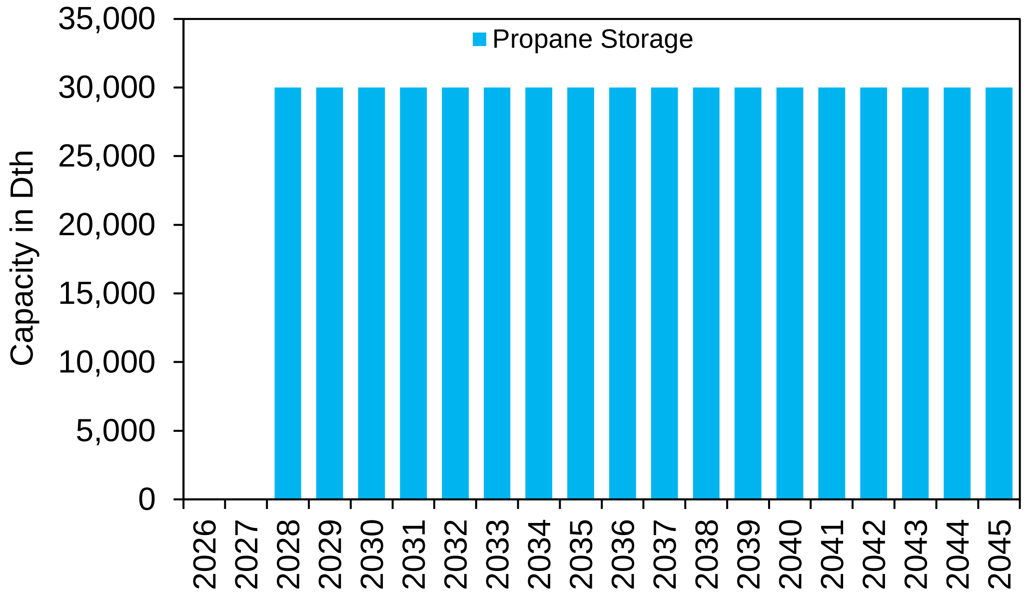


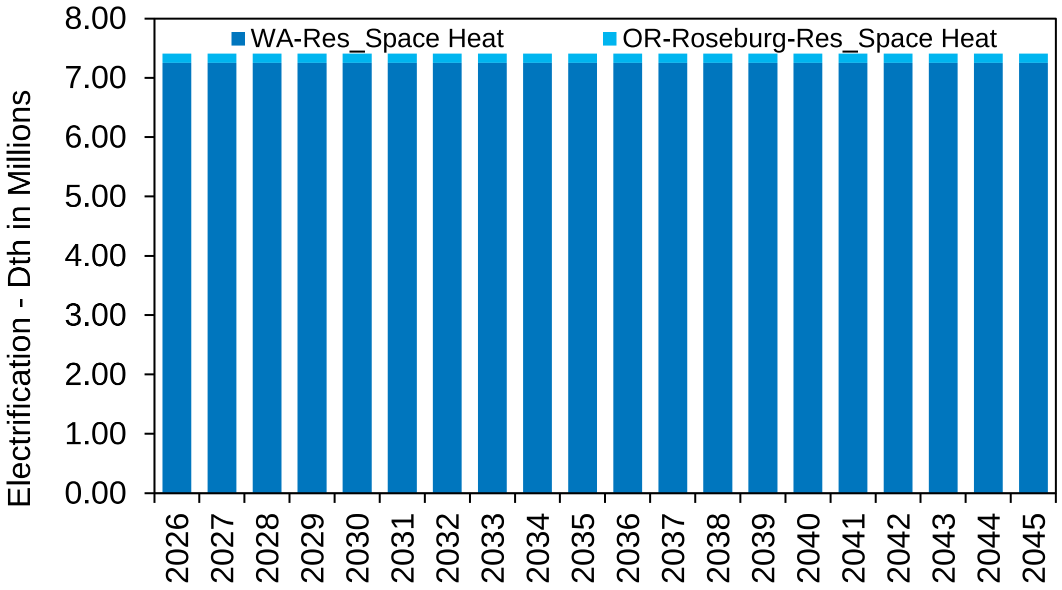






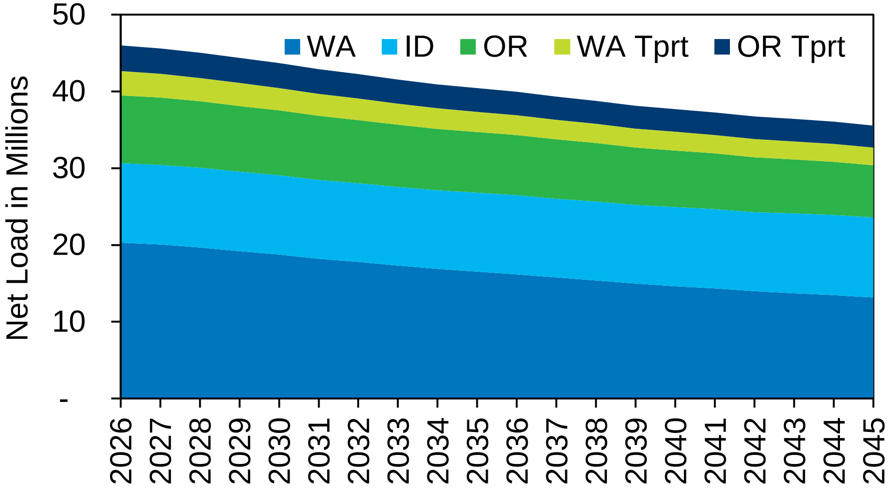
Resiliency Cont.

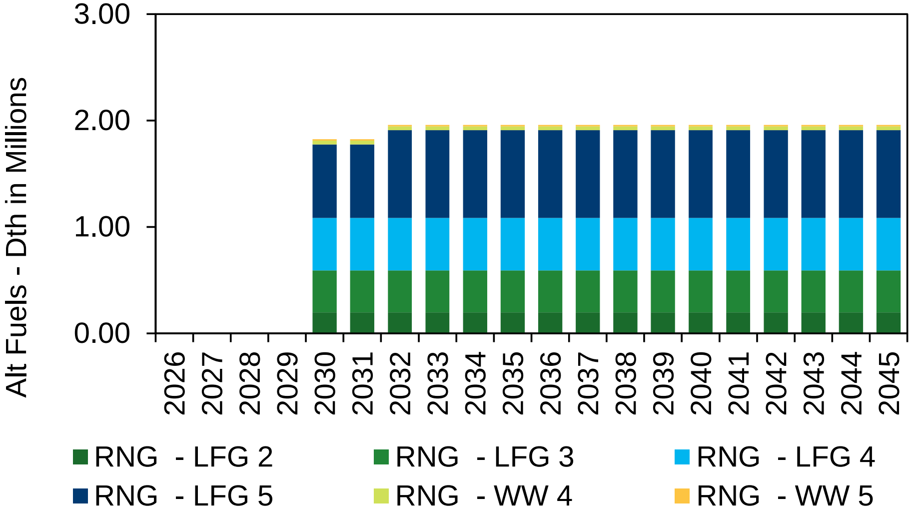


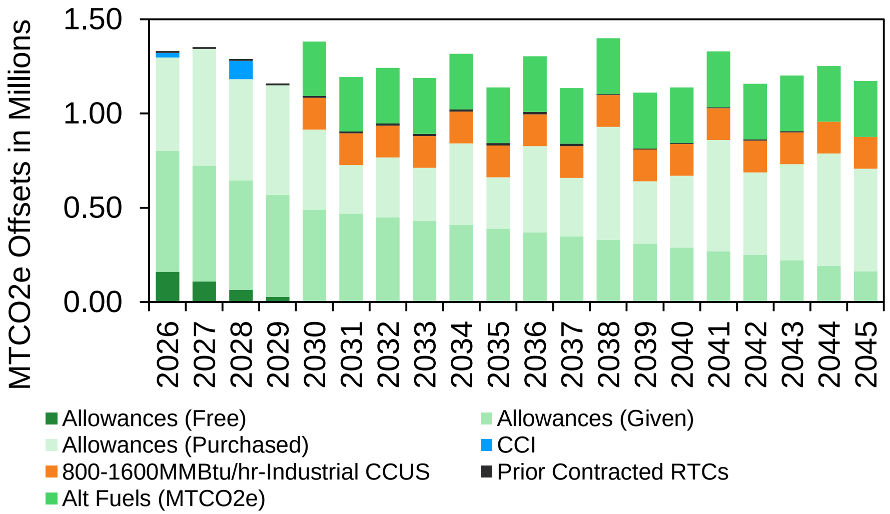


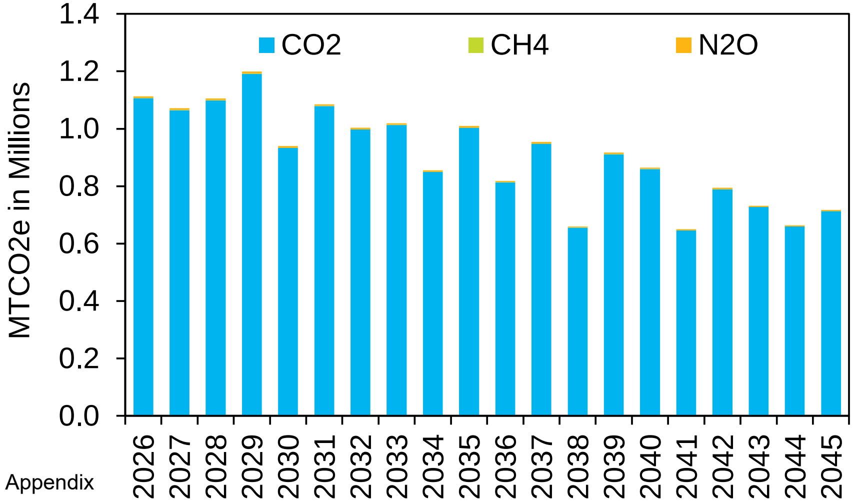
Scenario Description	Changes from PRS
Considers a Forced Fuel Mix	• **RNG, SM, H2 Hard Selection**

Diversified Portfolio



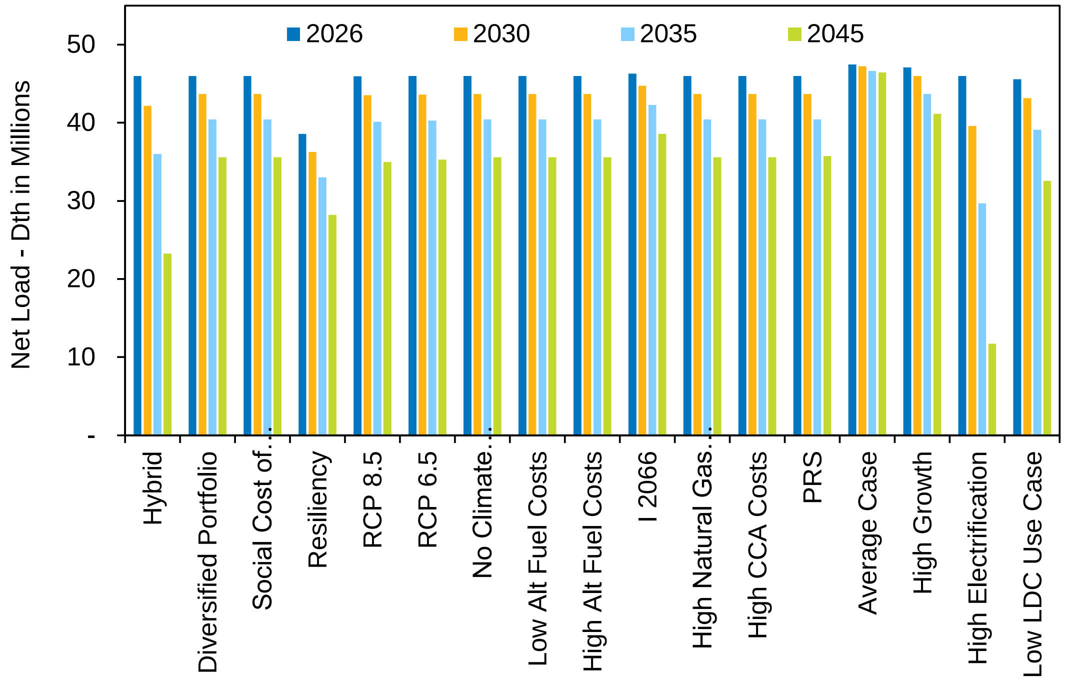


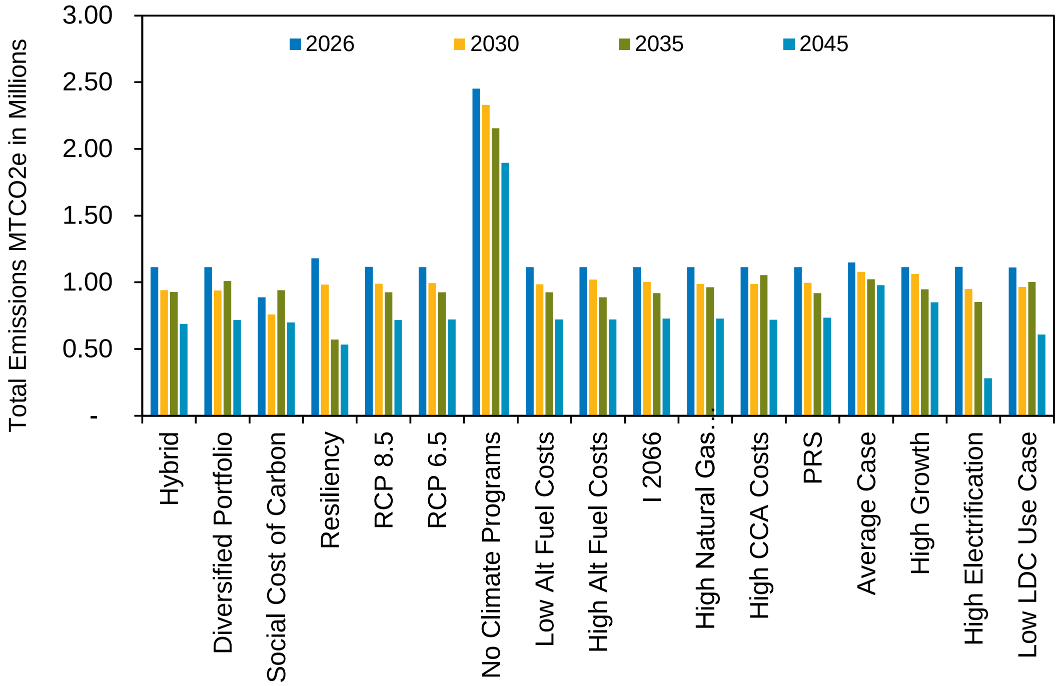




All Case Comparisons

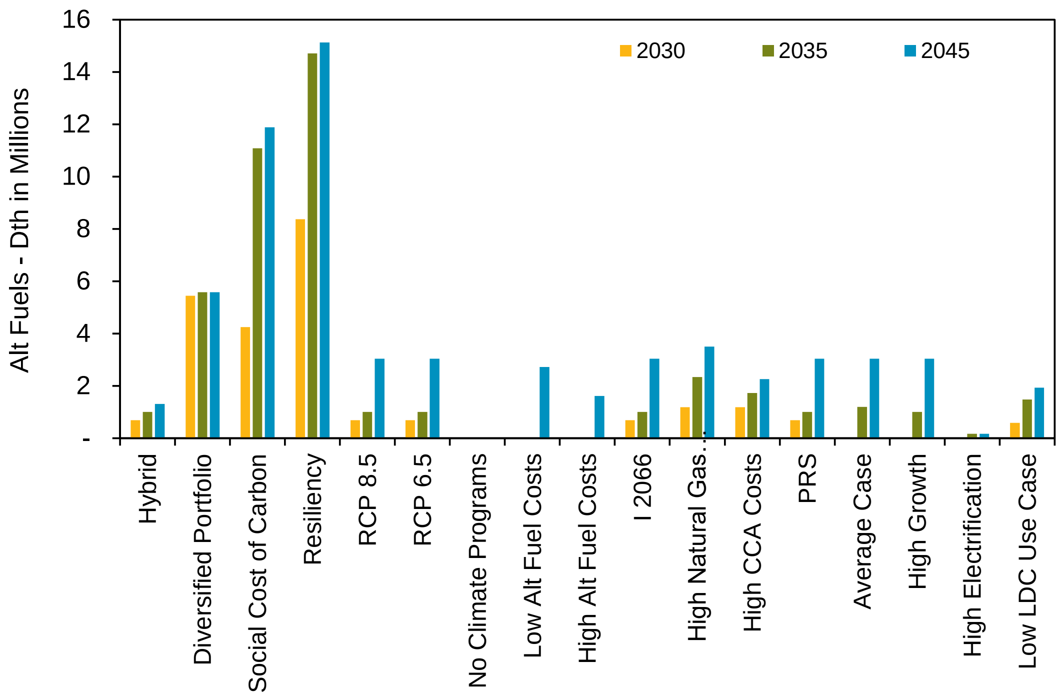
Net Load and Emissions

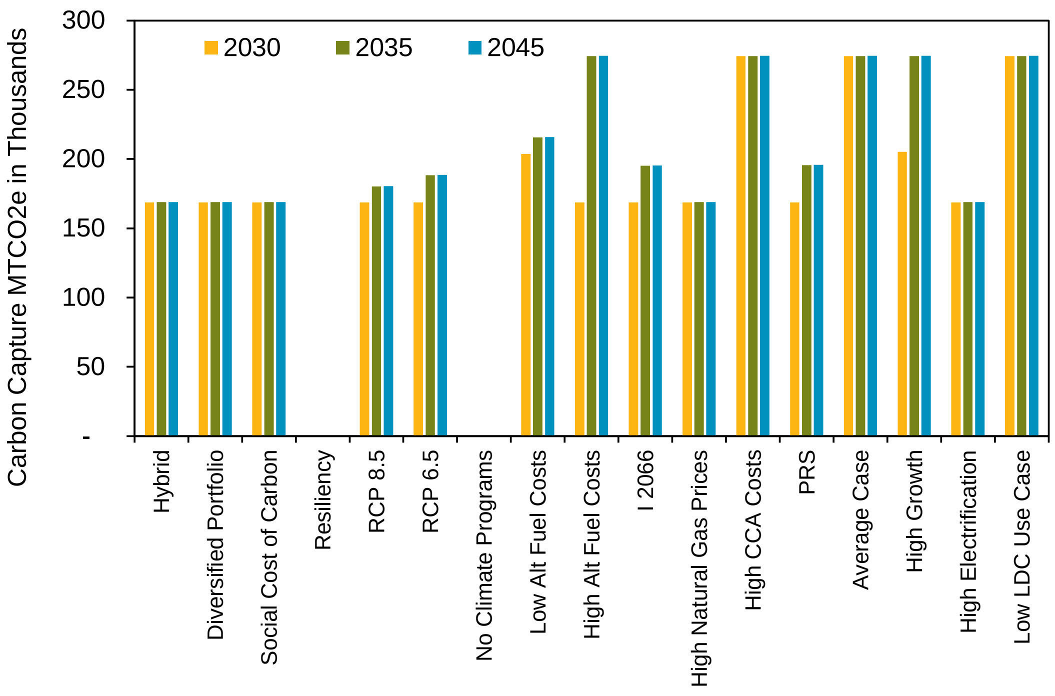




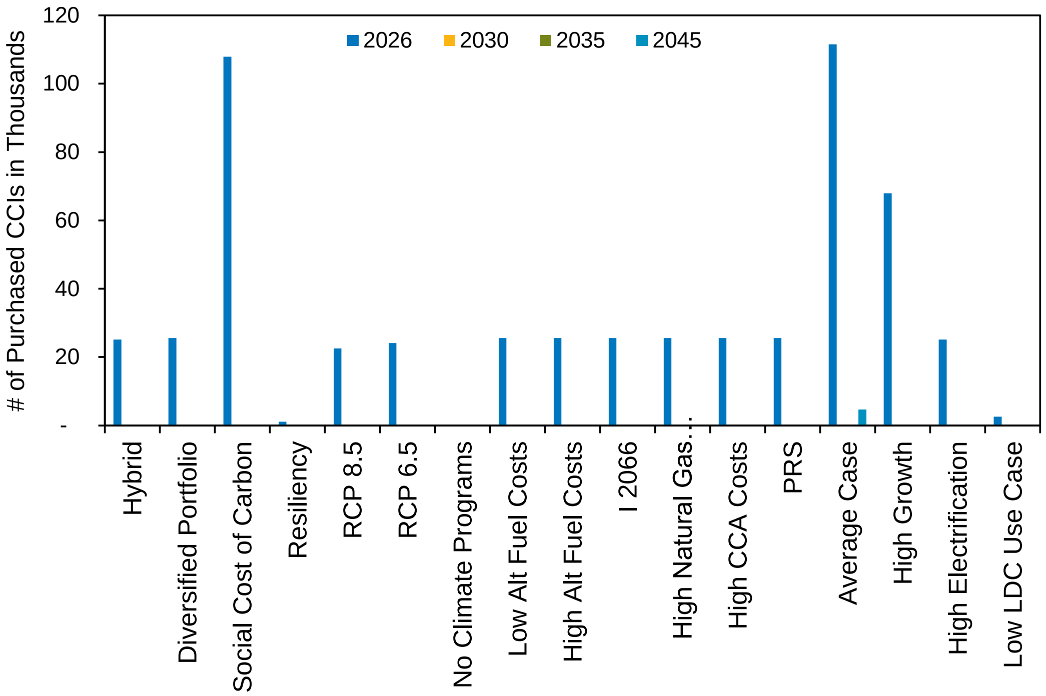
*Includes CO2, CH4, NO2

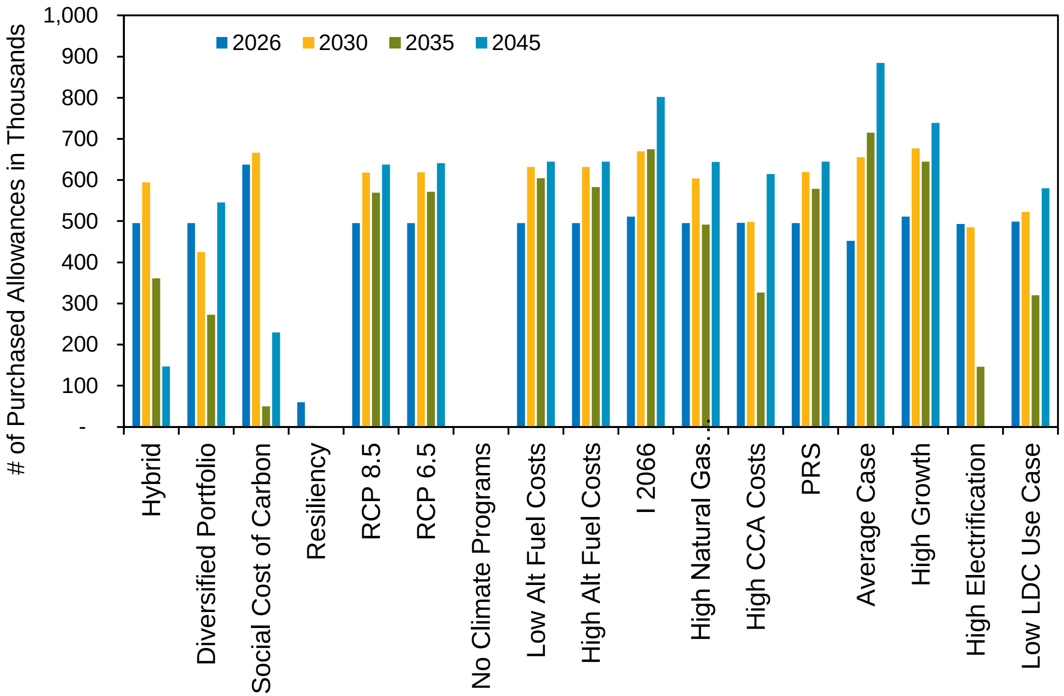
Alternative Fuels and Carbon Capture



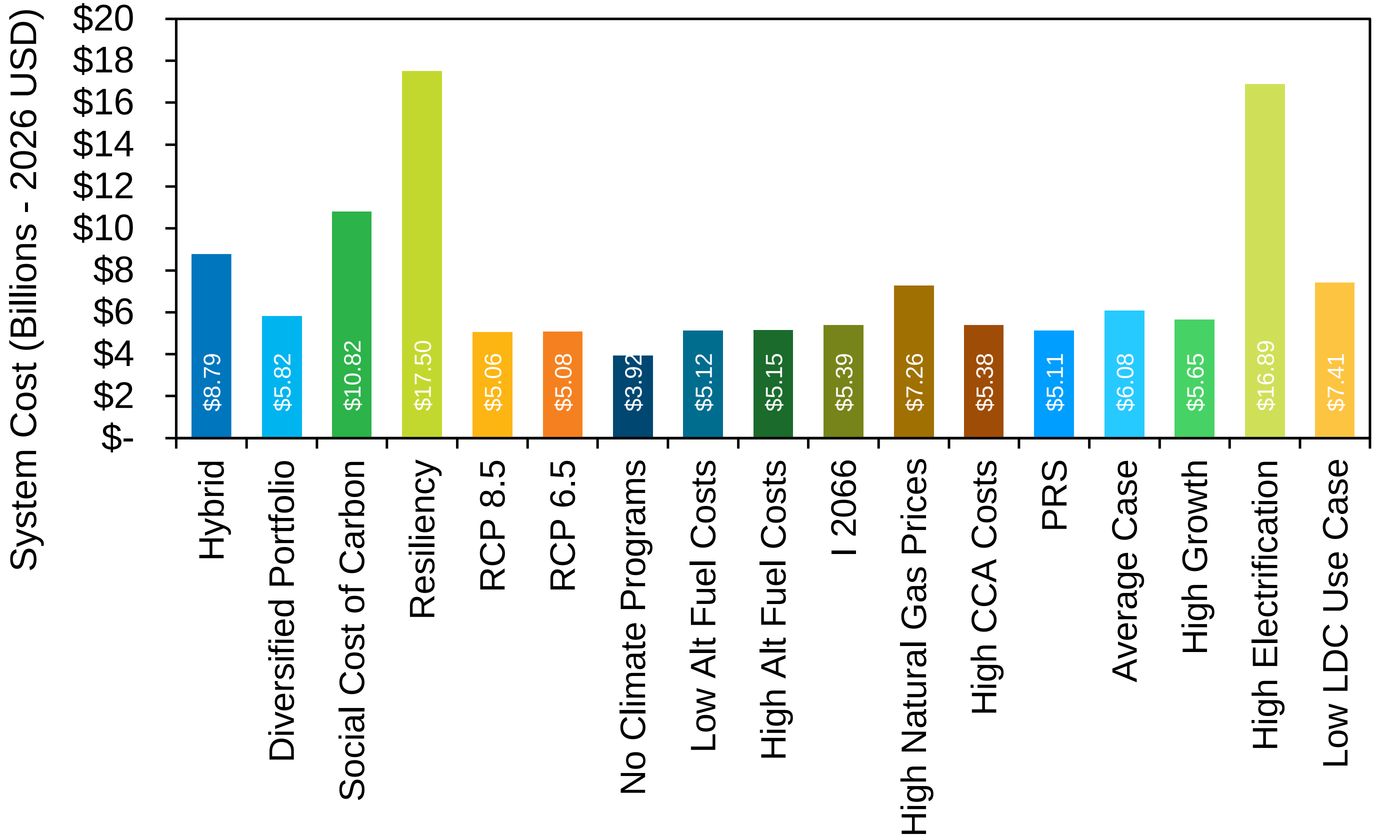


Climate Program Offset Purchases (CCIs and Allowances)





System Cost



System Cost (Billions - 2026 USD)
$20
$18
$16
$14
$12
$10
$8
$6
$4
$2
$-
$8.79
$5.82
$10.82
$17.50
$5.06
$5.08
$3.92
$5.12
$5.15
$5.39
$7.26
$5.38
$5.11
$6.08
$5.65
$16.89
$7.41
Hybrid
Diversified Portfolio
Social Cost of Carbon
Resiliency
RCP 8.5
RCP 6.5
No Climate Programs
Low Alt Fuel Costs
High Alt Fuel Costs
I 2066
High Natural Gas Prices
High CCA Costs
PRS
Average Case
High Growth
High Electrification
Low LDC Use Case

Next Steps

- Confirm PRS Selection
  - Determine if Carbon Capture is realistically available in 2030 with TAC
  - Or if scenarios should not be allowed Carbon Capture until 2040 timeframe
- Run all models again based on input of deterministic results and final EE savings and costs
- Run Alternative Scenarios through 500 Monte Carlo Futures
- Send out Draft to TAC with all available chapters and the PRS by January 31, 2025
- Send out remaining chapters to TAC once all results from Alternative Scenarios are finished
- Avista will accept feedback to it’s Draft Gas IRP through March 9th to incorporate into final version of the 2025 Gas IRP document

Avista 2025 Natural Gas Integrated Resource Plan

Tom Pardee
Natural Gas Planning Manager

Disclaimer

This document contains forward-looking statements. Such statements are subject to a variety of risks, uncertainties and other factors, most of which are beyond the Company's control, and many of which could have a significant impact on the Company's operations, results of operations and financial condition, and could cause actual results to differ materially from those anticipated.

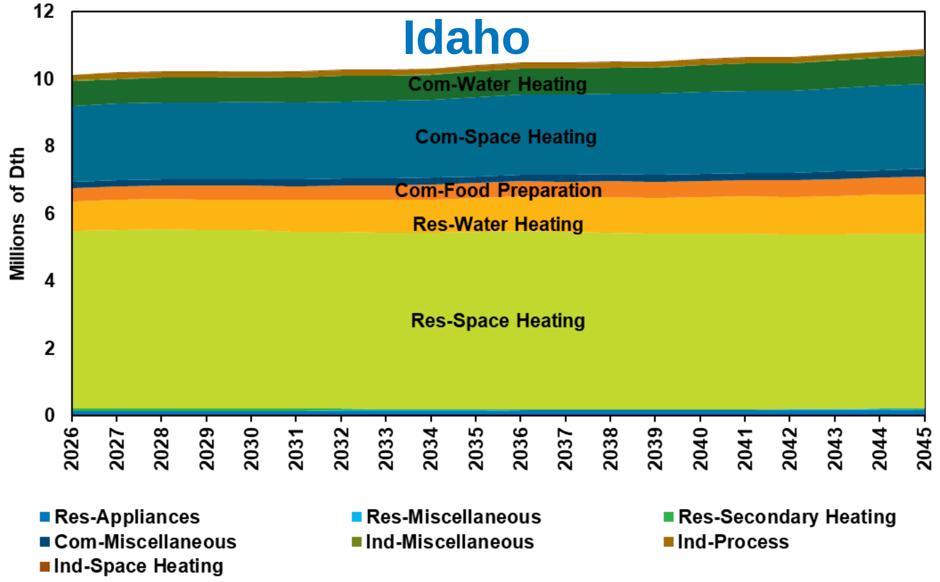
For a further discussion of these factors and other important factors, please refer to the Company's reports filed with the Securities and Exchange Commission. The forward-looking statements contained in this document speak only as of the date hereof. The Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events. New risks, uncertainties and other factors emerge from time to time, and it is not possible for management to predict all of such factors, nor can it assess the impact of each such factor on the Company's business or the extent to which any such factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement.

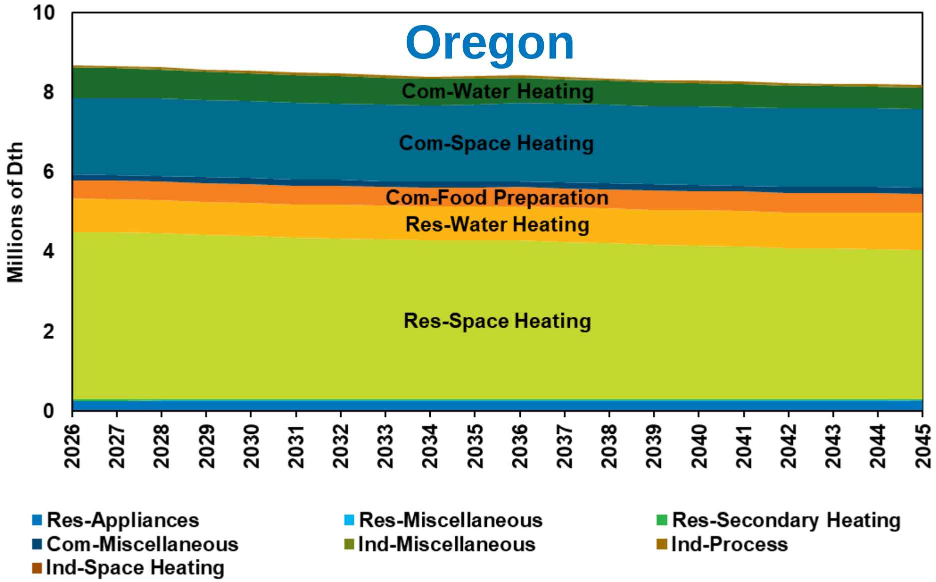
Integrated Resource Planning Requirements

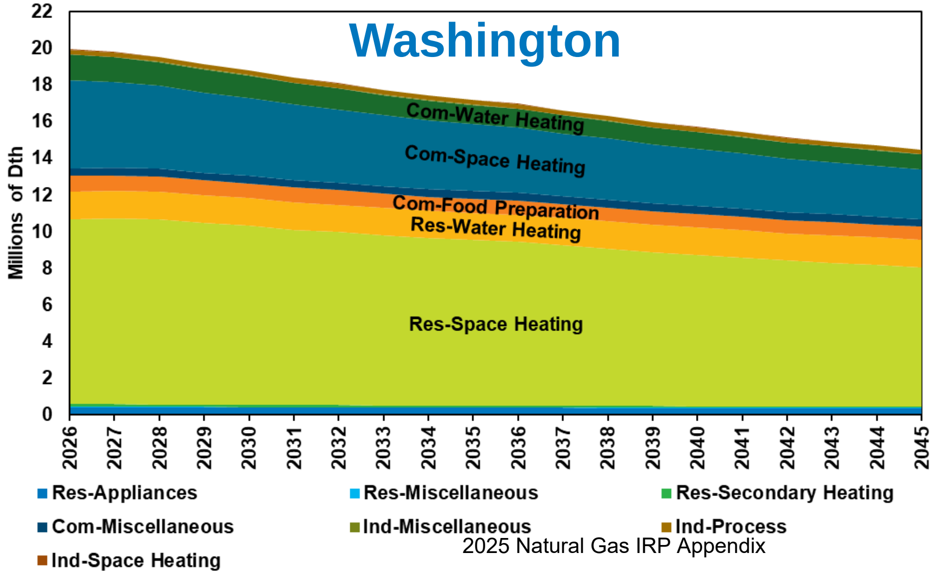
- Public plan outlining a ***resource strategy*** to meet ***future customer energy needs*** – a direction of what the Company currently sees as the best path.
- Must consider public input
- Account for future risks
- Meet state policy objectives
- Conducted every 2 years
- Filed with Idaho, Oregon and Washington state commissions

https://www.myavista.com/about-us/integrated-resource-planning

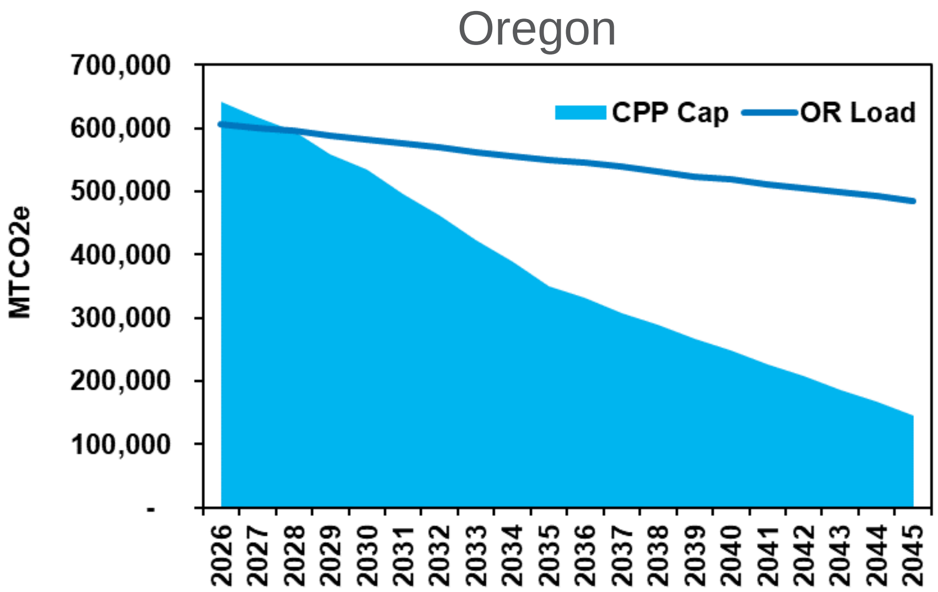
Firm Customer Demand by End Use





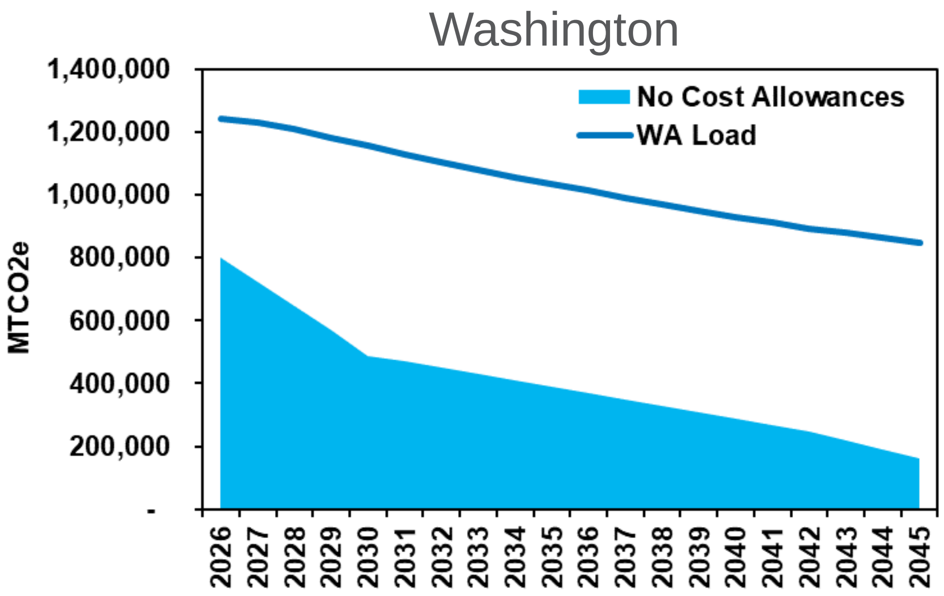


Green House Reduction Policies



Climate Protection Plan

90% reduction by 2050



Climate Commitment Act

95% reduction by 2050

-Figures include Transport customers where Avista has the responsibility to comply with the state program

What are the options to meet our customer obligations?

New Resource Selections
(Annual Average Quantity)

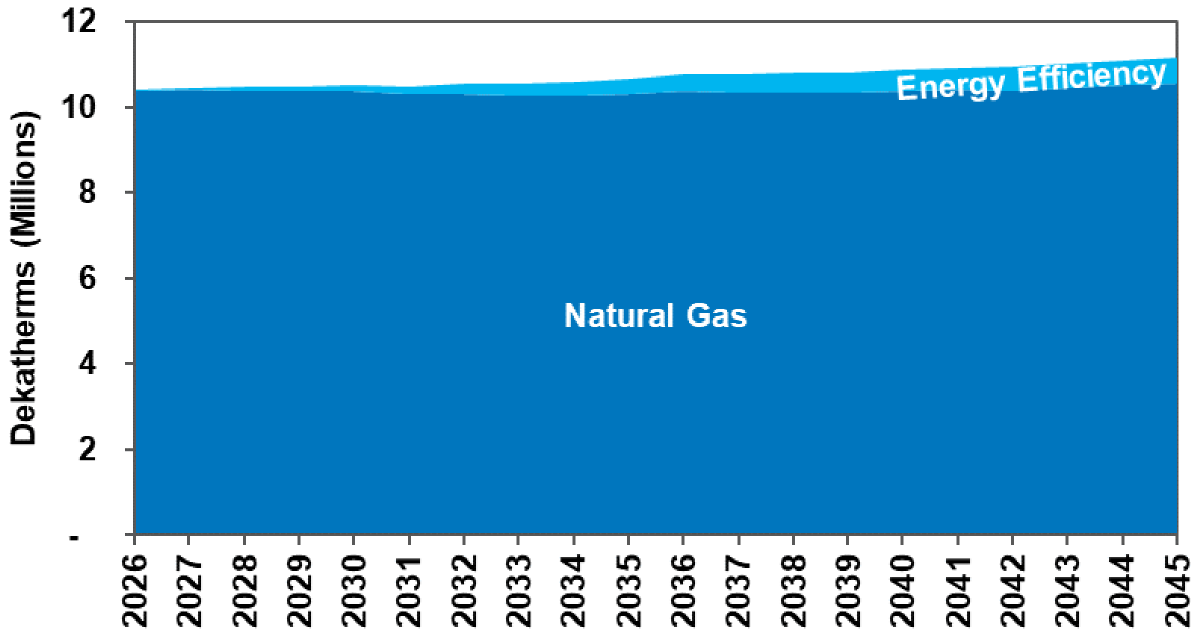
Volume Key:
Metric Tonne of CO2 equivalent
10 Therms of energy

	2026 to 2030	2031 to 2039	2040 to 2045
Program Resources	CCI: 3,000 Allowances: 576,000	CCI: 11,000 Allowances: 650,000	Allowances: 671,000
Clean Resources	RNG: 240,000	CCUS: 98,000 RNG: 2,100,000	CCUS: 157,000 RNG: 2,800,000
Demand Resources	ID EE: 87,000 OR EE: 207,000 WA EE: 318,000	ID EE: 240,000 OR EE: 830,000 WA EE: 1,220,000	ID EE: 240,000 OR EE: 1,557,000 WA EE: 1,851,000
Infrastructure and Storage			

Fossil Fuel Resources: Natural Gas

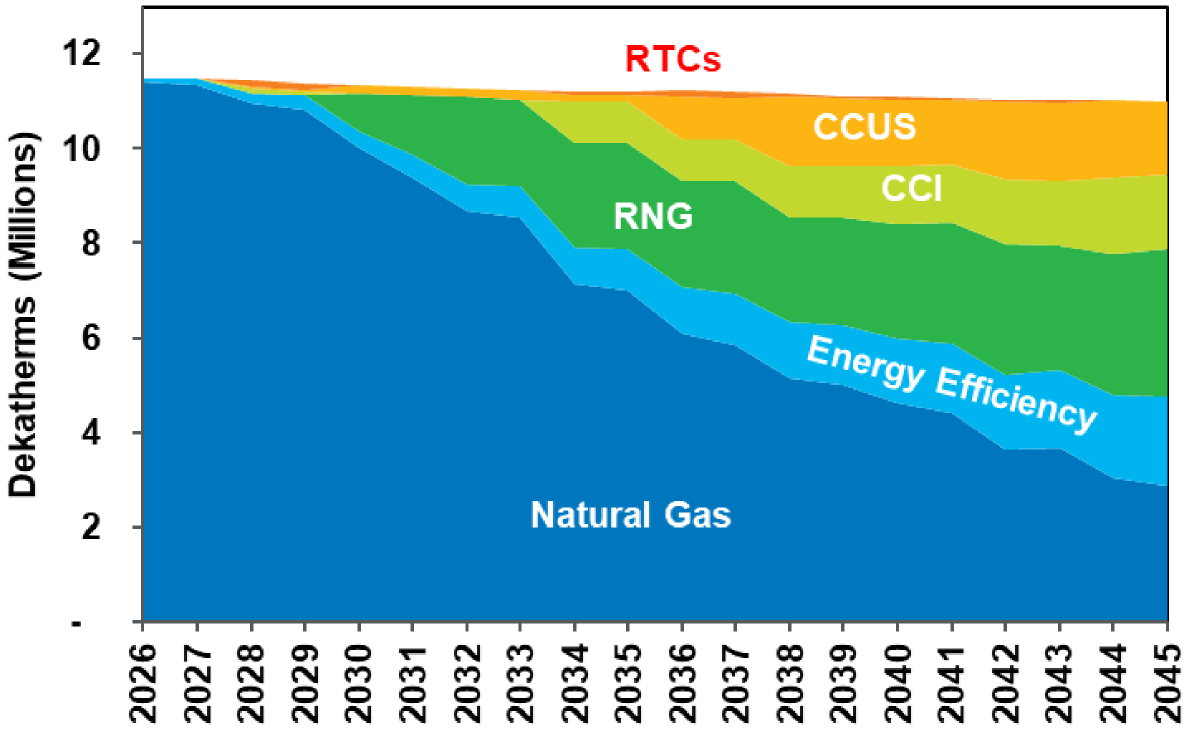
AVISTA

Idaho Preferred Resources



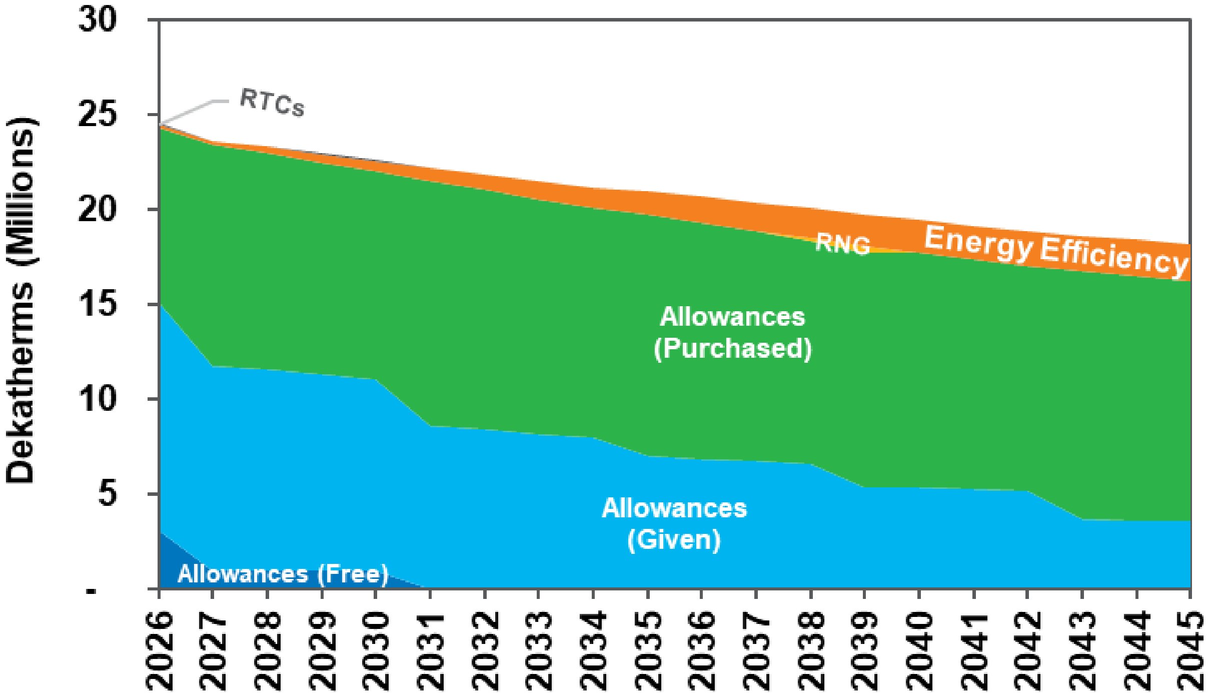
Average Growth Rate	Resources
0.37%	Natural Gas, Energy Efficiency

Oregon Preferred Resources



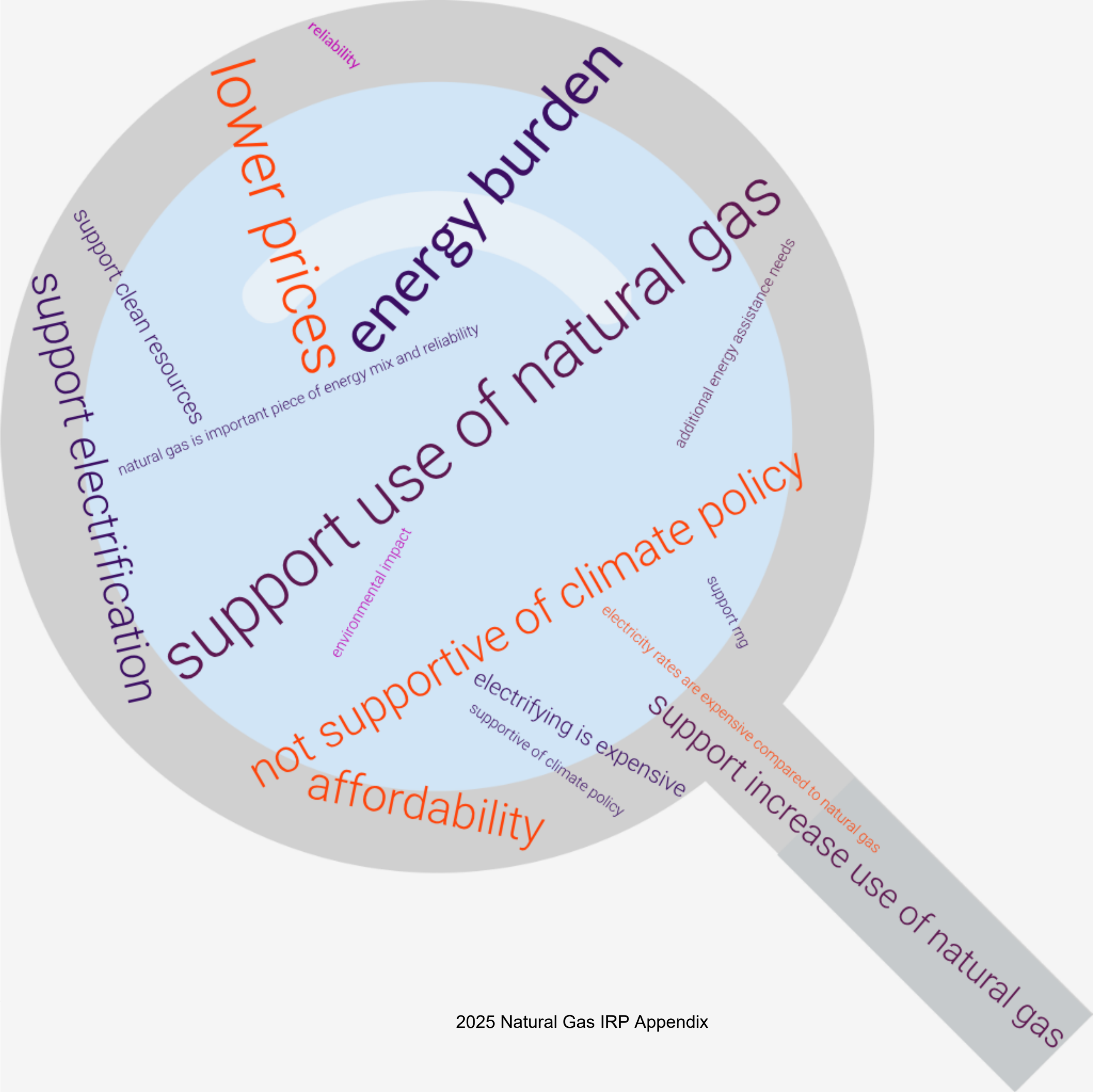
Average Growth Rate	Resources Selected
-0.31%	Natural Gas, Energy Efficiency, RNG, CCI, CCUS, RTCs

Washington Preferred Resources



Average Growth Rate	Resources
-1.68%	Natural Gas + Allowance, RNG, Energy Efficiency, RTCs

Public Meeting Written Feedback – Word Cloud



How Can You Get Involved

- **Provide comments today or by email by March 14th**
  - irp@avistacorp.com
- **Join our Technical Advisory Committee (TAC)**
  - https://www.myavista.com/about-us/integrated-resource-planning
- **File comments with the IPUC (Idaho Customers)**
  - https://puc.idaho.gov/Form/CaseComment
- **File comments with the OPUC (Oregon Customers)**
  - https://www.oregon.gov/puc/filing-center
- **File comments with the WUTC (Washington Customers)**
  - https://www.utc.wa.gov/e-filing
  - Email: records@utc.wa.gov