NW Natural®

250 SW Taylor Street
Portland, OR 97204

503-226-4211
nwnatural.com

VIA ELECTRONIC FILING

March 1, 2021

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Post Office Box 1088
Salem, Oregon 97308-1088

RE: LC 71—NW Natural's 2018 Integrated Resource Plan (IRP) Update

Northwest Natural Gas Company, dba NW Natural, provides the enclosed 2018 IRP Update in compliance with OAR 860-027-0400(8), OAR 860-027-0400(10) and Order No. 21-013.

If you have any questions, please contact Rebecca Brown at 503-610-7326.

Sincerely,

/s/ Natasha Siores

Natasha Siores
Manager, Regulatory Compliance
NW Natural
250 SW Taylor Street
Portland, OR 97204
503-610-7074
natasha.siores@nwnatural.com

Attachments:

cc: Bob Jenks, CUB
Chad Stokes, AWEC

NW Natural's 2018 IRP Update 3
Docket No. LC 71/UG-170911
March 1, 2021

Contents

Index of Tables

Index of Figures

Index of Appendix Tables

Index of Appendix Figures

Section 1: Overview

1.A Introduction

NW Natural filed its 2018 Integrated Resource Plan (2018 IRP) on August 24, 2018, docketed as LC 71 at the Public Utility Commission of Oregon (OPUC) and UG-170911 at the Washington Utilities and Transportation Commission (WUTC). The OPUC acknowledged the action items in the action plan in Order No. 19-073, entered on March 4, 2019. The Washington Utilities and Transportation Commission (WUTC) recognized compliance with (WAC) 480-90-238 on February 20, 2019. NW Natural filed the first update to the 2018 IRP with the OPUC on April 17, 2019 and did not seek acknowledgement of any action items within the update. NW Natural filed a second update to the 2018 IRP on November 7, 2019 and did not seek acknowledgement of any action items within the update. On March 10, 2020, Oregon Governor Brown issued an executive order, EO 20-04, directing state agencies to take actions to reduce and regulate greenhouse gases. Due to the uncertainty for Local Distribution Company (LDC) integrated resource planning from EO 20-04, NW Natural felt it was in the best interest of customers and stakeholders to delay the next IRP until after rulemaking for the executive order. NW Natural petitioned the OPUC and WUTC to delay the Company's next IRP until July 30, 2022 with a third update to the 2018 IRP to be file by March 1, 2021, and was granted the extension by both Commissions. NW Natural submits this update in compliance with Oregon Administrative Rule (OAR) 860-027-0400(8) and 860-027-0400(10) and Commission Order No. 21-013 and WUTC Order O1 in Docket UG-190711.

Table 1 provides an update on the action items that were acknowledged by the OPUC in Order No. 19-073.

Table 1: Update on Actions Acknowledged in NW Natural's 2018 IRP

Action	Status
Recall Mist Storage Capacity for the 2020-21 and 2021-22 Gas Years	Updated load projections resulted in no Mist Recall being required for the 2020-21 gas year. Lower cost Citygate deliveries of 5,000Dth/Day are to be deployed for the 2021-22 gas year.
Use "all=in cost" RNG Evaluation Methodology to evaluate RNG resources	Item was not acknowledged, but transitioned to an investigation. Docket no. UM 2030 was started in 2019 and completed October 2020. The RNG evaluation methodology was amended and approved, and is now being used to evaluate RNG resources.
Complete Hood River Reinforcement Project	Construction started and the project was placed into service in September 2020 and included in rates.
Complete Happy Valley Reinforcement Project	Construction started and the project was placed into service in March, 2020 and included in rates.
Complete Sandy Feeder Reinforcement Project	Construction started and the project was placed into service in October, 2020 and included in rates.
Complete South Oregon City Reinforcement Project	Construction started and the project was placed into service in April, 2020 and included in rates.
Complete Kuebler Road (Salem) Reinforcement Project	The project is currently in the planning phase. It's yet to be determined what environmental permits, if any, will be required as final environmental studies are still to be performed. At this time the target is to start construction in the summer of 2021 and finish in Q4 of 2021.
Acquire Energy Efficiency savings via Energy Trust for Oregon for 2019 and 2020	Energy Trust acquired 97% of the 2019 goal on behalf of NW Natural customers. Final 2020 results are still pending.
Acquire Energy Efficiency savings via Energy Trust for Washington for 2019 and 2020	Energy Trust acquired 101% of the 2019 goal on behalf of NW Natural customers. Final 2020 results are still pending.

1.B Executive Summary and Planning Environment

As described in NW Natural's petitions to both the OPUC and WUTC to delay the Company's IRP until July of 2022[1] the current planning environment is highly uncertain, primarily due to the rulemaking and regulatory processes underway to implement Oregon Executive Order 20-04. It is anticipated that NW Natural may need to implement substantial changes to its integrated resource planning activities to model compliance with these future policies. In particular, the Oregon Department of Environmental Quality's Climate Protection Program (CPP, often referred to as the "Cap and Reduce" program), which is anticipated to set emissions caps for Oregon LDCs, could require changes to the Company's load forecasting, energy efficiency, resource options, and portfolio modeling assumptions and methodologies. The CPP rules, as well as many of the other processes underway to implement EO 20-04, are scheduled to be complete by the end of 2021. Given this, NW Natural filed to delay its next full IRP until it can incorporate these policies into its planning, while using this expanded 2018 IRP Update to keep stakeholders apprised of planning activities and provide interim updates to key forecasts and assumptions.

The Company plans to hold three technical planning workshops (NW Natural's workshops are called Technical Working Groups, or TWGs) over the remainder of 2021 to present to stakeholders its initial thoughts on – and gain feedback about – how it might implement ODEQs CPP program as more information on the program is received and draft rules are issued. After the final CPP rules are formalized and other processes complete, NW Natural will hold its typical set of six TWGs on a compressed schedule during the first months of 2022, distribute a draft IRP in June, and file the 2022 IRP in July with an Action Plan that incorporates the new policies. A timeline of NW Natural's IRP activities and the primary policies impacting it can be found in Appendix A.

Largely incorporating new data since the last IRP was filed into the same methodologies employed and detailed in the 2018 IRP, this IRP Update refreshes most of the key projections in the 2018 IRP. The following list details the key changes that are not data update related and Table 2 summarizes the key changes from the 2018 IRP provided in this Update:

1. <u>Planning horizon extended to 2050</u>
    - To better align with a policy environment that often that sets goals to be achieved by 2050, NW Natural has extended the planning horizon from the standard 20 years to the year 2050

2. <u>The impact of climate change added to weather modeling of the heating season</u>
    - While the Company already evaluates and models climate change in terms of peak hour, peak day, and peak event planning (see pages 3.38-3.43 of the 2018 IRP)[2], this update incorporates climate change modeling into the Company's weather forecasts for an entire heating season (both under expected conditions for load and emissions forecasting and "peak heating season" conditions for storage resource adequacy) for the first time using similar models and assumptions to the Northwest Power and Conservation Council (see Section 2.C)

[1] More detail on NW Natural's rationale to seek a delay in its upcoming IRP can be found in its petitions to the OPUC (see LC 71, https://edocs.puc.state.or.us/efdocs/HAO/lc71hao84521.pdf) and WUTC (see UG-190711)
[2] As well as the discussion in post-filing comments related to the 2018 IRP in OPUC Docket No. LC 71.

3. <u>Greenhouse gas prices updated for new policies</u>
    - To comply with WA HB 1257 the Social Cost of Carbon (SCC) inclusive of upstream emissions now represents the base case planning assumption in Washington state. Similarly, based has the OPUC's Work Plan to implement EO 20-04, NW Natural is using the same SCC figure provided by the WUTC for HB 1257 implementation for the base case in Oregon (though not inclusive of upstream emissions). This represents a meaningful increase in the base case "carbon price" from the 2018 IRP, which was based upon expected prices in the Western Climate Initiative cap and trade allowance market that includes California (see Section 2.B)

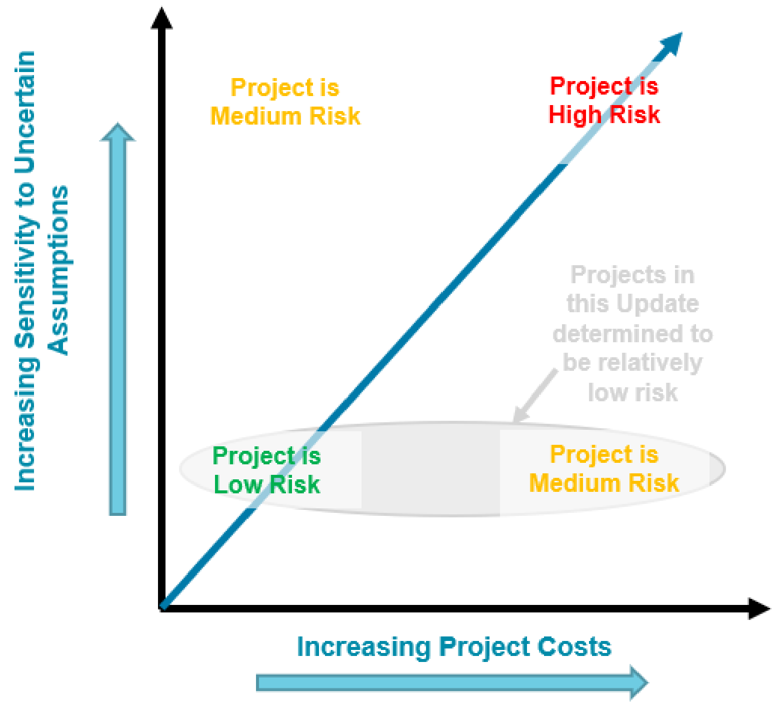
4. <u>Impact of OR SB 98 and UM 2030 included in RNG resource evaluation and emissions forecasting</u>
    - Oregon Senate Bill 98 (SB 98) passed in June of 2019 and set voluntary targets for LDC procurement of Renewable Natural Gas (RNG). Order No. 20-227 formalized the subsequent rulemaking (OPUC Docket No. AR 632) to implement SB 98 in July of 2020. Additionally, UM 2030, a docket opened by the OPUC to investigate NW Natural's Action Item in the 2018 IRP related to its RNG evaluation methodology, concluded with Order No. 20-403 approved the updated methodology, which folds in to the rules established from AR 632. The impacts of these changes have been incorporated into the Company's RNG acquisition activities and planning (see Section 2.G) included in NW Natural's updated emissions forecast (see Section 2.H)

Table 2: Summary of Changes from 2018 IRP

	Methodology Change?	Updated with New Assumptions?	Updated with New Data?
Planning Horizon	✓	✓	✓
Conventional Gas Prices			✓
Expected Heating Season Planning Standard	✓	✓	✓
Peak Heating Season Planning Standard	✓	✓	✓
Peak Day Planning Standard			✓
Peak Hour Planning Standard			✓
Customer Count Forecasts			✓
Use Per Customer Forecasts			✓
Annual Energy Forecasts			✓
Peak Day Forecasts			✓
GHG Prices		✓	✓
GHG Policy Modeling Implementation			
Avoided Costs		✓	✓
Emissions Forecasts		✓	✓
Resource Selection Modeling			✓
Energy Efficiency Cost-Effectiveness Evaluation			✓
Gas Supply Resource Options		✓	✓
Stochastic Risk Analysis		✓	✓
Risk Adjusted Decision Criteria			✓
Distribution System Planning Criteria			

While the current uncertainty in the planning environment greatly increases the risk of long-lived actions that are dependent upon long-term load forecasts and other projections, NW Natural still has an obligation to safely and reliably serve its customers. Given this primary concern, the Company weighed the risks of potential projects using the risk assessment shown in Figure 1 to determine if all of the projects facing the most urgent need are relatively low risk. It was decided that urgent and relatively low-risk projects should not wait for acknowledgement through the next full IRP (to be filed in July 2022) and that this IRP Update is a reasonable forum to seek acknowledgement.

Figure 1: Project Risk-Assessment



With this background, NW Natural is seeking acknowledgement of two Action Items in this Update that are:

1. needed in the short-term to maintain reliability to meet current loads;
3. the least-cost option regardless of what long-term load materializes; and
3. not relatively high cost projects

One Action Item is for a NW Natural system-wide gas supply resource that is applicable to both Oregon and Washington customers (Action Item 1) and one is a distribution system reinforcement project that is applicable only to Oregon customers (Action Item 2):

Action Item 1:

> **Replace the Cold Box at the Newport liquified natural gas (LNG) facility for a targeted in-service date of 2025 at an estimated cost of $14.6 to $18.9 million**

Action Item 2:

> **Proceed with uprating the North Coast Feeder to be in service for the 2022-2023 heating season at an estimated cost of $5.1 to $10.2 million**

The rest of this IRP Update outlines NW Natural's confidence and reasoning that these two projects, which NW Natural is seeking acknowledgement, are required based upon current need (i.e., are not dependent upon long-term projections) and inaction on these projects would pose meaningful near-term risks to reliably serve customers.

1.C Public Participation

Stakeholder engagement is an integral part of NW Natural's resource planning process. During this planning cycle, NW Natural worked with representatives from Citizens' Utility Board of Oregon; Energy Trust of Oregon; Alliance of Western Energy Consumers; Public Utility Commission of Oregon staff; Washington Utilities and Transportation Commission staff; Northwest Gas Association; and other stakeholders.

NW Natural continued this engagement with an Open House presentation as part of the 2020 IRP process, and held a TWG meeting as part of the revised process. The Open House was held on November 26, 2019 in anticipation of the upcoming 2020 IRP process. This meeting was designed to provide a general overview of the Company, as well as modeling tools that would be used in the IRP planning process.

A technical working group (TWG) meeting was held on February 2, 2021 to present materials germane to this 2018 IRP Update. This included a status update of the 2018 IRP action plan, current planning environment, climatic data, load forecasts, cost estimates, and potential for RNG and hydrogen. Finally, the 2018 IRP Action Items, replace Cold Box at Newport and uprate the North Coast Feeder were discussed.

The sign-in sheet from the in-person open house and the virtual attendance for the TWG is included in Appendix D: Public Participation.

Section 2: Key Updates from 2018 IRP

2.A Natural Gas Prices

NW Natural uses planning horizon forecasts of natural gas prices by trading hub for IRP analysis and this update. These forecasts include monthly price forecasts for Rockies (using the Opal trading hub), British Columbia (West Coast Station 2 and Sumas/Huntingdon), and Alberta (AECO). These long-term price forecasts are developed by a third-party provider (IHS/S&P Global),[3] updated semi-annually (in March and September of each year), and are based on a market fundamentals model which balances supply and demand. These forecasted prices are used in our SENDOUT® resource planning modeling software, which is used for analyzing portfolio impacts of the Newport Cold Box alternatives analysis presented in this update. See the Chapter 2 of the 2018 IRP for more detail about gas price fundamentals. See Appendix B: IRP Update Analysis and Assumptions Detail for figures and summaries.

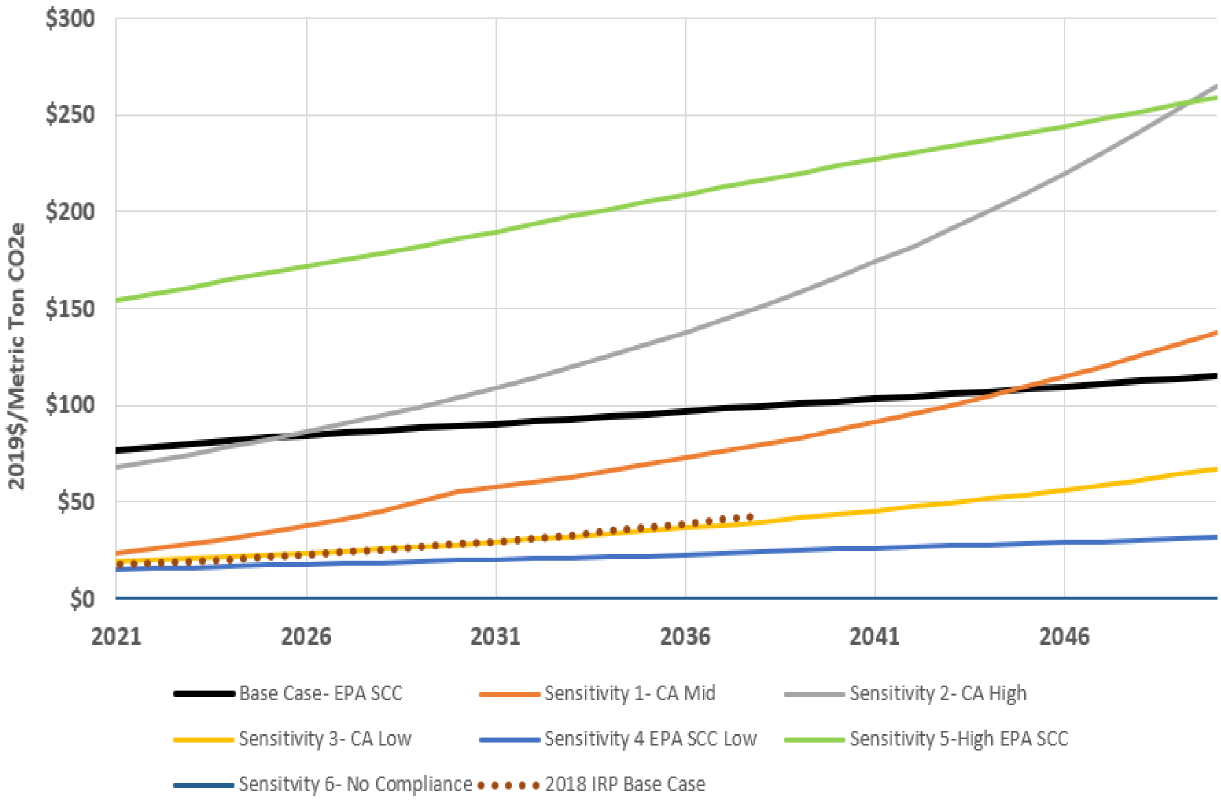
2.B Greenhouse Gas Policy Costs

Policy changes, or changes in expected policy, have resulted in a meaningful update in NW Natural's expected cost of greenhouse gas policy/compliance costs since the 2018 IRP was filed. Supported by the Company's interpretation of the OPUC's IRP guidelines as well as best practices for resource planning, the IRP is not a policy advocacy tool about what climate policy the Company prefers, but rather an assessment of what policy or policies appear most likely over the planning horizon (accounting for uncertainty with sensitivities). As was discussed in the executive summary above, there remains a large degree of uncertainty about climate policy implementation in Oregon from EO 20-04, but much of that uncertainty is likely to become clearer over 2021 for implementation in the 2022 IRP. With that, both Oregon and Washington have taken steps towards a policy that has also taken hold in other states and internationally – requiring or recommending utilities use the Social Cost of Carbon (SCC) in making resource planning decisions. In this sense, utilities are required to analyze resource decisions as if there were a carbon tax in place at the SCC level, even if actual compliance costs do not exist in the jurisdiction. In Washington, HB 1257 was passed, which requires natural gas utilities to evaluate resources inclusive of the SCC. In Oregon, the OPUC's EO 20-04 Work Plan suggests the Commission is likely to require Oregon utilities to do the same.

Figure 2 shows the base case SCC climate policy cost expectation applied to NW Natural's resource evaluation, including energy efficiency, renewable natural gas and other lower carbon sources of gas supply. The base case value is the SCC sourced via the US EPA and provided by the WUTC.[4] The figure also shows the sensitivities used for risk analysis in Oregon (noting that sensitivities are not applied for Washington given that HB 1257 requires use of the SCC).

[3] S&P Global recently agreed to acquire IHS Markit in December of 2020 and is expected to close later in 2021.
[4] See https://www.utc.wa.gov/regulatedIndustries/utilities/Pages/SocialCostofCarbon.aspx

Figure 2: Greenhouse Gas Policy Costs – Base Case and Sensitivities



The sensitivities used for risk analysis are based upon sensitivities for the price of carbon allowances in the Western Climate Initiative (Sensitivities 1, 2, and 3) that includes California's Cap and Trade program, alternate estimates of the SCC from the US EPA (Sensitivities 4 and 5), and a sensitivity where there is no carbon compliance obligation for NW Natural over the planning horizon (Sensitivity 6). Please see Chapter 7 of the 2018 IRP for detail about how the Company implements the GHG pricing sensitivities into its risk analysis.

2.C Weather Pattern Forecasts

It is important to consider the long-term effect of climate change trends on NW Natural's resource planning to ensure the Company's planned resource acquisitions are optimized for expected climate change. This section explains how the Company plans to incorporate climate change impacts in our load forecasts.

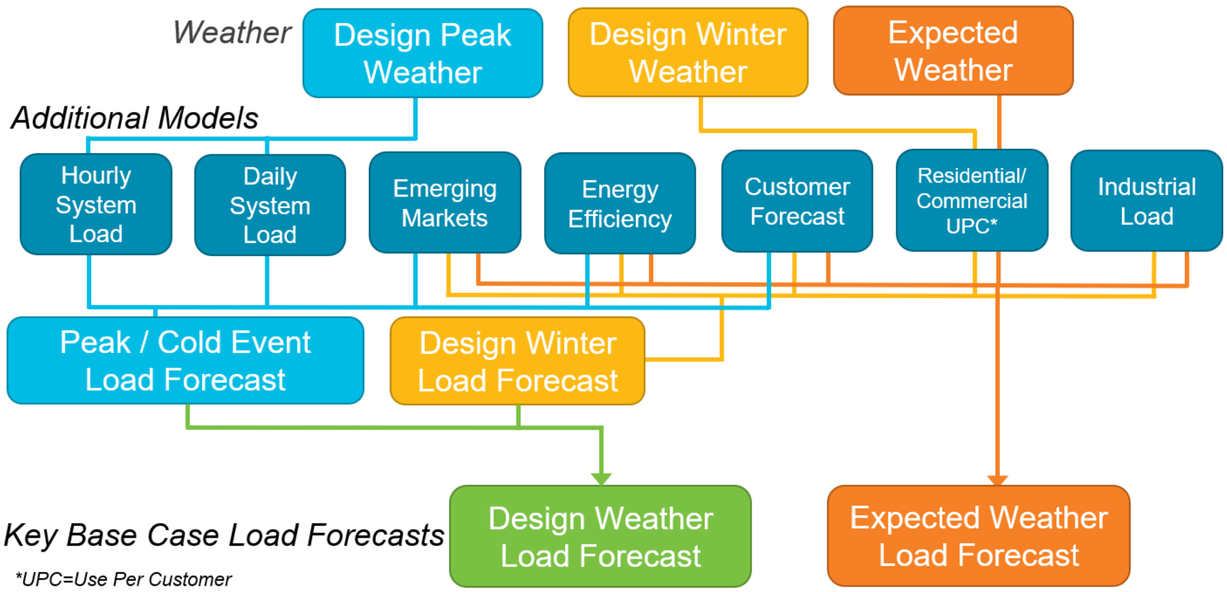
IRP Weather Patterns

Our demand forecast process uses three different kind of weather patterns as one of the inputs in the models.

- Design peak weather
- Design winter weather
- Expected weather

Figure 3 shows a flow chart illustrating how different weather inputs are used in demand forecast process.

Figure 3: Weather Pattern Flow Chart



The design peak weather and design winter weather are used for resource planning. It facilitates decision making regarding gas supply purchases, storage injections and withdrawals in order to meet demand throughout the year and also ensuring adequate system capacity in order to meet peak demand during extreme weather events. The design peak (peak day plus surrounding days) and design winter weather forecasts combine to make the weather forecast that is used in NW Natural's resource modeling to ensure the Company's design hour, design day, design event, and design winter planning standards are all met.

Once capacity resource adequacy is ensured based on forecasts that meat design planning standards, resource selection work is completed using expected weather to evaluate portfolios based on cost (where "expected weather" is the preferred term as it implies the incorporation of climate trends whereas "normal weather" implies a historical average of temperatures).

Data Source for incorporating weather with climate change trends:

We used the data from climate models from the Intergovernmental Panel on Climate Change (IPCC). The climate model predictions are on coarse grid of about 300 square kilometers. The coarse grid predictions are downscaled using a local weather to get weather at a service territory. The downscaled projections are available on the IPCC website for each of our service locations. The recommendation from IPCC is to use an ensemble of climate models. We therefore selected the following five climate models:

- ccsm4.6
- cnrm-cm5.1
- gfdl-cm3.1
- hadgem2-cc.1

- miroc5.1

The climate change trends are implemented in the expected weather and design weather but not in peak day weather (which still uses the methodology detailed in Chapter 3 of the 2018 IRP).

Expected weather generation: In 2018 IRP we used historical thirty-year average of daily temperatures as the normal weather inputs the Company's load forecast models. The new method incorporates the trends of climate change for nine locations around our service territory as follows:

1. First, choose a representative year which is same for each service location as a daily shape to the weather. The year 2012 was chosen after looking at the median annual HDDs.
2. Then, adjust the annual HDDs of the representative year to match the trend from the average of the annual HDDs from the five selected climate models for each year starting from 2020 till 2050.

Design weather generation: In previous IRPs we generated design weather using the 90th percentile of heating season HDDs (Nov-April) for the last 30 years. The new method for generating design weather with climate change trends is given as follows:

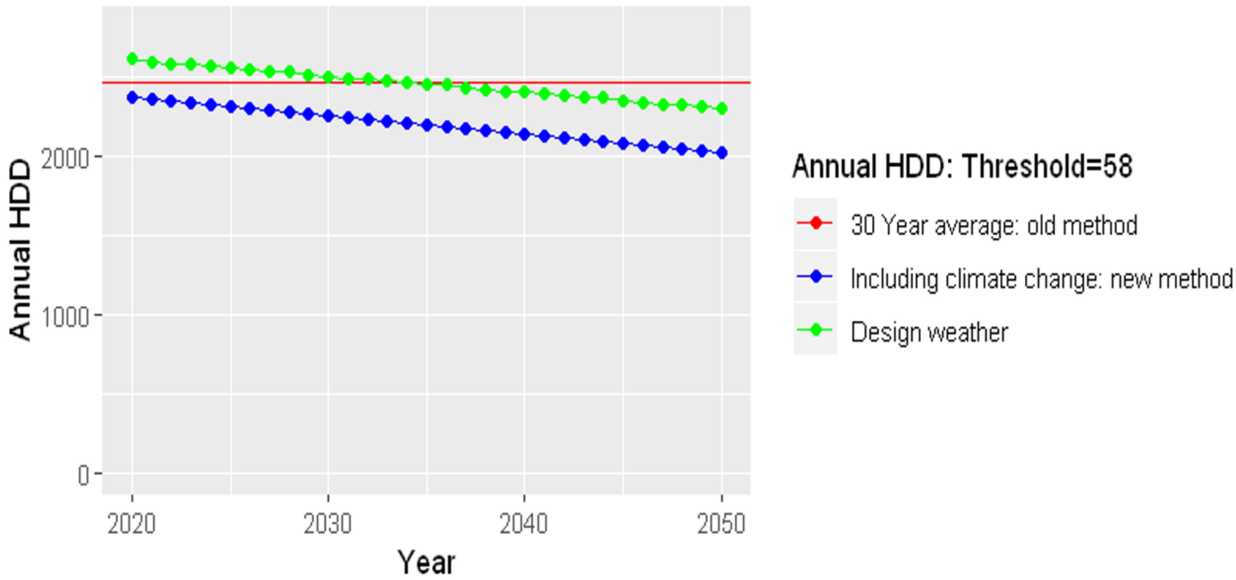
1. First, find the 90th percentile winter over the last 30 years based on cumulative winter HDDs (Nov to April) from historical data. This was year 2000 based on past data.
2. Next, compute the difference between 90th percentile winter daily temperatures and 30-year historical average winter daily temperatures.
3. Finally, use the deviations computed in step 2 above to adjust the winter days in expected weather. This gives daily design winter weather for each year in the planning horizon.

Portland weather:

As an example, we present a plot of annual HDDs for three different weather patterns in Portland for the 2020-2050 shown in Figure 4.

The red line represents annual HDDs for historical 30-year average daily temperatures (akin to the normal weather used in the 2018 IRP). The blue line is annual HDDs for expected weather along with climate change trends and the green line represents annual HDDs for design weather that incorporates climate change trends

Figure 4: Annual HDD Over Time - Portland



2.D Load Forecast

NW Natural updates the Company's long-term load forecasts annually to incorporate data from the previous winter and other updated input forecasts (e.g., short-term meter set forecast). The inclusion of the Company's load forecast in this update is informational only and the projects being considered for acknowledgement are required given current load. It should also be noted that these load forecasts do not reflect any outcomes from EO 20-04, but are simply updates to the methodologies applied in the 2018 IRP with a few improvements, which are identified this section and Appendix B: IRP Update Analysis and Assumptions Detail.

Customer Count Forecast and Annual Load Forecast

NW Natural updated the 2018 customer count and annual load forecasts, following the methodology detailed in Chapter 3 and Appendix C of the 2018 IRP with minor updates driven by new input data and routine model testing. One update of note, is the incorporation of long-term climate change weather modeling, as described above, as an input for annual load forecasts (both expected weather load and design winter load). The updated load forecasts reflect these climate change trends, which have a sizable impact in the long-term, but does not impact the immediate demand requirements of customers during a peak cold event as described for the two project the Company is asking for acknowledgment. Summaries of customer count and load forecasts are included in Appendix B: IRP Update Analysis and Assumptions Detail of this document.

Peak Day Load Forecast

The peak day load forecast incorporates the customer forecast, the industrial load forecast, energy efficiency forecast, the daily system load model, and the peak day planning standard.[5] The combination

[5] The peak day planning standard requires the resources necessary to meet the highest firm sales demand with 99% certainty going into any future winter. This planning standard is described in more detail in NW Natural's 2018 IRP – LC 71.

of these models results in a long-term forecast of the daily resource requirement needed to meet daily firm sales demand during an extreme cold weather event. The methodology used for peak day planning is detailed in Chapter 3 and Appendix C of the 2018 IRP. Updates driven by additional data and routine model testing resulted in roughly a 2% lower firm sales peak day forecast for the 2021-2022 winter as compared to the 2018 IRP and a negligible change from the firm sales peak day forecast used in the second 2018 IRP update filed November 7, 2019. Summaries and technical details for this update are available in Appendix B: IRP Update Analysis and Assumptions Detail.

2.E Near-term Resource Planning

Currently, daily firm sales resource capacity requirements are driven by the firm sales peak day load forecast. NW Natural customers benefit from having two relatively short notice[6] resource options to serve daily deliverability capacity needs:

1. Mist Recall - Transferring Mist storage assets from interstate storage to utility customers
2. Citygate Deliveries - Contracts for gas supplies delivered directly to NW Natural's service territory by the supplier utilizing their own NWP transportation service

In previous IRPs Mist Recall has shown to be the least cost least risk resource for meeting firm sales peak day demand. Citygate deals can be evaluated in comparison to Mist Recall based on costs and risks in order to serve potential daily firm sales peak demand. NW Natural will rely a citygate deal for 5,000 Dth/day for the upcoming 2021-2022 winter. Over the next few years the Company will utilize Mist Recall, Citygate deliveries, or a combination of both to meet potential firm sales peak demand. For further details see Appendix B: IRP Update Analysis and Assumptions Detail.

As an update to Action item #1 of the 2018 IRP, NW Natural will rely on a 5,000 Dth/day Citygate delivery agreement to cover a forecasted potential daily firm sales peak resource capacity requirement for the 2021-2022 winter. In the interim of this update and the next acknowledgement of the 2022 IRP, NW Natural will rely on either Mist Recall, Citygate deliveries, or a combination of both for near term system supply capacity resource requirements.

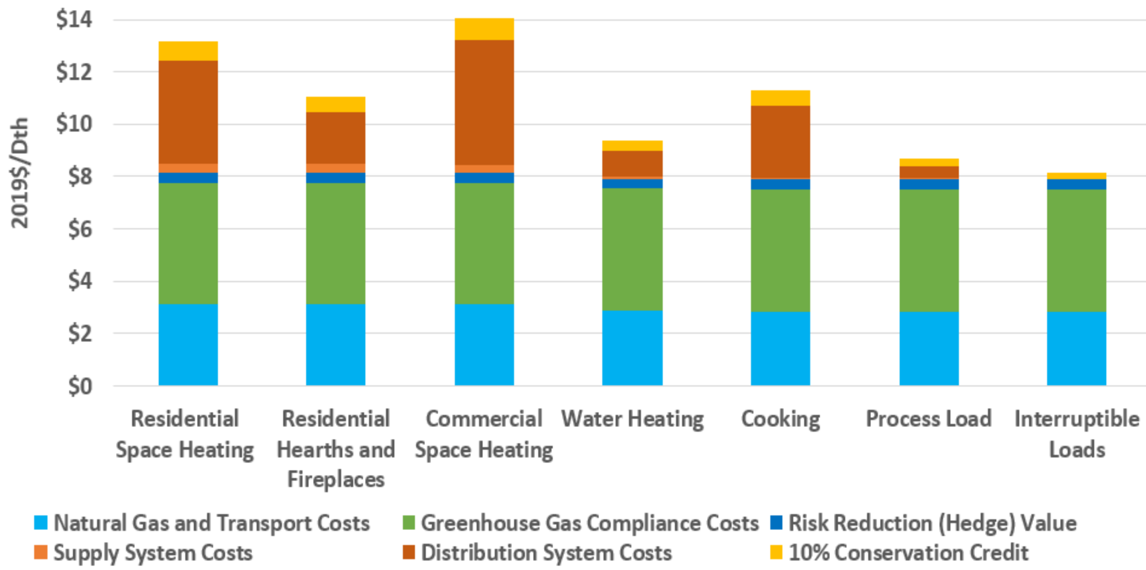
2.F Avoided Costs

Using the methodologies described in the 2018 IRP NW Natural has updated its avoided cost values with the natural gas and GHG policy costs described in previous sections and results in the outcome shown in Figure 5[7]:

[6] The lead time for Mist Recall is about 12 months prior to the winter when it would be required. Citygate deals can be negotiated with even less lead time. Other traditional supply-side capacity resources (e.g., a pipeline expansion, storage expansion, or LNG facility) could take multiple years to a decade to permit, site and construct.

[7] See Figure B.13 in Appendix B: IRP Update Analysis and Assumptions Detail for Washington's 20-year levelized avoided costs

Figure 5: Oregon 20-year Levelized Avoided Costs

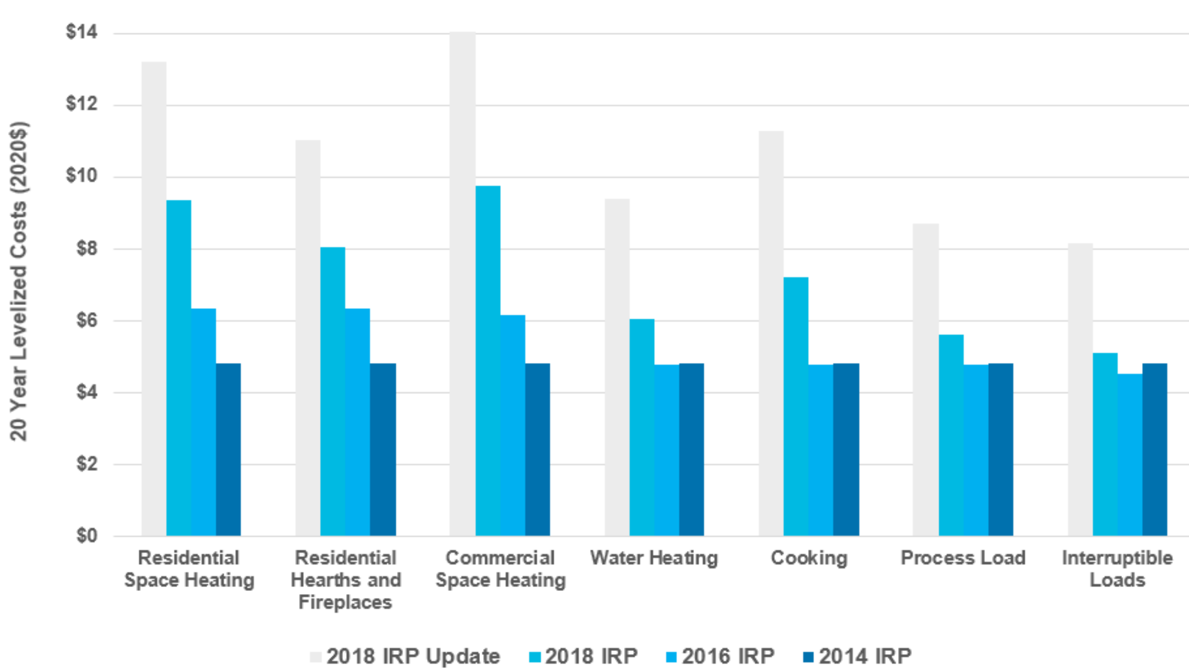


Note that this is a meaningful increase in avoided costs since the 2018 IRP, with the vast majority of the increase due to two factors:

1. The increase in the GHG policy cost assumption update discussed in Section 2.B;
2. Updates to the distribution system capacity costs estimates from the outcomes of rate cases in both Oregon and Washington (see pages 4.7 - 4.8 in the 2018 IRP for more detail on the methodology for estimating distribution system avoided costs)

Figure 6 shows how avoided costs have changed through time.

Figure 6: Changes in Oregon Levelized Avoided Costs Through Time



2.G RNG and Hydrogen Market and Project Information

RNG Policy Update

Since NW Natural filed its last full IRP there have been several major changes in in Renewable Natural Gas (RNG) policy of both Oregon and Washington states. Oregon passed Senate Bill 98 (SB 98) with an effective date of September 29, 2019. This bill directed the OPUC to adopt rules on RNG programs for utilities with the summary reading in part: "Requires Public Utility Commission to adopt by rule large renewable natural gas program and small renewable natural gas program. Requires commission to adopt rules no later than July 31, 2020." The legislation established voluntary RNG goals as shown in the Table 3.

Table 3: SB 98 RNG Voluntary RNG Goals

Years	Targeted Goals
2020-2024	5%
2025-2029	10%
2030-2034	15%
2035-2039	20%
2040-2044	25%
2045	30%

To implement the rulemaking process, the OPUC opened docket AR 632. This docket codified the rules, which are included in the Oregon Administrative Rules (OARs) Chapter 860, section 150. These rules are somewhat parallel to the rules around renewable electricity, including for instance, a compliance tracking instrument (MRETs vs WREGIS). Both sets of rules allow for compliance with bundled, or unbundled certificates. Similar to the renewable electricity requirements, there are cost guardrails for RNG, where incremental costs of acquiring RNG is limited up to five percent of annual revenue requirements.

The Commission also completed an investigation into the Company's Renewable Gas Supply Resource Evaluation Methodology, as contained in Appendix H of the 2018 IRP. While the investigation, docket UM 2030, was an outgrowth of the 2018 IRP, wherein NW Natural requested acknowledgement of the methodology to evaluate RNG, it was just as applicable to the AR 632 process which requires cost-effectiveness calculations.

UM 2030 consisted of two phases. The first phase was to walk regulators and stakeholders through the methodology itself. Appendix H included a process flow chart for initial evaluation of projects. This is followed by the following equation to calculate the actual cost of the resource.

> Annual all-in cost of RNG (R) = Cost of methane (M) + Emissions compliance costs (E) – Avoided infrastructure costs (I)

Many of the components that go into the methodology need to be updated fairly regularly. The update schedule for the methodology components are shown in Table 4.

Table 4: Forecast and Assumption Update Frequency

Inputs and Forecasts	Frequency of Update	Additional Explanation
Resource Under Evaluation	Most Current Estimate	For example, if an RNG project requires any capital costs, the most current estimate of those costs will be run through the cost-of-service model and used for the evaluation.
Gas Prices (Deterministic and Stochastic)	Twice a year	Our third-party consultant provides long term gas price forecasts twice each year in August and February.
Peak Day & Annual Load Forecast	Once a year	These forecasts are updated spring/summer to include data from the most recent heating season.
GHG Compliance Cost Expectations (Deterministic and Stochastic)	Once a year	The GHG compliance cost assumptions will be updated each year after the legislation sessions in each state or when legislation is signed into law.
Design, Normal, and Stochastic Weather	Each IRP	Resources are planned based on design weather, but are evaluated on cost using normal and stochastic weather.
Gas Supply Capacity Costs (Deterministic and Stochastic)	Each IRP	Supply capacity costs (e.g., Mist Recall, a pipeline uprate or a local pipeline expansion) are updated each IRP.
Distribution System Capacity Costs	Each IRP	NW Natural will calculate and present the avoided distribution avoided costs through the IRP process.

Phase 2 of the docket examined the costing of an actual project, as opposed to the hypothetical discussion in Phase 1. Following comments for both phases, Staff recommended approval of the method proposed by NW Natural. The Commission concurred with Staff in Order No. 20-403.

In addition to Oregon, Washington moved forward on policies related to RNG. The state passed House Bill 1257 (HB1257) in 2019, with several of the sections dealing specifically with RNG. Section 12 determined that RNG provides benefits to customers, and the public. As well, the development of RNG resources should be encouraged. Similar to the Oregon legislation, there is a cost cap to protect ratepayers in Section 13. Contained in Section 14 is a requirement to develop voluntary RNG programs. And finally, Section 15 (not limited to RNG) requires the use of the social cost of carbon in planning processes.

RNG Market Update

As NW Natural enters the RNG market, the Company is in direct competition for the fuel in a market powered by the Federal Renewable Fuel Standard (RFS) which generates credits in the form of Renewable Identification Numbers (RINs), the California Low Carbon Fuel Standard (LCFS) which generates LCFS credits and to some extent the Oregon Clean Fuels Program. These other markets are focused on using RNG as a transportation fuel while SB 98 allows for RNG to be used by residential, commercial and industrial gas customers.

RNG producers focused on the RFS earn 11.727 RINs per Dth of RNG produced. These RINs are actively traded and marketed based on the feedstock that generated the RNG. As a general rule, landfill gas and RNG produced from wastewater operations would generate D3 RINs[8] while RNG generated from food waste would generate D5 RINs[9]. RIN pricing has been volatile and historically one Dth of RNG would provide $7 to $34 for D3 RINs and $2 to $13 for D5 RINs. Most recent spot market RIN pricing values D3 RINs at $2.40 which is about $28 per Dth (multiply by 11.727) and D5 RINs recently reached an all-time

[8] D3 RINs are produced from cellulose, hemicellulose, or lignin with a 60% lifecycle GHG reduction.
[9] D5 RINs are produced from non-corn starch renewable biomass with a 50% lifecycle GHG reduction.

high at $1.10 which is about $13 per Dth. As this is the case, NW Natural has found itself in direct competition for RNG in this price range.

RNG producers are also able to take advantage of the California LCFS market in addition to the RINs market. This double benefit is called stacking and can create even more value for RNG production. The LCFS market is a heavily regulated, carbon intensity (CI) focused, market. RNG with a lower CI score will generate more LCFS credits than RNG produced with a higher CI score. Carbon intensity is measured in grams per megajoule and a landfill gas project for example with a CI score of 40 g/MJ would provide about $9 per Dth of value in the LCFS market (when LCFS credits are trading at their $200/ton cap price which is often the case). A dairy project on the other hand with a CI score of -250 g/MJ would provide about $70 of value per Dth in the same market. Lower CI RNG projects are therefore often focused on this California LCFS market which is a difficult market for NW Natural to secure the lowest cost of RNG for our customers.[10]

RNG Development Update

NW Natural recently formed a partnership with BioCarbN, a developer and operator of sustainable infrastructure projects, to convert biogas from some of Tyson Foods facilities into RNG. Under this partnership, the Company holds the option to invest in various RNG development projects that will access biogas derived from water treatment at Tyson Foods' processing plants. In December 2020, the Company exercised an option for the first development project which is in Lexington, Nebraska, initiating investment in an estimated $8 million project. Construction on this first project is expected to begin in early 2021, with completion and commissioning expected in late 2021. This is the company's first investment under SB 98; the request to defer costs for this project are included in UM 2145.

On System RNG Projects

NW Natural is also interconnecting various RNG projects to our own local distribution system. These include the City of Portland's Bureau of Environmental Services' Columbia Boulevard Wastewater Treatment Plant; the Eugene-Springfield Water Pollution Control Facility; and the Shell New Energies Junction City biomethane facility. The Company will be buying the natural gas from these projects but the renewable credits are currently being managed by the project owners and will be directed to other markets. As such, these projects will not count toward NW Natural's SB 98 targets. These three projects are expected to come online in 2021.

Potential RNG Resources

There are many pathways to obtain renewable and low-carbon molecules to deliver requisite energy amounts through the natural gas system not only now, but also well into the future. The sources vary geographically as well; projects are being constructed in our region, many parts of the country, and world-wide wherever low-cost feedstock can be obtained. These multiple pathways provide competition to lower costs and increase resilience of supply in the case of any issues with feedstocks used to create the gas.

[10] For comparison purposes, NWN uses 56g/MJ for the CI of conventional natural gas. This assumes direct use of gas by customers whereas CI scores within the California LCFS also include energy losses due to the compression or liquefaction required to use RNG as a transportation fuel.

Most of the pathways use mature technology, and the projects are increasing not only in number, but in size, which is critical to reducing costs. The following sections present non-traditional sources of renewable gas (i.e. other than waste water treatment plants, landfills, and animal waste) which are in various stages of development.

Woody Biomass

The forest industry is one of the largest resources in the Pacific Northwest, and provides an opportunity for producing renewable energy and jobs, and keeps energy expenditures in the states where the energy is produced. Two processes are largely used to create hydrogen from woody biomass: pyrolysis and gasification. Both of these processes create synthetic gas or syngas, and a subsequent methanation process can be used to create renewable natural gas for standard injection into the gas grid.

In 2018, the Oregon Department of Energy produced an inventory report[11] of available sources of renewable natural gas in the state of Oregon, and concluded that there is almost 40 billion cubic feet of annual methane production potential from forestry harvest residuals alone. Significant developments in this space are underway in British Columbia, with additional projects being planned for Washington and other areas of North America.

The costs for RNG derived from Woody Biomass is still at the higher end of the spectrum; however, building large-scale projects reduces costs and availability of this renewable gas which is anticipated to be available in the near future.

Hydrogen and Power to Gas

As part of a portfolio of low-carbon gas supplies, hydrogen and synthetic methane provide pathways to essentially unlimited volumes which would be delivered through the gas system. The gas industry is currently targeting a maximum blend of 20% hydrogen in the existing gas system with minimal impact on downstream appliances and the system itself. The remaining 80% of the gas will be a mixture of RNG and methanated hydrogen. Dedicated 100% hydrogen systems may also be required for industries moving exclusively to this fuel, which include medium and heavy-duty over-the-road transportation, maritime, and aviation. As a point of clarity, green hydrogen is hydrogen sourced from non-fossil sources.

Blue Hydrogen

Blue hydrogen is 100% hydrogen gas that is derived from traditional natural gas sources through steam methane reformation (SMR), and is coupled with capture and sequestration of the associated carbon dioxide (CO_2). The SMR process is mature and efficient, and is the predominant method of creating hydrogen today worldwide. The $CO_2$is typically injected into depleted oil wells on land or at sea, and remains there permanently. The carbon intensity of blue hydrogen is estimated to range from 19.6 to 34.5 g CO2e/MJ[12].

Benefits of using blue hydrogen include leveraging the industry's existing production assets and resources, it relies on a very low cost of energy, and it could be scaled up and plentiful in less time than

[11] https://www.oregon.gov/energy/Data-and-Reports/Documents/2018-RNG-Inventory-Report.pdf
[12] https://www.pembina.org/reports/hydrogen-climate-primer-2020.pdf

other low carbon gases. Canada has released its hydrogen strategy[13], which identifies blue hydrogen as a key resource for internal use, but also for exporting to the US. This hydrogen may be delivered through new hydrogen transmission lines or repurposed natural gas lines and blended into regional distribution systems, or delivered directly to customers through dedicated hydrogen distribution systems.

In addition to sourcing blue hydrogen from existing natural gas locations, blue hydrogen could potentially be produced in our region. Significant saline and basalt formations exist in Oregon and Washington, and could be used to sequester significant amounts of CO_2. The US Department of Energy[14] estimates there is enough storage in Oregon for 6.81 to 93.70 billion metric tons of CO_2, which using Oregon DEQ 2019 greenhouse gas emissions data[15] equates to 400 to 5500 years' worth of sequestration for the state of Oregon's overall natural gas usage. This does not include off-shore storage, or storage in Washington state.

Predicted costs for blue hydrogen are a fraction of the cost (one half to one third) of electrolytic hydrogen, which is discussed in more detail below.

Power to Gas

Electrolytic Hydrogen

Hydrogen derived through electrolysis from low-carbon renewable electricity is another source of renewable gas. This gas becomes cost competitive with RNG at scale and when the cost of electricity is low. Just like the price of conventional and renewable natural gas depends on location, different areas of North America have renewable electricity prices at low enough levels to make them attractive as sources for renewable gas. These areas are typically in the "wind belt", where wind resources are abundant and often constrained due to limited transmission capacity; however, areas of Canada also have very low cost, and low carbon electricity available.

Along with the low cost of electricity, size is critical; accessing these opportunities is through large-scale projects, whereby economies of scale can be realized. Large power to gas plants (e.g. greater than 40MW) could be constructed to produce hydrogen near low-cost power, and inject the gas into the natural gas transmission or distribution system, which creates renewable thermal credits through M-RETs, which could be retired for Oregon and Washington customers benefit.

Locating large power-to-gas projects in our region would be preferable for a number of reasons. The economic benefits would be captured within each state, and the ancillary grid benefits could also be leveraged by local utilities. These include voltage stabilization, demand response, and avoidance of operating reserve costs, which is enabled through fast-acting electrolyzers. There would also be larger avoided costs by having renewable gas enter the distribution system directly. Until electricity rates in the region reflect these benefits, large power to gas plants will likely be located elsewhere to produce the lowest cost, low-carbon energy.

Hydrogen is currently not being blended directly into any portions of the gas system in North America, save for some small pilot projects at the distribution level. Until such time that blending is possible,

[13] https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf
[14] https://www.netl.doe.gov/sites/default/files/2018-10/ATLAS-V-2015.pdf
[15] https://www.oregon.gov/deq/FilterDocs/GHGNatGasSuppliers.xlsx

electrolytic hydrogen will need to be methanated (i.e. combined with carbon, typically from a waste CO_2source) to produce synthetic methane.

Synthetic Methane

By combining carbon with hydrogen, synthetic methane can be produced using mature technology at reasonable efficiencies. This low carbon gas is completely compatible with midstream and downstream systems and appliances, and requires limited to no consideration of blend limits. Similar to electrolytic hydrogen projects mentioned previously, scale and location are critical factors. One additional factor; however, is the need for a consistent, low cost source of CO_2.

Synthetic methane produced at locations and at large enough scale (e.g. 40 MW and greater) can provide large volumes of low carbon gas today, and in the near future when direct hydrogen blending is possible, these plants can be repurposed to produce hydrogen only at higher volumes and lower costs. The carbon intensity of synthetic methane depends entirely on the source of the electricity, as the carbon added to make the methane molecules is a pass through, and is only an energy carrier for the hydrogen.

The first synthetic methane project for our region is currently being planned through a partnership between NW Natural, the Eugene Water and Electric Board (EWEB), and the Bonneville Environmental Foundation. The proposed pilot power to gas plant will be located in Eugene, and is currently being estimated to be 2-10MW in size, and will combine hydrogen created through electrolysis with carbon gathered from local industrial emission sources to produce the low-carbon gas. Although this project is anticipated to produce a relatively small amount of gas (approximately 76,000MMBtu annually), it will provide essential learnings for large scale projects to be as efficient as possible, both in construction and operation.

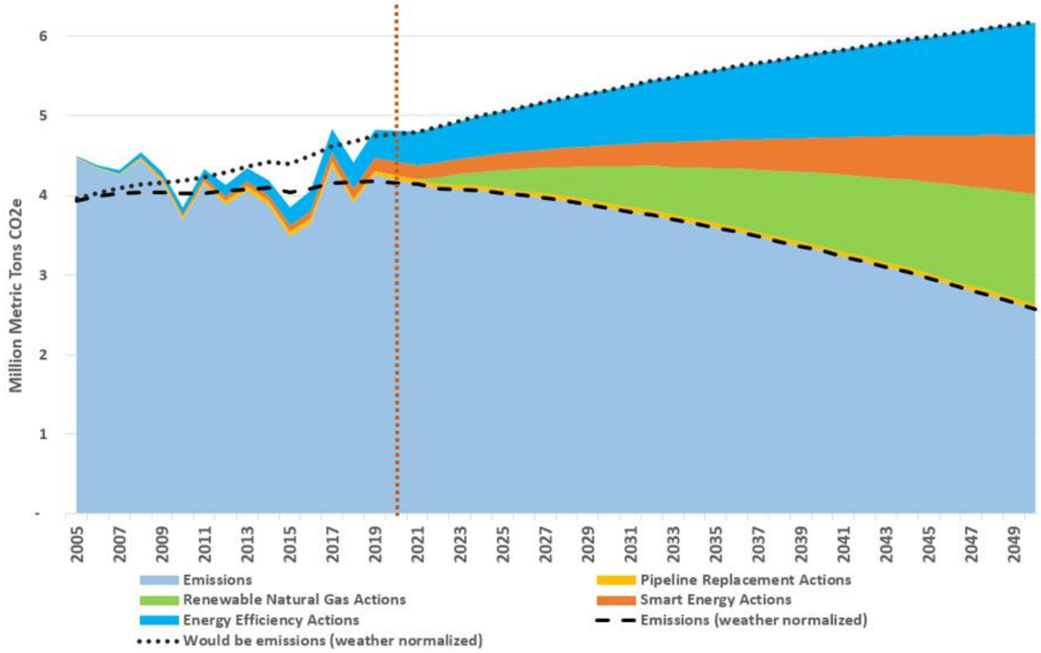
Ammonia

The Haber-Bosch process is used to convert hydrogen into ammonia by combining it with nitrogen from the air at high pressure and temperature. The process itself is energy intensive, but the final product of a liquid at modest pressures or temperatures that can be converted back to hydrogen and nitrogen relatively easily, and therefore lends itself to an efficient way of transporting hydrogen. It has a global warming potential of zero, and has a large existing supply chain. Recently, a few large ammonia projects located in the middle east have been announced, which could provide new supplies of low-cost hydrogen worldwide at very large scale, and could be delivered to the region by ships. Solar electricity is predominantly being used as the feedstock, which makes the derivative hydrogen a near-zero carbon intensity gas.

2.H Emissions Forecast

Incorporating the updated load forecasts and the expectations from OR SB 98, OPUC UM 2030, and WA HB 1257 NW Natural has updated its emissions forecast, which is shown in Figure 7.

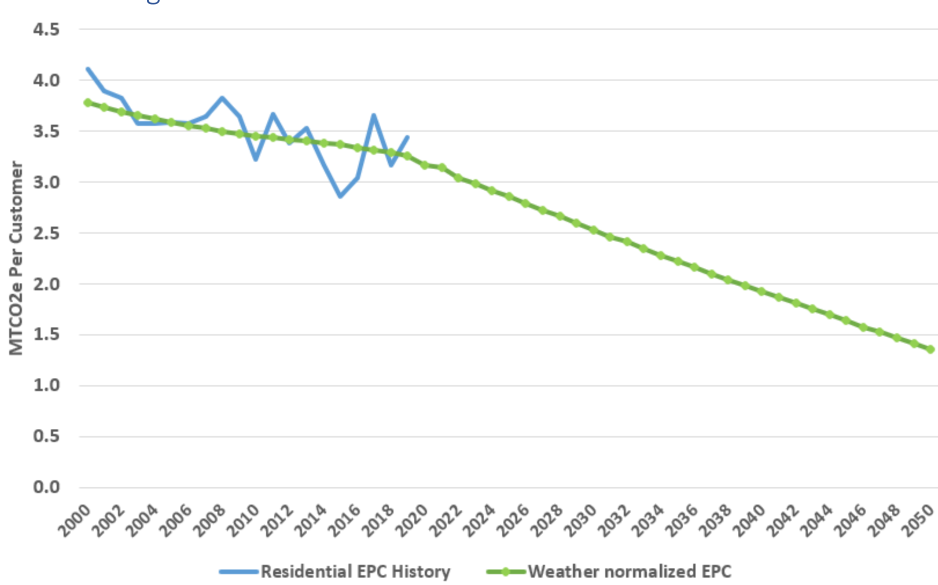
Figure 7: NW Natural Emissions Forecast Update



Note also that (i) the emissions from load on sales schedules are shown, (ii) actual emissions will always be “noisy” due to weather variation from year to year where emissions are higher than normal weather expectation in years with colder than typical heating seasons (and lower for milder than typical heating seasons), and (iii) the forecast does not include expected impact of ODEQ’s cap-and-reduce program, other EO 20-04 related initiatives, or prospective legislation being considered in the 2021 session.

Incorporating the expected emissions expectations with the residential use per customer forecast discussed above results in the average NW Natural residential customer projected to contribute annual emissions along the trajectory shown in Figure 8.

Figure 8: Residential Per Customer Emissions Forecast



Section 3: IRP Update Projects

3.A North Coast Feeder

Distribution System Planning – Brief Overview

NW Natural plans and manages its distribution system to safely and reliably meet the demands of its customers under all potential weather conditions. The need for distribution system reinforcement can be identified through system modeling, recorded data, or (less commonly) reported issues indicating conditions that violate the Company's system standards in a given geographic area. These system reinforcement standards, which ensure safe and reliable service, are outlined in Appendix C.

Once a need is confirmed, the Company performs a thorough set of engineering and economic alternatives analyses to identify a least-cost, least-risk means to meet customers' needs. Conventional engineering project alternatives include:

- Pipeline construction
- Equipment addition (e.g., district regulators, compressor stations)
- Additional gas supply (e.g., gate station changes)
- Operating pressure uprates

The objective is to identify the most efficient, least cost, least risk conventional solution that solves the identified issue. NW Natural validates the identified solution with system modeling to verify effectiveness.

Against this solution, the Company compares the viability and efficiency of non-pipeline supply side options (i.e., satellite LNG facilities) as well as demand side solutions that may help defer or avoid infrastructure investments. One such potential demand side alternative is targeted interruptible schedule agreements, a form of demand response for large industrial and commercial peak loads. NW Natural begins the assessment of this alternative by examining historical loads of current larger non-residential firm service customers in the area of impact. If the estimated peak usage by these customers is potentially of sufficient volume to materially defer (or eliminate) the need to implement a supply-side solution, NW Natural would then conduct additional analysis regarding whether customer-specific geographically focused interruptibility agreements could be negotiated with these customers.

NW Natural is committed to advancing additional demand-side alternatives for meeting system needs; a pilot project studying options for geographically-targeted energy efficiency investments (GeoTEE) is currently underway through a partnership with Energy Trust, and the Company will be filing a study of demand response options for residential and non-residential loads with its 2022 IRP.

North Coast Feeder System Reinforcement Project

In 2018, the Company identified a potential distribution system reinforcement need in the northwest corner of its Oregon territory. The issue was first identified through system modeling, and verified with data gathered directly from equipment in the field. During both 2019-20 and 2020-21 heating seasons, pressure recorders in the field captured low-pressure events in violation of the Company's system reinforcement standards. These violations indicate an unacceptable risk to the Company's ability to safely and reliably serve its current customers in the area.

The supply side option identified as best suited to address the system reinforcement needs is a pipeline uprate and limited concomitant equipment installation in the affected area. The Company also completed alternatives analyses of both targeted interruptible agreements and the siting of a satellite LNG facility. It was determined that potential interruptible schedule agreements with the limited number of large customers in this region would be insufficient to avoid the need for additional capacity in the area, and cost estimates for a satellite LNG facility far exceed the cost of the selected uprate project.

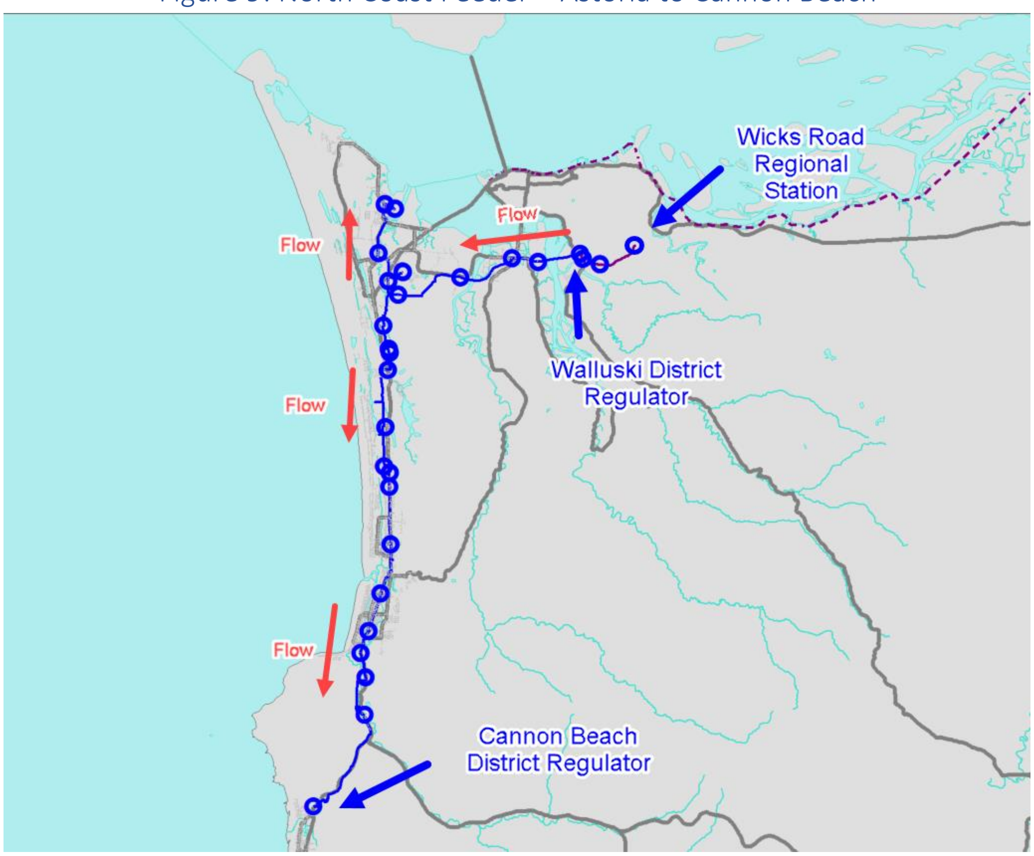
The lead time for this project is estimated to be 9 to 12 months. Because this project is required to meet the existing need of existing customers within the area, it is planned to begin in 2022.

A detailed description of a violation of the Company's system reinforcement standards along NW Natural's North Coast Feeder, an analysis of the proposed system reinforcement project solution and the alternatives considered follows in the next section.

System Analysis and Issues

In 2018, Synergi modeling results indicated that the North Coast high pressure system has low pressures at the inlet of the Cannon Beach district regulator. The Cannon Beach district regulator is fed from a single 175 MAOP high pressure line by the Walluski district regulator from the north. The low-pressure results found in the model are caused by high velocity gas traveling 26.7 miles from the Walluski district regulator to the Cannon Beach district regulator.

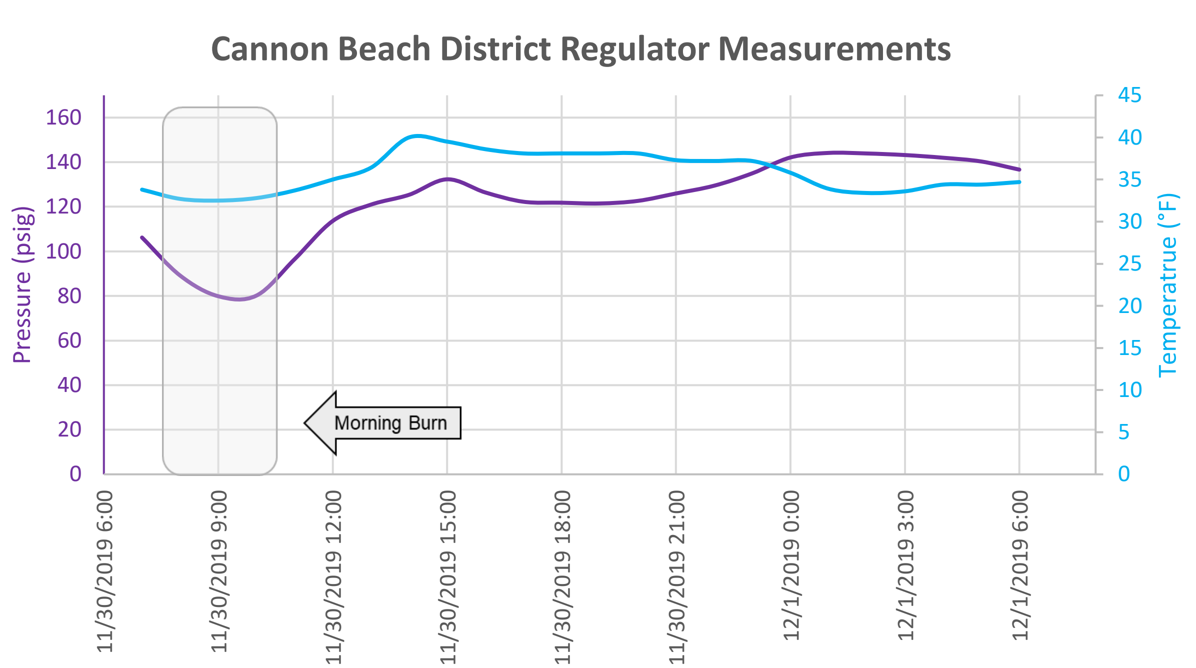
Figure 9: North Coast Feeder – Astoria to Cannon Beach



The low pressures found in the hydraulic model led to a request by the Engineering to site an Electronic Portable Pressure Recorder (EPPR) at the inlet of the Cannon Beach district regulator. An EPPR is a measuring device that can record attributes such as temperature and pressure to obtain system performance. Placing an EPPR at the inlet of the Cannon Beach district regulator allows NW Natural to monitor pressures at the end of the 175 MAOP system. Monitoring of the inlet of the Cannon Beach district regulator commenced during the 2019-2020 heating season.

During the month of November 2019, data retrieved from the EPPR revealed that the Cannon Beach district regulator inlet pressure fell below 80 psig when the Walluski district regulator was set at 162 psig. The findings of the EPPR data supported the pressure losses identified in the model because the pressure dropped by 50.7% from the Walluski district regulator to the inlet of the Cannon Beach district regulator. NW Natural's high-pressure reinforcement parameters include addressing pressure drops that exceed 40%. A system with a pressure reduction of 40% equates to an 80% level of capacity utilization. During this low-pressure event, the EPPR case temperature during this day revealed that Cannon Beach experienced a 29-heating degree day (36°F). Figure 10 illustrates the pressure sagging below 80 psig on 11/30/2019 at around 9:00 AM.

Figure 10: November 30, 2019 Intraday Temperature and Pressure



The low pressures recorded on the EPPR at the inlet of the Cannon Beach district regulator led to a request by Engineering to increase the set point of the Walluski district regulator from 162 psig to 166 psig in December 2019. Since this pressure increase, the lowest pressure recorded at the inlet of the Cannon Beach district regulator was 109 psig (34.2% drop), which occurred on a 28-heating degree day (37°F). Although this pressure reading did not exceed the 40% planning criteria, the measurement is still concerning considering that the demands during the day were nowhere near peak levels.

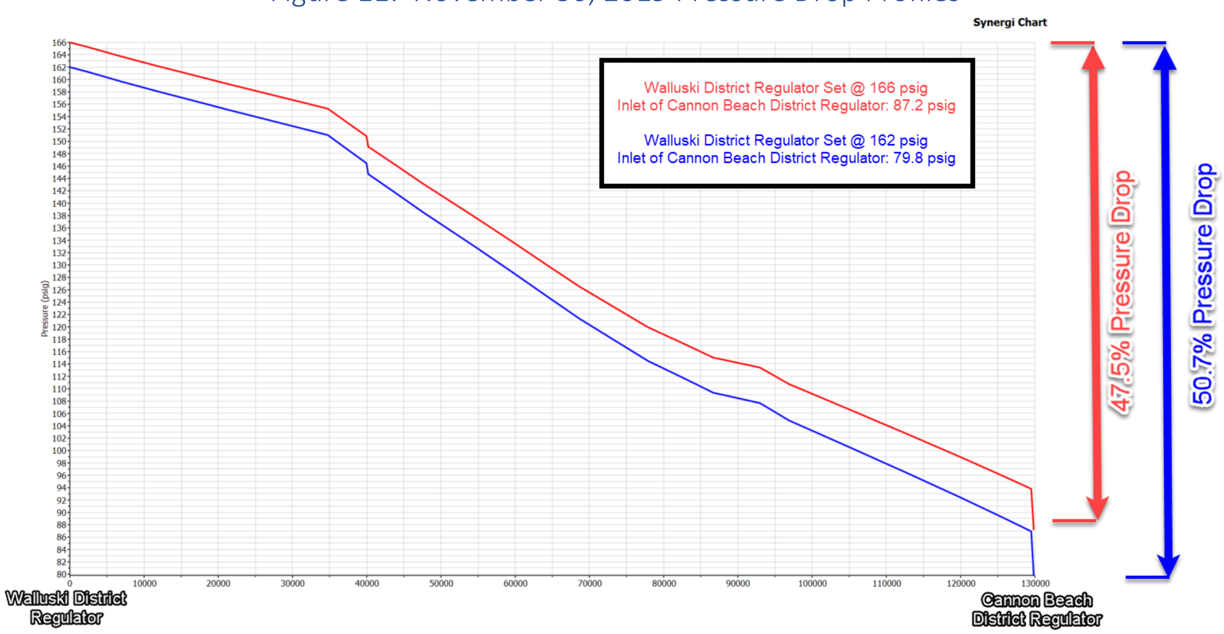
A model was developed to evaluate what the Cannon Beach district regulator inlet pressure would be during the 11/30/2019 event with the Walluski district regulator set at 166 psig instead of 162 psig. This model was established with the following conditions:

1) The demands in the model are equal to the low-pressure event that occurred on 11/30/2019

2) The Walluski district regulator is set to 166 psig instead of 162 psig

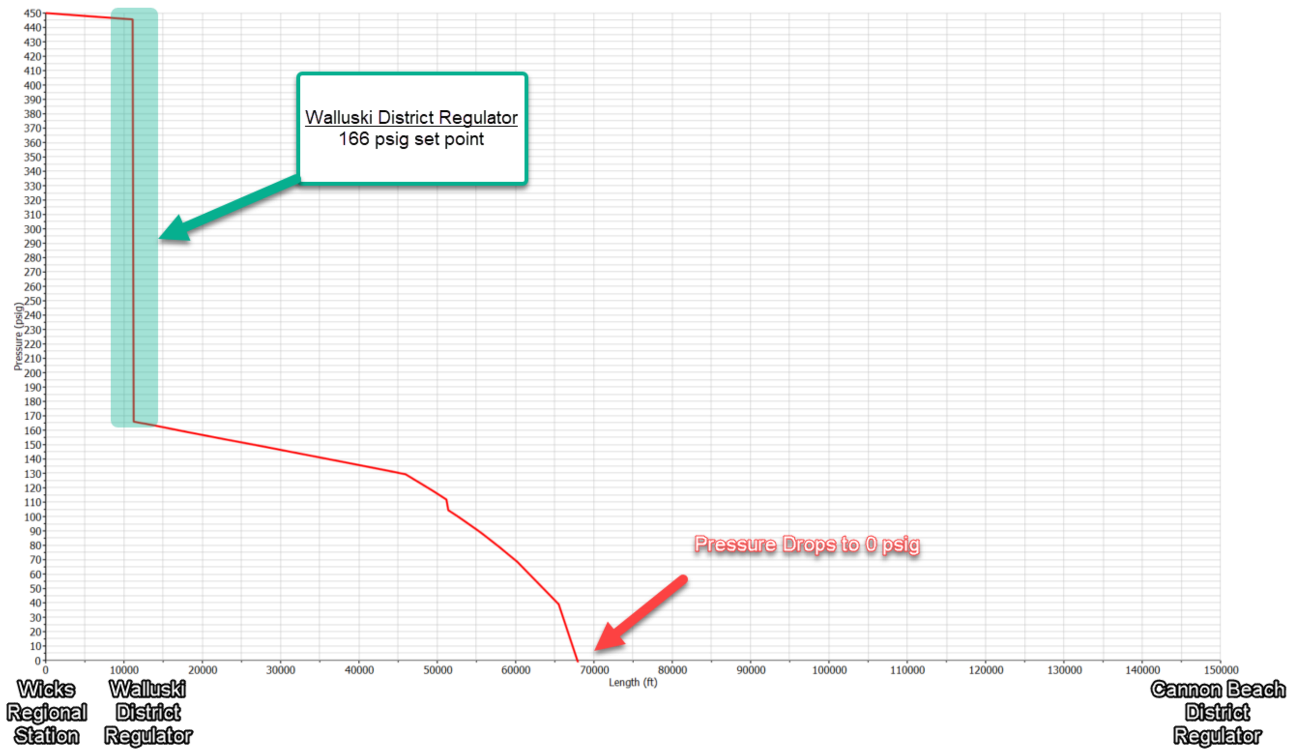
The two conditions were met by tuning the demands of the North Coast model so that the inlet of the Cannon Beach district regulator was between 79 and 80 psig, while the Walluski district regulator set to 162 psig. After the model was tuned, the set pressure of the Walluski district regulator was raised from 162 psig to 166 psig. Thus, the demands would remain constant and the only modification to the system is the higher set point at the Walluski district regulator. The model results indicated that if the Walluski district regulator was set at 166 psig, then the inlet of the Cannon Beach district regulator would have measured 87.2 psig. The corresponding pressure drop for the high-pressure line equals 47.5%. Since 47.5% exceeds the 40% pressure drop criteria, it further validated the need to reinforce the North Coast 175 MAOP system. Figure 11 is the model results illustrating the pressure profiles for the demands found on 11/30/2019 for Walluski district regulator set points at 162 psig and 166 psig.

Figure 11: November 30, 2019 Pressure Drop Profiles



As there is no recorded data for extreme weather, a model was developed to establish pressure losses on the high-pressure line under a design day. This was accomplished by setting the Walluski district regulator to 166 psig and loading the demands equal to an extreme weather day. The model provided infeasible results because pressures on the high-pressure system plummeted to 0 psig. The pressure decrease is due to pipe losses from high velocity gas traveling over long distances from the outlet of the Walluski district regulator to the inlet of the Cannon Beach district regulator. A bulk of the line losses appear on small diameter pipe (6”,4” and 2”) between Rodney Acres (Plat 3-055-092) and the inlet of the Cannon Beach district regulator. With the Walluski district regulator set at the current pressure of 166 psig, the model runs indicate that the pressure drops to zero at approximately 12.8 miles downstream of the Walluski district regulator outlet. Figure 12 illustrates this pressure drop.

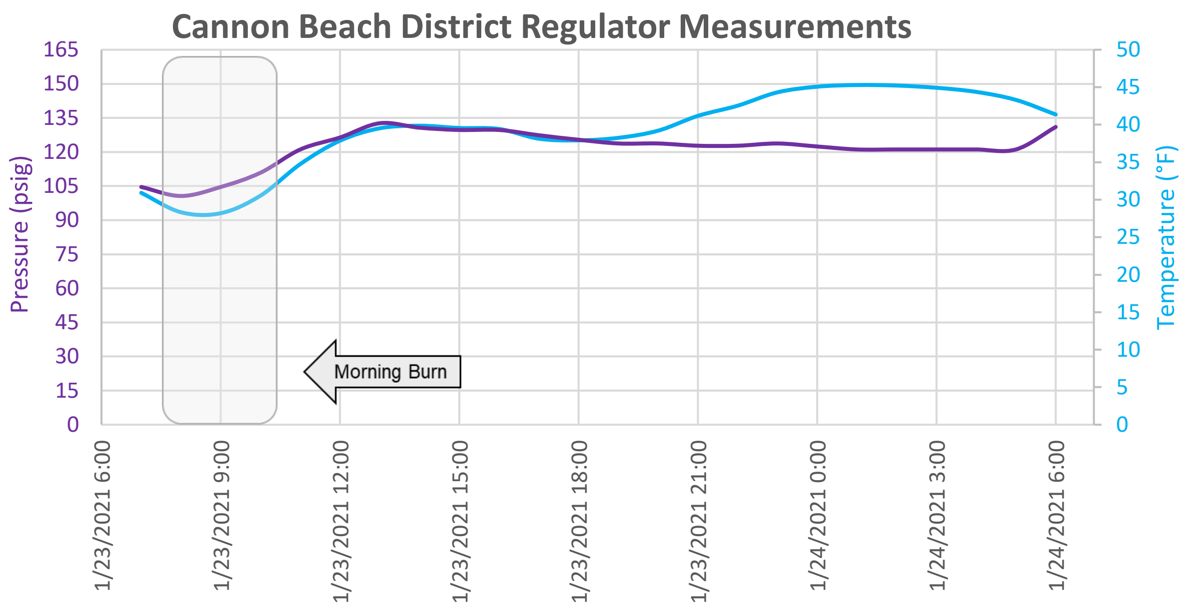
Figure 12: November 30, 2019 Pressure Drop Profile



Recent Developments

At the beginning of the 2020-2021 heating season, an EPPR was installed on the Cannon Beach District Regulator to continue monitoring pressures at the end of the North Coast Transmission Feeder. On January 25, 2021, a dataset was extracted from the EPPR which includes a 40% pressure drop violation. The low-pressure measurement appeared on January 23, 2021, where the EPPR recorded a measurement of 93.1 psig at the inlet of the Cannon Beach District Regulator. The low pressure reading took place while the Walluski District Regulator was set to 165 psig. A pressure reading of 93.1 psig indicates that the North Coast Transmission Feeder experienced a 43.6% pressure drop from the outlet of the Walluski District Regulator to the inlet of the Cannon Beach District Regulator. During this low-pressure event, the case temperature corresponded to a 28-heating degree day (37°F). The EPPR measurements record confirms the model results provided in the previous sections. Figure 13 highlights the temperature and pressure on January 23, 2021.

Figure 13: Cannon Beach District Regulator Measurements



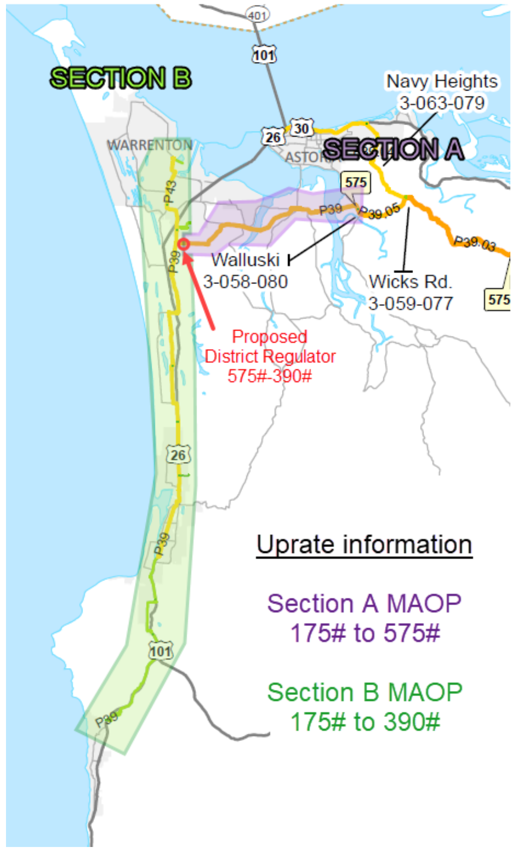
Proposed Project

The recommended improvement consists of uprating the North Coast Transmission Feeder west of the Walluski district regulator. The proposed uprate is broken into two sections, Section A and Section B.

Section A consists of uprating the 8"(W) high pressure main between Walluski District Regulator to Rodney Acres Road from a MAOP of 175 psig to a MAOP of 575 psig. After the uprate, Section A will be classified as transmission because it will be operating above 20% SMYS due to the proposed uprate. Uprating Section A allows for the abandonment of the Walluski district regulator because the line east of the regulator station is already operating at a MAOP of 575 psig.

Section B includes uprating the high pressure system west of where the 8"(W) terminates near Rodney Acres Road. The uprate for Section B will uprate the section of pipe from a MAOP of 175 psig to a MAOP of 390 psig. Section B will still be classified as high-pressure distribution because the MAOP is set below the definition of transmission. Figure 14 below provides a general overview of the uprating followed by a more detailed description of the scope of the uprates.

Figure 14: Uprate Project Overview Map

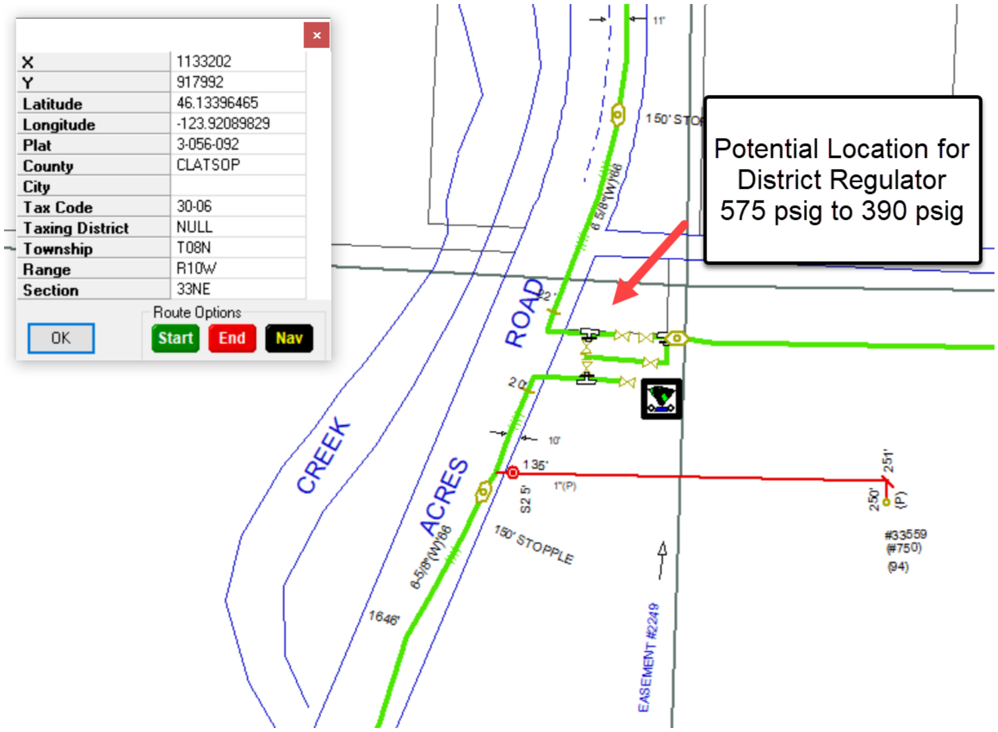


Section A

Section A consists of uprating the pipe, appurtenances and fittings between Walluski district regulator and Rodney Acres Road from a MAOP of 175 psig to a MAOP of 575 psig. The maximum pressure of the line west of Walluski can be taken to stay below the definition of transmission (20% SMYS) is 300 psig. This is due to the 8" Grade B pipe between the Walluski district regulator outlet and Rodney Acres Road (Plat 3-055-092). Added cost associated with placing the high pressure from distribution to transmission include but are not limited to additional testing and the installation of a pig launcher and receiver.

After the uprating, the entire section between Rodney Acres Road and Wicks regional station will be operated at an MAOP of 575 psig. Therefore, the regulation at Walluski will no longer be required after the pipeline has been uprated and will be abandoned. However, a new high-pressure district regulator will be required between Section A and Section B to control pressures between the 575 MAOP system to the 390 MAOP system.

Figure 15: Uprate Details



Section A Summary:

- Uprate approximately 6.6 miles of high pressure main
- Potentially uprate/replace inlets to 3 district regulators
- Potentially uprate/replace 1 service regulator inlets
- Abandon Walluski district regulator
- Wicks regional station upgrades
- Install new district regulator near Rodney Acres Road
- Construction of a pig launcher and receiver

<u>Section B</u>

Section B consists of uprating the high-pressure pipe downstream of the proposed district regulator on Rodney Acres Road from Warrenton to Cannon Beach from a MAOP of 175 psig to 390 psig. Uprating to 390 psig keeps the Section B at high pressure distribution classification.

Section A Summary:

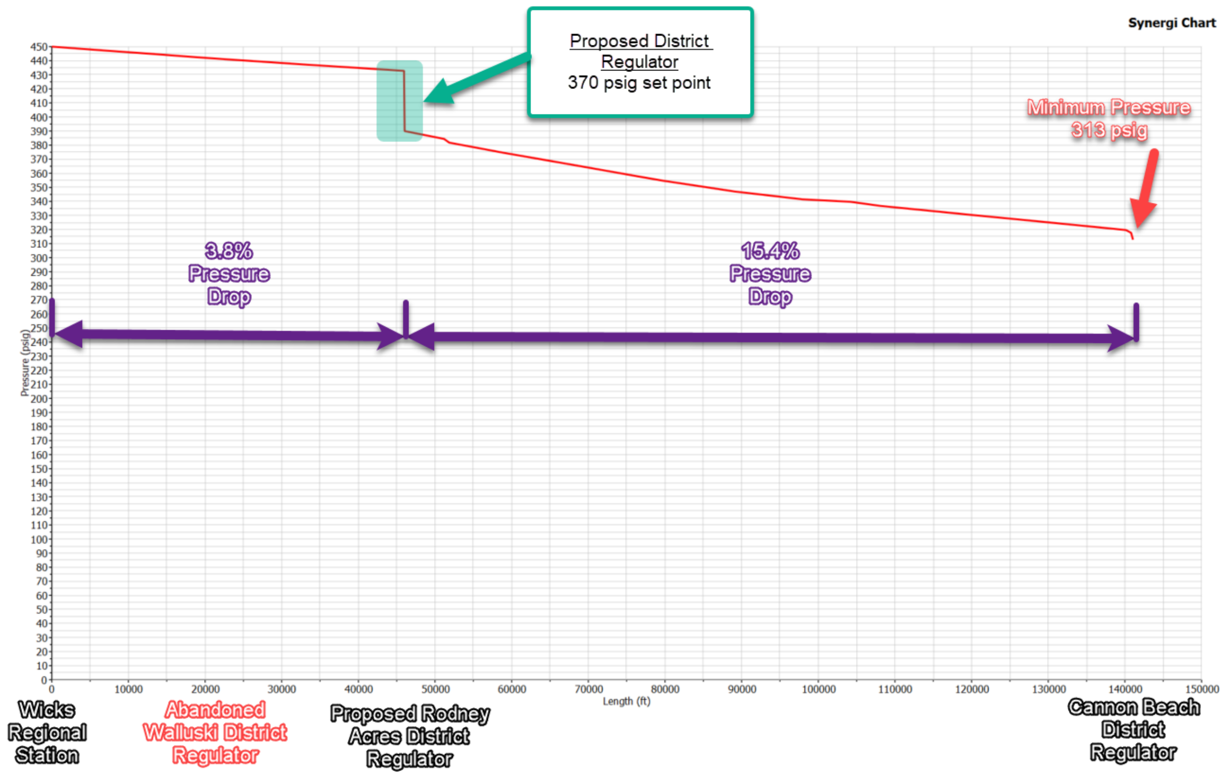
- Uprate approximately 22.2 miles of high pressure main
- Potentially uprate/replace inlets to 10 district regulators

- Potentially uprate/replace 10 service regulator inlets

Uprate Model Results

Although section A was uprated to an MAOP of 575 psig, during an extreme weather event would be for lower than the normal operating pressure because of higher demands. Taking peak usage into consideration, the model pressure was set to 450 psig at the Wicks Road regional station. The final model results conclude that the inlet of Cannon Beach district regulator will see a pressure of 313 psig during a peak day with the uprating. The modeling reinforces that the uprate adequately serves existing demands and should satisfy potential growth on the North Coast for the foreseeable future. Figure 16 shows the pressure drop from Wicks Regional Station to Cannon Beach district regulator with the proposed section A and section B system reinforcements.

Figure 16: Pressure Drop Profile After Uprate Project is Completed



Alternatives Analysis

NW Natural investigated the viability of targeted interruptible schedule agreements within the affected area as an alternative to system reinforcement as outlined above. This particular region of the state includes a relatively small number of large firm load customers, and system modeling indicated that voluntary curtailment of these loads would not be sufficient to avoid the need for additional peak capacity in the area.

NW Natural also assessed the option of siting a satellite LNG facility to add peaking capacity to the impacted area of the distribution system. Though such a facility could provide the required capacity, the estimated cost of the project - far exceed that of the proposed pipeline uprate project. Table 5 summarizes the costs of the proposed project and satellite LNG option.

Table 5: North Coast Feeder System Reinforcement Alternatives Costs

Alternative	Estimated Cost (with COH)	20-year PVRR
Feeder Uprate	$4.6M - $9.1M	$5.1M - $10.2M
Satellite LNG Alternative	$19.6M	$26.3M

3.B Newport Cold Box

Newport LNG Background

The Newport LNG Plant (Newport) is located in Newport Oregon at the western end of NW Natural's Central Coast Feeder Pipeline (See Figure 9). The Central Coast Feeder Pipeline runs approximately 90 miles from Williams NW Pipeline McMinnville-Amity Gate Station to Lincoln City and south to Newport. This pipeline serves as the sole source of natural gas to the towns of Lincoln City, Newport and the surrounding communities and the primary source of gas for McMinnville, Sheridan, Willamina, Dallas, Independence, Monmouth and many other smaller communities during peak events.

It consists of a 1,008,500 Dth capacity storage tank, liquefaction facilities capable of processing about 6,000 Dth/day, and vaporization capacity of up to 108,500 Dth/day. Due to CO_2 and seismic constraints the maximum fill level of the plant is at 90% full, or 976,500 Dth. Because the Company's pipeline system limits Newport to serving the central coast and Salem market areas, the full 108,500 Dth/day vaporization rate is not achievable. Instead, 65,100 Dth/day is the effective limit on vaporization at Newport.[16] The Newport LNG plant (Newport) was constructed by Chicago Bridge and Iron and commissioned in 1977. The facilities and major process components of the Newport LNG plant were designed for a nominal 25-30-year life and Newport is now 44 years old. The Company has replaced many of the primary components of the facility over the last few years.

Primary Role Played by Newport LNG

Newport is a valuable resource for meeting our customer's peak needs. To understand the operational significance of the Newport LNG facility, it is important to first provide background information about the Company's storage facilities. NW Natural relies on four existing storage facilities to augment the supplies transported from British Columbia, Alberta and the Rockies. These consist of underground storage at Mist and Jackson Prairie, along with LNG plants located in Portland (referred to as PDX-LNG) and Newport, Oregon. The Company owns and operates Mist, PDX-LNG, and Newport LNG, all of which reside within the Company's service territory. These three storage facilities are considered 'on-system'

[16] All of the values listed are based on a gas heat content of 1,085 Btu/cf

gas supply resources. Gas is typically placed into storage at these facilities during off-peak periods, which is also known as 'injecting' (for underground storage) or 'liquefaction' (for the LNG facilities). When needed, these on-system resources do not require further transportation on the NW Pipeline interstate pipeline system, but rather use 'withdrawal' or 'vaporization' from Mist or the LNG facilities, respectively, to supply gas directly to NW Natural's system.

In contrast, Jackson Prairie storage is located about 80 miles north of Portland near Centralia, Washington, i.e., outside the Company's service territory. Jackson Prairie has been owned and operated by other parties since its commissioning in the 1970s. The Company contracts for Jackson Prairie storage service from NW Pipeline, which also contracts separately for the transportation service from Jackson Prairie to the citygates to NW Natural's system.

Table 6 shows the daily supply capacity of these resources.

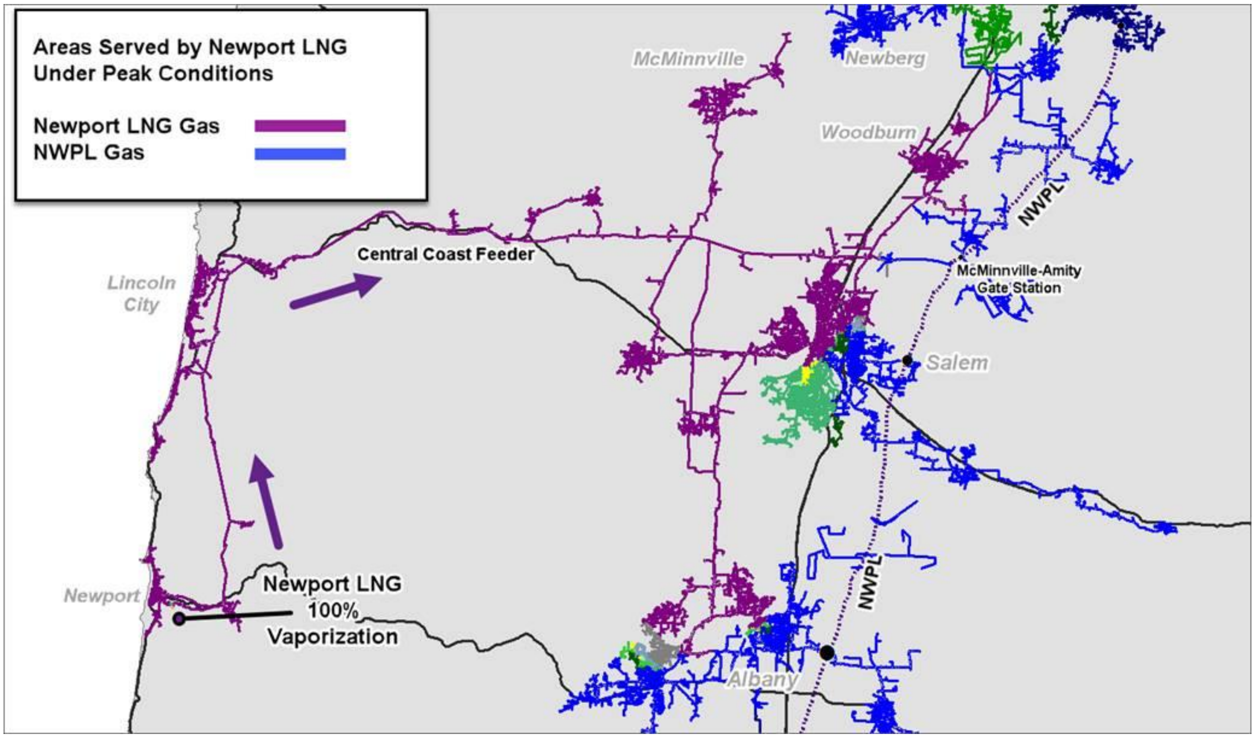
Table 6: Firm Storage Resources[17]

Facility	Maximum Daily Rate (Dth/day)
Jackson Prairie	46,030
Mist (reserved for core)	305,000
Newport LNG	65,100 *
PDX-LNG	129,480 *

Figure 17 shows how the gas from the facility flows under peak conditions to the coastal and southern service area of NW Natural's system.

[17] The numbers in Table 6 with an asterisk originated from volumetric units (e.g., Bcf) that have been converted to energy units (Dth) using the current heat content (Btu per cf) of the applicable facility. The other numbers included do not need to be adjusted for heat content because they originate from contracts (Jackson Prairie) or deliverability calculations (Mist) that are specified in energy units.

Figure 17: Newport LNG Gas Flows



Additional Roles the Newport LNG Facility Plays

The Newport plant serves as not just a wintertime peaking supply but as a source of supply for emergency situations and pipeline maintenance. Any significant damage or event along the 90-mile-long pipeline length can interrupt gas flow which could cause outages to thousands of customers downstream of the event if an alternate supply (Newport LNG) were not available. The Newport LNG plant represents a source of supply that can be used to maintain reliable service to customers.

The Echo Mountain Wildfire in September 2020 served as an example of this capability as it damaged the primary district regulator station serving Lincoln City. To safely operate NW Natural's high-pressure system, a portion the Central Coast Feeder pipeline was shut down near Lincoln City to reduce risk and damage. While the segment of the Central Coast Feeder was shut down, the primary gas feed from the Williams NWPL McMinnville-Amity gate station was severed. During the shutdown, the Newport LNG plant was used to continue serving approximately 10,000 customers in Newport, Toledo and Lincoln City. Newport LNG gas was used to serve affected customers from September 9, 2020 through September 16, 2020. The Central Coast Feeder was reestablished to regular operations on September 16 after state fire managers determined it was safe to do so.

Cold Box Project Background

The Cold Box is an essential component in an LNG liquefaction plant, it is where natural gas is cooled to cryogenic temperatures to convert the gas to liquid. Once liquefied, it is pumped from the Cold Box to the onsite insulated storage tank where it can later be used in the winter. A Cold Box, see Figure 18, is made up of multiple aluminum heat exchangers, which are stacked on top of each other and encased in a single unit measuring approximately 30 feet in height. The Cold Box at Newport LNG is 44 years old. This places it well past its design life and it is currently showing signs of its age through performance problems.

Figure 18: Cold Box Illustration

While an initial consultant recommended replacing the Cold Box in a 2014 study, it was later determined the estimate they provided for the cost of replacement was drastically low. Additionally, in 2016 NW Natural installed a new pretreatment system to address high CO_2 in the supply of gas, which was making it through the liquefier and into the LNG tank. The new pretreatment process dramatically improved the quality of gas entering the Cold Box. However, the original pretreatment design required additives such as methanol to be injected ahead of the Cold Box to absorb moisture. The methanol was then removed after liquefaction. This is no longer required. Nevertheless, Without the additive, contaminants were able to easily foul the Cold Box causing increased differential pressure in the system and reducing production. Inspections to understand this issue revealed contaminants on the interior surfaces within the Cold Box heat exchangers, which compound flow restriction issues caused by poor gas quality entering the system. The differential pressure is higher than design allows in the first two exchangers within the Cold Box. This is believed to be due to several issues, including internal contamination as shown in Figure 19 upon inspection. The Cold Box itself is not the only contributor to operational issues, as higher levels of heavy hydrocarbons are contained within the gas stream than were present at the time of the original design of the facility. Heavier hydrocarbons tend to freeze at higher temperatures and can create blockages in the system, which also contribute to higher operating pressures within the Cold Box.

Figure 19: Contaminated Heat Exchanger

After learning the original cost estimate from the consultant for Cold Box replacement was quite low NW Natural's engineering team reviewed a lower-cost alternative: to clean the Cold Box to improve its near-term operation and possibly extend its life. A consultant was engaged to perform the cleaning. After discussion with the consultant (a vendor of the manufacturer), an agreement could not be made to have the Cold Box cleaned that did not seem to introduce more risk to damaging the Cold Box, and it was not guaranteed to fix the problem.

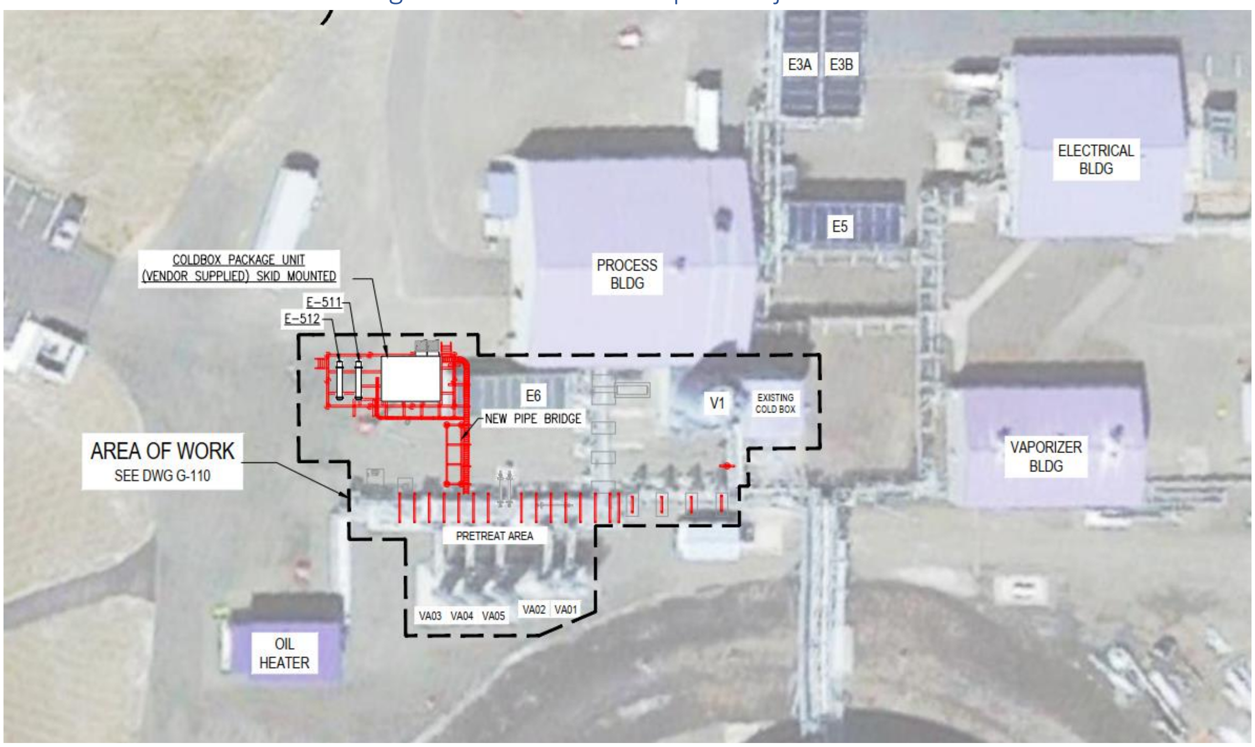
At this time NW Natural engaged another consultant that specializes in LNG to provide a report and recommendation specific to the Cold Box at the Newport facility. This study, completed by Sanborn, Head, and Associates determined that continued operation of the Newport LNG facility without replacement of the Cold Box and upgrading the pretreatment system equipment is not recommended and provided the following conclusions[18]:

> *Aging equipment – The design and construction of the existing Cold Box heat exchangers are outdated. Industry experience with this type of equipment has demonstrated that it is significantly more prone to failure than newer designs. This Cold Box has reached its end of life and should it fail, repair is most likely not possible. A failure and replacement could cause significant downtime for the facility, at least 1.5 years on the most accelerated schedule.*
>
> *Reliability - The current liquefaction system at Newport is unreliable. Ongoing issues with Cold Box freezing, and carbon dioxide (CO2) build-up in the storage tank require that upgrades including new equipment and system modifications be implemented.*
>
> *Modernization - Replacement of the Cold Box with a modern design would allow one heat exchanger to be installed in place of the existing two exchangers. This would improve system reliability and minimize downtime. It would also allow removal of the aging Cryex CO2 removal vessel. This vessel is a remnant of the previous (original) pretreatment system. Its removal would eliminate an original, 10,000-gallon LNG pressure vessel, which was installed in 1977, without any secondary containment.*

[18] From page 3 of the Sanborn Head NWN Cold Box Replacement Engineering Study

At this point the Cold Box replacement is necessary to be able to continue to rely upon Newport LNG as a firm resource to serve NW Natural's current needs. Should the Cold Box fail, the ramifications to the plant would be significant. A replacement unit would require approximately two years to install. Repairs to this type of equipment can be very costly or even impractical. If a failure occurred at the beginning of the production season, this would leave the facility without a reasonable means to refill the storage tank. As a result, all remaining LNG may boil off prior to equipment replacement (depending on the tank level at the time of failure), which in turn, would allow the large LNG tank to warm significantly, inducing stress on the tank due to thermal expansion. Customers would also be left without the benefit of backup storage to support periods of peak demand during cold weather or other supply constraints.

Figure 20: Overview Map of Project Area



Sanborn Head also identified potential improvements in the pretreatment system which could be implemented to ultimately aid in reducing stresses on the Cold Box. These suggested improvements are being addressed now. This project and a broader update on activities at the Newport LNG facility can be found in Appendix E.

Cost Estimate of Cold Box Replacement

Table 7 lists the major project components as well as their costs. These capital costs include a 30% contingency. For the total costs for the cost-of-service modeling there are also additions for allowance for funds used during construction (AFUDC) and associated taxes. There is also a 3% cost of overhead adder bring the total for COS modeling to just over $18 million.

Table 7: Newport Cold Box Cost Estimates

Project Components	Cost (includes 30% Contingency)
Engineering & Overhead	$4,275,793
Major Equipment	$4,384,600
Demolition	$594,935
Civil/Site Construction	$1,166,853
Structural Construction	$1,348,780
Mechanical Construction	$2,953,791
Electrical Construction	$734,563
Instrumentation/Control	$1,490,819
Startup and Commissioning	$318,500
Training	$71,500
Freight	$260,694
Subtotal	$ 17,600,827
COH 3%	$528,750
AFUDC/Taxes	$24,172
Total	$ 18,153,747

Alternatives Analysis

For the alternative to replacing the Cold Box the Company looked at solutions similar to those in the 2014 IRP. The alternatives examined then are still the alternatives most appropriate to examine today. These alternatives are discussed below.

<u>Alternative A:</u> Contract with NWP for additional pipeline capacity from Sumas south to city gates on NWP's Grants Pass Lateral

<u>Alternative B:</u> Construct a 25-mile-high pressure transmission facility between Newburg and the Central Coast Feeder coupled with additional Mist Recall

To receive the same capacity benefit of Newport, Alternative A would require annual demand payments of $23-$43 million, in addition to potential gate station and distribution upgrades. Table 8 shows the potential costs associated with additional capacity additions.

There are two possibilities for securing additional pipeline capacity, with the least expensive option being a regional expansion from Sumas to Molalla. This would occur in the event NW Pipeline held an open season and could justify the expansion based upon demand from multiple parties in addition to NW Natural (i.e. this option in not in NW Natural's control and is unlikely to be a viable option in the near term). An estimated cost for capacity under this option is $0.98/Dth/day. The higher cost option would require NW Natural to contract with NW Pipeline for a NW Natural-specific buildout. Estimated costs here are nearly double the regional expansion at $1.80/Dth/day.

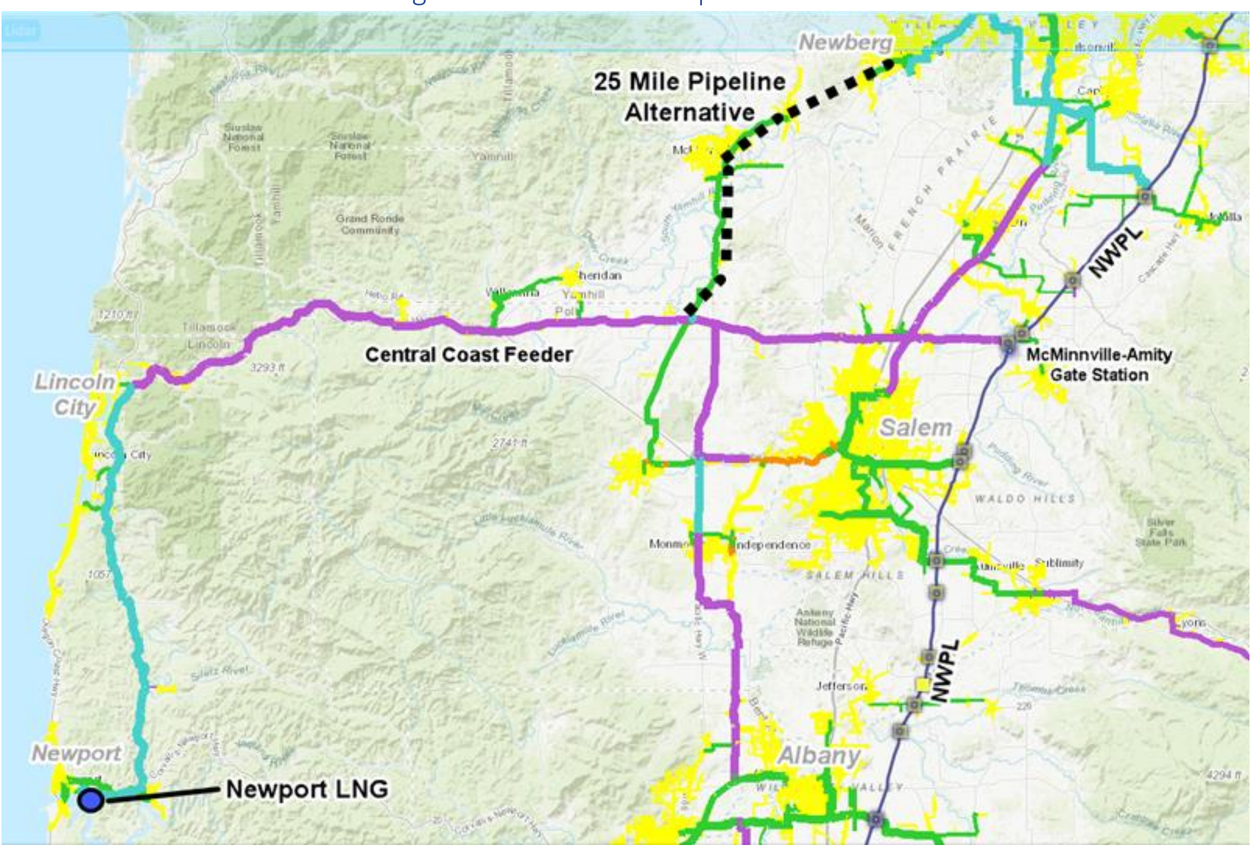
Table 8: Pipeline Expansion Cost Estimates

	$/Dth/day	Dth	Annual Cost
Regional Expansion from Sumas to Molalla	$0.98	65,000	$23,250,500
Local Expansion from Sumas to Molalla	$1.80	65,000	$42,705,000

Alternative A was not considered to be cost-effective option following the initial analysis, given that the annual costs, even at the lower end (for an option that NW Natural cannot control), are higher than the total capital costs associated with the Cold Box of approximately $18 million. As such this option was not analyzed further.

Alternative B, a new 25-mile pipeline, is less expensive, but still much costlier with an installed cost of approximately $171 million. Figure 21 shows the potential route, highlighted in blue.

Figure 21: Alternative Pipeline Route



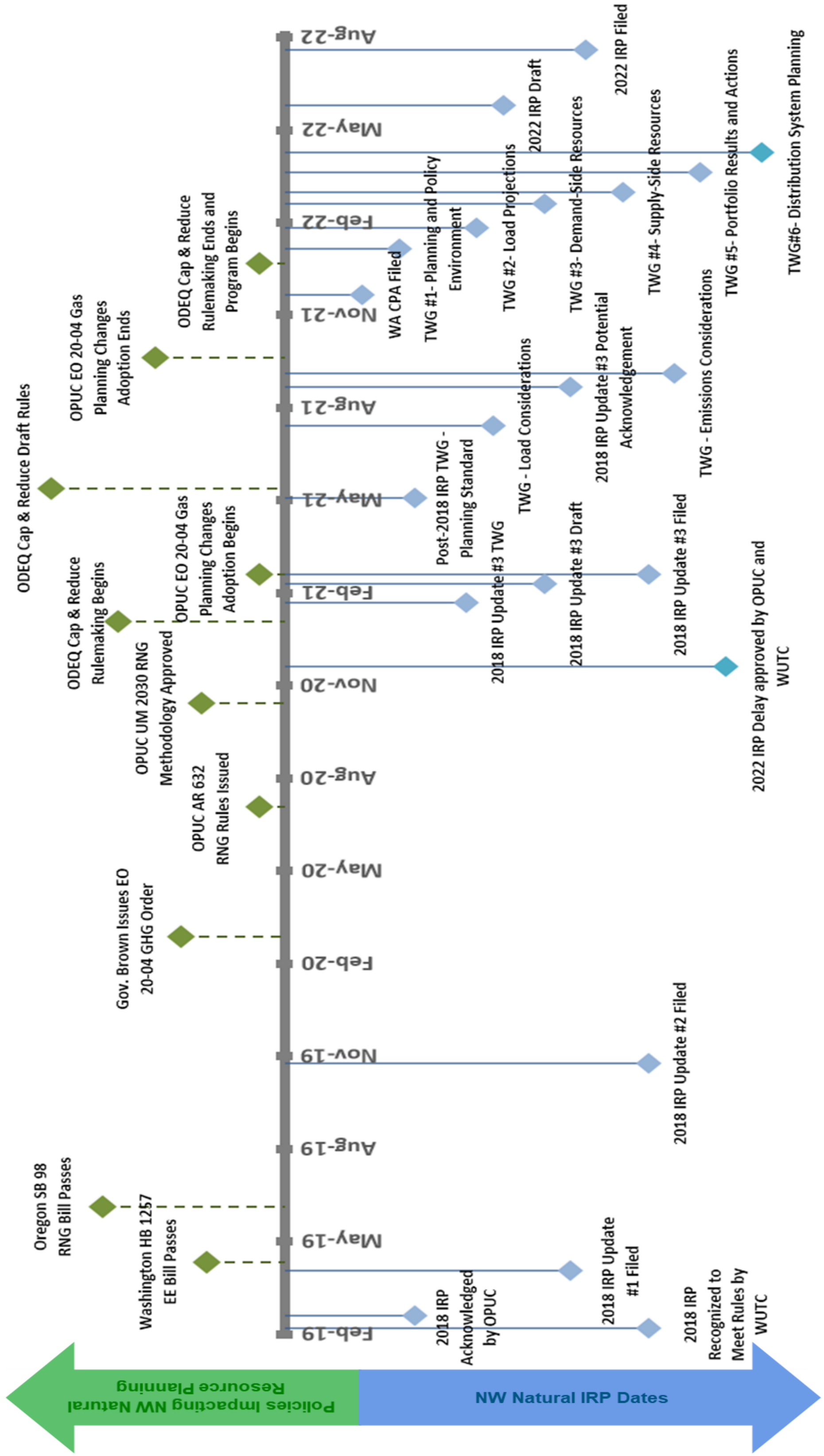
For the final cost analysis, NW Natural used SENDOUT® to determine whether the Company should replace the Newport Cold Box or pursue Alternative B. Table 9 shows the present value of revenue requirement (PVRR) of portfolios over the planning horizon (2021-2050) associated with each of the two courses of action.

Table 9: Portfolio Cost Comparison

	Fixed Storage Costs	Fixed Pipeline Costs	Supply Variable Costs	Other Variable Costs	Total Portfolio Costs
Cold Box Replacement	$63 M	$1,162 M	$10,548 M	$69 M	$11,841 M
Alternative Pipeline	≥$58 M	≥$1,312 M	$10,542 M	$70 M	≥$11,986 M
Delta	-$5 M	$150 M	-$2 M	$1 M	≥$145 M

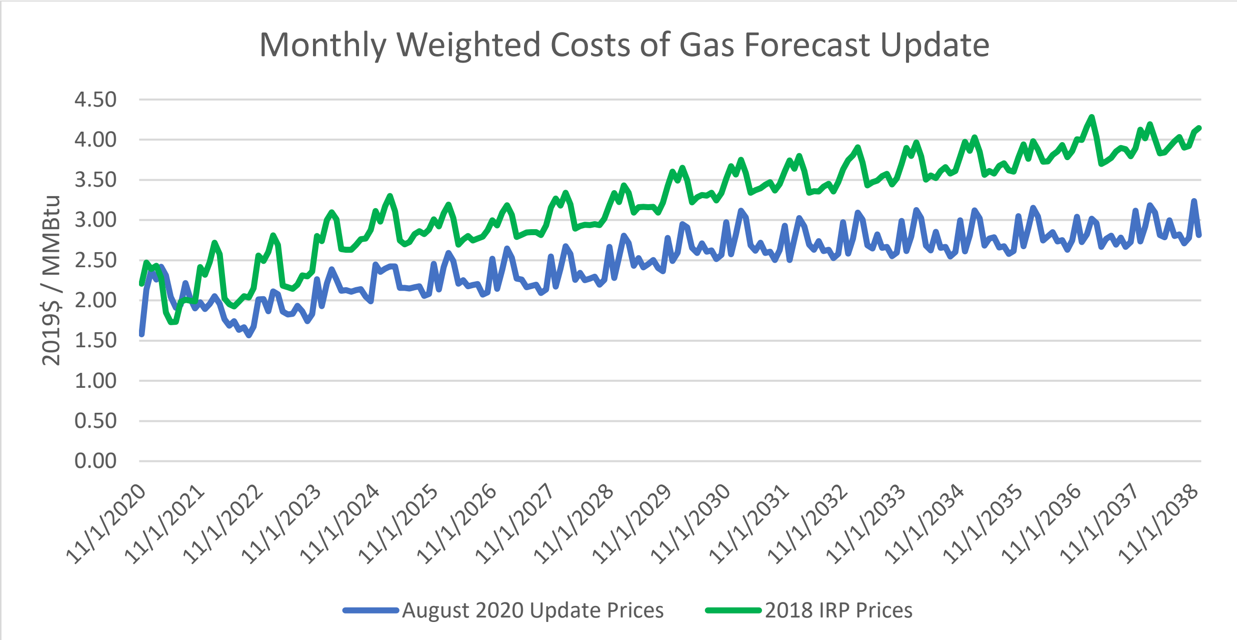
As shown, the portfolio including Newport after the $18 million Cold Box replacement project has a NPVRR savings of approximately $145 million versus the next best option.

Appendix A: 2018 IRP and 2022 IRP Timeline



Appendix B: IRP Update Analysis and Assumptions Detail

Figure B.1: Natural Gas Price Update



Note: Figure B.1 shows the weighted price of gas using the same SENDOUT run, but different gas prices as specified.

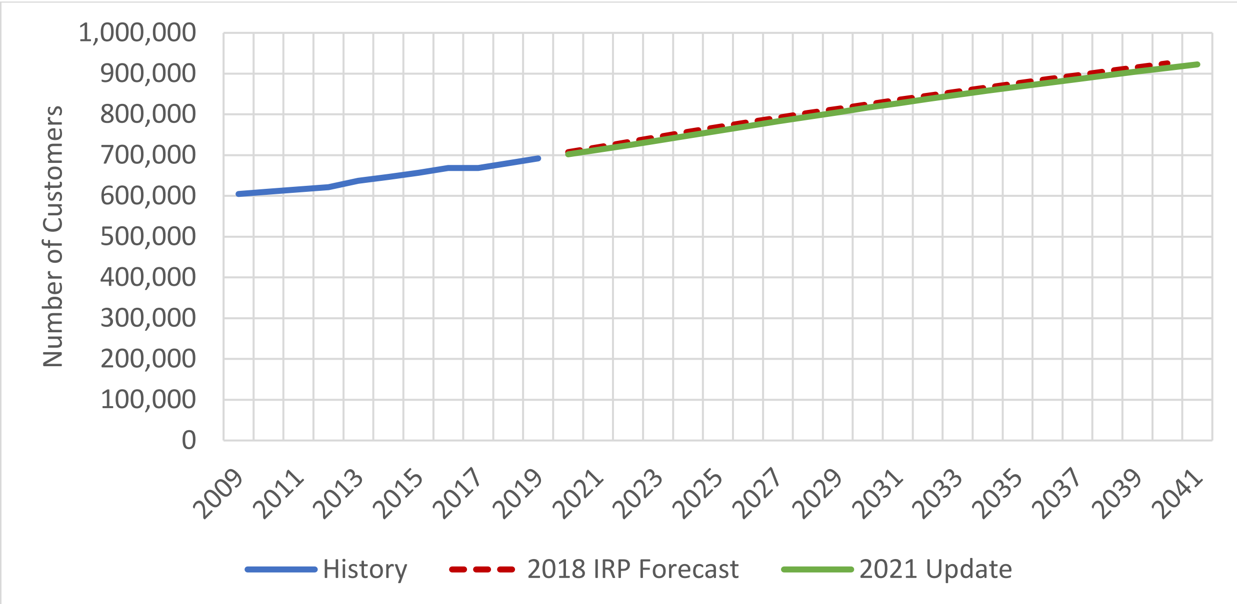
Gas Price Summary

- *Gas prices still exhibit an upward trend across all trading hubs, but generally lower gas prices relative to prices used in the 2018 IRP*
- *Larger decreases in the forecasts relative to the 2018 IRP have occurred at AECO and West Coast Station 2, particularly in the long-run*
- *West Coast Station 2 is still forecasted to be slightly cheaper than AECO year round*
- *Opal is forecasted to be the most expensive gas during summer months, while Sumas is more expensive in the near-term during winter months, but is similar to Opal during winter months further out in the future.*

Customer Count Forecast

The following figures summarize updates to the annual load forecast described in detail in the 2018 IRP. Summaries and technical notes follow each graph.

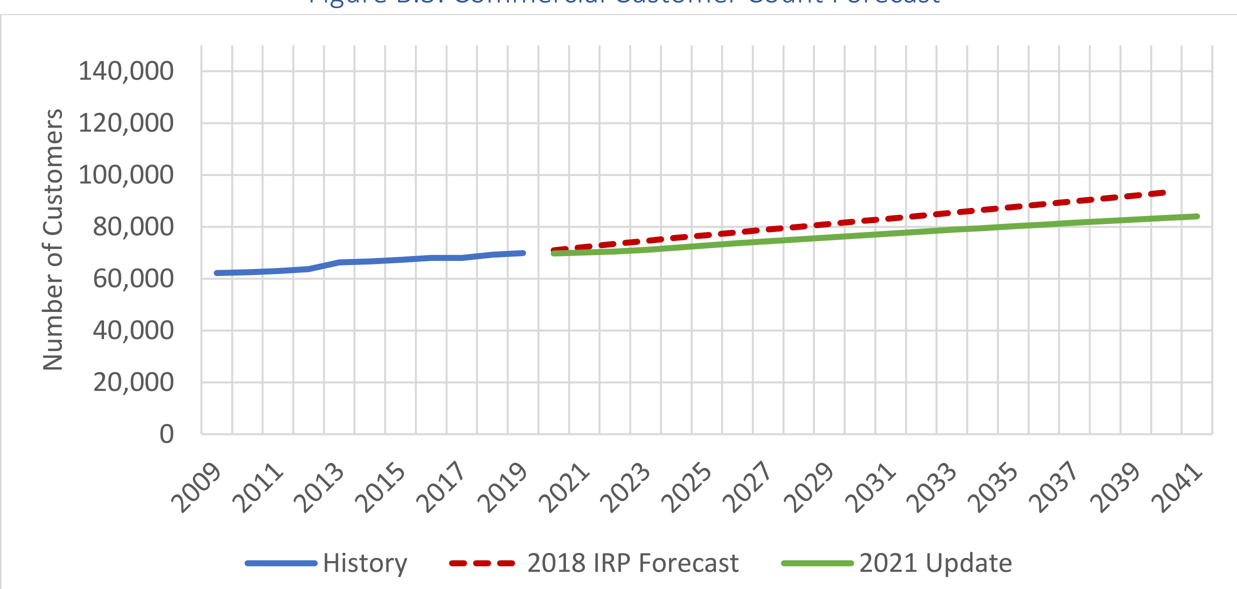
Figure B.2: Residential Customer Count Forecast



Residential Customer Count Forecast Summary:

- *20-year CAGR: 1.30% (2018 IRP forecast 20-year CAGR was 1.35%)*
- *Minor changes to forecasting regression model:*
    - *Driver (right-hand-side) variable for OR residential model changed from US Housing Starts to Oregon Housing Starts. Forecast of driver variable provided by Oregon Office of Economic Analysis*
    - *Driver (right-hand-side) variable for WA residential model – US Housing Starts – transformed to log form from level form*

Figure B.3: Commercial Customer Count Forecast

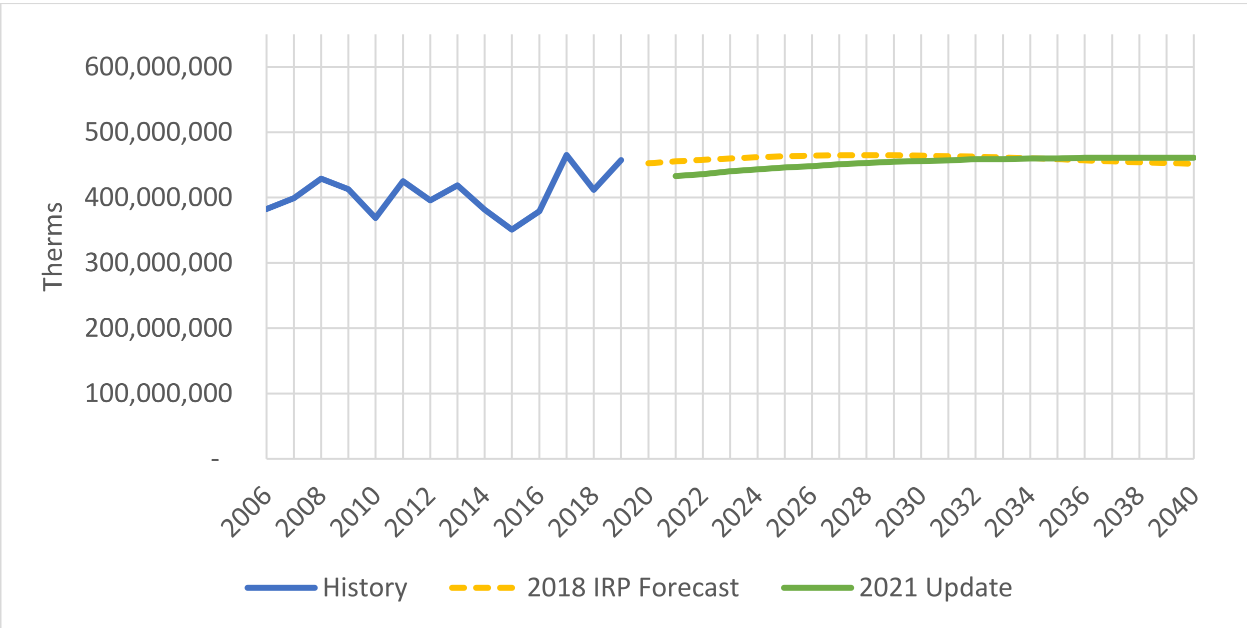


Commercial Customer Count Forecast Summary:

- *20-year CAGR: 0.9% (2018 IRP forecast 20-year CAGR was 1.38%)*
- *Minor changes to forecasting regression model:*
    - *Driver (right-hand-side) variable for OR commercial model – Oregon population – transformed to log form from level form.*
    - *Autoregressive terms in 2018 WA commercial model no longer statistically significant and were dropped*

Annual Expected Load Forecasts

Figure B.4: Residential Annual Expected Load Forecast



Residential Annual Load Forecast Summary:

- *20-year CAGR: 0.3% (2018 IRP 20-year CAGR was close to zero)*

Figure B.5: Residential Annual Use Per Customer (UPC) Forecast

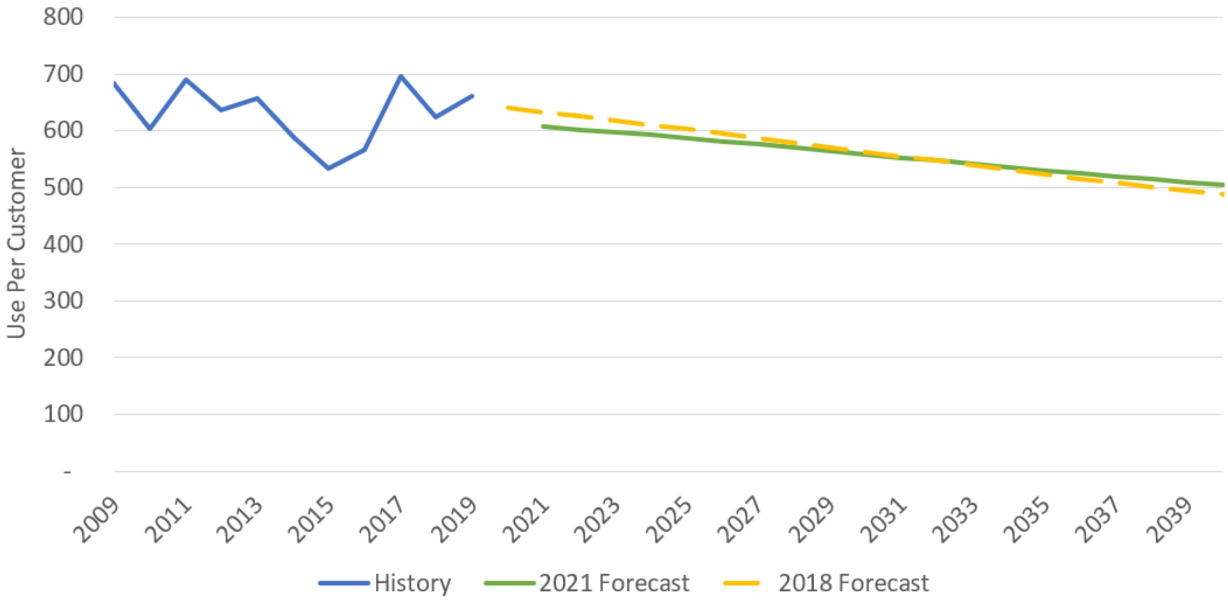
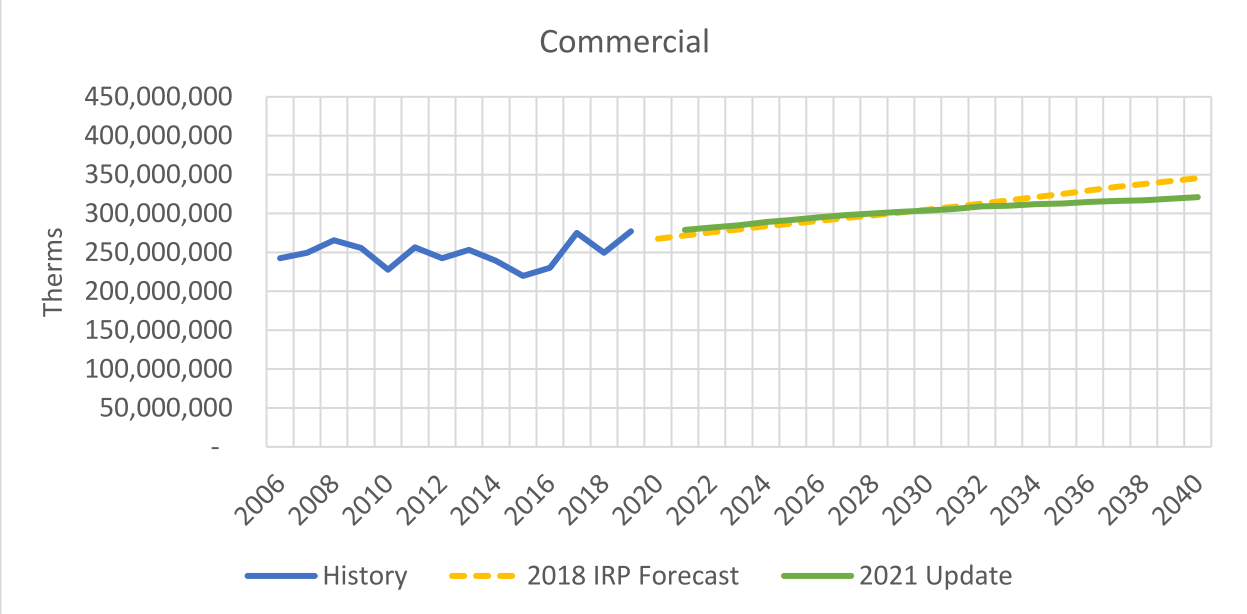


Figure B.6: Commercial Sales Expected Load Forecast



Commercial Customer Count Forecast Summary:

- *20-year CAGR: 0.7% (2018 IRP forecast 20-year CAGR was 1.3%)*

Figure B.7: Industrial Sales Load Forecast

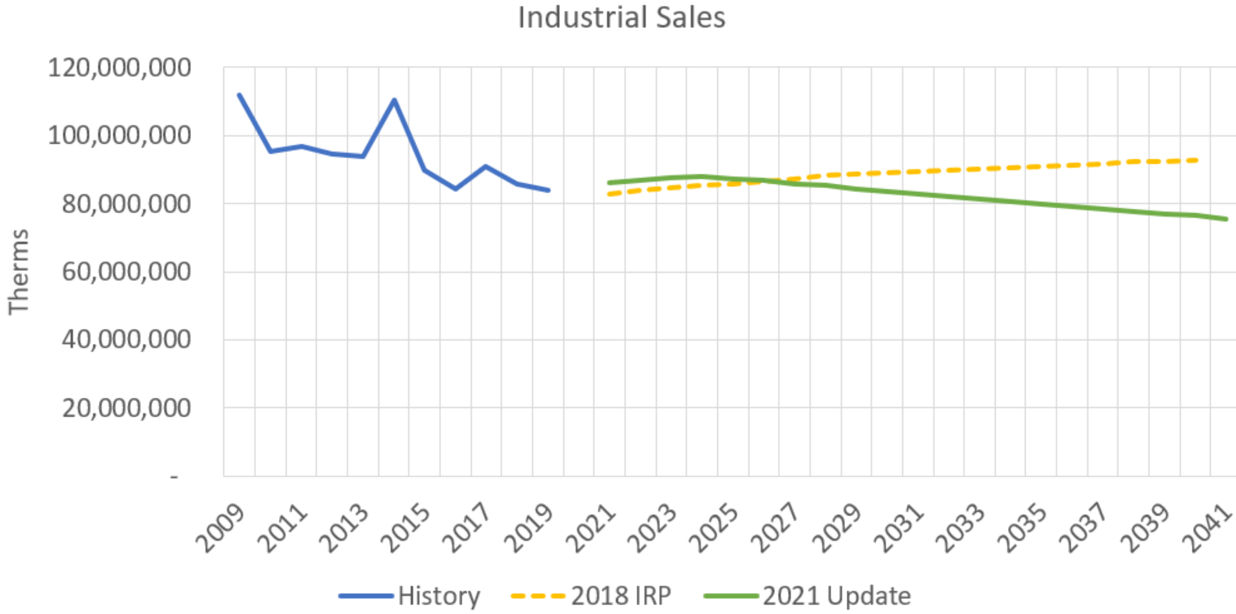
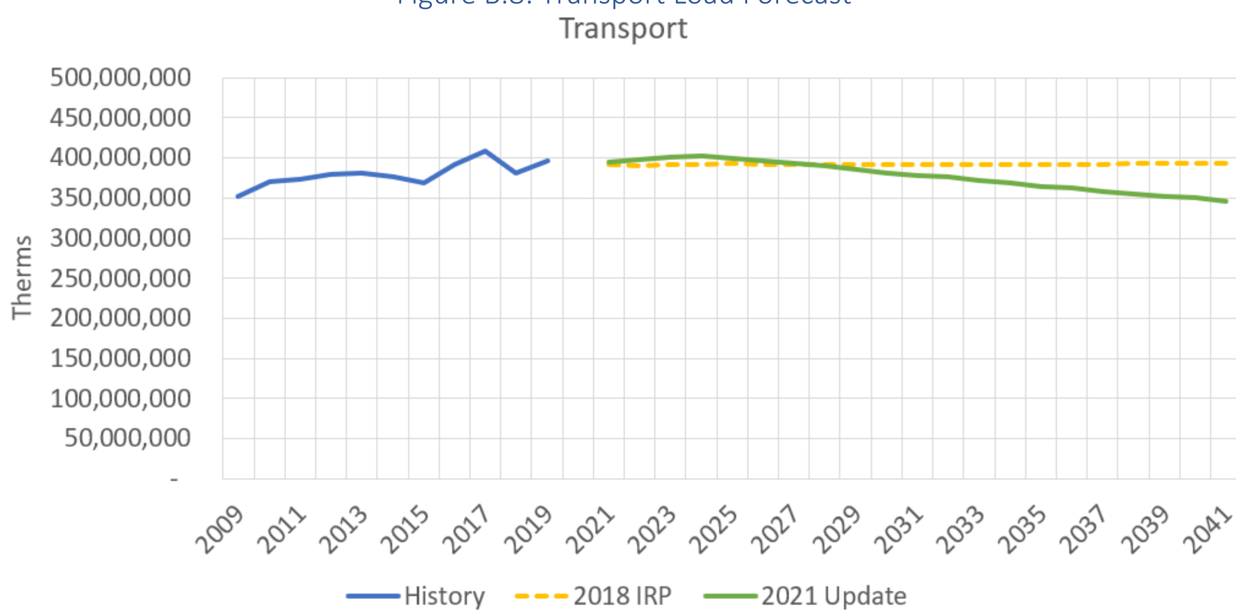


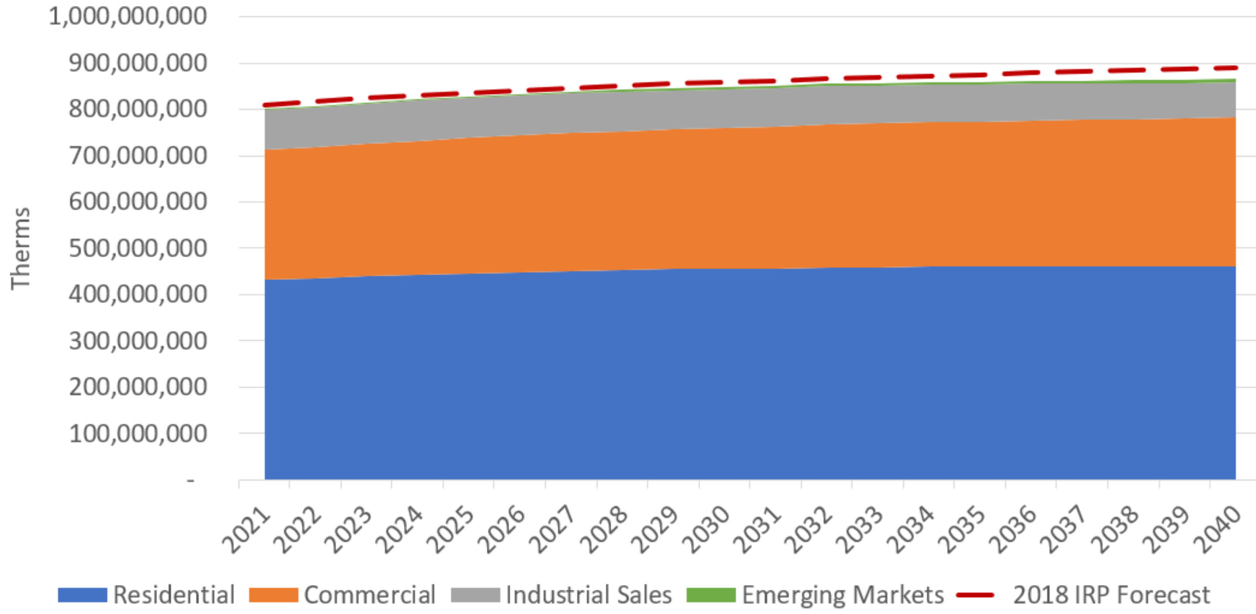
Figure B.8: Transport Load Forecast



Industrial Sales and Transport Forecast Summary:

- 20-year CAGR: -0.64% (2018 IRP forecast 20-year CAGR for total industrial load was -0.1%)
- *Minor changes to forecasting regression model:*
    - *Driver (right-hand-side) variable for total industrial sales and transport model changed from Oregon manufacturing employment level to US industrial output. Forecast of driver variable provided by Oregon Office of Economic Analysis*

Figure B.9: Total Annual Sales Load Forecast



Total Annual Sales Forecast Summary:

- *20-year CAGR: 0.4% (2018 IRP forecast 20-year CAGR was 0.6%)*
- *Includes Residential, Commercial, Industrial, and emerging markets (i.e., CNG) sales loads*

Firms Sales Peak Day Load Forecast

Figure B.10 depicts a flow chart of the inputs and process for the firm sales peak day load forecast.

Figure B.10: Firm Sales Peak Day Load Forecasting Flow Chart

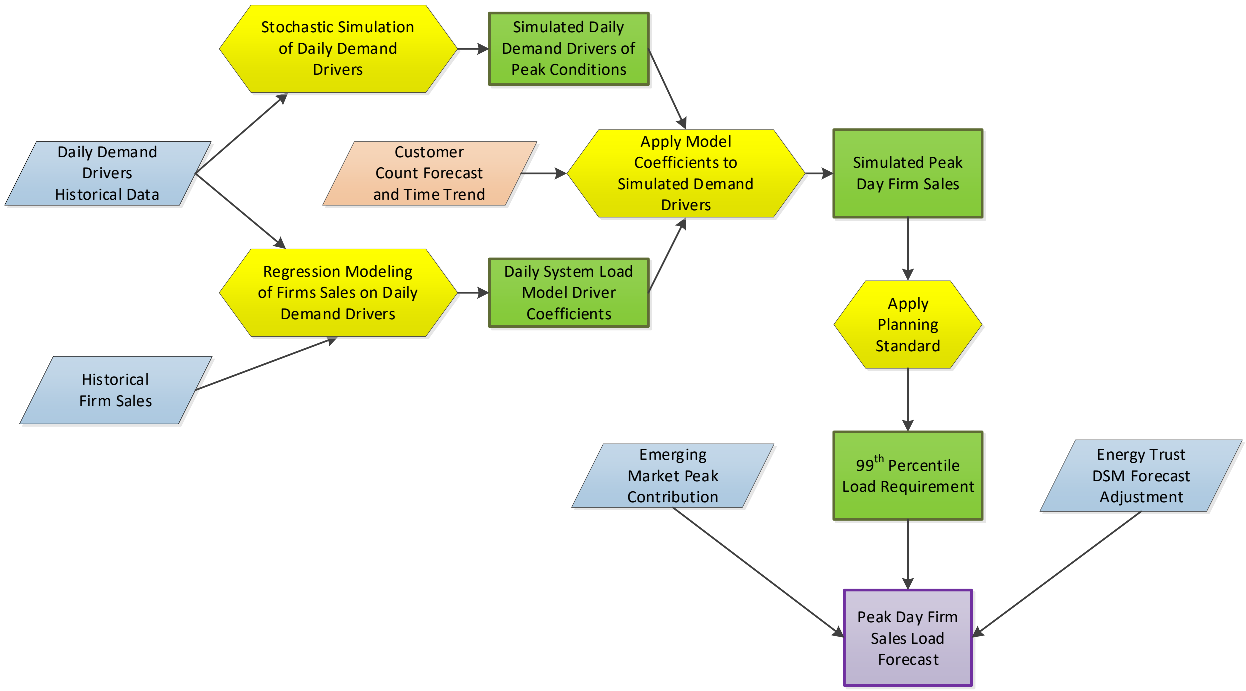
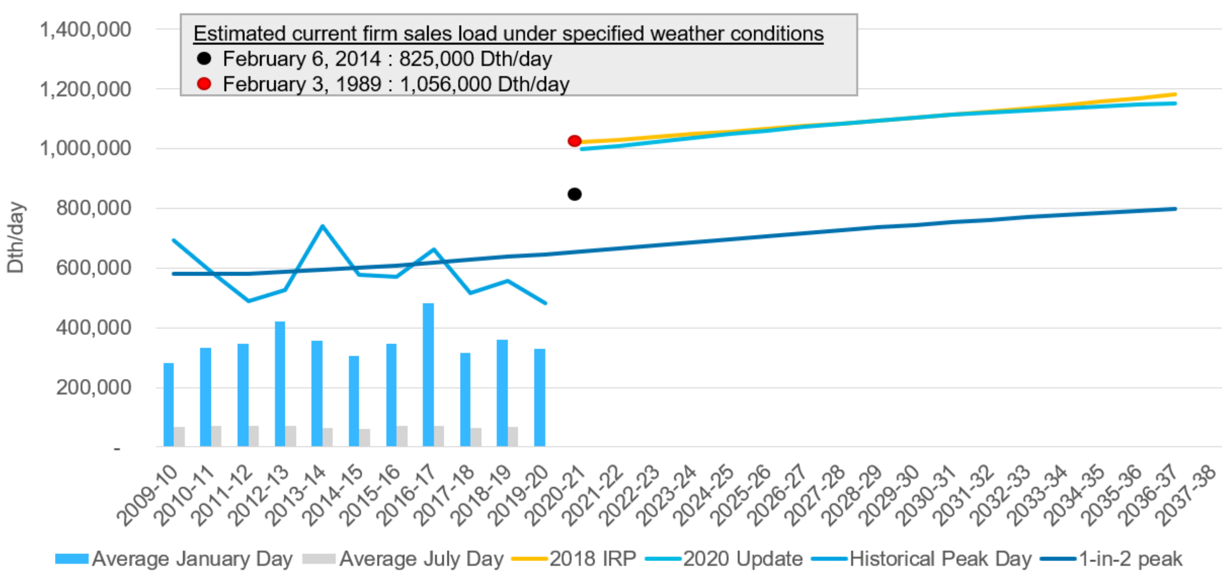


Figure B.11 shows the updated peak day forecast as compared to the 2018 IRP along with historical highest firm sales daily demand, the 1-in-2 peak forecast, historical average firm sales for January and July. The black and red dots in the figure show the predicted values from the regression model for 2020-year-end customer counts and corresponding historical weather conditions.[19]

Figure B.11: Firm Sales Peak Day Load Forecast



---

[19] February 6, 2014 set the record for NW Natural daily gas demand. February 3, 1989 weather conditions would have the highest daily demand requirement for the available weather data going back to 1985.

Table B.1 shows the first 9 years of the of the final peak day forecast for both the updated peak day forecast and the 2018 IRP firm sales peak day forecast.

Table B.1: Firm Sales Peak Day Forecast

Gas Year	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
2018 IRP	1,020,674	1,029,761	1,039,007	1,048,235	1,057,505	1,066,704	1,075,701	1,084,648	1,093,560
2019 Summer Update	995,714	1,008,348	1,019,601	1,030,255	1,041,884	1,052,711	1,064,690	1,075,054	1,086,090
2020 Summer Update	997,147	1,008,849	1,022,060	1,035,599	1,049,355	1,061,146	1,074,071	1,084,532	1,094,089

Firm Sales Peak Day Forecast Summary:

- *Down 2% (24,000 Dth/day) for the 2021-2022 gas year compared to the 2018 IRP forecast*
- *Negligible change (up 2,000 Dth/day) for the 2021-2022 gas year compared to the forecast used for the previous 2018 IRP update (IRP Update #2)*
- *Minor changes to training data for regression model:*
    - *Training data for firm sales load and driver data (e.g., weather) updated through March of 2020*
    - *Training data limited to winter months (Nov-March) and days <= 58°F*
- *Minor changes to regression model specification:*
    - *Temperature added as a stand-alone driver variable in addition to interactions with other driver variables*
    - *Triple interaction between temperature, wind speed, and time trend removed*
    - *Interaction between temperature and holiday dummy variable removed*
- *Minor change to Monte Carlo Simulation:*
    - *Model uncertainty from the customer count forecast model as a stochastic variable has been removed from the Monte Carlo simulation*[20]

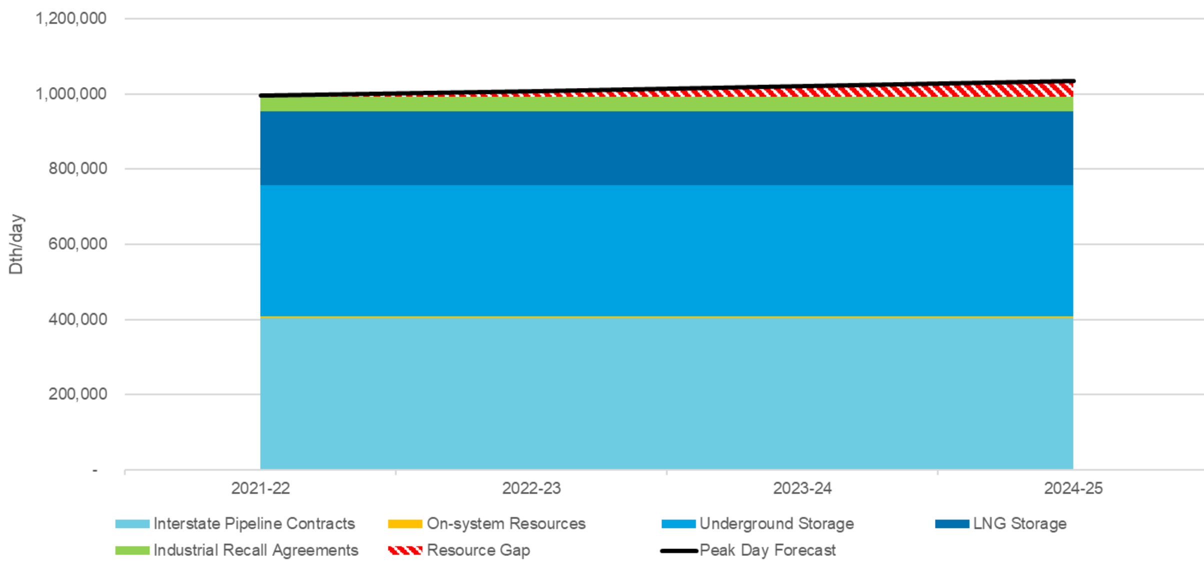
Near-term resource planning

The 2018 IRP introduced a new planning standard using a probabilistic approach to determine the level of resources required to serve the highest daily firm sales demand with 99 percent certainty for each

[20] The peak day planning standard requires the resources necessary to meet the highest firm sales demand with 99% certainty going into any future winter. This is primarily focused of the planning standard is on weather uncertainty. Uncertainty in the customer count forecast increases further into the future, but will become very certain time moves along and the company plans for the upcoming winter, thus the customer count uncertainty was removed from the peak day Monte Carlo simulation. The company will still include high and low customer count scenarios within the IRP risk analysis.

year in the planning horizon. Figure B.12 illustrates the update firm sales peak day forecast compared to NW Natural's existing resources and identifies the resource deficiency (i.e., resource gap) for the next 4 winters.

Figure B.12: Updated Resource Deficiency



Previous IRPs, including the most recent 2018 IRP, have shown Mist Recall as the least-cost least-risk resource for meeting a growing firm sales peak day load. NW Natural updates and re-evaluates the need for Mist Recall each summer for the following gas year.[21] Table B.2 shows the 2018 IRP peak day forecast and the Mist Recall needed for the resource the firm sales supply capacity. Note that Mist Recall requirements are rounded to the nearest 5,000 Dth/day.

Table B.2: 2018 IRP Resource Requirement

Winter	Peak Day Forecast (Dth/day)	Cumulative Mist Recall - rounded to nearest 5,000 (Dth/day)	Incremental Mist Recall (Dth/day)
2019-2020	1,003,836	20,000	20,000
2020-2021	1,012,125	30,000	10,000
2021-2022	1,020,674	65,000	35,000

[21] For example, if Mist Recall is needed for the 2021-2022 winter NW Natural needs to make that decision in the fall of 2020 in order to reserve the necessary storage to be recalled the following spring and filled for the following winter.

The requirements for these winter for the 2018 IRP resulted in the acknowledged Action Item #1:

> *Recall 10,000 Dth/day of Mist storage capacity for the 2020-21 gas year. Recall 35,000 Dth/day of Mist storage capacity for the 2021-22 gas year.*

Note that the initial 20,000 Dth/day, shown in Table B.2, was not included as a part of the action item for acknowledgement since the IRP was filed in August of 2018 and acknowledgement of the action item was not expected to be received until March of 2019. This would be too late to Recall Mist conditional of Commission acknowledgement, but would be recalled as in the course of business. An IRP update was filed in the LC 71 docket on April 7, 2019 as an update to the 2016 IRP Action Item, which called for a Mist Recall for the 2019-2020 winter. An update to the firm sales peak day forecast at the end of summer 2018 (after the IRP was filed) showed that a recall for the 2019-2020 winter was not necessary. Another update to the 2018 IRP was filed on November 7, 2019 as an update to the 10,000 Dth/day Mist Recall requirement for the 2020-2021 winter. This Mist Recall was also not required for the 2020-2021 winter.

In line with the Companies usual process NW Natural updated its peak day forecast in the summer of 2020. Along with the peak day forecast, NW Natural also updates factors that impact the Company's daily deliverability from existing resources. This includes heat content of the gas in the LNG facilities, an assessment of the reliability of segmented capacity[22], and assessment of on-system resources. The assumptions align with the 2019 PGA filing. At the time of the summer 2020 update our existing had firm deliverability of 991,547 Dth/day for the 2020-2021 winter[23]. A small amount of gas from the waste water treatment plant in Eugene is expected to be interconnected to the Company's system by the 2021-2022 winter, which brings the total firm deliverability of 992,047 Dth/day for the following year. The updated peak day forecast for that winter is 997,147, resulting in a resource need of 5,100 (Dth/day).

Table B.3: Existing Resources, Peak Day Forecast, and Resource Need

Winter	Firm Supply Resources	Peak Day Forecast	Resource Need
2020-2021	991,547	983,866	0
2021-2022	992,047	997,147	5,100

Mist Recall is one of NW Natural's short notice options in order to meet the resource need for the 2021-22 gas year. The lead time for a Mist Recall decision is about 12 months from the start of the gas year when it is forecasted to be needed for a potential peak. This lead time is relatively short compared to other supply resources, which is a significant benefit for customers. Based on the need, the Company can reserve Mist derivability and associated capacity for customers during the prior gas year and recall Mist resources on May 1st and filled over the summer months. Mist Recall is not free for customers, but

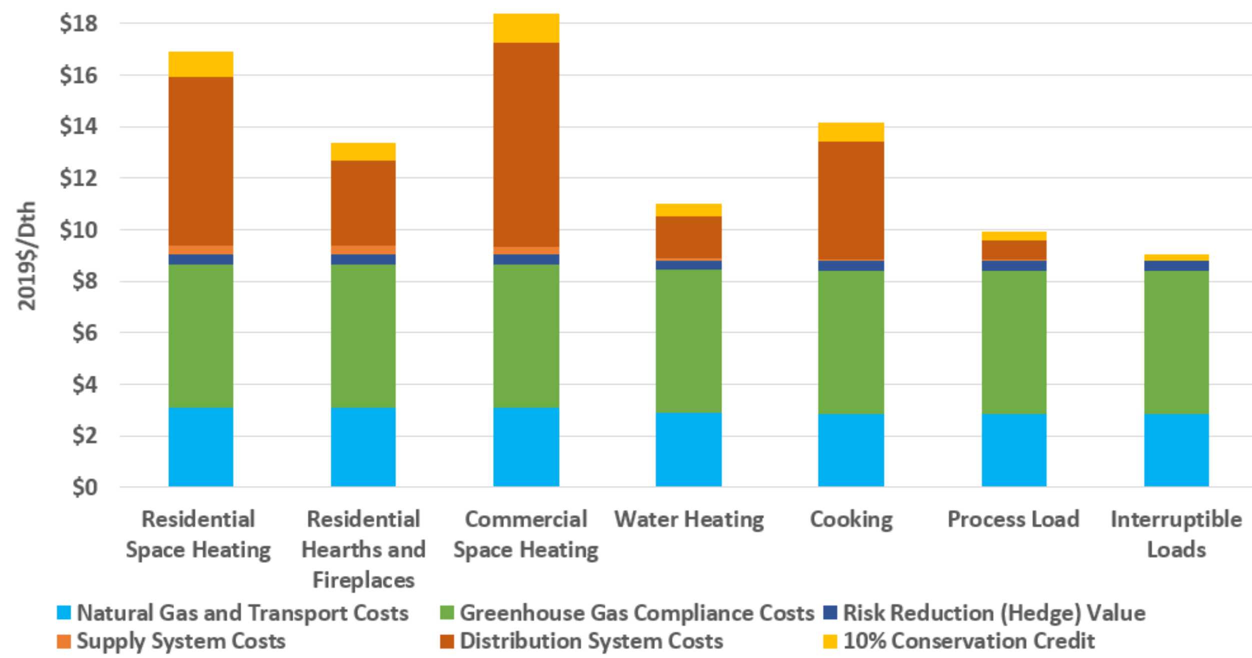
[22] See Chapter 6 of the 2018 IRP (LC-71) for further details about assessment of segmented capacity.
[23] The existing resources shows a slight increase for the 2020-2021 winter from the 2018 IRP due increased heat content of the gas in the LNG facility.

has been shown in previous IRPs to be the least cost least risk resource for meeting near term resource requirements.

Citygate deliveries are another short-term option that NW Natural can use to meet peak demand requirements. As the name implies, these are contracts for gas supplies delivered directly to NW Natural's service territory by the supplier utilizing their own NWP transportation service. These are near term contracts that are typically signed for a specified amount and a delivery window (e.g., 5 days) for a single winter. If exercised the gas is indexed to a specified price hub (e.g., Sumas).

NW Natural negotiated a Citygate deal for 5,000 Dth per day, with a total five-day maximum of 25,000 Dth for the 2021-2022 winter. NW Natural evaluated this deal in lieu of Mist Recall to be used as a part of the Company's firm sales resource stack for the 2021-2022 winter. Considering potential gas cost risks and the likelihood of needing to execute this option, NW Natural found using this deal in lieu of Mist Recall to be in the best interests for customers for the 2021-2022 winter.

Figure B.13: Washington 20-year Levelized Costs



Appendix C: Distribution System Reinforcement Standards

Design Procedure **System Reinforcement Standards**	
Revision: 00	Effective Date: 06/14/2019
Approved: *Joe Karney*	Reviewed: *Andy Fortier*

Purpose

This procedure defines the system reinforcement standards that NW Natural utilizes to determine when a transmission, high pressure distribution, or Class B distribution system needs to be reinforced.

System reinforcement standards are a required component of the transmission, high pressure distribution, and Class B distribution system planning process. The standards are based on multiple criteria that indicate conditions representing a pipeline nearing peak capacity, sub-standard regulator performance, customers not being served with adequate pressure or volume, etc. The system reinforcement standards represent trigger points which indicate systems under stress and in need of imminent attention to reliably serve customers.

Pressures that are experienced during cold weather events that meet the criteria defined below may be observed and documented by means of:

- SCADA Data Pressure Logs.
- Portable Pressure Recorders (PPR's) Temporarily Sited in the field.
- Cold Weather Survey Points that are manually read by a NW Natural Technician.
- Pressures at customer locations documented by manual pressure readings or Industrial Billing System devices.
- Gas Control Room records of System Operations Crew activities in the field, including by-passing regulator stations, manual pressure readings, or reports of system outages.

Once experience or modeling has shown that the system reinforcement standards defined below have been violated for a transmission, high pressure distribution, or Class B distribution system, then an investigation will be initiated. This investigation may include further validation of pressure data to confirm system modeling, preliminary design of system reinforcement projects, potential alternatives to these projects, and estimated scope, schedules, and budgets. These projects will then follow Engineering Project Management and IRP process for review and approvals.

Definitions

IRP – Integrated Resource Plan

Procedure

Transmission and High Pressure Distribution Systems

The system reinforcement parameters associated with peak hour load requirements for transmission and high pressure distribution systems (systems operating at greater than 60 psig) are:

- Experiencing at least a 30% pressure drop over the facility that indicates an investigation will be initiated.
- Experiencing or modeling a 40% pressure drop that indicates reinforcing the facility is critical, as a 40% pressure drop equates to an 80% level of capacity utilization[24].
- Consider minimum inlet pressure requirements for proper regulator function in addition to total pressure drop for pipelines that feed other high pressure systems[25].
- Near-term growth indicated by one or more leading indicators (e.g., new road construction, subdivision, or planned industrial development) may require reinforcing a system that currently has satisfactory performance.
- The ability to meet firm service customer delivery requirements (flow or pressure).
- Identified in the IRP associated with supply requirements or needs.

Class B Distribution Systems

[24] This standard is based on the Gas Engineering and Operating Practices (GEOP), Volume 3, Distribution, Book D-1, System Design Revised, Chapter 2: Gas Flow Calculations, page 111.

[25] This standard is based on pressure regulator manufacturer requirements. NW Natural has a variety of pressure regulators in its systems, and the manufacturer requirements for minimum inlet pressure for proper regulator function are used on a case by case basis. Typical manufacturer and models of pressure regulators NW Natural uses are the Mooney Flowgrid, the Honeywell American Axial Flow, and the Fisher 627.

The system reinforcement parameters associated with peak hour load requirements for Class B distribution systems (systems operating at 60 psig or less) are:

- Experiencing a minimum distribution pressure of 15 psig that indicates an investigation will be initiated.
- Experiencing or modeling minimum distribution pressure of 10 psig that indicates reinforcement is critical[26].
- Near-term growth indicated by one or more leading indicators (e.g., new road construction, a new subdivision, or planned industrial development) may require reinforcing a system that currently has satisfactory performance.
- Firm service customer delivery requirements (flow or pressure).

Training Requirements

Engineering

Periodic Review

This procedure shall be reviewed at least once every three years.

Impacted Departments

Engineering
Construction
System Operations
Gas Control
Strategic Planning

References

Gas Engineering and Operating Practices (GEOP), Volume 3, Distribution, Book D-1, System Design Revised

49 CFR §192.381 Service lines: Excess flow valve performance standards

SPO/W 623 MAOP for Class A and B Distribution Systems

SPO/W 627 MAOP for Transmission and Distribution Lines with MAOP>60 psig

[26] This standard is based on the minimum inlet pressure required for an Excess Flow Valve (EFV) to properly function, per 49 CFR §192.381 Service lines: Excess flow valve performance standards.

Appendix D: Public Participation

Table D.1 is a copy of the sign-in sheet for NWN's Open House held on November 26, 2019.

Table D.1: Open House Sign-in Sheet

November 26, 2019 - NW Natural Open House		
Name	**Company**	**Email**
Ted Drennan	NWN	ted.drennan@NWNATURAL.com
Matt Doyle	NWN	Matthew.doyle@NWNatural.com
Tamy Linver	NWN	tsl@nwnatural.com
Andy Hudson	Energy Trust	andrew.hudson@energytrust.org
Doug Tilguer	NWN	dlt@nwnatural.com
EDWARD THURMAN	NWN	ECT@NWNATURAL.COM
Alishia Zoucha	NWN	Alishia.Zoucha@NWNatural.com
Mike Parsellewicz	NWN	m3p@nwnatural.com
Nicole Woodfill	NWN	nicole.woodfill@nwnatural.com
Randy Friedman	NWN	randy.friedman@nwnatural.com
Ryan Bracken	NWN	rjb@nwnatural.com
Rebecca Brown	NWN	rebecca.brown@nwnatural.com
NATASHA SIORES	NWN	NATASHA.SIORES@NWNATURAL.COM
Rose Anderson	OPUC	rose.anderson@state.or.us
Eric Shierman	OPUC	eric.shierman@state.or.us
Nicholas Colombo	OPUC	nicholas.colombo@state.or.us
Jim Woodward	WA-UTC	Jim.Woodward@utc.wa.gov

Table D.2 is a list of everyone who participated in the 2018 IRP Update Technical Working Group held virtually via MS Teams on February 2, 2021.

Table D.2: List of TWG Attendees

Name	Organization
Bob Jenks	CUB
Mike Goetz	CUB
Will Gehrke	CUB
Sudeshna Pal	CUB
Kathi Scanlan	WUTC
Jennifer Snyder	WUTC
Kim Herb	OPUC
Chad Stokes	AWEC
Ed Finklea	AWEC
Ryan Bracken	NWN
Tamy Linver	NWN
Matt Doyle	NWN
Kruti Pandya	NWN
Mike Paruszkiewicz	NWN
Ted Drennan	NWN
Rebecca Brown	NWN
Natasha Siores	NWN
Andy Fortier	NWN
Randy Friedman	NWN
Scott Johnson	NWN
Rick Hodges	NWN
Edward Thurman	NWN
Doug Tilgner	NWN
Delaney Ralph	NWN
Joe Karney	NWN
Zack Kravitz	NWN
Hunter Wiencken	NWN

Appendix E: Newport LNG Update

The following are a list of projects completed since the 2018 IRP which was submitted in August 2018. Some of these projects were originally identified and acknowledged in the 2014 IRP.

Glycol Piping Project, completed October 2018 (2014 IRP Acknowledged by OPUC)

Actual project cost $1.3M. Estimated at $1.4M in 2018 IRP Appendix F
This project replaced the majority of the original plant glycol piping system and modernized its controls.

- Replace buried PVC piping with an above ground carbon steel piping system.
- Installed structural system of pipe supports for new overhead piping which meets current seismic code.
- Replace (2) glycol pumps at end of life
- Automate system

E-5 Heat Exchanger Replacement, Completed October 2018

Actual Project cost $1.7M. Identified in Appendix F of the 2018 IRP and estimated $1.6M
This project replaced a large aluminum fin fan heat exchanger which no longer met the demands of the facility and was at the end of its useful life. The heat exchanger provides cooling for the plant glycol system which is central to cool rotating equipment within the facility. Due to changes in the structural code since the original plant construction new foundations were required. Steel piles were driven to bedrock to ensure the new equipment would survive a large earthquake.

E-3 Heat Exchanger Replacement, Completed October 2018

Actual Project cost $1.8M. Identified in Appendix F of the 2018 IRP, estimated at $1.8M
This project replaced an exchanger which is used within the plant's mixed refrigerant system. The heat exchanger provides cooling by blowing outside air through an exchanger. The exchanger supports the liquefaction process which cools natural gas to a liquid. Due to changes in the structural code since the original plant construction new foundations were required.

C-1 Compressor Motor Replacement, Completed December 2018

Actual Project Cost $256k, identified in Appendix F of the 2018 IRP, estimated at $300k
The existing motor for the C-1 natural gas compressor was at the end of its expected life and no longer operating reliably. A new 900hp motor was installed and tested.

H-2 Vaporizer Controls Project, Placed into service in October 2020

Actual Project cost $3M, identified in Appendix F of the 2018 IRP, estimated at $2M
The H-2 vaporizer is one of two vaporizers at Newport LNG. Each is rated for 50MMSCF per day (total facility send out is limited to 60 MMSCF per day) and provide natural gas to the Salem area. The vaporizer is critical to support winter operations during adverse weather or supply shortages. This project replaced the majority of the piping and automation components of the H-2 Vaporizer. The equipment was purchased from the original manufacturer of the vaporizer (Linde) in a skidded system which was installed by a general contractor. The equipment was tested and performed as intended. The upgrade removed an obsolete computer controlling the system and replaced control valves at the end

of life. This project extends the useful life and improves the reliability of the H-2 vaporizer. This replacement includes the fuel gas piping, water piping, burners, valves, instrumentation, and controls.

Standby Generator Replacement, placed into service October 2018, (2014 IRP Acknowledged by OPUC)

Actual Project Cost $1.9M, identified in Appendix F of the 2018 IRP, estimated at $1.4M
This project replaced the facility's emergency standby generator. The previous standby diesel generator was at the end of its expected life and no longer meeting the performance requirements.

Ongoing Work at Newport LNG

NLNG Pretreatment Regeneration Optimization

In late 2020, NW Natural started the Newport LNG Pretreatment Regeneration Optimization project. This project is forecasted at $3.6 Million and is expected to be completed by the end of 2021. The project was started shortly after being identified, as a necessary measure to preserve overall plant reliability and readiness to support winter operations.

At Newport LNG the production of LNG occurs in two primary phases. In the first production phase, the natural gas is pretreated to remove contaminants, which would be harmful to the process. The gas is then liquefied in the second phase. Pretreatment removes contaminants entrained in the gas stream entering the Plant such as; water, mercaptan (odorant), and $CO_{2.}$ Liquefaction then cools and condenses the gas into a cryogenic liquid suitable for onsite storage.

As the gas is processed, adsorbent media in the pretreatment vessels become saturated with contaminants removed from the gas, primarily water and C02. Once saturated, the adsorbent media are regenerated by circulating hot natural gas through the vessels, which removes the contaminants and carries them away. Once the regeneration process is complete, the capacity of the adsorbent media in each vessel is restored and ready to continue capturing contaminants from the incoming gas stream. This project is designed to improve the performance of this process.

Currently, a portion of the contaminants in the natural gas process stream is bypassing pretreatment and creating the need to shut the plant down frequently during production. These unplanned shutdowns typically occur within a 10 to 14-day period. Such abnormally frequent interruptions tend to shorten the lifespan of major plant equipment, due to the inherently large thermal changes created with each start-up and shut down cycle.

This project intends to change the design of the dehydration portion of pretreatment from an open loop, to a semi-closed loop regeneration cycle. When installed the existing system minimized the amount of equipment required thus a lower initial investment. However, this also requires a greater rate of natural gas consumption by the city of Newport. Analysis of current trends of natural gas consumption indicates that the City does not consume a sufficient amount of natural gas to support this design.

The project will improve system reliability and better situate Newport LNG to operate effectively into the future if Natural gas consumption reduces over the summer months.