NW Natural®

2022 NW Natural Integrated Resource Plan

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Forward-looking statements are based on our current expectations and assumptions regarding our business, the economy and other future conditions. Because forward-looking statements relate to the future, they are subject to inherent uncertainties, risks and changes in circumstances that are difficult to predict. Our actual results may differ materially from those contemplated by the forward-looking statements, so we caution you against relying on any of these forward-looking statements. They are neither statements of historical fact nor guarantees or assurances of future performance. Important factors that could cause actual results to differ materially from those in the forward-looking statements are discussed by reference to the factors described in Part I, Item 1A “Risk Factors,” and Part II, Item 7 and Item 7A “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” and “Quantitative and Qualitative Disclosure about Market Risk” in the Company’s most recent Annual Report on Form 10-K, and in Part I, Items 2 and 3 “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Quantitative and Qualitative Disclosures About Market Risk”, and Part II, Item 1A, “Risk Factors”, in the Company’s quarterly reports filed thereafter.

All forward-looking statements made in this presentation and all subsequent forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are expressly qualified by these cautionary statements. Any forward-looking statement speaks only as of the date on which such statement is made, and we undertake no obligation to publicly update any forward-looking statement, whether as a result of new information, future developments or otherwise, except as may be required by law.

S&P Global Commodity Insights Gas Price Forecast Disclaimer

A Message from NW Natural President and CEO

President and CEO David H. Anderson at company headquarters and operations center.

It is an exciting time for energy system planning as the energy transition is fully underway. Since we filed our last Integrated Resource Plan (IRP) transformative climate policies have been established in both Oregon and Washington. These policies require emissions reductions from gas utilities and drastically changes the calculus of comparing low emissions resources against traditional resources. While NW Natural has long been a leader amongst gas utilities in planning for a low carbon future, our 2022 IRP is our first comprehensive analysis to support implementation of our obligations under existing climate policies. The outcome of this complex and technical work is a flexible long-term resource acquisition plan, supported by concrete near-term action designed to achieve the emissions reductions needed to support local, state, and federal climate policies at a reasonable cost, while continuing to provide safe and reliable service.

The highlights of this plan include expanding our acquisition of renewable natural gas (RNG) over the next few years and working with the Energy Trust of Oregon to expand energy efficiency (EE) programs that serve our customers within the context of complying with climate policy. To address any compliance obligations not met by RNG and EE before filing our next IRP (expected in 2024), we will acquire emissions compliance instruments made available to covered parties in the climate programs in Oregon and Washington. These compliance instruments include Community Climate Investments in Oregon's Climate Protection Program and emissions allowances and offsets that can be used for compliance in Washington's Cap-and-Invest program. Longer-term, we expect the mix of biofuel-sourced renewable gas we deliver to our customers to be supplemented by renewable hydrogen and synthetic natural gas made from renewable hydrogen. While there is still much to sort out regarding the specific resources we will need going forward as policy, technology, and markets develop, we expect the majority of the energy we deliver to our customers to be from renewable and net zero sources by the late 2030s.

While climate policy has led to a substantial change to our expected resource acquisition, a critical role played by IRPs is the analysis to ensure reliability and resource adequacy. For a gas utility, this means ensuring we have sufficient resources to serve all of our customers' needs during the coldest weather we can experience in our service territory. In this regard, the capacity resources that we need in this IRP are similar to that in our previous IRPs—maintaining our existing energy storage resources, adding storage capacity from our Mist underground storage facility in Northwest Oregon, and a reliance upon non-pipeline solutions (energy efficiency and demand response).

I am extremely proud of the work that has gone into developing our 2022 IRP and want to thank everyone who participated in the public process that helped shape this document. Your feedback and participation in this process has made our IRP better and our plan to move forward more robust. The analysis included in this IRP demonstrates how a natural gas utility can contribute to the energy transition needed to address climate change by rapidly reducing emissions while continuing to deliver safe, reliable, and affordable energy services. I encourage our energy and climate stakeholders in the Pacific Northwest to review the detailed plan we have developed.

David H. Anderson

David H. Anderson
President and Chief Executive Officer

Table of Contents

A Message from NW Natural President and CEO iii

Table of Contents iv

Table of Figures xii

Table of Tables xvi

Glossary 1

1 Executive Summary 9

1.1 Overview 10

1.1.1 About NW Natural 10

1.1.2 IRP Planning Process 10

1.2 Planning Environment 12

1.2.1 Economic Outlook and Energy Markets 12

1.2.2 Environmental Policy 14

Climate Policy Enacted Since Last IRP - Oregon 15

Climate Policy Enacted Since Last IRP - Washington 16

1.3 Determining Resource Needs – Energy, Capacity, and Compliance 19

1.4 Resource Options to Meet Needs 21

1.4.1 Energy and Capacity Options 21

1.4.2 Emissions Policy Compliance Options 22

Energy Efficiency 23

Supply-Side Low GHG Resources 24

Compliance Instruments 24

1.5 Resource Selection and Preferred Portfolio 25

1.5.1 Capacity Results 25

1.5.2 Emissions Compliance Results 25

1.6 Action Plan Covering the Next Two to Four Years 27

2 - Planning Environment 30

2.1 Planning Environment Overview 31

2.2 Economic and Demographic Factors 31

2.2.1 U.S. Economic and Demographic Outlook 31

2.2.2 Oregon Economic and Demographic Outlook 33

2.2.3 NW Natural System Area Economic and Demographic Outlook 38

2.3 Natural Gas Prices 41

2.3.1 Natural Gas Supply Sources 42
2.3.2 Natural Gas Price Forecast 43
2.3.3 Current Conditions 45
2.3.4 Natural Gas Price Uncertainty 46
2.4 RNG and Hydrogen Markets 48
2.5 Efficient End Use Equipment 50
2.5.1 Efficient Gas Water Heaters 50
2.5.2 Efficient Rooftop Units 51
2.5.3 High-Performance Windows 51
2.5.4 Other Portfolio Activities 52
2.6 Environmental Policy- Overview 52
2.6.1 Environmental Policy – Federal 52
2.6.2 Environmental Policy / Codes – OR 53
Oregon Climate Protection Program (CPP) 53
Senate Bill 98 (SB 98) 54
Status of Oregon Codes 54
Potential Impacts of Oregon House Bill 3055 55
2.6.3 Environmental Policy / Codes – WA 55
Washington Climate Commitment Act (CCA) 55
House Bill 1257 (HB 1257) 57
Status of Washington Codes 57
2.6.4 Environmental Policy – Local 58
2.6.5 Equity and Environmental Justice 58
2.6.6 Low Income Needs Assessment 58
2.7 Transformative Change for Resource Planning 59
3 - Resource Needs 61
3.1 Overview 62
3.2 Reference Case Forecasts 65
3.2.1 Customer Forecast – Reference Case 66
Subject Matter Expert Panel 68
Econometric Models 68
SME and Econometric Blending 69
Residential and Commercial Customer Count Forecast 70

3.2.2 Climate Change Adjusted Weather Forecasts 72
Expected Weather 74
Design Winter Weather 74
Design Peak Weather 75
Weather Patterns for Resource Planning 75
Weather Uncertainty 77
3.2.3 Residential and Small Commercial Use per Customer – Reference Case 81
Use per Customer Regression Model 82
Cost-Effective Energy Efficiency 87
Residential and Small Commercial Annual Use per Customer and Annual Forecast 88
3.2.4 Industrial, Large Commercial and Compressed Natural Gas (CNG) Load Forecast – Reference Case 90
Econometric Forecasts 91
SME Panel Forecasts 92
Compressed Natural Gas Service 92
Industrial, Large Commercial Load, and CNG Annual Load Forecast 92
3.2.5 Expected Weather Annual Load Forecast – Reference Case 93
3.2.6 Daily System Load Model 95
Daily Demand Drivers 95
Interaction Effects 98
Firm Sales Daily System Load Regression Model 99
3.2.7 Capacity Requirement Planning Standard 99
3.2.8 Design Day Peak Savings from Energy Efficiency 100
3.2.9 Peak Day Forecast – Reference Case 101
3.2.10 Demand Response 105
3.3 End Use Load Forecast Model 106
3.3.1 Disaggregating Load by End Use 107
3.3.2 Stock Rollover Model 108
3.4 Customer Count Uncertainty 109
3.5 Annual Load Uncertainty 110
3.6 Peak Load Uncertainty 113
3.7 Defining Capacity Resource Needs 115
3.8 Defining Compliance Resource Needs 116

4 - Avoided Costs 118
4.1 Avoided Costs – Overview 119
4.2 Avoided Cost Components 120
4.2.1 Commodity Related Avoided Costs 120
4.2.2 Gas and Transport Costs 120
4.2.3 Greenhouse Gas Emissions Compliance Costs 121
4.2.4 Commodity Price Risk Reduction Value or the Hedge Value of DSM 121
4.2.5 Infrastructure Related Avoided Costs 122
4.2.6 Supply Capacity Costs 123
4.2.7 Distribution Capacity Costs 125
4.2.8 Ten Percent Northwest Power and Conservation Council Conservation Credit 126
4.3 Demand-side Applications of Avoided Costs 127
4.3.1 Avoided Costs and DSM in the Overall IRP Process 127
4.3.2 Avoided Cost Component Breakdown Through Time 128
4.3.3 Avoided Costs Results Across IRPs 133
4.3.4 Avoided Costs for Carbon Emissions Reductions 134
4.4 Supply-side Applications of Avoided Costs 135
4.4.1 Avoided Costs of Low Carbon Gas Supply 135
4.4.2 Avoided Costs of On-System Gas Supply 136
5 - Demand-Side Resources 137
5.1 Energy Trust of Oregon 138
5.1.1 Energy Trust Forecast Overview and High-Level Results for Oregon 139
5.1.2 Energy Trust Resource Assessment Economic Modeling Tool 142
5.1.3 Methodology for Determining the Cost-Effective DSM Potential 143
5.1.4 RA Model Results and Outputs 149
Forecasted Savings Potential by Type 149
Supply Curve and Levelized Costs 152
5.1.5 2022 Oregon Model Results Compared to 2018 153
5.1.6 Oregon Final Savings Projection 155
Oregon Final Savings Projection Extended to 2050 157
Oregon Peak Savings Deployment 159
Impacts of Changing Market Conditions on Energy Trust Oregon Forecast 161
5.2 Conservation Potential Assessment in Washington 165

5.2.1 Background 165
5.2.2 Analysis Approach 165
5.2.3 Baseline Projection 167
5.2.4 DSM Potential 168
5.3 DSM Potential for Oregon Transportation Customers 172
5.3.1 Background 172
5.3.2 Methodology 172
5.3.3 Results Summary 173
5.4 DSM Potential for Washington Transportation Customers 174
5.5 Transportation Energy Efficiency Programs 176
5.6 Gas Heat Pumps/Gas Heat Pump Water Heaters 176
5.7 Dual-Fuel (Hybrid) Heating Systems 178
5.8 Key Demand-Side Input Assumptions 179
5.9 Low Income Programs 181
5.9.1 Oregon Low-Income Energy Efficiency Program (OLIEE) 181
5.9.2 Washington Low-Income Energy Efficiency Program (WA-LIEE) 182
6 - Supply-Side and Compliance Resources 183
6.1 Overview 184
6.1.1 Compliance Resource Types 187
6.2 Low Carbon and Zero Carbon Gas 187
6.2.1 Biofuels 188
Emissions Benefits of RNG 190
Renewable Thermal Certificates (RTCs) 192
RNG Supply 193
Renewable Natural Gas Procurement 195
6.2.2 Hydrogen 197
The Hydrogen Rainbow 197
Power-to-gas 199
Synthetic Methane 200
Power-to-gas and the Need for Seasonal Energy Storage 201
Power-to-gas Existing Technologies and Trends 203
The Economics of Power-to-gas for the Direct-use Natural Gas System 203
6.3 RNG and Hydrogen Evaluation Methodology 207

6.4 Current Resources 209
6.4.1 Gas Supply Contracts 209
6.4.2 Pipeline Capacity 210
Firm Pipeline Transport Contracts 211
Exposure to Sumas 212
Segmented Capacity 213
6.4.3 Storage Assets 214
6.4.4 On-system Production Resources 215
6.4.5 Mist Production 216
6.4.6 On-system Production 216
6.4.7 Industrial Recall Options 216
6.4.8 Existing RNG Contracts 216
Renewable Natural Gas RTC (Renewable Thermal Certificates) Offtakes 217
Renewable Natural Gas Development 217
6.5 Future Compliance Resource Options 218
6.5.1 Biofuel RNG 218
6.5.2 Hydrogen and Synthetic Methane 220
6.5.3 Community Climate Investments (CCIs) 223
6.5.4 Tradable Emission Allowances 223
6.5.5 Offsets 224
6.5.6 Compliance RNG Resources and Compliance Instruments Comparison 224
6.6 Future Capacity Resource Options 228
6.6.1 On-system Production for Capacity 228
6.6.2 Mist Recall 229
6.6.3 Newport Takeaway Options 230
6.6.4 Mist Expansion 231
6.6.5 Upstream Pipeline Expansion 232
6.6.6 Portland LNG 233
Alternative 1- Keep Portland LNG Operational 234
Replace the Cold Box and upgrade the pre-treatment system 235
Replace the Cold Box and keep the existing pretreatment skid 240
Keep the existing Cold Box and the pretreatment systems 241
Alternative 2-Decommission Portland LNG and Enhance Mist Takeaway Capabilities 242

Alternative 3– Decommission Portland LNG and Enhance NWP Takeaway Capabilities............ 248
Alternative 4- Decommissions Portland LNG and Complete No Replacement Alternative......... 249
6.6.7 Capacity Resource Comparison 250
6.6.8 Capacity Resource Cost Uncertainty 252
7 System Resource Portfolio Optimization and Result.. 254
7.1 Least Cost Least Risk Portfolio Selection – Overview 255
7.2 Resource Planning Optimization Model (PLEXOS®) 256
7.3 Risk Analysis Overview 261
7.3.1 Scenario Analysis Overview 261
7.3.2 Monte Carlo Simulation Analysis Overview 264
7.4 Scenario Results.. 265
7.4.1 Scenario 1-Balanced Decarbonization.. 266
7.4.2 Scenario 2- Carbon Neutral 272
7.4.3 Scenario 3- Dual-Fuel Heating 278
7.4.4 Scenario 4- New Customer Moratorium 284
7.4.5 Scenario 5- Aggressive Building Electrification... 290
7.4.6 Scenario 6- Full Building Electrification 296
7.4.7 Scenario 7- RNG & H_2 Federal Policy Support 302
7.4.8 Scenario 8- Limited RNG Availability 308
7.4.9 Scenario 9- Supply-Focused Decarbonization 314
7.5 Scenario Results Takeaways 320
7.6 Monte Carlo Outcomes 320
7.6.1 Capacity Resource Acquisitions... 321
7.6.2 Compliance Resource Acquisitions and Purchases 322
7.6.3 Demand Reduction Investments 324
7.6.4 Weighted Average Cost of Gas 325
7.6.5 Weighted Cost of Decarbonization... 326
7.7 Preferred Portfolio and Analyzed Risk.. 328
7.7.1 Oregon Preferred Compliance Portfolio.. 328
8 - Distribution System Planning 332
8.1 Introduction.. 333
8.2 Distribution System Planning Process 334
8.2.1 Forecasting Peak Hour Load 336

8.2.2 Estimating Peak Hour Load 337
8.2.3 Peak Hour Loads 340
8.3 Distribution System Planning Tools and Standards 340
8.3.1 System Modeling 340
8.3.2 Customer Management Module (CMM) 343
8.3.3 System Reinforcement Standards 344
8.3.4 Identification of Distribution System Needs 345
8.4 Distribution System Resources 346
8.4.1 Existing Distribution System 346
8.4.2 Geo Current and Future Distribution System Planning Resources 347
Supply-side Options – Pipeline-related Resources 348
Supply-side Options - Non-pipeline Resources 351
Demand-side Resources 353
8.5 Distribution System Projects – 2022 IRP Action Item 360
8.5.1 Forest Grove Feeder Uprate 361
8.5.2 Customer Management Module (CMM) 362
8.5.3 Analysis 362
8.5.4 Uprate Scope 370
8.5.5 Hydrogen Compatibility 370
8.5.6 Project Alternatives 371
9 – Action Plan 373
9.1 Action Plan 374
10 – Public Participation 376
10.1 Public Participation 377
10.2 Technical Working Groups 377
10.3 IRP Draft Release and Meeting for the Public 381
10.4 Community and Equity Advisory Group 382

Table of Figures

Figure 1.1: NW Natural's Service Territory 10
Figure 1.2: Oregon Population Growth Slowing 13
Figure 1.3: Weighted Average Cost of Gas 14
Figure 1.4: NW Natural OR Emissions- Historical Trend and Impact of SB 98 and CPP 16
Figure 1.5: NW Natural WA Emissions- Historical Trend and Free Allowances in CCA 17
Figure 1.6: Monthly Sales Load by End Use 20
Figure 1.7: Annual Deliveries (Including Transportation) Forecast Range 20
Figure 1.8: Peak Day Load Resource Balance 21
Figure 1.9: Oregon Sales Customer Energy Efficiency Forecast: 2022 vs 2018 IRP 23
Figure 1.10: Emissions Compliance Option Cost Trajectories 24
Figure 1.11: Scenario 1 Oregon CPP Compliance Portfolio 26
Figure 1.12: Scenario 1 Washington Cap-and-Invest Compliance Trajectory 27
Figure 2.1: Inflation at a 41-Year High 32
Figure 2.2: Real Gross Domestic Product, Percent Change, Annualized 34
Figure 2.3: Oregon Employment Fully Recovered 35
Figure 2.4: Oregon Population Growth Slowing 37
Figure 2.5: Oregon House Prices Increasing Much Faster than U.S. 38
Figure 2.6: Pandemic Employment Impacts Across NW Natural Territory 39
Figure 2.7: Single Family Building Permits Issued (Annual) 41
Figure 2.8: Historical Daily Natural Gas Prices 42
Figure 2.9: Supply Diversity by Location January 2021-December 2021 43
Figure 2.10: Historical Natural Gas Prices and Forecasts by Trading Hub 44
Figure 2.11: Weighted Average Cost of Gas 45
Figure 2.12: Gas Price Basis to AECO 47
Figure 2.13: Gas Price Simulations – Annual Averages 48
Figure 2.14: RNG Projects 49
Figure 3.1: Load Forecast Model Flow Diagram 65
Figure 3.2: Load Forecast Model Flow Diagram – Customer Counts 66
Figure 3.3: Customer Count Forecast Process Diagram 68
Figure 3.4: System Residential Customers – Reference Case 71
Figure 3.5: System Commercial Customers– Reference Case 71
Figure 3.6: Load Forecast Model Flow Diagram – Weather Patterns 74
Figure 3.7: Weather Patterns for Resource Planning 76
Figure 3.8: Portland Example Annual Expected and Design HDDs 77
Figure 3.9: Expected and Design Weather Intra-Year Shaping – Portland Daily Temperatures 78
Figure 3.10: Single Simulation for Three Load Centers 79
Figure 3.11: Weather Simulation - Cumulative HDDs for Portland (Base 58°F) 80
Figure 3.12: Load Forecast Model Flow Diagram – UPC Models 82
Figure 3.13: UPC model 84
Figure 3.14: UPC Model Predicted Values 85
Figure 3.15: First Year Residential Annual Usage per Customer 86
Figure 3.16: First Year Commercial Annual Usage per Customer 86
Figure 3.17: OR Residential Cumulative Annual Savings and UPC Adjustment 88

Figure 3.18: Trend in Use per Customer With and Without Energy Efficiency – Reference 89
Figure 3.19: Residential and Small Commercial Annual Demand Forecast 90
Figure 3.20: Load Forecast Model Flow Diagram – Industrial, Large Commercial and CNG Load Forecast 91
Figure 3.21: System Industrial, Large Commercial and CNG Load by Service – Reference Case 92
Figure 3.22: Load Forecast Model Flow Diagram – Expected Annual Load Forecast 93
Figure 3.23: Expected Weather Annual Sales – Reference Case 94
Figure 3.24: Expected Weather Annual Throughput – Reference Case 94
Figure 3.25: Load Forecast Model Flow Diagram – Daily System Load 95
Figure 3.26: Daily Firm Sales Load and Temperature 96
Figure 3.27: Average Winter (Nov-Feb) Firm Sales Daily Use by Weekday 97
Figure 3.28: 2022 Firm Sales Peak Day Distribution 100
Figure 3.29: DSM Peak Day Savings Trend and Forecast 101
Figure 3.30: Load Forecast Model Flow Diagram – Peak Day Load Forecast 102
Figure 3.31: Peak Day Load Forecast Flow Chart 103
Figure 3.32: Peak Day Load Forecast Without DSM 104
Figure 3.33: Peak Day Load Comparison 2018 IRP to 2022 IRP 105
Figure 3.34- Existing Demand Response Impact 106
Figure 3.35: End Use Load Forecasting Process 107
Figure 3.36: Load Breakdown by End Use 108
Figure 3.37: Oregon Residential Customer Count Monte Carlo Results 109
Figure 3.38: Total System Load (Deliveries) by Scenario 110
Figure 3.39: Oregon Residential Stochastic Load Results 111
Figure 3.40: Total System Load Stochastic Simulation Results 112
Figure 3.41: Firm Sales Peak Day Load by Scenario 113
Figure 3.42: System Firm Sales Peak Day Load Stochastic Simulation Results 114
Figure 3.43: Peak Day Capacity Load Resource Balance 115
Figure 3.44: Oregon CPP Emission Compliance Needs 116
Figure 3.45: Washington Cap-and-Invest Emissions Compliance Situation 117
Figure 4.1: Residential Space Heating Peak Day Savings Estimate and Peak to Annual Ratio 124
Figure 4.2: NW Natural IRP Process 127
Figure 4.3: Example Avoided Cost Breakdown Through Time – Oregon Residential Space Heating 129
Figure 4.4: Oregon 30-year Levelized Avoided Costs by End Use 131
Figure 4.5: Washington 30-year Levelized Avoided Costs by End Use 132
Figure 4.6: Levelized Avoided Costs: 2022, 2018, 2016, and 2014 IRPs – Oregon 133
Figure 4.7: Levelized Avoided Costs: 2022, 2018, 2016, and 2014 IRPs – Washington 134
Figure 4.8: Avoided Costs by Life Cycle of Natural Gas and Year 135
Figure 5.1: 20-year Savings Potential by Sector and Potential Type - Oregon 140
Figure 5.2: Annual Savings Projection Comparison for 2018 and 2022 IRPs, with Actual savings since 2010 - Oregon 142
Figure 5.3: Three categories of savings potential identified by RA Model 143
Figure 5.4: Energy Trust's 20-Year DSM Forecast Determination Methodology 144
Figure 5.5: The Progression to Program Savings Projections 149
Figure 5.6: Summary of Cumulative Modeled Savings Potential - 2022–2041 - by Sector and type of Potential - Oregon 150

Figure 5.7: 20-year Cumulative Cost-Effective Potential by End Use - Oregon 150
Figure 5.8: Cumulative 20-year potential by savings type, detailing the contributions of commercially available and emerging technology - Oregon 151
Figure 5.9: 20-year Gas Supply Curve - Oregon 153
Figure 5.10: 20-Year Annual Savings Projection by Sector - Oregon 156
Figure 5.11: Annual Savings Projection by Sector-Measure Type - Oregon 157
Figure 5.12: Annual Savings Projection by Sector through 2050 - Oregon 158
Figure 5.13: Annual Savings Projection by Sector through 2050 - Oregon 159
Figure 5.14: NW Natural's Annual Peak-Day Savings Projection by Sector - Oregon 160
Figure 5.15: NW Natural's Annual Peak-Hour Savings Projection by Sector - Oregon 160
Figure 5.16: 20-Year Lower Bound Annual Savings Projection by Sector - Oregon 163
Figure 5.17: Annual Lower Bound Savings Projection by Sector-Measure Type - Oregon 164
Figure 5.18: Approach for Energy Efficiency Measure Characterization and Assessment 167
Figure 5.19: Baseline Projection Summary by Sector - Washington 168
Figure 5.20: Summary of Annual Cumulative Energy Efficiency Potential (mTherms) - Washington 169
Figure 5.21: Reference Case Cumulative Potential: Oregon Transportation 174
Figure 5.22: 2050 Cumulative Savings by Sector and Case: Washington Transportation 175
Figure 5.23: Gas-Fired Heat Pumps 177
Figure 5.24: Gas Heat Pump Technology Readiness by Manufacturer 178
Figure 5.25: Efficiency of Electric Heat Pumps and Ambient Temperature 179
Figure 5.26: Assumptions on Emerging Technology Adoption Over Time 180
Figure 6.1: Carbon Intensities for Registered Projects in the Oregon Clean Fuels Program 191
Figure 6.2: Tracking RTCs 193
Figure 6.3: Tracking RECs 193
Figure 6.4: ICF 2021 Net Zero Report Key Findings 194
Figure 6.5: 2021 RFP by Feedstock 196
Figure 6.6: Schematic of Polymer Electrolyte Membrane (PEM) Electrolysis 199
Figure 6.7: Synthetic Methane Production Process 200
Figure 6.8: Increasing renewable curtailment observed with increasing regional RPS goals 201
Figure 6.9: Comparative Energy Storage Resources: Size and Duration 202
Figure 6.10: Electrolyzer Fixed Cost per MMBtu vs. Facility Capital Costs 204
Figure 6.11: Electrolyzer Fixed Cost per MMBtu vs. Utilization Factor 205
Figure 6.12: Mid-Columbia Trading Hub Peak Wholesale Electricity Prices, Daily Low 206
Figure 6.13: Summary of Current Committed RNG Portfolio- Contracted Resources by Opportunity 208
Figure 6.14: Average Cost of RNG 209
Figure 6.15: Pacific Northwest Infrastructure and Capacities (MDth/day) 210
Figure 6.16: Current RNG Contracts 216
Figure 6.17: Tyson Lexington Skid 218
Figure 6.18: Combined RNG Supply Curve in 2040 219
Figure 6.19: Biofuels Supply Curve and Tranche 1 & 2 Portfolio Cost 220
Figure 6.20: Production Cost of Hydrogen 222
Figure 6.21: Reference Case Oregon Compliance Resource Bundled Price Paths 228
Figure 6.22: Reference Case Washington Compliance Resource Bundled Price Paths 228
Figure 6.23: Mist Recall Decision Timeline 229

Figure 6.24: Portland LNG Cold Box 235
Figure 6.25: Aluminum Pitting 236
Figure 6.26: Aluminum Pitting Clamp 236
Figure 6.27: D-1 & D-2 238
Figure 6.28: A-1 & A-2 239
Figure 6.29: Portland LNG Gas Flow Diagram with Middle Pipeline No LNG 243
Figure 6.30: North Corridor Route Options 245
Figure 6.31: Middle Corridor Route Options 247
Figure 6.32: Portland LNG Gas Flow Diagram 248
Figure 6.33: Portland LNG Gas Flow Diagram With LNG 249
Figure 6.34: Box and Whisker Plot for Capacity Resources 252
Figure 6.35: Box and Whisker Plot for Portland LNG Alternatives 253
Figure 7.1: System Resource Planning Requirements and Options 255
Figure 7.2: PLEXOS® Simple Model Example 258
Figure 7.3: 2022 IRP PLEXOS® Model Topography 260
Figure 7.4: Monte Carlo Example - 500 Draws 264
Figure 7.5: Monte Carlo Mist Recall Acquisition 322
Figure 7.6: Monte Carlo RNG Compliance Resource Acquisition 323
Figure 7.7:Monte Carlo Compliance Instruments Purchases 324
Figure 7.8: Demand Reduction Investment Totals 325
Figure 7.9: Monte Carlo WACOG 326
Figure 7.10: Monte Carlo WACOD from Renewable Compliance Resources 326
Figure 7.11: Monte Carlo WACOD from Compliance Instruments 327
Figure 7.12: Monte Carlo WACOD from Demand Reduction Investments 327
Figure 7.13: Monte Carlo Total WACOD 327
Figure 7.14: Oregon SB 98 and CPP Compliance Preferred Portfolio 329
Figure 8.1: Distribution System Planning Process 335
Figure 8.2: Distribution System Planning Process – Peak Hour 337
Figure 8.3: Hood River Area Intraday Load Shapes 338
Figure 8.4: Hood River and Portland, Oregon, Distribution Systems 339
Figure 8.5: Distribution System Planning Process – System Modeling 341
Figure 8.6: Data Used in Synergi™ Models 342
Figure 8.7: Distribution System Planning Process – Reinforcement Standards 344
Figure 8.8: Illustration of Hood River Area Pressure Issues 346
Figure 8.9: Purpose of Non-pipeline Solutions 348
Figure 8.10: Illustration of Hood River Area Pressure Issues and Resolution 351
Figure 8.11: Just in Time Supply-side Solutions 354
Figure 8.12: Timing for Demand-side Non-pipeline Solution 354
Figure 8.13: Distribution System Planning with Uncertainty 355
Figure 8.14: GeoTEE Phases 358
Figure 8.15: Hydrogen Blending Pressure Drop 360
Figure 8.16: Forest Grove Feeder System Identification 361
Figure 8.17: Forest Grove District Regulator Inlet Pressure - CMM vs EPPR 362
Figure 8.18: Existing System Peak Model 363

Figure 8.19: Forest Grove District Regulator Inlet Pressure Over Various Temperatures ... 364
Figure 8.20: Pressure Drop Vs Demand ... 365
Figure 8.21: 40% Pressure Drop for the Existing System ... 366
Figure 8.22: EPPR Data - February 23, 2022 ... 367
Figure 8.23: Proposed System Reinforcement ... 368
Figure 8.24: Uprated System Peak Model ... 369
Figure 8.25: Pressure Improvement ... 370
Figure 8.26: Uprated System Peak Model with 10% Hydrogen Blend ... 371

Table of Tables

Table 1.1: RNG Targets 2020-2050 ... 15
Table 1.2: Capacity Resource Options ... 22
Table 1.3: Emissions Compliance Options ... 23
Table 3.1: System Resource Planning by Customer Type ... 62
Table 3.2: Customer Count Series ... 67
Table 3.3: Exogenous Variables used in Econometric Customer Forecast Models ... 69
Table 3.4: Customer Forecasting Comparison between the 2022 and 2018 IRP ... 72
Table 3.5: Planning Standard Descriptions ... 73
Table 3.6: UPC Regression Data Details ... 83
Table 3.7: Driver Variable Impacts on Load Modeling ... 98
Table 4.1: Avoided Costs Components and Application Summary ... 120
Table 4.2: End Use Specific Peak Day Usage/Savings Ratios ... 125
Table 4.3: End Use Specific Peak Hour Usage/Savings Ratios ... 126
Table 4.4: Energy Efficiency Avoided Cost Summary Results by End Use and State (2021$/Dth) ... 132
Table 4.5: Costs Avoided by Low Carbon Resource Type ... 136
Table 5.1: Summary of Cumulative Modeled Savings Potential - 2022–2041 - Oregon ... 149
Table 5.2: Cumulative Cost-Effective Potential (2022-2041) due to use of Cost-effectiveness override (Millions of Therms) - Oregon ... 152
Table 5.3: Total 2022 IRP Cost-Effective Modeled Potential compared to 2018 and IRP modeled potential by Sector - Oregon ... 154
Table 5.4: Key Changes in Model that Increased Potential from 2018 IRP to 2022 IRP - Oregon ... 154
Table 5.5: 20-Year Cumulative Savings Potential by type, including final savings projection (Millions of Therms) - Oregon ... 155
Table 5.6: 20-year and 29-year Final Savings Projection (Millions of Therms) - Oregon ... 158
Table 5.7: 20-year Lower Bound Cumulative Savings Potential by type, including final savings projection (Millions of Therms) - Oregon ... 162
Table 5.8: 2023 and 2024 Annual Energy Trust Savings Projection (Therms) - Oregon ... 162
Table 5.9: Types of Potential and Definitions ... 166
Table 5.10: Baseline Projection Summary by Sector, Selected Years (mTherms) - Washington ... 168
Table 5.11: Summary of Energy Efficiency Potential (mTherms) - Washington ... 169
Table 5.12: Cumulative TRC Achievable Economic Potential by Sector, Selected Years (mTherms) - Washington ... 170
Table 5.13: Peak Day Potential Summary (mTherms) - Washington ... 171
Table 5.14: Peak Hour Potential Summary (mTherms) - Washington ... 171

Table 5.15: Summary Potential Results – Reference Case: Oregon Transportation 173
Table 5.16: 2050 Cumulative Savings by Sector and Case in mTherms: Washington Transportation 174
Table 5.17: Cumulative TRC Potential Savings by Customer Segment in mTherms: Washington Transportation 175
Table 5.18: Assumptions on Cost for Emerging Technologies 181
Table 5.19: Homes Served through OLIEE Program 182
Table 5.20: Homes Served through WA-LIEE Program 182
Table 6.1: Policies Driving RNG Acquisitions 189
Table 6.2: 2021 RFP Responses- Summary 197
Table 6.3: Hydrogen Sources 198
Table 6.4: Segmented Capacity Availability Assumption 214
Table 6.5: Long-term Compliance vs Short-term Flexibility 224
Table 6.6: Renewable Natural Gas Costs and Volumes 225
Table 6.7: Compliance Instrument Costs and Volumes 227
Table 6.8: Portland LNG Alternatives 234
Table 6.9: Replace Cold Box and Pretreatment System 240
Table 6.10: Pretreatment Improvement Cost Estimates 240
Table 6.11: Replace the Cold Box and Keep the Pretreatment System 241
Table 6.12: Keep the Existing Cold Box and Incremental Improvements to Existing Pretreatment System 242
Table 6.13: Phase 2 Results 248
Table 6.14: Capacity Resource Cost and Deliverability 251
Table 7.1: Decision Variables and Constraints 257
Table 7.2: Object Properties Example 258
Table 7.3: 2022 IRP Scenarios 263
Table 7.4: Stochastic Variables for Risk Analysis 265
Table 7.5: Capacity Resource Monte Carlo Acquisition Summary 321
Table 7.6: Oregon Short-term Preferred Portfolio Development 330
Table 8.1: Areas with a Peak Hour Load Forecast 340
Table 8.2: Distribution System Planning Alternatives 347
Table 8.3: Pipeline Uprate Capacity Example 350
Table 8.4: Distribution System Project 372

Glossary

AECO	Alberta Energy Company
AEG	Applied Energy Group
AGA	American Gas Association
AMA	Asset Management Agreement
ARIMA	Autoregressive integrated moving average
AWEC	Alliance of Western Energy Consumers
Baseload demand	Refers to utility customer demand that is constant over the year
Bcf	A billion cubic feet
Biogas	Gaseous fuel, especially methane, produced by fermentation of organic matter
Biomethane	A naturally occurring gas which is produced by anaerobic digestion of organic matter such as dead animal or plant material, manure, sewage, organic waste, etc.
Boiler	A large furnace in which water-filled tubes are heated to produce steam
Book and Claim Accounting	A chain of custody model which recognizes that environmental attributes (e.g., RTCs) can be separated from physical product and possession of environmental attribute can be used to deliver sustainable product
Brown Gas	The physical gas product from an RNG project where the environmental attributes have been separated and the RTC is not included
Btu	British thermal unit
Bundled RNG	RNG including the physical gas molecules and renewable thermal certificate (RTC)
CAGR	Compound Annual Growth Rate
Capacity	The maximum load that a gas pipeline or gas storage facility can carry under existing service conditions
Cap-and-Invest Program	Section of Washington's CCA, regulated by the Department of Ecology, which sets emissions caps, allowances, and trading mechanisms
Carbon cap	A limit on the amount of allowable carbon produced in a given region for a defined time period
Carbon Cap and Trade	A market mechanism to limit carbon emissions. Carbon emissions are capped at a certain level. Allowances are provided to companies and these allowances can be traded. The market sets the price of the allowances, creating a market incentive to reduce carbon emissions

Carbon credits or allowances	A fixed amount of carbon emissions to be produced is set for a period of time, and allowances or credits are allocated to carbon generators. The idea is that entities producing less carbon than their allowed amount can sell their allowances to other parties who are producing more than their allowed credit allowance. Often these can be traded or re-sold
CCA	Washington Climate Commitment Act
CCA allowances	A Cap-and-Invest Program mechanism for covered entities to obtain such allowances to cover emissions not reduced within a particular compliance period
CCI	Community Climate Investment
CCI credit	"an instrument issued by DEQ to track a covered fuel supplier's payment of community climate investment funds, and which may be used in lieu of a compliance instrument, as further provided and limited in this division." Or. Admin. R. 340-271-0020
CD	Contract Demand
CEAG	Community and Equity Advisory Group
CHP	Combined Heat and Power
CIS	Customer Information System
Citygate	The point of delivery at which a local gas distribution company takes custody of gas from an interstate pipeline; Meter stations which serve as designated point(s) on a distribution system where the distributor takes delivery of its gas supply from a pipeline source
Class B (pipeline system)	A pipeline system operating at 60 psig or less
CMM	Customer Management Module
CNG	Compressed natural gas
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
Cogeneration	The use of a single prime fuel source to generate both electrical and thermal energy in order to optimize the efficiency of the fuel used. Usually, the dominant demand is for thermal energy, with any excess electrical energy being transmitted into the lines of local power supply company
Common Carrier Pipeline	A pipeline that is connected to the continent-wide natural gas pipeline grid
Compliance obligation	"Total quantity of covered emissions from a covered fuel supplier rounded to the nearest metric ton of CO_2e." Or. Admin. R. 340-271-0020
Conservation Potential Assessment (CPA)	Analysis preformed to provide an outlook on the potential amount of energy efficiency or energy

	conservation that is available within a given area or territory over a defined period of time
Conversion	An existing residential or commercial building which adds natural gas service to the building and becomes a new NW Natural customer
CPI	Consumer Price Index
CPP	Oregon Climate Protection Program
CUB	Oregon Citizens' Utility Board
Curtailment	A method to balance natural gas requirements with available supply. Usually there is a hierarchy of customers for the curtailment plan. A customer may be required to partially cut back or totally eliminate its take of gas depending on the severity of the shortfall between gas supply and demand and a customer's position in the hierarchy
Degree day	The number of degrees that the average outdoor temperature falls below or exceeds a base value in a given period of time
Demand-side resource	An energy resource such as conservation that is based on how energy is used, not produced
DEQ	Department of Environmental Quality
Deterministic	A defined set of properties, constraints, or equations that explicitly defines the relationship between variables; deterministic solutions provide a single outcome; contrast with stochastic
DR	Demand response; reducing peak demand by either shifting or interrupting load
DSM	Demand-side management
Dth	Dekatherm (or dekatherm)
Discount rate	An interest rate that reflects the value of money over time. In comparing alternatives for a decision, a discount rate is applied to make different monetary stream flows equivalent, in terms of a present value or a levelized value
Distribution/Distribution System	The pipeline system that transports gas from interstate pipelines to customers.
EE	Energy Efficiency; EE is a reduction in energy use, production, or distribution as a result of greater efficiency
EFRC	Energy Frontier Research Center
EIA	U.S. Energy Information Administration
Energy savings	A term used to define the reduced energy usage as a result of energy efficiency initiatives
End-use consumer	Someone who uses energy to run equipment or appliances, such as for space heating and cooling, ventilation, refrigeration, and lighting

EPA	Environmental Protection Agency
EPPR	Electronic Portable Pressure Recorder
ERU	Emission Reduction Unit
ETO	Energy Trust of Oregon
Entitlement	An event during which gas shippers must not take delivery of more than a specified volume of gas in a day
Exogenous (variable)	A variable that is independent or determined outside of the model
FERC	Federal Energy Regulatory Commission
Firm (Sales, Service, Customers)	Service offered to customers under schedules or contracts which anticipate no interruptions. The period of service may be for only a specified part of the year as in off-peak service. Certain firm service contracts may contain clauses which permit unexpected interruption in case the supply to residential customers is threatened during an emergency.
GAP; GASP	Gas Acquisition Plan; Gas Acquisition Strategy and Policies
Gasco	NW Natural’s Portland LNG plant
Gas Day	A period of twenty-four consecutive hours, coextensive with a "gas day" as defined in the tariff of the Transporter delivering Gas to the Delivery Point in a particular transaction
GeoTEE	Geographically Targeted Energy Efficiency
GIS	Geographical information system
GHG	Greenhouse gas
GTI	Gas Technology Institute
HDD	Heating degree day
Hedging	Any method of minimizing the risk of price change.
Henry Hub	A natural gas national trading hub typically used for referencing national natural gas prices
Incremental costs	Additional costs that a utility would incur by operating a power plant, the cost of the next MMBtu generated or purchased, or the cost of producing and/or transporting the next available unit of energy above the current base cost previously determined
Interstate pipeline	Pipelines owned and operated by pipeline companies, where 3rd party shippers contract for firm and interruptible capacity

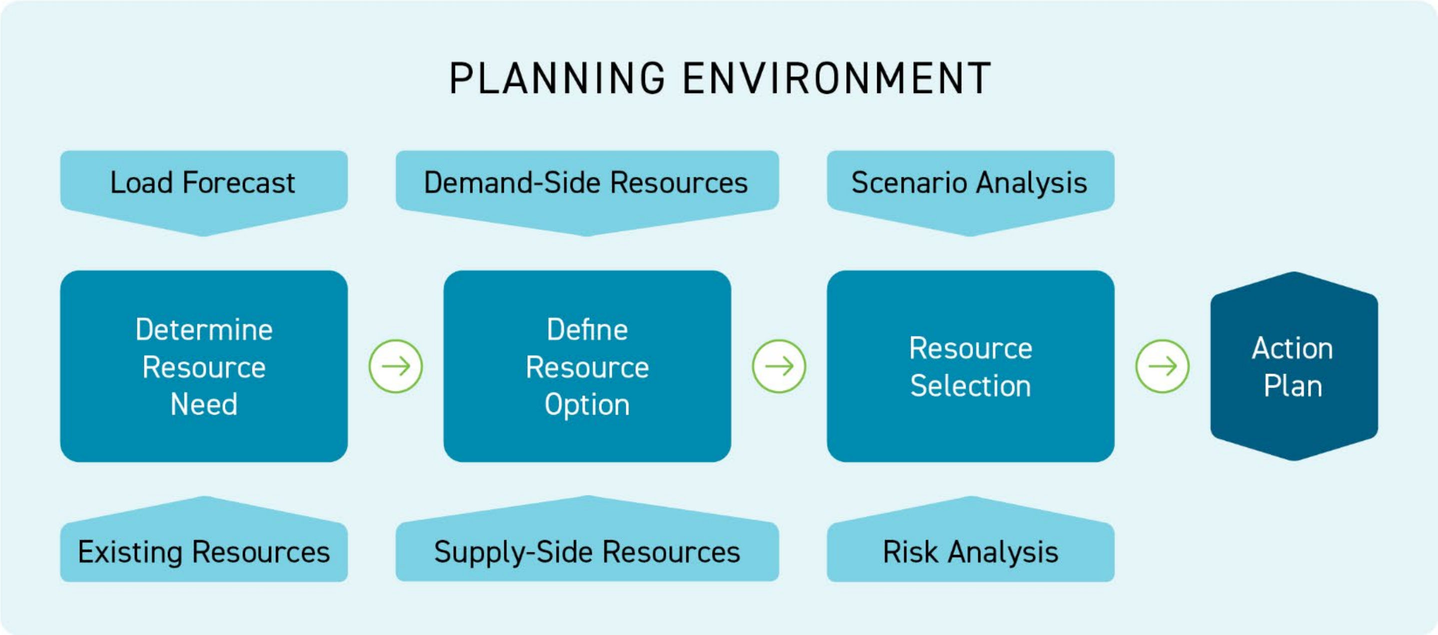
Interruptible (service, i.e., Sales or Transportation and also customers(s) of such service)	A transportation service similar to firm service in operation, but a lower priority for scheduling, subject to interruption if capacity is required for firm service. Interruptible customers trade the risk of occasional and temporary supply interruptions in return for a lower service rate.
IRP	Integrated Resource Plan
Jackson Prairie	A gas storage facility near Centralia, Washington, contracted by NW Natural
LDC	Local distribution company
Least-cost planning	Method of meeting future energy needs by acquiring the lowest cost resources first, considering all possible means of meeting energy needs and all resource costs including construction, operation, transmission, distribution, fuel, waste disposal, end-of-cycle, consumer, and environmental costs
Levelized (cost)	Equal periodic cost where the present value is equivalent to that of an unequal stream of periodic costs (typically expressed as a periodic rate; e.g., levelized cost per year)
LNG	Liquefied natural gas
Load	The demand for energy/power averaged over a specific time period
Load center	Geographical service area or collection of areas defined by NW Natural
Load factor	Ratio of total energy (example: therms) used in a period divided by the possible total energy used within the period, if used at the peak demand during the entire period
MAOP	Maximum allowable operating pressure
MAPE	Mean absolute percentage error
Marginal cost	The cost of producing the marginal, or next, unit
Mbtu	Thousand British thermal unit
Mbtu/ day	Thousand British thermal unit per day
Mcf	A thousand cubic feet
MDDO	Maximum daily delivery obligation
MDT	A thousand dekatherms
MMbtu	A million British thermal unit
MMbtu/ day	A million British thermal unit per day
MMcf	A million cubic feet
MMDT	A million dekatherms
MPH (or mph)	Velocity in miles per hour
MSA	Metropolitan Statistical Area: a geographical area as defined by the U.S. Office of Management and Budget (OMB)

$MTCO_2e$	A metric ton of carbon dioxide equivalent
Monte Carlo (simulation, analysis)	Statistical methods based on repeated sampling to simulate probability-based outcomes
Moving average	A statistical average calculated over a rolling period in time series data
NEEA	Northwest Energy Efficiency Alliance
New Construction	Newly constructed residential or commercial building with natural gas service which become a new NW Natural customer
NGL	Natural gas liquids
Nominations	The process of scheduling gas on the interstate pipeline. The shipper notifies the pipeline the volume and receipt point and the delivering receipt point in accordance with the transportation contract
Non-pipeline alternatives	Strategies to use natural gas more efficiently so that new pipeline capacity is not needed
Normal distribution	Commonly used probability distribution in statistical analysis
Normal weather	Expected weather conditions based on observed historical data
NPVRR (also PVRR)	Net present value revenue requirement
NWEC	NW Energy Coalition
NWIGU	Northwest Industrial Gas Users
NWGA	Northwest Gas Association
NWPCC	Northwest Power and Conservation Council
NWPL	Northwest Pipeline
ODOE	Oregon Department of Energy
OEA	State of Oregon's Office of Economic Analysis
Off-peak	Refers to a period of relatively low demand on a natural gas system. This can also refer to low demand months
OFO	Operational flow orders
OLIEE	Oregon Low Income Energy Efficiency
OPUC	Public Utility Commission of Oregon
Outage	A period, scheduled or unexpected, during which the transmission of power stops or a particular power-producing facility ceases to provide generation
P2G	Power-to-gas
Peak (day, hour)	A period in which a maximum value of a process (e.g., gas demand) occurs or is expected to occur
Peak day shaving	A peak day is the one day (24 hours) of maximum system deliveries of gas during a year. Peak shaving is a load management technique where supplemental supplies, such as LNG or storage gas,

	are used to accommodate seasonal periods of peak customer demand
PGA	Purchased gas adjustment
Planning Horizon	The timeframe which the IRP evaluates the net present value costs and outcomes for resource decisions. For this IRP the planning horizon is 2022-2050.
PLEXOS®	Optimization modeling software used by NW Natural
PSIG	Pounds per square inch gauge
PST	Pacific Standard Time
PVRR (also NPVRR)	Present value of revenue requirement
REC	Renewable energy certificate
Reference Case	An analytical scenario (e.g., forecast scenario) to which other scenarios are compared
RIN	Renewable identification number
RMSE	Root mean squared error
RNG	Renewable natural gas. “RNG” is gas that satisfies the definition of “renewable natural gas” or “renewable hydrogen” in either Oregon or Washington. **Oregon definition per ORS 757.392(7)**: “Renewable natural gas” means any of the following products processed to meet pipeline quality standards or transportation fuel grade requirements: (a) Biogas that is upgraded to meet natural gas pipeline quality standards such that it may blend with, or substitute for, geologic natural gas; (b) Hydrogen gas derived from renewable energy sources; or (c) Methane gas derived from any combination of: a. Biogas; b. Hydrogen gas or carbon oxides derived from renewable energy sources; or c. Waste carbon dioxide. **Washington definitions per RCW 54.04.190(6):** "Renewable natural gas" means a gas consisting largely of methane and other hydrocarbons derived from the decomposition of organic material in landfills, wastewater treatment facilities, and anaerobic digesters. "Renewable hydrogen" means hydrogen produced using renewable resources both as the source for the hydrogen and the source for the energy input into the production process.
ROW	Right of way
RPS	Renewable portfolio standards

RTC	Renewable thermal certificate An RTC is a *sole* claim to the environmental benefits of a dekatherm of RNG, separate from the physical gas of RNG (i.e., unbundled RNG)
Sales (service, customers)	Service provided whereby NW Natural acquires gas supply and delivers it to customers
SCADA (system)	Supervisory Control and Data Acquisition
SME panel	A panel composed of subject matter experts
Stochastic	The property of being randomly distributed or including a random component; a stochastic variable often feeds into a forecast, property or constraint providing a range of outcomes; contrasts with deterministic
Synergi™	A computer-based model used to simulate the physical natural gas system
T-DSM	Targeted demand-side management
TF-1	Northwest Pipeline's rate schedule designation for firm, year-round transportation service on its system
TF-2	Northwest Pipeline's rate schedule designation for firm transportation service on its system from certain storage facilities (e.g., Jackson Prairie). TF-2 service may have the same scheduling priority as, or may be subordinate/secondary in priority to, TF-1 service
Therm	Unit of measurement: 1 Therm = 29.3 KWh
Transportation (service, customers)	Service provided whereby a customer purchases natural gas directly from a supplier but pays the utility to transport the gas over its distribution system to the customer's facility
UPC	Use per customer
WACOG	Weighted average cost of gas
Weatherization	The use of structural changes, such as storm windows and insulation, in order to decrease use of heating fuel
Weather normalization	A method of averaging energy use under normal conditions. Also known as weather corrected, normalization enables comparison of energy use across periods of time or geography
W & P	Woods & Poole forecasting service
WUTC	Washington Utilities & Transportation Commission

1 | Executive Summary



1.1 Overview

1.1.1 About NW Natural

NW Natural is a natural gas local distribution and storage utility headquartered in Portland, Oregon with a 163-year history. NW Natural serves approximately 2.5 million people in Oregon and Washington via nearly 800,000 customer accounts. The service territory includes the Portland-Vancouver metropolitan area, the Willamette Valley, much of the Oregon Coast, and a portion of the Columbia River Gorge. Approximately 89% of NW Natural's customers reside in Oregon, with the other 11% in the state of Washington. Residential customers account for roughly 90% of our customer accounts.

Figure 1.1: NW Natural's Service Territory

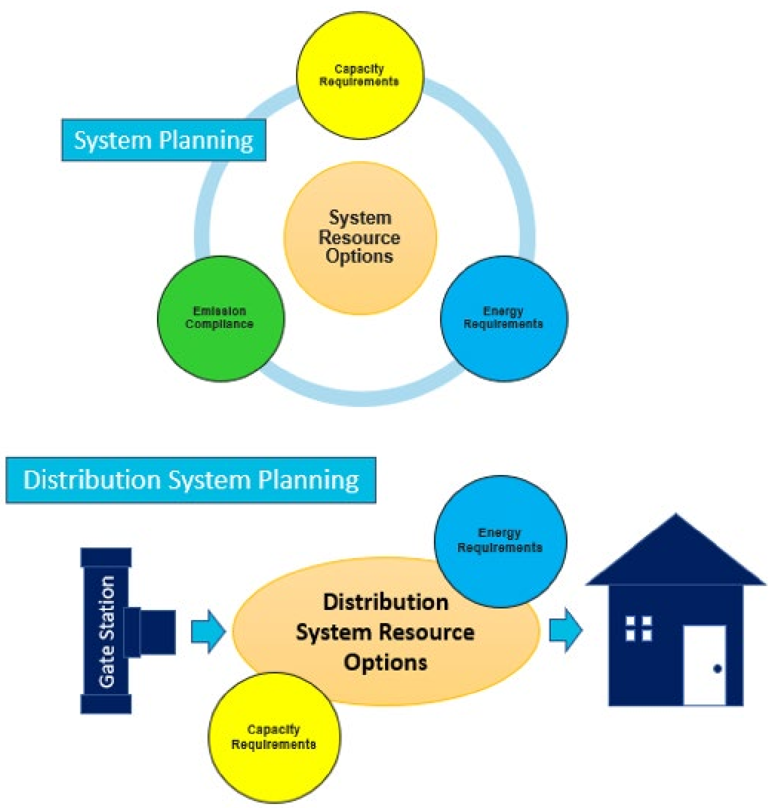
1.1.2 IRP Planning Process

Guided by the economic, political, and technological landscape in which we operate, and consistent with the requirements for Integrated Resource Planning set forth in Oregon Administrative Rule (OAR) 860-027-400 and Washington Administrative Code (WAC) 480-90-238, NW Natural develops a resource acquisition plan (an Integrated Resource Plan, or IRP) on approximately two-year cycles, with this plan looking out to 2050.

The IRP is the result of a rigorous analytical process that follows three broad steps:

1) forecasting our customers' future energy, capacity, and environmental compliance needs;
2) determining the resource options available to meet those needs, inclusive of both resource options that help reduce the amount of gas our customers use (demand-side resources) and options that help us deliver energy and meet emissions compliance obligations (supply-side resources); and finally
3) identifying the portfolio of resources with the best combination of cost and risk for our customers.

NW Natural conducts this involved analytical process to ensure that we have adequate gas supply to meet customer needs on each day and across a year (energy planning) and during the coldest days we might experience (system capacity planning). Additionally, we acquire resources that will allow us to comply with environmental compliance laws and rules (environmental compliance planning). Lastly, the analytical process ensures that we can distribute the gas coming onto our system so that each of our customers can be served reliably (distribution system planning).



Given that IRPs are completed roughly every two year and are updated annually, this IRP should not be viewed as a "set it and forget it" plan, but rather a snapshot of the resource portfolio that shows as the "least-cost- least-risk" way to meet customers' needs going forward with the information currently available. While each IRP has a long planning horizon, the primary output of each IRP is the Action Plan, which details the activities we propose taking before the completion of the next IRP (the next two to four years). As such, the actions detailed in the Action Plan are the near-term activities that are needed to serve customer needs now while allowing the utility to remain on a path that supports longer-term needs, noting that the next IRP will also include an Action Plan that will rely upon updated information, data, and analysis.

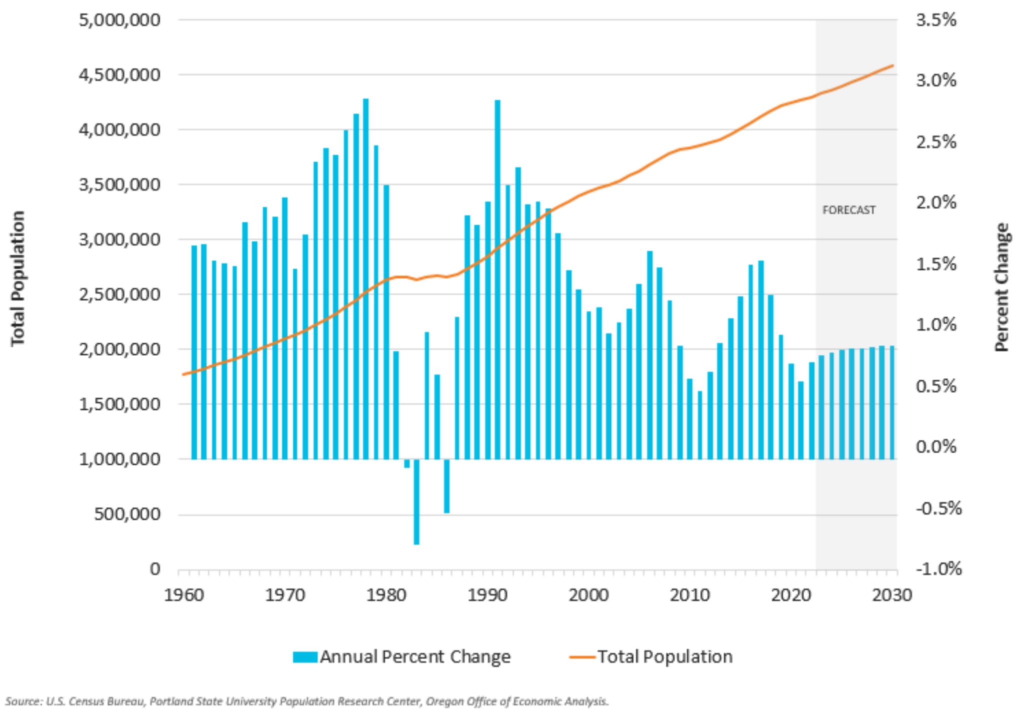
1.2 Planning Environment

Broader market and policy conditions and developments influence our customers' gas needs and the resource options that are suitable for us to serve those needs. While the planning environment presents analytical challenges and uncertainty in every IRP, the combination of the dynamic environmental policy associated with the energy transition in the Pacific Northwest, the current uncertainty in energy markets and the broader economy, and adjustments associated with the COVID-19 pandemic make the current planning environment particularly challenging.

1.2.1 Economic Outlook and Energy Markets

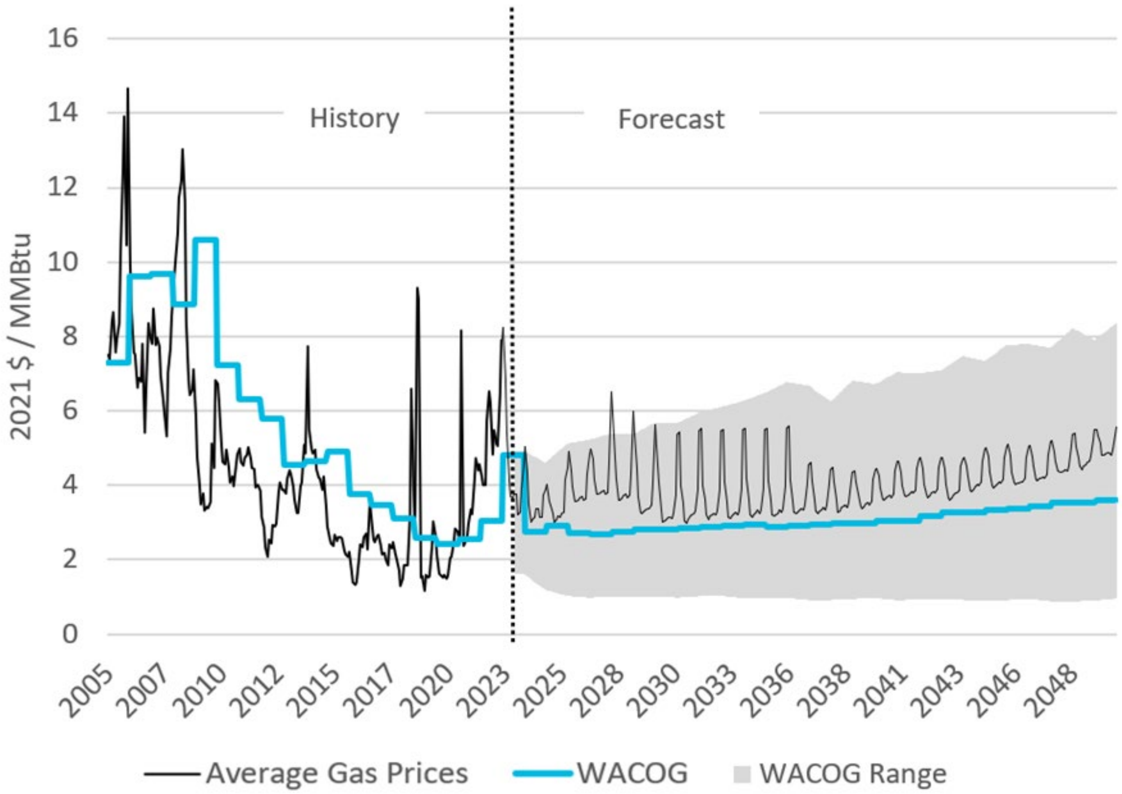
The broader economy is an important driver of the customer growth and gas use of NW Natural customers. When NW Natural completed its last IRP in 2018, our service territory, like the rest of the United States, was roughly a decade into the recovery from the Great Recession of the 2007-2009 period. While the 2018 IRP did not contemplate the COVID-19 pandemic, the current environment of high inflation or the acuteness of the housing shortage in our service territory, the customer growth projected in the 2018 IRP has largely materialized. As we draft this IRP a high level of economic uncertainty has settled on the Pacific Northwest, the United States, and the globe. While employment in NW Natural's service territory has largely recovered to pre-pandemic levels, high inflation, increasing interest rates, housing affordability, a potential recession on the horizon, living preferences, and working options changed by the pandemic all could impact NW Natural customer growth and residential, commercial, and industrial gas usage moving forward. These and other factors have slowed expected population growth in our service territory.

Figure 1.2: Oregon Population Growth Slowing



While the conventional natural gas markets, where NW Natural purchases gas on behalf of our customers, are currently experiencing prices higher than in recent years due primarily to Russia's invasion of Ukraine, prices of conventional gas are expected to return to levels consistent with prices in recent years over the medium- and long-term. However, while long-term expectations in conventional gas prices have not changed substantially compared to the 2018 IRP, limited capacity in regional and national natural gas infrastructure is driving an increase in price *volatility*, particularly during extreme weather events when NW Natural customers' gas needs are highest. Market dynamics suggest this current environment of more volatile prices during extreme weather is likely to continue, even as prices fall back to those in line with recent years.

Figure 1.3: Weighted Average Cost of Gas[1]



1.2.2 Environmental Policy

The single largest driver of change in this IRP is climate policy established in Oregon and Washington in recent years, and uncertainty about potential additional policies that could impact NW Natural's resource planning. NW Natural has implemented changes over recent IRP cycles to assess and evaluate low-GHG emissions supply resources, forecast emissions, and analyze demand- and supply-side resources on an apples-to-apples basis within the context of not only energy needs but also GHG emissions[2]. These innovations, along with new analytical tools developed for this IRP, are needed to evaluate customer needs with NW Natural being a covered entity with compliance obligations under GHG emissions cap programs. Also, while NW Natural plans its resources on a service-territory wide basis for energy and capacity needs to the benefit of customers in both Oregon and Washington, differing climate policy in the two states requires that for the first time our emissions compliance planning be conducted at the state level, resulting in a more complex IRP than in previous years.

[1] The range for the forecasted WACOG is based on the 5th and 95th percentile outputs of a stochastic simulation process optimized through the Resource Planning Optimization Model (i.e., PLEXOS®). The forecasted WACOG is the annual mean of these simulations.

[2] Apples to apples comparison here refers to using the same least cost least risk framework and using PVRR and risk analysis to evaluate portfolio options.

Climate Policy Enacted Since Last IRP - Oregon

1. **Senate Bill 98 (SB 98)**- Passed in 2019 SB 98 encourages the development of renewable natural gas (RNG) and allows natural gas utilities to procure RNG at the following voluntary targets as a percentage of natural gas sales:

Table 1.1: RNG Targets 2020-2050

Year	RNG Target (% of gas sales)
2020-2024	5%
2025-2029	10%
2030-2034	15%
2035-2039	20%
2040-2044	25%
2045-2050	30%

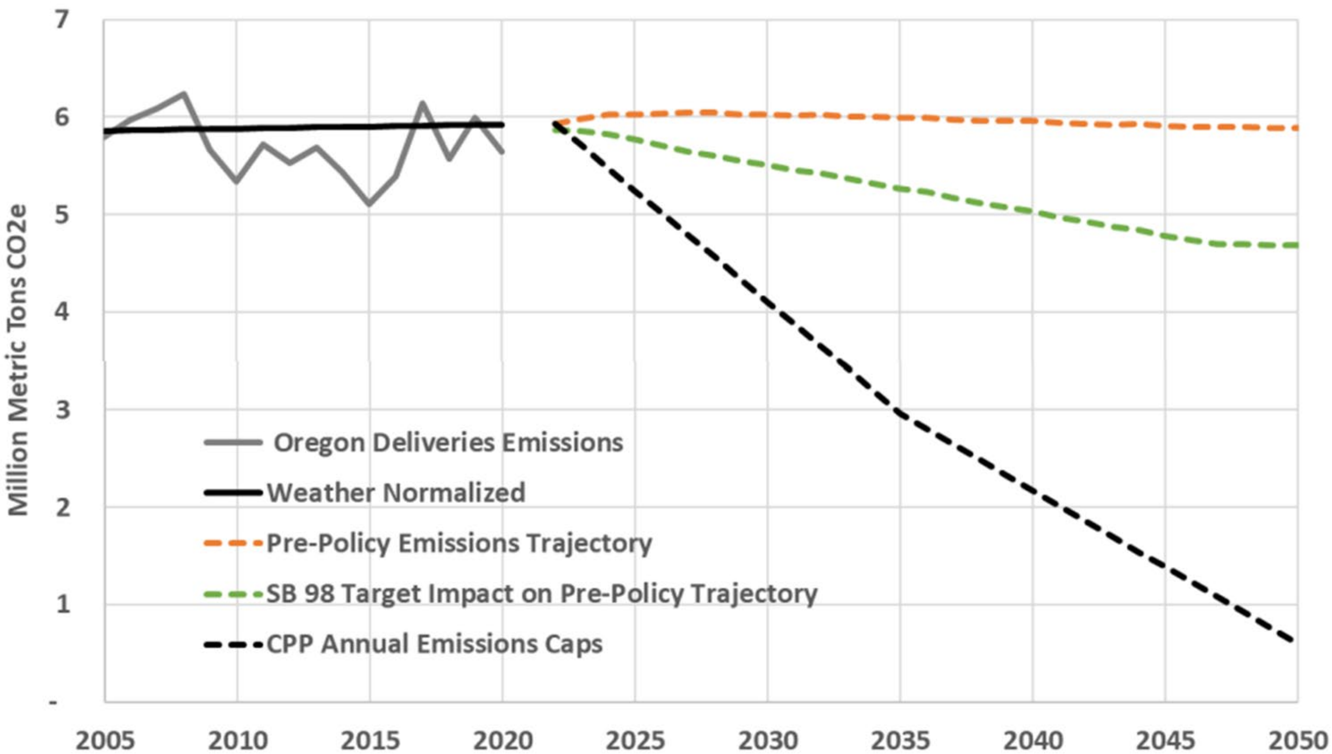
Rules for program implementation were established at the Oregon Public Utility Commission in 2020[3] and NW Natural has begun procuring RNG to meet the targets in SB 98. The law states that it may not be allowed to continue to pursue additional RNG qualified investments if the incremental cost of RNG exceeds 5 percent of total revenue requirement in a given year.

2. **Climate Protection Program (CPP)**- The CPP is a GHG emissions cap program established with an initial compliance year of 2022 administered by the Oregon Department of Environmental Quality (ODEQ). The CPP was established from direction from Executive Order 20-04 issued by Gov. Brown in 2020. The program includes roughly half of the state's emissions and primarily covers the transportation and natural gas utility sectors. The CPP has three-year compliance periods and sets annual emissions compliance limits for natural gas utilities and associated customer emissions. The CPP also establishes gas utilities as the covered party for the emissions associated with the use of gas on utility transportation rate schedules. The CPP is not a typical cap-and-trade system that includes state-sanctioned allowance auctions.

   Figure 1.4 shows the expected impact of SB 98 and the CPP relative to a pre-policy emissions trajectory to show the requirements of the CPP relative to historical trends and details the emissions reduction requirements that are a key driver of the activities in this IRP.

[3] For additional information please see Oregon Docket AR 632

Figure 1.4: NW Natural OR Emissions- Historical Trend and Impact of SB 98 and CPP

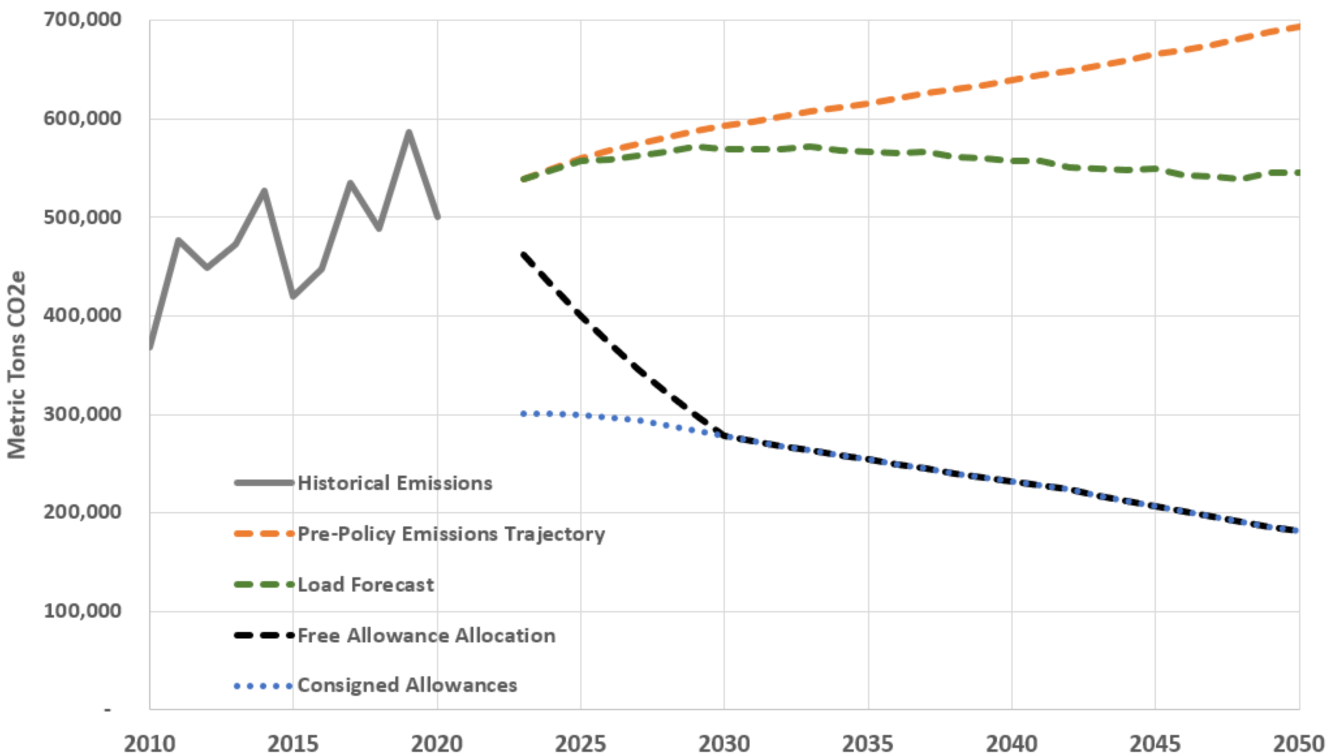


Climate Policy Enacted Since Last IRP - Washington

1. **House Bill 1257 (HB 1257)**- Passed in 2019. Establishes a requirement for natural gas utilities to establish a voluntary renewable natural gas option for customers, conduct energy efficiency forecasts (or conservation potential assessments (CPAs)) with economically incented targets, and use the social cost of carbon for resource planning. Similar to SB 98 in Oregon HB 1257 also declares the value of RNG for reducing emissions and includes a provision that allows natural gas utilities to sell and/or deliver RNG to all customers up to a total cost of 5% of revenue requirement.

2. **Climate Commitment Act (CCA)**- Passed in 2021. Directs establishment of a cap-and-invest program with similar provisions as the trading program currently in practice in California. The cap-and-invest program is currently in rulemaking. Covered parties need to demonstrate they have compliance instruments equal to their emissions over 4-year compliance periods. The program will establish a state-sanctioned allowance trading program and provides free and consigned emissions allowances to natural gas utilities for some of their customers' expected emissions. Gas utilities are also established as the point of regulation for most customers on gas transportation schedules. Figure 1.5 shows the CCA Pre-policy emissions trajectory along with the expected compliance allowances.

Figure 1.5: NW Natural WA Emissions- Historical Trend and Free Allowances in CCA



3. **Building Codes Updates**- Residential building codes were updated in 2018 and commercial codes in 2022. Both updates made it more challenging to meet energy and emissions standards with the most common natural gas equipment installed in homes and businesses today.

For gas utilities the climate policies established since the filing of our last IRP are transformative policies that have generated transformative changes in NW Natural's resource planning and the Action Plan in this IRP. In fact, waiting for the OR-CPP rules to be finalized was the primary driver of NW Natural delaying its IRP until 2022. While these programs have provided certainty by establishing emissions reduction requirements with natural gas utilities as covered parties, they also create substantial uncertainty in resource planning and a heightened focus on resources that can help reduce GHG emissions.

Furthermore, there is still substantial policy uncertainty given that additional local, state, or federal climate policies that are currently being considered could restrict growth and incent electrification. This policy uncertainty manifests in key planning assumptions important to conducting IRP analysis and requires different tools to comprehensively analyze outcomes that represent large changes from current trends.

The climate policies enacted since our last IRP, current uncertainty, and stakeholder feedback through the IRP process were the impetus for the following changes in this IRP:

1. Development of a Community and Equity Advisory Group
    - Recognizing the need to hear additional voices that have been underrepresented in past IRPs, this IRP was the impetus for the formation of NW Natural's Community and Equity Advisory Group (CEAG). This group was recently formed but it is anticipated that the CEAG will assist NW Natural on various programs and processes including the resource planning process.
2. Switching to the PLEXOS® software resource planning optimization
    - The change to the far more flexible PLEXOS® software allowed NW Natural to develop the complex model needed to conduct robust emissions compliance planning to develop appropriate strategies for emissions compliance in both Oregon and Washington.
3. More detailed assumptions about low-GHG emitting resources
    - While NW Natural has analyzed both low carbon supply-side (e.g., RNG, clean hydrogen, etc.) and demand-side (e.g., natural gas heat pumps) resources in prior IRPs, these resources did not show as cost-effective resources in the near term given that we did not have authority to procure these resources if they were more expensive than conventional gas. Emissions cap programs change this dynamic and require these resources as part of the preferred portfolio and the Action Plan.
4. Change in load forecasting methodology
    - Given the transformative emissions policies that have been established and the current policy uncertainty, we have decided it is no longer appropriate to project forward historical trends to project our customers' needs. We have deployed forecasting techniques that project a change from historical trends. Additionally, we have modeled dual-fuel (or hybrid) gas-electric space heating for the first time in this IRP.
5. Including transportation schedule loads in our optimization modeling
    - In previous IRPs NW Natural's gas supply and emissions planning did not include loads on gas transportation rate schedules (though transportation loads were included in distribution system planning) since NW Natural does not need to supply/sell (only distribute) gas to transportation rate schedule customers. However, given that gas utilities were made the point of regulation for transportation schedule emissions in both the OR-CPP and WA-CCA it is required that these loads be included in our resource modeling to appropriately model emissions compliance.
    - Furthermore, given that there are not currently utility affiliated energy efficiency (EE) programs that serve transportation schedule customers there is discussion in both Oregon and Washington about establishing EE programs for transportation schedule customers to be part of the utilities' emissions compliance options. In anticipation that EE programs for transportation customers might be established, and to better

understand what cost-effective EE might be available to contribute to emissions compliance obligations, NW Natural had an independent consultant conduct the CPA for its transportation customers. Like existing energy efficiency programs, this CPA showed meaningful cost-effective savings in the context of compliance with the OR-CPP and WA-CCA.

6. Utilizing stochastic risk analysis as the primary tool for developing the Action Plan
    - While NW Natural has conducted robust risk analysis for numerous IRPs, in past IRPs a single base case was developed, and the Action Plan was constructed primarily using the results from this base case. Given the high degree of uncertainty and the transformative new policies which we are implementing the Action Plan and preferred portfolio in this IRP is based upon a risk-adjusted approach based upon the range of outcomes of our stochastic Monte Carlo simulations.

To assess a prudent path for implementing the climate policies discussed above in the context of a high degree of uncertainty NW Natural developed nine scenarios to understand the least-cost resource portfolio under a wide range of "what if" potential futures to supplement the reference case with input from stakeholders in the IRP process. Complying with the provisions of the OR-CPP and the WA-CCA is required of all scenarios. The results from this scenario analysis were ultimately used to help define the stochastic risk analysis conducted to develop the preferred portfolio in this IRP.

1.3 Determining Resource Needs – Energy, Capacity, and Compliance

On an annual basis, NW Natural's sales load[4] consists predominantly of space heating. During peak conditions, sales load and total deliveries are driven by space heating. Because of the needs for space heating, our loads are very seasonal and have peaks that are much higher than average daily loads. After adjusting for expected energy efficiency acquisition over the planning horizon it is expected that annual load will decline over the planning horizon. While peak load may decline in the long-term in the short- and medium term it is expected that it will continue to rise similar to recent history. While these forecasts represent our risk-adjusted expectations, there is uncertainty in load forecasting – particularly in the later years of the planning horizon – so expected resource decisions are tested for robustness using a wide range of peak capacity and annual load forecasts.

[4] "Sales" load is a bundled service where NW Natural provides a bundled service that includes both the natural gas commodity and delivery services, whereas "transportation" load does not include sale of the natural gas commodity, simply delivery of the gas purchased by another gas supplier

Figure 1.6: Monthly Sales Load by End Use

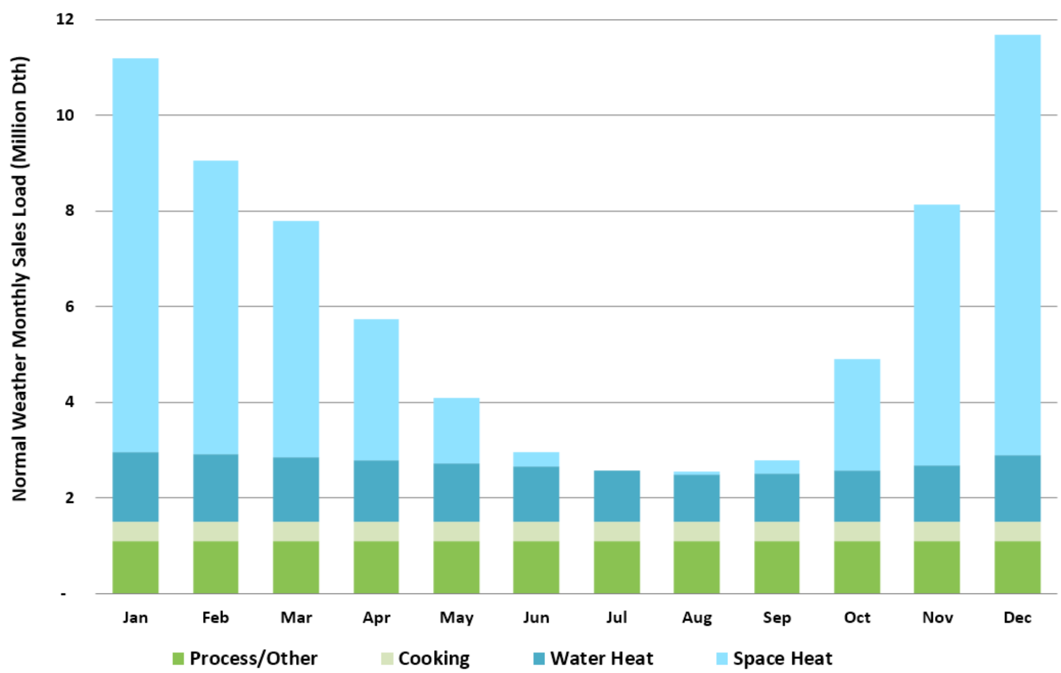
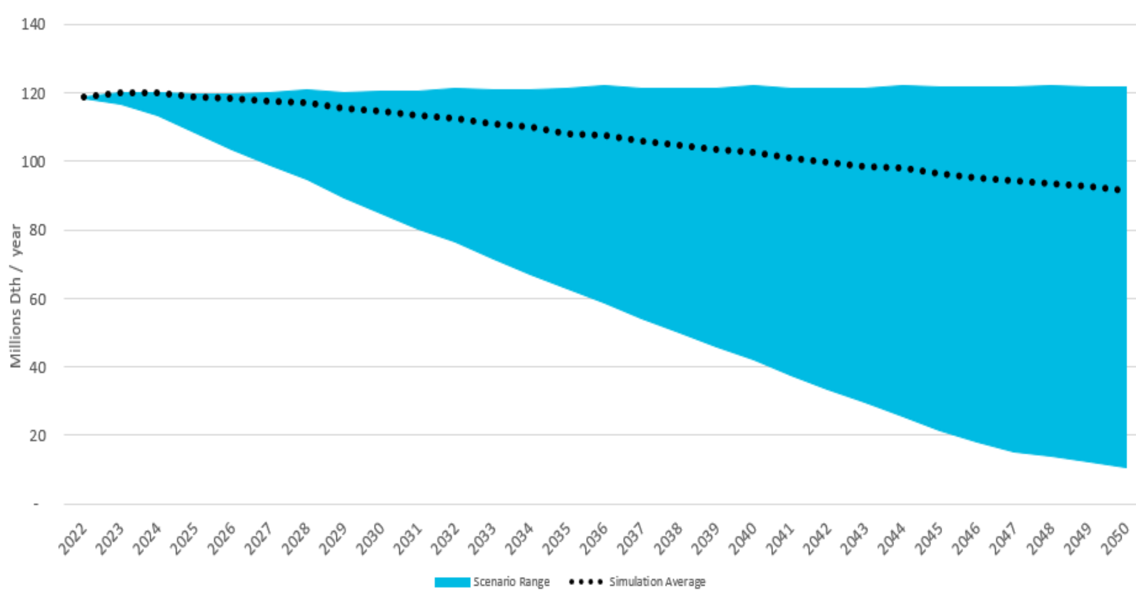
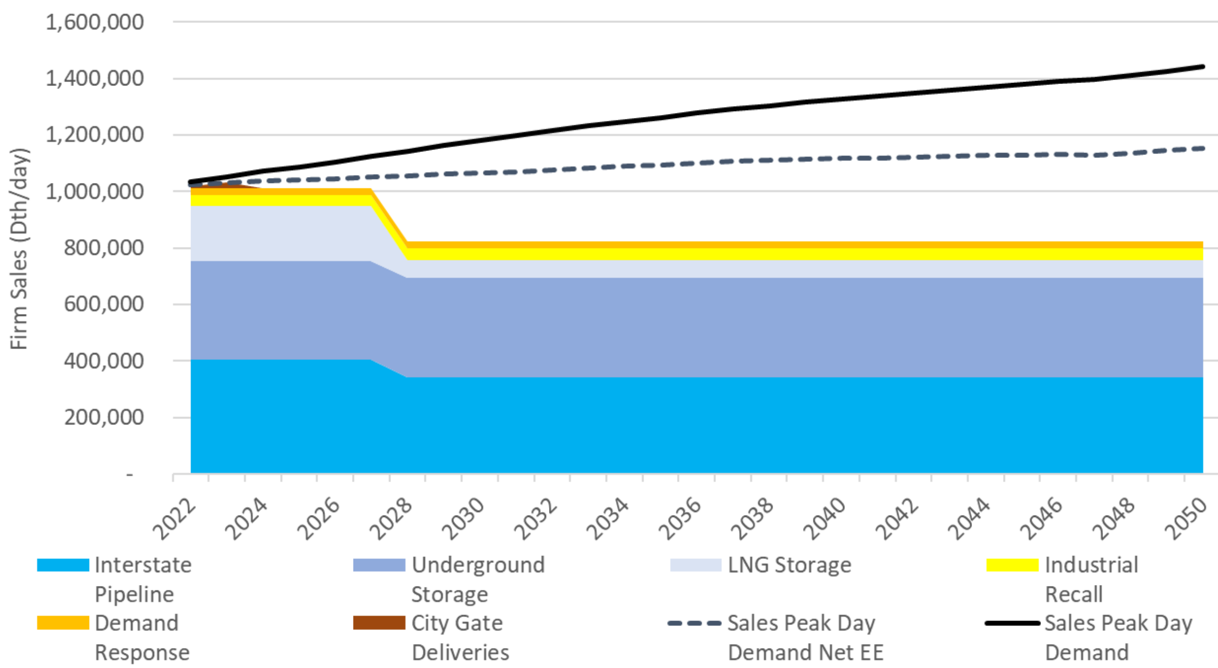


Figure 1.7: Annual Deliveries (Including Transportation) Forecast Range



The risk-adjusted peak load forecast, in coordination with assumptions about the availability of energy efficiency savings shown above translates to the capacity load-resource balance shown in Figure 1.8.

Figure 1.8: Peak Day Load Resource Balance



Along with energy and capacity needs, both customers in Washington and Oregon have compliance needs to meet emission compliance with the environmental policies discussed above.

1.4 Resource Options to Meet Needs

Resource options to meet these needs will vary in each resource's ability and cost to meet these needs.

1.4.1 Energy and Capacity Options

Figure 1.8 shows the peak capacity load resource balance that NW Natural needs to fill to ensure that it can reliably serve customers in the event of an extreme cold event. As the figure shows, without action to replace the Cold Box at the Company's Portland liquified natural gas (LNG) facility a resource that NW Natural relies upon from to serve customers during peak periods would no longer be available and its capabilities would need to be replaced. Table 1.2 below shows the capacity resource options analyzed to fill the resource deficiency depicted in Figure 1.8.

Table 1.2: Capacity Resource Options

Capacity Resource	Cost ($/Dth/day)	Daily Deliverability (Dth/day)
Mist Recall	$ 0.09	As needed Max : 203,800
Newport Takeaway 1	$ 0.14	16,125
Newport Takeaway 2	$ 1.00	13,975
Newport Takeaway 3	$ 1.41	12,900
Mist Expansion	$ 0.62	106,000
Upstream Pipeline Expansion	$ 2.12	50,000
Portland LNG - Cold Box	$ 0.06	130,800
Interstate Pipeline Looping Plus Required Mist Recall	$ 0.39	130,800†
Middle Corridor NWN System Pipeline Plus Required Mist Recall	$ 0.35	130,800‡

Notes: Pipeline options are available for selection November 1st of year; storage options are available for selection May 1st in each year. Newport Takeaway options must occur sequentially.

† Pressure modeling shows that with this option would allow for additional Mist takeaway and would increase the max Mist Recall to 240,492 Dth/day. 130,800 is used in this table for a direct comparison to the deliverability enabled by the Cold Box alternative.

‡ Pressure modeling shows that with this option would allow for additional Mist takeaway and would increase the max Mist Recall to 204,422 Dth/day. 130,800 is used in this table for a direct comparison to the deliverability enabled by the Cold Box alternative.

1.4.2 Emissions Policy Compliance Options

Defining and assessing options to reduce emissions is a primary focus of this IRP, and the options that can be used to reduce or offset emissions for compliance vary between the OR-CPP and the WA-CCA. Some forms of energy efficiency and emissions compliance options are more flexible than others and can be procured to and used for emissions compliance on short timeframes, while others require a longer lead time for construction (e.g., development of a new RNG or hydrogen project) or attrition through time (e.g., energy efficiency).

Table 1.3 below shows the options evaluated by NW Natural for compliance with the OR-CPP and WA-CCA.

Table 1.3: Emissions Compliance Options

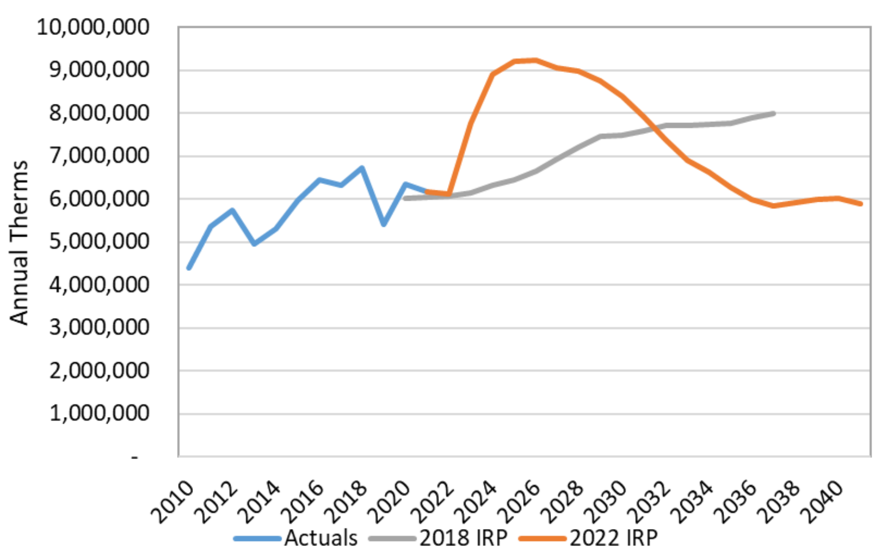
Emissions Compliance Options	Long-term Compliance Option	Short-term Compliance Flexibility
Energy Efficiency	✓	
Development RNG	✓	
RNG offtake from existing project	✓	✓
Development Hydrogen	✓	
Development Synthetic Gas	✓	
Community Climate Investments*	✓	✓
Banking	✓	✓
Allowance Trading Auction**	✓	✓
Bilateral Allowance Trading*	✓	
Offsets**	✓	✓

* Only and option under Oregon Climate Protection Program
** Only and option under Washington Cap-and-Invest

Energy Efficiency

The OR-CPP substantially increased avoided GHG emissions costs compared to the last IRP, leading to a sizeable increase in near- to mid-term energy efficiency expectations from Energy Trust of Oregon programs for customers with a bundled gas sales service, as can be seen in Figure 1.9.

Figure 1.9: Oregon Sales Customer Energy Efficiency Forecast: 2022 vs 2018 IRP



Supply-Side Low GHG Resources

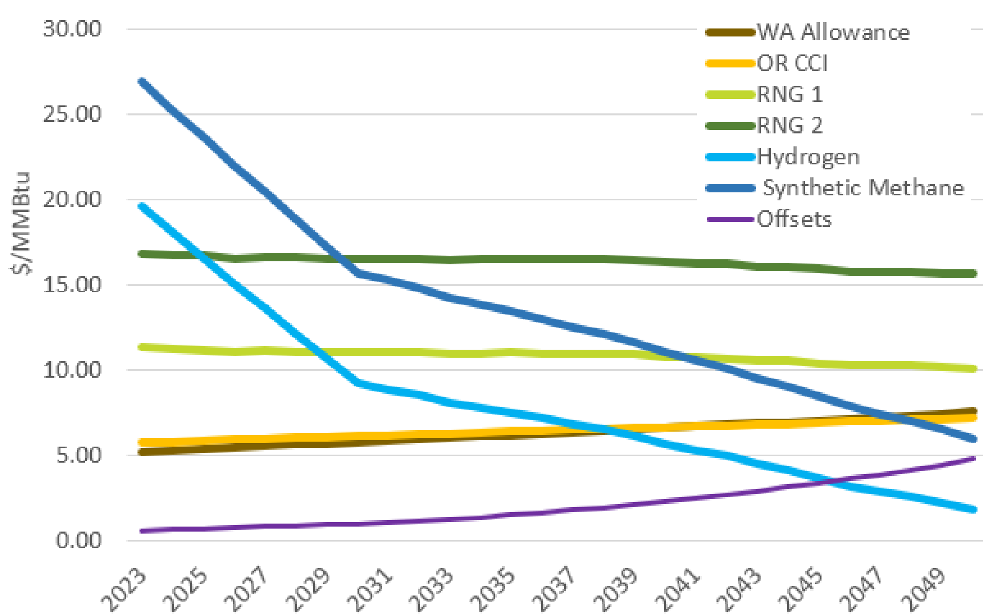
This IRP focuses on assessing the cost and availability of RNG, clean hydrogen and synthetic gas derived from clean hydrogen combined with carbon capture. Independent third parties served as the primary source for establishing many of these assumptions, where NW Natural's experience in the biofuel RNG market served a key role in understanding prices and validating availability.

Compliance Instruments

Both the OR-CPP and the WA-CCA have options that are allowed for compliance which are not direct emissions reductions from NW Natural customers. In simplistic terms, from NW Natural's customers' perspective, these options can be thought of as offsets. In the OR-CPP the purchase of CCIs serve this role, whereas emissions offsets and emissions allowances can be used for compliance in the WA-CCA. Prices for CCIs are set in rule, where offsets need to be acquired by covered parties in the WA-CCA and the allowance trading market, with bounds set in rule, determine the prices of allowances in the program (noting that the Social Cost of Carbon (SCC) replaces the cost of allowances for resource decision-making purposes in complying with the WA-CCA).

Like other key inputs, these prices and availabilities are somewhat uncertain, and ranges for these assumptions are deployed in both scenario and stochastic risk assessment, with the primary cost assumptions for these resources are shown in Figure 1.10.

Figure 1.10: Emissions Compliance Option Cost Trajectories[5]



[5] Costs show the unbundled price. See Chapter 6 for details about bundled vs. unbundled RNG.

1.5 Resource Selection and Preferred Portfolio

Using the newly developed PLEXOS® model, least-cost portfolio optimization was conducted on the nine "what if" scenarios and 500 stochastic simulations (also known as draws) each with a unique set of input assumptions. While there is substantial long-term uncertainty in the levels of capacity needed and what (and how much) emissions reduction resources are the lowest cost options for customers, this work resulted in the emergence of clear paths forward in terms of ensuring reliability (capacity planning) and meeting emissions compliance obligations in the near-term (i.e., the period covered by the action plan in this IRP). In other words, the results show that an Action Plan in this IRP can be developed that represents a low regret path forward.

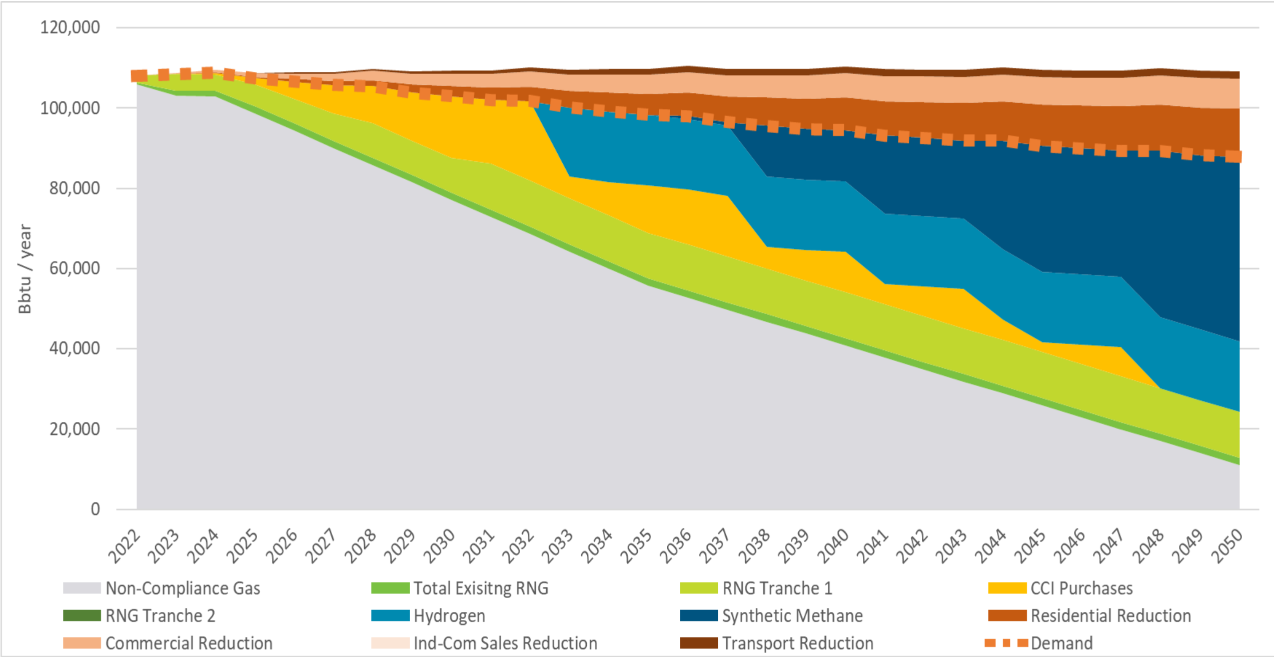
1.5.1 Capacity Results

All scenarios except for the most extreme electrification scenario show that replacing the Cold Box at the Portland LNG facility to retain the plants peaking capabilities moving forward is the cheapest way to serve customer needs. Additionally, all scenarios rely upon recalling deliverability from NW Natural's Mist storage facility to serve and meet expected capacity needs over the planning horizon. While a decision needs to be made now to address a potential shortfall in 2027 if the Portland LNG facility is not retained in the resource portfolio, recalling Mist deliverability is a flexible resource with a short lead time that can be optimized through annual updates to resource planning work.

1.5.2 Emissions Compliance Results

Figure 1.11 and Figure 1.12 show the least-cost compliance options for Scenario 1, which has results that are indicative of most scenarios and representative of the average results of the stochastic simulation work.

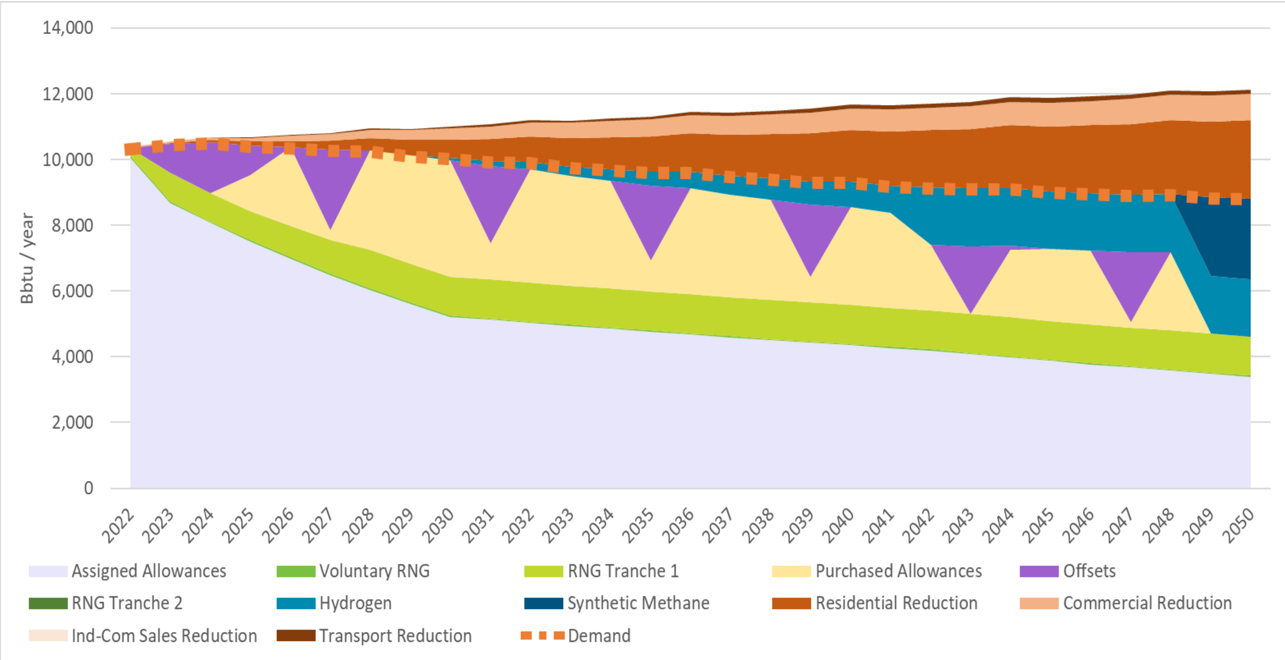
Figure 1.11: Scenario 1 Oregon CPP Compliance Portfolio



The majority of scenarios and simulation draws show that in the OR-CPP's first compliance period (2022-2024) biofuel RNG to meet SB 98 targets make up the majority of the needed compliance action. Depending on weather and other load developments a small amount of the lowest cost incremental option – CCIs – could be needed during the first 3-year compliance period. In no scenario do the CCIs projected approach the limit for CCIs allowed in the first compliance period. Since the amount of RNG needed to achieve SB 98 targets varies by scenario due to differences in load (SB 98 targets are a percentage of sales load), higher load scenarios show more SB 98 RNG and lower load scenarios show smaller amounts SB 98 RNG, though the difference is small given that load cannot change materially from current levels by the end of 2024. Also, even in scenarios with aggressive load reductions going forward, the amount of RNG that aligns with near-term SB 98 targets would be able to be utilized for compliance (i.e., not "wasted" in terms of compliance needs). Furthermore, over the first compliance period it is not anticipated that RNG or clean hydrogen would be cheaper than CCIs, making a strategy of purchasing compliance needs, more than SB 98, a robust option.

Looking at the results across scenarios and simulation draws shows a consistent trend in expected OR-CPP emissions compliance resources through time. In the near-term biofuel RNG is the cheapest option and is used to meet SB 98 targets, whereas renewable hydrogen is expected to become the incremental resource starting around 2030, and once blending limits are reached around 2040, synthetic methane (or methanated renewable hydrogen) becomes the cheapest resource.

Figure 1.12: Scenario 1 Washington Cap-and-Invest Compliance Trajectory



The Washington Cap-and-Invest program the results are similar to the results in Oregon, where biofuel RNG supported by HB 1257 is expected to be a core resource in the near term, one that is supplemented by offsets and allowance purchases. At current price expectations for offsets a strategy of maximizing the offsets allowed in the program shows as the least cost option. However, there is still work that needs to be done to understand what offsets might be available on tribal lands and what they might cost, but if these can be procured at a price lower than the expected price of allowances they would also be acquired for compliance. Allowance purchases show as the lowest cost option to fill in the remaining compliance need over the first compliance period (2023-2027), even if allowance prices are at the price ceiling currently detailed in the draft rule. Consequently, a strategy of purchasing allowances in the quarterly auction adjusting in real time to load expectations and weather over the compliance period is a strategy that is robust across scenarios and simulation draws.

1.6 Action Plan Covering the Next Two to Four Years

The Action Plan turns the results of the IRP analysis into discrete near-term activities that represent the best combination of least cost and least risk over the IRP planning horizon. The action items in this Action Plan are robust in regard to a wide range of potential future outcomes and therefore all represent low regret ways to move forward in the current environment.

Capacity Resource Action Items:

1. Acquire 20,000 Dth/day of deliverability from either recalling Mist, a city gate deal, or a combination of both for the 2023-24 gas year. Based upon updated load forecast in upcoming IRP updates recall Mist capacity as required for the 2024-25 and 2025-26 gas years.
2. Replace the Cold Box at the Portland liquified natural gas (LNG) facility for a targeted in-service date of 2026 at an estimated cost of $7.5 to $15 million.
3. Scope a residential and small commercial demand response program to supplement our large commercial and industrial programs and file by 2024.

Oregon Emissions Compliance Action Items:

4. Working through Energy Trust of Oregon, acquire 5.7 – 7.8 million therms of first year savings in 2023 and 6.7 – 8.9 million therms of first year savings in 2024, or the amount identified by the Energy Trust board.
5. In Oregon, to achieve SB 98 targets, seek to acquire 3.5 million Dths of renewable natural gas (RNG) in 2024 and 4.2 million Dths of RNG in 2025, representing 5% and 6% of normal weather sales load in 2024 and 2025.
6. Work with Energy Trust of Oregon, the Alliance of Western Energy Consumers and other stakeholders to develop energy efficiency programs for transportation schedule customers by 2024.
    - While this item is a part of our compliance strategy, NW Natural is not asking for acknowledgment from the OPUC of this item as we are already pursuing this action.
7. In Oregon, purchase Community Climate Investments representing any additional Climate Protection Plan (CPP) compliance needs for years 2022 and 2023 in Q4 2023 and for year 2024 in Q4 2024 based upon actual emissions to ensure compliance with the 2022-2024 compliance period.

Distribution System Action Item:

8. In Oregon, uprate the Forest Grove Feeder (also known as the McKay Creek Feeder) to be in service for the 2025 gas year at an estimated cost of $3.0 to $7.0 million.

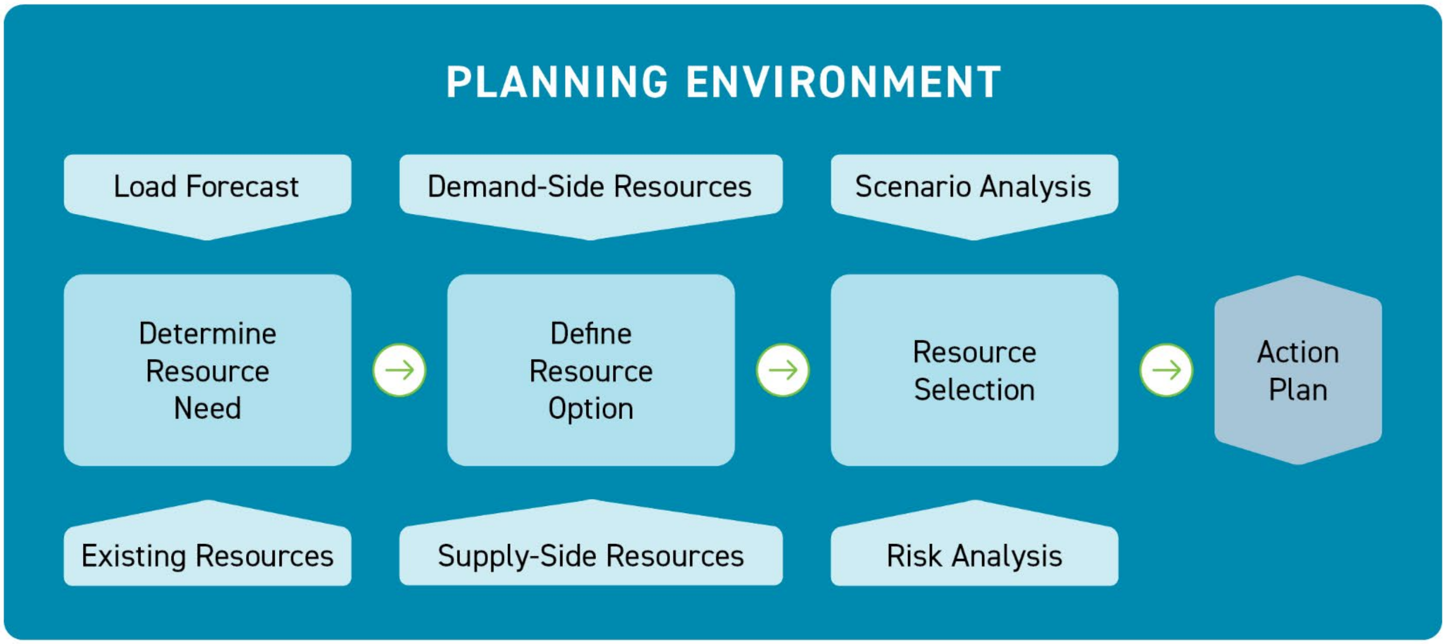
Washington Emissions Compliance Action Items:

9. In Washington, acquire carbon offsets compliant with the Climate Commitment Act's Cap-and-Invest program for 5% of expected weather emissions in year 2023 and 2024. Seek to acquire additional offsets representing 3% of expected weather emissions allowed for CCA compliance on tribal lands, and if they can be acquired for a lower price than the program allowance price floor for years 2023 and 2024, acquire these offsets.

10. In Washington, to support HB 1257, seek to acquire 600,000 Dths of renewable natural gas (RNG) in 2024 and 800,000 Dths of RNG in 2025, representing 6% and 8% of normal weather compliance gas in 2024 and 2025.
11. In Washington, purchase emissions allowances equal to emissions at an estimate of the 95th percentile of need for annual compliance net of voluntary RNG, carbon offsets, and freely allocated but not consigned allowances.
12. Working through Energy Trust of Oregon, acquire 275,000-370,000 therms of first year savings in 2023 and 276,000-310,000 therms of first year savings in 2024, or the amount approved through WUTC Biennial Energy Efficiency Plan.
13. Work with Energy Trust of Oregon, the Alliance of Western Energy Consumers and other stakeholders to develop energy efficiency programs for transportation and industrial sales schedule customers by 2024.

Environmental policy, economic conditions, market forces, and technological change are the backdrop that helps define key assumptions and objectives in an IRP. Chapter 2 lays out this planning environment with a focus on the transformational state greenhouse gas reduction policies that are the drivers of large changes in this IRP.

2 | Planning Environment



2.1 Planning Environment Overview

Fundamental in developing an IRP is an understanding of the planning environment and potential impacts to the plan now and in the future. The planning environment is a holistic review of potential risks, opportunities and important factors that can impact the IRP.

When evaluating the planning environment NW Natural considers:

- Economic and demographic factors
- Commodity price forecast
- Environmental policy
- New technology or game changers
- Load service environment

NW Natural takes these factors into consideration for our load forecast, potential future resources, and risk analysis. These factors are discussed in more detail below.

2.2 Economic and Demographic Factors

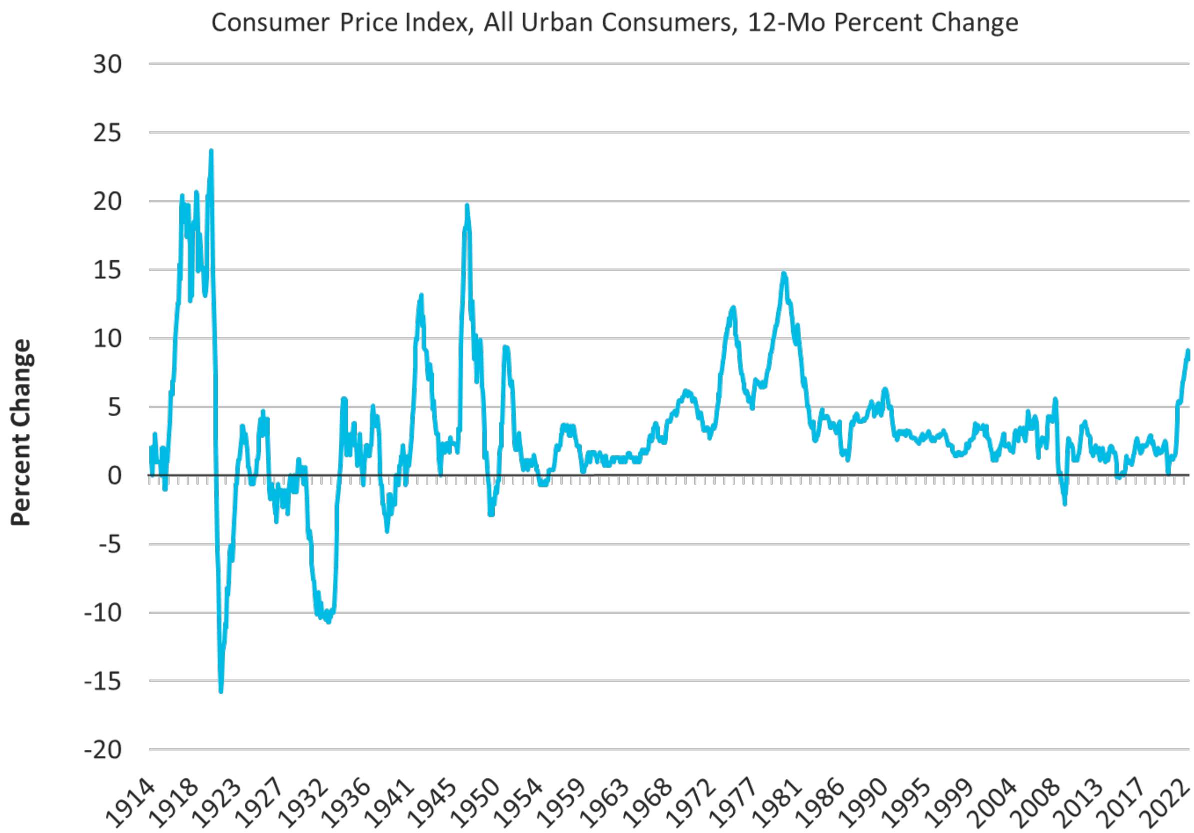
Economic and demographic factors are important underlying drivers of load growth. Changes in customer volume and usage patterns, especially for industrial customers, are impacted by broader trends in the economy and changing demographics.

2.2.1 U.S. Economic and Demographic Outlook

The U.S. economy continues its recovery from the COVID-19 pandemic, but inflation and uncertainty are slowing growth. In July 2022, the unemployment rate was 3.5 percent, the same rate as February 2020 before the COVID-19 pandemic. Similarly, total nonfarm employment in July 2022 was essentially the same as February 2020, with full recovery of total jobs lost during the pandemic. The labor market appears to be back at full employment, and while leisure and hospitality employment is still down 7.1 percent from pre-COVID-19 levels, employment has grown and shifted to other industries like transportation and warehousing, and professional and business services, making up the difference. The labor force participation rate has increased from its April 2020 low, but remains below pre-COVID-19 levels, contributing to the extremely tight labor market.

But the economy is slowing. On one hand, economic growth ought to slow given labor constraints, but beyond the labor market, inflation, supply chain issues, and uncertainty surrounding monetary and fiscal policy, as well as geopolitical risks and energy supply shocks from the war in Ukraine, are putting downward pressure on growth. Massive deficit spending in the wake of COVID-19 and expansionary monetary policy by the Federal Reserve boosted the money supply in the U.S. to unprecedented levels in 2020 and 2021, which led to inflation. Energy price increases caused by the war in Ukraine further exacerbated inflation in early 2022. The Consumer Price Index in July 2022 was 8.5 percent higher year-over-year, following 9.1, 8.6, 8.3, and 8.5 percent increases the previous four months. This is the highest year-over-year inflation since 1981 (Figure 2.1).

Figure 2.1: Inflation at a 41-Year High



Source: U.S. Bureau of Labor Statistics.

The Federal Reserve has the unenviable task of trying to engineer a "soft landing" from this high inflationary environment. Historically, this rarely happens, and it has never happened with inflation this high, and the unemployment rate this low. Nonetheless, the Federal Open Market Committee (FOMC) has begun raising interest rates, with a 25-basis point increase in March 2022, a 50-point hike in May, and 75-point hikes in June and July, the highest increases since 1994. The Fed is also beginning to reduce its holdings of Treasury securities and mortgage-backed securities, shrinking the Fed's balance sheet, and further shifting from a policy of quantitative easing to one of tightening. Forward guidance from the FOMC indicates more rate increases in 2022, up to 50 or 75-basis points at a time.

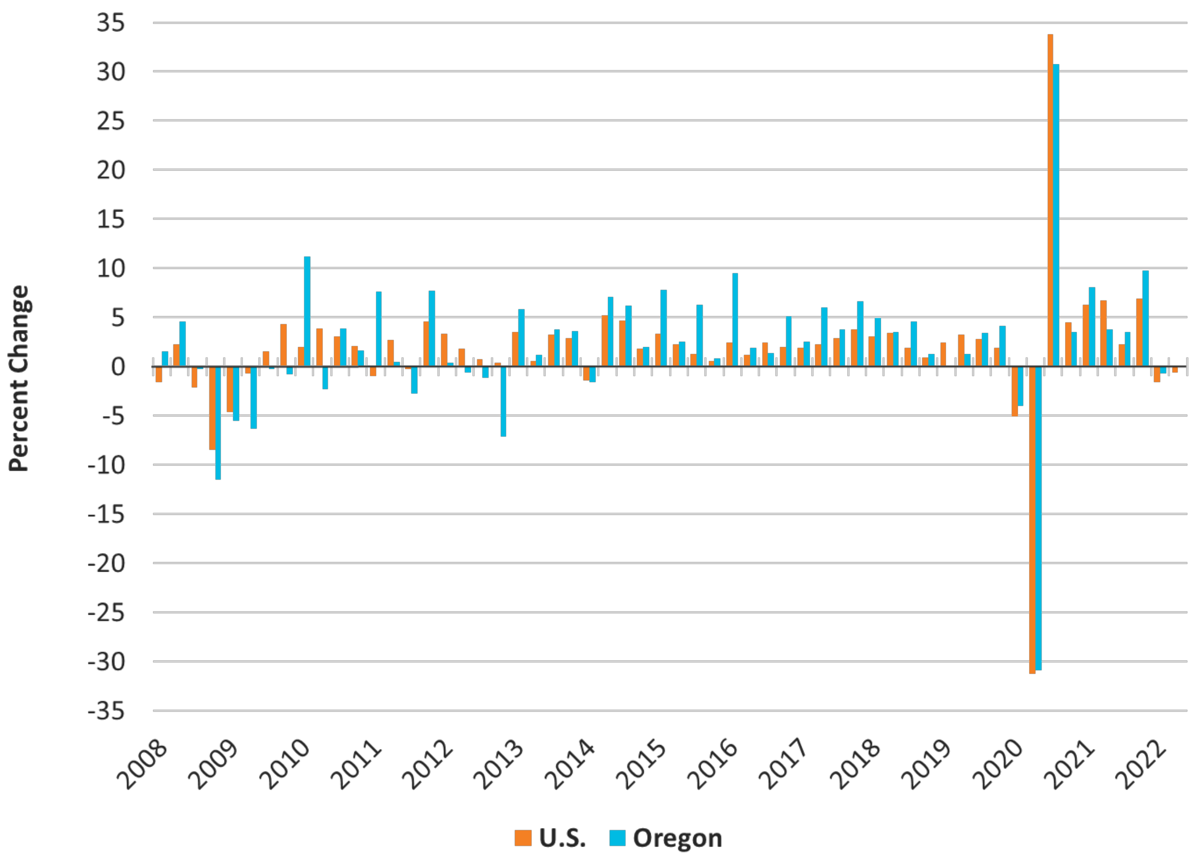
Real GDP declined in the first two quarters of 2022 by 1.6 and 0.9 percent. Two consecutive quarters of decline is a sign the economy may be in recession. GDP has declined due to decreases in government spending and investment, while real consumer spending is being eaten away by high inflation. The labor market remains strong, but unemployment claims are beginning to rise. Economists and business leaders have increased their probability of recession in their forecasting, with the chance of recession over the next 12-24 months as high as 50 percent.[6] The spreads between short and long-term Treasuries have shrunk significantly, another signal of recession. In fact, the yield on two-year Treasuries has been higher than ten-year Treasuries since July 2022 and continued to be through the end of August 2022. The S&P 500 officially fell into bear market (decline of 20 percent or more from previous peak) territory in June 2022. Stagflation – high inflation coupled with little to no economic growth – is a real possibility in the near-term, especially if efforts by the Fed do not lead to significantly lower inflation, but slow growth.

2.2.2 Oregon Economic and Demographic Outlook

During and after the recession of 2008 and 2009, Oregon GDP and employment followed similar trends to past economic cycles of greater loss during recession and greater gains in expansion years (Figure 2.2). Oregon's more cyclical economy is the result of larger-than-average durable goods manufacturing and related industries. Oregon's economy benefits from this industry concentration over time, with stronger GDP growth across cycles than the U.S. The recession caused by COVID-19 was different, though, since job losses were concentrated in industries like leisure and hospitality, air transportation, and retail trade – service industries that most states have in similar concentrations. As a result, negative GDP and employment impacts across states were more similar than a typical recession. Oregon's economic recovery coming out of the COVID-19 pandemic largely mirrors trends nationally.

[6] National Association for Business Economics, "NABE Outlook Survey, May 2022," www.nabe.com, May 23, 2022, https://nabe.com/NABE/Surveys/Outlook_Surveys/May-2022-Outlook-Survey-Summary.aspx; Reade Pickert and Kyungjin Yoo, "U.S. Recession Odds Within the Next Year Now 30%, Survey Shows," www.bloomberg.com, May 13, 2022, https://www.bloomberg.com/news/articles/2022-05-13/odds-of-a-us-recession-within-next-year-now-30-survey-shows#xj4y7vzkg; Prerane Bhat and Indradip Ghosh, "No Respite from Fed Rate Hikes This Year, Chances Rising of Four 50 bps in a Row – Reuters poll," www.reuters.com, June 9, 2022, https://www.reuters.com/markets/us/poll-no-respite-fed-rate-hikes-this-year-chances-rising-four-50-bps-row-2022-06-10/; Isabella Simonetti and Jason Karaian, "'Uncomfortably high': What economists say about the chance of recession," *The New York Times*, June 28, 2022, https://www.nytimes.com/2022/06/28/business/recession-probability-us.html#:~:text=S%26P%20Global%20Ratings%3A%20Beth%20Ann,walking%20out%20of%202023%20unscathed.%E2%80%9D.

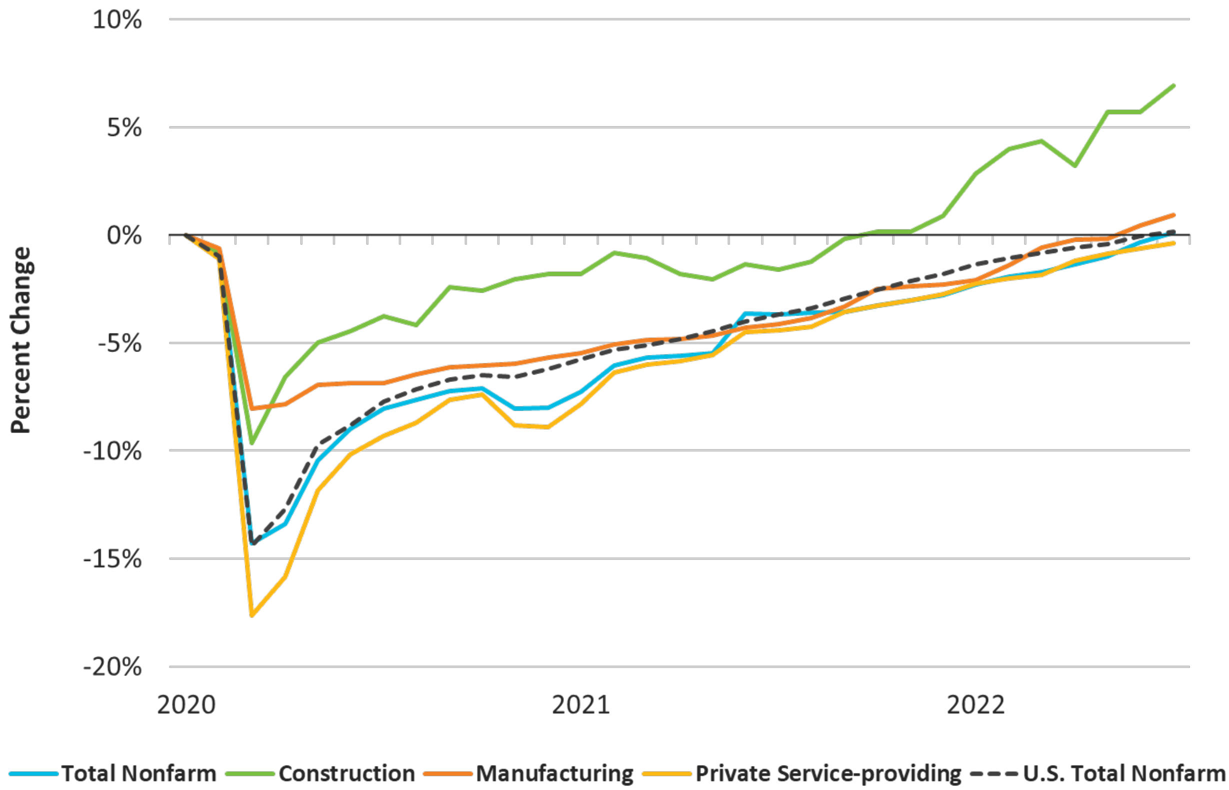
Figure 2.2: Real Gross Domestic Product, Percent Change, Annualized



Source: U.S. Bureau of Economic Analysis.

In August 2022, Oregon total nonfarm employment finally recovered total jobs lost since the beginning of the pandemic (Figure 2.3). Manufacturing employment, which declined 8 percent in April 2020, has also recovered all jobs lost during the pandemic. This is welcome news for Oregon's economy since jobs lost in manufacturing during recessions do not all come back historically. Some amount of structural job loss is typically realized, which reduces hard-to-replace, accessible, middle-wage jobs for Oregonians. Construction employment in Oregon is well above its pre-pandemic peak thanks to a strong rebound in residential building and related specialty trade contractors. Service industries experienced the largest employment declines during the pandemic and have recovered 99 percent of jobs lost since February 2020.

Figure 2.3: Oregon Employment Fully Recovered



Source: Oregon Employment Department, Current Employment Statistics, Official Oregon Series; U.S. Bureau of Labor Statistics.

The Oregon Office of Economic Analysis (OEA) September 2022 forecast projects all major industry sectors in Oregon will regain all jobs lost by the end of 2022, except leisure and hospitality, where employment is projected to return to its pre-pandemic peak in 2026. The baseline forecast, which assumes a “soft landing” by the Fed and no recession, calls for continued growth over the next five years, but at a slower rate. Employment growth is forecasted to be 3.8 percent in 2022, 1.8 percent in 2023, and down to 1.0 percent in 2024. With interest rates on the rise, economic activity is slowing, such as building permits and home sales. So far, the labor market remains solid, but further contractionary monetary policy moves are expected to lead to higher unemployment going forward as the economy cools.

Recent demographic trends in Oregon have created some uncertainty for demographic forecasters in the state. Oregon has enjoyed strong population growth for many years. That changed with COVID-19, and perhaps to a lesser degree, with the perceived lower quality of life experienced by Oregonians in the wake of protests, increased homelessness, and increased crime throughout the state, particularly in Portland. Immigration into the U.S. and migration between states slowed dramatically during the pandemic. Net migration into the U.S. dropped to 247,000 in 2021 – a 48 percent decline from 2020 –

and was down 76 percent from last decade's high in 2016.[7] Similarly, Oregon's number of foreign-born prime working age adults was 90,000 lower in the first half of 2022 than it was in 2016, a decline of nearly one-third.[8] While migration between states will increase with the pandemic largely behind us, it is unclear what immigration into the U.S. will look like going forward due to uncertainty surrounding immigration policies at the federal level. Another wrinkle is the impact of increased remote workers in the U.S. It is an open question whether a larger share of remote workers in the U.S. could have a positive or negative impact on Oregon's population and economy (or no impact at all). Oregon has historically attracted young, educated workers who see Oregon as a lower cost, higher quality of life destination than other places on the west coast. However, Oregon has a high personal income tax that remote workers may want to avoid. It is the 12th most expensive state in the U.S., up 8 spots from 2010 when it ranked 20th, and had the fourth highest increase in prices between 2015 and 2020.[9] That said, California and Washington are still more expensive than Oregon.

The latest demographic forecast from the OEA shows Oregon's population continuing to grow over the next decade, but at a slower rate than it has over the past three decades (Figure 2.4). Factors in the lower growth rate include slower growth trends since 2015, reduced migration during the pandemic, an aging population, and declining birth rate. A slower growing population will constrain potential labor force in Oregon, limiting economic growth as well. One of the potential barriers to higher growth is Oregon's affordability, in particular, its lack of affordable housing.

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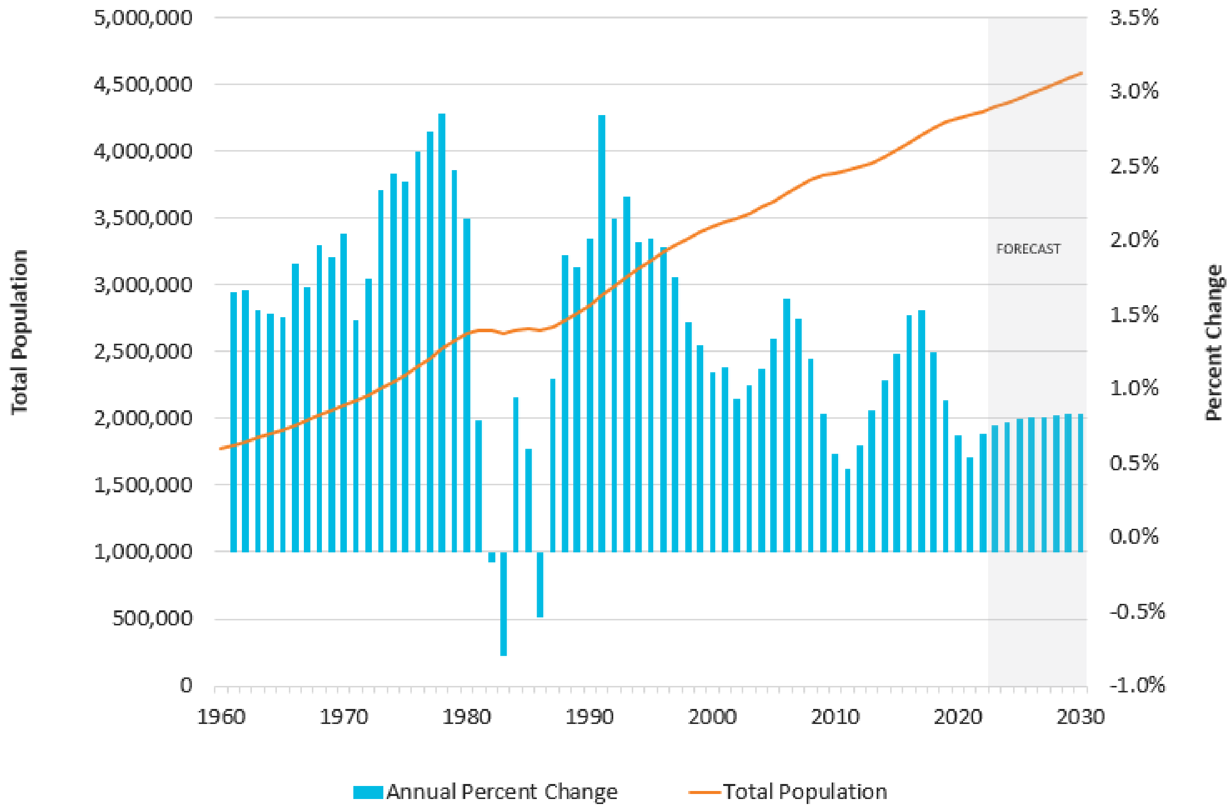
[7] Jason Schachter, Pete Borsella, and Anthony Knapp, "New Population Estimates Show COVID-19 Pandemic Significantly Disrupted Migration Across Borders," U.S. Census Bureau, December 21, 2021, https://www.census.gov/library/stories/2021/12/net-international-migration-at-lowest-levels-in-decades.html.

[8] IPUMS-CPS, University of Minnesota, www.ipus.org, retrieved June 21, 2022.

[9] U.S. Bureau of Economic Analysis, Regional Economic Accounts, Regional Price Parities by state, www.bea.gov, retrieved June 21, 2022.

Figure 2.4: Oregon Population Growth Slowing



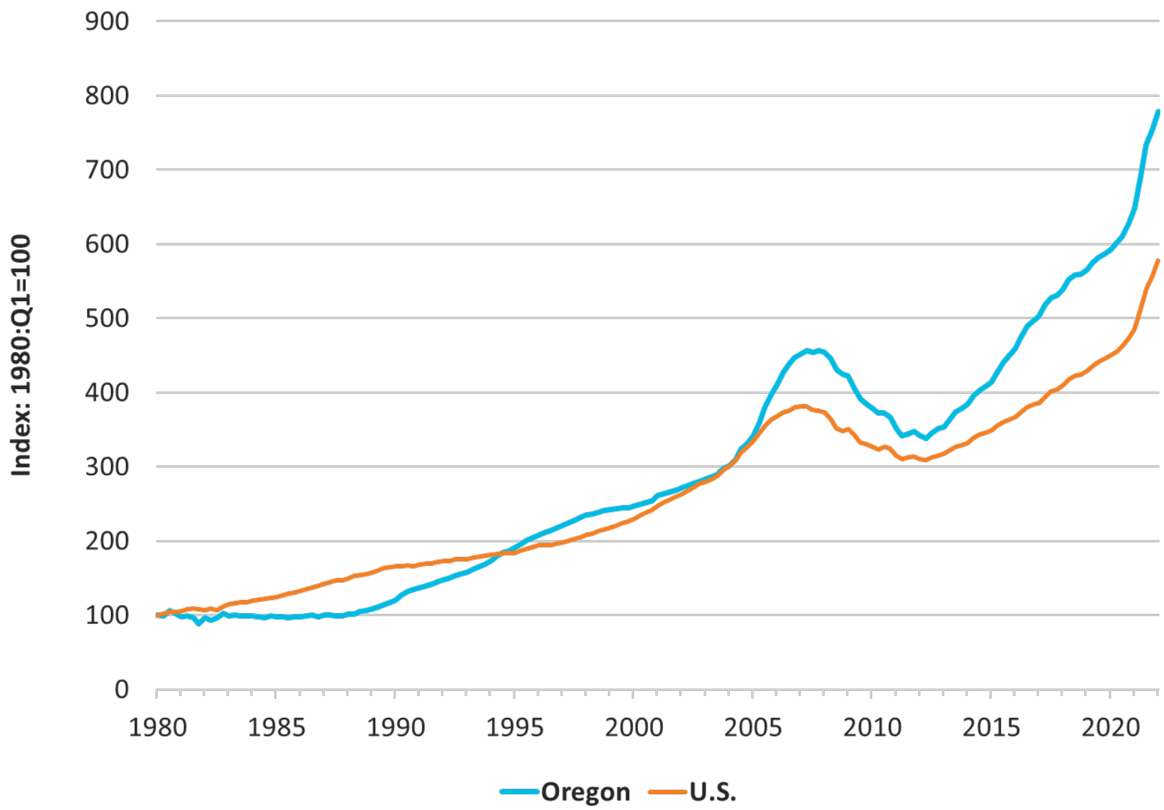
Source: U.S. Census Bureau, Portland State University Population Research Center, Oregon Office of Economic Analysis.

Housing affordability continues to be a problem in Oregon, as supply is not keeping up with demand. Oregon has underproduced about 110,000 housing units as of 2021, which is 19 percent of total units needed in the state.[10] Demand remains strong, with prices at record highs and inventories at record lows.[11] Oregon house prices increased at a much faster rate than prices in the U.S. over the past decade (Figure 2.5). Oregon prices were 20 percent higher in the first quarter of 2022 than they were the year before, which was equal to the highest quarterly year-over-year percent change experienced before the Great Recession in the first quarter of 2006.

[10] ECONorthwest. *Implementing a Regional Housing Needs Analysis Methodology in Oregon: Approach, Results, and Initial Recommendation*. Portland, Oregon: ECONorthwest, 2021. Accessed June 30, 2022. https://www.oregon.gov/ohcs/about-us/Documents/RHNA/RHNA-Technical-Report.pdf.

[11] Realtor.com. Housing Inventory Core Metrics. Accessed June 30, 2022, via Federal Reserve Bank of St. Louis, Federal Reserve Economic Data. https://fred.stlouisfed.org/series/ACTLISCOUOR.

Figure 2.5: Oregon House Prices Increasing Much Faster than U.S.



Source: Federal Housing Finance Agency, FHFA House Price Index.

Growth appears to be slowing, though, as a result of increasing interest rates brought on by the Federal Reserve's actions to tamp down inflation. At the end of August 2022, the 30-year fixed rate mortgage average in the U.S. was 5.6 percent, almost double what it was a year earlier.[12] Market data through July 2022 show that new listings of homes for sale in Oregon are beginning to decline, along with closed sales and the median sale price, while inventory is slowing increasing from historic lows.[13] This trend is likely to continue as further interest rate increases are expected from the Fed in 2022. Single family residential building permits in Oregon have been declining on a year-over-year basis since October 2021 based on three month moving averages. The OEA also expects housing starts in Oregon to decline in 2022. Housing starts are forecasted to grow from 2023 to 2030, but at a slower rate than they did pre-pandemic. Most of the slower growth in starts is tied to slower population growth.

2.2.3 NW Natural System Area Economic and Demographic Outlook

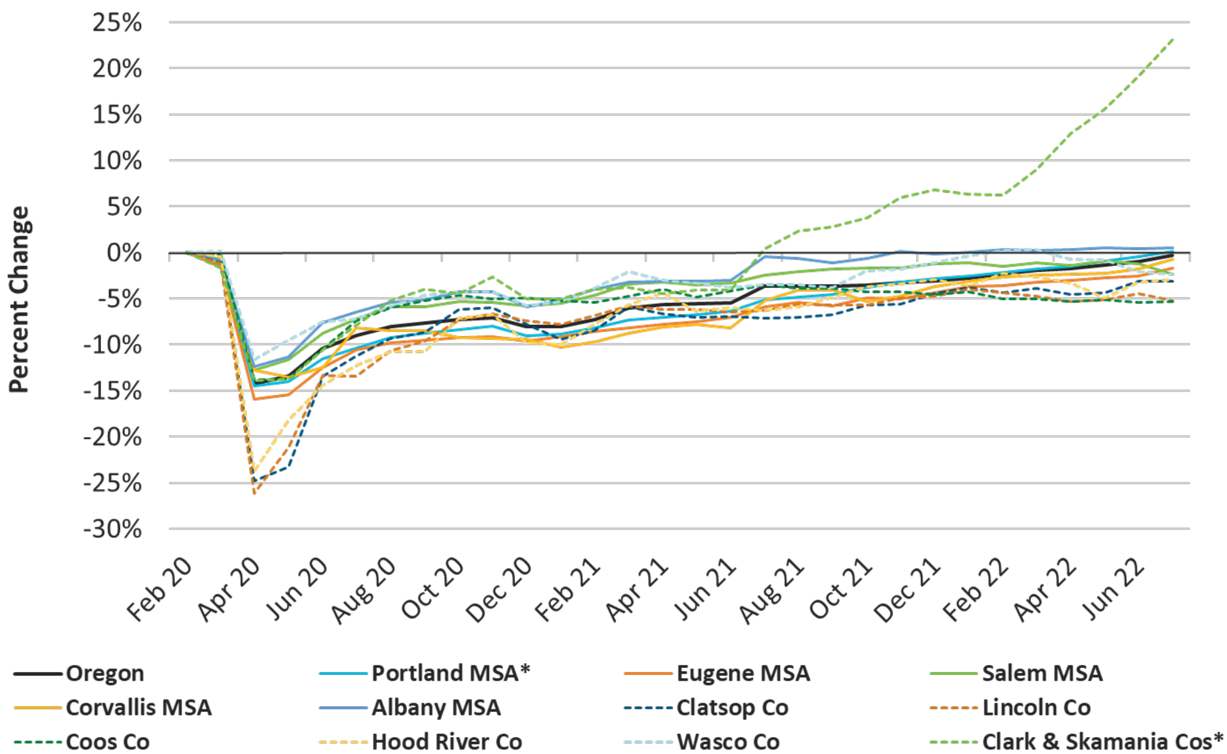
The COVID-19 pandemic impacted cities and counties differently across the Company's service territory. In the service territory, as well as across the U.S., the pandemic had a larger negative impact

[12] Freddie Mac. Primary Mortgage Market Survey. Accessed August 30, 2022, via Federal Reserve Back of St. Louis, Federal Reserve Economic Data. https://fred.stlouisfed.org/series/MORTGAGE30US.

[13] RMLS. "July 2022 Market Action Statistics (Real Talk with RMLS, Episode 61." August 17, 2022. https://rmlscentral.com/podcast/july-2022-market-action-statistics-real-talk-with-rmls-episode-61/.

in communities with above average concentrations of service sector employment in leisure and hospitality, arts, entertainment, and recreation, personal services, and air transportation. Employment in these industries is typically more concentrated in metropolitan areas than rural areas and in areas with significant tourism. Throughout the Company's service territory, employment declined the most in Lincoln, Clatsop, and Hood River counties – rural areas with significant tourism (Figure 2.6). The Portland metro area, which includes Clark and Skamania counties in Washington, and Eugene metro area also experienced larger employment declines than average across the state.

Figure 2.6: Pandemic Employment Impacts Across NW Natural Territory



***Portland MSA includes Clark and Skamania counties**

Source: Oregon Employment Department, Current Employment Statistics, Official Oregon Series.

Within the Portland MSA, employment in Clark and Skamania counties in Southwest Washington has soared in comparison to other areas within the Company's service territory since February 2020 and is 23 percent higher than its pre-pandemic peak. The Albany MSA has eclipsed pre-pandemic total employment, and the Portland MSA has recovered all jobs lost since the beginning of the pandemic as of July 2022. The Eugene and Salem MSAs were still down about 2 percent from their peak. Coos and Lincoln counties were still down 5 percent from their pre-pandemic peaks, while Clatsop and Hood River counties were still down 3 percent. August 2022 data shows Oregon has now recovered all jobs lost during the pandemic. Areas that experienced larger job losses in the most impacted industries will take longer to recover.[14]

The pandemic led to lower rates of migration across the nation and migration out of larger cities. Total population in the Portland metro area declined by about 4,600 in 2021 from 2020. More significantly, Multnomah County's population dropped by 12,500, a decline of 1.5 percent. It remains to be seen how much this population shift out of larger cities and into suburbs and less populated areas will influence growth patterns going forward, but forecasters expect population growth to return to the Portland metro area, albeit at slower rates than experienced over the decade preceding the pandemic.[15] Population forecasts for metro areas and counties in the Company's service territory have not been developed since the onset of the pandemic. Based on the current population forecast for Oregon developed by the OEA, population growth across the service territory will be slower between 2020 and 2030 than it was between 2010 and 2020.

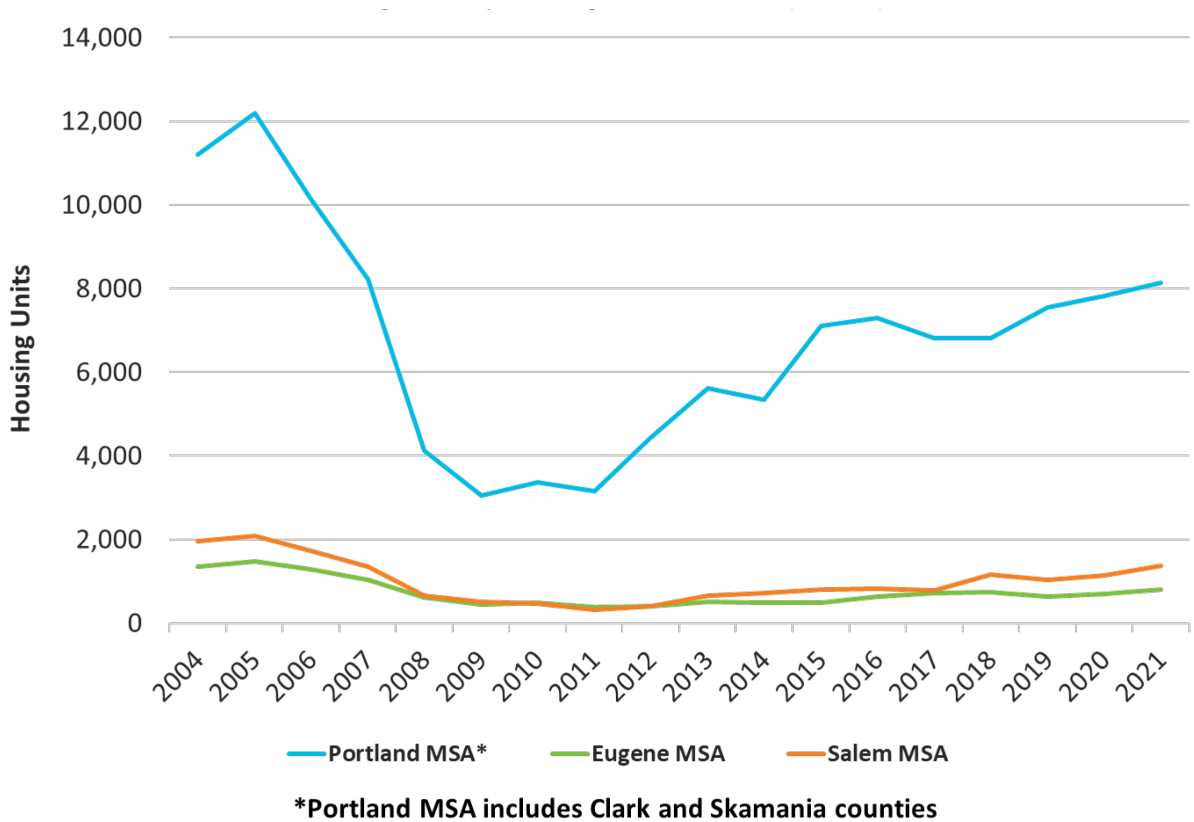
Like Oregon, housing affordability in the service territory is an area of concern. Figure 2.7 shows recent trends in single family building permits in the territory's three largest metro areas and, while growth in permits has continued to rise from lows experienced after the Great Recession, the pace of housing construction does not appear to be meeting increased demand in the area based on price and inventory trends. This was the case before the pandemic, but the situation worsened even more during the pandemic with extraordinarily low mortgage rates, migration out of cities to suburbs, and higher household incomes. Clark County continues to produce housing at a far greater rate than other counties in the Portland MSA, accounting for 37 percent of metro residential building permits in 2021. In 2011, that number was 18 percent. The S&P CoreLogic Case-Shiller Portland Home Price Index increased at an annualized rate of 5.2 percent between April 2010 and April 2020. In the two years since, it increased at a 17.4 percent annualized rate. Increasing mortgage rates, brought on by interest rate increases by the Fed, have begun to dampen sales and prices in region. In the Portland metro area, pending sales were down 27.5 percent in June 2022 from a year ago.[16] The median sale price appears to have topped out as well and inventory is beginning to rise. Similar trends are occurring in Eugene, Salem, and other areas of the service territory.

[14] Oregon Office of Economic Analysis, *Oregon Economic and Revenue Forecast, June 2022*. Salem, Oregon: Department of Administrative Services, 2022. Accessed July 6, 2022. https://www.oregon.gov/das/OEA/Documents/forecast0622.pdf.

[15] Metro (MPO), *Portland-area 2045 Population and Housing Forecasts by City and County*. Portland, Oregon: Metro, 2021. Accessed July 5, 2022. https://www.oregonmetro.gov/sites/default/files/2021/03/26/2045-regional-population-housing-forecast-by-city-county.pdf.

[16] RMLS, *Market Action, June 2022*. Portland, Oregon: RMLS, 2022. Accessed July 11, 2022. https://www.rmlsweb.com/v2/public2/loadfile.asp?id=12507.

Figure 2.7: Single Family Building Permits Issued (Annual)



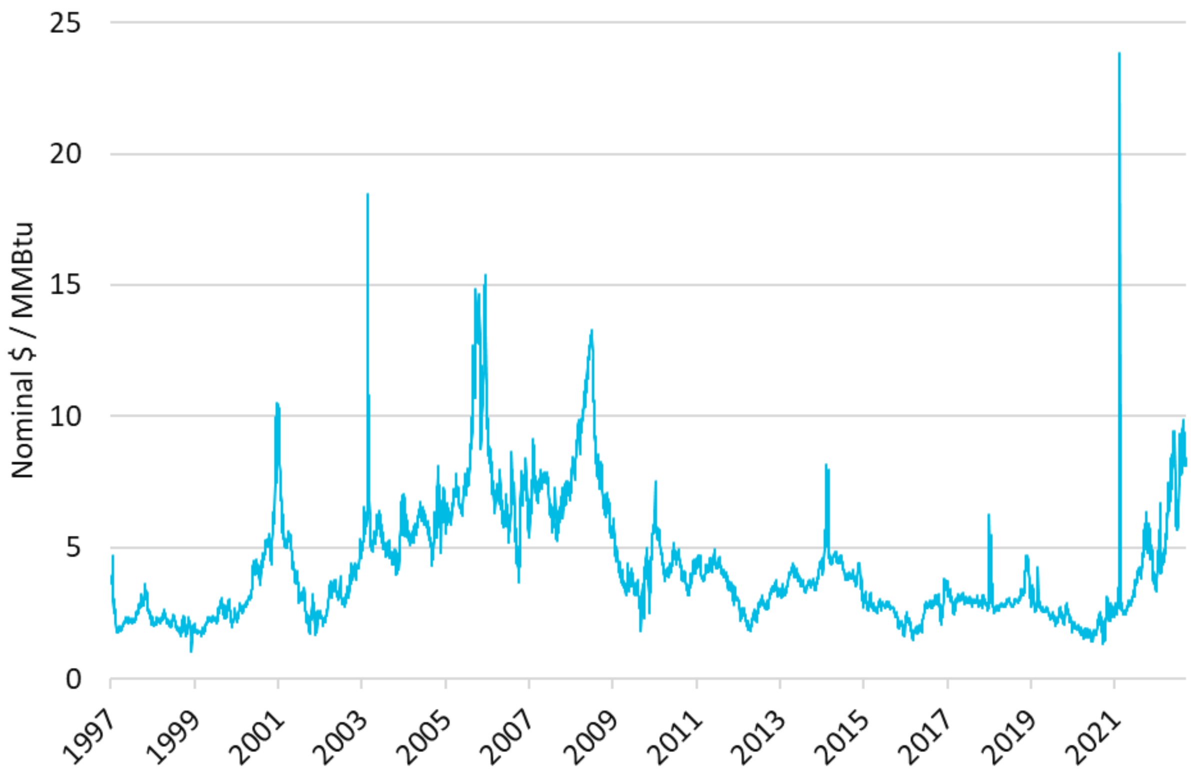
Source: U.S. Census Bureau, Building Permits Survey.

2.3 Natural Gas Prices

Like many commodities, volatility in natural gas prices is influenced by numerous factors, including macro-economic factors, weather, power generation demand, and production constraints and development in new and traditional supplies — such as more efficient extraction technologies or additional access to RNG. Figure 2.8 depicts historical gas prices at Henry Hub and how natural gas prices have been changing over time.[17]

[17] Henry Hub is the US benchmark pricing delivery location for futures contracts on the New York Mercantile Exchange (NYMEX).

Figure 2.8: Historical Daily Natural Gas Prices



Source: EIA

2.3.1 Natural Gas Supply Sources

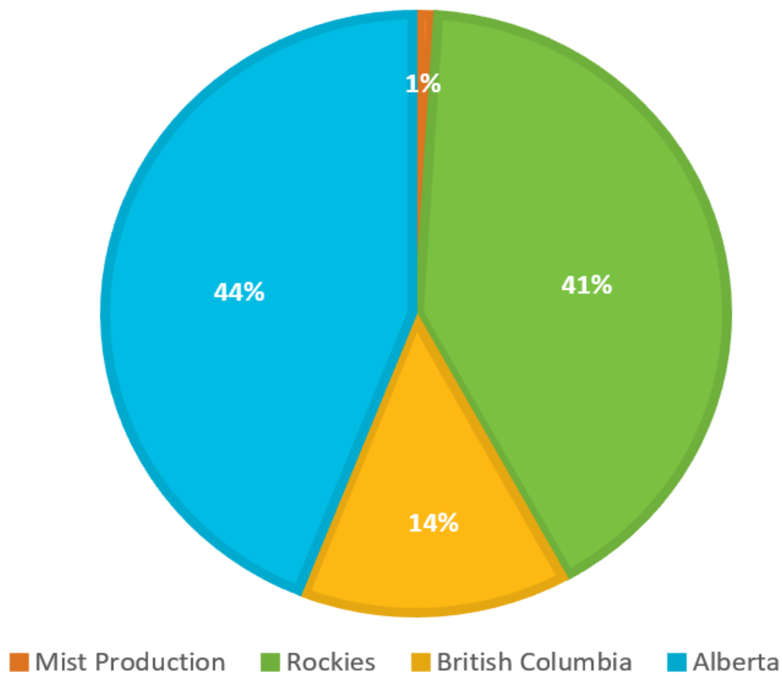
NW Natural purchases natural gas on behalf of all sales customers. Purchasing natural gas from producers located in Canada or the Western US requires the corresponding interstate/interprovincial pipeline capacity rights to ship the gas from the location of production to our service territory. NW Natural, as customer of the interstate/interprovincial pipeline companies, holds capacity contracts that allow us to ship conventional gas that is purchased from out-of-state production basins and deliver it to NW Natural's service territory.

NW Natural's current upstream pipeline capacity contracts allow us to access and buy Canadian natural gas, which is shipped south from British Columbia and Alberta, and natural gas coming out of the Rockies, primarily in Wyoming and Colorado. In 2021, these contracts enabled us to purchase roughly 38% of our supplies from Rockies, 28% from Alberta and 34% from British Columbia (see Figure 2.9).[18]

[18] There is a small amount of gas being produced at Mist that comes onto our system through a third-party producer and new RNG interconnections that began to flow onto our system in 2021.

Looking forward, gas from RNG sources, either with or without environmental attributes, will become a larger share of the Company's supply purchases.[19]

Figure 2.9: Supply Diversity by Location January 2021-December 2021



While our contracts allow us to access various points along the interstate/interprovincial pipelines, the gas prices we pay for gas produced in these basins are closely correlated with three major natural gas trading hubs in the corresponding production areas: AECO (Alberta), Opal (Rockies), and Westcoast Station 2 (British Columbia). Additionally, NW Natural purchases gas at a fourth trading hub at Sumas, which is on the Washington (U.S.)/British Columbia (Canada) border, however, there is no major production operations associated with Sumas.[20]

2.3.2 Natural Gas Price Forecast

NW Natural subscribes to a gas market fundamentals forecasting service through a third-party, IHS Markit.[21] IHS Markit implements a nation-wide supply and demand fundamentals model for the natural gas sector. Using this model IHS Markit publishes a long-term gas price forecasts for numerous natural gas hubs around the U.S. and Canada. The IRP uses these gas price forecasts as the expected gas price for the four natural gas price hubs where the company purchases gas, AECO, Opal (i.e., Rockies), Sumas and West Coast Station 2. Natural gas prices will vary by location and time of year. As

[19] Please see Chapter 6 for more information on RNG

[20] Purchases at Sumas are grouped together with British Columbia in Figure 2.9, however; Sumas is a trading hub and most of the gas being bought and sold at this location is likely being transported from either Alberta or Northern British Columbia.

[21] IHS now owned by S&P Global.

demand increases in a specific region and pipeline capacity to ship gas into that area becomes constrained, prices in the constrained region can spike. Figure 2.10 shows both historical prices and forecasted prices for these four hubs.

Figure 2.10: Historical Natural Gas Prices and Forecasts by Trading Hub[22]

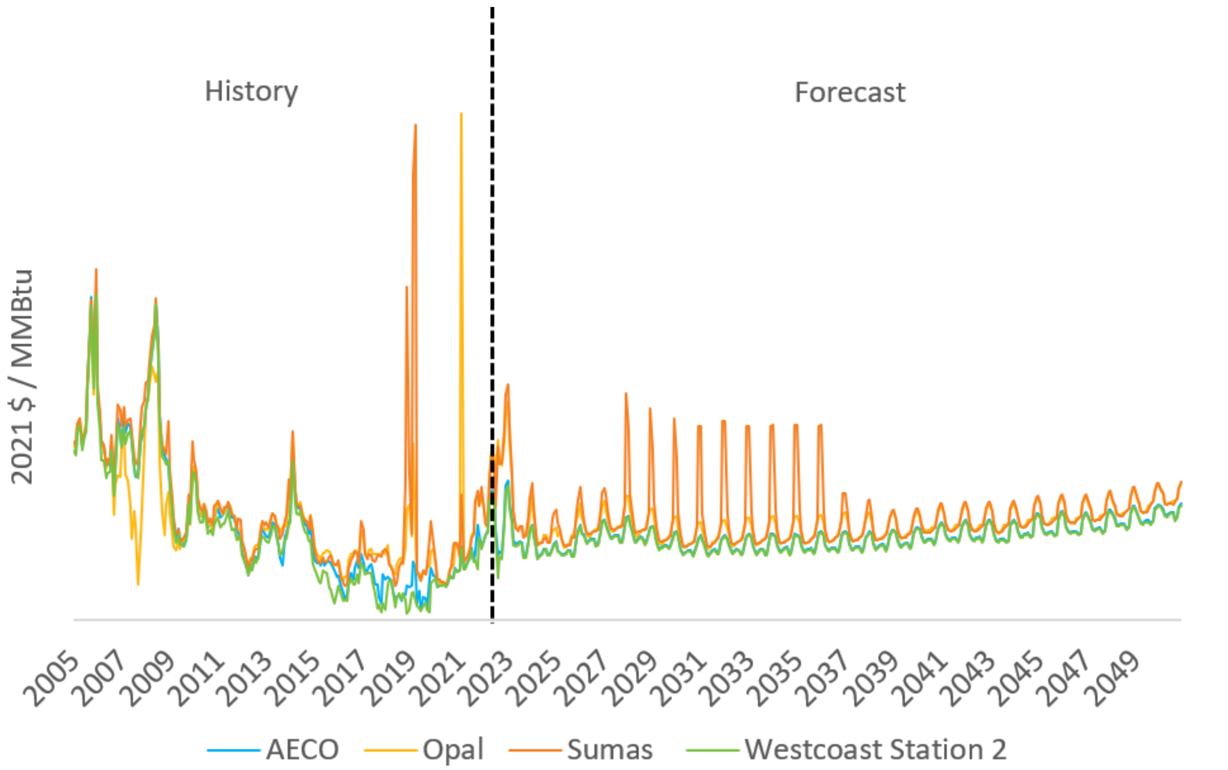
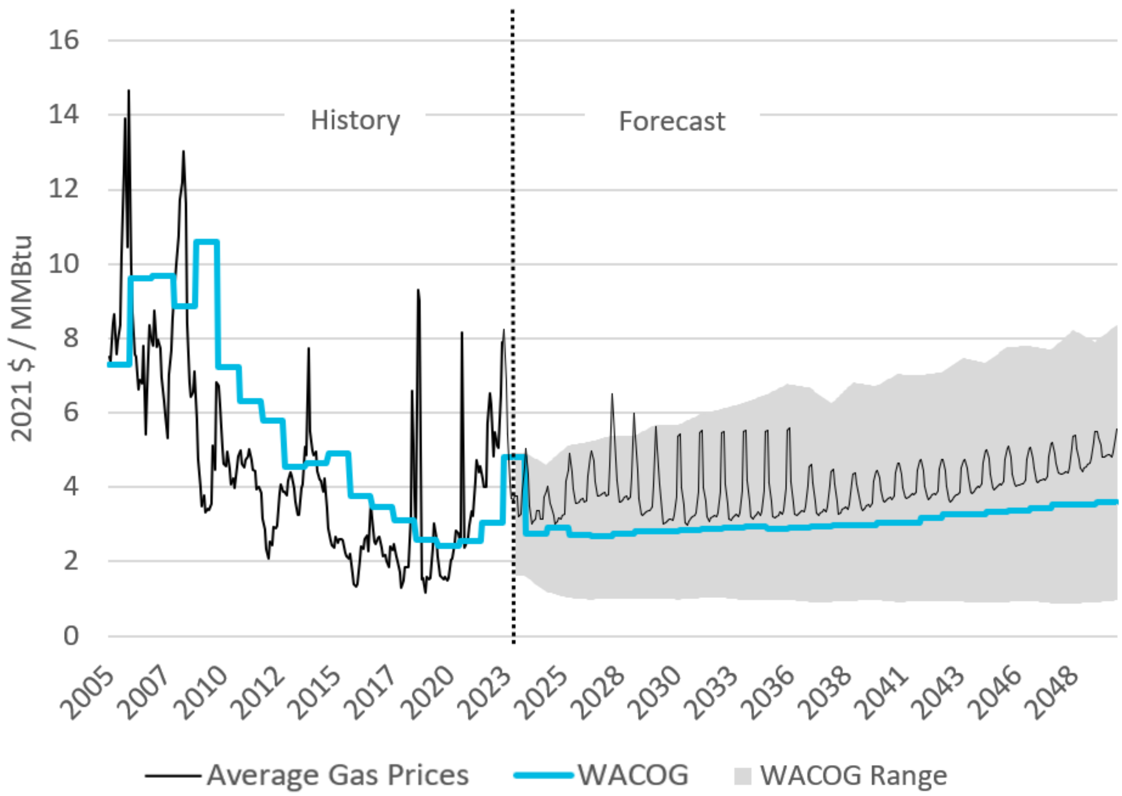


Figure 2.11 shows a historical average gas price, the historical weighted average cost of gas (WACOG), the forecasted WACOG over the planning horizon and the range of potential WACOG into the future. The WACOG is inclusive of fuel and variable charges to ship the gas to NW Natural's system. In practice the WACOG is forecasted in advanced for customers for the upcoming gas year and filed each fall through the purchased gas adjustment (PGA) filing. Any over/under collection of revenues from WACOG is trued up in rates in the following year's PGA.

[22]Source: IHS "North American Natural Gas Long-Term Outlook Market outlook data tables - August 2022," September 2022. Y-axis values were removed to protect proprietary hub specific forecasts provided by IHS for this IRP.

Figure 2.11: Weighted Average Cost of Gas[23]



2.3.3 Current Conditions

While demand has continued to recover following the impact of the COVID-19 pandemic, production growth has lagged as producers have focused on capital discipline. The market has been additionally strained with an increase in LNG and Mexico pipeline exports, strong demand for natural gas generation, and a low storage inventory. Without additional supply to balance demand, the market has faced sustained high prices.

With new LNG export facilities and expansions, the seven big U.S. export plants are expected to have a capacity of 13.8 Bcf/d by the end of 2022. LNG exports have hit record levels due to the capacity additions along with strong global demand as a result of Russia's invasion of Ukraine. While a June 8 fire at Freeport LNG has taken the facility offline until late 2022, the additional 2 Bcf/d of supply added to the market has been swallowed up by strong demand for natural gas generation and injections into storage. LNG exports have increased from an average of 6.5 Bcf/d in 2020 to 9.8 Bcf/d in 2021 to 11.2

[23] The range for the forecasted WACOG is based on the 5th and 95th percentile of annual WACOG that is an output of the Monte Carlo process optimized through the Resource Planning Optimization Model (i.e., PLEXOS®). The forecasted WACOG is the annual mean of these simulations. The average gas prices is a weighted average across the 4 purchasing hubs based on 2022 modelled weights.

Bcf/d for the first half of 2022. The EIA expects LNG exports to increase to 12.7 Bcf/d in 2023.[24] LNG export growth will be constrained until the Golden Pass LNG Terminal is online in 2024, which will increase export capacity to 16.3 Bcf/d.

Despite high prices, power sector demand for natural gas generation is near record levels from 2020 as gas-to-coal fuel switching for electric generation is less flexible and new renewable generating capacity is facing construction delays due to supply-chain issues.[25] Coal generation is constrained due to low coal stockpiles resulting from low production and increased exports, rail transport issues, and coal plant retirements. More than 100 GW of coal retired across the US over the past 10 years and an estimated 90 GW of retirements have been announced or are planned by 2030.[26] Demand for natural gas in the electric power sector is expected to grow through 2025 even as new renewable energy resources come online.[27]

Storage inventory is expected to head into the winter of 2022-23 below average. The EIA is forecasting that storage will end the 2022 injection season around 6% below the five-year average. This creates anxiety in the market in the event of a colder-than-normal winter.

An increase in crude oil and natural gas prices have contributed to increased drilling activity. Dry gas production is growing in the Haynesville region and the Permian Basin. Associated gas production, which is dependent on the crude oil market, is also expected to grow in the Permian Basin as high oil prices have led to plans to increase oil production. The EIA forecasts that dry natural gas production will increase 2.7 Bcf/d or 3% compared to 2021 and 3.7 Bcf/d or 4% in 2023.[28] Gas production from the Montney region in northern British Columbia and Alberta, Canada has also been increasing. Canadian production is currently just below the April 2006 all-time record high as Canadian producers were in better financial shape than U.S. producers and were able to boost production when prices began to rise.[29]

Volatility has been up due to the continual shifts in the market. Volatility of U.S. natural gas futures prices reached a record-high level in February with the 30-day historical volatility of gas futures reaching 179.1%. Upward price pressure and volatility will remain until supply and demand are balanced.

2.3.4 Natural Gas Price Uncertainty

As seen by historical data in Figure 2.8, Figure 2.10, and Figure 2.11, gas prices can be quite volatile. NW Natural has the resources, such as our Mist storage facility, and gas hedging programs that limits rate payer's exposure to short-term price volatile. However, gas prices over the long-term are also

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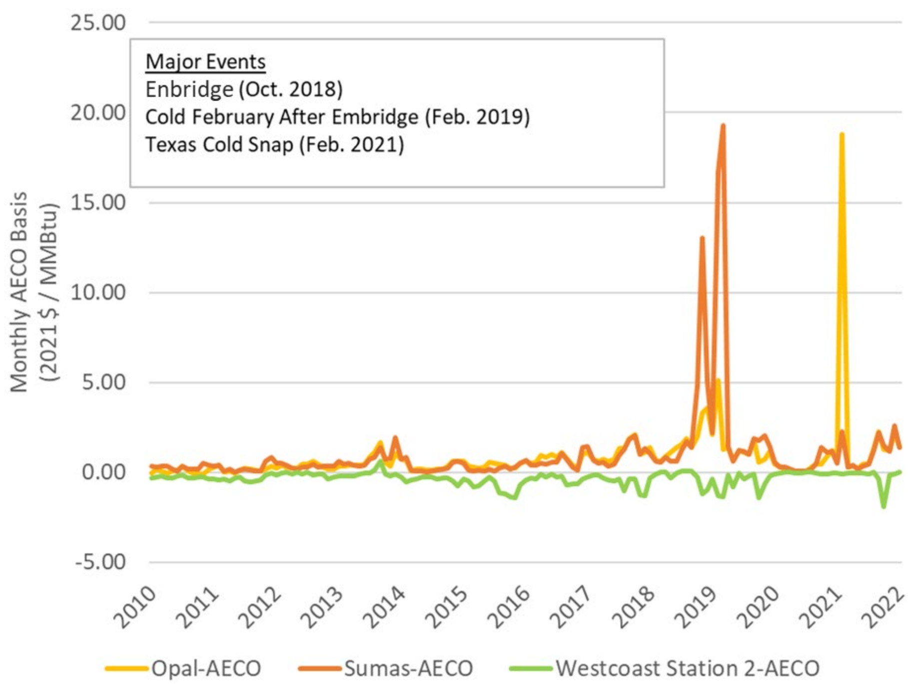
[24] Source: EIA, Short Term Energy Outlook, July 12, 2022
[25] Source: Platts Gas Daily, "Gas demand from US power generators continues at record pace in July", July 11, 2022
[26] Source: IHS Markit, North American Power Market Outlook, July 14, 2022
[27] Source: IHS Markit, North American Natural Gas Short-Term Outlook, June 2022
[28] Source: EIA, Short Term Energy Outlook, July 12, 2022
[29] Source: Platts Gas Daily, "West Canada spot gas prices plummet as production soars to 16-year highs", July 11, 2022

uncertain and this uncertainty increases further out into the future (see Figure 2.11). NW Natural conducts a Monte Carlo simulation of natural gas prices using historical data in combination with the long-term natural gas prices forecast from a third-party consultant (IHS) to simulate natural gas prices. This simulation provides insight into the range of potential short-term and long-term gas prices.[30]

Price simulation for each of the four basins in which NW Natural purchases gas is used in the risk analysis for the IRP (discussed in Chapter 7). Each simulation uses historical annual and monthly prices at each hub (AECO, Opal, Sumas, and Station 2) from 2010 through 2022 to capture cross hub correlation, incorporating potential price spikes at Sumas and Opal, as were recently seen at those locations. Figure 2.12 shows historical price spreads between AECO and the three other gas hubs. This graph demonstrates how long stable periods of gas price spreads can have sudden volatility, primarily due to weather and upstream pipeline capacity constraints.

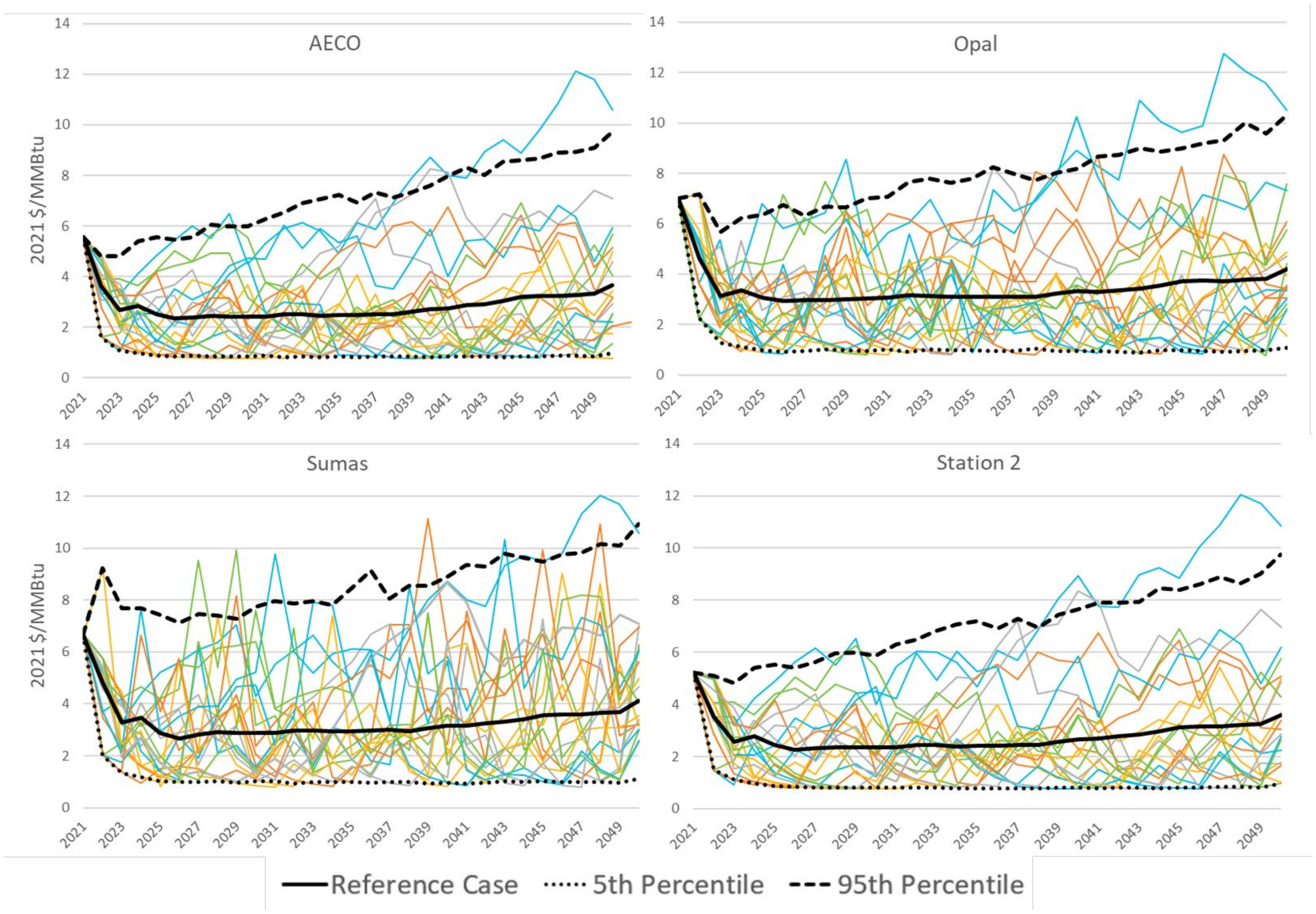
Figure 2.12: Gas Price Basis to AECO



The IRP refers to the gas price forecast from our third-party consultant as the reference case price forecast. Figure 2.13 shows annual average gas price forecasts for each hub along with the 5th percentile, 95th percentile, and a select number of individual simulations.

[30] See Appendix F for more technical details on the gas price simulation.

Figure 2.13: Gas Price Simulations – Annual Averages



2.4 RNG and Hydrogen Markets[31]

The renewable natural gas (RNG) market in the United States has matured significantly over the last several years. Whereas in previous years, most of the financing of new RNG projects came from private equity, this year saw substantial development and acquisition activities from large established players in the oil and natural gas and asset management space, such as Kinder Morgan and BlackRock. As can be seen in Figure 2.14, this year the RNG industry reached the milestone of over 250 operational projects in the U.S. and Canada,[32] up from 100 projects just three years ago in 2019.[33]

[31] Please see Chapter Six for additional information on both RNG and Hydrogen
[32] https://www.rngcoalition.com/media-room
[33] https://www.rngcoalition.com/renewable-natural-gas-market-surpasses-100-project-pinnacle-in-north-america

Figure 2.14: RNG Projects

Source: RNG Coalition. https://www.rngcoalition.com/infographic

The key markets that have historically driven RNG project development are transportation fuel-driven, such as the federal United States Environmental Protection Agency's Renewable Fuel Standard and the California Low Carbon Fuel Standard and Oregon Clean Fuels Program. The value of certain RNG that can qualify for the generation of credits under the federal program has been hovering around $35/MMBtu, and the value for certain RNG that is selling into the Oregon Clean Fuels Program has been $50/MMBtu and up, depending on the resource. These revenue opportunities have driven the strong growth in project development and have helped to grow a more established RNG industry. An increasing number of engineering and construction firms now have RNG experience, and NW Natural has seen a growing number of traditional energy project engineering and construction firms building out dedicated RNG teams. This year NW Natural issued an RFP for engineering firms to provide services as "owners engineers" for future RNG projects and received six responses from firms with significant RNG experience and expertise.

To maintain its awareness of current market dynamics and identify new resource opportunities, NW Natural issues annual RFPs for RNG resources. Our 2022 RFP process is currently ongoing, but we received 20 individual bids from RNG developers and brokers and are currently reviewing the bids. There continues to be a strong response to our annual RFPs and a clear interest in selling RNG into markets such as gas utilities that can offer revenue opportunities separate and distinct from the transportation fuel credit markets. Those transportation fuel credit markets, while lucrative, are also highly volatile, and very hard to forecast or hedge against. Utilities, then, represent a steady and reliable source of revenue for RNG projects, and revenue that can help project developers secure project-level financing.

Hydrogen markets continue to be based on the lowest-cost available feedstocks and direct on-site use of the commodity for processes such as liquid fuels refining and fertilizer production. There is minimal large-scale use of non-fossil sources due to costs and limited carbon policies incentivizing lower-carbon sources. For off-site hydrogen use, costs are higher due to liquifying and truck transportation costs.

That said, there are signs the hydrogen market is changing. NW Natural has received responses in its annual RNG RFP for hydrogen at competitive prices, even lower than many RNG sources. Hydrogen developers are finding sources of low-cost electricity in regions outside of Oregon to use for electrolytic hydrogen production. Direct injection of hydrogen into interstate pipelines has yet to become widespread; developers are therefore exploring methanation to produce synthetic methane still at competitive prices. Transmission system hydrogen blending is predicted to become available in the future, at which time these methanation plants can be re-purposed to produce hydrogen at lower production costs.

NW Natural and many other gas utilities are predicting increased hydrogen production in their regions and are preparing for wide-scale hydrogen blending. Hydrogen developers have expressed interest in developing projects in our region and have requested information about how and where they can blend. By preparing for hydrogen blending, NW Natural is positioning itself to accept large volumes of clean hydrogen to reduce the carbon intensity of its energy and potentially enable other segments to decarbonize, such as heavy-duty transport, aviation, and maritime shipping. Economies of scale generated through large hydrogen production projects for utility use can decrease the costs of hydrogen for these other industries.

2.5 Efficient End Use Equipment

To accelerate the development and market adoption of efficient natural gas products, practices, and services, NW Natural partners with the Energy Trust of Oregon and natural gas utilities in Oregon and Washington through the Northwest Energy Efficiency Alliance (NEEA) to create a long-term market transformation strategy to ultimately increase consumer choices for the efficient use of natural gas in the Northwest.

There are three initiatives currently in NEEA's portfolio representing a technical savings potential of over 360 million annual therms in the Northwest. The specific technologies and their associated anticipated savings are outlined below.

2.5.1 Efficient Gas Water Heaters

The Efficient Gas Water Heater program seeks to transform the residential gas water heating market, making gas-fired heat pump water heaters the standard in gas water heating appliances. These units use half the energy of today's standard tanked gas water heaters and therefore represent tremendous savings opportunity. NEEA's 2020-2024 Business Plan[34] indicates a significant market for this product in the Northwest (1.7 million customers) and a high cumulative savings potential (over 200 million annual therms). NEEA is working to achieve this goal through exploring opportunities to accelerate adoption of currently available efficient products while driving manufacturers to develop and commercialize heat pump water heater technology, and ultimately influencing federal manufacturing standards for natural gas water heaters. Broad commercialization of heat pump water heaters is estimated by 2025.

2.5.2 Efficient Rooftop Units

Rooftop units (RTUs) are heating, and air conditioning appliances fueled by natural gas and are prevalent in low rise commercial buildings in the Northwest. RTUs are often purchased as a like-for-like replacement based on cost and availability and, therefore, strategic efficiency improvements may achieve savings without onerous customer adaptation.

NEEA identified best practices for effectively adopting RTU's with more efficient furnace components. Through additional modeling in 2020, NEEA staff identified several other, commercially available efficiency measures beyond the furnace (heating component of the RTU system) that could provide significant whole system efficiency gains and are not currently valued by existing metrics or widely used by manufacturers.

Current efficiency metrics and specifications focus only on some of the energy used by RTUs; for example, TE (thermal efficiency that measures a gas furnace's efficiency in converting fuel to energy) only accounts for the efficiency of the burner in the gas furnace (which is only one component of the RTU), and does not consider the efficiency of controls, insulation, damper leakage, and performance in different climates. To meet the need for a more comprehensive view of efficiency, updated metrics and specifications for RTUs are needed. To this end, NEEA is developing and promoting a new efficient Gas RTU national specification, comprehensive test procedure and associated Qualified Products List (QPL) that recognizes the efficiency improvements provided by these additional RTU characteristics that voluntary programs can reference and will provide modes to value higher system efficiency in the market. Ultimately, the program aims to lock in this efficiency shift through state codes and Federal Standards to represent a 10% efficiency gain above 2020 standards. This effort has the potential to save over 80 million annual therms in the Northwest.

2.5.3 High-Performance Windows

New technology advancements in ultra-thin glass production and low-conductivity gases that are inserted in between the panes of glass, have created the opportunity for a new caliber of high-performance windows. Designed to be the same width and virtually the same weight as existing double-glazed windows, new triple-paned windows offer a sleek and non-invasive retrofit solution for existing homes with poor-performing windows. They can also help builders in the new construction

[34] NEEA's 2020-2024 Business Plan can be found at: NEEA-2020-2024-Strategic-and-Business-Plans.pdf

market reach above-code program targets more easily than other options. NEEA's High-Performance Windows program will focus on stimulating national builder and consumer demand, influencing the ENERGY STAR® specification to reach higher performance levels, and including high-performance windows in building codes. The efficiency of windows is measured in U-Values, the lower the U-Value number, the better the thermal performance of the window.[35] Today ENERGY STAR® rated windows for the northern climate zone have a U-Value of 0.27; the long-term goal of this program is for windows with a 0.20 U-Value, or less, to reach over 50% share of sales in the Northwest which will benefit both natural gas- and electrically-heated homes and have the potential to save over 80 million annual therms in the Northwest.

2.5.4 Other Portfolio Activities

NEEA also recognizes the necessity of other activities to advance the portfolio, such as scanning for new technologies and codes and standards work, the activities for which are closely coordinated with the strategies and activities of the alliance's Market Transformation programs. For additional detail, please refer to NEEA's 2020-2024 Business Plan.[36]

2.6 Environmental Policy- Overview

Both Oregon and Washington have adopted climate policies that call for transformative change in energy systems. While state policy is driving much of the change, federal and local policies continue to influence NW Natural investments. The emission reduction targets in both states are aggressive but the policy structures are quite different. Most notably options for compliance and compliance periods in state carbon goals are not the same across both states. This requires greater differentiation as the company works to decarbonize the system at large and to comply with the laws in both states. Each law is detailed more completely in Sections 2.6.2 and 2.6.3.

In addition to the transformative climate policy that sets carbon emission reduction goals, the environmental policy landscape in each state includes additional important elements including such factors as policy movement in building codes and renewable energy procurement.

2.6.1 Environmental Policy – Federal[37]

At the federal level, greenhouse gas emissions from the natural gas supply chain continue to be a focus of the Environmental Protection Agency (EPA) agenda. Under 40 CFR Part 98, the Greenhouse Gas Reporting Rule, NW Natural reports to EPA the emissions from the use of our product by our customers and the fugitive emissions from our system. Emissions are reported for operations in both

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[35] The typical U-Values on windows is **a measurement of heat loss and the rate at which it is lost**. U-Values indicate the overall performance in retaining heat and preventing it from escaping to the outside. U-Values are measure in Watts per square meter Kelvin, or W/m2 K.

[36] https://neea.org/img/documents/NEEA-2020-2024-Strategic-and-Business-Plans.pdf

[37] At the time of this writing, the Inflation Reduction Act was recently passed. Due to the timing of its passage, NW Natural was not able to include it in this section but as the environmental policy space is very dynamic on many levels, we will continue to monitor environmental policy especially as it applies to our action plan.

Oregon and Washington. At this time, there is not a federal carbon market or cap on emissions. NW Natural emissions are limited by policy at the state level.

To spur innovation in alternative fuels there is ongoing work at the federal level for financial incentives for the development of hydrogen and renewable natural gas (RNG). Much like incentives that were provided to alternative electricity generation projects, hydrogen and RNG projects would benefit greatly from federal investments as these markets develop. One example of such investments is the Regional Clean Hydrogen Hub program administered by the US Department of Energy (US DOE). As part of the 2021 Bipartisan Infrastructure Law, $8,000,000,000 was allocated to the US DOE to support the development of at least 4 regional clean hydrogen hubs to improve clean hydrogen production, processing, delivery, storage, and end use.

2.6.2 Environmental Policy / Codes – OR

Oregon Climate Protection Program (CPP)

On March 10th, 2020, Governor Kate Brown issued Executive Order 20-04 directing state agencies to take actions and regulate greenhouse gas emissions. The Climate Protection Program (CPP) was developed as an outcome of this executive order with Department of Environmental Quality (DEQ) as the administrator and regulator. Following a formal rulemaking process, the program went into effect on January 1, 2022.

The CPP sets a declining limit, or cap, on greenhouse gas emissions from fossil fuels used throughout the state of Oregon, including diesel, gasoline, natural gas, and propane, used in transportation, residential, commercial, and industrial settings (the program is not inclusive of fossil fuel used in electric generation). The CPP also regulates site-specific greenhouse gas emissions at large stationary sources, such as emissions from industrial processes. The program baseline is set at average greenhouse gas emissions from covered entities from years 2017-2019. Reductions from this baseline are set at 50% by 2035 and 90% by 2050.

NW Natural is the entity responsible for decarbonizing all load delivered on the company's system. This includes not only sales customers- those customers for whom the company purchases and delivers the commodity but also transportation schedule customers. Transport schedule customers purchase the commodity they use directly from marketers and suppliers and pay NW Natural for delivery via the distribution system. This customer segment has not historically had rate funded energy efficiency programs.

Covered entities emissions are reported annually through the existing DEQ greenhouse gas reporting program and compliance will be demonstrated by each covered entity at the end of each three-year compliance period. To comply, covered entities like NW Natural can work to reduce usage through efficiency measures, introduce renewable and low carbon alternative fuels, trade for additional compliance instruments with other covered entities, or purchase a limited amount of Community Climate Investments (CCI).

CCIs are a unique compliance tool developed by DEQ specifically for the CPP. These tools were designed to focus on funding emission reduction projects benefitting underrepresented communities. In the rulemaking, DEQ established a set dollar amount that a regulated entity must invest in an approved project to earn a credit. The regulated entities using this compliance tool will pay a DEQ designated third party to invest in projects that reduce or remove greenhouse gas emissions in Oregon's communities.

These instruments are not conventional offsets. The program requires all CCI investments be located in Oregon and intends to prioritize investments in environmental justice and other impacted communities. CCIs are not available for purchase in the first year of the CPP as that part of the program and its administration is still under development. CCIs are projected to be available by the first demonstration of compliance. Per the rule making, the price of CCIs will be set at $107/ton for the first compliance period and raise over time. Use of CCIs as a compliance instrument is limited to 10% of the compliance demonstration during the first compliance period (2022-2024), 15% during the second compliance period (2025-2027), and 20% during the subsequent compliance periods (2028-2050).

Senate Bill 98 (SB 98)

NW Natural worked collaboratively with legislators and renewable natural gas (RNG) stakeholders to create SB 98, a groundbreaking bill that was signed into law by Oregon Governor Kate Brown in 2019. In 2020, rulemaking for SB 98 was completed[38] and NW Natural was able to begin procuring RNG for our customers. SB 98 sets the following voluntary targets of 5% RNG for 2020-2024 period, 10% for 2025-2029, 15% by 2030, 20% by 2035, and 30% by 2050. It enables utilities to procure RNG through offtake contracts or invest in and own cleaning and conditioning equipment required to bring raw biogas and landfill gas up to pipeline quality, as well as allowing the facilities to connect to the local distribution system. The rule does contain cost containment measures that only allow for up to 5% of the utility's revenue requirement to be used to cover the incremental cost of investments in RNG infrastructure. The RNG procured under SB 98 may be acquired locally or from sources across the nation.

Status of Oregon Codes

The 2021 Oregon Residential Specialty Code (ORSC) went into effect in April 2021 and is based on the 2018 International Residential Code. The current ORSC is fuel neutral. The next residential code cycle process began in June 2022 and will be effective in the fall of 2023. Review of proposals and the discussion process began in September 2022.

[38] For more information about the rulemaking, please see Oregon PUC docket AR 632

Oregon commercial energy code is currently based on the national ASHRAE 90.1 – 2019 standard. The ASHRAE 90.1 – 2019 standard became effective in 2021 and is fuel neutral. The Oregon Building Codes Division has expressed intent to continue use of the national ASHRAE standard for the next commercial energy code cycle.

We expect future code cycles to continue to encourage electric heat pump technology adoption with opportunities for hybrid and gas heat pump technologies as well. For example, commercial and industrial gas heat pumps are available now and are comparable in price to their electric counterparts. We fully anticipate residential gas heat pumps, now in late-stage pilots, to be commercially available soon. In turn, we would expect building codes to reflect these high-efficiency options, as they lower emissions while reducing grid reliability risks.

Potential Impacts of Oregon House Bill 3055

Oregon House Bill (HB) 3055, effective September 25, 2021, creates new provisions and amends numerous Oregon Revised Statutes (ORS) including ORS Chapter 757 - Utility Regulation Generally. The majority of HB 3055 focuses on State programs outside of natural gas planning, however, Section 23 creates allowances and pathways for natural gas utilities to recover costs for expenses for investments in infrastructure to support the adoption and service of alternative fuel vehicles if particular conditions are met.[39] Such conditions are as follows:

Allows natural gas utilities to recover costs from investments related to infrastructure to support the adoption and service of alternative fuel vehicles if they can reasonably be expected to:

- *Support vehicles that are powered by renewable natural gas or hydrogen;*
- *Support reductions in transportation sector greenhouse gas emissions over time; and,*
- *Benefit the natural gas utility system; or that revenues from natural gas utilities from fueling alternative forms of transportation vehicles offset utilities' fixed costs that may otherwise be charged to retail natural gas customers*

It is unclear at this point to what extent this legislation will have on the CNG market locally and regionally.

2.6.3 Environmental Policy / Codes – WA

Washington Climate Commitment Act (CCA)

In 2021, the Washington Legislature passed the Climate Commitment Act (or CCA) which establishes a state-wide program to reduce carbon pollution and achieve greenhouse gas limits set in state law (RCW 70A.45.020). The Climate Commitment Act (CCA) caps and sets reduction targets for greenhouse gas emissions from identified emitting sources and industries. The program will start Jan. 1, 2023.

The primary regulator of the CCA is Washington Department of Ecology (Ecology). The agency is in the process, throughout 2022, of developing rules to implement the cap on carbon emissions, including

[39] https://www.oregon.gov/puc/Documents/2021-Legislative-Summary.pdf

mechanisms for the sale and tracking of tradable emission allowances, along with compliance and accountability measures. Long term, the program is intended to allow for linkage with similar programs in other states/jurisdictions. California has been identified as the most likely first partner.

The cap-and-invest program works by setting a limit, or 'cap', on greenhouse gas emissions in the state, and then lowering that cap over time to ensure Washington meets the greenhouse gas targets. The program baseline is set at average covered entity greenhouse gas emissions from years 2015-2019. Reductions from this baseline are set at 45% by 2035, 70% reduction by 2050 and 95% by 2050.

When it launches on Jan. 1, 2023, the cap-and-invest program will cover industrial facilities, certain fuel suppliers, in-state electricity generators, electricity importers, and natural gas distributors with annual greenhouse gas emissions above 25,000 metric tons of carbon dioxide equivalent. Over time additional portions of the economy will be moved under the program. On Jan. 1, 2027, the program adds waste-to-energy facilities and on Jan. 1, 2031, the program adds railroad companies.

All participating entities must obtain allowances equal to their covered emissions. The Legislature determined that 'emissions-intensive, trade exposed' entities (EITEs), natural gas utilities, and electric utilities will be issued some allowances at no cost. Businesses can also buy and sell allowances on a secondary market. The total number of allowances issued each year will be equal to the 'emissions cap' and will decrease over time to meet statutory limits.

Most businesses will purchase their allowances at auction (consigned allowances). Ecology will host quarterly emission allowance auctions for covered entities. Funds from the auction of emission allowances are intended to support new investments in climate resiliency programs, lower carbon transportation, and addressing health disparities across the state. Ecology is proposing floor and ceiling prices for allowances to prevent allowance prices from going too high.

A portion of a covered entity's compliance obligation can be covered by credits generated by projects that reduce, remove, or avoid greenhouse gas emissions, called offset projects. Covered entities can meet up to 5% of their obligations with offset credits through 2026 (plus an additional 3% for offset projects on tribal lands), and 4% from 2027 to 2030 (plus an additional 2% for projects on tribal lands). To qualify under the CCA, offset projects must result in greenhouse gas reductions that are real, permanent, quantifiable, verifiable, and enforceable. They must also be in addition to emissions reductions that are required by law.

The cap-and -invest program is still in the final stages of rulemaking and will not be complete before the publication of this plan. As such, it is possible that some details included may shift before implementation.

House Bill 1257 (HB 1257)

House Bill 1257, The Washington Clean Buildings Bill, passed in 2019. HB 1257 adopts energy performance standards, aimed at reducing the energy intensity of Washington's commercial building stock, for commercial buildings exceeding 50,000 square feet. Buildings that fit this category will be required under the law to meet Energy-Use Intensity targets (EUIt) to reduce greenhouse gas emissions.

HB 1257 also includes four provisions that represent meaningful policy changes Washington's natural gas distribution utilities:

1) Requires utilities to identify and acquire all natural gas conservation measures that are available and cost-effective. To achieve this goal, the legislation requires the utilities to establish a conservation acquisition target every two years (also referred to as a biennial energy efficiency plan). To identify all conservation measures the company contracted the consulting firm AEG to conduct a conservation potential assessment (CPA).
2) Requires all Washington natural gas utilities to offer a voluntary renewable natural gas tariff. NW Natural's voluntary renewable natural gas offering was approved by the Washington commission in March of 2022 and went live for customer participation in July of 2022.
3) Permits natural gas utilities to propose a renewable natural gas program for delivery to all retail customers at a total cost of up to 5% of revenue requirement. This is a key provision in this IRP and is used to set targets for RNG acquisition to be delivered to all NW Natural customers in Washington.
4) Requires gas utilities to use the Social Cost of Carbon (SCC), including an assessment of upstream emissions, to make resource planning decisions. NW Natural has included the SCC in its avoided costs in Washington and interprets this provision along with the CCA to mean that NW Natural will use the higher of the SCC or the expected price of allowances in the cap-and-invest system as the price of carbon for the resource planning work in this IRP.

Status of Washington Codes

Washington's new residential code went into effect in February 2021. This change made it more expensive to build a single-family home with gas compared to electric – with the cost deferential varying depending on the home size, equipment choices, and shell measures selected. Despite this change, many homebuilders are opting to build with gas cooking and fireplaces, although some continue to build with gas space heating as well. New residential code development began in May 2022 and includes a prohibition on gas furnaces and water heating for residential new construction but allows for gas heat pumps and hybrid systems. The code draft will not be decided on until after the public comment period, which takes place from September to October 2022. The State Building Codes Council (SBCC) will take action on the new code in November 2022.

Washington commercial code changes were approved in April 2022 by the SBCC (with a final vote scheduled for November 2022) and will prohibit gas space and water heating in new construction and retrofits, with very limited exceptions beginning July 2023.

2.6.4 Environmental Policy – Local

In NW Natural's service territory several local jurisdictions (e.g., cities and counties) have or are in the process of creating Climate Action Plans as a means of addressing and reducing carbon emissions within the jurisdiction. The plans vary across the territory between direct actions that municipal facilities and operations can take to reduce emissions, to plans that encompass the activities of all citizens, institutions, and businesses. Most plans include a focus on a number of activities to reduce the use of fossil fuels in transportation and buildings. Within this spectrum of options, some municipalities consider banning natural gas or in some way limiting the growth of natural gas infrastructure.

2.6.5 Equity and Environmental Justice

In this IRP, there is a greater recognition for the need to hear the voices from communities historically underrepresented in public processes. Environmental justice recognizes that these communities may bear a disproportionate amount of either energy burden and/or negative impacts from climate change and seeks environmental justice through having voices heard, directing benefits to these communities, and/or providing additional supports. These communities typically include but are not limited to communities of color, communities experiencing lower incomes, and tribal communities. As discussed more in Chapter 10, NW Natural has recently created a Community and Equity Advisory Group (CEAG) with the hopes of hearing from more of these voices.

2.6.6 Low Income Needs Assessment

As a result of an all-party settlement agreement in docket UG-200994, NW Natural's 2020 general rate case filed on December 18, 2020, the Company agreed to conduct a Low Income Needs Assessment (LINA). The LINA will consist of a compilation and analysis of relevant data to inform NW Natural's low-income programs in both Oregon and Washington. Some of the broad topics the LINA will be evaluating are eligibility/participation, penetration rate, characteristics of communities, identifying barriers to program participation, and energy burden. The LINA will help NW Natural better understand its customers' needs to design programs that are adapted specifically for the benefit of our customers.

After conducting an RFP, NW Natural contracted with Applied Energy Group (AEG) in February 2022 to estimate the total number of customers eligible to receive energy assistance benefits in its service territory. The Company is aware of the current energy assistance program penetration rate; the goal is to reach those customers that are eligible but have not received energy assistance in the past. AEG conducted a survey of known low-income customers, the results of which will be included in the final report expected in October 2022.

Current NW Natural energy assistance programs consist of the following:

- Oregon Customers - Low Income Home Energy Assistance Program (LIHEAP), Oregon Low-Income Gas Assistance (OLGA), and Gas Assistance Plan (GAP)
- Washington Customers - Low Income Home Energy Assistance Program (LIHEAP), Gas Residential Energy Assistance Tariff (GREAT), and Gas Assistance Plan (GAP)

2.7 Transformative Change for Resource Planning

NW Natural recognizes the climate imperative for society to decarbonize across the energy sector. Equally important is the means to decarbonization by equitably distributing the costs and benefits to utility ratepayers. To this end, NW Natural has taken many actions prior to this IRP to advance the company's decarbonization goals, such as the replacement of all bare steel and cast-iron pipes, developing an opt-in smart energy program, and pushing forward SB 98 legislation to voluntary acquire RNG on the behalf of all sales customers. For several IRPs, NW Natural has evaluated resource decisions inclusive of a forecasted GHG compliance price as an added cost for conventional gas and in the 2018 IRP proposed a concrete, yet flexible, methodology for evaluating renewable energy resources based on the *all-in* costs to serve customers.

The Company's IRP process is accustomed to incorporating new policies and legislation into the long-term planning of resources and their associated risks. At a high-level this IRP uses the same process directed by commission IRP guidelines to incorporate new and known legislation discussed in this chapter into the 2022 IRP. However, what is different is the scale at which, the CPP and the CCA impact resource decisions over the planning horizon relative to previously filed IRPs.

To understand the impact of these transformative policies in the context of the IRP, we develop a reference case that projects forward historical trends of critical drivers that make up total system demand. This includes trends in market share of gas customers in new construction, historical conversion rates, share of the end-use equipment operating in the service territory and the overall efficiency of that equipment found in homes and businesses. Defining a reference case provides a hypothetical construct for the "but for" world where natural gas demand continues in the same trajectory as the past absent decarbonization policies or meaningful changes in end-use equipment efficiency or deployment.[40] Given the planning environment, the likelihood of the reference case occurring is minimal, but establishes a starting point for comparison when forecasting deviations from historical trends into the future. How a reference case is defined may differ across different utilities or from one IRP to the next. For this IRP, we define the reference as the following:

[40] The reference case focuses on the demand for energy rather than being applied to resource supply assumptions, as we still have the resource optimization model solve the reference case to meet CPP and CCA emissions compliance obligations for comparison to resource optimization for the other scenarios and stochastic futures.

Reference Case – a projection of demand based on historical trends of customer additions and gas usage. The reference case shows what load would look like if all trends embedded in historical data continued over the remainder of the planning horizon to 2050. The reference case is not a base case or preferred portfolio, it is a tool used to show how the scenarios being modeled in the IRP differ from the prior "business-as-usual" state.

In addition to the Reference Case, the IRP conducts several "what-if" scenarios where a few key demand and supply inputs are explicitly modified in-contrast to the Reference Case. The results from these scenarios provide insights to the resource planning impacts, risks, and rate implications from changes specific input assumptions.[41] Separate from the scenario work, the IRP process also employs stochastic simulations, which randomly varies numerous key inputs that have a high level of uncertainty over the planning horizon (such as gas prices). This stochastic process simulates 500 different potential futures for the resources optimization software to solve for the optimal resource portfolio for each of the 500 simulations.

Unlike previous IRPs, this IRP does not define or select any single scenario or set of outcomes as a base case. Typically, a base case consists of a set of assumptions and outcomes, which given the knowledge at a moment in time, represent the Company's best expectations of the future. With these transformative policies, the resources need, and the cost and availability of demand-side and supply-side resources required to meet those needs is very uncertain. Therefore, this IRP does not present a base case, but instead outlines a wide range of potential outcomes through scenario and simulation work. Using this work, we develop an action plan that is robust to the uncertain future.

Per the above, with feedback from stakeholders NW Natural defined 9 scenarios to better understand the impact of changing key assumptions in the context of complying with transformation climate policies. The goal of scenario development is not to predict the future, and it is important not to vary too many variables when comparing one scenario to another, or the primary driver of differing results between scenarios may be hard to untangle. The specific assumptions of each of the scenarios is discussed in more detail throughout this IRP and the key inputs and results by scenario are detailed in Chapter 7.

[41] See Table 7.3: 2022 IRP Scenarios in Chapter 7 for details on supply and demand input assumptions for scenarios.

The first step in determining resource needs is projecting the energy needs of our customers. Chapter 3 describes our load forecasting techniques and shows load projections under a wide range of circumstances. These load forecasts are then used to define the amount of greenhouse gas emissions reduction needed to comply with environmental regulations.

3 | Resource Needs

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This chapter examines the future resource requirements for NW Natural's system. This includes resources needed for capacity, energy, and emissions compliance. Establishing resource need begins with the load (i.e., demand) forecast, which is the focus of this Chapter. The resources needed are ultimately determined by demand specific type of customer. Table 3.1 lays out how system resources are planned to meet capacity, energy, and emissions compliance needs by customer type.

Table 3.1: System Resource Planning by Customer Type

	System Resource Planning		
Customer Type	**Design Winter Weather Energy Requirements**	**Peak Day Capacity Requirements**	**Expected Weather Emissions Compliance**
Firm Sales	✓	✓	✓
Interruptible Sales	✓		✓
Firm Transport			✓
Interruptible Transport			✓

3.1 Overview

Given the planning environment as outlined in the previous chapter, this IRP develops a range of load forecasts over a 28-year planning horizon from 2022 to 2050. The resulting demand and emissions reduction requirements from these load forecasts determine the need for *gas supply and compliance resources*, which include options for both demand-side and supply-side resources and are discussed in detail in the following chapters). Developing a range of load forecasts and understanding the potential uncertainty of the load is a critical first step to determining the resource need.

NW Natural's load forecasts are compiled from several bottom-up modeling components including customer count forecast, use per customer modeling, industrial load forecast, and energy efficiency projections, and are combined with a top-down daily/hourly system load modeling approach. Each of these components of the load forecast is done at a selected granularity of time, geography, and customer type and allocated to lower levels where necessary. This component-by-component approach to load forecasting provides a deep understanding of the demand drivers, while balancing model complexity with accuracy and precision.

NW Natural's load forecasts start with historical data, input from subject matter experts (SME), and econometric models to project historical trends into the future. The combination of these historical trend models builds a *reference case* load forecast, which serves as a starting point for developing a range of load forecasts. The reference case represents a business-as-usual perspective, where the future looks like the past. Given the changing policy landscape, the imperative to address climate change, and the company's own carbon commitment goals, load forecasts are likely to deviate from these historical trends. To adequately model changes to these historical trends, NW Natural implements an end-use load forecasting model using the reference case as an anchoring point to adjust for changing expectations. This IRP's scenarios and stochastic forecasts all require the reference case as a starting point.

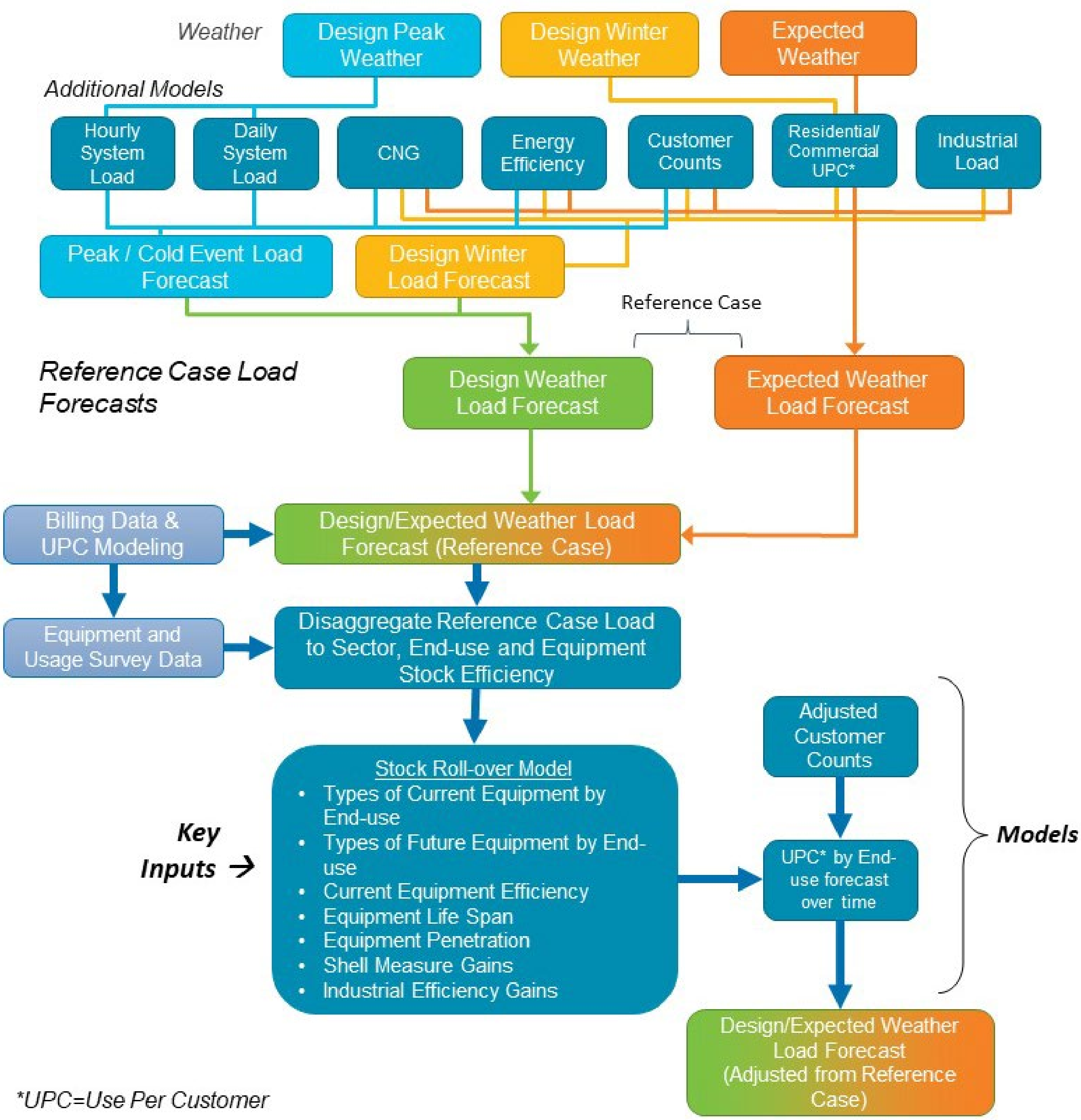
NW Natural first implemented end-use load forecasting in the 2018 IRP to analyze several scenarios. This IRP expands the use of the end-use load forecasting model to all scenarios (to be discussed in more detail later in this chapter) in combination with Monte Carlo simulations to create a range of potential load forecasts.

Figure 3.1 illustrates a high-level flow chart for the various models needed to develop the reference case for a given weather pattern and how it then feeds into the end-use load forecasting model.[42] The

[42] The color patterns correspond to the type of weather being used in the forecast. Light blue is design peak weather (i.e., design cold event, design day or design hours), yellow is design winter weather (November-April), and orange is expected weather. The design weather load forecast is green as it combines both the peak design weather and the design winter weather. Dark blue boxes are various models or combination of models.

rest of this chapter is arranged by following this diagram through the different components of the load forecasting model.

Figure 3.1: Load Forecast Model Flow Diagram



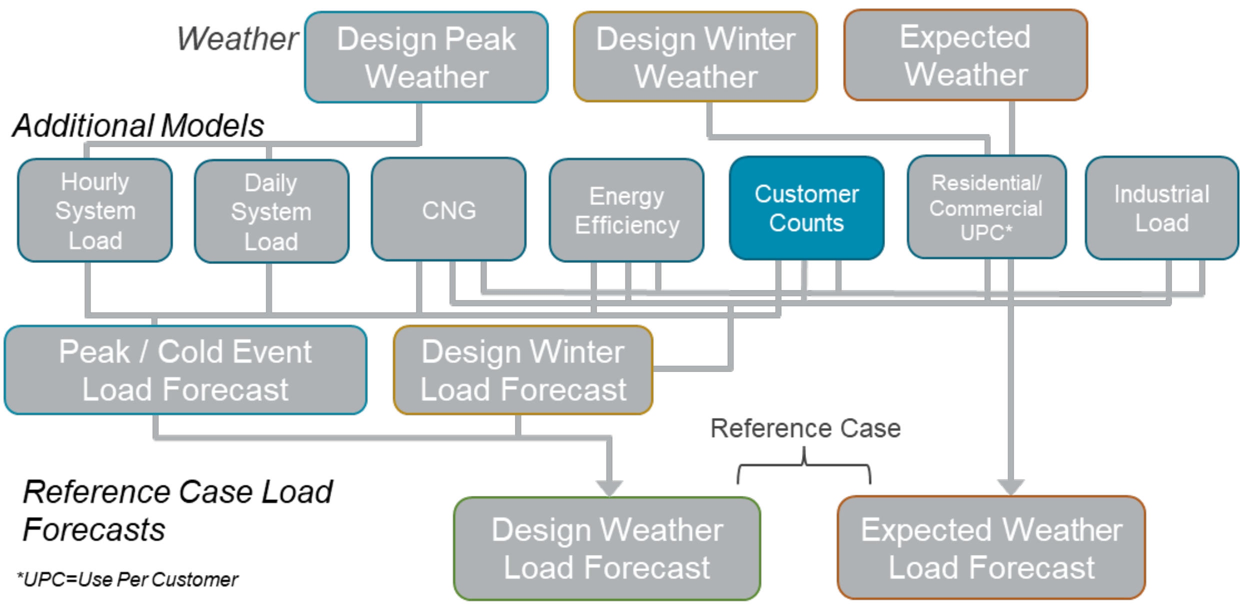
3.2 Reference Case Forecasts

The reference case forecasts rely on historical data to project forward historical trends. This means using statistical regression models and experience from internal subject matter experts to develop the reference case forecasts that enables the application of the stock roll-over model.

3.2.1 Customer Forecast – Reference Case

NW Natural serves a wide variety of homes and businesses where multiple people typically live in a single home and hundreds of consumers may patron a single business. As a common practice, the IRP defines a single customer as a natural gas meter in service. The customer count (i.e., meter count) forecast for residential and commercial customers is a critical input of the load forecast models (see Figure 3.2).

Figure 3.2: Load Forecast Model Flow Diagram – Customer Counts



NW Natural develops separate customer count forecasts for residential customers and commercial customers with four and three sub-classes, respectively. Each sub-class is allocated across ten load centers, which comprise NW Natural's service territory (see Table 3.2). In total, 70 separate customer count series are generated from the sub-class and load center combination. The customer count forecast is developed at this granular level as customer usage profiles are distinctly different across both sub-class and location (e.g., gas usage for the average residential house on the Pacific coast is very different than the average residential home in Portland).

Table 3.2: Customer Count Series

Class	Sub-class
Residential	Existing New Construction - Single Family New Construction - Multi Family Conversions
Commercial	Existing New Construction Conversions

X

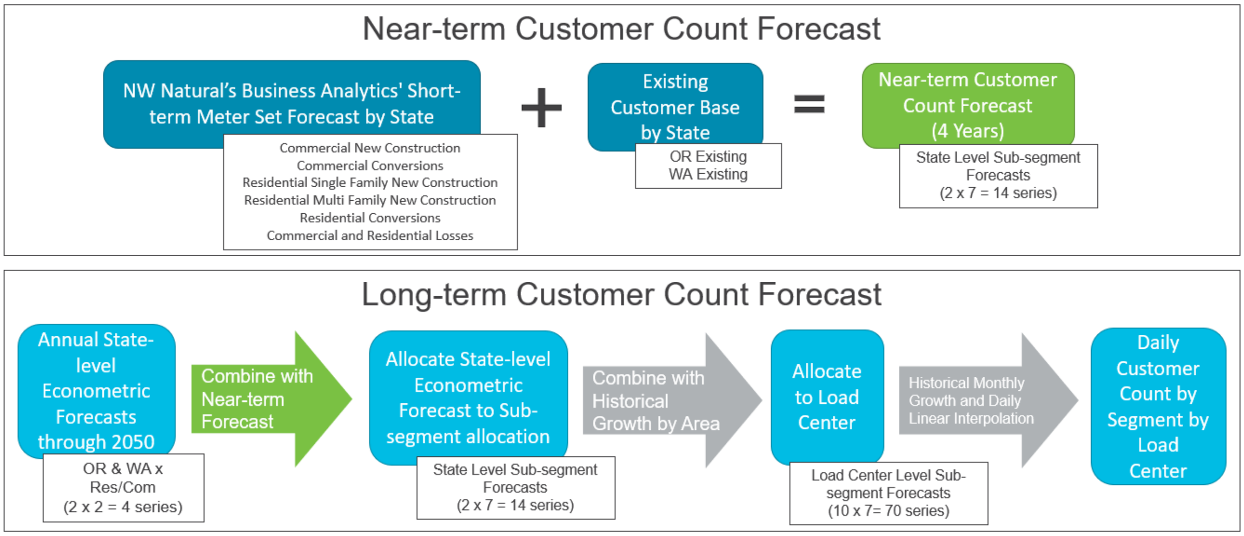
Load Center†
Albany
Astoria
The Dalles OR
The Dalles WA
Coos Bay
Eugene
Lincoln City
Portland
Salem
Vancouver

†The 10 Load centers include a broader area than indicated by its name (e.g., the Vancouver load center includes all of NW Natural's service territory in Clark County).

The IRP customer count forecast for the planning horizon combines a near-term customer count forecast provided by internal subject matter experts (SME), with an econometric model that captures long-term trends. The near-term forecast is projected by state and sub-class, while the econometric model is estimated by class (residential and commercial) and by state. Using historical data and growth rates, these forecasts are combined and allocated to each load center as illustrated in Figure 3.3.[43] Note that the IRP models do not forecast the number of industrial or large commercial customers due to the extreme difference in usage profiles among these customers. Load forecasting for these large usage customers is discussed later in this chapter.

[43] See NW Natural's 2018 IRP, Chapter 3, Section 2.2 in which NW Natural evaluated several alternative bottoms-ups approaches for the customer count forecast including estimating sub-segments (referred to as components in the 2018 IRP) at the load center level. For a variety of reasons, including data availability and predictive power, NW Natural concluded that a top down statewide forecast for residential and commercial customer counts was the appropriate methodology.

Figure 3.3: Customer Count Forecast Process Diagram



Subject Matter Expert Panel

NW Natural's customer forecasts blend two different types of forecasts, that is, econometric method-based long-term trend forecasts as detailed in the following section and near-term forecasts provided by a panel of internal subject matter experts (SME panel). The SME panel is composed of NW Natural employees from multiple departments across the company. The panel meets quarterly to update its previous forecast and prepare a budgetary forecast in the fourth quarter. The panel uses quantitative macroeconomic information such as the number of Oregon housing starts forecasted by Oregon's Office of Economic Analysis (OEA) or state immigration numbers, and qualitative information including up-to-date intel about potential multifamily new construction housing customer additions or information gathered directly from the trade ally community. Using information from departments across the company, the panel develops a near-term annual forecast for residential and commercial customer counts.

Econometric Models

NW Natural used some of the same steps in its approach to developing and evaluating econometric models for customer forecasts in the 2022 IRP as in the 2018 IRP Update #3, 2018 IRP, and 2016 IRP. These include the use of annual data, ensuring stationarity of dependent variables, and evaluating multiple explanatory variables and their transformations.

Annual data is used for two primary reasons. First, a much longer time series is available for customer data at an annual frequency than at a monthly frequency. Second, potential explanatory variables are typically not available at a monthly frequency, but at quarterly or annual frequencies. This is often the case for both historical and forecast values.

NW Natural tested dependent variables for stationarity and differenced where stationarity was not indicated. The Company assessed econometric models with alternative autoregressive integrated moving average (ARIMA) structures for each forecast, generally selecting the structure with the best information criterion value.

NW Natural also evaluated multiple potential explanatory variables for each customer forecast. These included transformations of values, such as differencing, moving averages, leads/lags, and their combinations. The Company eliminated from further consideration explanatory variables with less satisfactory results, such as limited correlation with the dependent variable or an indication of a non-normal distribution of model errors.

Econometric models are developed by class and by state.

Table 3.3 shows the explanatory variables and source used in the econometric customer forecasting models. Technical details for the econometric forecast can be found in Appendix B.

Table 3.3: Exogenous Variables used in Econometric Customer Forecast Models

Model	Oregon Models (Source)	Washington Models (Source)
Residential	U.S. Housing Starts (OEA)	U.S. Housing Starts (OEA)
Commercial	Oregon Population (OEA)	Oregon Nonfarm Employment (OEA)

SME and Econometric Blending

Timing requirements of the IRP process are such that NW Natural finalized customer forecasts in the 2022 IRP before 2021 annual data was available. Therefore, the first forecast year is 2021. The Company used the SME panel forecast for years between 2021 and 2023 and as demonstrated in the 2018 IRP the SME panel forecast is arguably more accurate than the econometric forecast in the near term.[44] For year 2024, the Company blends the two types of customer forecasts, with the SME panel forecast and the econometric forecast receiving a one-half weight each. As a standard, the fourth year of the customer count forecast is “blended”. For years 2025 forward, the Company added the rate of change from the econometric customer forecast to the value of the customer forecast of the prior year. This merges the state by class econometric model to the state by sub-class SME forecast. Counts are then allocated to load center and daily counts.

[44] See NW Natural’s 2018 IRP, Chapter 3 pages 3.8-3.10 for a detailed comparison.

Residential and Commercial Customer Count Forecast

As shown in Table 3.2 the customer count forecast models develop 70 separate series by load center and sub-class.

Figure 3.4 and Figure 3.5 aggregates those series for the system residential and system commercial counts, respectively. See Appendix B for state specific breakouts.

Figure 3.4: System Residential Customers – Reference Case

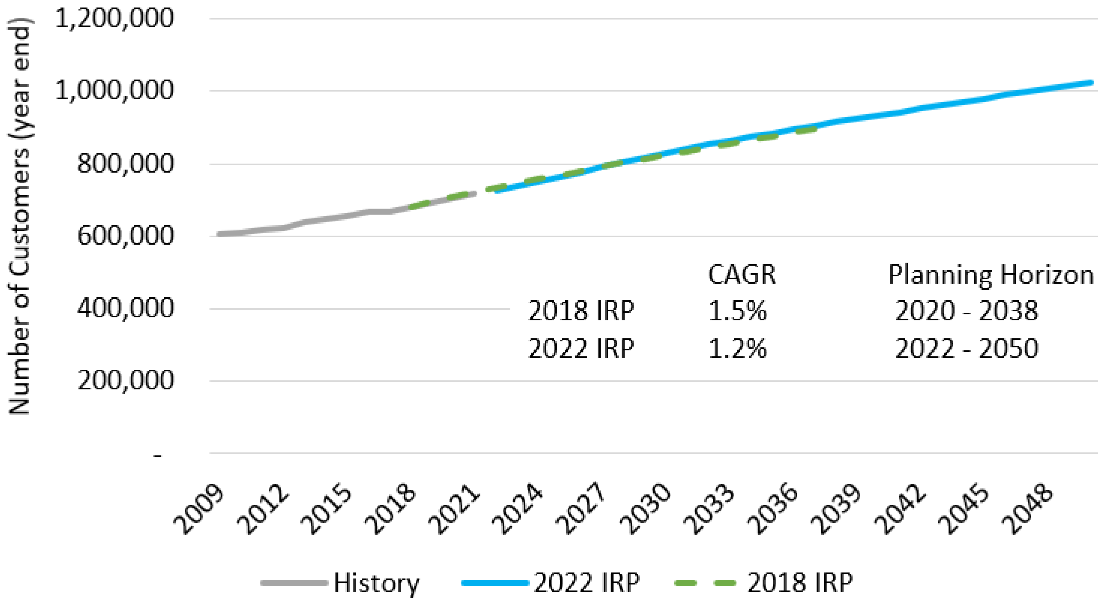


Figure 3.5: System Commercial Customers– Reference Case[45]

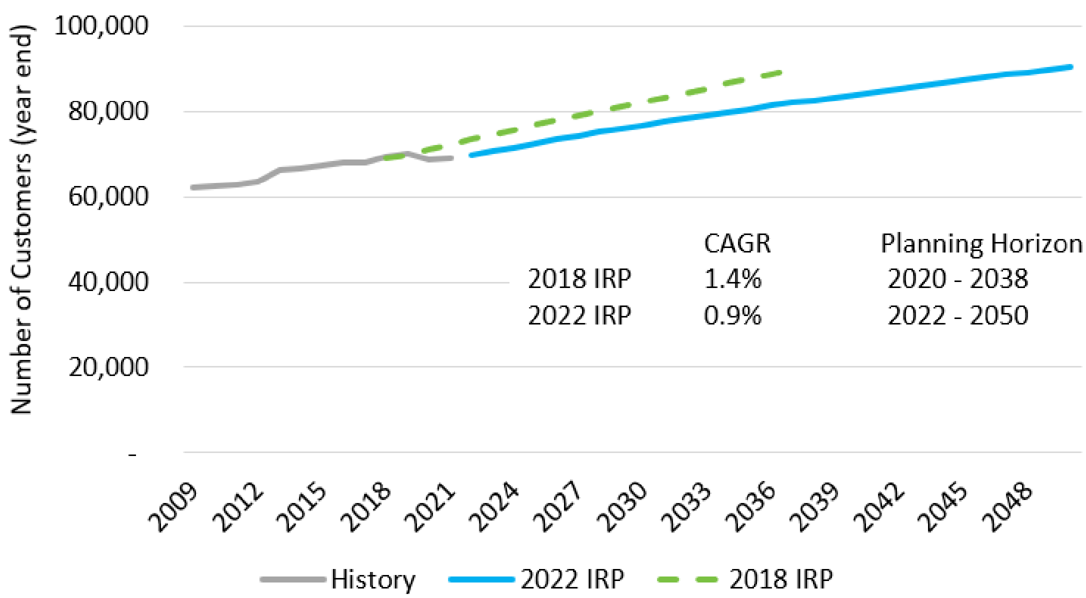


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Figure 3.5 includes customer counts for large commercial customers on rate schedules 31/32/41/42, but these customer counts are subtracted from the commercial customer count that is used in the use-per-customer model, which estimates small commercial customer usage. This is discussed later in this chapter.

Table 3.4 summarizes the primary similarities and differences between customer forecasts in the 2022 IRP and the 2018 IRP.[46]

Table 3.4: Customer Forecasting Comparison between the 2022 and 2018 IRP

	2022 IRP	2018 IRP Update
Econometric Models	State by Class Oregon Residential Oregon Commercial Washington Residential Washington Commercial	State by Class Oregon Residential Oregon Commercial Washington Residential Washington Commercial
Left-hand side variable	**Right-hand side variable (source)**	
Residential customers (OR)	OR Housing Starts (OEA)	U.S. Housing Starts (OEA)
Residential customers (WA)	U.S. Housing Starts† (OEA)	U.S. Housing Starts (OEA)
Commercial customers (OR)	OR Population‡ (OEA)	OR Population (OEA)
Commercial customers♠ (WA)	OR Nonfarm Employment (OEA)	OR Nonfarm Employment (OEA)
Year of SME panel and econometric forecast blending	Year 4 - 2024	Year 4 - 2020

† Right-hand side variable for WA residential model – US Housing Starts – transformed to log form from level form
‡ 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

3.2.2 Climate Change Adjusted Weather Forecasts

Climate change is impacting weather patterns across the globe, including here in the Pacific Northwest. As weather is a primary driver for gas usage and a critical input for forecasting load, the long-term trends in weather are important to consider for NW Natural's long-term resource planning. This section explains how the Company incorporates climate change trends into our load forecast modeling.[47]

[46] These are the same changes made for the 2018 IRP Update #3. There were no changes in methodology between the 2018 IRP Update #3 and the 2022 IRP. Only data was updated.

[47] NW Natural has included climate change models into our long-term load forecasts for several years, but first presented these changes to external stakeholder through the 2018 IRP Update #3.

NW Natural develops weather forecasts, which incorporates data from climate models from the Intergovernmental Panel on Climate Change (IPCC). These climate model predictions are available on a coarse grid of about 300 square kilometers. The coarse grid predictions are further downscaled using a local weather to get weather projections for NW Natural's service territory. The downscaled projections of the IPCC climate models are available through a website maintained by the Lawrence Livermore National Laboratory (LLNL) and are matched to weather stations for each load center.[48] The IPCC publishes numerous models from several different agencies around the world. For a robust outlook of weather trends, the IPCC recommends using an ensemble of climate models. We selected the five climate models to inform the long-term trends in annual HDDs forecasted out to 2050.

IPCC Climate Models
ccsm4.6
cnrm-cm5.1
gfdl-cm3.1
hadgem2-cc.1
miroc5.1

The IRP implements several deterministic and stochastic weather pattern forecasts as inputs into the demand models to establish resource requirements. Table 3.5 describes the three primary deterministic weather patterns.

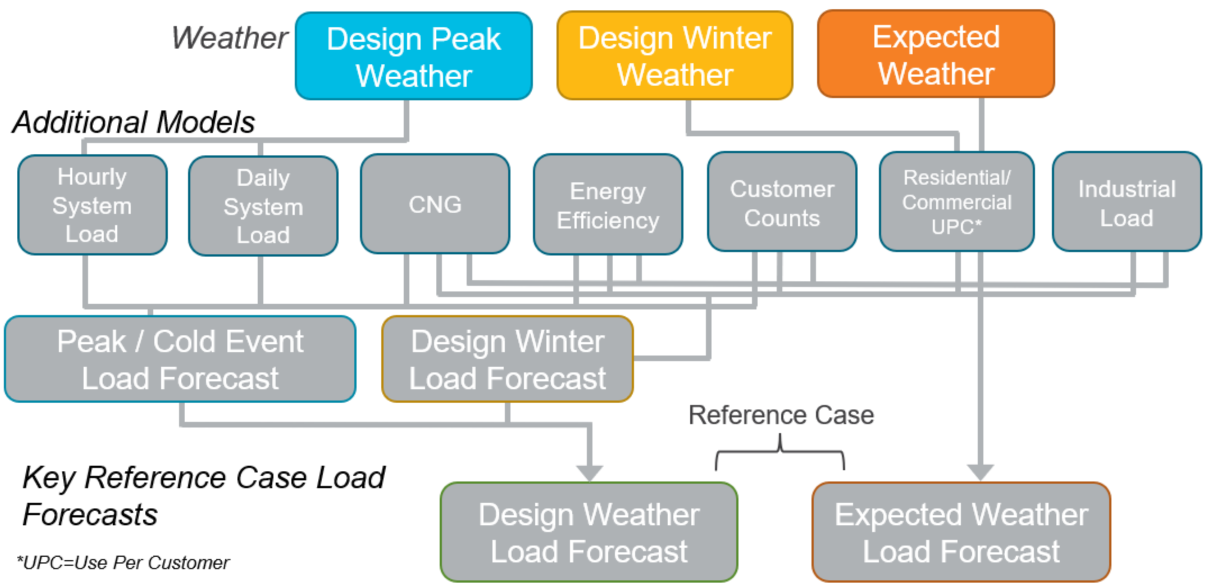
Table 3.5: Planning Standard Descriptions

Weather Pattern	Description	Purpose
Expected Weather	Expected weather is similar to "normal weather" uses in previous IRPs, however; expected weather is now incorporating long-term climate change trends based on cumulative annual HDDs. The expectation into the future is that on average weather would be reflected by expected weather.	Expected weather is the baseline used for emissions compliance planning and resource portfolio evaluation as expected weather will be a primary driver for expected natural gas and compliance costs.
Design Winter Weather	Cold winter weather adjusted from the expected weather based as a 90th percentile severe winter, based on cumulative winter HDDs (November-April).	The design winter weather drives annual energy requirements, ensuring resources are planned adequetly to meet annual energy requirement to sufficiently manage a colder than usual winter.
Design Peak Weather	The design peak day uses historical data to simulate a 1-in-100 year winter event.	Peak day weather drives the system capacity requirement for each forecasted winter in NW Natural's IRP. Peak hour weather drives the distribution capaacity requirement for a specfic area on NW Natural's distribution system.

[48] Downscaling of the IPCC data to NW Natural's service territory if made available by Archive Collaborators (i.e. Bureau of Reclamation, California-Nevada Climate Applications Program, Climate Analytics Group, Cooperative Institute for Research in Environmental Sciences, Lawrence Livermore National Laboratory, National Center for Atmospheric Research, Santa Clara University, Scripps Institution of Oceanography, Southwest Climate Adaptation Science Center, U.S. Army Corps of Engineers, and U.S. Geological Survey). The downscaling tool is free to use and is hosted on a website maintained by Lawrence Livermore National Laboratory (LLNL): https://gdo-dcp.ucllnl.org/downscaled_cmip_projections

Figure 3.6 shows the load forecast flow chart illustrating how different weather inputs are used in demand forecasting models. See Appendix B for technical details on how these weather forecasts are generated.

Figure 3.6: Load Forecast Model Flow Diagram – Weather Patterns



Expected Weather

Since NW Natural's load is primarily driven by heating requirements, the expected weather forecast focuses on the expected level of annual HDDs out to 2050. The expected annual HDDs is based on the average of the annual HDDs from the five selected IPCC climate models for each load center. Intra-year shaping is then applied for each month and then intra-month shaping is applied to each day to generate a daily forecasted temperature. This daily shaping is developed using a representative temperature pattern that is applied to each year in the forecast. In other words, each year in the forecast will have the same shape, but overall temperatures are increasing (i.e., HDDs are decreasing) over the planning horizon. Using a representative weather pattern, creates realistic volatility in daily temperatures, which is important for modeling resource dispatching.

Design Winter Weather

Design winter weather is generated to ensure our resource plan is adequate to serve customers during a colder than normal winter. This is particularly important for storage resource planning, such that the storage facilities maintain a sufficient inventory level to serve customers throughout colder than normal winter. NW Natural uses a 90th percentile design winter planning standard based on cumulative winter (Nov-April) HDDs. The design winter weather is developed as an adjustment to the expected weather forecast for the winter months, thus incorporating climate change trends for those winter months.

Design Peak Weather

Design peak weather includes a five-day cold event where NW Natural's system experiences a peak day on the third day of the five-day cold snap. Temperatures for this design peak weather for each location are based on temperatures from February 3, 1989, where system weighted temperatures fell to 10°F. Note that the peak day sales load forecast is discussed in more detail later in this chapter and is a function of many more drivers than temperature, but the design peak weather describe here is used in combination with the UPC model to allocate system load for the two days prior to the peak, the peak day, and the two days after the peak to each load center. Design peak weather is modeled from February 1st to February 5th and combined with design winter weather to produce the design weather to ensure capacity and energy requirements can be met by NW Natural's resource stack.

Weather Patterns for Resource Planning

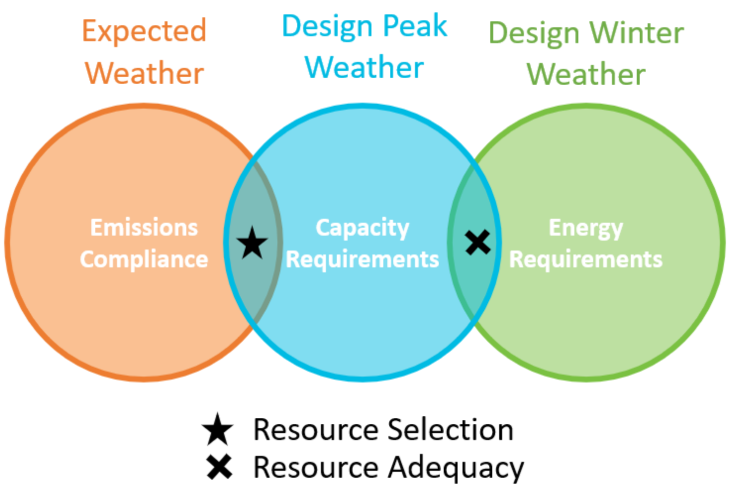
In previous IRPs, NW Natural has used the combination of design winter weather and design peak weather to ensure the selected resource portfolio could meet both capacity requirements and total annual energy requirements. Capacity requirements, specifically the ability to serve customers on a peak day, has been the primary driver for resource selection in previous IRPs. Resource selection for this IRP will need to fulfill an additional emission reduction requirement to comply with the state legislated emissions targets for utilities. Emissions reduction requirements must be based on expected weather. Due to modeling limitations, a single weather pattern, and therefore daily demand profile, must be used per run in the cost minimizing resource selection model.[49]

As emissions compliance and capacity requirements are critical to the long-term resource plan, this IRP uses expected weather with a single design peak day for resource selection. This will ensure that the resource planning optimization model (PLEXOS®) selects a least cost resource portfolio that meets both capacity and emission reduction requirements illustrated by

Figure 3.7. The combination of design peak and design winter weather is still used to test the resource adequacy NW Natural's resource stack.

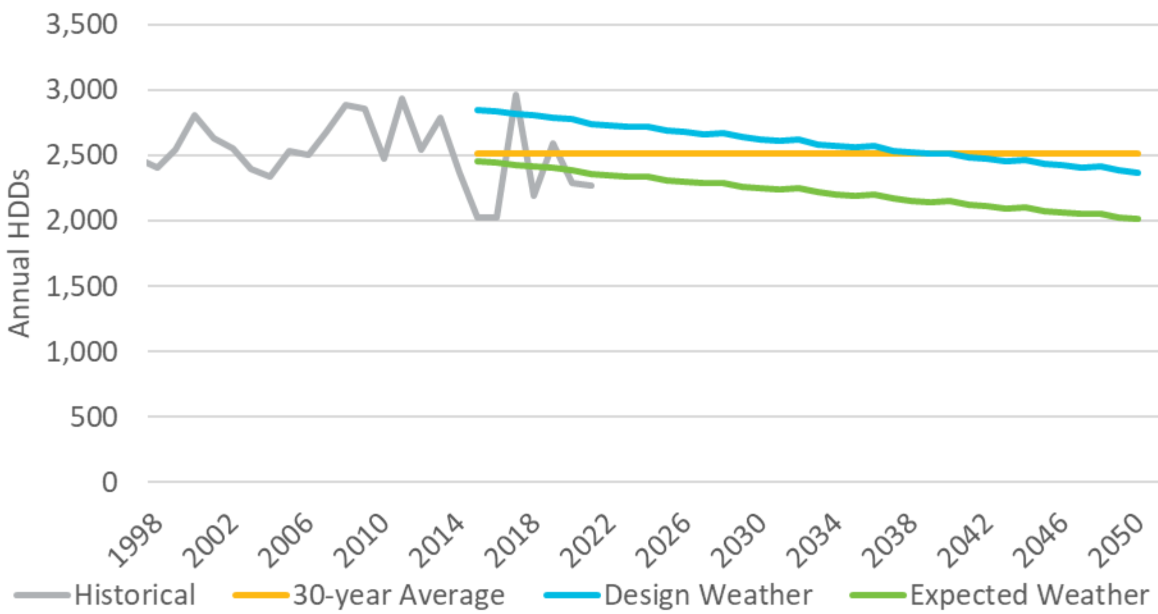
[49] NW Natural generates 500 runs through the Monte Carlo simulation, where weather is a key variable treated as uncertain both year-over-year and within a given forecast year.

Figure 3.7: Weather Patterns for Resource Planning



Embedded in both expected and design weather are the impacts from climate change. The climate change models predict as substantial decrease in annual HDDs over the planning horizon. Figure 3.8 illustrates the annual HDDs for expected weather and design weather for the Portland load center used for this IRP. The 30-year average is simply shown for historical context.

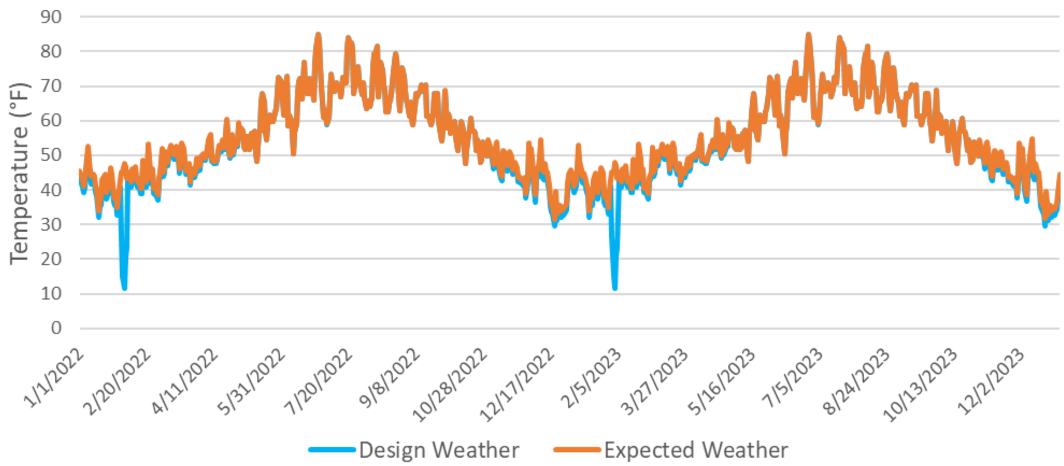
Figure 3.8: Portland Example Annual Expected and Design HDDs



Weather Uncertainty

Thus far we have discussed how specific weather patterns are modeled and implemented for resource planning. For both expected and design weather, the intra-year shape is the same in each forecast year even though cumulative annual HDDs are steadily decreasing over the planning horizon. Figure 3.9 illustrates the intra-year shaping for Portland daily temperatures for both design and expected weather. We use a representative year to get daily temperature volatility within a year; the year-over-year shape is the same.

Figure 3.9: Expected and Design Weather Intra-Year Shaping – Portland Daily Temperatures



The reality is that weather is random, both at a daily level and at an annual level. Some years will be overall colder than expected and have higher cumulative HDDs than expected. It is also possible that the Pacific Northwest experiences consecutive colder years or consecutive warmer years than expected weather. For system resource planning, it is important to understand the bounds of these possibilities, especially now with emissions compliance obligations under the CPP and CCA. Colder years will have higher emissions and warmer years will have lower emissions, but NW Natural's compliance obligation under the CPP is a straight trajectory reduction from the baseline. The CCA has a similar straight-line trajectory for the quantity of assigned allowances to the gas utility. Having a few consecutive cold years will have meaningful consequences for acquiring qualified compliance resources within a compliance period.

The IRP implements a Monte Carlo simulation to understand the potential range of daily, monthly, and annual temperature and HDDs.[50] Relying on both historical data and climate change modeling forecasts from the IPCC, we create a weather simulation for each load center over the planning horizon. This simulation provides different intra-year weather patterns (

Figure 3.10) as well as variation in annual cumulative HDDs from one year to the next (

[50] See Appendix F for further technical details on the Company's weather simulation.

Figure 3.11).

Figure 3.10: Single Simulation for Three Load Centers

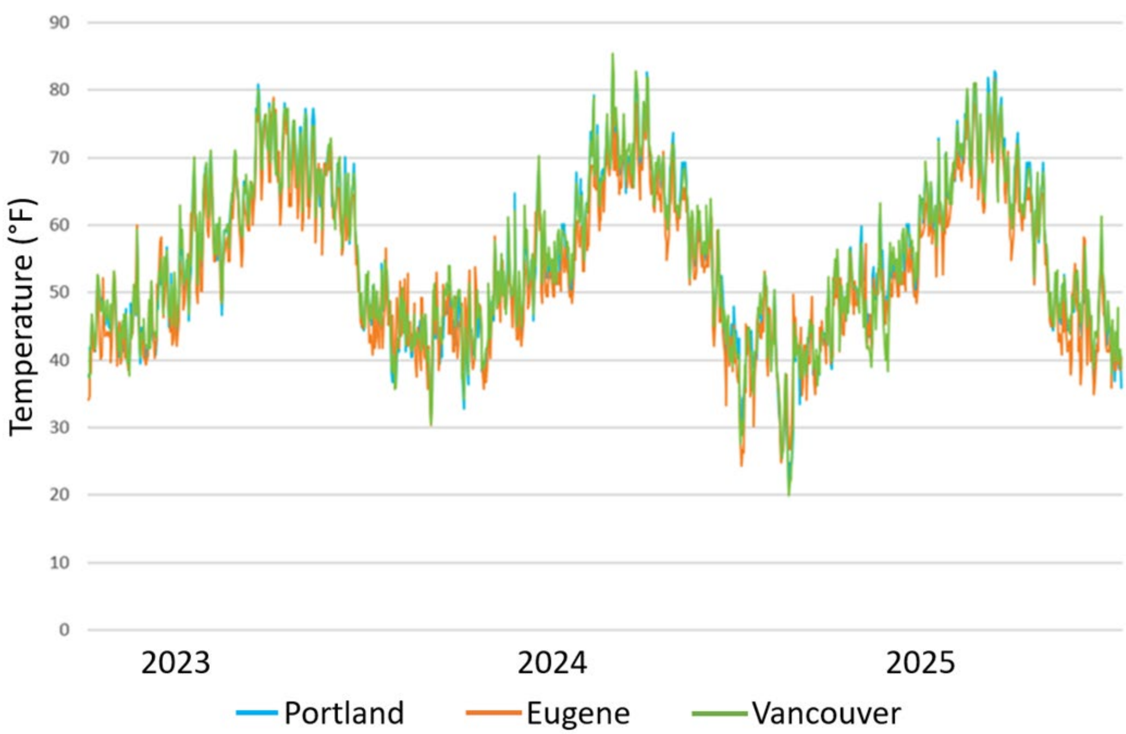
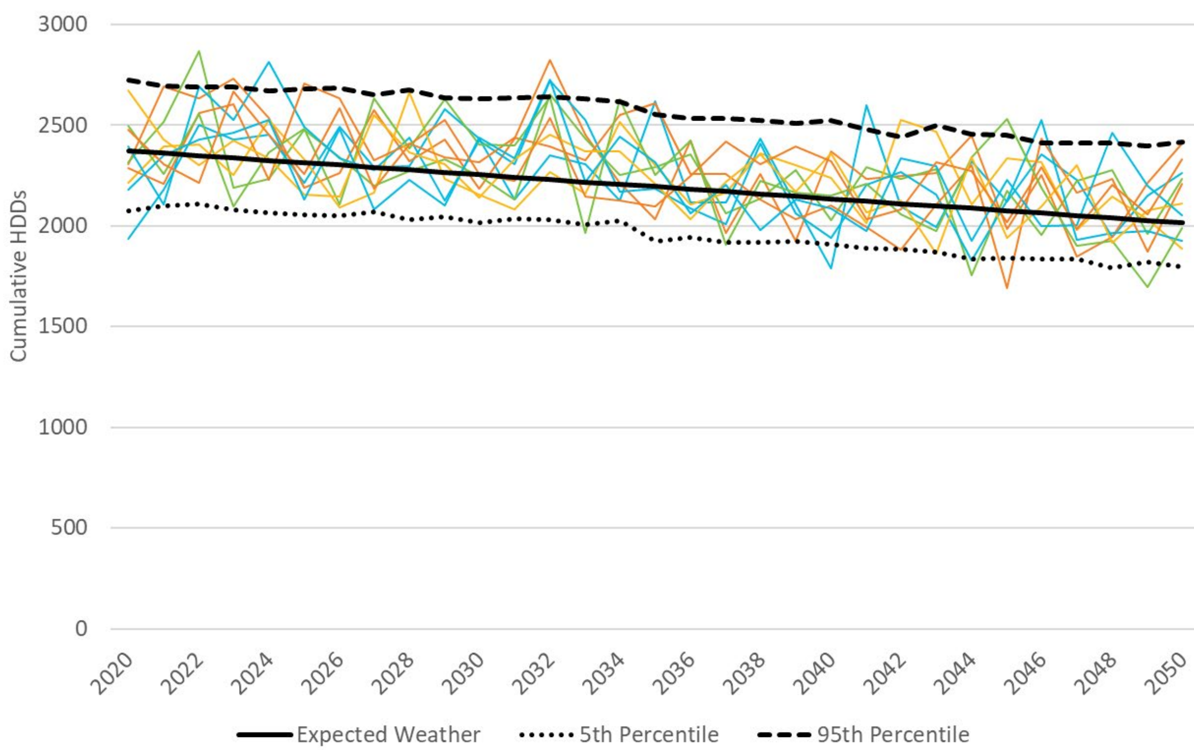


Figure 3.11: Weather Simulation - Cumulative HDDs for Portland (Base 58°F)



3.2.3 Residential and Small Commercial Use per Customer – Reference Case

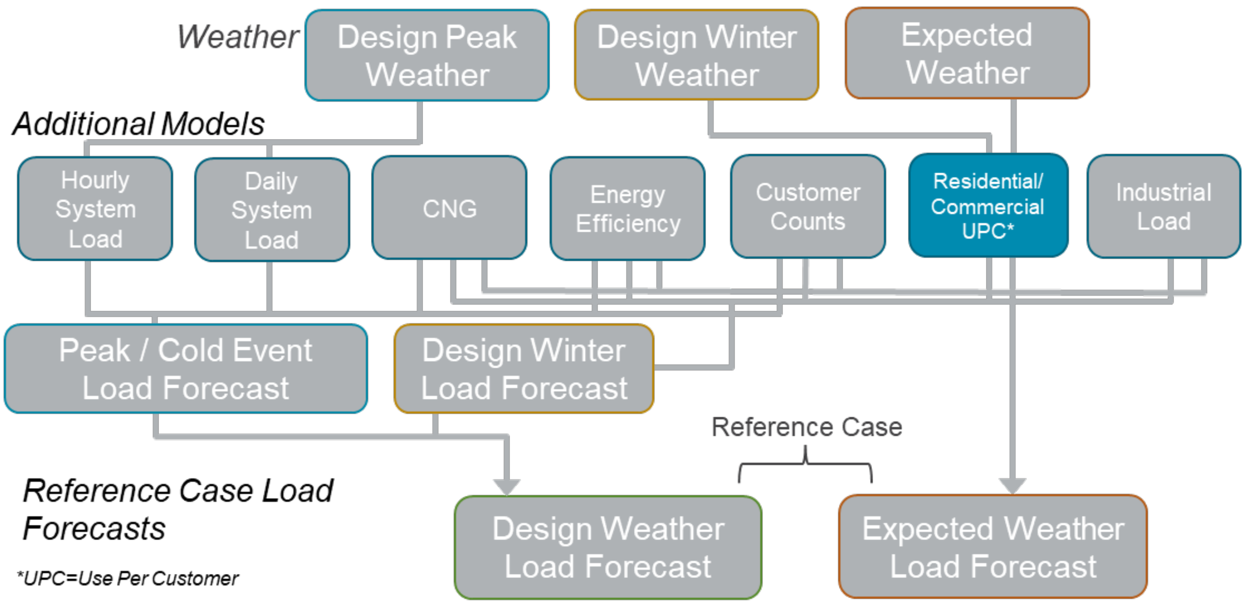
The reference case demand for residential and small commercial customers is developed by first modeling daily use per customer (UPC) demand as a function of daily temperatures.[51] UPC models match up historical billing data with historical weather data and are estimated for each sub-class of customer by location. The daily weather patterns then feed into these UPC models (see

Figure 3.12) which are then are multiplied by the customer count forecast to create daily residential and commercial load forecasts. Energy efficiency adjustments are made at the state and customer class level to create the reference case demand for residential and small commercial.

[51] Load from large commercial customer on rate schedules 31/32/41/42 and special contracts is estimate along-side the industrial load and is discussed in the industrial load section.

Use per Customer Regression Model

Figure 3.12: Load Forecast Model Flow Diagram – UPC Models



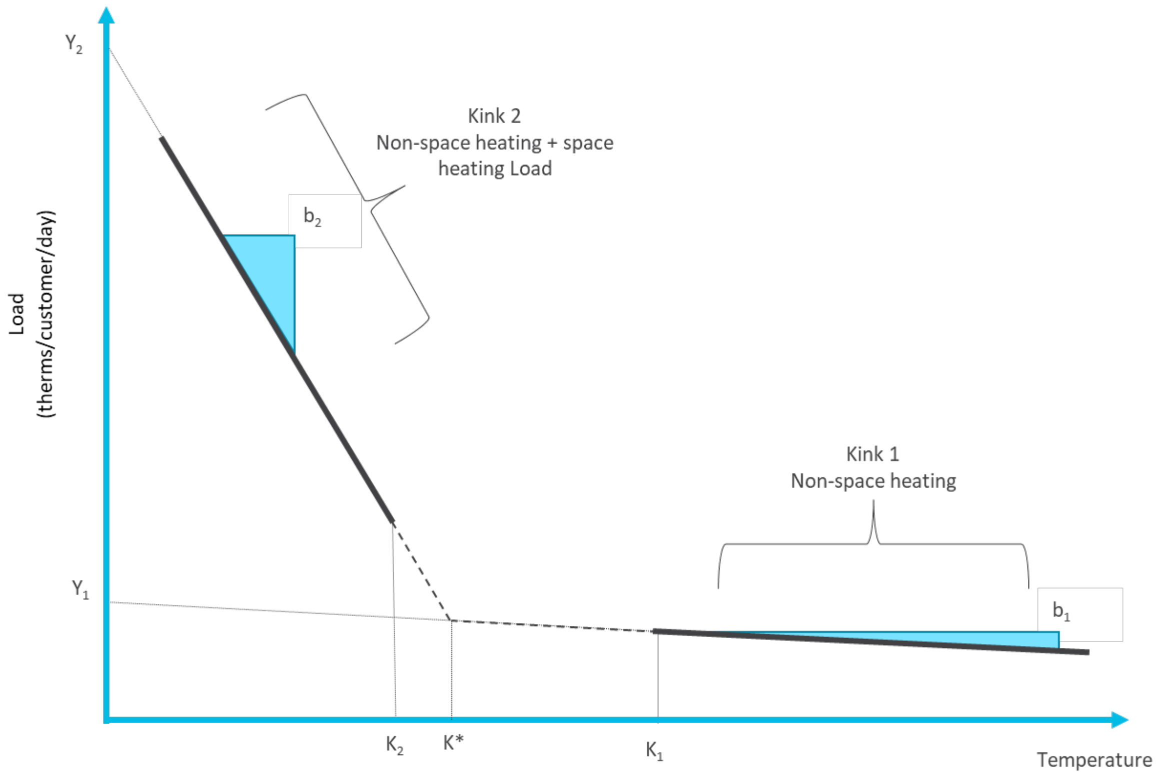
The UPC models estimates a two-segment piece-wise demand function for each customer sub-class and location. Demand functions for existing customers are estimated by load center and demand functions for new construction and conversion customers are estimated by state. Table 3.6 lays out the details of the billing data used in each UPC model.

Table 3.6: UPC Regression Data Details

Sub-class	Bills Used In Regression Model	Geographic Grouping
Residential Existing	All current residential customers	Load Center
Residential Conversion	Residential new construction/conversions since 2018	State
Residential Single-family New Construction		
Residential Multi-family New Construction		
Commercial Existing	All current commercial customers	Load Center
Commercial Conversion	Small commercial new construction/conversions since 2018	State
Commercial New Construction		

The two segments of the piece-wise demand function represent customer demand as 1) non-heating load at warmer temperatures and 2) heating + non-heating load at colder temperatures. A simplified model is illustrated by Figure 3.13.

Figure 3.13: UPC model



The temperature point (K*) for when heating load starts for the average customer varies by location and customer sub-class. K* is calculated based on where the two regression lines intersect.[52] Regression models are used to estimate the parameters b_1, b_2, Y_1, and Y_2 for each of the models outlined by Table 3.2. Given these parameters, use per customer demand as a function of temperature (T) is specified as:

$$\underline{Use\ Per\ Customers\ (UPC)}$$

$$= Y_1 + b_1 * (T) \qquad\qquad if\ :\ T \geq K^*$$

$$= Y_2 + b_2 * (T) \qquad\qquad if\ :\ T < K^*$$

A table with b_1, b_2, Y_1, Y_2, K_1, K_2, and K* parameters for each model is listed in Appendix B.

[52] Due to the nature of the monthly billing data used in the UPC model, data points with temperatures above K_1 are used for kink 1 regressions and data points with temperatures below K_2 are used for kink 2 regressions.

Figure 3.14 shows the predicted values for four of the residential UPC models as an example.

Figure 3.14: UPC Model Predicted Values

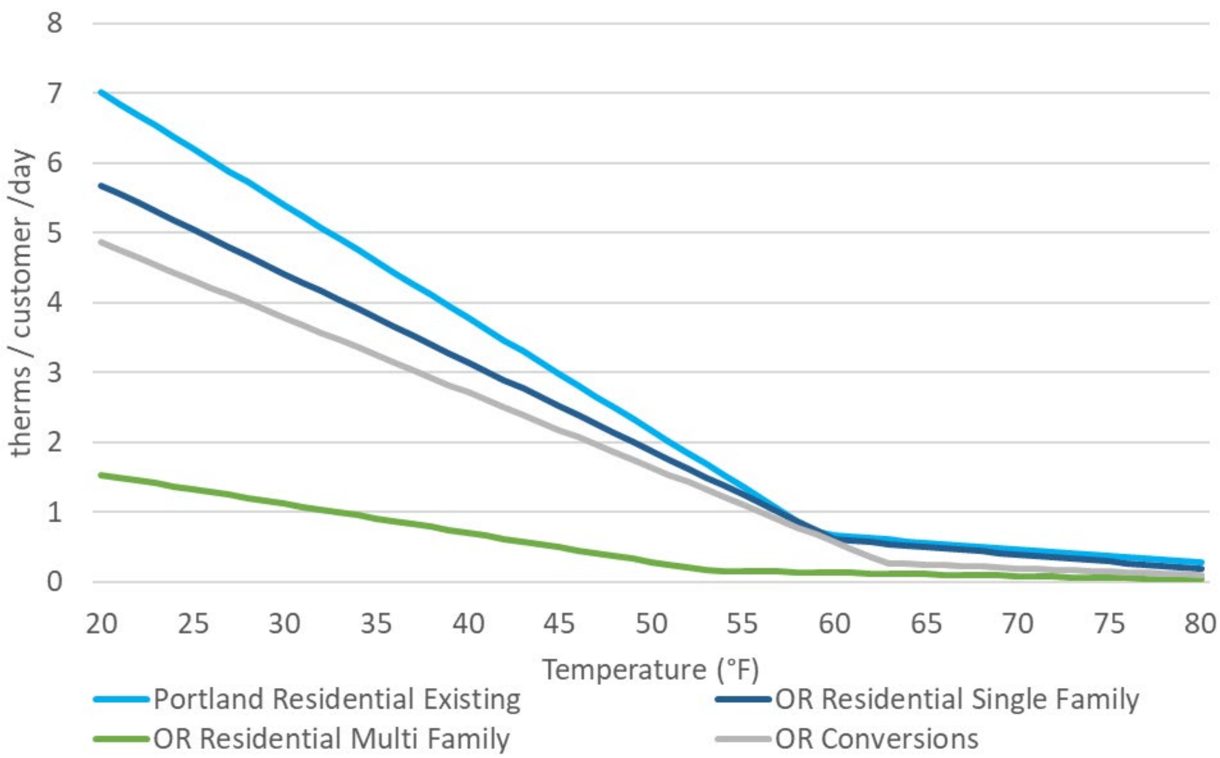


Figure 3.15 and Figure 3.16 show the forecasted first year estimates of usage per customers for residential and commercial customer classes, respectively. While residential existing customer usage has remained almost unchanged over several IRPs, residential conversion, and new construction in the 2022 IRP have seen a reduction of 30% and 41%, respectively, in estimated annual usage compared with the 2016 IRP. In contrast, commercial customer usage is slightly lower (about 9% lower for the commercial conversion customers) between the 2022 and the 2016 IRPs.

Figure 3.15: First Year Residential Annual Usage per Customer

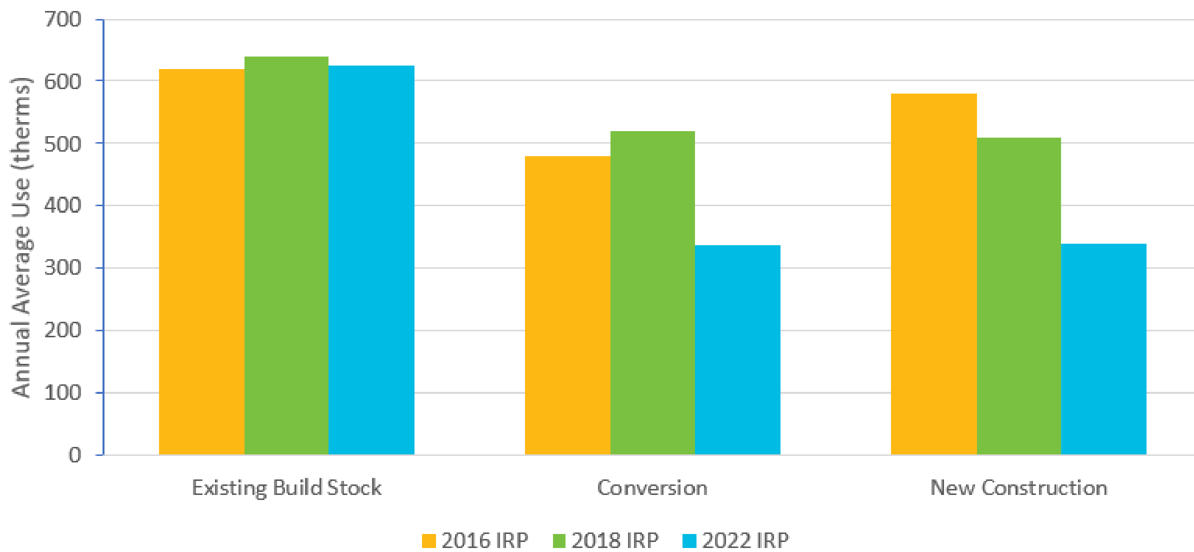
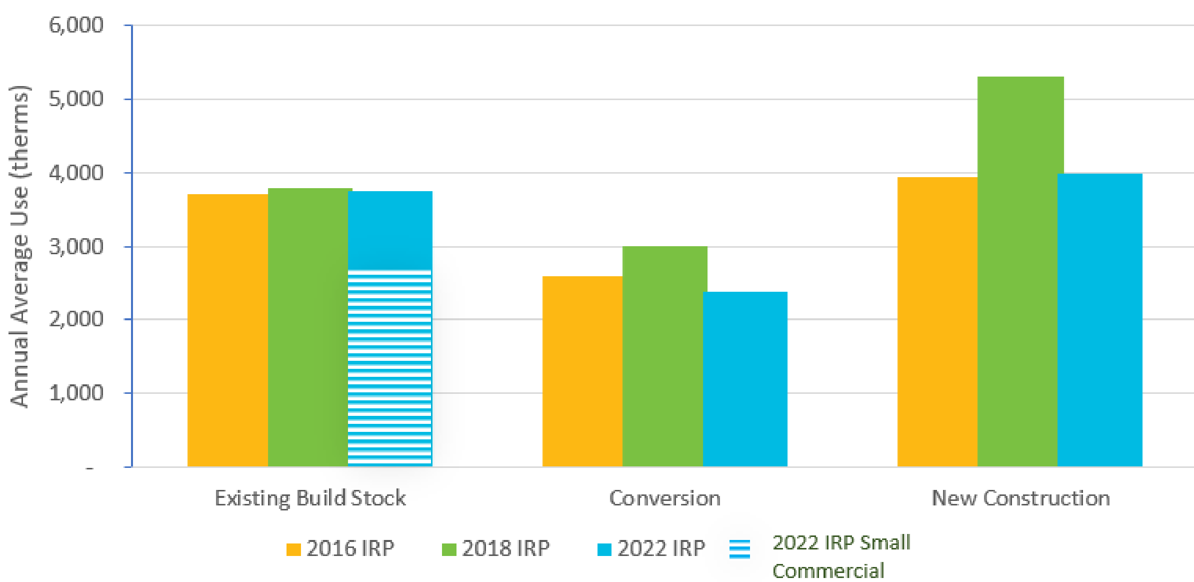


Figure 3.16: First Year Commercial Annual Usage per Customer



By multiplying the customer count forecast by the UPC model conditional on a given weather pattern (i.e., temperature) provides daily load for each sub-class and load center.

Cost-Effective Energy Efficiency

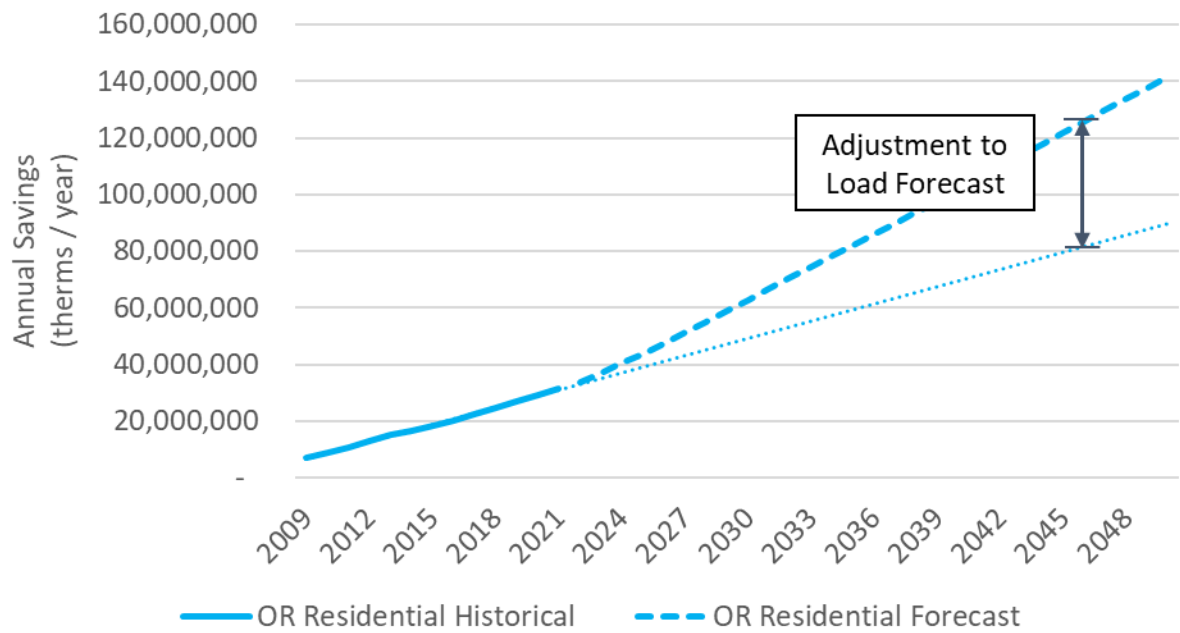
The Energy Trust of Oregon (Energy Trust) currently administers energy efficiency programs for residential, commercial, and industrial sales customers in Oregon and residential and commercial sales customers in Washington. NW Natural is working to establish energy efficiency programs for industrial sales customers in Washington and transportation customers across the system to further the therm savings, and therefore maximize emission reductions from energy efficiency for the whole gas system.

Energy Trust provides NW Natural with a therm savings forecast, known as a resource assessment (RA) or conservation potential assessment (CPA), for the incentive programs currently being offered in Oregon. Additionally, NW Natural hired a third-party consultant, Applied Energy Group (AEG), to conduct a CPA for Washington sales customers. AEG also conducted two high-level CPAs for transport customers in NW Natural's system, one for Oregon and one for Washington. See Chapter 5 for details for these various CPAs.

Customer Type	CPA Developer
Oregon	
Sales Residential Commercial Industrial	Energy Trust
Transport	AEG
Washington	
Sales Residential Commercial Industrial **Transport**	AEG

Historical billing data used in the UPC models will reflect underlining trends in customer usage, but the UPC models by themselves will not reflect forecasted ramping up of incentivized energy efficiency programs. NW Natural uses the CPAs provided by Energy Trust and AEG to adjust output from the UPC models by the difference between the historical energy efficiency trend and the forecast from the CPA for cumulative therm savings. Figure 3.17 illustrates this difference and the adjustment made to the UPC modeled forecast for Oregon residential savings. These adjustments are done by state and customer type. Annual savings predictions are allocated to the day and load center based on load. A similar adjustment is made for design peak day savings to the peak day forecast discussed later in this chapter.

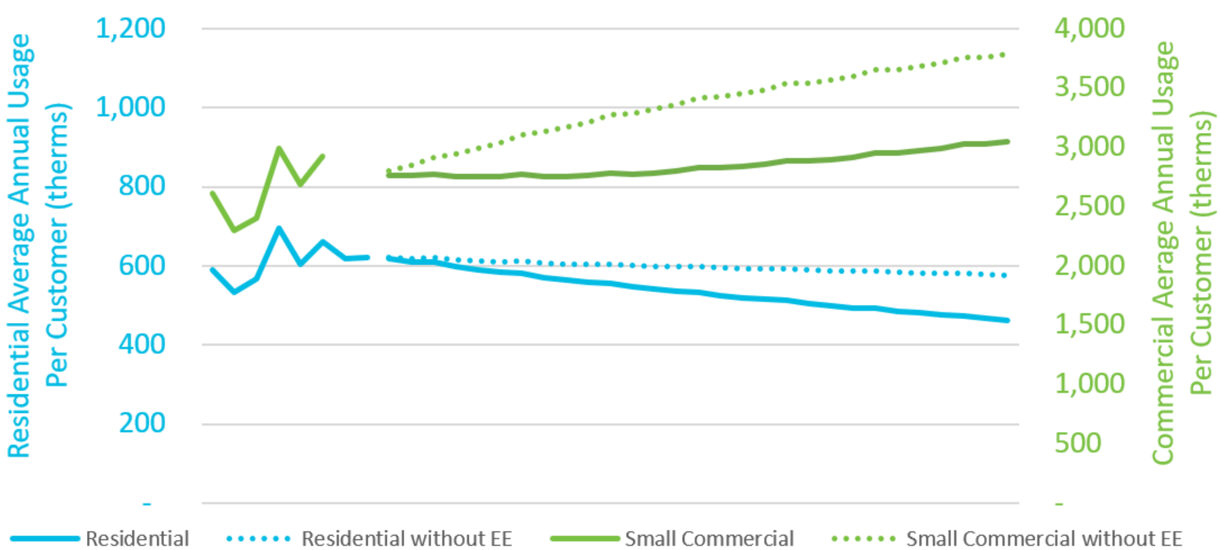
Figure 3.17: OR Residential Cumulative Annual Savings and UPC Adjustment



Residential and Small Commercial Annual Use per Customer and Annual Forecast

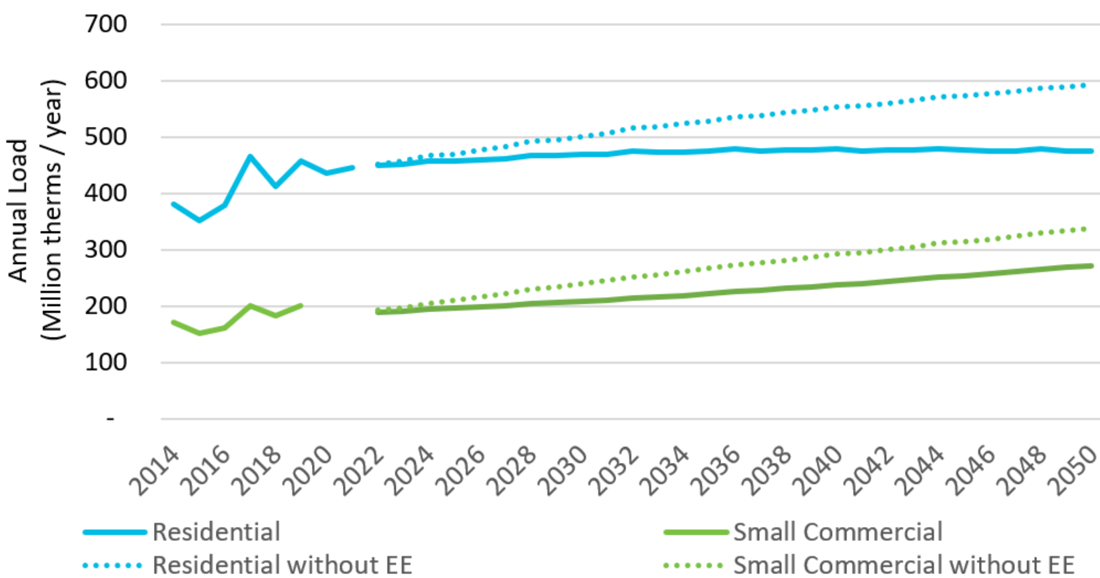
Figure 3.18 shows NW Natural's forecast of average annual use per customer for residential and commercial customers before and after incentivized energy efficiency savings. Residential average annual use per customer for the reference case declines, while commercial average annual use per customer for the reference case increases over the planning horizon. This increase in the reference case commercial UPC is reflective of the new construction commercial customers on average using more gas than existing customers.

Figure 3.18: Trend in Use per Customer With and Without Energy Efficiency – Reference



Multiplying the customer count forecast and the daily use per customer forecast provides a daily residential and small commercial forecast. Aggregating the daily number for each year provides the annual load forecasts for residential and small commercial customers (Figure 3.19). Due to declines in residential UPC and increases in residential customers over the planning horizon, the annual residential reference case demand grows slowly till 2040 before beginning to decline. Small commercial reference case total demand increases throughout the planning horizon driven by increases in commercial customers.

Figure 3.19: Residential and Small Commercial Annual Demand Forecast



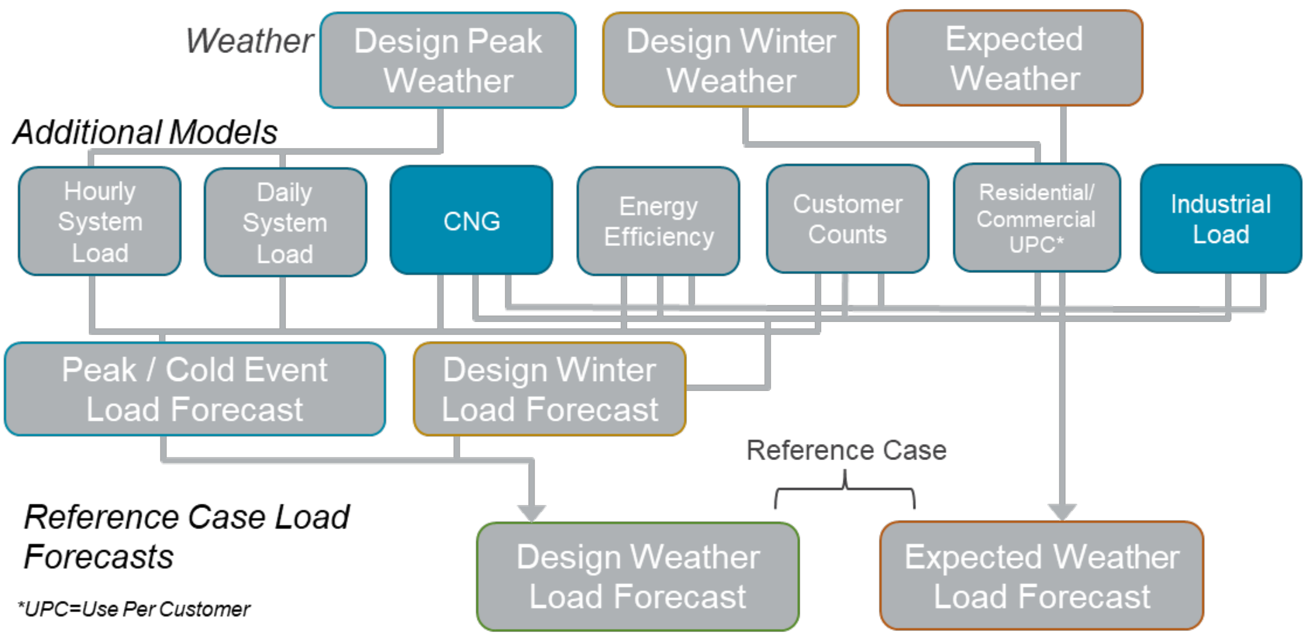
3.2.4 Industrial, Large Commercial and Compressed Natural Gas (CNG) Load Forecast – Reference Case

As noted earlier, NW Natural does not forecast Industrial load by forecasting use per customer and multiplying by forecasted customers due to the extreme differences in usage levels by these customers. Instead, we directly forecast the annual load of all industrial customers and large commercial customers. NW Natural's industrial load can then be allocated into four categories of service: firm sales, firm transportation, interruptible sales, and interruptible transportation.[53] Large commercial sales load is forecasted separately but is include as a part of the industrial load box in the

Figure 3.20 flow chart.

[53] There are a few large commercial customers on transportation rate schedules. Load from these customers is included in the industrial load forecast (i.e., not the large commercial sales forecast) and is not separated out from the overall transport load forecast.

Figure 3.20: Load Forecast Model Flow Diagram – Industrial, Large Commercial and CNG Load Forecast



Econometric Forecasts

NW Natural uses methods to develop an econometric forecast of industrial load like the methodology for the long-term econometric models implemented for residential and commercial customer counts, including an ARIMA structure and exogenous variable selection. Forecasting approaches involving separately forecasting loads for each industrial class of service were generally unsuccessful.[54] Therefore, NW Natural forecasts the aggregate industrial load (for all classes of service) and allocates the total to individual classes of service as well as to month and load center. Large commercial sales load is forecasted separately. See Appendix B for technical details related to the econometric models used to forecast industrial load.

[54] The industrial classes of service are firm sales, interruptible sales, firm transportation, and interruptible transportation.

SME Panel Forecasts

Similar to customer forecasts, NW Natural also uses an SME panel forecast of industrial load to blend with the econometric forecast discussed above. More specifically, NW Natural uses the SME panel forecast for 2022 and 2023, an equally weighted blend of the two forecasts for 2024, and the econometric forecast for 2025 forward.

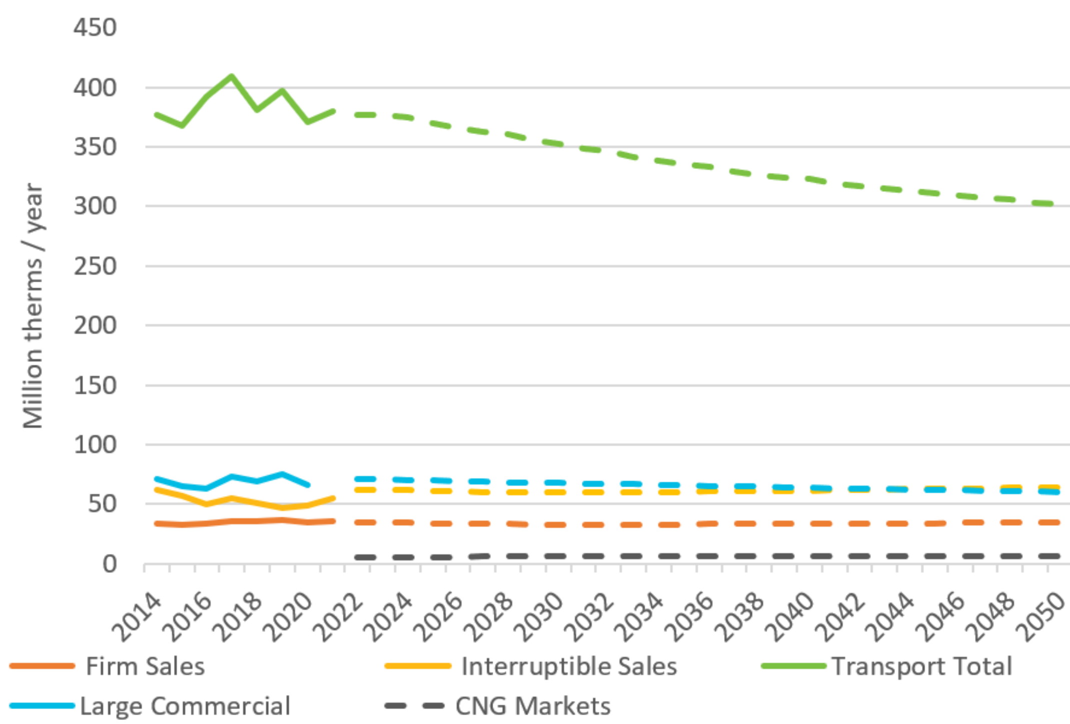
Compressed Natural Gas Service

The 2022 IRP load forecast includes a load forecast associated with NW Natural's compressed natural gas (CNG) service, which NW Natural has previously labeled as an emerging market in previous IRPs. NW Natural's relies on SME who work with CNG customers to develop the CNG load forecast. CNG customer load is forecasted to be less than 0.5% of NW Natural's annual throughput for any year over the planning horizon (see Figure 3.24).

Industrial, Large Commercial Load, and CNG Annual Load Forecast

NW Natural uses the composition of the SME panel industrial load forecast, which is by service category, to allocate the total industrial load to the four classes of service for 2022 forward. Figure 3.21 shows the annual industrial load by service category and large commercial sales load.

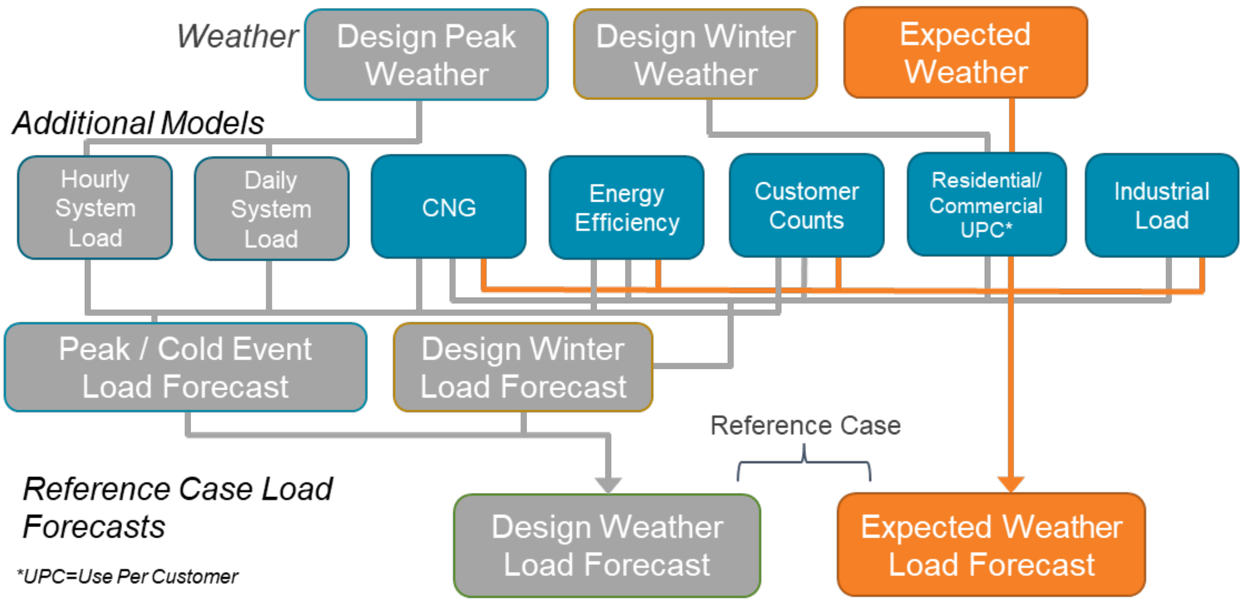
Figure 3.21: System Industrial, Large Commercial and CNG Load by Service – Reference Case



NW Natural uses details provided in the SME panel forecast of industrial load to allocate these load forecasts by service type from annual to monthly and from system totals to load centers.

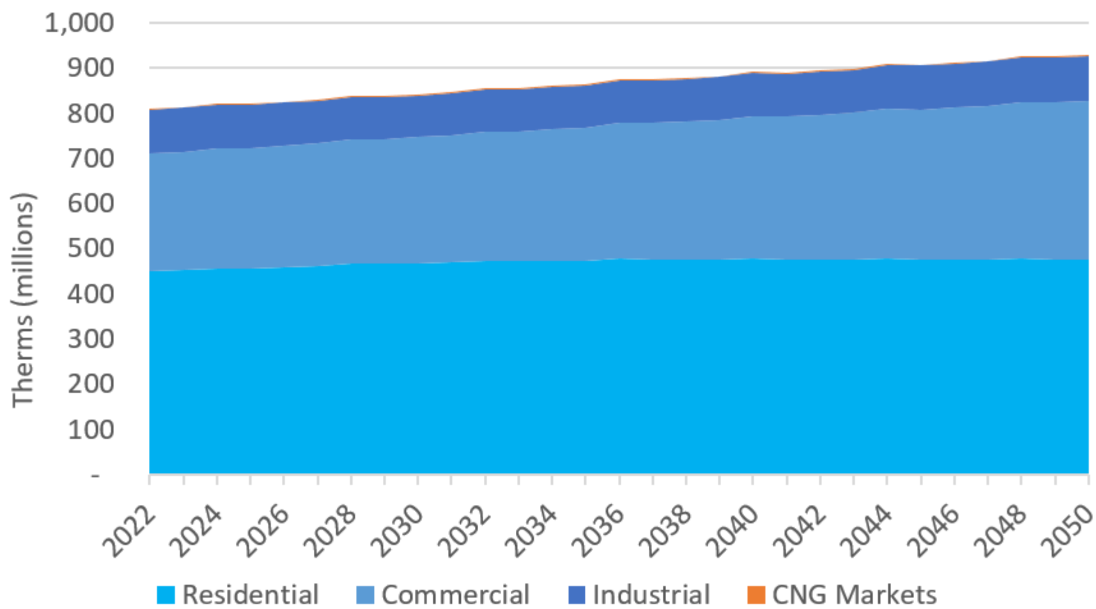
3.2.5 Expected Weather Annual Load Forecast – Reference Case

Figure 3.22: Load Forecast Model Flow Diagram – Expected Annual Load Forecast



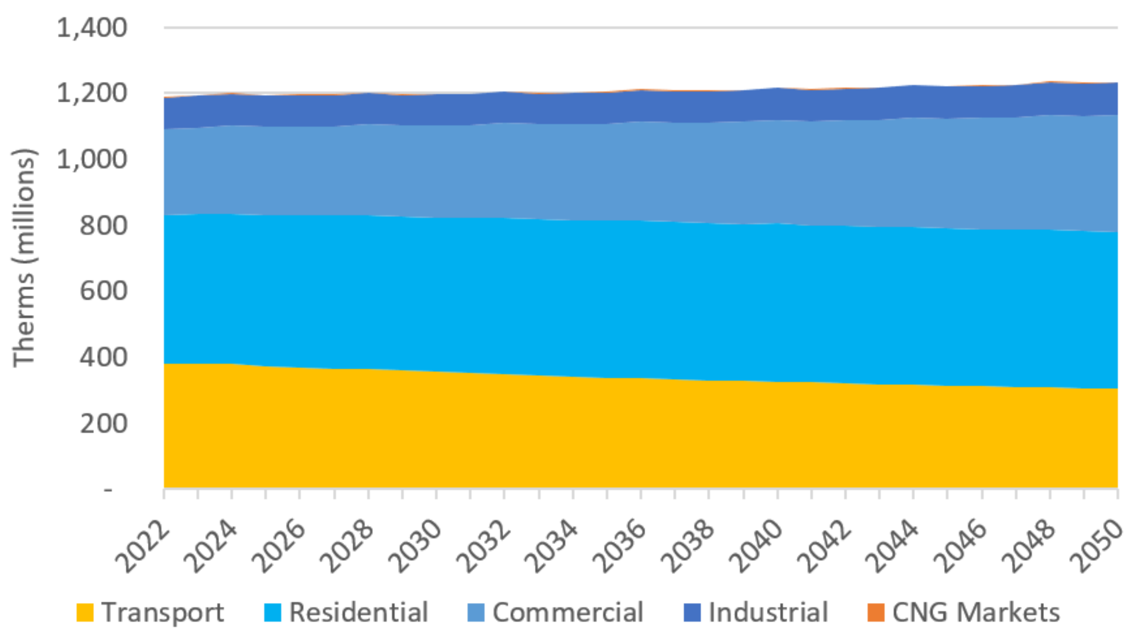
Combining the expected weather, the customer counts, the residential UPC models, the small commercial UPC models, the industrial load, the large commercial sales load, the CNG market forecasts and energy efficiency forecast provides the total reference case expected weather load forecast (Figure 3.23).

Figure 3.23: Expected Weather Annual Sales – Reference Case[55]



Emission compliance will be based on total throughput (i.e., sales load plus transport).

Figure 3.24: Expected Weather Annual Throughput – Reference Case[56]

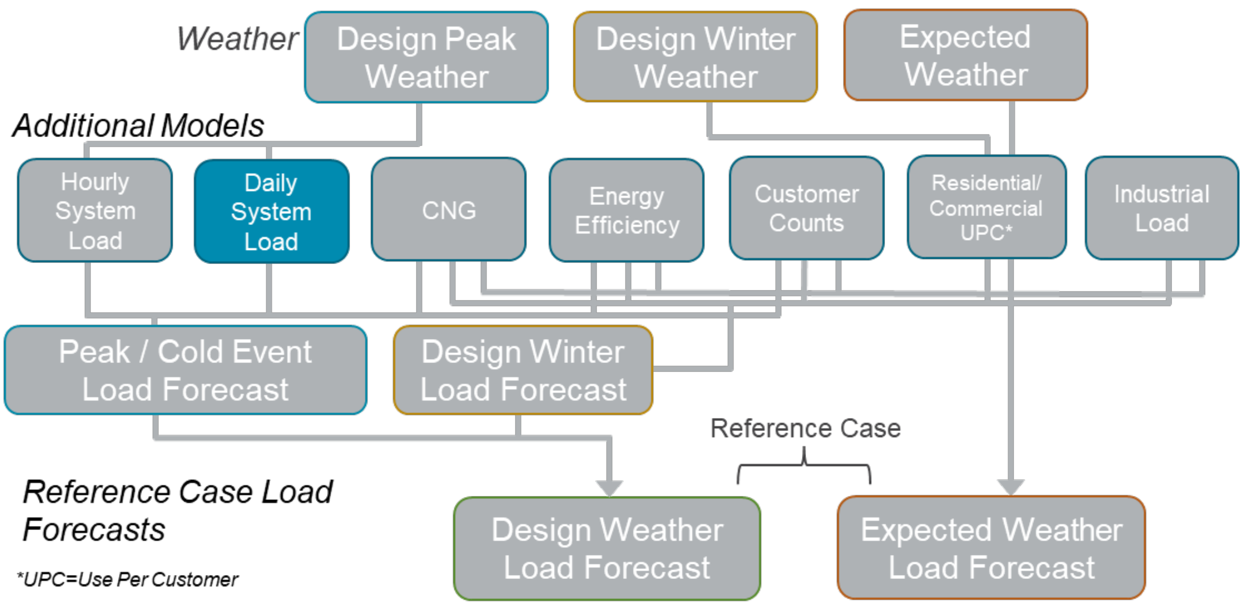


[55] These forecasts are adjusted for energy efficiency forecasts as shown in Figure 3.17.
[56] These forecasts are adjusted for energy efficiency forecasts as shown in Figure 3.17.

3.2.6 Daily System Load Model

The daily system load model is an econometric model that measures the relationship between daily firm sales load and its drivers such as temperature. Using historical data of daily firm sales load and drivers, the model statistically estimates coefficients, which represent the effect of each daily driver.[57] These coefficients are subsequently used as an input into the peak day planning standard, discussed in the next section. The daily system load model for resource planning is used to predict daily firm sales during peak demand conditions created from a combination of several factors. Ultimately, the daily system load model used for the peak day firm sales load forecast that determines the daily capacity requirements for resource planning (see Figure 3.25).

Figure 3.25: Load Forecast Model Flow Diagram – Daily System Load



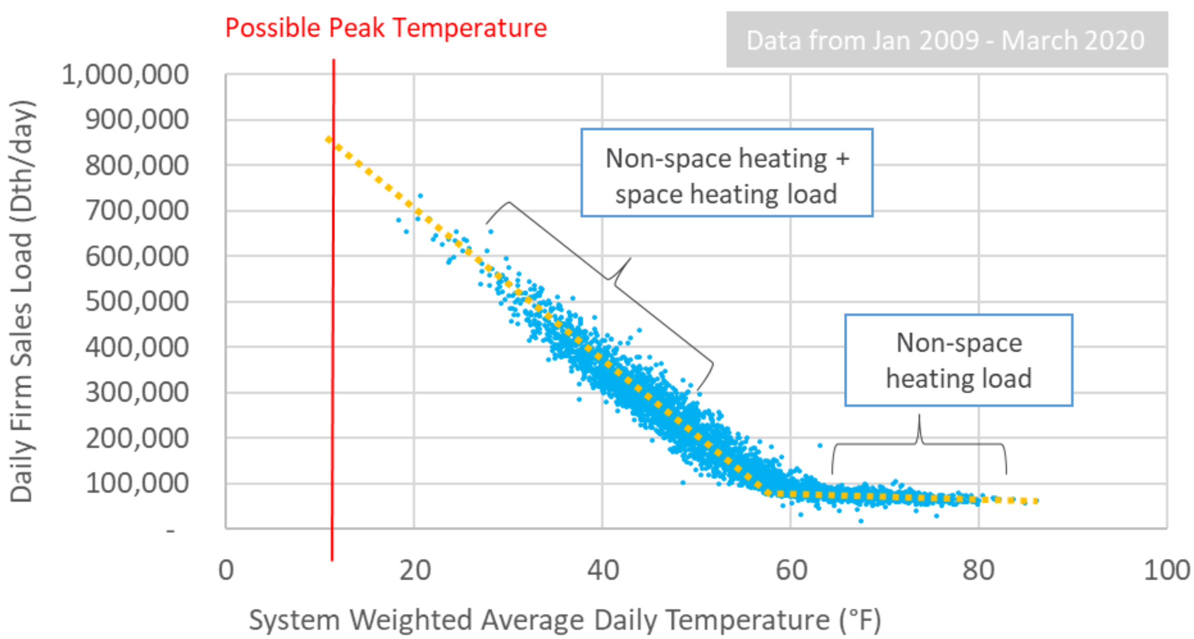
Daily Demand Drivers

The daily system load model includes 11 drivers: temperature, daily lagged temperature, solar radiation, wind speed, snow depth, customer count, day of the week indicator variables, a holiday indicator variable, a time trend, water heater water inlet temperature and an indicator variable for the pandemic shutdown in March of 2020. During peak conditions roughly 84% of NW Natural's sales throughput is used for space heating. Therefore, weather is a prominent driver of peak load and peak conditions. Peak conditions take place on very cold and windy winter weekdays when temperature drops and gas demand for space heating spikes. Figure 3.26 shows a scatter plot of temperature and a daily firm sales load. This figure illustrates that a negative linear relationship exists between daily load

[57] The daily system load model focuses on daily firm sales as NW Natural must buy the gas and have enough capacity resources to bring that gas on system during a peak day. Daily load for a gas day (7 a.m. - 7 a.m.) is used as gas is typically scheduled for an entire day in a day-ahead market. Hourly load is relevant for distribution system planning, but not necessary for supply planning and gas scheduling.

and temperature. There is a structural break in this relationship at 58°F as space heating equipment (e.g., furnaces) kicks on at temperatures less than 58°F. To capture this relationship the daily system load model is estimated in two versions: average daily temperature less than 59°F and average daily temperature greater than 59°F.[58] The coefficients from the less than 59°F model version are used as inputs into the peak day planning standard.

Figure 3.26: Daily Firm Sales Load and Temperature



In addition to temperature, NW Natural includes a daily lagged temperature variable into the model. The necessity of including a temperature lag is due to the physical location of where data is collected and the speed at which gas flows through pipelines. Data on daily flow is collected at NW Natural's gate stations and at our on-system storage locations. Additionally, data is collected at the end use location for interruptible sales and transportation customers who have higher frequency meters that record their daily usage. Non-firm sales customer usage is subtracted coincidently from the flow coming from the gate stations and on-system storage, but these customers could be located far from the gate station. Since gas does not flow instantaneously, there is a delay between when customers use gas and when it flows through the gate stations.[59] Including a lagged temperature variable helps capture this lagged data response to changes in weather.

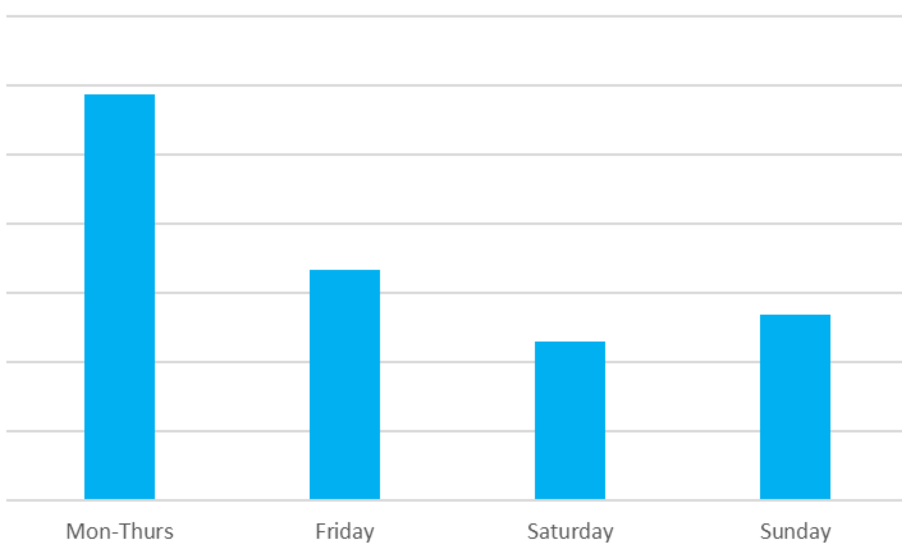
[58] Daily temperatures are calculated as system-weighted daily averages from hourly weather data.

[59] The duration of the delay is dependent on several factors including the pipeline distance from the gate station and the speed of gas flow (which is dependent on the overall demand and pipeline pressure). This delayed response is applicable to all customers, i.e., firm sales customers as well.

Wind and solar radiation have positive and negative impacts on daily load, respectively. High winds cool building structures, which in turn require additional gas to maintain space heating. Conversely, higher solar radiation heats buildings and hence reduces heating demand.

The day of the week also impacts natural gas load. The data shows a statistically significant increase in daily load during a weekday relative to a Saturday or Sunday. This is mainly driven by schools and businesses closing for the weekend. Daily load on Friday also shows a significant decrease in daily load relative to Monday through Thursday.[60] Figure 3.27 shows daily average use for Monday–Thursday, Friday, Saturday, and Sunday. To capture this effect the model includes Friday, Saturday, and Sunday indicator, or dummy, variables.[61] A similar effect is captured by a holiday indicator variable.[62]

Figure 3.27: Average Winter (Nov-Feb) Firm Sales Daily Use by Weekday



Snow depth and water heater inlet temperature were first introduced in the 2018 IRP daily system load model and are used again in the 2022 IRP model. Snow depth is a proxy for business closures and the effect is like the effect of a weekend or holiday. Since snow depth is often correlated with cold weather, this effect is less intuitive. After controlling for other weather drivers, additional snow depth causes more schools and businesses to shut down and has a statistically significant negative impact on load.[63] NW Natural uses Bull Run River water temperature as a proxy for water heater inlet temperature.[64] Colder inlet water temperature requires additional heat to warm and thus has a negative effect on load meaning that load will increase.

[60] For a 7 a.m. - 7 a.m. gas day, Friday includes 7 hours of Saturday. Including these hours into a Friday is a primary reason why Friday is different than other weekdays.
[61] Throughout this section weekday refers to a Monday through Thursday.
[62] Holidays are identified as federal holidays where most business and schools close. If the holiday falls on weekend the following Monday is considered a holiday as this a typical practice for schools and businesses to grant the following Monday as a holiday.
[63] NW Natural initially tried to attain data on school closures but could not find sufficient data.
[64] Portland is NW Natural's largest load center with data on surface water temperature readily available through the U.S. Geological Survey (USGS).

The impact from the COVID-19 economic shutdown was overall negative as school and business closed for social distancing. It is likely that residential usage increased from people spending more time at home, either from unemployment or remote working, but the system data used for this model indicates an overall decrease in firm sales load. As the data for this model ends in March of 2021, the longer-term impacts of COVID-19 on load is yet to be discovered, however; by including an indicator variable for the COVID-19 shutdown we account for its immediate impact during the 2020-2021 winter.

Table 3.7: Driver Variable Impacts on Load Modeling

Driver Variable	Impact on Load
Temperature	(-)
Previous Day Temperature	(-)
Solar Radiation	(-)
Wind Speed	(+)
Snow Depth	(-)
Water Heater Inlet Temperature	(-)
Fri/Sat/Sun or Holiday	(-)
Customer Count	(+)
Time Trend	(-)
COVID 19	(-)

The last two drivers include customer counts and a time trend. Customer growth has increased over the past decade and has a positive impact on NW Natural's daily load.[65] Counter to customer growth, through energy efficiency efforts and changes in customer profiles,[66] use per customer is declining. To account for this change over time the model includes a time trend.

Interaction Effects

Beginning with the 2018 IRP daily system load model, we have been incorporating interaction effects between variables, primarily temperature and other independent variables. The reason for including interaction effects starts with recognizing that a single driver alone fails to sufficiently explain changes in daily demand primarily used for space heating. For example, demand on a warm summer day with no wind will not be very different from demand on a windy summer day. However, the impact of wind greatly increases as temperatures decrease. In other words, demand on a cold windy day will be much greater than demand on a day with the same temperature and no wind. For more technical details on the daily system load model see Appendix B.

[65] A negative impact means that the values of the attribute go in the opposite direction as load. Whereas a positive impact means the values of the attribute go in the same direction as load. As an example, as temperature increases, load decreases and correspondingly, as temperatures drop, load increases.

[66] For example, the addition of higher efficiency new construction homes.

Firm Sales Daily System Load Regression Model

Daily load drivers constitute the independent, or right-hand-side, variables in the econometric model and daily system firm sales is the dependent, or left-hand-side, variable.

$$System\ Firm\ Sales_t = \alpha + \sum_{i=1}^{23} \beta_i\ Drivers_{it} + \epsilon_t$$

Where α is a constant, β_i are the estimated coefficients, *i* is an index for drivers, *t* is a daily index and ε is a random error.

The right-hand-side variables include the previous day's temperature, solar radiation, wind speed, snow depth, customer count, Friday, Saturday, Sunday and holiday dummy variables, a time trend, and the Bull Run River water temperature. Temperature interacts with each dependent variable except for the Bull Run River water temperature. The data shows that the efficiency of insulated water heaters is independent of the outside temperature and therefore an interaction between temperature and the water heater inlet water temperature is not considered in this model.

3.2.7 Capacity Requirement Planning Standard

Developing a planning standard is important for selecting the right mix of resources to cost-effectively serve customers and ensure the reliability of the service under design peak weather conditions. Gas supply capacity requirements refers to the daily maximum volume of gas that the system can deliver to customers. In the 2018 IRP, NW Natural implemented a new planning standard that uses statistics and Monte Carlo simulation of the demand drivers to set a standard that the company's resource capacity can serve the highest firm sales demand day going into each future winter with 99% certainty. This is equivalent to planning for a 1-in-a-100-year weather event. This IRP uses the same planning standard as the 2018 IRP.

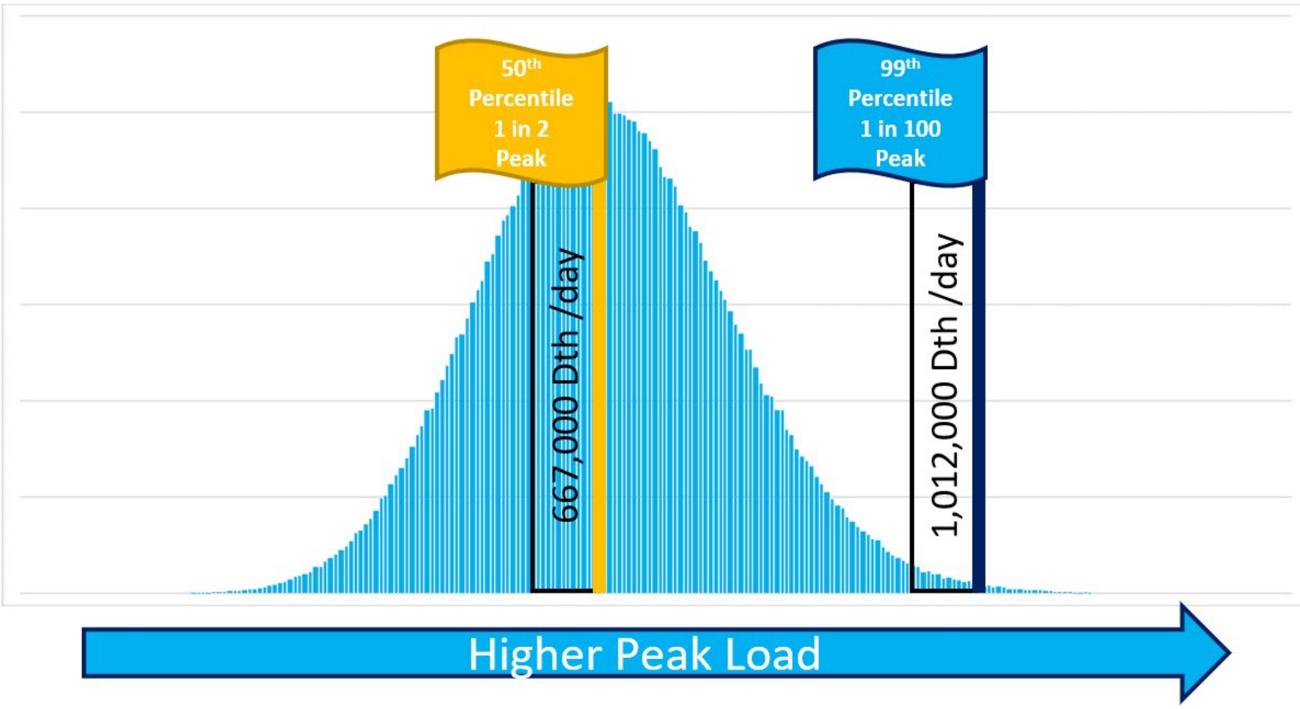
As weather is random, a 1-in-a-100-year event has a probability of occurring more often than once every 100 years. On the other side of the coin, this type of event also has the probability of not occurring within the next 100 years.[67] We plan our system resources to be available to serve firm sales demand during this extremely rare cold winter day. This should not be confused with 1-in-2 peak, which is the expected firm sales peak load that we are likely to see occur each year. In fact, we will see a daily peak load lower than a 1-in-2 peak occur in about half of the winters in the future.

Using the regression coefficients from the firm sales daily system load model and the Monte Carlo simulation of the demand drivers create a distribution of peak day demand under potential peak conditions. Using this distribution and accounting for model error the 99th percentile is pulled from this distribution to establish the firm sales peak load that would occur under a 1-in-a-100-year weather event. Figure 3.28 demonstrates the difference between a 1-in-2 peak (50th percentile) and the 1-in-a-

[67] See the 2018 IRP Chapter 3, Section 7.2 for a detail discussion on this topic.

100-year (99th percentile) firm sales peak load, which we plan our system resources. Note that these percentiles are dynamic as customers counts and a time trend are included as regressors and change over time.

Figure 3.28: 2022 Firm Sales Peak Day Distribution

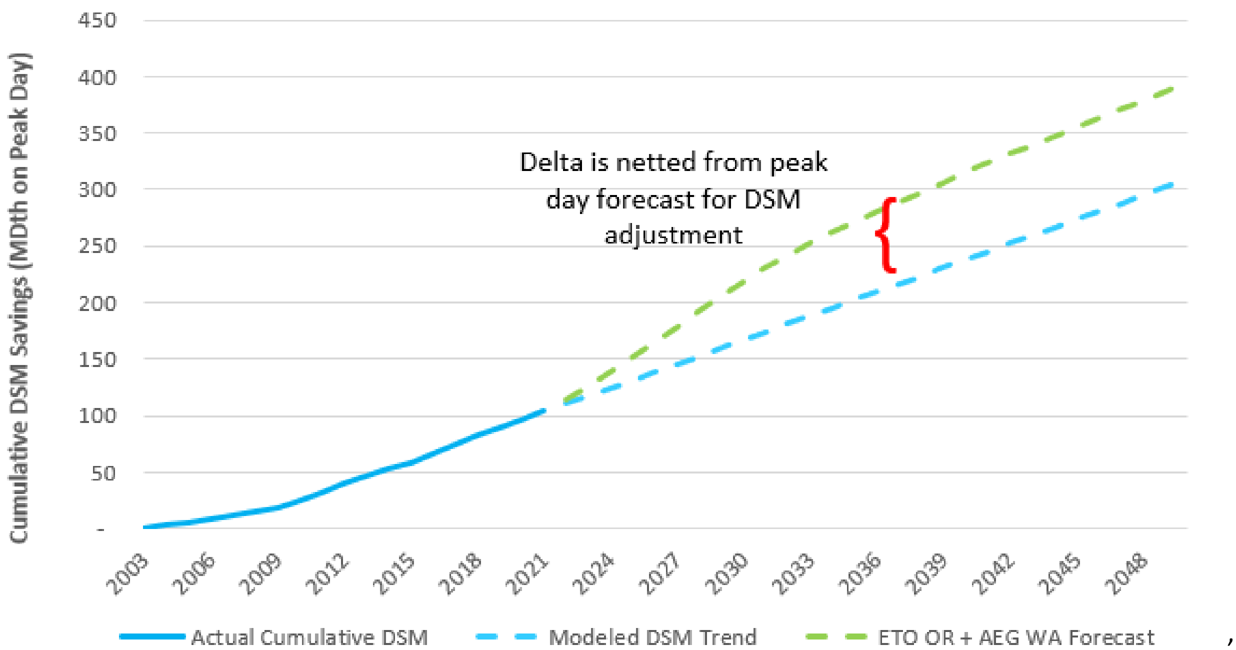


3.2.8 Design Day Peak Savings from Energy Efficiency

The 99th percentile load requirement includes a time trend capturing underlying trends in the data, part of which is driven by past energy efficiency programs. There is an adjustment to the 99th percentile to account for design peak therm energy savings forecast, similar to the adjustment discussed for annual therm savings. These design peak therm savings are calculated using peak factors estimated by NW Natural for each end-use and are further discussed in Chapter 4, Section 4.3. These factors are applied to the annual sales savings forecasted by the Energy Trust (Oregon sales) and AEG (Washington sales).

Figure 3.29 illustrates the adjustment made to the 99th percentile load requirement.

Figure 3.29: DSM Peak Day Savings Trend and Forecast



3.2.9 Peak Day Forecast – Reference Case

The peak day load forecast, which is modeled as the third day of a cold event, combines the customer forecast, peak day therm savings energy efficiency forecast, the daily system load model, and the peak day planning standard.[68] The combination of these models results in a forecast of the gas supply capacity requirements over the planning horizon (see Figure 3.30).[69]

[68] Note that peak day contribution from CNG markets is included in the peak day forecast but are de minimis.

[69] Peak day is defined, per the peak day planning standard, as the firm resource requirement needed to have a 99% chance to be able to meet the highest firm sales demand day in a gas year.

Figure 3.30: Load Forecast Model Flow Diagram – Peak Day Load Forecast

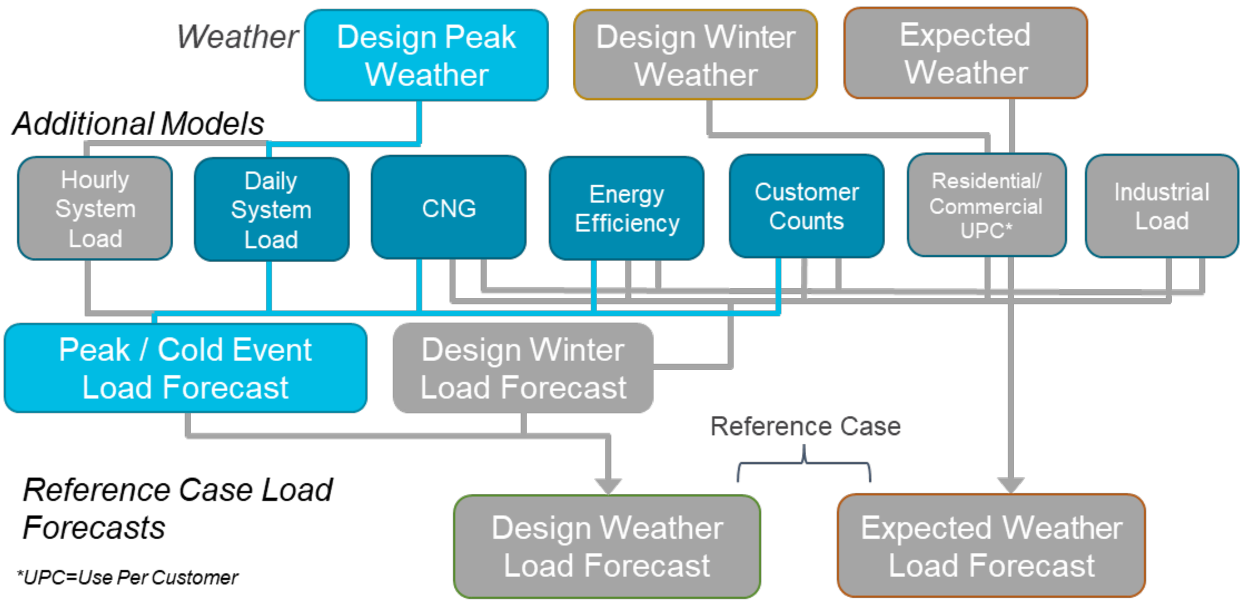
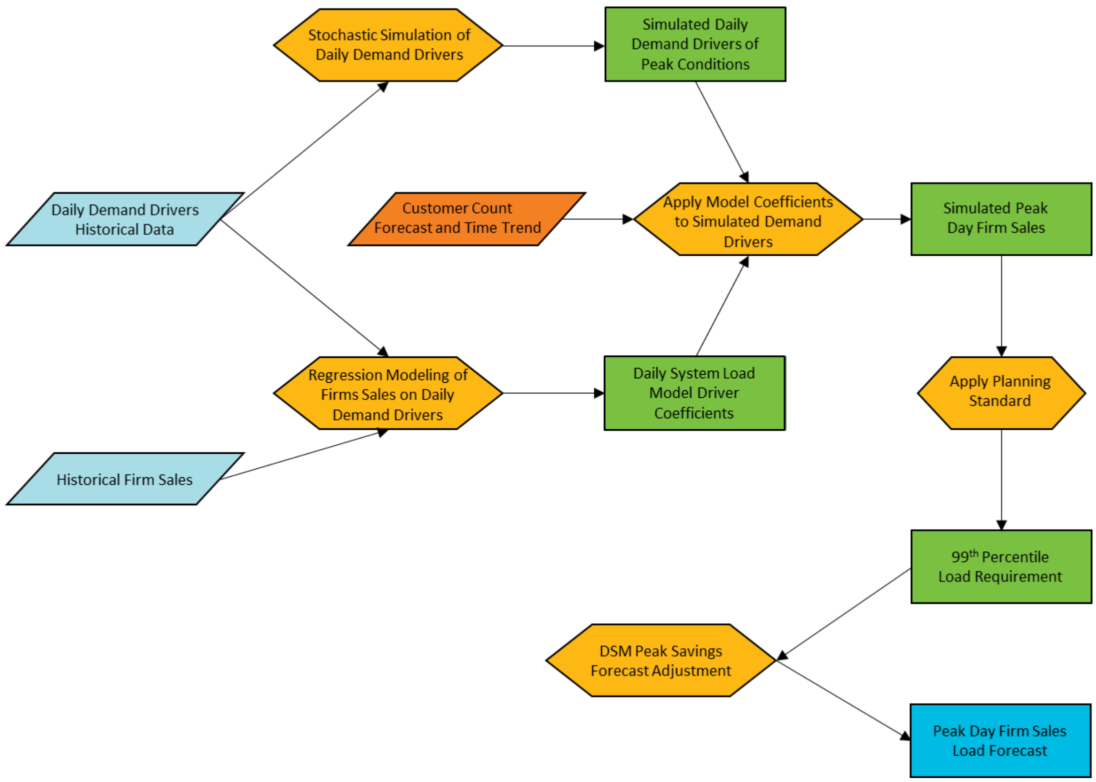


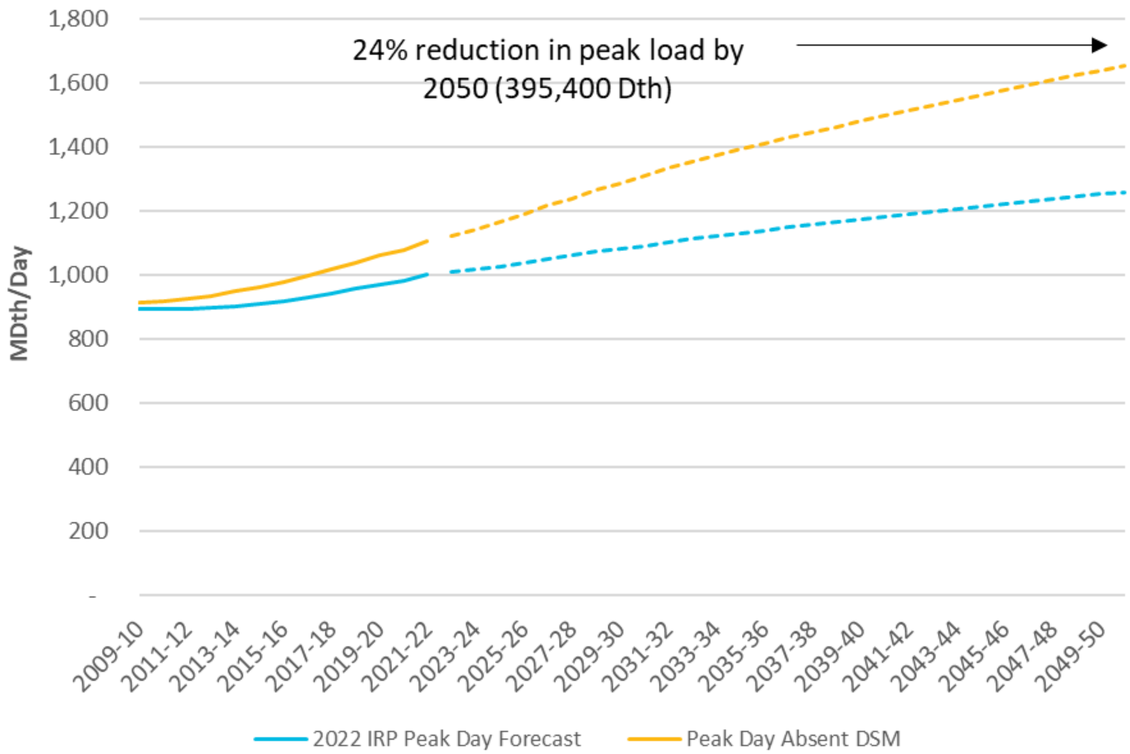
Figure 3.31 illustrates a flow chart for how the daily system load model, forecast of design peak day therm savings, and the planning standard are combined to develop the peak day forecast.

Figure 3.31: Peak Day Load Forecast Flow Chart



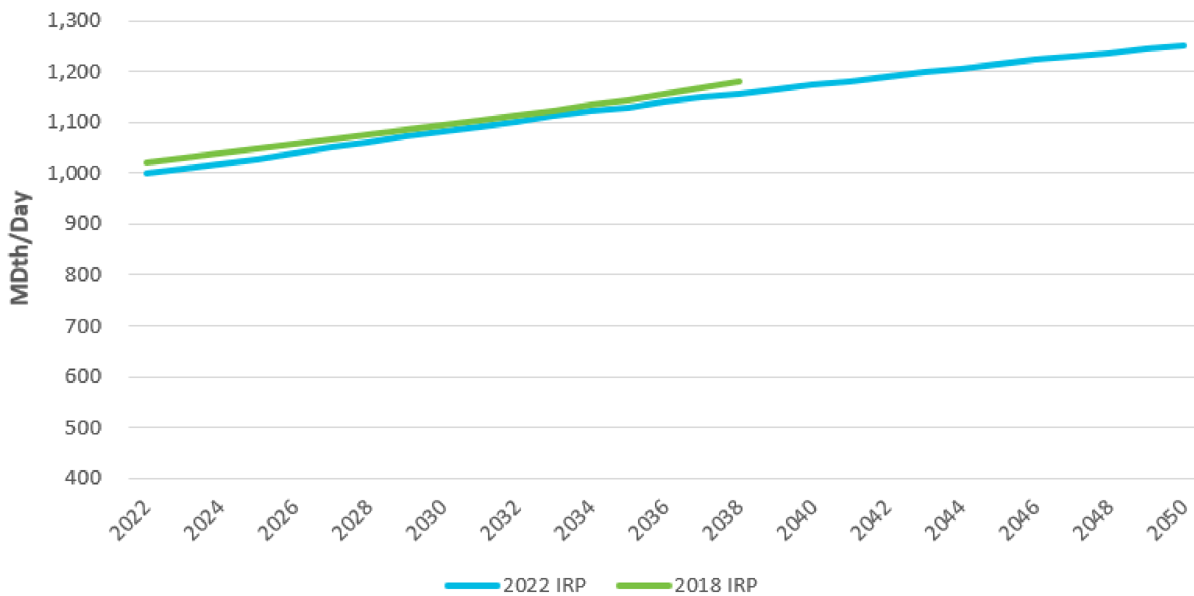
The impact of DSM programs has been and will continue to be a significant way to reduce annual load, but also generates significant savings on peak, particularly measures related to space heating. Figure 3.32 shows the peak day forecast, absent any DSM programs relative to the 2022 IRP peak day forecast adjusted for ETO and AEG's DSM forecast.

Figure 3.32: Peak Day Load Forecast Without DSM



By 2050, DSM programs will reduce peak day load by about 395,400 Dth or 24% of peak load. This is roughly the capacity equivalent of three Portland LNG facilities. Compared to the 2018 IRP, the reference case peak day forecast is lower by 1.5% by in 2038 as shown in Figure 3.33 but extends out to 2050.

Figure 3.33: Peak Day Load Comparison 2018 IRP to 2022 IRP

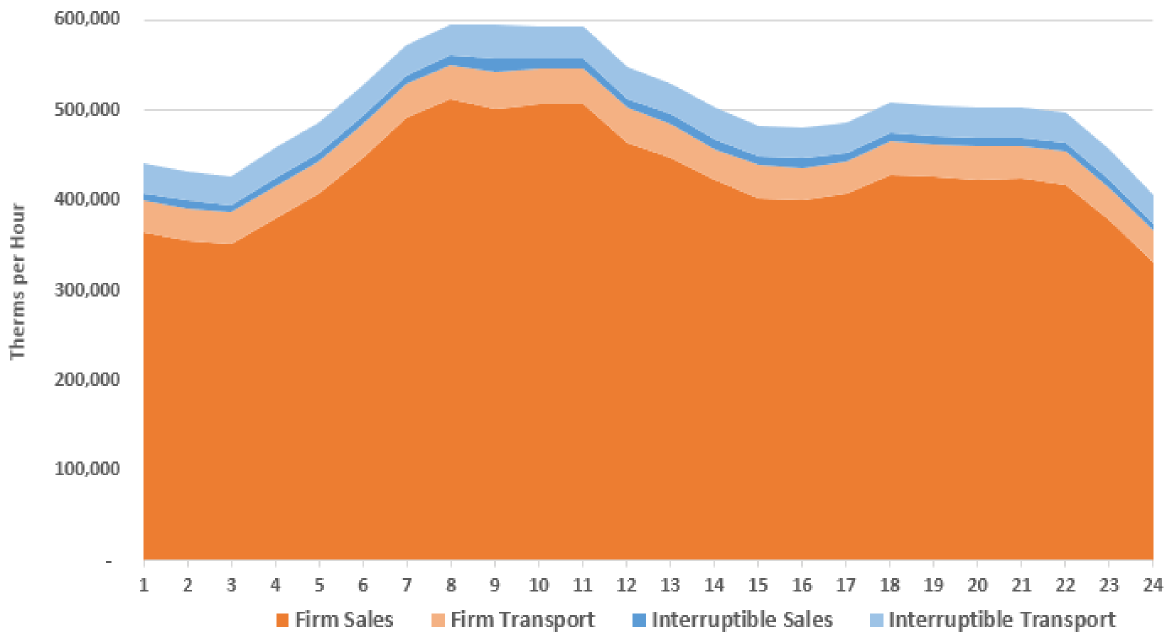


3.2.10 Demand Response

Demand response (DR) is a key resource that can be deployed to reduce peak loads. While there is interaction between DR and energy efficiency programs DR programs should not be thought of as emissions reduction programs given the infrequent use of demand response resources. NW Natural has substantial demand response programs via its interruptible schedules that have been in use for many years.

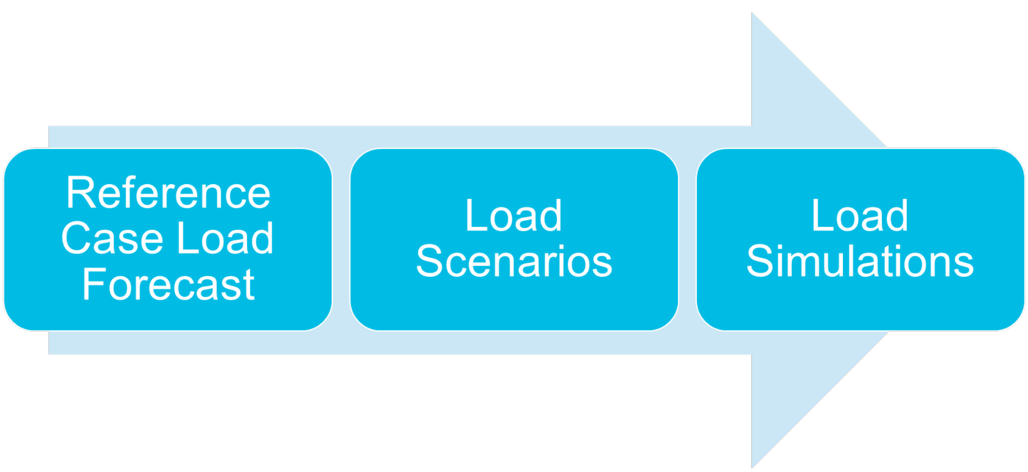
Figure 3.34- Existing Demand Response Impact shows what NW Natural's peak load would be by hour without its interruptible schedules. More than 2% of sales load on a peak day can be interrupted during peak periods, and roughly 9% of deliveries can be interrupted during a peak hour to maintain pressure on the distribution system. Without these DR programs substantial investment would be needed to maintain reliability on peak. While cost effective storage resources (see Chapter 6) make the potential capacity costs avoided from DR programs relatively small for gas utilities compared to electric utilities a confluence of new technologies in metering and smart devices makes potential additional DR peak savings possible from residential and small commercial customers to supplement existing industrial and large commercial programs. NW Natural engaged a third-party consultant to provide a comprehensive demand response potential study (please see Appendix B). Smart thermostats in particular could be a valuable demand response resource, and while the incentive that can be supported by NW Natural's relatively low-capacity avoided costs (see Chapter 4) we propose an Action Item in this IRP to establish a residential and small commercial DR program by 2024.

Figure 3.34- Existing Demand Response Impact



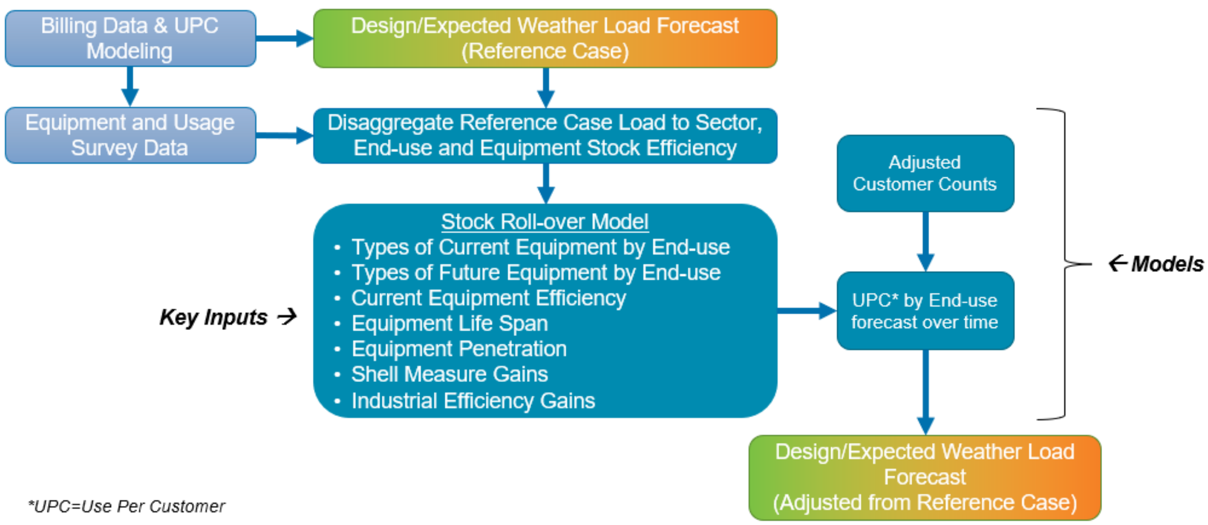
3.3 End Use Load Forecast Model

The statistical models used to the develop the forecasts in Section 3.2 are appropriate to use when historical trends are expected to continue and have been used to develop base case forecasts in NW Natural's prior IRPs. However, they are not appropriate for forecasting structural change like that could be afoot from the transformational climate policies recently established in the Company's service territory.



In order to evaluate potential large-scale changes in end use equipment technology, customer preferences, and/or the policy environment NW Natural developed an end use load forecasting methodology in the 2018 IRP that has been improved and becomes the driver of the key load forecasts used in this IRP (i.e., the forecasts used in each of the scenarios as well as the stochastic Monte Carlo simulation draws). End use load forecasting is not possible without a reference case to model changes against, and those changes are modeled relative to the reference case forecasts detailed in the previous section. While end use load forecasting is more flexible than forecasts derived only from econometric techniques, it has the drawback of being dependent upon user defined assumptions. The end-use load forecasting process is detailed below.

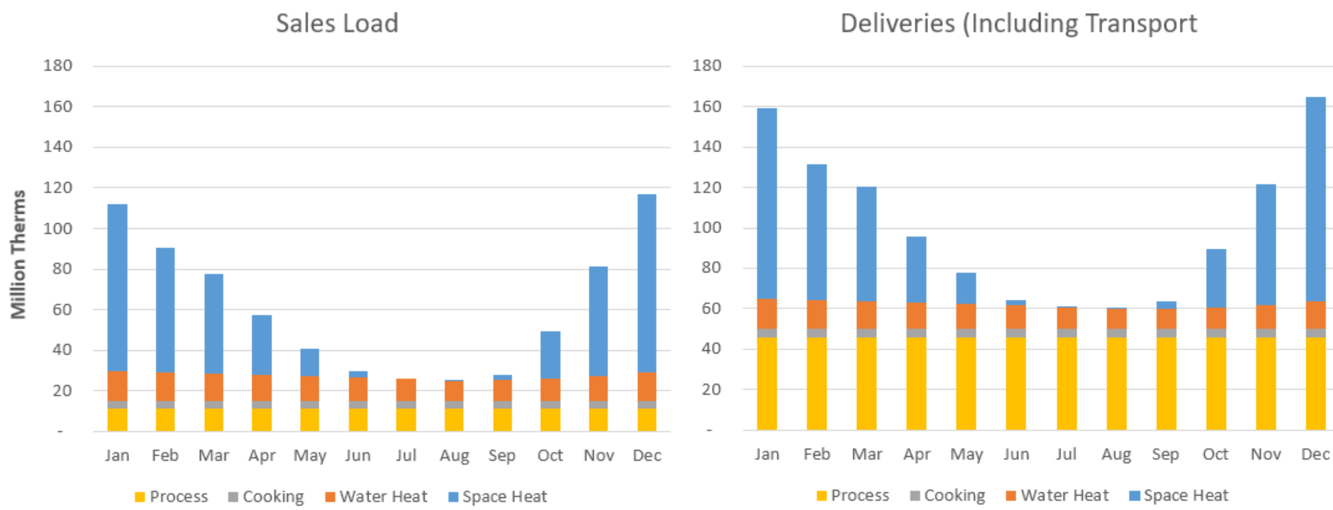
Figure 3.35: End Use Load Forecasting Process



3.3.1 Disaggregating Load by End Use

Forecasting by end use requires breaking down total load into end uses like space heating, water heating, cooking, and industrial applications to forecast each end use separately. The statistical techniques described in Section 3.2 are modified to estimate load by end use. This work shows that NW Natural's sales load is primarily space heating load.

Figure 3.36: Load Breakdown by End Use



Roughly 2/3 of the gas delivered to NW Natural customers is sold as a bundled product by the utility to customers on sales schedules, with the majority of the load on transport schedules being comprised of industrial process loads. While space heating makes up the majority of the load sold on sales schedules throughout the year, it accounts for roughly 90% of the firm sales load that is expected on a peak day or hour.

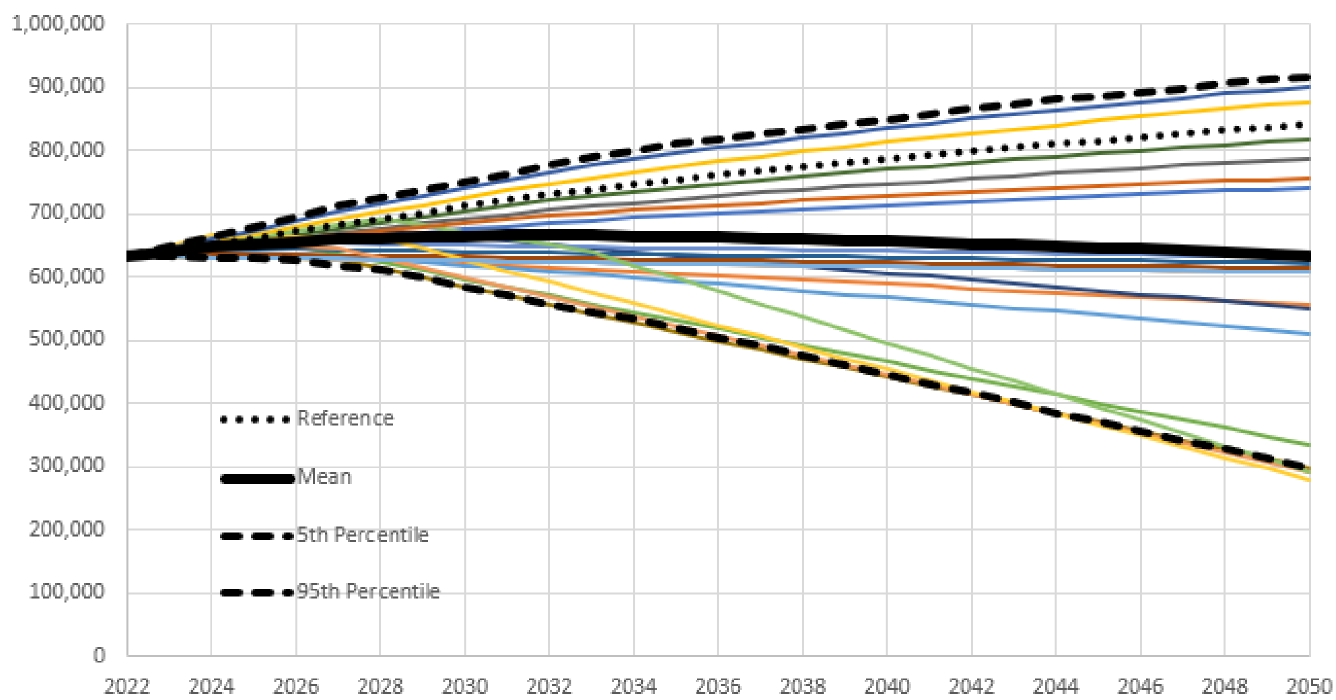
3.3.2 Stock Rollover Model

The relative efficiencies and equipment options available determine how much energy is needed for end use energy services like keeping a home warm or having hot water for a shower. To understand how changing technology or deploying more energy efficient technologies would be expected to impact load the efficiency of the stock of equipment and rate of stock turnover/replacement based upon expected equipment lives needs to be estimated. A key source of information on the efficiencies of equipment in use in NW Natural's service territory are building stock assessments completed by the Northwest Energy Efficiency Alliance, though this information is supplemented by NW Natural's own analysis of customer billing data surveys as well as national building stock assessments. The assumptions about emerging end use equipment deployment are discussed in Section 5.8.

3.4 Customer Count Uncertainty

Six of the nine scenarios utilize the same customer count forecast, whereas the electrification scenario assume varying degrees of customer declines. These scenario help define the residential and commercial customer count stochastic simulation results shown in Figure 3.37.

Figure 3.37: Oregon Residential Customer Count Monte Carlo Results[70]



[70] For graphs showing the mean and dispersion of a Monte Carlo simulation, the colored lines represent individual stochastic draws from that simulation.

3.5 Annual Load Uncertainty

Combining the uncertainty in customer counts, energy efficiency, emerging technology deployment, economic activity, and weather allow total load uncertainty to be developed.

Figure 3.38: Total System Load (Deliveries) by Scenario

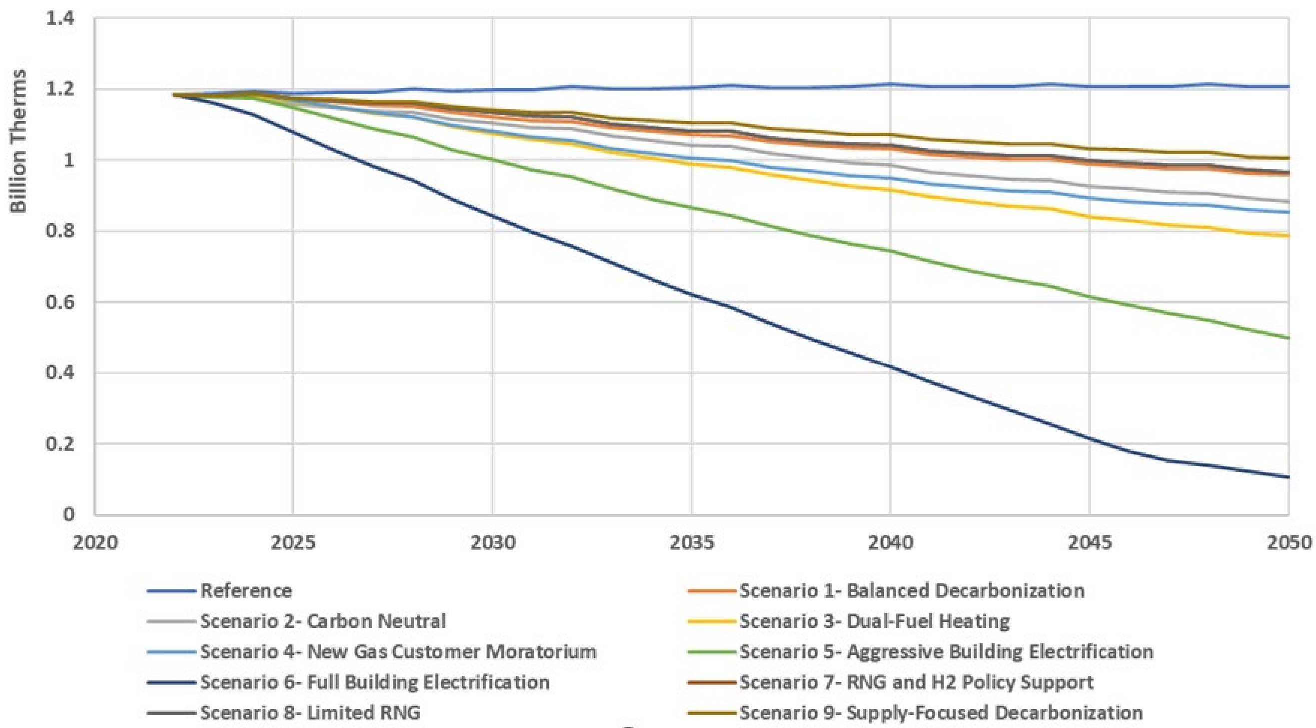


Figure 3.39: Oregon Residential Stochastic Load Results

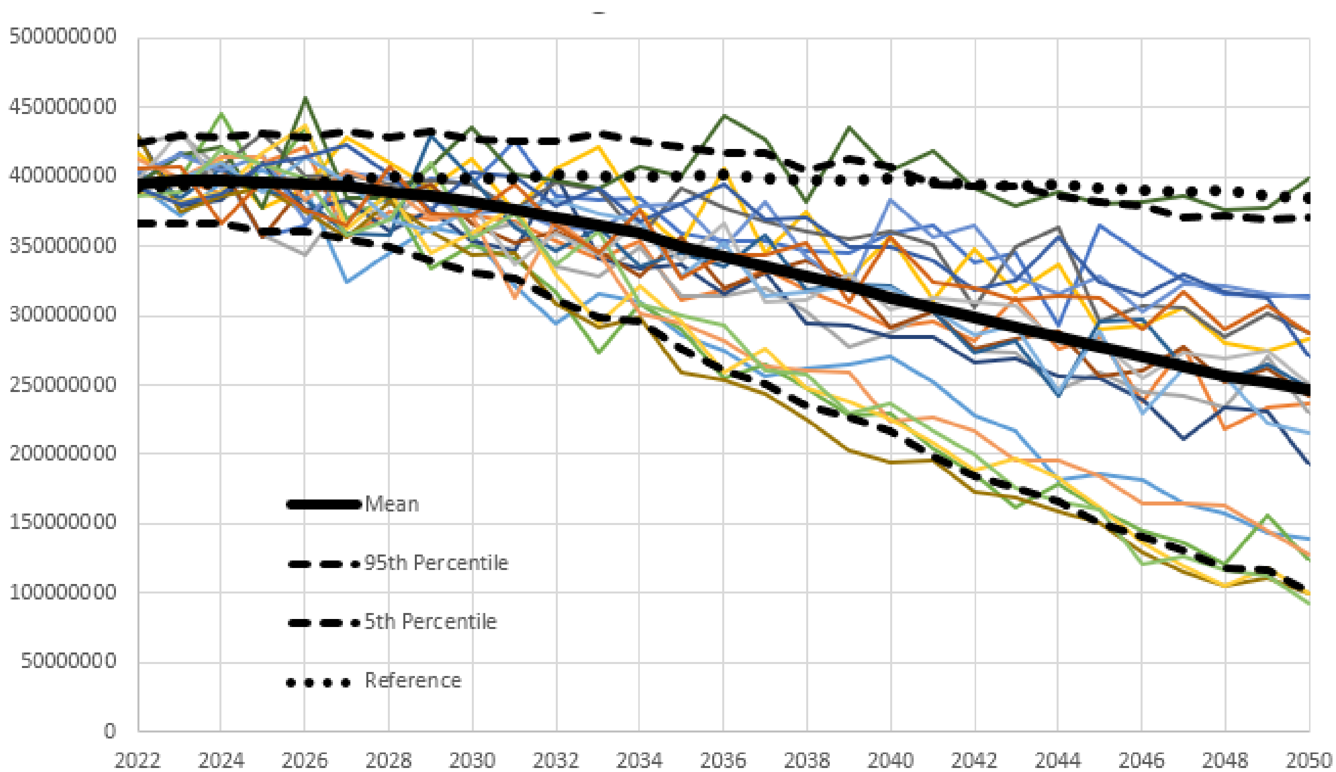
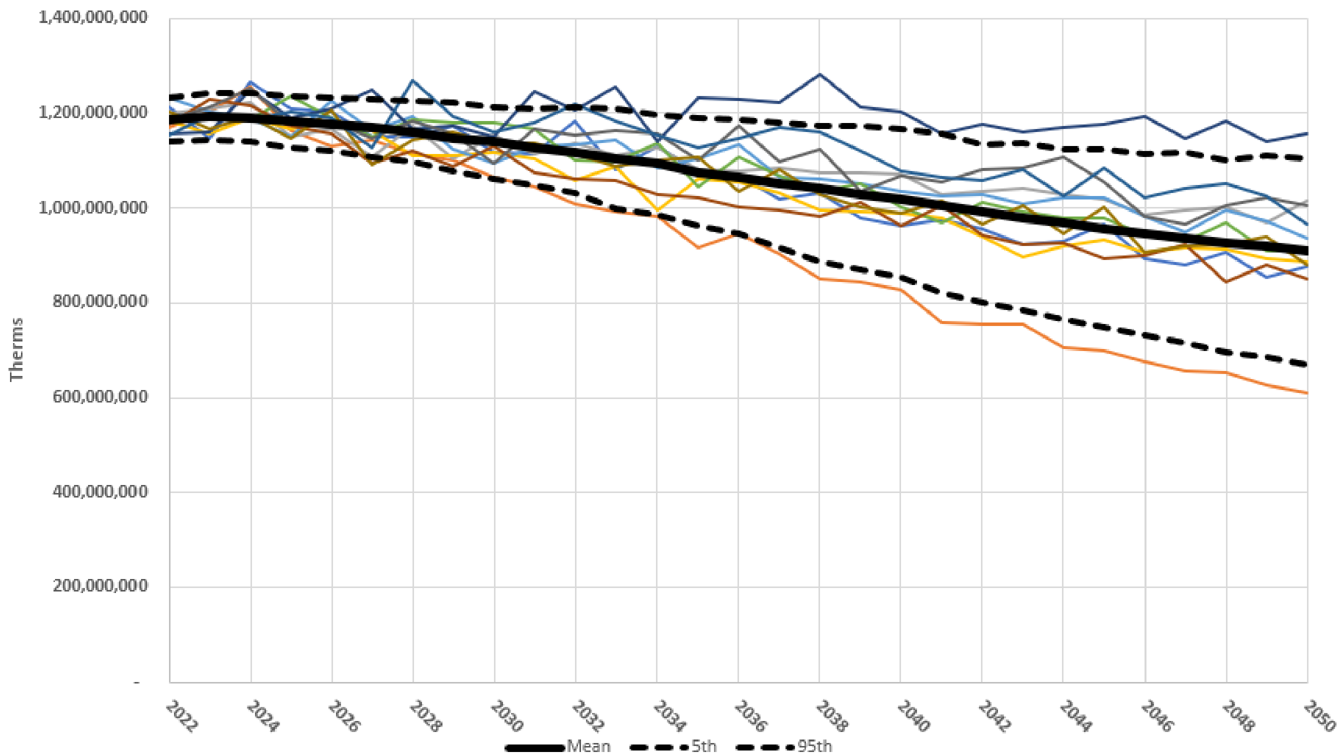


Figure 3.40: Total System Load Stochastic Simulation Results



3.6 Peak Load Uncertainty

The peak loads associated with the load forecasts of each scenario and the results of the stochastic Monte Carlo simulation are shown below.

Figure 3.41: Firm Sales Peak Day Load by Scenario

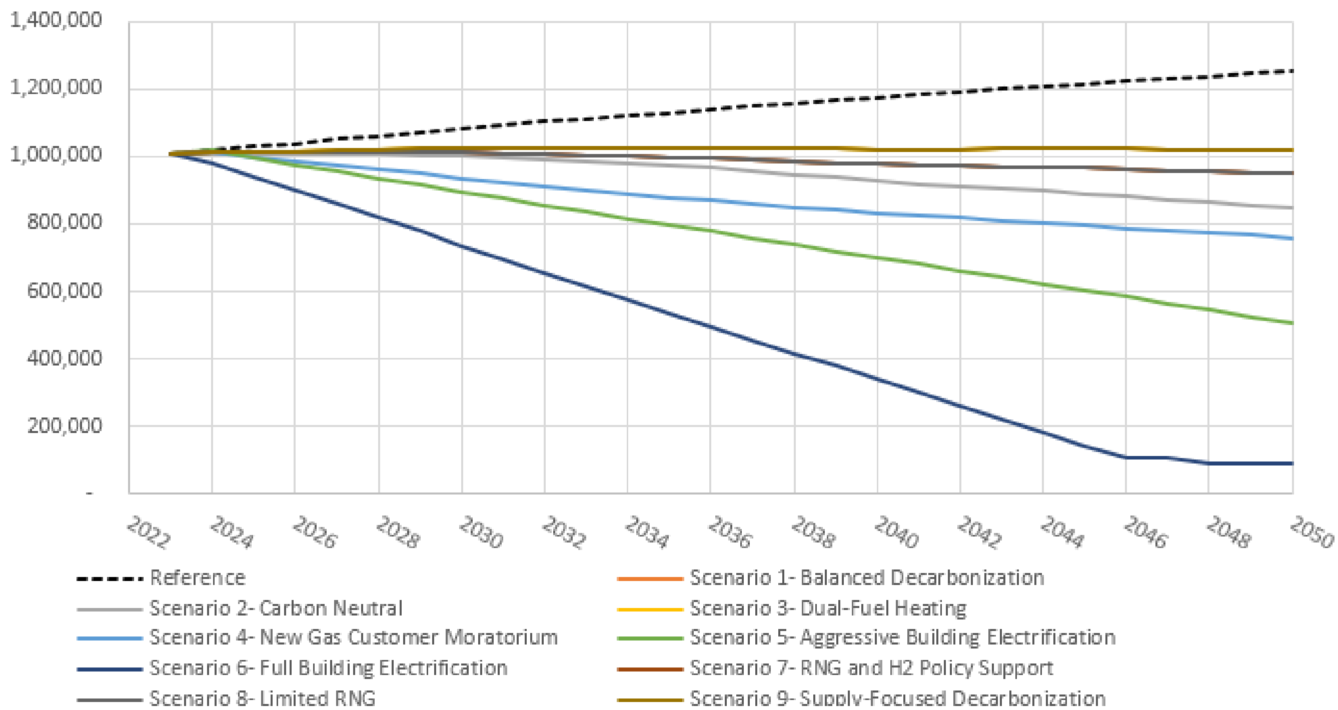
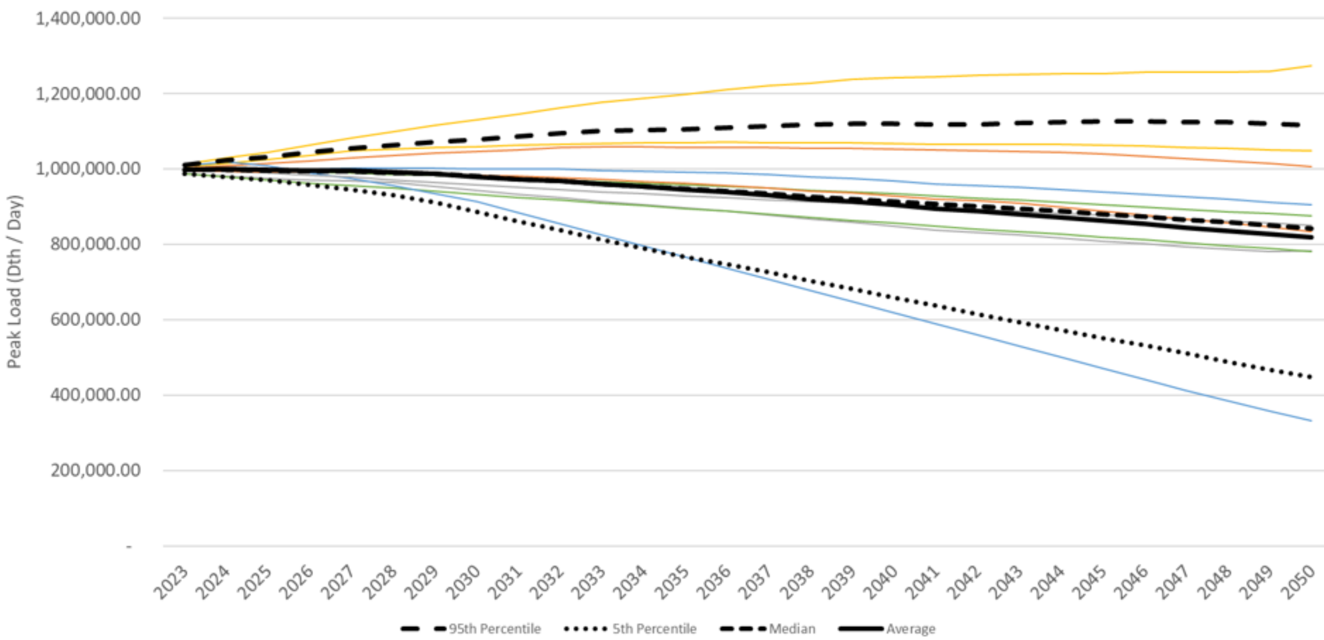


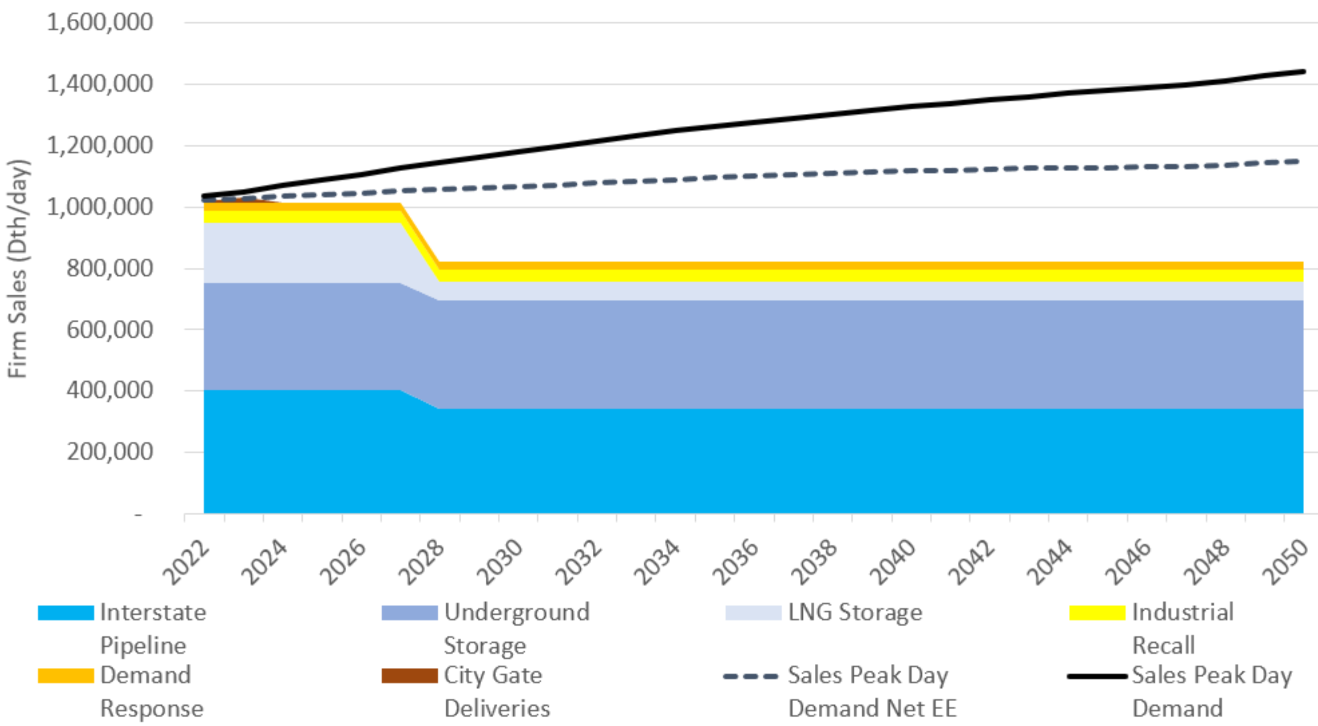
Figure 3.42: System Firm Sales Peak Day Load Stochastic Simulation Results



3.7 Defining Capacity Resource Needs

Figure 3.43 shows an example peak day load-resource balance. The gap between the peak load net of energy efficiency and the expected resources represents the capacity needs to address. The options to fill this gap are discussed in Chapters 5 and 6, and the least cost results for filling the gap for each scenario and across simulation draws are shown in Chapter 7.

Figure 3.43: Peak Day Capacity Load Resource Balance[71]



[71] Scenario 1 load depicted as an example. The peak load resource balance for each scenario can be seen in Chapter 7.

3.8 Defining Compliance Resource Needs

Similar to the capacity needs shown in the previous section, once load is forecasted and the requirements of Oregon's Climate Protection Program and Washington's Cap-and-Invest program defined the emissions reductions required to comply with the programs can be defined.

Figure 3.44: Oregon CPP Emission Compliance Needs

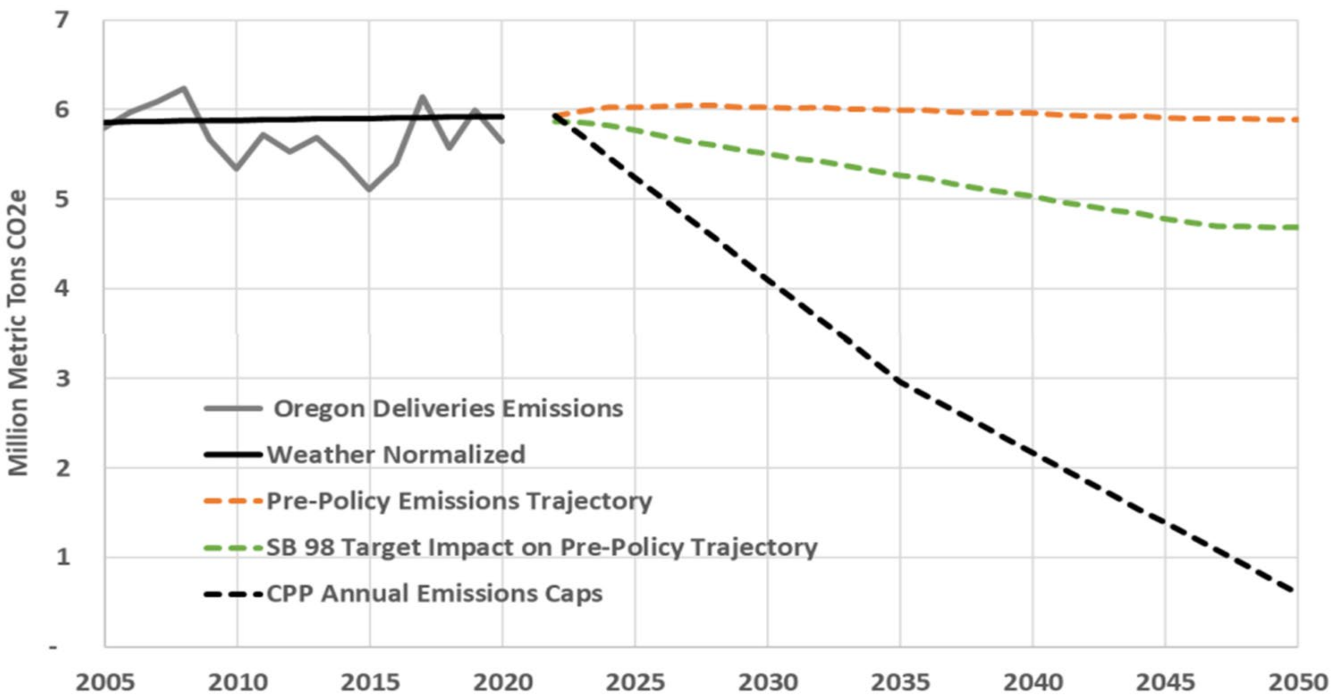
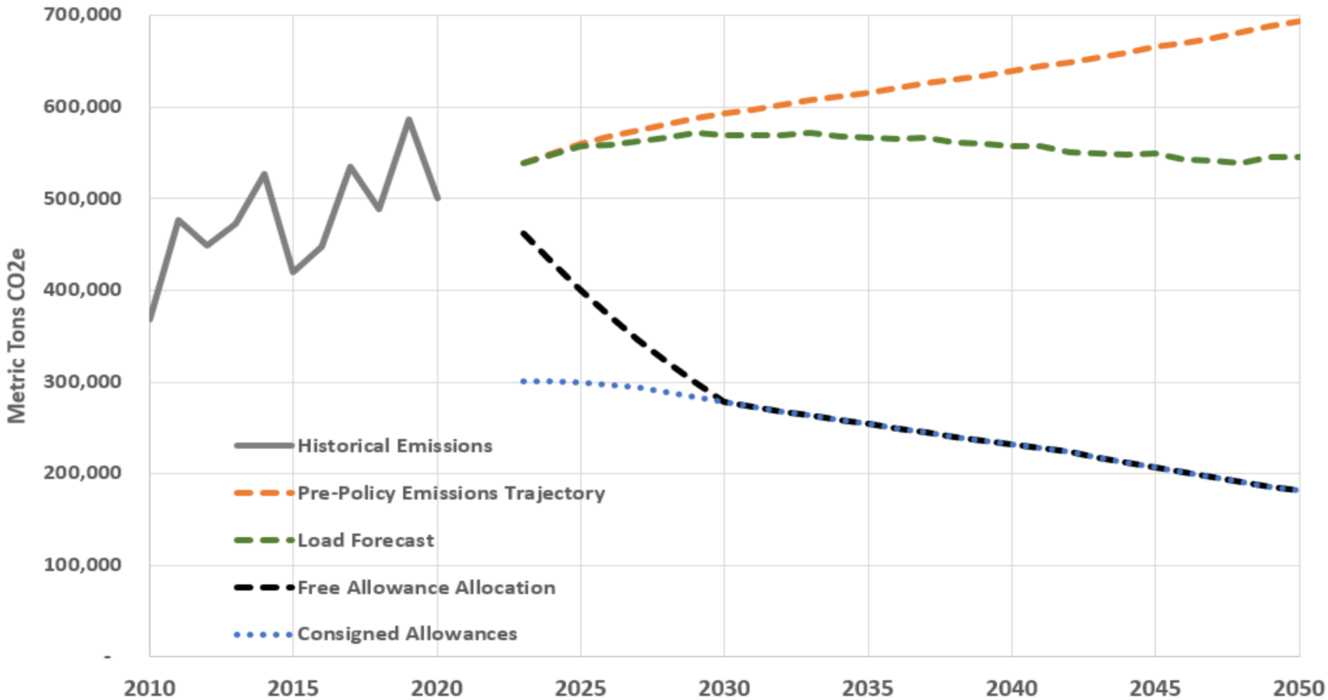


Figure 3.45: Washington Cap-and-Invest Emissions Compliance Situation



Choosing amongst resource options requires understanding the cost tradeoffs amongst resource options. Chapter 4 describes the methodologies used to determine the costs that are avoided when one resource is chosen over the other available options.

4 Avoided Costs

NW Natural®

4.1 Avoided Costs – Overview

As part of the IRP process, NW Natural forecasts avoided costs over the planning horizon. Total avoided cost is an estimate of the cost to serve the marginal unit of demand with conventional supply-side resources. This incremental cost represents the cost that could be avoided if that unit of gas were not demanded, due to efforts such as demand-side management (DSM), or through on-system supply side resources such as locally sourced renewable natural gas.

Therefore, the avoided cost forecast can be used as a guideline for comparing the cost of acquiring gas and supply-side resources to meet demand with other options so that the most cost-effective solutions are identified to meet customer needs. Practically, the avoided cost forecast is a key component of the cost-effectiveness test that is conducted by Energy Trust of Oregon (ETO) and Applied Energy Group (AEG) to determine the DSM savings projections for Oregon (ETO) and Washington (AEG) detailed in Chapter 5.

Chapter 4 details the methodology used to calculate each component of NW Natural's avoided costs. The methodology we used to calculate our avoided cost forecast has seen continued improvement since the 2014 IRP, and we are working with ETO and AEG to make additional improvements implementable within the broader distribution planning and IRP processes. For the 2022 IRP, NW Natural's avoided cost forecast features the following key methodological improvements:

- A new methodology is used to measure the reduction in price risk (hedge value) for avoided cost that is based on the same Monte Carlo gas price simulations and aligns with NW Natural's methodology for evaluating risk of other resources, particularly the methodology being applied for RNG.
- Avoided costs have been applied to more diversified on-system and low carbon supply-side resources so the entire value these resources provide to customers is included when they are evaluated against conventional resources.
- Environmental incremental policy compliance costs for recent Climate Protection Program (CPP) and Community Climate Investments (CCI) for Oregon and Climate Compliance Act (CCA) for Washington have been explicitly included in its portfolio modeling assumptions to generate state-specific avoided costs in NW Natural's territory.
- This is the first time in NW Natural's IRP filing that avoided costs are estimated based on the resource optimization results obtained from the current IRP modeling and filed in the same IRP.

This chapter also presents the avoided costs results for both the demand-side and the supply-side resources to which the concept is applied. NW Natural continues to work on improving its methodologies and internal processes relative to avoided costs in a continuing effort to ensure that all resources, be they demand- or supply-side, are evaluated on a fair and consistent basis in a fully integrated process.

4.2 Avoided Cost Components

Table 4.1 summarizes each of the components of avoided costs and shows which components are included in the evaluation of the different resource options NW Natural considers in its resource planning. Additionally, Table 4.1 shows which values of the avoided costs components vary by end use or supply resource.

Table 4.1: Avoided Costs Components and Application Summary

Costs Avoided		Resource Option Application					
		Demand-Side Resources			Supply-Side Resources		
			Demand Response		Low-Carbon Gas Supply		
		Energy Efficiency	Interruptible Schedules	Other DR	On-System Resources	Off-System Resources	Recall Agreements
Commodity Related Avoided Costs	Natural Gas Purchase and Transport Costs	✓			✓	✓	
	Greenhouse Gas Compliance Costs	✓			✓	✓	
	Commodity Price Risk Reduction Value	✓			✓	✓	
Infrastructure Related Avoided Costs	Supply Capacity Costs	✓	✓	✓	✓		✓
	Distribution System Costs	✓	✓	✓	✓		
Unquantified Conservation Costs	10% Northwest Power & Conservation Council Credit	✓					

4.2.1 Commodity Related Avoided Costs

These avoided costs are those that apply equally on a per unit of natural gas saved or supplied basis. This is to say that for these components it is either irrelevant or somewhat unimportant when the energy is saved or supplied.[72] For example, it is irrelevant from a greenhouse gas (GHG) emissions compliance cost perspective whether the emissions occur during a peak period or any other time of the year.

4.2.2 Gas and Transport Costs

This component represents the cost of the natural gas commodity itself. The main driver of these costs is the natural gas price forecast detailed in Chapter 2, though it also includes the following minor costs: 1) "line losses," or the amount of gas that is used to deliver gas from where it is purchased to where it is consumed; 2) applicable variable transmissions costs; and 3) storage inventory carrying costs. On any given day in the forecast period the avoided gas and transport costs represent the cost of the last unit of gas sold during that particular day,[73] where that unit may be from an expected daily spot purchase

[72] Noting that seasonality of natural gas prices and the storage resources in NW Natural's portfolio make it inaccurate to claim that when the energy is saved or served has no impact on these avoided costs.
[73] Which by cost minimization protocols is the most expensive unit of gas purchased that day.

or a storage withdrawal depending on the load that needs to be served and gas prices on that day. This daily figure comes from the resource planning optimization model and is aggregated to the monthly level. Note that avoided commodity and transport costs varied not only through time but also across end uses since each end use has its own estimate based on the seasonal usage or supply portfolio of that resource and the seasonality of natural gas prices exhibited in the price forecast. The details of this calculation can be found in Appendix C.

4.2.3 Greenhouse Gas Emissions Compliance Costs

NW Natural explicitly includes incremental environmental policy compliance costs for the CPP in Oregon and the CCA in Washington in its portfolio modeling assumptions. This is in addition to the current state and federal policies embedded in the gas price forecasts provided by a third-party consultant. Potential compliance costs are hence separately generated by state to meet environmental policy requirements specific to each state in NW Natural's service territory.

For Oregon, the incremental environmental policy cost is based on the marginal compliance resource needed for compliance with the CPP in Oregon. Potential marginal compliance resources and their costs are discussed in Chapter 6. It should be noted that the avoided GHG compliance costs are CCP specific and do not include compliance resources that are acquired to meet Oregon SB 98 targets, even though these resources could be counted toward emissions compliance.

For Washington, the calculation is slightly more straightforward as House Bill 1257 directs natural gas utilities to use the social cost of carbon inclusive of upstream emissions for planning purposes. It is the Company's interpretation that this bill applies to avoid costs and hence the Company uses the social cost of carbon published on the WUTC's website as the incremental environmental policy cost for Washington.[74]

4.2.4 Commodity Price Risk Reduction Value or the Hedge Value of DSM

While the "cost to achieve natural gas price certainty" is a more descriptive name for this component of avoided costs, this component is more commonly referred to as the "hedge value of DSM."[75] Natural gas prices are volatile and uncertain, particularly when analyzing long-term price forecasts as is necessary to 1) forecast costs in IRPs; and 2) evaluate the cost-effectiveness of resource options that provide energy savings or gas supply for multiple years (and in the case of DSM, sometimes indefinitely). If price hedging is not used to remove or mitigate this price volatility and uncertainty, customers are exposed to changes in the trend of prices in the long-term, and price fluctuations around this long-term trend in the short-term. DSM savings are a type of long-term hedge: if the actual energy savings that are going to be acquired and the costs to obtain those savings are known with

[74] https://www.utc.wa.gov/regulated-industries/utilities/energy/conservation-and-renewable-energy-overview/clean-energy-transformation-act/social-cost-carbon

[75] See OPUC docket No. UM 1622 for a lengthy discussion of the hedge value of DSM in avoided costs. Also, see page 10 and Appendix 1 of NW Natural's reply comments in the Company's 2016 IRP proceeding (OPUC docket No. LC 64) for a detailed history on how the hedge value of DSM came to be included in the NW Natural's avoided costs starting with the 2016 IRP. (https://edocs.puc.state.or.us/efdocs/HAC/lc64hac115929.pdf).

certainty, acquiring demand-side savings removes the price risk associated with unhedged supply resources that would be necessary if energy savings were not acquired. The hedge value of DSM represents the risk premium gas purchasers need to pay (i.e., the cost to fix the price) to obtain a long-term fixed price financial hedge at the time of the IRP analysis.[76]

This IRP applies a new methodology to measure the reduction in price risk (hedge value) for avoided cost that uses a similar risk assessment as the portfolio risk-adjusted present value revenue requirement (rPVRR) and the same methodology is used to determine the risk-adjusted incremental cost of renewable resources and based on data from the same Monte Carlo gas price simulations:

Risk Adjusted Cost of Gas = 75%*Mean Price + 25%* 95th Percentile Stochastic Price

The second term on the right-hand side of the formula represents the risk premium, which is a quantitative valuation of the cost risk associated with a given resource type. This is the risk that a hedge protects against, and hence the risk reduction value is calculated as:

Risk Reduction Value = Risk Adjusted Cost of Gas – Mean Stochastic Price of Gas

When the risk reduction value of DSM is added to the gas and transport costs described above, it represents the fixed price of gas that could be obtained through financial hedging instruments. The same risk reduction value is applied in both states and to all end uses and is the least significant component of avoided costs.

4.2.5 Infrastructure Related Avoided Costs

Infrastructure needs are driven by peak loads. Consequently, the extent to which resources reduce or supply energy on peak determines the infrastructure costs they avoid. To estimate infrastructure costs avoided for any resource there are two pieces that need to be calculated:

1) the incremental cost of serving additional peak load; and
2) the amount energy that would be saved or supplied during a peak

Note that the incremental cost of serving additional peak load is the same for all resources but the energy supplied or saved on peak is resource specific. Take energy efficiency as an example. A significant share of the energy savings achieved through DSM programs comes from large industrial customers, though many of these customers elect to be on interruptible schedules.[77] These customers are interrupted during peak events, so they do not contribute to peak load or the infrastructure designed to serve it. Therefore, savings acquired for interruptible customers avoid commodity related

[76] Inclusive of the costs of assessing and managing counterparty risk of financial hedging.
[77] Note that interruptible customers pay a lower rate than firm customers, with the difference in rate being the estimated infrastructure costs that are saved by interrupting customers during peak events.

costs, but do not avoid infrastructure related costs related to peak planning. On the other hand, DSM measures that target space heating, by contrast, result in relatively pronounced peak day load reductions (recall that space heating represents the vast majority of the peak load) in addition to the energy savings they provide on an annual basis.

There are two infrastructure-related avoided costs components — supply capacity avoided costs and distribution system avoided costs. Supply capacity resources are the resources we use to get gas onto our system of pipelines and are primarily interstate pipeline capacity and storage resources. Distribution system resources are the assets, primarily smaller pipelines, on NW Natural's system that distribute the gas that arrives at NW Natural's system via its supply resources to customers as it is demanded. Note that supply resources are held on a service territory-wide portfolio basis and serve both states, so supply capacity costs avoided per unit of gas are the same in both states. However, distribution assets are separate in Oregon and Washington, so distribution capacity costs avoided differ by state based upon the expected costs of the distribution system in that state. Per Commission guidance and industry best practices, infrastructure resource costs are based upon the costs of the incremental capacity resource (i.e., cost of the marginal resource) needed to meet customer needs.

4.2.6 Supply Capacity Costs

NW Natural's methodology for estimating supply capacity costs has not changed since the last IRP and has been applied to the end uses considered for DSM and the on-system supply resources discussed in Chapter 6.

1) Estimating the incremental infrastructure costs of serving peak day load:

Given the longstanding process of coordination between NW Natural and ETO/AEG (see Figure 4.2 in Section 4.3 for a visual depiction of this coordination) the DSM savings projections provided by ETO and AEG are completed before the supply resource optimization. Therefore, the incremental supply resources that would be saved for each year in the planning horizon with DSM need to be assumed before the supply resource optimization to assign a cost for the supply capacity costs being avoided. The assumptions made about what supply portfolio resources would be acquired in each year were not significantly different from the actual supply resource choices detailed in Chapter 7.[78] For supply-side resources, the supply capacity costs avoided are determined within the resource planning optimization.

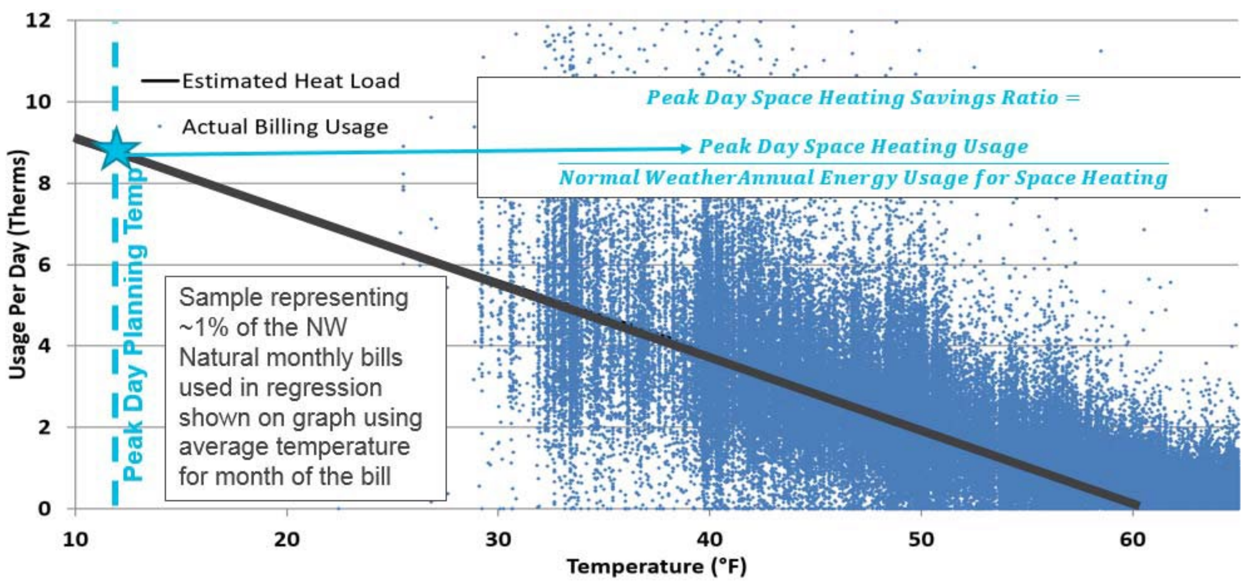
2) Estimating the energy savings or supply on a peak day for each resource option:

To give an idea of how this calculation works, the largest contributor to peak day load — residential space heating — is used as an example. Figure 4.1 shows daily usage for NW Natural residential

[78] Note that the avoided cost figures have been updated and will be used by Energy Trust for budgeting if the avoided costs in the 2018 IRP are acknowledged.

customers who use natural gas to heat their homes.[79] While there is much variation in usage due to differences in customer equipment efficiency, behavior, home type and size, and relative shell efficiency, the average NW Natural residential customer's space heating usage across temperatures is depicted by the black line. As the graph shows, using an estimate of the temperature that corresponds with NW Natural's peak day planning standard (see Chapter 3), an average residential customer would use roughly nine therms of gas for space heating on a peak day.

Figure 4.1: Residential Space Heating Peak Day Savings Estimate and Peak to Annual Ratio



In conjunction with an estimate of the average annual usage for space heating under normal Weather, this peak day usage estimate can be used to determine the share of annual space heating load that occurs on a planning peak day. Assuming the savings shape and the load shape are the same, this ratio can be multiplied by the ETO and AEG's annual savings estimated for each residential space heating measure to estimate the peak savings for that measure. This can then be used to calculate the supply infrastructure avoided costs on an energy basis. Similarly, the peak day to annual usage ratios were calculated for all the end uses considered. These ratios are shown in Table 4.2.

[79] Note that if a thermostat is set to a fixed temperature and the efficiency of the customer's space heating equipment is not a function of temperature (which is generally true of any natural gas space heating equipment currently used by NW Natural customers) usage will be linear in temperature.

Table 4.2: End Use Specific Peak Day Usage/Savings Ratios

Peak DAY Usage to Normal Weather Annual Usage Factors for SUPPLY Costs		Source of Information
Residential Space Heating (Including Hearths and Fireplaces)	**0.01983**	NW Natural Regressions
Commercial Space Heating	**0.01769**	NW Natural Regressions
Water Heating	**0.0033**	NW Natural Regressions and NEEA Water Heater Study
Cooking	**0.00356**	Analysis of ODOE RECS Data
Process Load	**0.00274**	Annual/365

4.2.7 Distribution Capacity Costs

The same general process undertaken for supply resource capacity costs avoided is also completed for avoided distribution capacity costs, with the key metric being the incremental costs associated with enhancing or reinforcing the distribution system to serve peak hour demand, rather than peak day demand.

1) Estimating the incremental infrastructure costs of serving growing peak hour load:

This state-specific calculation relies on historical data of the costs to reinforce NW Natural's distribution system and is based on an average of the revenue requirement of reinforcement projects that were completed over the previous five years. Note that these costs do not include the costs associated with installing new services or meters, operation, and maintenance costs, or with commodity purchases or our supply capacity resources. They represent only the cost-of-service revenue requirement of capital expenditures to reinforce the distribution system so that it is sufficient to reliably serve all our customers. The primary driver of these costs is growing peak hour load. Therefore, to estimate the cost of reinforcing NW Natural's distribution system as peak hour load grows, the growth in peak hour load for each of Oregon and Washington over the same five years was estimated using the peak hour load forecasting technique described in Chapter 7.7. Dividing the revenue requirement from the sum of the reinforcement projects over the past five years by the growth in peak hour load over the same period, gives an estimate of the cost of incremental peak hour load on a per unit of peak hour load for the two states in our service territory. This is the estimate of the costs that would be avoided by serving or saving a unit of gas on a peak hour. This methodology has been applied since the 2018 IRP.

2) Estimating the energy savings or supply on a peak day for each resource option

For each resource considered, the amount of natural gas it will supply or save on a peak hour is what is determined for each resource evaluated. Given that the peak hour is typically the hour starting at 7 a.m. on the peak day, this is done by estimating the share of peak day savings/supply that will occur during that hour and multiplying this factor by the peak day factors in

Table 4.2. Take again the largest contributor to peak hour load — residential space heating — as an example: dividing the peak hour space heating load (7 a.m.) by the total space heating load for the peak day, provides an estimate of the share of peak day load served during the peak hour that distribution system infrastructure is designed to serve. This estimate was made using two sources, NW Natural system hourly flow regressions and the Electric Power Research Institute (EPRI) residential peak space heating load shape. These sources were averaged to calculate the hourly to daily peak hour factor for residential space heating. Using NW Natural's hourly load forecasting methodology described in Chapter 7.7, subtracting summer loads from peak day loads for each hour of the day provides an estimate of space heating load on a peak day, which can then be turned into the peak hour factor described above. For residential space heating, this factor is 5.79%.[80] Multiplying this factor times the peak day factor in Table 4.2 gives an estimate that the average residential NW Natural customer would use the equivalent of 0.115% of their normal weather *annual* residential space heating load on a peak hour. This figure, along with the peak hour to annual usage ratios for the other end uses considered in this IRP, is shown in
Table 4.3.

Table 4.3: End Use Specific Peak Hour Usage/Savings Ratios

Peak HOUR Usage to Normal Weather Annual Usage Factors for DISTRIBUTION System Costs		Source of Information
Residential Space Heating	0.00115	NWN System Hourly Flows & EPRI Load Shape
Hearths and Fireplaces	0.00058	EPRI Load Shape
Commercial Space Heating	0.00139	NWN System Hourly Flows & EPRI Load Shape
Water Heating	0.00026	NWN System Hourly Flows & Ecotope Water Heating Study
Cooking	0.00071	EPRI Load Shape
Process Load	0.00011	Daily/24

Multiplying the factor shown in Table 4.3 by the annual normal weather usage for each end use measure or on-system supply resource gives an estimate of the energy saved or supplied on a peak hour, which can be multiplied by the estimate of the cost of serving an additional unit of peak hour load to estimate the costs avoided by that measure or supply resource.

4.2.8 Ten Percent Northwest Power and Conservation Council Conservation Credit

This credit is applied for DSM and is calculated from a summation of all the components of avoided costs except the hedge value of DSM and the GHG compliance cost components. Note that even

[80] Note that a flat load has a factor of 1/24, or 4.17%.

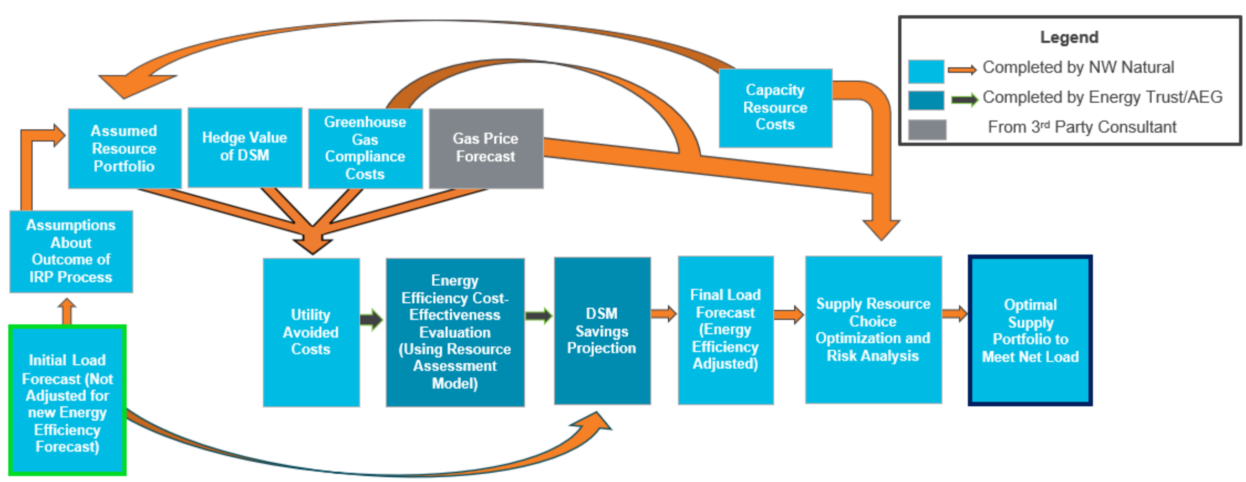
though the 10% conservation credit is applied consistently across all DSM resources, the actual credit included in avoided costs varies since some of the avoided costs components vary by state, end use, and/or time. While the credit was originally designed to apply to DSM, it is unclear whether it should also be applied to supply-side resources that also conserve the use of conventional natural gas (most notably renewable natural gas) so that demand- and supply-side resources are treated on a fair and consistent basis per Oregon PUC's IRP guidelines. NW Natural has not included the Conservation Credit in the avoided costs of any resources except DSM in this IRP, but it warrants consideration in future IRPs.

4.3 Demand-side Applications of Avoided Costs

4.3.1 Avoided Costs and DSM in the Overall IRP Process

Figure 4.2 details how avoided costs and DSM energy savings are integrated into the broader IRP process and shows what work is completed by NW Natural and what work is completed by ETO or AEG. Note that estimating the infrastructure (capacity) costs that can be avoided with DSM complicates the general process of obtaining the DSM savings projections from ETO and AEG. This complexity arises because the DSM savings projection has to be made before supply-side resource choice modeling to net the DSM savings projection out of load and start the supply-side resource optimization. That is, assumptions about what supply-side capacity resources to choose from need to be made before the resource optimization process has begun for ETO and AEG to complete their cost-effectiveness test and savings projections for DSM required by the IRP.[81]

Figure 4.2: NW Natural IRP Process



As shown in Figure 4.2, the optimal supply portfolio to meet net load is obtained during the final stage of the IRP modeling process, which is necessarily after NW Natural provides ETO avoided cost

[81] Note that the work done by ETO and AEG to complete their DSM savings projections, and the projections for this IRP cycle, are the topic of Chapter 5.

estimates for developing the savings projection found in Chapter 5. However, upon completion of the modeling in the IRP, a more accurate avoided cost estimate can be developed based upon the marginal costs of the supply-side resources from the preferred portfolio developed in Chapter 7. In prior IRPs NW Natural included in the IRP for acknowledgement the avoided costs provided to ETO early in the IRP analysis timeline. However, in this IRP the Company has decided to update the avoided costs based upon final IRP results as they represent the most accurate and up to date estimates of avoided costs at the time of filing the IRP, and those estimates are what is shown in this Chapter.

4.3.2 Avoided Cost Component Breakdown Through Time

For each end use, avoided costs vary through time (and by state). Figure 4.3 uses Oregon residential space heating as an example to show the component breakdown of avoided costs through time for this end use.[82] It is interesting to note that in contrast to the 2018 IRP, a similar sharp increase in avoided costs is perceived in the 2030s but due to different reasons. In the 2018 IRP the sharp increase in avoided costs was due to supply capacity costs increasing dramatically as the Mist storage was expected to be exhausted in 2030. In this IRP, assumption about Mist Recall has changed: the Mist storage capacity may be recalled and transferred for use by core utility customers so this avoided costs component is forecasted to be small and steady throughout the planning horizon.[83] As shown in Figure 4.3, the sharp increase in avoided costs in Oregon this IRP comes from a significant increase in avoided GHG compliance costs. In Oregon, energy efficiency cannot avoid RNG acquisition to support SB 98, but it can be used for compliance under the Climate Protection Program (CPP), and as such the avoided GHG compliance costs are represented by the marginal emissions reduction activity expected to comply with the CPP in each year. Per Chapter 7[84], the marginal CPP activity is expected to be Community Climate Investments (CCIs) until 2035. However, the limit on the number of CCIs used for compliance will be reached in 2036. At this point in time the marginal cost of emissions reduction from the incremental renewable supply resource in a given year becomes the cost that can be avoided with additional EE savings. It is noticeable in Figure 4.3 that the avoided GHG compliance costs are decreasing over time after 2036, in alignment with the trend in renewable resource costs as described in Chapter 6. It is also worth noting that space heating has the greatest impact on peak loads, so the distribution infrastructure costs avoided are largest for space heating relative to the other end uses.

[82]See Appendix C for the same graph for each end use and also for Washington State.
[83] See Chapter 6 for a more detailed discussion regarding the Mist storage recall.
[84] Marginal resources from Scenario 1 are used to determine avoided costs.

Figure 4.3: Example Avoided Cost Breakdown Through Time – Oregon Residential Space Heating

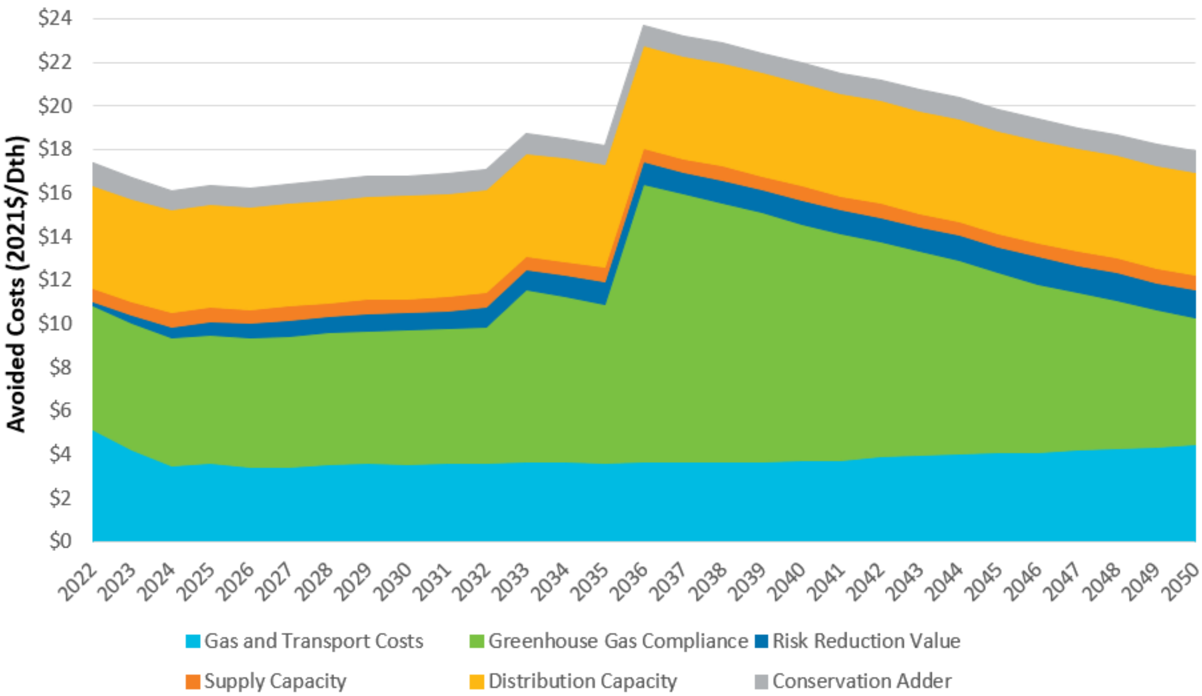


Figure 4.4 (Oregon),

Figure 4.5 (Washington) and Table 4.4 summarize the component breakdown of avoided costs by end use and by state. The values are presented in levelized terms to provide a more succinct summary of the results. Note that the first bar (far left) in Figure 4.4 is a levelized representation of the time path shown in Figure 4.3.

Figure 4.4: Oregon 30-year Levelized Avoided Costs by End Use

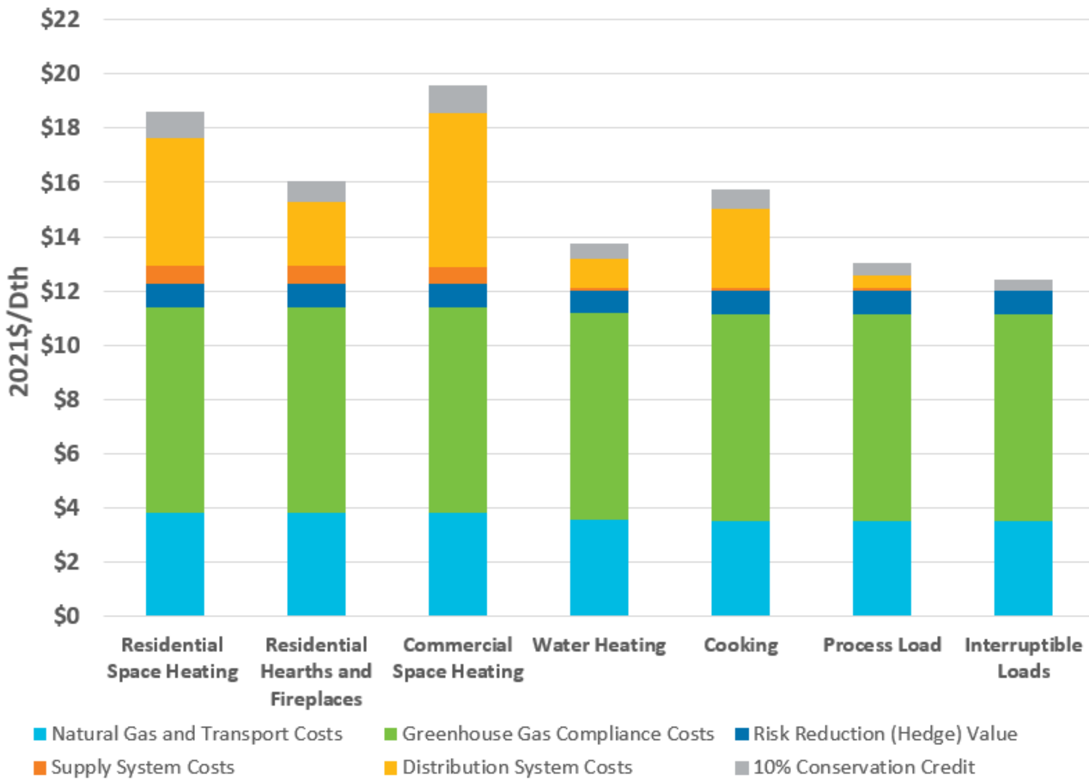


Figure 4.5: Washington 30-year Levelized Avoided Costs by End Use

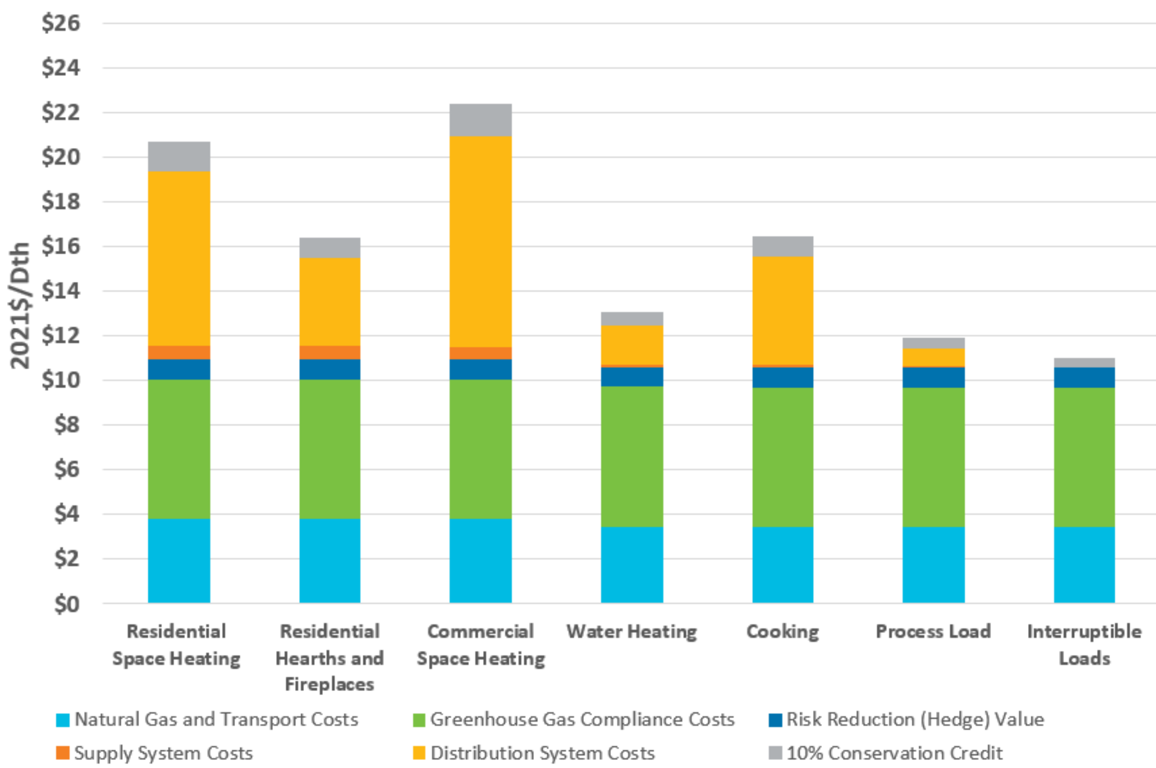


Table 4.4: Energy Efficiency Avoided Cost Summary Results by End Use and State (2021$/Dth)

		Commodity Costs			Capacity Costs		10% Conservation Credit	**Total Avoided Costs**
		Natural Gas Commodity and Transport	Greenhouse Gas Compliance Costs	Risk Reduction (Hedge) Value	Supply Capacity Costs Avoided	Distribution System Resources		
Oregon	Residential Space Heating	$3.83			$0.64	$4.72	$0.92	**$18.58**
	Residential Hearths and Fireplaces	$3.83			$0.64	$2.37	$0.68	**$16.00**
	Commercial Space Heating	$3.83			$0.57	$5.69	$1.01	**$19.57**
	Water Heating	$3.58	$7.61	$0.86	$0.11	$1.07	$0.48	**$13.70**
	Cooking	$3.55			$0.12	$2.92	$0.66	**$15.72**
	Process Load	$3.55			$0.09	$0.47	$0.41	**$12.99**
	Interruptible Loads	$3.55			X	X	$0.36	**$12.38**
Washington	Residential Space Heating	$3.83			$0.64	$7.81	$1.23	**$20.64**
	Residential Hearths and Fireplaces	$3.83			$0.64	$3.93	$0.84	**$16.37**
	Commercial Space Heating	$3.83			$0.57	$9.42	$1.38	**$22.33**
	Water Heating	$3.50	$6.26	$0.86	$0.11	$1.77	$0.55	**$13.04**
	Cooking	$3.47			$0.12	$4.84	$0.85	**$16.40**
	Process Load	$3.47			$0.09	$0.78	$0.44	**$11.90**
	Interruptible Loads	$3.47			X	X	$0.36	**$10.95**

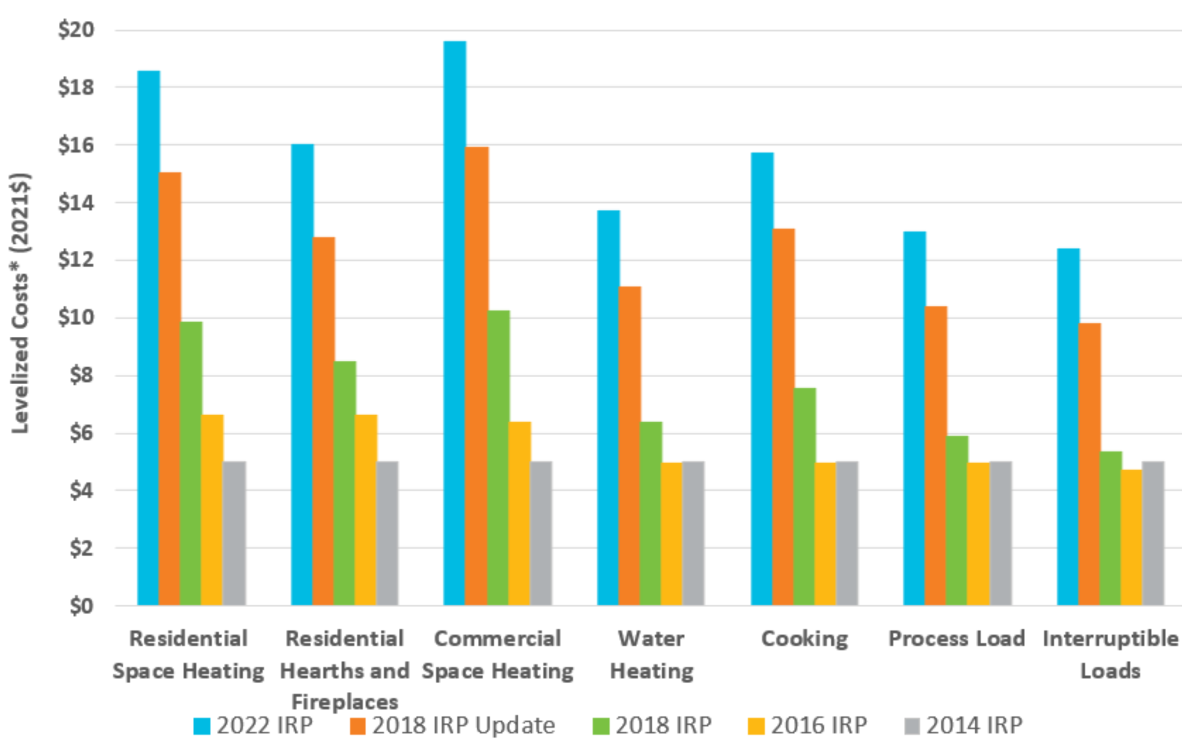
Table 4.4 shows that Washington avoided costs are slightly higher than Oregon avoided costs for space heating and cooking, due to the differences in distribution capacity costs across the states. Relative to

Oregon, Washington avoided costs are more than 11% higher for residential space heating, 14% higher for commercial space heating, and 4% higher for cooking. However, Washington avoided costs for other end uses appear to be slightly lower than their Oregon counterparts because the difference in GHG compliance costs outweighs the differences in distribution capacity costs across the states.

4.3.3 Avoided Costs Results Across IRPs

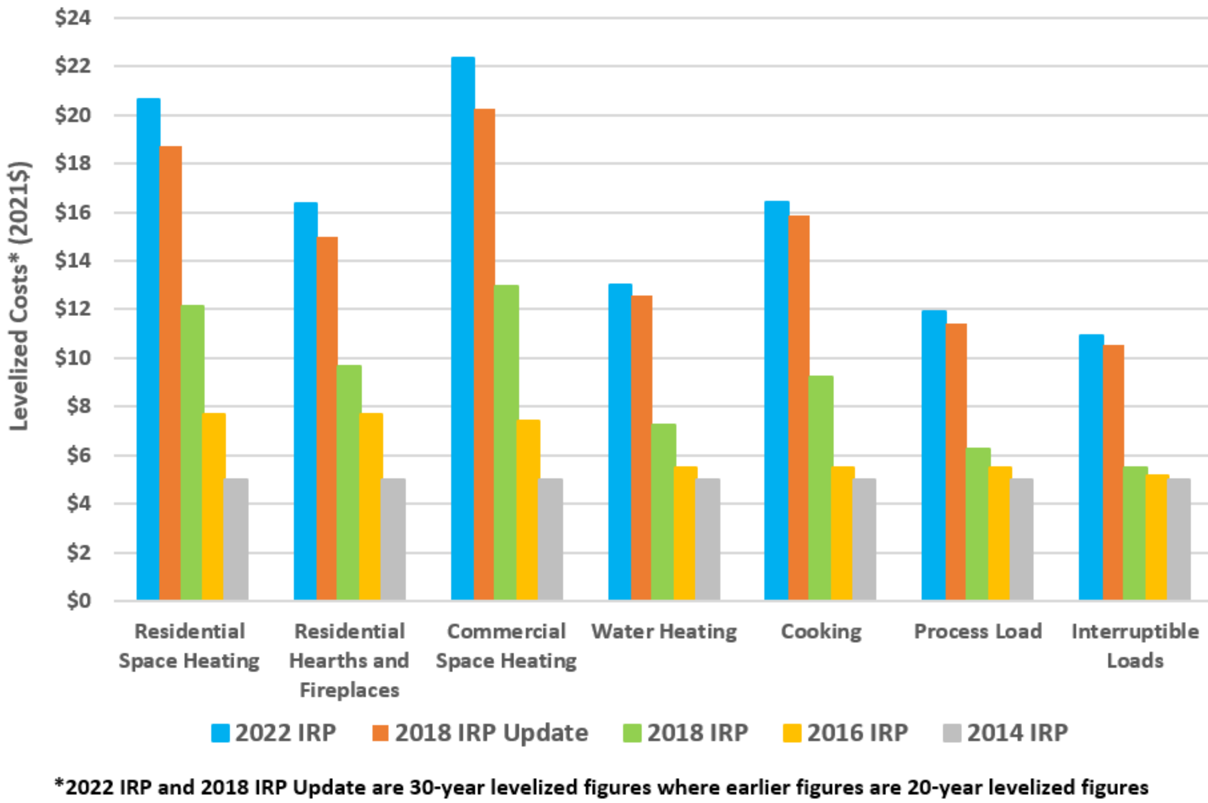
Figure 4.6 and Figure 4.7 show avoided costs for Oregon and Washington, respectively, by end use evaluated in the 2022 IRP, the avoided costs from the 2018 and 2016 IRPs, and those filed in the 2014 IRP (which were constant across end uses). Improvements to NW Natural's methodology for calculating peak savings from DSM are visible in the marked increase in estimated avoided costs for space heating measures.

Figure 4.6: Levelized Avoided Costs: 2022, 2018, 2016, and 2014 IRPs – Oregon



*2022 IRP and 2018 IRP Update are 30-year levelized figures where earlier figures are 20-year levelized figures

Figure 4.7: Levelized Avoided Costs: 2022, 2018, 2016, and 2014 IRPs – Washington

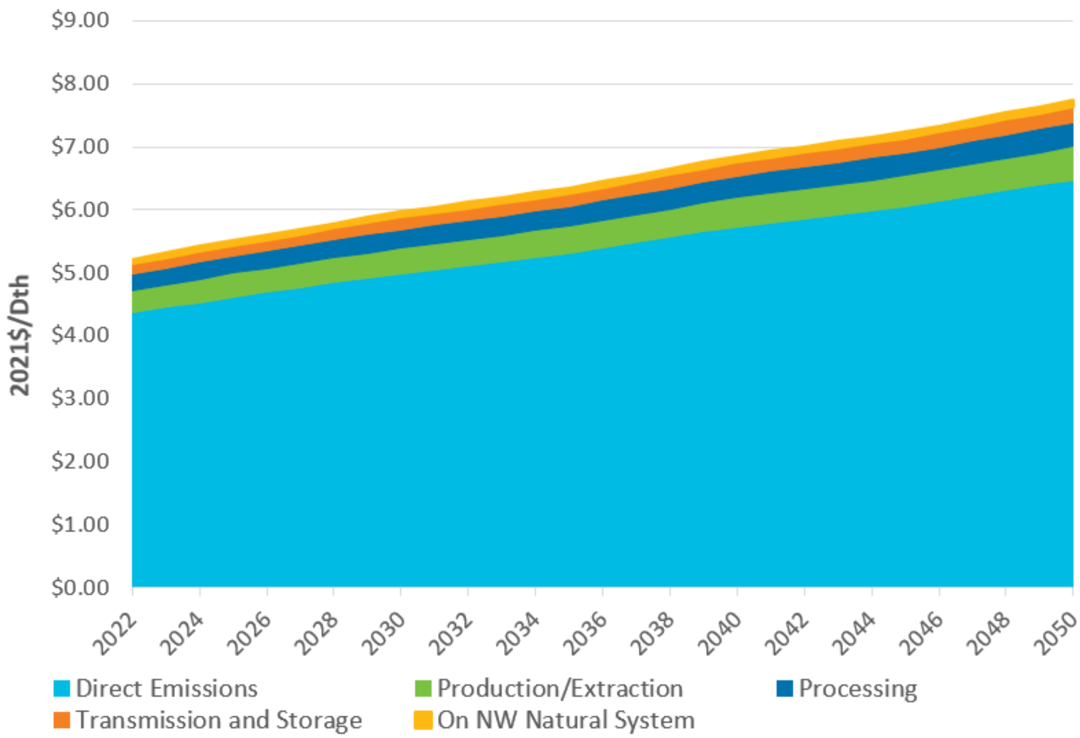


4.3.4 Avoided Costs for Carbon Emissions Reductions

As is discussed in Chapter 2, full compliance with the federal and state climate and environmental policies and regulations is a key requirement for this IRP. Potential GHG emissions compliance costs are consequently an important component of avoided costs.

Figure 4.8 shows how avoided costs for emissions reduction across the life cycle of natural gas change over the planning horizon 2022-2050. Note that the avoided costs for GHG emissions reduction come mostly from direct emissions (i.e., combustion of natural gas), accounting for 84 percent of the total. The GHG costs avoided from production/extraction, processing, transportation, and storage, and on NW Natural system are seven, five, three, and one percent in the total, respectively.

Figure 4.8: Avoided Costs by Life Cycle of Natural Gas and Year



4.4 Supply-side Applications of Avoided Costs

Non-conventional supply-side resources can also avoid costs associated with conventional resources. There are two primary examples where this can occur: 1) natural gas supply resources with lower carbon intensities, and 2) natural gas supply resources that are injected directly onto NW Natural's pipeline network ("on-system gas supply"). It is important to note that lower carbon on-system supply resources avoid both GHG compliance costs and the infrastructure costs associated with off-system gas supply.

4.4.1 Avoided Costs of Low Carbon Gas Supply

Natural gas supply alternatives that have a carbon intensity lower than conventional natural gas avoid expected GHG compliance costs, and the costs avoided depend upon the carbon intensity of the resource. For example, if a source of renewable natural gas has a carbon intensity of zero, it would avoid all the expected GHG compliance costs associated with conventional natural gas. The specific avoided cost items applied to these lower carbon gas supply resources are shown in

Table 4.5, which shows that GHG compliance costs avoided are applied to all low carbon gas resources. The primary application of avoided costs is in the Low Carbon Gas Evaluation Methodology, which is detailed in the appendix.

Table 4.5: Costs Avoided by Low Carbon Resource Type

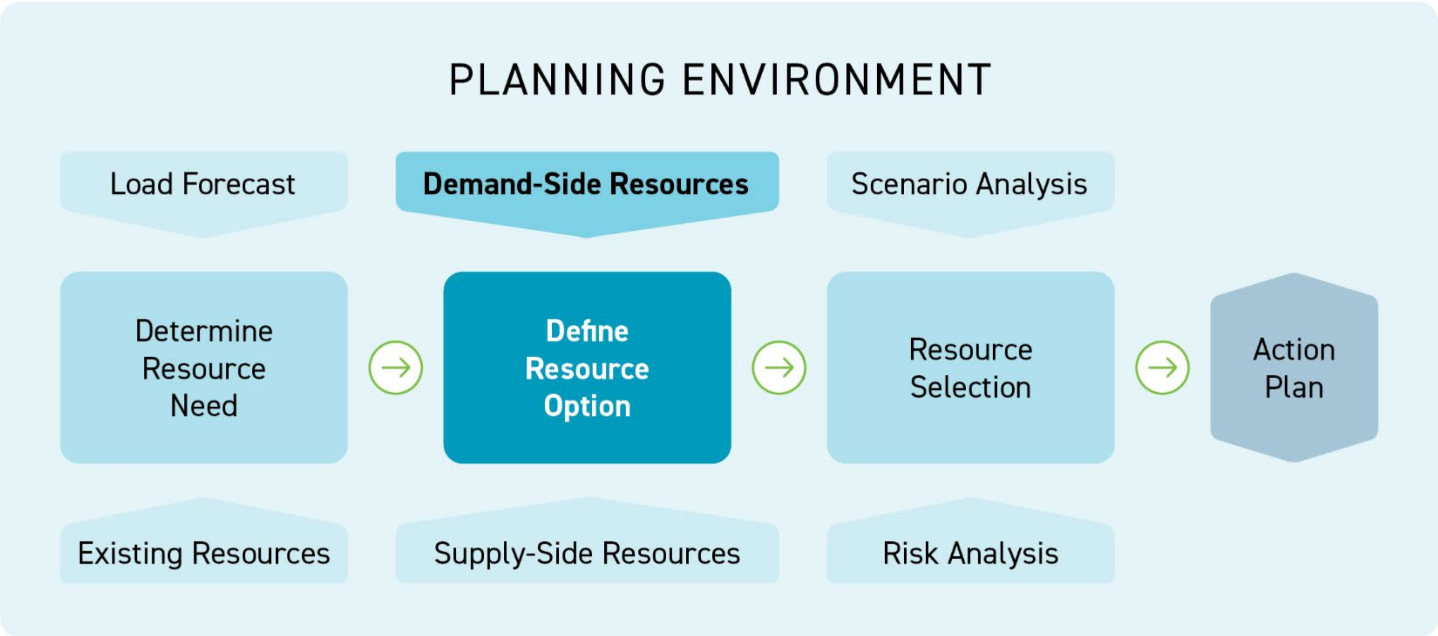
Costs Avoided by Resource Type	Conventional Gas Purchase and Transport Costs	Greenhouse Gas Compliance Costs	Gas Supply Capacity Costs- On-System Dispatch	Gas Supply displacement from bundled product	Distribution Capacity Costs
On-System Bundled RNG Purchase	X	X	X		X
RNG with Delivery to NW Natural- Bundled	X	X	X	X	
RNG with Sale of Brown Gas- Bundled - Choose Sales Hub	X	X			
Unbundled Environmental Attribute Purchase		X			

4.4.2 Avoided Costs of On-System Gas Supply

As described above, on-system natural gas supply avoids the incremental costs associated with serving peak load based upon how much gas is supplied directly onto NW Natural's system during a peak hour and day. The amount of gas supplied during peak times is resource-specific and the more on-system resources can supply gas directly onto NW Natural's system during peak times, the more value the resource provides to NW Natural's system and customers via delayed or avoided infrastructure investments. Like with demand-side resources, avoided supply capacity infrastructure costs from on-system gas supply are determined by multiplying the cost to bring an additional unit of peak day load onto NW Natural's system by the amount of gas the resource is expected to supply on a peak day. Similarly, avoided distribution system enhancement costs are calculated by multiplying the costs to serve an additional unit of peak hour load on NW Natural's distribution system by the amount of gas the resource is expected to supply on a peak hour.

Once resource needs are established it is important to take a wide scope to assess what options are available to meet those needs. Chapter 5 evaluates and forecasts resources that can be deployed to reduce customer energy use throughout the year (energy efficiency) and during the coldest days we experience (demand response).

5 | Demand-Side Resources



5.1 Energy Trust of Oregon

The following section provides was drafted by the Energy Trust of Oregon. Energy Trust is the administrator for NW Natural energy efficiency programs (EE) and completes the cost-effectiveness evaluation of the majority of the EE programs available to NW Natural's customers. Content provided by the Energy Trust territory is shown in maroon text, where the following section is specific to NW Natural's customers in Oregon.[85]

In 2002, as part of an agreement that allowed NW Natural to implement a decoupling mechanism, the Public Utility Commission of Oregon directed the Company to collect a public purpose charge for the funding of its residential and commercial energy efficiency programs and low-income programs, and to transfer the responsibility of energy efficiency programs to a third party.[86]

NW Natural chose Energy Trust as its program administrator. Energy Trust is a non-profit organization that was established as a result of electric direct access legislation adopted in 2002 to administer the Oregon-based, investor-owned electric utilities' energy efficiency programs. Energy Trust began managing NW Natural's residential and commercial program in 2003. The programs are outlined in the Company's Tariff Schedule 350 and funded through the public purpose charge, Schedule 301.

After NW Natural's 2008 IRP[87] identified that cost-effective industrial savings were available, the Company worked with Energy Trust to launch an Industrial demand-side management (DSM) program in Oregon. This program is available to large Firm and Interruptible Sales customers, but not transportation customers. Costs for the program, described in Schedule 360 of the Company's tariff, are deferred for recovery a year later through the charge published annually in Schedule 188.

With the exception of the first few years of the residential and commercial programs in Oregon when gas customers were just learning about the availability of incentives for energy efficient equipment, Energy Trust has been meeting and even exceeding the annual savings targets derived through the biannual IRP analysis of the available, cost-effective DSM potential.

Since October 1, 2009, NW Natural has provided energy efficiency programs to its Washington Residential and Commercial customers in compliance with the direction provided by the WUTC in the Company's 2008 rate case.[88] The programs were developed and continue to evolve under the oversight of the Energy Efficiency Advisory Group (EEAG), which is comprised of interested parties to the Company's 2008 rate case. Energy Trust administers the programs, leveraging the offerings available in Oregon to customers located in Washington.[89]

[85] Energy Trust administers NW Natural's energy efficiency programs in both Oregon and Washington. The methodology and results in this chapter are provided by Energy Trust and are Oregon specific. NW Natural's Washington energy efficiency forecast was performed by a different entity and the results of which are described in a separate section.

[86] See Order No. 02-634 in Docket No. UG 143.

[87] See Docket No. LC 45.

[88] See Order No. 4 in Docket UG-080546.

[89] The program's parameters are provided in the Company's Schedule G and its Energy Efficiency Plan, which by reference is part of the Tariff. The program is funded through a charge collected in accordance with Schedule 215.

5.1.1 Energy Trust Forecast Overview and High-Level Results for Oregon

Energy Trust developed a 20-year DSM resource forecast for NW Natural territory in Oregon using Energy Trust's DSM resource assessment modeling tool (hereinafter 'RA Model') to identify the total 20-year cost effective modeled savings potential. Energy Trust then deploys this cost-effective potential exogenously to the RA model into an annual savings projection based on past program experience, knowledge of current and developing markets, and future codes and standards. This final 20-year savings projection is provided to NW Natural for inclusion in the Company's forecasts. The 2022 IRP results show that NW Natural can save 41.2 million therms[90] in Oregon in the next five years from 2022 to 2026 and over 147.1 million therms by 2041.[91] These results represent a 37% and 6% increase respectively in cost-effective DSM potential over the prior IRP in 2018. The two main drivers of this increased potential are:

1) *Increased budgets and program forecast:* NW Natural and Energy Trust coordinated on assumptions associated with accelerating the energy efficiency forecast to reflect increased annual program budgets in the first five years of the IRP.
2) *Measure additions and updates:* Energy Trust added several new emerging technologies to the model and updated measure level assumption for several of the existing measures

Figure 5.1 depicts the full suite of savings potential identified both in the model (Technical, Achievable, Cost-effective achievable) as well as the amount included in the final savings projection by Sector.

[90] The savings discussed in this chapter and appendices, depicted in all tables and the following figures showing savings projections are in gross savings for Oregon unless otherwise explicitly noted. Energy Trust publicly reports its Oregon savings and goals in gross savings as determined in consultation with OPUC and stakeholders in 2019. Energy Trust public reports prior to 2020 included net savings which are adjusted for market effects including free ridership and spillover. Prior Energy Trust DSM chapters for NWN IRP were in gross savings. Gross savings are not adjusted for market effects and most accurately reflect the reductions NW Natural will see on their system.

[91] Includes over 6.6 million therms of market transformation savings resulting from code changes driven by Energy Trust's New Buildings Program. Also includes 4.5 million therms from a large project adder incorporated into the savings forecast; more details on this adder are included later in this chapter.

Figure 5.1: 20-year Savings Potential by Sector and Potential Type - Oregon

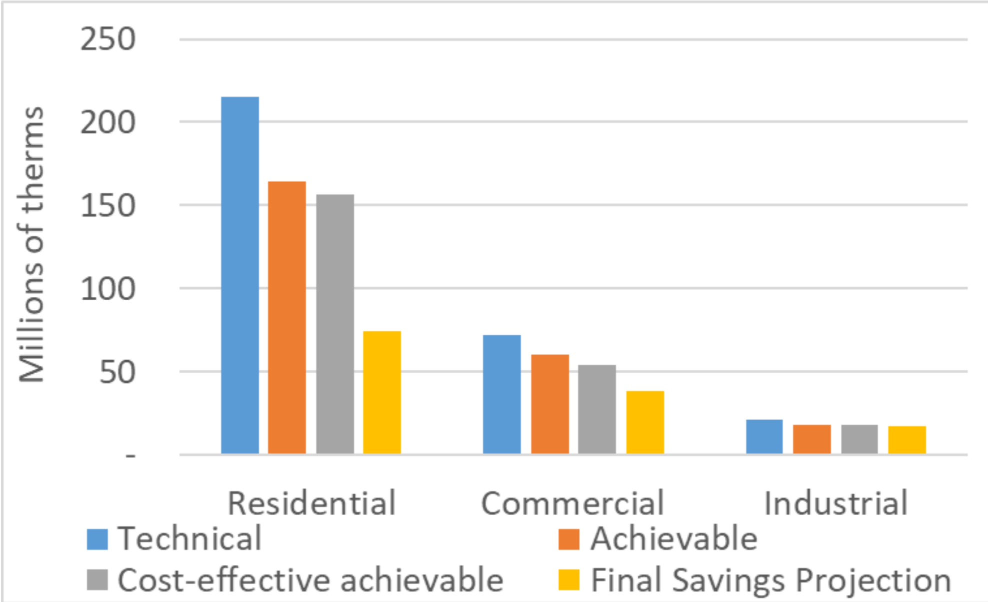
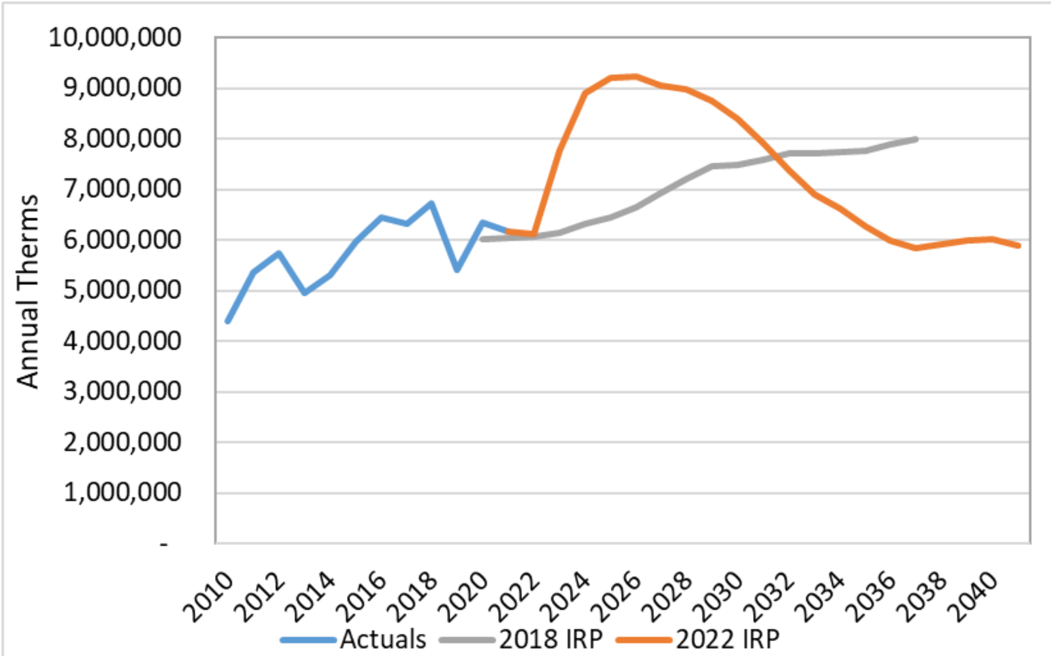


Figure 5.2 links actual historical savings going back to 2010 to the new savings projection for the 2022 IRP. It also compares the 2022 IRP forecast to the 2018 IRP forecast.

Figure 5.2: Annual Savings Projection Comparison for 2018 and 2022 IRPs, with Actual savings since 2010 - Oregon



5.1.2 Energy Trust Resource Assessment Economic Modeling Tool

Energy Trust owns, operates, and maintains a RA Model to perform the complex calculation process to create DSM forecasts for each of the utilities it serves, including NW Natural. The tool estimates the total technical, achievable, and cost-effective achievable potential for acquiring DSM resources in NW Natural's service territory across residential, commercial, and industrial sectors. The model primarily takes a bottom-up approach that begins with estimating available measure level savings and related cost and market penetration assumptions. These measure level savings are scaled up to NW Natural's service territory based on a set of applicability assumptions for each measure adjusted based on NW Natural inputs, such as customer and load forecasts, among others. The product of all these factors results in the total 20-year DSM savings potential available that can be acquired by providing energy efficiency services to NW Natural's customers.

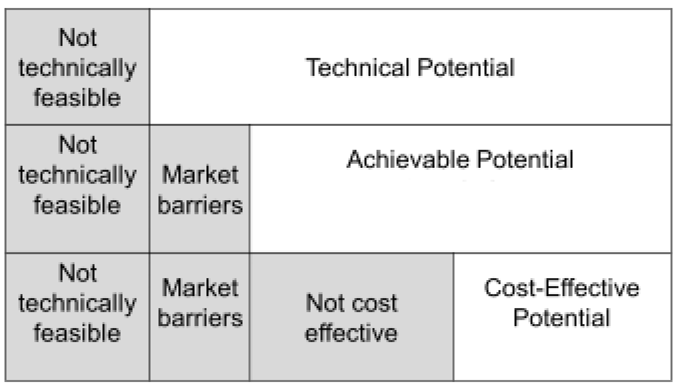
In the intervening years since NW Natural's 2018 IRP, Energy Trust has made several updates and improvements to the RA model. These enhancements contributed to the increase in energy efficiency potential identified in this DSM forecast:

- *Refreshed measure level assumptions* – Measure inputs for measures spanning residential, commercial, and industrial program sectors were reviewed and updated using a combination of Energy Trust primary data review and analysis, regional secondary sources, and engineering analysis. The refreshed assumptions include baseline adjustments, savings and costs updates, as well as density assumptions pertaining to where measures can be installed and existing measure saturation rates.

- *Lost opportunity measures and unconstrained potential to replace failed equipment* – Lost opportunity measures are constrained in each year by the assumed failed equipment burnout rate as a percentage of total stock. Energy Trust has aligned how the RA model treats lost opportunity measures to be consistent with Northwest Power and Conservation Council (NWPCC) methodology, constraining replace on burnout turnover exogenously to the RA model and allowing lost opportunities to recycle throughout the forecast period.
- *Updated achievability assumptions to align with NWPCC methodology* – Energy Trust has updated achievability assumptions to be consistent with what was used in the most recent power plan. Historically achievability rates were assumed to be 85% for all measures. NWPCC has updated these rates for some measures based on market research. At a high level these changes result in greater achievability for market transformation and codes and standards, and lower achievability for shell measures.

Figure 5.3 shows a graphical representation of the three categories of savings potential identified by Energy Trust's RA Model. The following methodology section describes the inputs and methods to calculate each of these potential types in detail.

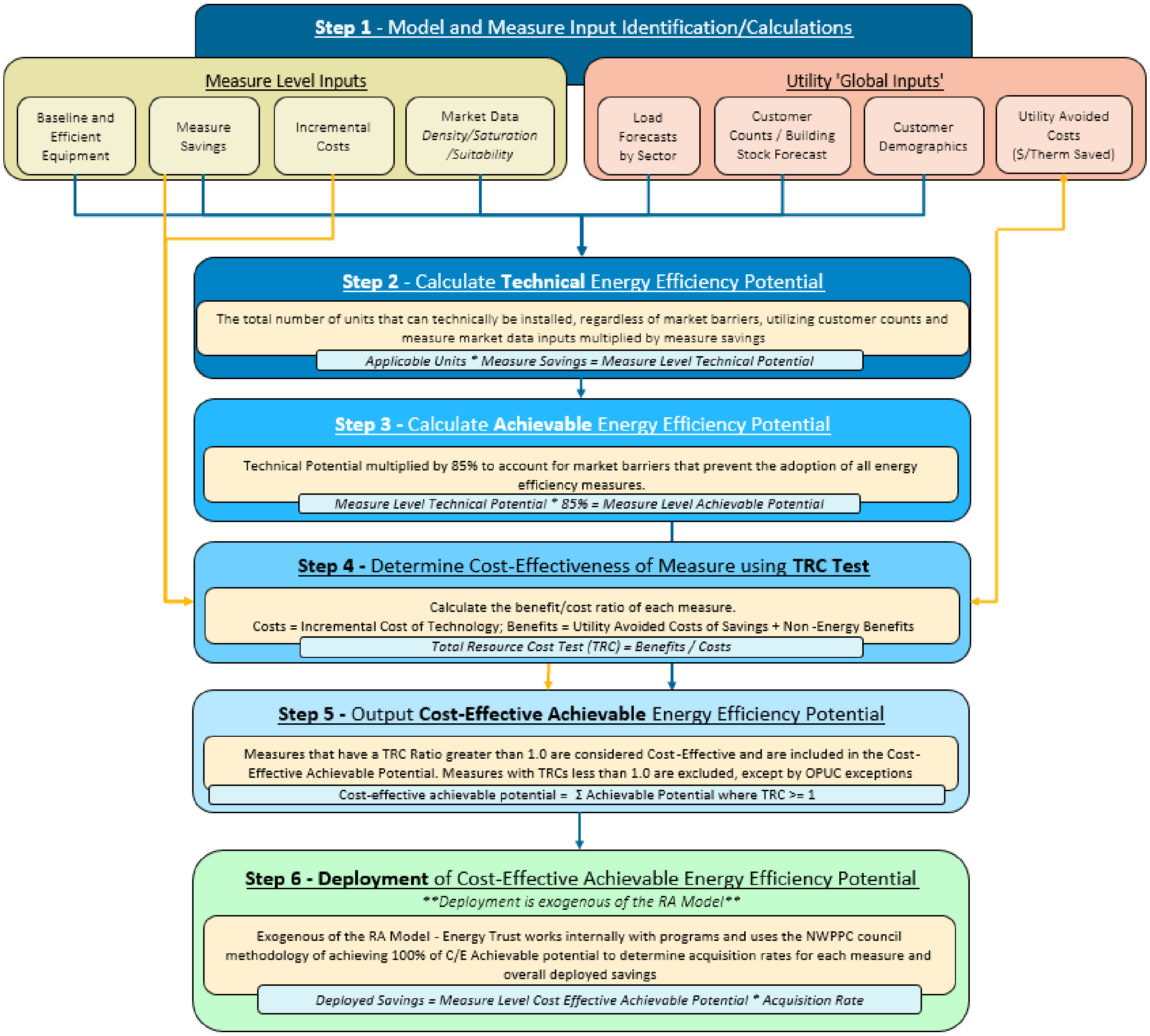
Figure 5.3: Three categories of savings potential identified by RA Model



5.1.3 Methodology for Determining the Cost-Effective DSM Potential

Energy Trust's DSM resource assessment follows six overarching steps from initial calculations to deployed savings, as shown in Figure 5.4. Steps 1 through 5 (Measure Identification/Input Development to Cost Effective Achievable Output) are calculated within Energy Trust's RA Model. This results in the total cost-effective potential that is achievable over the forecast horizon. The actual deployment of these savings (the acquisition percentage of the total potential each year – Step 6 of Figure 5.4 is done exogenously of the RA model and is explained in further detail in the next section. The remainder of this section provides further detail on steps 1 – 5 of the overall methodology shown in Figure 5.4.

Figure 5.4: Energy Trust's 20-Year DSM Forecast Determination Methodology



Step 1: Model and Measure Input Identification/Calculations

The first step of the modeling process is to identify and characterize the list of measures to include in the model, as well as receive and format utility 'global' inputs for use in the model. Energy Trust compiles and loads a list of all commercially available and emerging technology measures for residential, commercial, industrial and agricultural applications installed in new or existing structures. The list of measures is meant to reflect the full suite of measures offered by Energy Trust, plus a spectrum of emerging technologies.[92] Simultaneous to this effort, Energy

[92] An emerging technology is defined as technology that is not yet commercially available but is in some stage of development with a reasonable chance of becoming commercially available within a 20-year timeframe. The model is capable of quantifying costs, potential, and risks associated with uncertain, but high-saving emerging technology measures. The savings from emerging technology measures are reduced by a risk-adjustment factor based on what stage of development the technology is in. The concept is that the incremental risk-adjusted savings from emerging technology measures will result in a

Trust collects necessary data from the utility to run the model and scale the measure level savings to a given service territory (known as 'global inputs').

- ***Measure Level Inputs:***
  Once the measures to include in the model have been identified, they must be characterized in order to determine their savings potential and cost-effectiveness. The characterization inputs are determined through a combination of Energy Trust primary data analysis, regional secondary sources[93], and engineering analysis. There are over 30 measure level inputs that feed into the model, but on a high level, the inputs are put into the following categories:
  1. *Measure Definition and Equipment Identification*: This is the definition of the efficient equipment and the baseline equipment it is replacing (e.g., a 70+% EF gas storage water heater replacing an 60% EF baseline gas water heater).
  2. *Measure Savings:* the therms savings associated with an efficient measure calculated by comparing the baseline and efficient measure consumptions.
  3. *Incremental Costs:* The incremental cost of an efficient measure over the baseline. The definition of incremental cost depends upon the replacement type of the measure. If a measure is a Retrofit measure, the incremental cost of a measure is the full cost of the equipment and installation. If the measure is a Replace on Burnout or New Construction measure, the incremental cost of the measure is the difference between the cost of the efficient measure and the cost of the baseline measure.
  4. *Market Data:* Market data of a measure includes the density, saturation, and suitability of a measure. A density is the number of measure units that can be installed per scaling basis (e.g., the average number of showers per home for showerhead measures). The saturation is the average saturation of the density that is already efficient (e.g., 50% of the showers already have a low flow showerhead). Suitability of a measure is a percentage input to represent the percent of the density that the efficient measure is actually suitable to be installed in. These data inputs are all generally derived from regional market data sources such as RBSA and CBSA.
- ***Utility Global Inputs:***
  The RA Model requires several utility-level inputs to create the DSM forecast. These inputs include:
  1. *Customer and Load Forecasts:* These inputs are essential to scale the measure level savings to a utility service territory. For example, residential measures are characterized on a scaling basis 'per home', so the measure densities are calculated as the number of measures per home. The model then takes the number of homes that NW Natural serves currently and the forecasted number of homes to scale the measure level potential to their entire service territory.

reasonable amount of savings over standard measures for those few technologies that eventually come to market without having to try and pick winners and losers.

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

2. *Customer Stock Demographics:* These data points are utility specific and identify the percentage of stock that utilize different heating fuels for both space heating and water heating. The RA Model uses these inputs to segment the total stocks to the stocks that are applicable to a measure (e.g., gas storage water heaters are only applicable to customers that have gas water heat).
3. *Utility Avoided Costs:* Avoided costs are the net present value of avoided commodity and commodity-related costs as well as avoided supply-side and demand-side resource costs associated with energy efficiency savings represented as $s per therm saved. Please see Chapter 4 for more detail. Avoided costs are the primary 'benefit' of energy efficiency in the cost effectiveness screen.

Step 2: Calculate Technical Energy Efficiency Potential

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

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

The measure level technical potential is then summed up to show the total technical potential across all sectors. This savings potential does not take into account the various market barriers that will limit a 100 percent adoption rate.

Step 3: Calculate Achievable Energy Efficiency Potential

Achievable potential is simply a reduction to the technical potential based on each measure's achievability assumption rate, to account for market barriers that prevent total adoption of all cost-effective measures. Historically the achievable potential was defined as 85 percent of the technical potential. The Northwest Power and Conservation Council (NWPCC) updated the achievability assumption for certain measures in the most recent power plan, and Energy Trust has aligned the RA model with these assumptions. Many measures still have 85 percent achievability while market transformation and codes and standards are assumed to be closer to 100% achievable while shell measures are closer to 60% achievable.

Achievable Potential =	*Technical Potential * achievability%*

Step 4: Determine Cost Effectiveness of Measure using TRC Test

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

TRC = Present Value of Benefits / Present Value of Costs

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

a) Avoided Costs: The present value of natural gas energy saved over the life of the measure, as determined by the total therms saved multiplied by NW Natural's avoided cost per therm.[94] The net present-value of these benefits is calculated based on the measure's expected lifespan using the Company's discount rate.[95]
b) Non-energy benefits are also included when present and quantifiable by a reasonable and practical method (ex. Water savings from low-flow showerheads, Operations and Maintenance (O&M) cost reductions from advanced controls).

Where the *Present Value of Costs* includes:

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

[94] See Chapter 4 for a discussion of NW Natural's avoided cost.

[95] NW Natural's real after-tax annual discount rates used in the 2018 IRP are 3.83 percent for Oregon. As discussed in Chapter Four, DSM energy savings forecasts need to be completed prior to NW Natural's resource optimization analysis. Therefore, NW Natural provided the 3.83 percent discount rate to ETO in 2021 and updated the discount rate to 3.4 percent in May 2022 and used it in resource optimization to reflect the influence of the recent dynamic economic environment. It is worth noting that the cost of a DSM measure occurs typically in the year of installation while the stream of its benefits lasts over its entire useful life. Therefore, a higher discount rate results in a lower present value for the benefits and so forth a lower cost effectiveness test value. That is, compared to the more recent discount rate of 3.4 percent, the use of a 3.83 percent discount rate could lead to a more conservative DSM savings forecast.

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

Step 5: Quantify the Output of Cost-Effective Achievable Energy Efficiency Potential

The RA Model's final output of potential is the quantified cost-effective achievable potential. If a measure passes the TRC test described above, then *achievable savings* from a measure is included in this potential. If the measure does not pass the TRC test above, the measure is not included in cost-effective achievable potential. However, the cost-effectiveness screen is overridden for some measures under two specific conditions: 1) The OPUC has granted an exception to offer non-cost-effective measures under strict conditions or 2) the measure is cost-effective when using blended gas avoided costs[96] and is therefore offered by Energy Trust programs.

Step 6: Deployment of Cost-Effective Achievable Energy Efficiency Potential

After determining the cumulative 20-year[97] cost-effective achievable modeled potential, Energy Trust develops a savings projection based on past program experience, knowledge of current and developing markets, and future codes and standards. The savings projection is a 20-year forecast of energy savings that will result in a reduction of load on NW Natural's system. Energy Trust ramp rates are based on Northwest Power and Conservation Council method and ramp rates, but calibrated to be specific to Energy Trust. Retrofit measure potential continues until 100% of the cost-effective achievable potential is acquired and saving potential is exhausted. Lost opportunity measures continue to ramp up to 100% of annual available cost-effective achievable potential at which point all savings are realized annually. Hard to reach measures or emerging technologies do not ramp to 100%. This savings forecast includes savings from program activity for existing measures and emerging technologies, expected savings from market transformation efforts that drive improvements in codes and standards, and a forecast of what Energy Trust is describing as a 'large project adder', savings that account for large unidentified projects that consistently appear in Energy Trust's historical savings record and have been a source of overachievement against IRP targets in prior years. The evolution from modeled technical potential to savings projections is depicted in Figure 5.5.

[96] Energy Trust uses blended avoided costs for measure development and cost-effectiveness screening to provide uniform gas offerings throughout Oregon. Utility specific avoided costs are used in RA modeling to align inputs with utility IRPs.
[97] Energy Trust provided NW Natural with a final savings projection extended to 2050. These results are discussed in section 5.1.6.

Figure 5.5: The Progression to Program Savings Projections

Not Technically Feasible	Technical Potential			
Not Technically Feasible	Market Barriers	Achievable Potential		
Not Technically Feasible	Market Barriers	Not Cost Effective	Cost Effective Potential	
Not Technically Feasible	Market Barriers	Not Cost Effective	Program Design, Market Penetration	Final Savings Projection

5.1.4 RA Model Results and Outputs

The RA Model outputs results by potential type, as well as several other useful outputs, including a supply curve based on the levelized cost of energy efficiency measures. This section discusses the overall model results by potential type and provides an overview of the supply curve.

Forecasted Savings Potential by Type

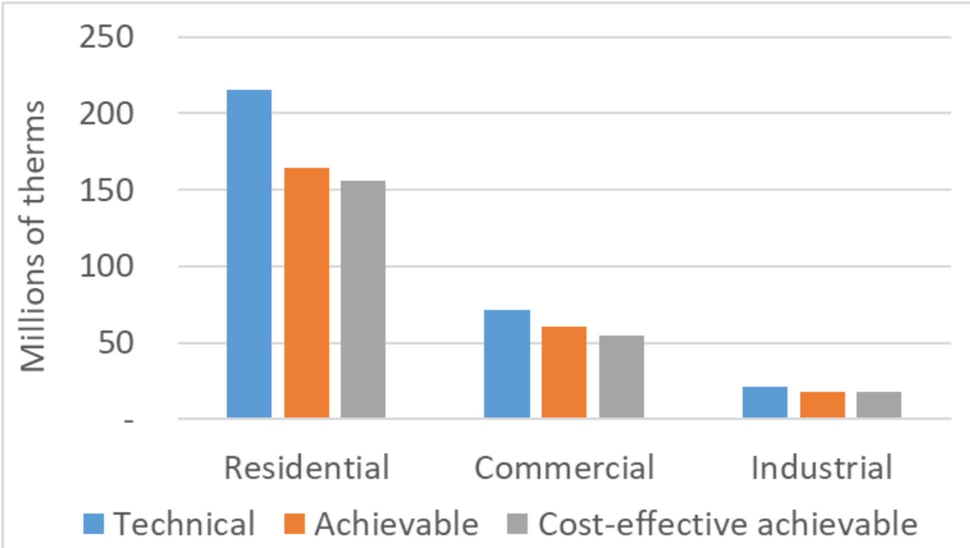
Table 5.1 summarizes the technical, achievable, and cost-effective potential for NW Natural's system in Oregon by market sector. These savings represent the total 20-year cumulative savings potential identified in the RA Model by the three types identified in Figure 5.3. Modeled savings represent the full spectrum of potential identified in Energy Trust's resource assessment model through time, prior to deployment of these savings into the final annual savings projection.

Table 5.1: Summary of Cumulative Modeled Savings Potential - 2022–2041 - Oregon

Sector	Technical Potential (Therms)	Achievable Potential (Therms)	Cost-effective achievable Potential (Therms)
Residential	215,276,957	164,364,887	156,369,194
Commercial	71,737,121	60,455,169	54,208,488
Industrial	21,290,701	18,097,096	18,097,096
Total	**308,304,779**	**242,917,152**	**228,674,778**

Figure 5.6 shows cumulative forecasted savings potential across the three sectors Energy Trust serves, as well as the type of potential identified in NW Natural's Oregon service territory.

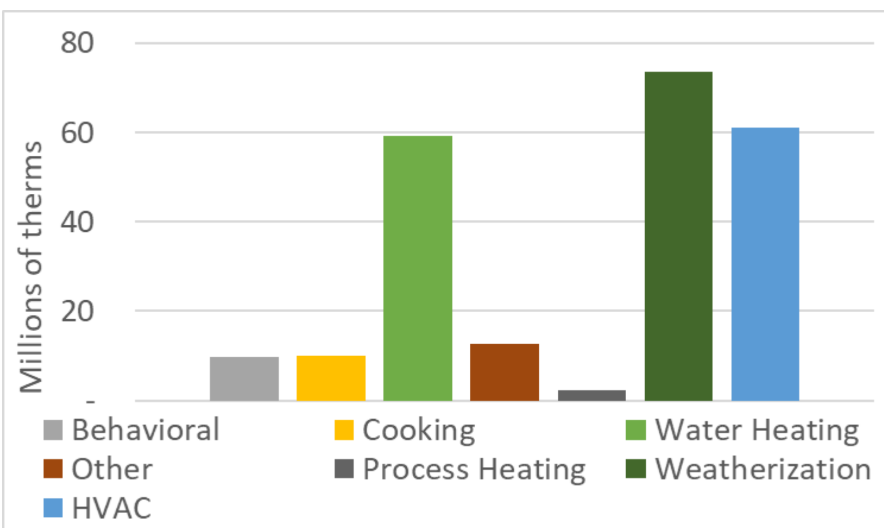
Figure 5.6: Summary of Cumulative Modeled Savings Potential - 2022–2041 - by Sector and type of Potential - Oregon



These results show that for the Residential and Commercial Sectors, approximately 73 and 76 percent of the technical potential identified in the model is found to be cost effective, with the majority of the DSM potential coming from the residential sector. For the Industrial Sector, 85 percent of the achievable potential identified is found to be cost effective.

Figure 5.7 provides a breakdown of NW Natural's 20-year cost-effective DSM savings potential by end use in Oregon.

Figure 5.7: 20-year Cumulative Cost-Effective Potential by End Use - Oregon



The weatherization and HVAC end uses top the list and represent all measures that save space heat. Water heating includes water heating equipment from all sectors. Behavioral consists primarily of potential from Energy Trust's commercial strategic energy management measure, a service where Energy Trust energy experts provide training to facilities teams and staff to develop the skills to identify operations and maintenance changes that make a difference in a building's energy use. The other category consists primarily of a commercial new construction design measure that is 10 percent better than code. Figure 5.18 shows the amount of emerging technology savings within each category of DSM potential, highlighting the contributions of commercially available and emerging technology DSM in Oregon. This graph shows that while over 66 million therms of the DSM technical potential consists of emerging technology, once the cost-effectiveness screen is applied, over 42 million, or 64 percent of that potential remains. For commercially available measures, of the 241 million therms of technical potential, over 185 million, or 77 percent of the potential remains. 19 percent of the total cost-effective potential identified in the model is from emerging technology measures including gas heat pump water heaters for both residential and commercial.

Figure 5.8: Cumulative 20-year potential by savings type, detailing the contributions of commercially available and emerging technology - Oregon

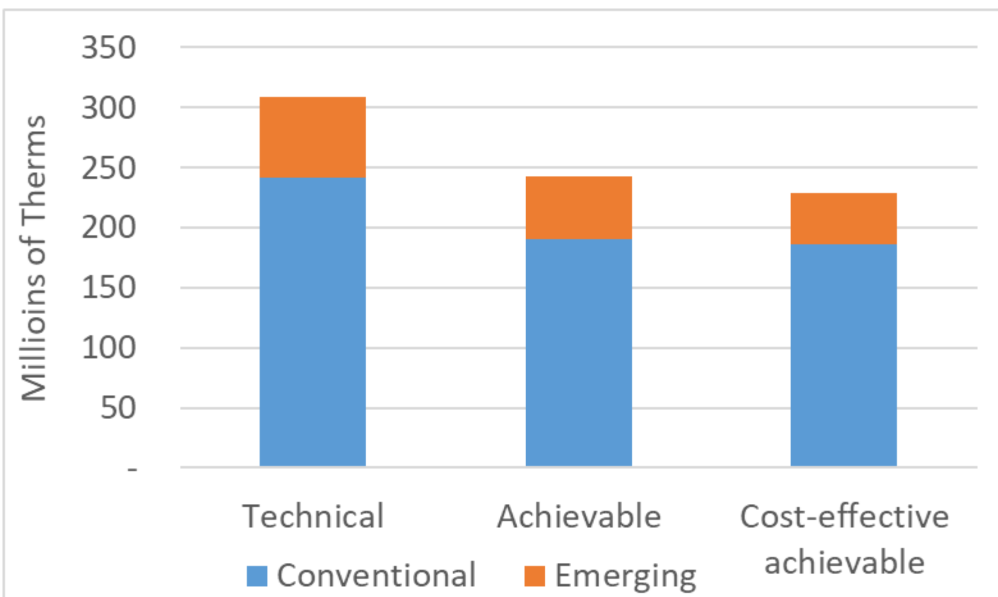


Table 5.2 shows the savings potential for Oregon in the resource assessment model that was added by employing the cost-effectiveness override option in the model. The cost-effectiveness override option forces non-cost-effective potential into the cost-effective potential results and is used when a measure meets one of the following two criteria.

1. The measure is not cost-effective but is offered through Energy Trust programs under an OPUC exception and is expected to be brought into cost-effective compliance in the near future.

2. The measure is cost-effective using Energy Trust's blended gas avoided costs and is currently offered through Energy Trust programs but is not cost-effective when modeled with NW Natural-specific avoided costs.

Table 5.2: Cumulative Cost-Effective Potential (2022-2041) due to use of Cost-effectiveness override (Millions of Therms) - Oregon

Sector	Yes CE Override	No CE Override	Difference
Residential	156.37	125.04	31.33
Commercial	54.21	47.19	7.01
Industrial	18.10	18.10	0
Total	**228.67**	**190.33**	**38.35**

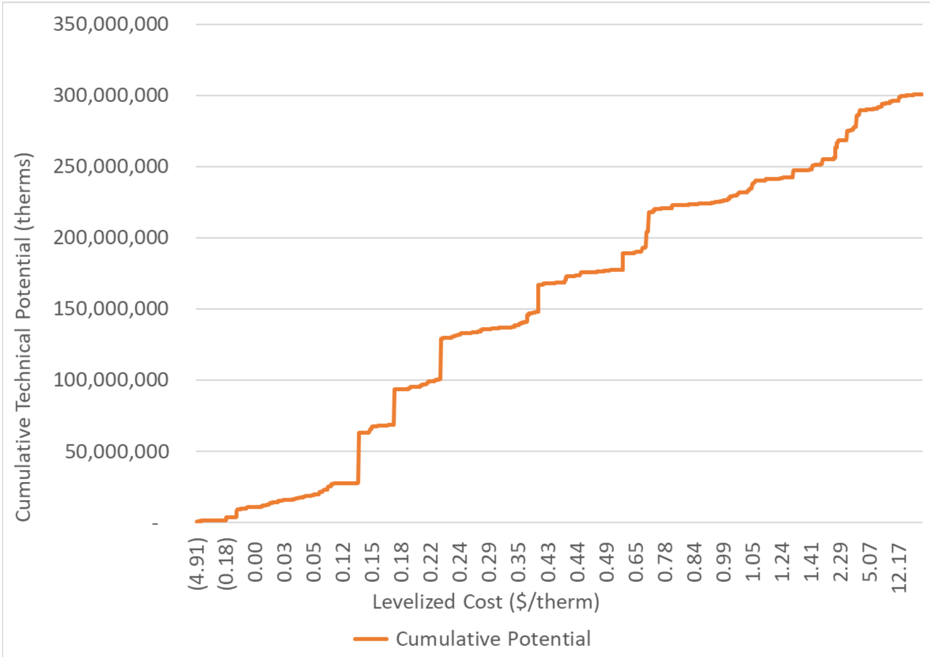
In this IRP, 17 percent of the cost-effective potential identified by the model is due to the use of the cost-effective override for measures with exceptions. The measures that had this option applied to them for measures under OPUC exception included manufactured home replacement, clothes washers, and attic, floor, and wall insulation. Measures overridden due to ETO's use of blended avoided costs are residential whole home new construction measures.

Supply Curve and Levelized Costs

An additional output of the RA Model is a resource supply curve developed from the levelized cost of energy of each measure that graphically depicts the total potential therms that could be saved at various costs for all measures.

The levelized cost for each measure is determined by calculating the present value of the total cost of the measure over its economic life, converted to equal annual payments, per therm of energy savings. The levelized cost calculation starts with the customer's incremental total resource cost (TRC) of a given measure. The total cost is amortized over an estimated measure lifetime using the NW Natural's Oregon discount rate of 3.83 percent. The annualized measure cost is then divided by the annual energy savings, in therms. Figure 5.9 shows the supply curve developed for this IRP that can be used for comparing demand-side and supply-side resources in Oregon.

Figure 5.9: 20-year Gas Supply Curve - Oregon



5.1.5 2022 Oregon Model Results Compared to 2018

Table 5.3 shows the total modeled potential for DSM in this IRP compared to the prior IRP in 2018. The increased potential is primarily found in the residential sector and is primarily driven by emerging technology, new measures that are being offered by programs, and changes in modeling assumptions. This modeled savings amount is mitigated by the amount of savings potential selected for deployment as shown in the final savings projection in Section 5.1.6. Only a portion of the cost-effective potential from lost opportunity measures, such as new construction and replacement of end-of-life equipment, is expected to be acquired given program budgets, incentive levels, and customer decision making preferences. Assumptions based on historical program performance are considered when generating the final annual savings projection. The final savings projection relies on program input and forecasts of what amount of the modeled cost-effective potential Energy Trust anticipates acquiring through programs, code improvements and market transformation.

Table 5.3: Total 2022 IRP Cost-Effective Modeled Potential compared to 2018 and IRP modeled potential by Sector - Oregon

	Total Cost-Effective Potential 2018 OR IRP (Millions of therms) 2018-2037	Total Cost-Effective Potential 2022 IRP (Millions of therms) 2022-2041
Residential	115.8	156.4
Commercial	62.8	54.2
Industrial	16.5	18.1
All DSM	195.1	228.7

Table 5.4 builds off Table 5.3 and details the key factors that drove the change in cost-effective potential for DSM in this IRP compared to the prior IRPs in 2018. The primary emerging technologies, Gas Heat Pump Water Heaters and Gas Fired Heat Pumps, are broken out separately in the table below and make up 13.56 MM therms of the total 23.02 MM therm savings from emerging technologies.

Table 5.4: Key Changes in Model that Increased Potential from 2018 IRP to 2022 IRP - Oregon

Change Component	**Change in DSM Savings (Millions of Therms) from 2018 to 2022 IRPs**	**% Of Total**
Emerging Technology[98]	23.02	69%
Gas Heat Pump Water Heater	*13.11*	
Gas Heat Pump	*0.45*	
New Measures	25.01	75%
Removed Measures	-25.08	-75%
CE override	29.98	89%
Change in Model Assumptions	-21.02	-63%
Total Change from 2018 to 2022 IRP	**33.56**	**95%**

[98] Emerging technology is made up of condensing gas rooftop units, gas absorption heat pump water heaters, gas fired heat pumps, industrial advanced wall insulation, and thin triple pane windows. Gas heat pump water heaters constitute 13.11 million therms of the emerging technology potential. Energy Trust applies a risk adjustment factor to emerging technologies based on market risk, technical risk and data risk ranging from 10% to 90%. Gas heat pump water heaters are assigned an adjustment of 70% to account for market uncertainty. Furthermore, while the total Cost-Effective potential is 13.11 million therms, the Energy Trust deployment process allows emerging technology measures to gradually enter the marketplace and gain market share over conventional measures. The final deployed savings projection for Gas fired heat pump water heaters is 2.5 million therms over the 20-year forecast period.

5.1.6 Oregon Final Savings Projection

The results of the final savings projection show that Energy Trust can save 41.2 million therms across NW Natural's system in Oregon in the next five years from 2022 to 2026 and over 147.1 million therms by 2041.

The final savings projection of 147.1 million therms by 2041 in NW Natural's service territory in Oregon, contains a reduction to the full cost-effective potential shown in

Table 5.5. This is due to additional market-related constraints on the ability to capture all market activity in a given year for measures meant to replace equipment that fails, and measures associated with the construction of new homes and buildings, otherwise known as 'lost opportunity' measures. These are measure opportunities that appear in a given year, but if lost, do not reappear again as savings potential until their useful life has passed. These savings are depicted in the savings deployment scenarios beginning on the next page.

Table 5.5 depicts savings projections for NW Natural's Oregon system. The 'Other' sector referenced in the savings projections include the large project adder, Commercial New Buildings market transformation savings, and code savings from several commercial cooking measures that result in a market baseline equivalent to efficient technology. Both Commercial market transformation and cooking savings were forecasted outside of that Sector's standard savings as Energy Trust does not claim those savings.

Table 5.5: 20-Year Cumulative Savings Potential by type, including final savings projection (Millions of Therms) - Oregon

	Technical	Achievable	Cost-effective	Energy Trust Savings Projection [99]
Residential	215.28	164.36	156.37	74.14
Commercial	71.74	60.46	54.21	38.09
Industrial	21.29	18.10	18.10	16.74
Other	0	0	0	18.12

[99] The savings deployment process applies ramp rates to shape forecasted annual cost-effective savings acquisition over the 20-year forecast horizon. The deployment accounts for near term program savings targets and past program activity. In general, deployments follow Power Council principles such that retrofit measures acquire all available cost-effective achievable savings in the 20-year period following a bell-shaped acquisition curve while lost opportunity measures ramp up throughout the modeling period to achieve 100% market annual penetration by the end of the forecast. Some measures assume a lower acquisition rate to reflect market characteristics, such as hard to reach measures including insulation and windows, and emerging technology. Emerging technology measures begin with low rates of forecasted market uptake and often do not ramp to full market penetration by the end of the forecast period. Hard to reach measures are the reason that the Residential savings deployment is proportionally less than the cost-effective achievable savings potential when compared to the projections for commercial and industrial as emerging technologies (primarily gas fired heat pump water heaters) and shell make up a higher share of cost-effective achievable savings potential for this sector.

All DSM	308.30	242.92	228.67	147.08

Figure 5.10 shows the annual savings projection by Sector. The growth in savings from 2022 to 2025 is a result of discussions with NW Natural to increase efficiency spending to accelerate cost effective potential acquisition in the near forecast term. These increases reflect Energy Trust's best attempt to estimate increased savings potential without running these estimates through the more comprehensive planning that accommodates our annual budgeting process. Energy Trust will use these savings targets as a starting point for constructing savings goals for the 2023-2024 budget and presenting the anticipated budget needs that will accompany these savings goals. The eventual savings goals and the revenue needed to fund the budget will be negotiated, per usual practice, as a component of the budget process. Furthermore, the magnitude of the savings increases reflected in the attached savings targets for 2023-2026 are subject to evolving program designs and offerings that will need to be tested to validate their resulting efficacy.

Figure 5.10: 20-Year Annual Savings Projection by Sector - Oregon

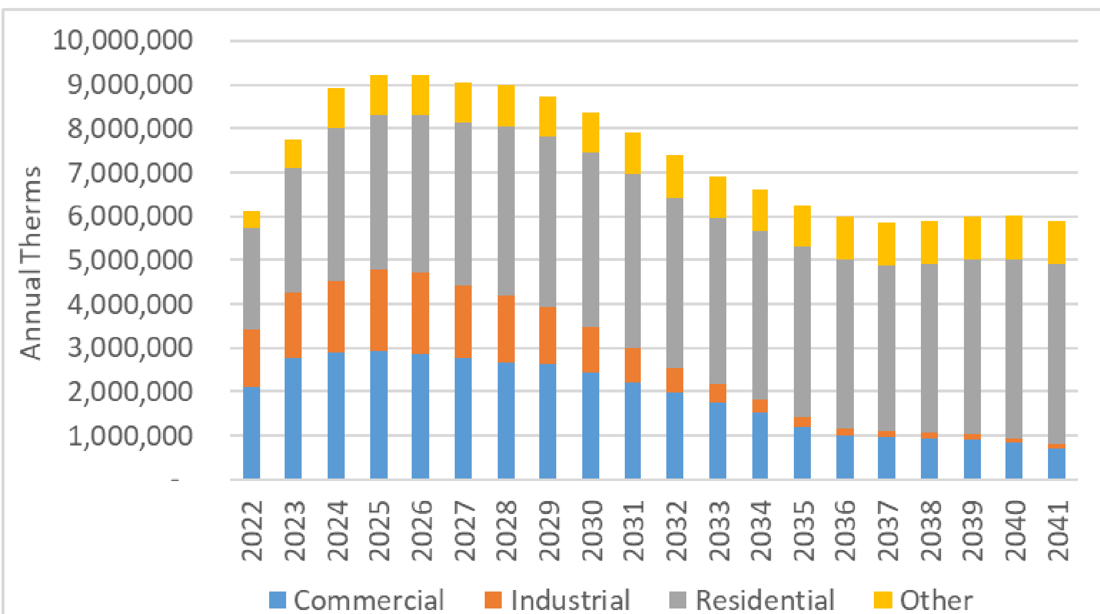
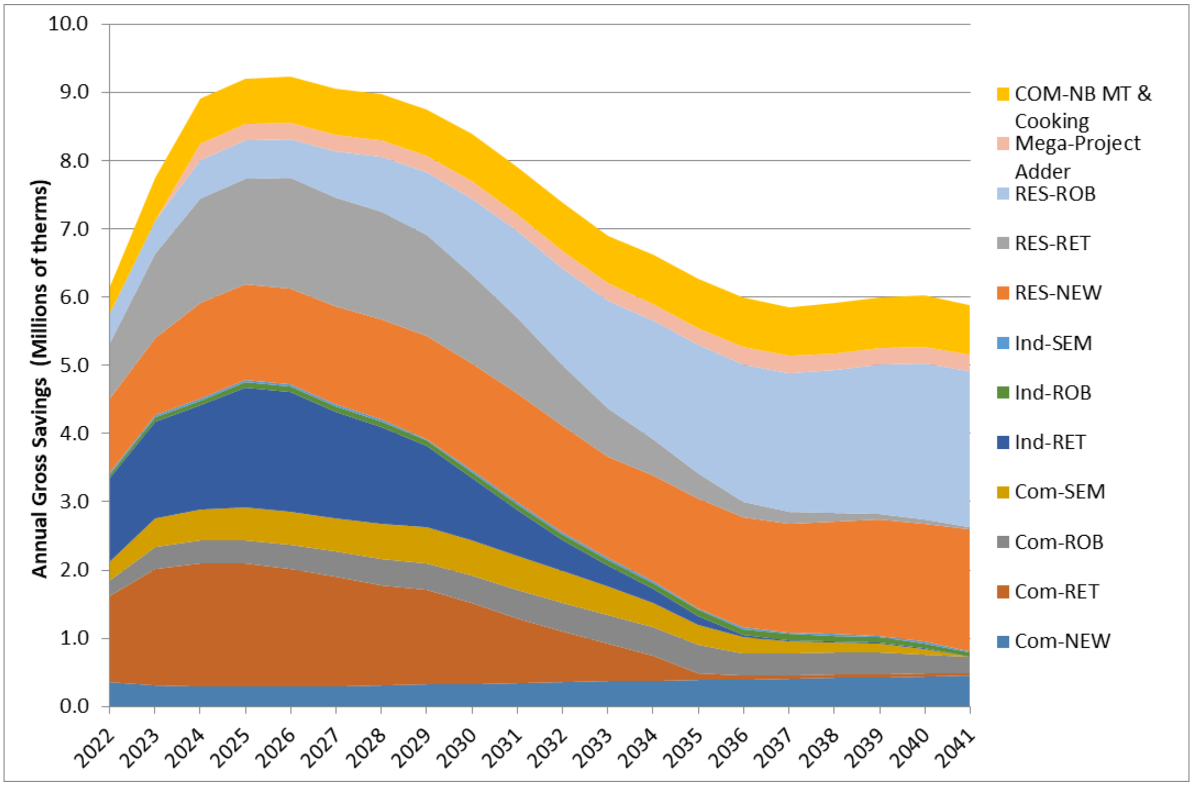


Figure 5.11 shows the annual savings projection by Sector-Measure Type. This view provides greater detail into the types of savings being forecasted and their relative contribution through time.

Figure 5.11: Annual Savings Projection by Sector-Measure Type - Oregon



Oregon Final Savings Projection Extended to 2050

The Energy Trust RA model is configured to calculate savings potential results over a 20-year forecast horizon. Energy Trust then deploys the cost-effective achievable potential exogenously to the RA model as described in Section 5.1.4 above. This deployment methodology has been modified to extend the final savings projection through 2050 to align with NW Natural's IRP horizon by continuing the energy efficiency acquisition curves for the additional nine years. This projection is different depending on the curve that was applied. As stated previously, Energy Trust ramp rates are based on Northwest Power and Conservation Council method and ramp rates but calibrated to be specific to Energy Trust. Retrofit measure potential continues until 100% of the cost-effective achievable potential is acquired and savings potential is exhausted. Lost opportunity measures continue to ramp up to 100% of annual available cost-effective achievable potential at which point all savings are realized annually. Hard to reach measures or emerging technologies do not ramp to 100%.

Table 5.6: 20-year and 29-year Final Savings Projection (Millions of Therms) - Oregon

	20-Year Savings Projection	9-Year Savings Extension	Total Final Savings through 2050
Residential	74.14	35.92	110.05
Commercial	38.09	6.66	44.75
Industrial	16.74	0.21	16.95
Other	18.12	5.86	23.97
All DSM	147.08	48.65	195.73

Figure 5.12: Annual Savings Projection by Sector through 2050 - Oregon

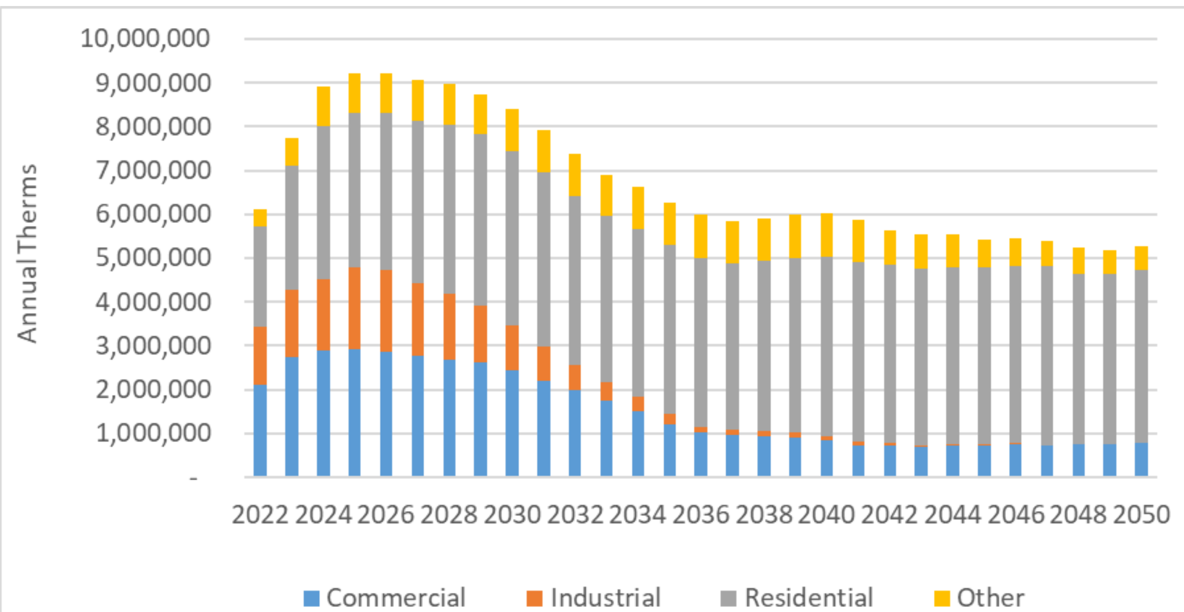
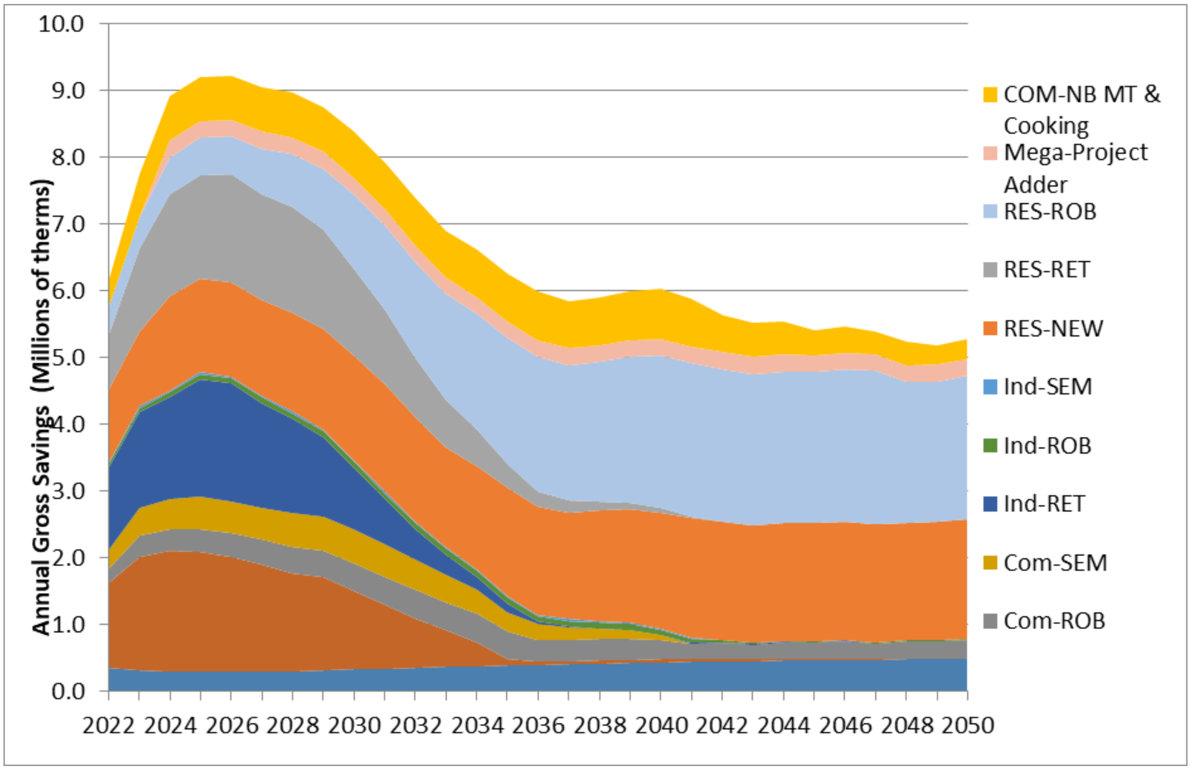


Figure 5.13: Annual Savings Projection by Sector through 2050 - Oregon



Oregon Peak Savings Deployment

Figure 5.14 and Figure 5.15 detail the amount of peak-day and peak-hour savings that Energy Trust forecasts to acquire as calculated from the annual savings projection using peak-day/annual use and peak-hour/annual use coincident load factors developed by NW Natural.

Figure 5.14: NW Natural's Annual Peak-Day Savings Projection by Sector - Oregon

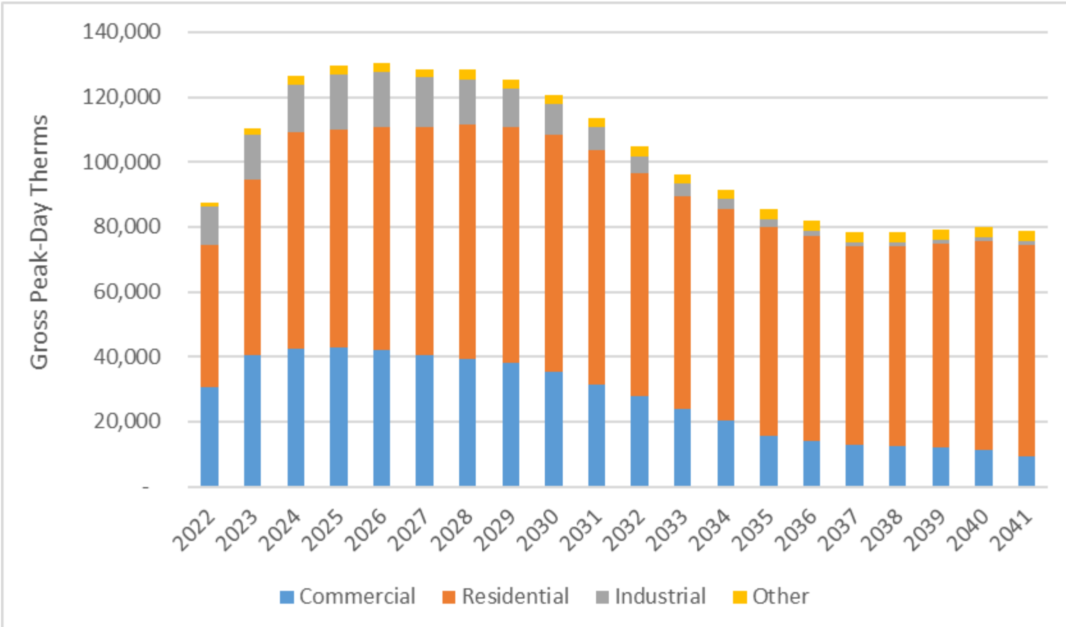
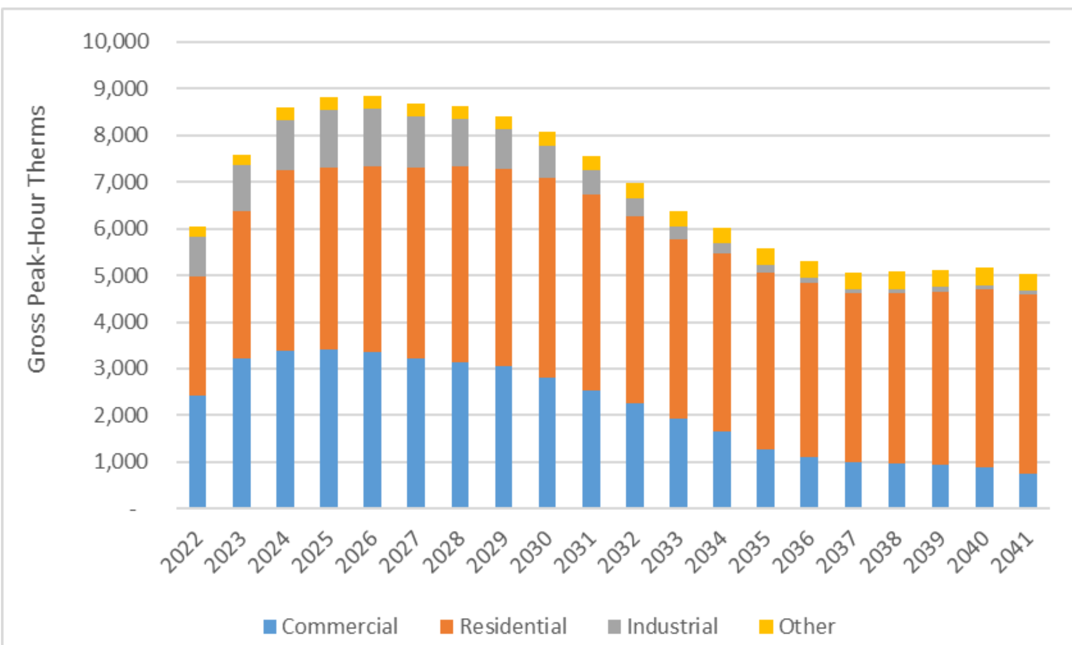


Figure 5.15: NW Natural's Annual Peak-Hour Savings Projection by Sector - Oregon



Residential and Commercial heating measures have the greatest savings coincident with peak, and in this forecast contribute the most peak savings potential. The total peak-day savings over the 20-year savings projection is 2,055,067 therms or 1.4% of the 147.1 million therm savings projection. The total peak-hour savings over the 20-year savings projection is 136,898 therms or 0.09% of the 147.1 million therm savings projection.

Impacts of Changing Market Conditions on Energy Trust Oregon Forecast

The deployment of the cost-effective achievable resource discussed in the chapter up to this point is based on Energy Trust assuming an aggressive market approach to maximize savings acquisition in the next few years in pursuit of carbon reduction objectives. Since Energy Trust originally assembled the forecast discussed in this chapter, Energy Trust's view of market conditions has changed to reflect limitations brought about by emergent supply chain issues and labor shortages that are outcomes of the ongoing impacts of the pandemic on the Oregon economy. Energy Trust's second quarter forecast for 2022 end of year results is showing that we are not on track to achieve 2022 goals. As a result, the 2023 and 2024 savings targets that are reflected in the deployment now seem overly aggressive as it is not possible to know when the market will correct to previous conditions.

Energy Trust and NW Natural discussed whether Energy Trust should update Energy Trust modeling results to reflect this updated market intelligence. Energy Trust and NW Natural jointly concluded that it will be too disruptive to NW Natural's modeling process to update the forecast at this time because NW Natural has already incorporated the previously submitted Energy Trust results into other NW Natural modeling protocols. Moreover, Energy Trust and NW Natural agreed that the long-term impact of the changes in 2023 and 2024 have minimal impact on the savings potential over the forecast horizon and the long-term impacts on NW Natural's system planning.

As an alternative, Energy Trust and NW Natural agreed that the 2023-2024 energy efficiency savings targets in the action plan will be framed by a range of potential energy savings outcomes that are influenced by market conditions. This range is bound on the lower end by the savings targets that reflect decelerated market conditions resulting in the savings goals from the first round of Energy Trust's 2023-2024 budget process. The higher end of the range of conditions included in the deployment earlier in this chapter is bound by the original, and now seemingly aggressive, savings targets associated with accelerated market conditions. Table 5.7 shows the lower bound of Energy Trust savings projection.

Table 5.7: 20-year Lower Bound Cumulative Savings Potential by type, including final savings projection (Millions of Therms) - Oregon

	Technical	Achievable	Cost-effective	Energy Trust Lower Bound Savings Projection
Residential	215.28	164.36	156.37	69.31
Commercial	71.74	60.46	54.21	38.00
Industrial	21.29	18.10	18.10	16.70
Other	0	0	0	18.10
All DSM	308.30	242.92	228.67	142.10

A comparison between the original NW Natural savings targets and the updated lower bound estimate reflecting the 2023-2024 Energy Trust budget is shown in Table 5.10 covering NW Natural's action plan years.

Table 5.8: 2023 and 2024 Annual Energy Trust Savings Projection (Therms) - Oregon

	2023	2024	Total
Upper Bound Reflecting Accelerated Market Conditions	7,750,168	8,910,070	16,660,239
Lower Bound Reflecting Decelerated Market Conditions	5,693,343	6,693,833	12,387,176

Figure 5.16 and Figure 5.17 below show annual lower bound savings projections by sector and by measure type in Oregon.

Figure 5.16: 20-Year Lower Bound Annual Savings Projection by Sector - Oregon

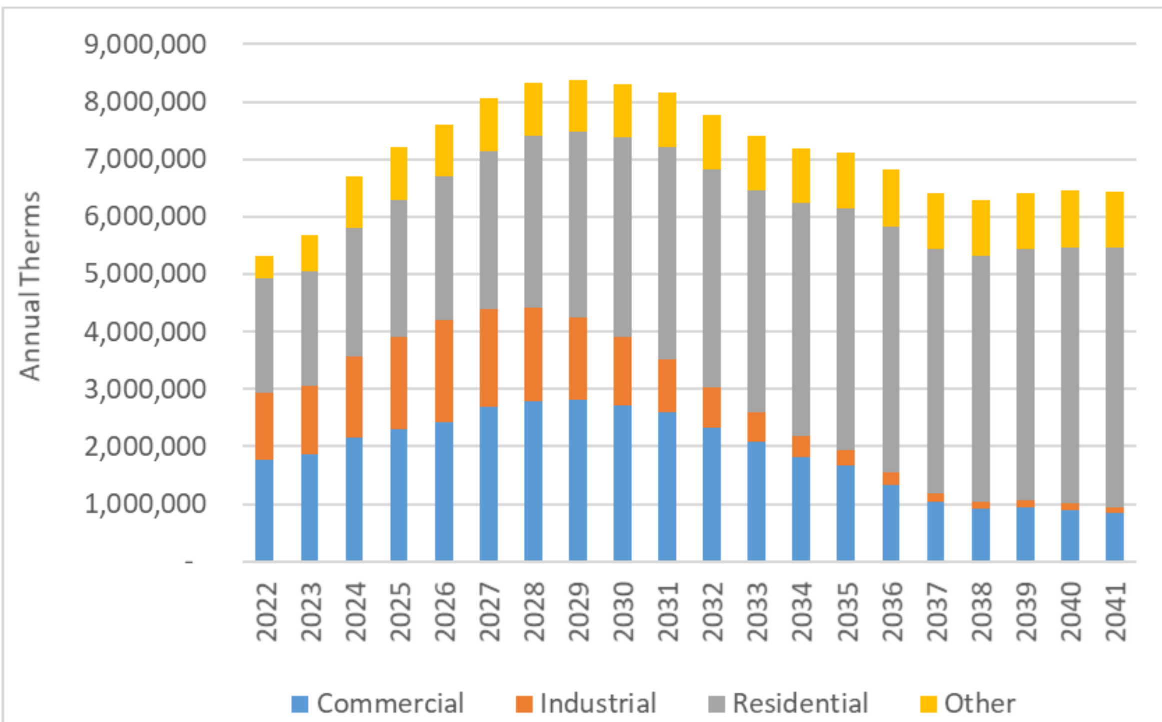
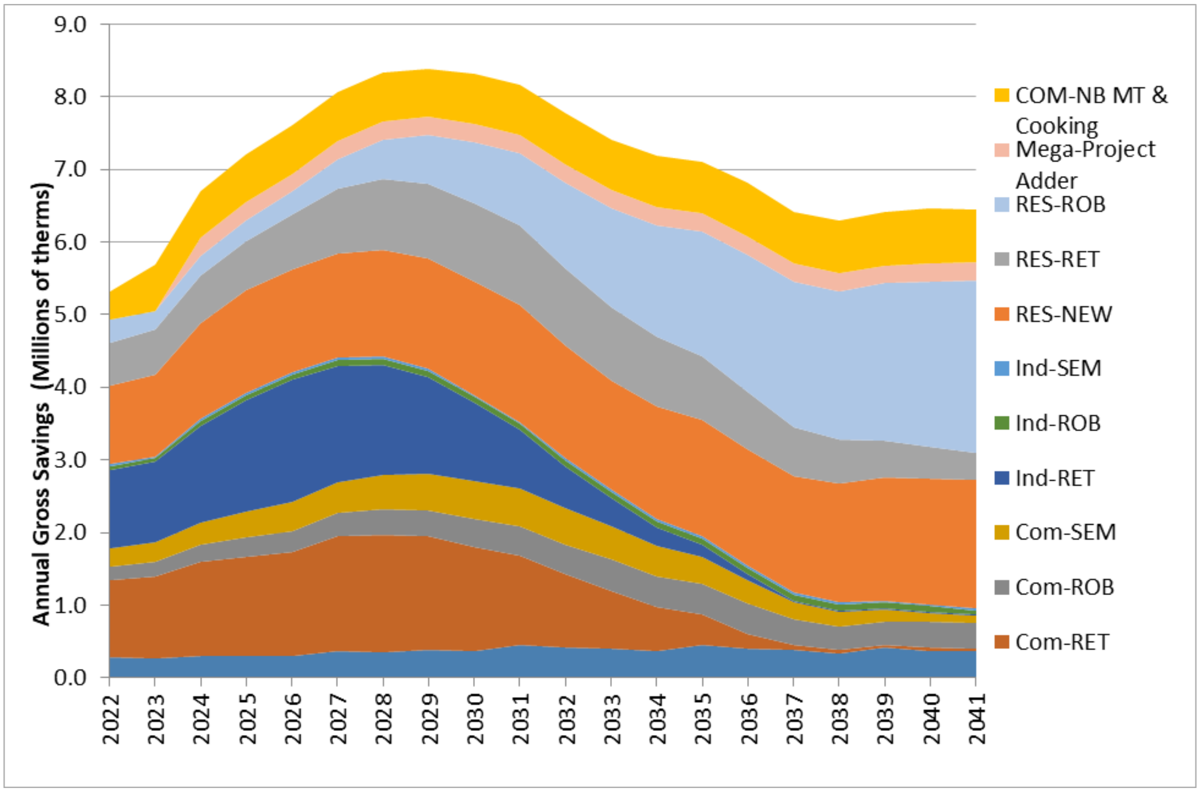


Figure 5.17: Annual Lower Bound Savings Projection by Sector-Measure Type - Oregon



5.2 Conservation Potential Assessment in Washington

This section is extracted and summarized from the final report of the 2021 NW Natural Washington Conservation Potential Assessment submitted by Applied Energy Group (AEG) to NW Natural. [100]

5.2.1 Background

In early 2021, NW Natural contracted with Applied Energy Group (AEG), a consulting firm known for its services to the energy industry including gas utilities, to conduct an assessment of available conservation potential in its Washington service territory. AEG applied standard industry and northwest regional methodologies to develop reliable estimates of technical, achievable technical, and achievable economic potential from two different cost-effectiveness perspectives for the period from 2022-2051. AEG completed the assessment in collaboration with NW Natural and ETO using information specific to NW Natural's customers and existing energy efficiency programs wherever possible and delivered the final study report to NW Natural in July 2021.

5.2.2 Analysis Approach

To perform the conservation potential analysis, AEG used a bottom-up approach following the major steps:

1) Performed a market characterization to describe sector-level natural gas use for the residential, commercial, and industrial sectors for the base year, 2019. This included extensive use of NW Natural data and other secondary data sources from NEEA and the Energy Information Administration (EIA).
2) Developed a baseline projection of energy consumption by sector, segment, end use, and technology for 2022 through 2051.
3) Defined and characterized several hundred EE measures to be applied to all sectors, segments, and end uses.
4) Estimated technical, achievable technical, and achievable economic energy savings at the measure level for 2022-2051. Achievable economic potential was assessed using both the Total Resource Cost (TRC) and Utility Cost Test (UCT) screens.

More specifically, AEG used its Load Management Analysis and Planning tool (LoadMAP™) version 5.0 to develop both the baseline projection and the estimates of potential. Built in Excel, the LoadMAP™ framework possesses key features that embody basic principles of rigorous end-use models, accommodates different levels of segmentation, includes algorithms that independently account for new and existing appliances and building stock, and balances the competing needs of simplicity and robustness. The LoadMAP™ model provides projections of baseline energy use by sector, segment, end

[100] The 2021 Washington Conservation Potential Study is available at the following URL: https://apiproxy.utc.wa.gov/cases/GetDocument?docID=3&year=2021&docketNumber=210773

use, and technology for existing and new buildings. It also provides forecasts of total energy use and energy-efficiency savings associated with the various types of potential.[101]

Three types of potential were analyzed in this AEG study: technical, achievable technical, and achievable economic. Table 5.9 provides detailed definitions on each type of potential.

Table 5.9: Types of Potential and Definitions

Potential Type	Definition
Technical	Everyone chooses the most efficient option regardless of cost at time of equipment replacement or measure adoption.
Achievable Technical	A modified technical potential that accounts for likely measure adoption within the market
Achievable Economic	A subset of achievable technical potential that includes only cost-effective measures

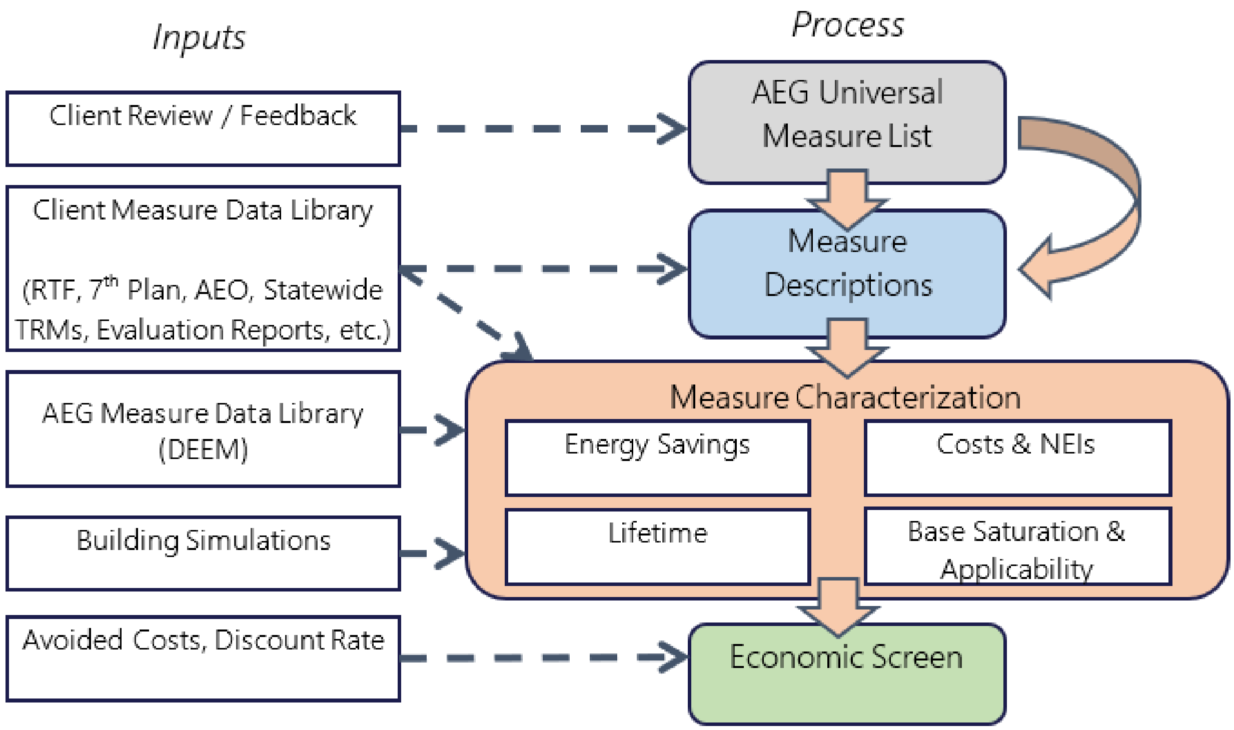
AEG developed the reference baseline in alignment with NW Natural's long-term demand forecast, but some modifications to account for known future conditions were also made. Inputs to the baseline projection include:

1) Current economic and load growth forecasts (i.e., customer growth, climate change assumptions)
2) Trends in fuel shares and equipment saturations
3) Existing and approved changes to building codes and equipment standards

To develop NW Natural's DSM measure list, in addition to its own databases, AEG also used datasets provided by NW Natural and ETO. As shown in Figure 5.18, first, a list of measures is identified; each measure is then assigned an applicability for each market sector and segment and is characterized with appropriate savings, costs, and other attributes; then cost-effectiveness screening is performed. NW Natural provided feedback during each step of the process to ensure measure assumptions and results lined up with real-world programmatic experience.

[101] The model computes energy forecasts for each type of potential for each end use as an intermediate calculation. Annual-energy savings are calculated as the difference between the value in the baseline projection and the value in the potential forecast (e.g., the technical potential forecast).

Figure 5.18: Approach for Energy Efficiency Measure Characterization and Assessment



5.2.3 Baseline Projection

Prior to developing estimates of energy conservation potential, baseline projections of annual natural gas use for 2022 through 2051 by customer segment and end use in the absence of new utility energy-efficiency programs were developed. The savings from past programs are embedded in the forecast, but the baseline projection assumes that those past programs cease to exist in the future to avoid double counting potential opportunities. Thus, the potential analysis captures all possible savings from future programs.

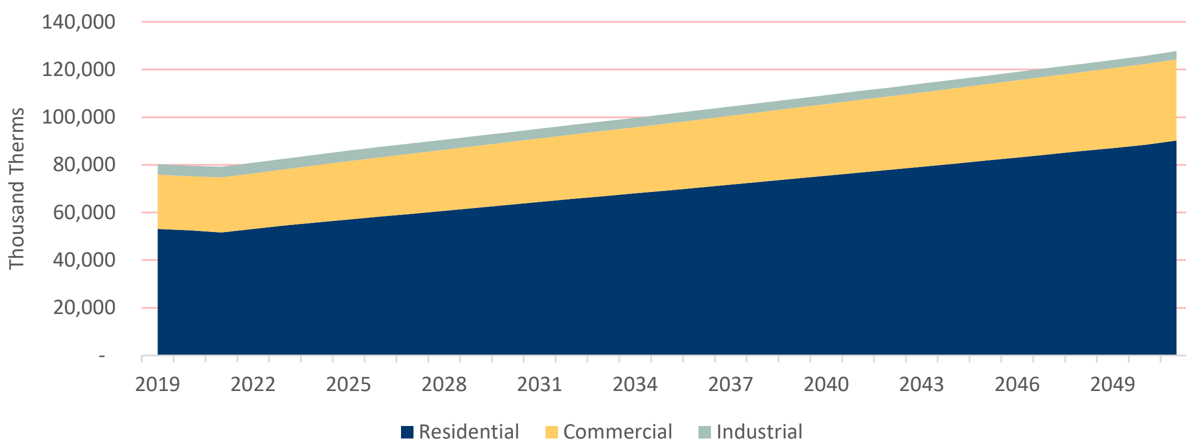
Table 5.10 and Figure 5.19 provide a summary of the baseline projection for annual use by sector for the entire NW Natural Washington service territory. Base year (2019) values[102] are weather normalized using HDD data provided by NW Natural's load forecast department. Years 2021 forward include the impact of climate trends through projected heating degree days (HDDs) supplied by NW Natural. Overall, the forecast shows modest growth in natural gas consumption, at an average rate of about 1.4% per year.

[102] NW Natural also provided 2020 consumption data for AEG's consideration in aligning the baseline projection with NW Natural's forecast

Table 5.10: Baseline Projection Summary by Sector, Selected Years (mTherms) - Washington

Sector	2019	2020	2021	2022	2023	2024	2031	2040	2050	% Change ('19-'50)	Avg. Growth
Residential	53,096	52,500	51,552	53,041	54,507	55,765	64,452	75,477	88,376	66.40%	1.60%
Commercial	22,840	22,754	23,213	23,350	23,623	24,112	26,657	30,083	33,935	48.60%	1.30%
Industrial	4,382	4,379	4,400	4,440	4,450	4,405	4,120	3,753	3,435	-21.60%	-0.80%
Total	**80,319**	**79,633**	**79,166**	**80,831**	**82,581**	**84,282**	**95,229**	**109,312**	**125,747**	**56.60%**	**1.40%**

Figure 5.19: Baseline Projection Summary by Sector - Washington



5.2.4 DSM Potential

Table 5.11 and Figure 5.20 summarize the energy conservation savings in terms of annual energy use for all measures for four levels of potential relative to the baseline projection. Savings are represented in cumulative terms, reflecting the effects of persistent savings in prior years in addition to new savings. This allows for the reporting of annual savings impacts as they actually impact each year of the forecast.

Table 5.11: Summary of Energy Efficiency Potential (mTherms) - Washington

Scenario	2022	2023	2024	2026	2031	2040	2050
Baseline Load Projection (mTherms)	80,831	82,581	84,282	87,530	95,229	109,312	125,747
Cumulative Savings (mTherms)							
TRC Achievable Economic Potential	354	725	1,036	1,827	4,390	9,345	11,392
UCT Achievable Economic Potential	477	992	1,470	2,671	6,523	13,936	16,818
Achievable Technical Potential	874	1,799	2,702	4,808	10,350	19,102	22,321
Technical Potential	2,033	4,189	6,160	10,491	20,957	35,383	42,373
Cumulative Savings (% of Baseline)							
TRC Achievable Economic Potential	0.40%	0.90%	1.20%	2.10%	4.60%	8.50%	9.10%
UCT Achievable Economic Potential	0.60%	1.20%	1.70%	3.10%	6.80%	12.70%	13.40%
Achievable Technical Potential	1.10%	2.20%	3.20%	5.50%	10.90%	17.50%	17.80%
Technical Potential	2.50%	5.10%	7.30%	12.00%	22.00%	32.40%	33.70%

Figure 5.20: Summary of Annual Cumulative Energy Efficiency Potential (mTherms) - Washington

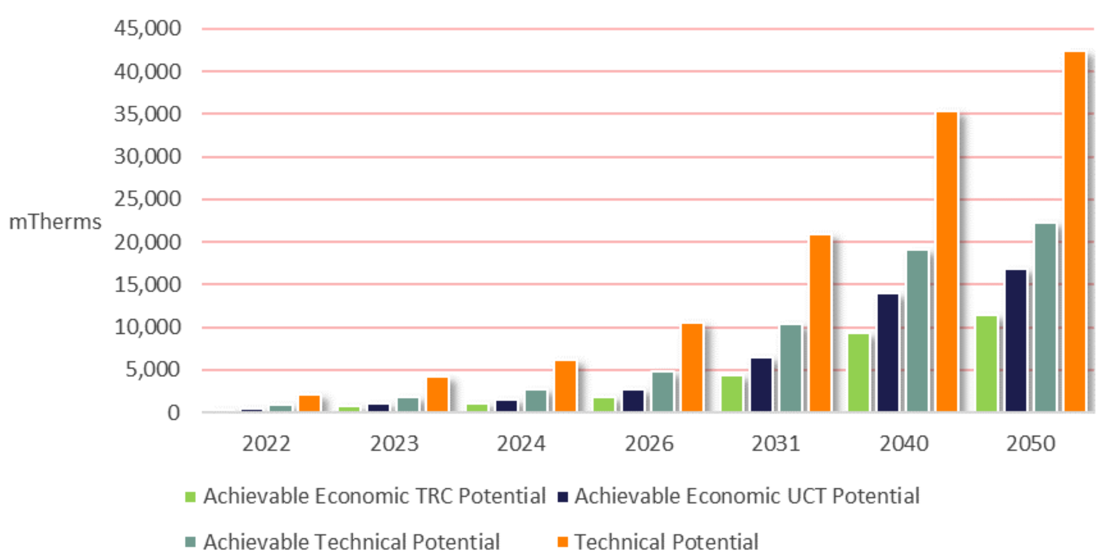


Table 5.12 summarizes TRC achievable potential by market sector for selected years. In general, residential and commercial potential are well balanced and dominant since industrial sales customer consumption represents a small percentage of the baseline and potential for this sector is also relatively small in size. In 2022, TRC achievable economic potential is 182 mTherms, or 0.3% of the

baseline projection for the residential sector, 155 mTherms, or 0.7% of the baseline projection for the commercial sector, and 16 mTherms, or 0.4% of the baseline projection for the industrial sector, respectively. By 2050, cumulative savings are 6,612 mTherms, or 7.5% of the baseline for the residential sector, 4,526 mTherms, or 13.7% of the baseline for the commercial sector, and 254 mTherms, or 7.4% of the baseline for industrial sector, respectively. Overall, in 2022, first-year savings are 354 mTherms, or 0.4% of the baseline projection. Cumulative savings in 2031 are 4,390 mTherms, or 4.6% of the baseline. By 2050 cumulative TRC achievable economic potential reaches 11,392 mTherms, or 9.1% of the baseline.

Table 5.12: Cumulative TRC Achievable Economic Potential by Sector, Selected Years (mTherms) - Washington

Sector	2022	2023	2024	2026	2031	2040	2050
Residential	182	369	478	837	2,250	5,380	6,612
Commercial	155	323	509	908	1,979	3,713	4,526
Industrial	16	33	49	82	162	253	254

Table 5.13 and Table 5.14 present the total reference baseline and potential savings for the peak day and peak hour, respectively. Peak day and hour impacts are estimated using the annual energy savings and conversion factors that relate peak day or hour consumption to annual consumption by end use obtained from NW Natural.

Table 5.13: Peak Day Potential Summary (mTherms) - Washington

Scenario	2022	2023	2024	2026	2031	2040	2050
Peak Day Savings (mTherms)							
TRC Achievable Economic Potential	5	11	16	27	60	124	148
UCT Achievable Economic Potential	7	15	22	38	85	179	208
Achievable Technical Potential	11	23	34	60	127	238	272
Technical Potential	27	55	79	134	265	473	563
Energy Savings (% of Baseline)							
TRC Achievable Economic Potential	0.50%	1.10%	1.40%	2.40%	4.90%	8.90%	9.30%
UCT Achievable Economic Potential	0.70%	1.40%	2.00%	3.40%	6.90%	12.80%	13.00%
Achievable Technical Potential	1.10%	2.20%	3.20%	5.40%	10.30%	17.00%	17.00%
Technical Potential	2.60%	5.20%	7.30%	11.90%	21.60%	33.80%	35.30%

Table 5.14: Peak Hour Potential Summary (mTherms) - Washington

Scenario	2022	2023	2024	2026	2031	2040	2050
Peak Hour Savings (mTherms)							
TRC Achievable Economic Potential	0.4	0.7	1.1	1.9	4.5	9.6	11.5
UCT Achievable Economic Potential	0.5	1	1.5	2.8	6.8	14.5	17.5
Achievable Technical Potential	0.9	1.9	2.8	5	10.9	20.1	23.4
Technical Potential	2.1	4.4	6.5	11.1	22.3	37.4	44.8
Energy Savings (% of Baseline)							
TRC Achievable Economic Potential	0.50%	0.90%	1.30%	2.20%	4.80%	8.80%	9.20%
UCT Achievable Economic Potential	0.60%	1.20%	1.80%	3.20%	7.30%	13.40%	14.00%
Achievable Technical Potential	1.10%	2.30%	3.40%	5.80%	11.60%	18.50%	18.80%
Technical Potential	2.70%	5.40%	7.80%	12.90%	23.60%	34.50%	35.90%

Key opportunities for savings include residential furnace and water heating equipment upgrades and weatherization, as well as behavioral programs and kitchen equipment. For detailed top DSM measures contributing to the potential savings reported above, refer to the 2021 Washington Conservation Potential Study.[103]

5.3 DSM Potential for Oregon Transportation Customers

5.3.1 Background

With the passing of Executive Order 20-04 in March 2020, statewide greenhouse gas emissions from large stationary sources, transportation fuel, and other liquid and gaseous fuels will be limited by new goals from the Oregon Department of Environmental Quality (DEQ). The resulting Climate Protection Program (CPP) formalizes emission reduction requirements for Oregon's natural gas utilities, including the responsibility for on-site emission of natural gas transportation customers.[104] NW Natural's transportation customers have not historically paid into the public purpose charge and thus are currently not eligible to participate in natural gas energy efficiency programs administered by ETO. NW Natural engaged AEG to assess the potential that exists with Oregon transportation customers and inform what DSM programs for transportation customers could look like in the future.

The Washington Conservation Potential Assessment (CPA) that AEG completed for NW Natural in 2021 provided a starting point to assess the potential for energy efficiency to reduce greenhouse gas (GHG) emissions at transportation customer sites.[105] AEG used many of the same data sources from the Washington CPA, updated as appropriate to capture Oregon transportation customer characteristics.

5.3.2 Methodology

AEG began the analysis by characterizing NW Natural's Oregon transportation customers' energy consumption in the base year of the study (2021) using NW Natural customer and sales data. This characterization resulted in energy use distribution by sector, segment, and end use. Using NW Natural load forecasts and measure characterizations from the 2021 Washington CPA, AEG then developed a baseline energy projection over the 30-year study period. Oregon transportation customer equipment specifications were informed by NW Natural's equipment database and vetted with NW Natural Field Technicians. The Northwest Power and Conservation Council (NWPCC) 2021 Power Plan ramp rates informed measure adoption throughout the forecast and were the basis in analyzing the three scenarios provided in this study.

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[103] The 2021 Washington Conservation Potential Study is available at the following URL: https://apiproxy.utc.wa.gov/cases/GetDocument?docID=3&year=2021&docketNumber=210773

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

[105] The 2021 Washington Conservation Potential Study is available at the following URL: https://apiproxy.utc.wa.gov/cases/GetDocument?docID=3&year=2021&docketNumber=210773

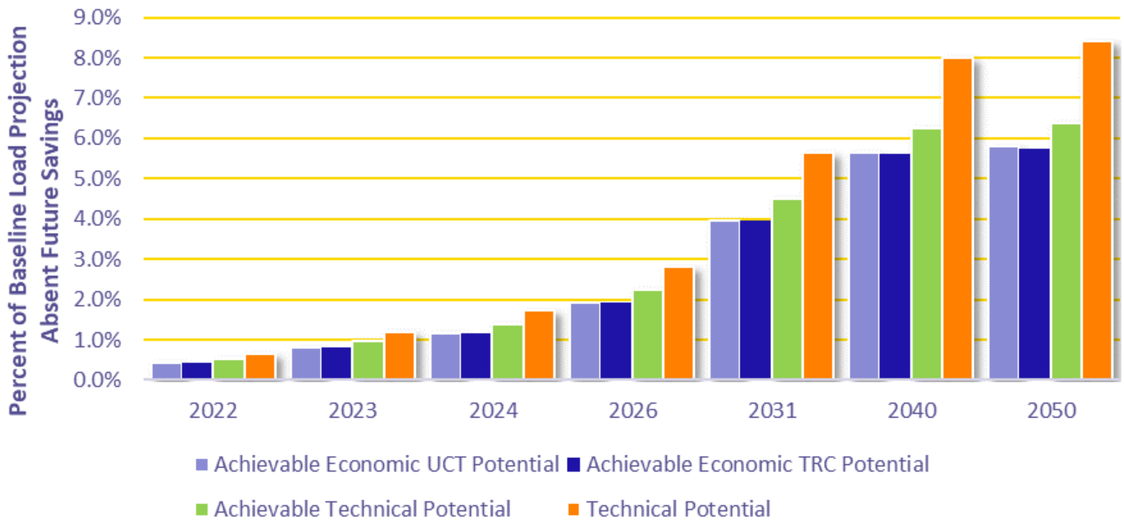
5.3.3 Results Summary

A summary of the identified DSM potential for the reference case at Oregon transportation customer sites is presented in Table 5.15 and Figure 5.21. A majority of the potential can be acquired over 10 years, and almost all over 20 years. Only a small amount of potential remains for acquisition from 2042-2051, primarily for equipment that was not assumed to be upgraded during the first 20 years of the forecast period. More specifically, in 2022, first year TRC achievable economic potential savings are 1,531 mTherms, or 0.43% of the baseline projection. Cumulative savings in 2031 are 13,424 mTherms, or 3.95% of the baseline. By 2050 cumulative TRC achievable economic potential slowly increases to 17,481 mTherms, or 5.75% of the baseline. The top measures identified to help achieve the savings potential over the next 20 years include strategic energy management, steam system efficiency improvements, hot water line insulation, building roof/ceiling insulation, and heated process fluid insulation.

Table 5.15: Summary Potential Results – Reference Case: Oregon Transportation

Scenario	2022	2023	2024	2026	2031	2040	2050
Baseline Load Projection Absent Future Savings (mTherms)	357,025	357,418	355,616	350,191	340,047	323,605	304,190
Cumulative Savings (mTherms)							
TRC Achievable Economic Potential	1,531	2,883	4,155	6,721	13,424	18,166	17,481
UCT Achievable Economic Potential	1,537	2,894	4,170	6,746	13,480	18,287	17,655
Achievable Technical Potential	1,844	3,448	4,929	7,867	15,346	20,220	19,392
Technical Potential	2,291	4,298	6,158	9,842	19,167	25,882	25,622
Cumulative Savings (% of Baseline)							
TRC Achievable Economic Potential	0.43%	0.81%	1.17%	1.92%	3.95%	5.61%	5.75%
UCT Achievable Economic Potential	0.43%	0.81%	1.17%	1.93%	3.96%	5.65%	5.80%
Achievable Technical Potential	0.52%	0.96%	1.39%	2.25%	4.51%	6.25%	6.37%
Technical Potential	0.64%	1.20%	1.73%	2.81%	5.64%	8.00%	8.42%

Figure 5.21: Reference Case Cumulative Potential: Oregon Transportation



5.4 DSM Potential for Washington Transportation Customers

While the DSM potential for Washington transports customers is not included in the final report of the 2021 NW Natural Washington Conservation Potential Assessment submitted by AEG to NW Natural, AEG also conducted the assessment and submitted the summary results to NW Natural in a separate Excel document. The data and methodologies employed by AEG in this assessment have been detailed in subsections 5.3.1 and 5.3.2. The potential cumulative savings in mTherms by sector and case for the transportation customers in Washington in 2050 are summarized in Table 5.16 and Figure 5.22. More detailed achievable economic TRC potential by transportation customer segment from 2022 to 2050 is reported in Table 5.17.

Table 5.16: 2050 Cumulative Savings by Sector and Case in mTherms: Washington Transportation

Sector	UTILITY Cost Effective Potential	SOCIAL Cost-Effective Potential	Achievable Technical Potential	Technical Potential
Commercial Transport	328	350	499	731
Industrial - Firm	578	579	612	750
Industrial - Interruptible	477	481	505	614
Total	**1,384**	**1,410**	**1,615**	**2,095**

Figure 5.22: 2050 Cumulative Savings by Sector and Case: Washington Transportation

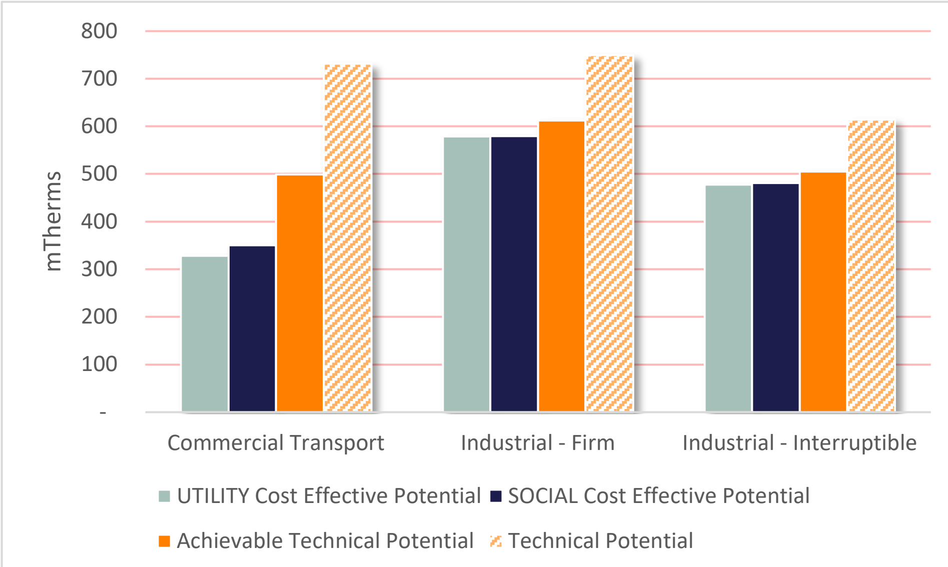


Table 5.17: Cumulative TRC Potential Savings by Customer Segment in mTherms: Washington Transportation

	2022	2023	2024	2026	2031	2040	2050
Commercial Transport	**7.95**	**16.74**	**26.86**	**50.32**	**120.76**	**265.16**	**350.43**
Retail	1.86	3.75	5.73	10.06	21.78	39.70	45.55
Grocery	0.81	1.78	2.95	5.82	14.58	35.15	49.70
Lodging	0.64	1.42	2.38	4.60	10.76	25.08	35.95
Other Health	4.63	9.80	15.79	29.84	73.64	165.24	219.23
Industrial - Firm	**38.05**	**75.93**	**113.62**	**189.12**	**368.64**	**575.46**	**579.45**
Electronics Manufacturing	16.75	33.39	49.96	83.65	168.04	266.83	266.40
Food Processing	19.08	38.09	57.02	94.45	180.04	278.32	282.34
Stone, Clay, Glass	0.62	1.23	1.83	3.03	5.25	6.90	6.92
Other Industrial	1.61	3.21	4.81	7.99	15.31	23.41	23.79
Industrial - Interruptible	**31.71**	**63.24**	**94.64**	**157.75**	**307.45**	**476.01**	**480.56**
Electronics Manufacturing	10.59	21.11	31.57	52.82	105.57	167.19	167.29
Food Processing	4.99	9.96	14.91	24.70	47.05	72.76	73.89
Lumber and Wood Products	3.52	7.02	10.51	17.55	34.79	55.27	55.85
Stone, Clay, Glass	8.50	16.94	25.36	42.28	81.42	122.51	124.33
Other Industrial	4.11	8.21	12.29	20.39	38.62	58.28	59.20
Grand Total	**77.70**	**155.91**	**235.12**	**397.19**	**796.84**	**1,316.63**	**1,410.44**

Table 5.15 shows that most of the achievable economic TRC potential is assumed to be acquired steadily over the next 20 years. This is particularly the case for the industrial firm and interruptible transportation customers: over 99 percent of their TRC potential is projected to be acquired by 2040.

The top measures identified to help achieve the savings potential over the next 20 years include strategic energy management, hot water line insulation, building automation systems, gas boiler stack economizers, roof/ceiling insulation, and gas boiler hot water reset.

5.5 Transportation Energy Efficiency Programs

NW Natural does not currently have energy efficiency programs for our transportation customers in either Oregon or Washington. Given that NW Natural will have compliance obligations for transportation customer's usage under the CPP, the Company recognizes the importance to pursue energy efficiency opportunities. NW Natural is already working on standing up an energy efficiency program for transportation customers and is actively engaging relevant stakeholders.[106] Establishing energy efficiency programs will be a critical part of the Company's compliance strategy in both states and will require engagement from stakeholders to find equitable funding mechanisms for these programs.

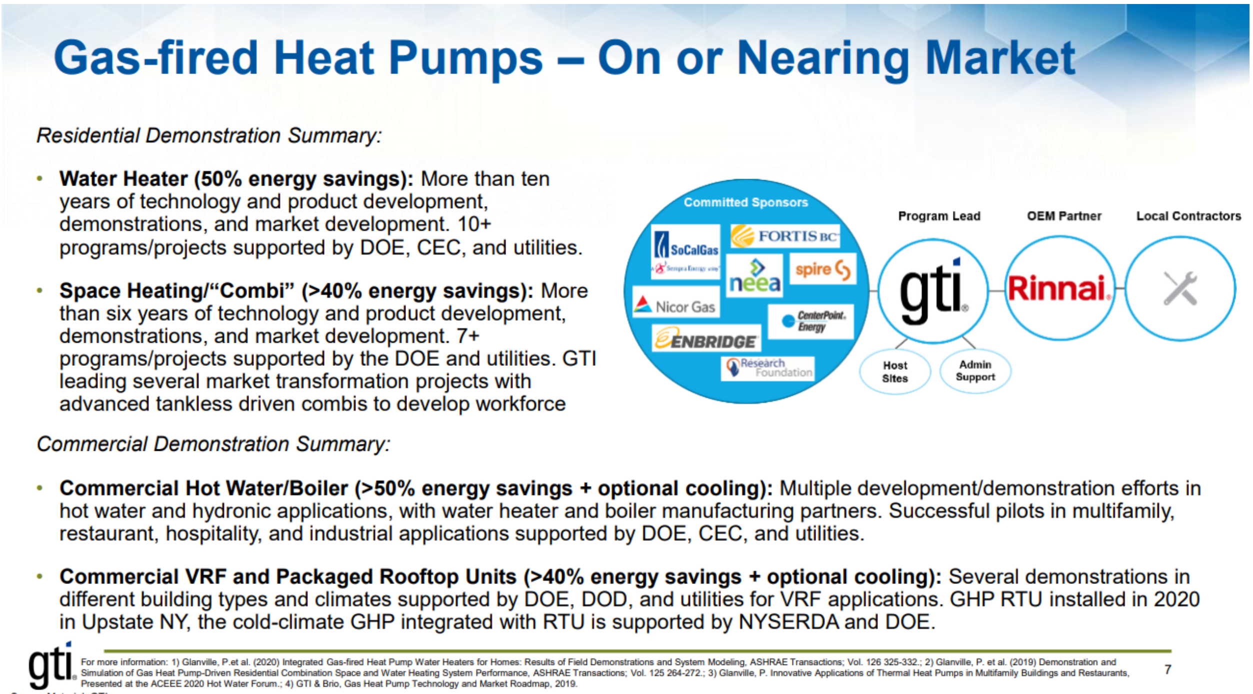
5.6 Gas Heat Pumps/Gas Heat Pump Water Heaters

Gas heat pumps are similar to heat pump technology on the electric side but are thermally driven using natural gas. They have the potential to reduce emissions and energy consumption by 40% or greater than existing natural gas furnaces and as they typically do not require back up heating, provide good opportunities for peak load management.

As shown in Figure 5.23[107], GTI identified gas heat pumps that are either on or near the market for both residential and commercial applications. In both markets, gas heat pumps can be used for space heating and cooling, for water heating or as "Combi" systems providing both hot water and space heating.

[106] As a practical matter for the IRP model, we shift the savings projections for transportation customers to start in 2025 to account for this initial ramp up period of a program. NW Natural is hoping to being taking advantage of energy efficiency opportunities prior to this date.
[107] NW Natural 2022 IRP Third Technical Working Group, April 13, 2022. This presentation and others may be found at https://www.nwnatural.com/about-us/rates-and-regulations/resource-planning

Figure 5.23: Gas-Fired Heat Pumps



Source Material: GTI

Figure 5.24 also shows the technology readiness of heat pumps from different manufacturers.

Figure 5.24: Gas Heat Pump Technology Readiness by Manufacturer

Technology Readiness

Green: Commercially available in North America

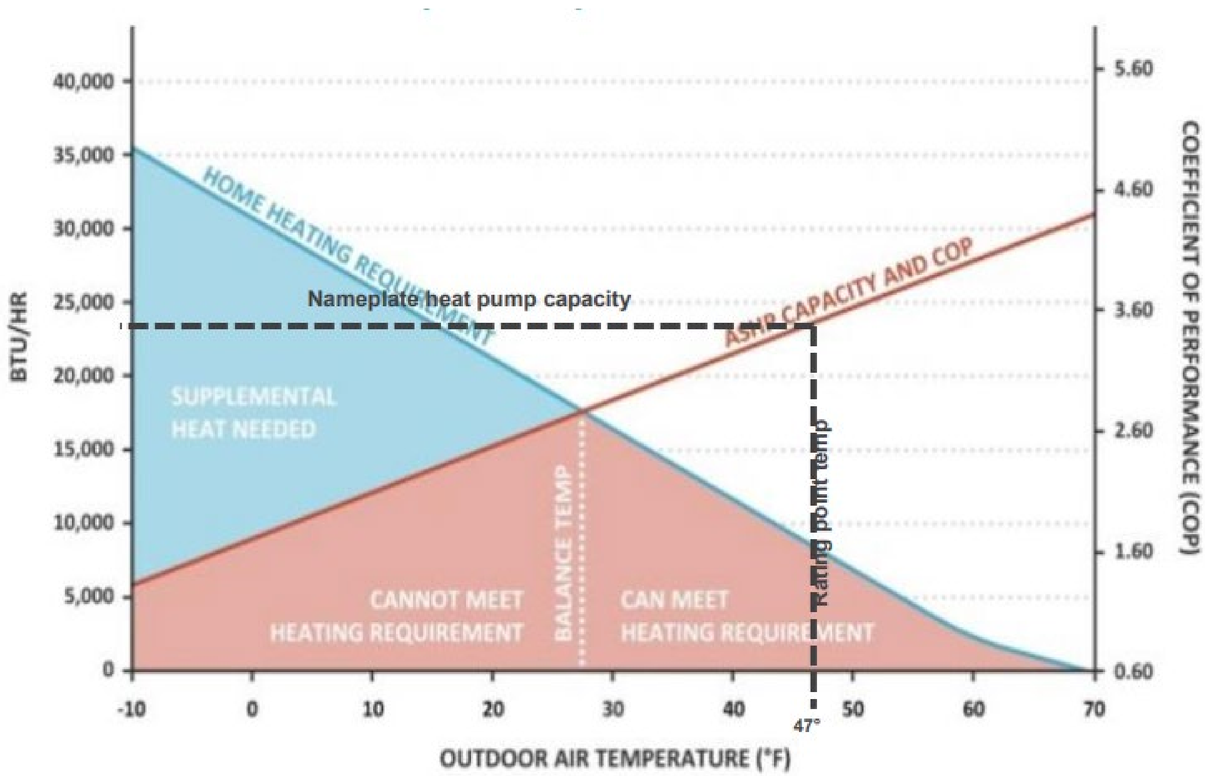
Source: Enbridge, NEEA, GTI

Manufacturer	Type	Primary Applications	Primary Sectors	Technology Readiness for North America
ROBUR	Absorption	Space and DWH heating Cooling (possible)	• Commercial • Residential	• Commercial size unit commercially available • Residential unit available in Europe. Efforts underway to bring it to NA
YANMAR	Engine driven	Space heating and cooling	• Commercial	• Commercially available
SMTI / ANESI	Absorption	Space and DHW heating	• Residential • Small commercial	• Field trials of pre-production unit underway
VICOT	Absorption	Space and DHW heating	• Residential • Commercial	• Commercially available in China • Lab testing and field trials of production unit underway in NA
ThermoLift	Thermal compression	Space heating, cooling and DHW heating	• Residential • Small commercial	• Lab testing and field trials of pre-production unit underway
HeatAmp	Adsorption	Space and DHW heating	• Residential • Small commercial	• Lab testing in Europe
Rinnai	Absorption	DHW heating	• Residential	• Lab testing and field trials planned

5.7 Dual-Fuel (Hybrid) Heating Systems

While not a new technology, dual-fuel (or hybrid) systems use electric heat pumps with direct use natural gas as back up for peak periods. Typically, electric heat pumps use resistance heating as back-up systems to heat pumps to help maintain comfort during cold temperatures. As can be seen in Figure 5.25, electric heat pumps are efficient, but efficiencies decline as temperatures decrease due to the use of resistance back up heating. This contributes to large peaks to utility loads and is expensive to customers.

Figure 5.25: Efficiency of Electric Heat Pumps and Ambient Temperature



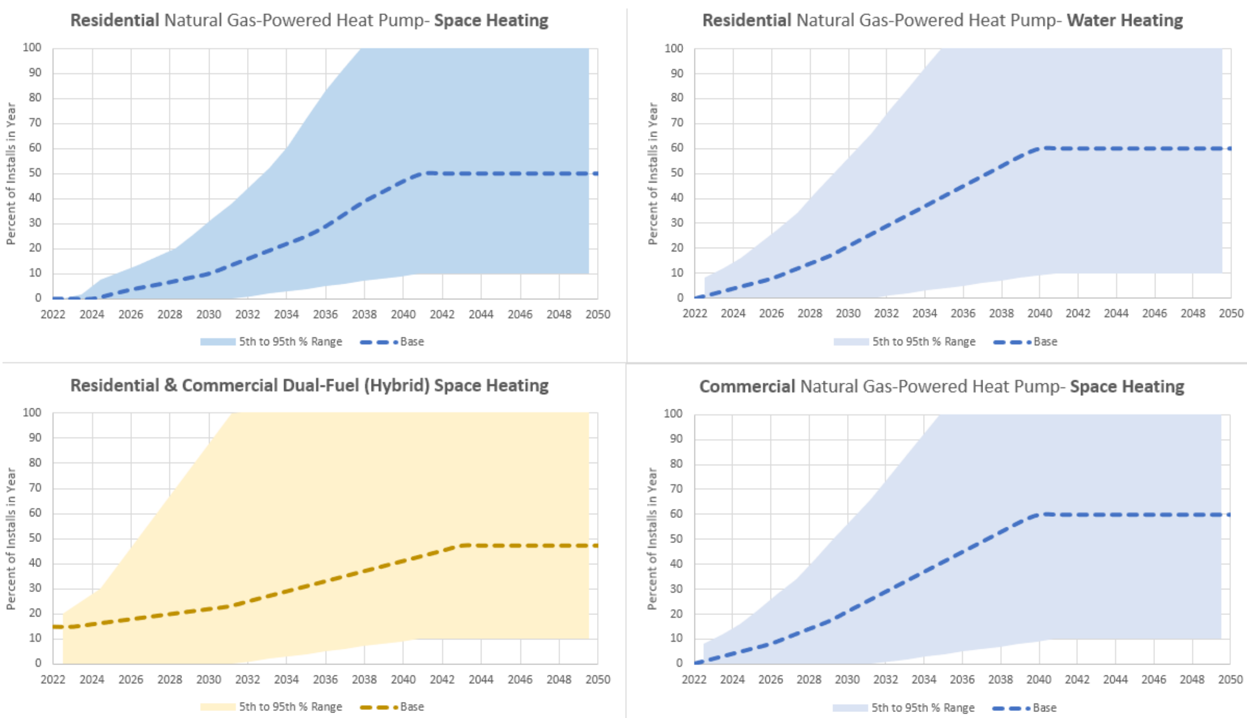
Hybrid heating systems consist of using an electric heat pump as the main source of space heating, but it is teamed with a natural gas furnace for back up heat. The benefit of using both energy systems is that it helps with energy system resource adequacy. With the natural gas energy system providing peak heat, these dual-fuel systems serve as demand response for the electric grid and allows the existing seasonal storage infrastructure to serve peak needs in a region that is capacity constrained. By displacing resistance back up heat and using natural gas only in times of cold temperatures not only does this help with resource adequacy but it also supports energy efficiency and decarbonization efforts. Decarbonization efforts are further supported as both energy systems use more renewable energy or low carbon energy.

5.8 Key Demand-Side Input Assumptions

NW Natural's primary driver of our demand-side assumptions are based on the forecasts that are discussed above and have been provided by both ETO and AEG. We adjust our load forecasts for these projections in the recognition that there is also DSM included in our historical data used to train our load forecasting models. These DSM efforts are material and NW Natural expects a reduction of roughly 20% in load in its reference case by 2050 from programs for sales customers. Assuming that DSM programs for our transportation schedule customers begins in 2024, NW Natural expects a reduction of 10% of its transportation load in its reference case by 2050. All load sensitivities and simulation draws adjust for electrification assumptions so that savings are not being claimed from an energy need not served by NW Natural.

The Figure 5.26 and Table 5.18 set forth the key assumptions NW Natural used for emerging end use equipment penetration and costs. Figure 5.26 depicts the range of equipment penetration analyzed in the IRP by showing the percent of installations per year of gas heat pumps for residential space heating, gas heat pump water heaters for residential water heating, gas heat pumps for commercial space heating, and hybrid heating for both residential and commercial applications.

Figure 5.26: Assumptions on Emerging Technology Adoption Over Time[108]



[108] In 2020, NW Natural surveyed 6 internal experts and the Northwest Energy Efficiency Alliance (NEEA) about expected adoption of gas heat pumps and gas heat pump water heaters. These responses were weighted to ascertain the adoption curves that were initially used in NW Natural's Carbon Neutral analysis published in 2021 (see https://www.nwnatural.com/about-us/the-company/carbon-neutral-future). Based upon stakeholder feedback during the UM 2178 and 2022 IRP processes, these deployment figures were reduced substantially. "Base" assumptions are those developed from this survey process and used to help define deployments across scenarios and in each stochastic draw.

Table 5.18 represents NW Natural's assumptions of cost for these emerging technologies.

Table 5.18: Assumptions on Cost for Emerging Technologies

Incremental Demand-Side Measure Costs	Incentive	Total Cost to Utility	Cost Range (5th and 90th Percentile)
Residential Hybrid Heating Incremental Incentive (2020$/System Install)	$1,200	$1,600	+/-30%
Residential Hybrid Heating Share of Incentive paid by non-CCI funds (%)	25%	$400	+/-50%
Residential Gas Heat Pump Incentive (2020$/System Install)	$3,000	$4,000	+/-40%
Residential Gas Heat Pump Water Heater Incentive (2020$/System Install)	$1,200	$1,600	+/-40%
Commercial Hybrid Heating Incremental Incentive (2020$/System Install)	$3,000	$4,000	+/-30%
Commercial Hybrid Heating Share of Incentive paid by non-CCI funds (%)	25%	$1,000	+/-40%
Commercial Gas Heat Pump Incentive (2020$/System Install)	$10,000	$13,333	+/-30%
First Year Transport Load Savings Cost (2020$/1st year therm saved)		$1.79	+/-100%

5.9 Low Income Programs

5.9.1 Oregon Low-Income Energy Efficiency Program (OLIEE)

Since 2002, a portion of the public purpose funding collected by NW Natural has been allocated for Oregon Low-Income Energy Efficiency (OLIEE) through a surcharge to Oregon Residential and Commercial customers' energy bills. The OLIEE program attempts to provide equitable access to DSM by funding high-efficiency equipment and weatherization measures to income qualified homes. The program consists of two parts: The Community Action Program (CAP), and the Open Solicitation Program (OSP).

The CAP provides energy evaluations of low-income dwellings and funding for qualifying DSM measures. In conjunction with DSM, health, safety, and repair (HSR) projects like improving ventilation may also receive funds through the CAP. The program is administered by 10 CAP agencies throughout the Oregon service territory.

OSP focuses on projects that do not fit into the CAP framework, including but not limited to, new affordable housing or temporary living space retrofits. NW Natural invites proposals that serve low-income qualified customers and allocates funds based on availability. Bi-annual meetings are held with both the CAP agencies and OLIEE Advisory Committee (OAC) to ensure proper implementation of the programs. Historical engagement in the OLIEE program is shown in Table 5.19.

Table 5.19: Homes Served through OLIEE Program

Program Year	Homes	Therms Saved
2015-2016	231	52,817
2016-2017	260	59,232
2017-2018	299	103,708
2018-2019	260	73,441
2019-2020	248	68,320
2020-2021	341	60,394

5.9.2 Washington Low-Income Energy Efficiency Program (WA-LIEE)

In 2009, NW Natural launched a revised low-income program identified as WA-LIEE (Washington Low-Income Energy Efficiency). Modeled after Oregon's low-income CAP program, the WA-LIEE program reimburses administering agencies for installing weatherization measures that are cost-effective when analyzed in aggregate.

In Washington, two agencies co-administer the program. The program is informed by input from NW Natural's Energy Efficiency Advisory Group (EEAG). Homes with gas in SW Washington tend to be newer construction with less of a need for weatherization, and only 2% of NW Natural's customers in Washington qualify as low-income. Barriers such as these limit participation. NW Natural continues to evaluate how to support agencies and adjust the program to increase the number of homes served per year. Table 5.20 shows the historical number of homes treated through the WA-LIEE program.

Table 5.20: Homes Served through WA-LIEE Program

Program Year	Homes	Therms Saved
2016	16	6,132
2017	13	6,048
2018	16	7,578
2019	22	20,170
2020	3	1,132
2021	11	3,568

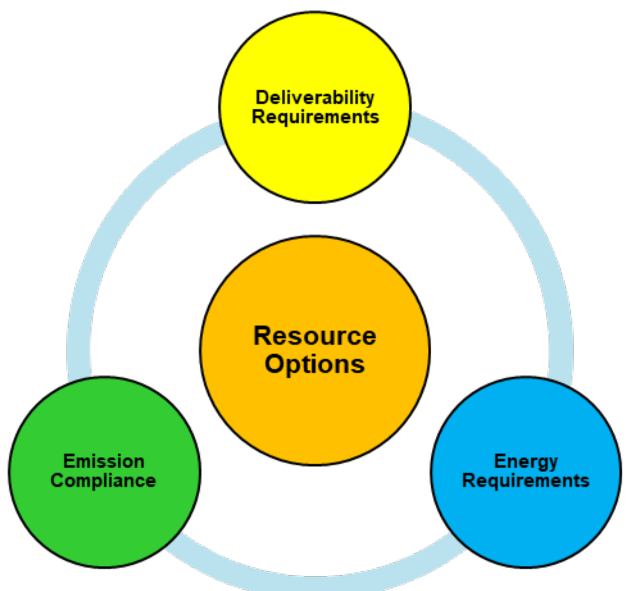
Once customer needs are established it is important to take a wide scope and assess what options are available to meet those needs. Chapter 6 discusses resources that can be used to serve customer energy and emissions needs throughout the year (conventional natural gas, renewable natural gas, and clean hydrogen) and during the coldest days we experience (pipelines and storage facilities).

6 Supply-Side and Compliance Resources

6.1 Overview

This chapter of the IRP discusses both current and potential supply-side resources that NW Natural uses to deliver conventional natural gas and renewable natural gas to customers. Supply-side resources include not only the gas itself, but also the upstream interstate pipeline capacity required to ship the gas, NW Natural's gas storage options, and other on-system resource options. Additionally, agreements for acquiring renewable thermal certificates (RTCs) on the behalf of customers and other emissions compliance resources, such as community climate investments (CCIs) are discussed in this chapter. Meeting compliance obligations in both Oregon and Washington over the planning horizon is a major focus for this IRP. While these compliance resources may not actually provide gas supply to the system, they are discussed in this supply-side resource chapter of this IRP.[109]

This suite of supply-side resources focused on in this chapter are associated with serving customers at the system level and meeting emissions requirements in both Oregon and Washington. Supply-side resource options associated with alleviating constraints in specific areas of the distribution system are discussed in Chapter 7.7.



All resources vary across three dynamics as to the value for what each resource provides to NW Natural's system; 1) the daily deliverability or capacity value, 2) the overall energy a resource can provide throughout the year, and 3) the contribution to emissions reduction under an emissions constraint. For example, a year-round pipeline capacity contract provides capacity every day of the year but needs to be paired with gas purchases to provide energy. Storage LNG facilities are limited on the amount of energy they can provide but can provide capacity for serving peak demand. Off-system RNG gas contracts provide emissions compliance requirements, but by themselves do not provide capacity to the system. All these different resources also vary in costs, availability, and risks.[110]

The rest of this chapter discusses general types of supply-side resources, NW Natural's current resource portfolio, future emissions compliance resource options, and future capacity resources

[109] Future discussion could help assess if resources needed for emissions compliance should be classified under a separate category as compliance resources such as CCIs do not clearly fall under the binary classification of demand-side or supply-side resources.

[110] Also, as done previously, potential resources are discussed in this chapter that ultimately are deemed too speculative to include in the portfolio choice analysis in Chapter Seven, with explanations for why they ended up on the "cutting room floor."

options available for NW Natural to address resource need. These current and future options are inputs to the resource planning optimization model discussed in Chapter 7. The ability to plan for customer requirement variations while maintaining reliability of service is best accomplished by having a diversity of resources available. The portfolio of supply-side resources available to NW Natural can be categorized under various primary resource types:

Natural gas, RNG, or hydrogen supply contracts – these are contract agreements for natural gas or RNG to be purchased from a producer or gas marketer for a specified volume for a given period and at a specific location known as a receipt point.[111] Natural gas supply contracts are purchased on a term basis, for example baseload contracts- or purchased on the spot (daily) market and must be used in conjunction with other supply-side resources, such as interstate pipeline contracts, to ship the gas from the receipt point to a delivery point connected to NW Natural's system, known as a citygate.[112] See Appendix E for further details about gas purchasing practices. RNG and Hydrogen are discussed in further detail later in this chapter.

Interstate/interprovincial pipeline capacity – NW Natural contracts with pipeline companies in the US and Canada to ship natural gas from receipt points, where gas is injected into the interstate/interprovincial pipeline, to delivery points where NW Natural physically takes custody of the gas. These capacity rights are used to ship gas supplies purchased for NW Natural sales customers to NW Natural's system.[113]

On-system production resources – On-system production resources are non-storage resources that produce gas and inject directly onto NW Natural's system. This primarily consists of injections from renewable methane sources, but also includes a minimal amount of Mist production gas still being collected from producing wells next to the underground Mist storage facility (a.k.a. Miller Station). The current on-system resources from renewable methane sources do not have environmental attributes, or RTCs, associated with the injected gas, however; future on-system renewable methane source could be bundled with the RTCs and used for emissions compliance for NW Natural customers.

Underground storage – There are 387 active underground natural gas storage fields in the Lower 48 states.[114] These facilities utilize depleted oil or gas production wells, natural aquifers, or salt caverns to store gas supplies. The geological properties of each of these underground facilities offers an effective means of storing large amounts of natural gas which can be accessed relatively quickly to meet seasonal demand shifts throughout the year.[115] Utilities, gas marketers, and other shippers of natural gas contract with the storage facility owners for both storage capacity (the total amount of gas stored

[111] Receipt points are commonly locations or gate stations on an interstate pipeline.
[112] The term ship is use purposefully here to refer to either physically flowing gas or moving gas via displacement on the interstate/interprovincial pipeline, as the pipeline contracts commonly refer to their customers, such as NW Natural as shippers.
[113] Transport customers are responsible for their own capacity and gas purchases upstream of NW Natural's system.
[114] https://www.eia.gov/naturalgas/storagecapacity
[115] For more information: https://www.eia.gov/naturalgas/storage/basics/

underground) and storage deliverability (the amount of gas that can be withdrawn from storage in a day).[116] While the storage capacity is a function of the geological properties of each facility, the storage deliverability is a function of the wells drilled into the formation and the piping and compression infrastructure used to withdraw stored gas. Note that storage capacity helps meet annual energy requirements, whereas storage deliverability helps meet system capacity requirements as discussed at the start of this chapter.

In addition, deliverability from underground storage can be a function of the storage inventory level (i.e., how full the storage facility is at any given time). When the facility is full, the pressure of the gas underground is high and therefore will flow freely out of the ground. As the facility empties, pressure declines and deliverability will also decline. Due to the physics of these facilities, storage contracts often include clauses known as "ratchets", which specify the deliverability as a function of a customer's capacity inventory level.

Above-ground LNG storage – Above-ground LNG tanks and facilities super-cool natural gas into a liquid, known as liquefaction, and are an effective way to store more energy per volumetric unit (e.g., cubic foot) compared to its gaseous form. LNG storage facilities reverse the process, known as vaporization, to quickly inject gas back into the system to meet spikes in demand. Compared to underground storage, these facilities have a higher ratio of storage deliverability to their overall storage capacity and are well-suited as "peaker" units to help meet demand spikes when temperatures plumet.

Industrial recall options – NW Natural contracts with several industrial counterparties for recall options wherein we would pay the replacement fuel price for an industrial company to switch to an alternative fuel source to propane, fuel oil or diesel and provide us with the natural gas supplies that they would have otherwise consumed. Note that these contracts are not with sales customers therefore would not be considered demand response. These contracts are agreements that provide additional interstate pipeline capacity and natural gas supplies if called upon. These contracts are limited to the number of days we can call on them in a winter season.

Citygate deliveries – The "citygate" is the point of delivery at which gas is transferred from an interstate or intrastate pipeline to a local distribution company's custody. Citygate contracts are for gas supplies delivered directly to NW Natural's service territory by the counterparty utilizing their own NWP pipeline capacity. Such deliveries could be arranged as baseload supplies, or on a swing basis, i.e., delivered or not each day at the option of NW Natural.

NW Natural has utilized citygate delivery agreements, on occasion, when cost effective. Such agreements usually take the form of swing arrangements that allow up to five days' usage during the period of December through February. As a near-term capacity resource city gate deliveries are relatively inexpensive, but if the option for deliveries is utilized, the commodity price for the delivered volumes is index-based and expected to be extremely high. The long-term reliability of citygate deliveries is very uncertain to be evaluated as a long-term option for IRP analysis, but these options are evaluated as an alternative for meeting design peak demand going into each winter.

6.1.1 Compliance Resource Types

Bundled and unbundled environmental attributes from RNG – unbundled purchases do not provide capacity nor energy to NW Natural's system but are a pathway for reducing carbon emissions or meeting state carbon reduction targets on behalf of NW Natural customers. One example is the purchasing of renewable thermal certificates (RTCs) that confer all the benefits of the RNG emissions reductions to NW Natural's customers. In other words, other parties cannot claim the emissions reductions for RTCs purchased and held by NW Natural. RTCs are generated when a Dth of RNG is injected into a gas pipeline, displacing fossil gas. Bundled purchases give NW Natural ownership of both the gas and the environmental attributes of RNG. A bundled resource could provide capacity and energy if bundled with an on-system production RNG resource or if it is used in combination with pipeline capacity contracts to ship the RNG to NW Natural's system. Alternatively, if the bundled RNG resource is not on-system or capable of utilizing NW Naturals pipeline contracts, NW Natural can unbundle the energy from the environmental attributes and sell the energy from that resource (often referred to as "*brown gas*") and retain the RTC of that RNG to retire on behalf of customers.

Qualified compliance instruments – certain compliance instruments are approved by legislation and qualify to be purchased to meet emissions compliance obligations. These compliance instruments are not tied a volumetric amount of methane but represent a metric ton CO_2e reduction for compliance obligation. The CPP in Oregon allows for CCIs, while in Washington the CCA allows for the purchase of both offset credits and tradable allowances (see Chapter 2 for policy details and section 6.6 of this chapter for modeling details).

6.2 Low Carbon and Zero Carbon Gas

The last few years have seen significant maturation in the technologies and markets around all types of decarbonized gases. Biofuel-based resources (typically referred to as Renewable Natural Gas, or RNG) are one type of low- or zero-carbon gas many are familiar with, as biogas has been used for decades to supply energy via direct heating use or power generation. But new technologies have opened new opportunities for decarbonized gases. Hydrogen generation from a variety of sources has also matured significantly, and projects looking to inject both pure hydrogen into gas lines as well as synthetic methane generated by marrying clean hydrogen with waste CO_2 are being developed today. Below we discuss the main types of low carbon gases NW Natural is currently considering as resources.

6.2.1 Biofuels

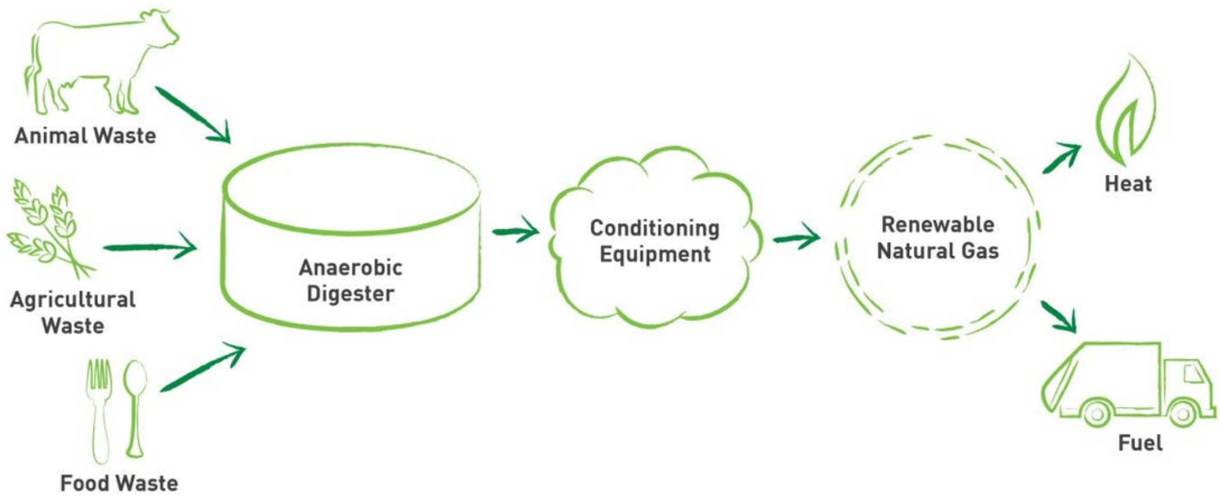
Biofuel gas or Renewable Natural Gas (RNG) is *pipeline-quality gas* derived by cleaning up the raw biogas emitted as organic material chemically breaks down. RNG going directly onto NW Natural's system must meet specified quality standards, be at least 97.3% methane and have an energy content of at least 985 BTUs/SCF. Once on our system, RNG is fully interchangeable with conventional natural gas, and requires no new equipment in customer homes or businesses.

In Oregon, RNG was defined in 2019's Senate Bill 98 as: "any of the following products processed to meet pipeline quality standards or transportation fuel grade requirements: Biogas that is upgraded to meet natural gas pipeline quality standards such that it may blend with, or substitute for, geologic natural gas; Hydrogen gas derived from renewable energy sources; or Methane gas derived from any combination of: Biogas; Hydrogen gas or carbon oxides derived from renewable energy sources; or waste carbon dioxide[117]." Thus, NW Natural takes a broad view of potential RNG resources it can secure on behalf of its Oregon customers.

In Washington, per 2019's House Bill 1257, renewable natural gas "means a gas consisting largely of methane and other hydrocarbons derived from the decomposition of organic material in landfills, wastewater treatment facilities, and anaerobic digesters." The bill further notes that "the [UTC]

[117] Oregon Senate Bill 98: https://olis.oregonlegislature.gov/liz/2019R1/Downloads/MeasureDocument/SB98/Enrolled

commission may approve inclusion of other sources of gas if those sources are produced without consumption of fossil fuels[118]."



There are many policies that drive NW Natural to procure RNG for its customers. Table 6.1 identifies the key driving policies that establish RNG goals, define RNG, define its role in our emissions compliance activities, and otherwise motivate NW Natural to secure least cost RNG resources on behalf of its customers.

Table 6.1: Policies Driving RNG Acquisitions

Policy	Relevance for RNG
Oregon Senate Bill 98	Volumetric targets for RNG procurement for Oregon sales customers
Oregon Climate Protection Program (CPP)	Compliance will include RNG and hydrogen (above and beyond Senate Bill 98 volumes) when cost-effective to procure
Washington House Bill 1257	Establishes both an option for delivery for RNG to all gas customers as well as a requirement to offer customers voluntary RNG tariff
Washington Climate Commitment Act (CCA)	Sets emission cap that applies to gas utilities, which can use RNG and hydrogen as a compliance tool
Voluntary offerings to customers	Building options for customers in Oregon and Washington to procure greater amounts of RNG and hydrogen

The policy that has had the largest impact to date on NW Natural's procurement of RNG is Oregon Senate Bill 98, which established volumetric targets for RNG that the Company internalized as its own RNG targets after the law passed. The law allows gas utilities to procure RNG and invest in RNG

[118] Washington House Bill 1257: https://lawfilesext.leg.wa.gov/biennium/2019-20/Pdf/Bills/House%20Passed%20Legislature/1257-S3.PL.pdf?q=20220917151937

projects, provided that the *incremental* cost of such procurement does not exceed 5% of the company's annual revenue requirement. The calculation for what costs are incremental is discussed later in this chapter.

Time Period	Large Gas Utility Volumetric Targets
2020-2024	5%
2025-2029	10%
2030-2034	15%
2035-2039	20%
2040-2044	25%
2045-2050	30%

Under Senate Bill 98 gas utilities can purchase RNG (including hydrogen) for all customers as part of our utility resource mix. This is a significant change, as prior to the passage of the bill, we could only buy the least-cost gas, which was not RNG. It also allows gas utilities to invest in and own the equipment necessary to bring raw biogas and landfill gas up to pipeline quality, as well as the facilities to connect to the local gas distribution system.

Senate Bill 98 has driven the Company to be a leader in the procurement of RNG among gas utilities, and to develop programs and build a team around the development and procurement of RNG. This technical and market knowledge can now be applied to NW Natural's compliance and planning under programs such as the Climate Protection Program, Washington House Bill 1257, and the Washington Climate Commitment Act.

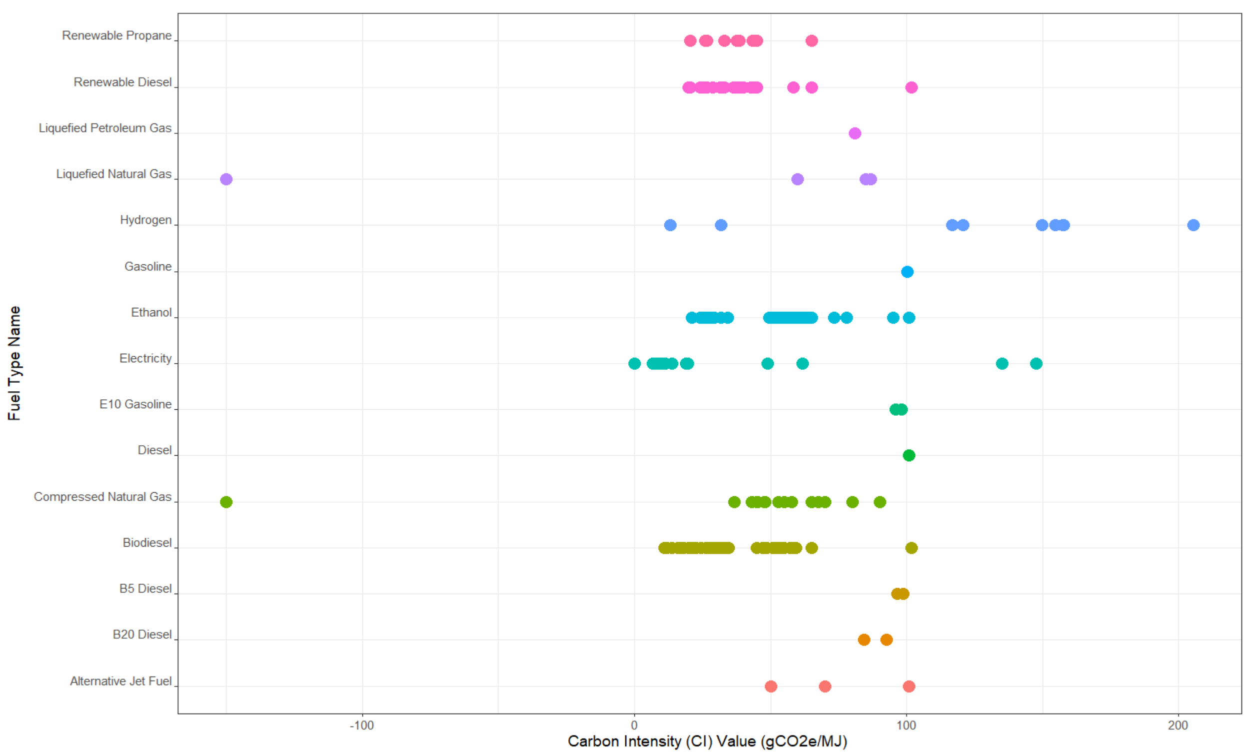
Emissions Benefits of RNG

There are several ways to evaluate the emissions of RNG. Both Oregon and Washington's laws relating specifically to procurement of RNG by gas utilities do not set parameters around prescribed carbon intensity of RNG. NW Natural considers RNG to be carbon neutral because the carbon dioxide that is emitted when RNG is combusted is biogenic – derived from and stored by organic matter – meaning that the combustion of it does not add any additional carbon into the carbon cycle. NW Natural reports its emissions in both states on a "combustion basis," which reflects the view that the carbon in RNG is biogenic, and thus the carbon emitted when combusted is not reported. This same approach is used by the U.S. Environmental Protection Agency, the International Energy Agency, and the Intergovernmental Panel on Climate Change, which all recognize that because the CO_2 in biogas is biogenic, it is appropriate to not report that carbon in RNG when reporting emissions.

There are other programs in the United States that use a different approach to measuring the emissions reduction benefits of RNG. These programs use "lifecycle-based" methodologies, which look at the total emissions embedded in the entire lifecycle of a fuel's production and utilization. These programs are mostly found in transportation fuels, which have several different types of fuels and use the lifecycle-based approach to evaluate these fuels on an "apples to apples" basis. This approach derives a "carbon intensity" of a fuel and includes considerations of the methane emissions that would have occurred had the RNG project not occurred, how efficient the use of the fuel is in the end use (e.g., how efficient is a certain motor?) and other aspects. Each fuel is given a "carbon intensity score" which can vary from month to month or year to year, depending on local policies that address methane emissions, project performance, etc. NW Natural does not use carbon intensity scores to evaluate RNG resources because our compliance environment uses combustion-based emissions treatment. However, NW Natural does record the carbon intensity score of its resources and reports it in its annual Senate Bill 98 reports. Oregon's rules for Senate Bill 98 require annual reporting of the carbon intensity of RNG, and we expect reporting for Washington under RNG delivered as part of a House Bill 1257 program will require similar data.

The carbon intensity of a resource using the lifecycle-based approach will vary depending on the raw feedstock, the process used, the efficiency of the equipment, etc. State-level clean fuels programs are the most advanced programs in evaluating and tracking the carbon intensity of RNG using this approach. Figure 6.1 shows the current carbon intensities of all the fuels currently registered in the Oregon Clean Fuels Program. As can be seen in the "compressed natural gas" fuel type, the carbon intensity score of CNG resources (most of which are RNG-derived) ranges from -150 to a little under 100 grams CO_2/MJ of fuel.[119]

Figure 6.1: Carbon Intensities for Registered Projects in the Oregon Clean Fuels Program



[119] Oregon DEQ's Clean Fuels Program: https://www.oregon.gov/deq/ghgp/cfp/Pages/Clean-Fuel-Pathways.aspx

Appendix E lists all the RNG projects located in Oregon, Washington, and California that are currently generating RNG using feedstocks that are common in the procurement of RNG currently being undertaken by NW Natural.

In Oregon, our compliance under the Climate Protection Program will be measured in part via the data reported in the Oregon Greenhouse Gas Reporting Program. Training provided by the Oregon DEQ notes that "We do not require direct delivery of the biomethane to the supplier, and an equivalent volume of natural gas can be assumed to have been displaced as long as the purchased biomethane was nominated to a natural gas pipeline[120]." This approach – separating the environmental attributes of the RNG from the physical delivered gas – is the standard used throughout the RNG industry, including in the U.S. Environmental Protection Agency's Renewable Fuel Standard, the Oregon Clean Fuels Program, Oregon Senate Bill 98, and the California Low Carbon Fuel Standard. As noted earlier, under SB 98 we are required to report the carbon intensity of all RNG resources utilizing the lifecycle approach, but that approach is not what is used to measure our emissions for purposes of the Climate Protection Program compliance.

Renewable Thermal Certificates (RTCs)

To track the environmental attributes of RNG and ensure that the benefits are not being claimed by multiple parties, the RNG industry has begun using the generation of "renewable thermal certificates" (RTCs) to track and record RNG transactions. Regardless of whether RNG is purchased bundled with or without the underlying physical gas, RTCs are recorded to ensure the environmental attributes of the gas are appropriately tracked.

An RTC is a sole claim to the environmental benefits of a dekatherm of thermal energy from sources such as RNG, hydrogen or synthetic methane, and is separate from the physical gas (i.e., unbundled RNG or hydrogen). RTCs are procured to meet compliance needs, to show how NW Natural is procuring renewable resources on behalf of its customers. The Midwest Renewable Energy Tracking System (MRETs), which has historically tracked the sale of electricity-based renewable energy credits (RECs) has emerged as the leading platform on which RTCs are tracked and recorded.

One RTC is created for every Dth of RNG produced and injected into the "common carrier" network or an LDC's distribution system.

[120] Oregon DEQ's Greenhouse Gas Reporting Training slides: https://www.oregon.gov/deq/ghgp/Documents/3pbC5ngSupplier.pdf and video recording: https://www.youtube.com/watch?v=FlzNhG-v16I

Figure 6.2: Tracking RTCs

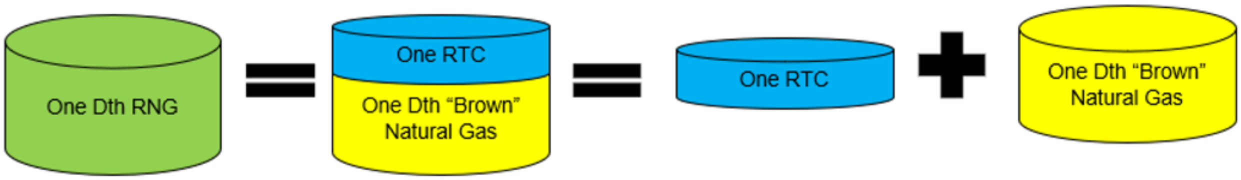
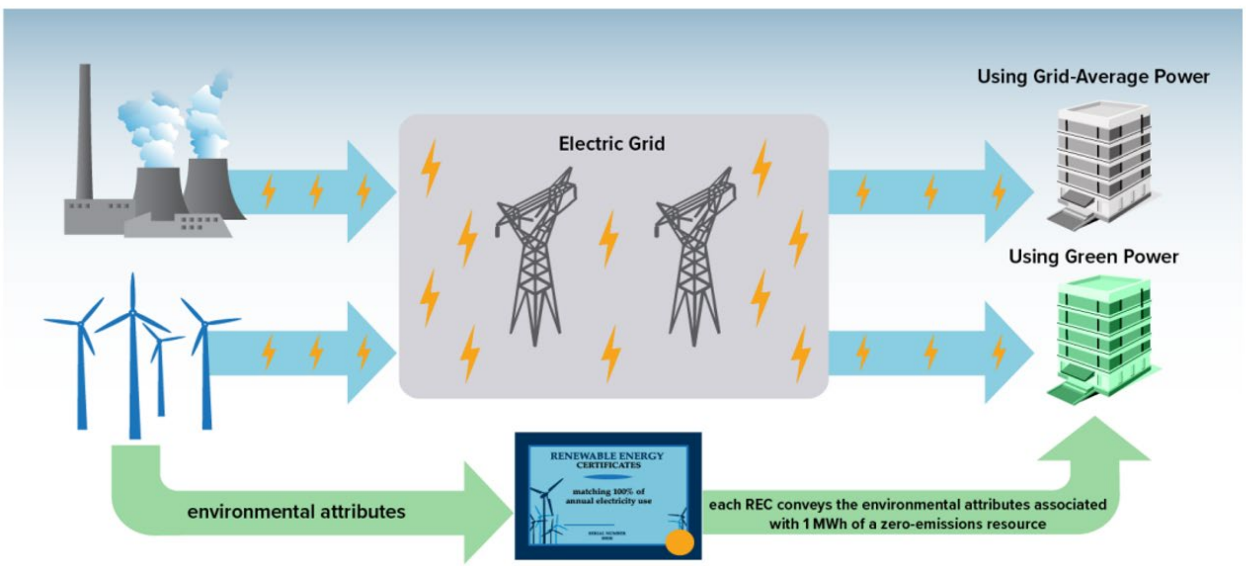


Figure 6.3: Tracking RECs



NW Natural purchases both bundled and unbundled RNG resources. Bundled resources means we are purchasing the physical energy and the RTC together; unbundled means we are just purchasing the RTC. Both are recognized as compliant resources under Senate Bill 98 and the Oregon Climate Protection Program. Contracts for RNG are either contracts for physical gas with special transaction confirmations and other elements that delineate what a producer will deliver RTCs into MRETs as part of their contractual obligations, or they are contracts just for the RTCs or environmental attributes of RNG.

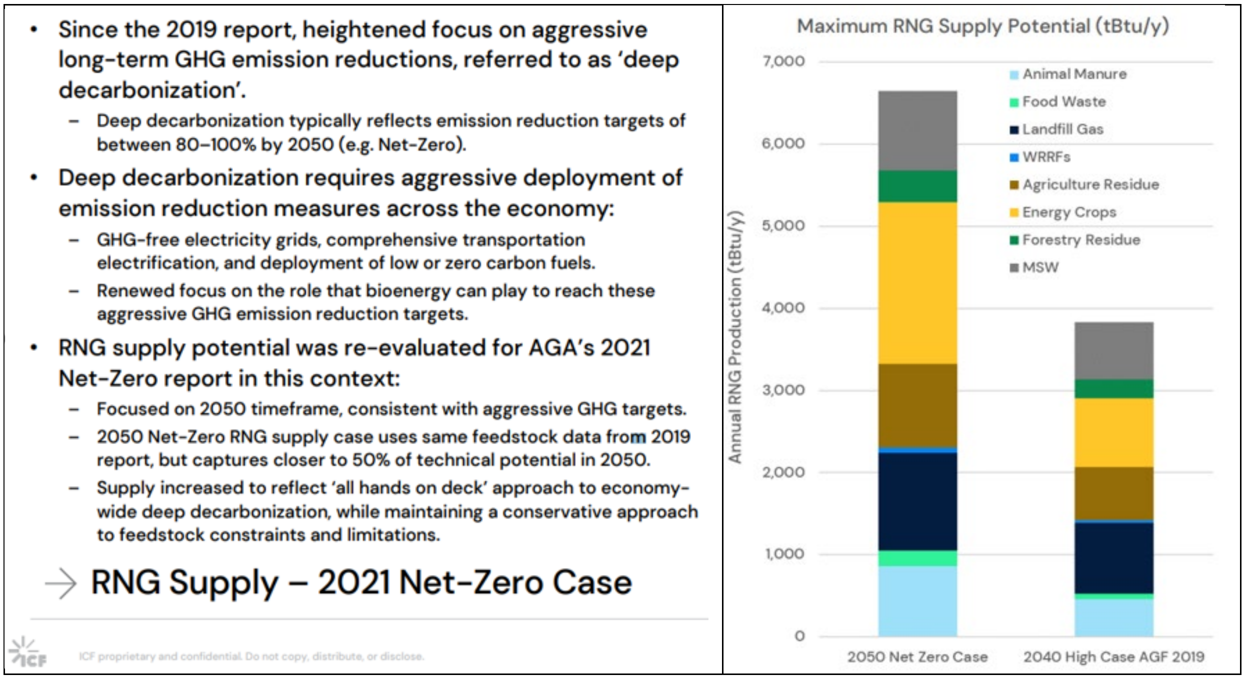
RNG Supply

RNG supply has recently been and continues to be a topic of research and new evaluation, as the industry matures, and more potential buyers seek to understand the type and amount, and economics of available RNG supplies. The American Gas Foundation supported a study by ICF in 2019[121] and the RNG supply potential was re-evaluated by ICF for the American Gas Association's 2021 Net-Zero

121 https://gasfoundation.org/2019/12/18/renewable-sources-of-natural-gas/

report.[122] ICF's updated Net-Zero report articulates that a larger maximum supply potential of RNG will be available with more aggressive decarbonization policies and utility renewable energy development. Figure 6.4 summarizes these findings.

Figure 6.4: ICF 2021 Net Zero Report Key Findings



NW Natural is a leader in RNG procurement and project development among gas utilities in the U.S. and Canada. In previous years, NW Natural considered the transportation fuel sector to be its primary competitor for low-cost RNG, due to the highly lucrative credit markets available to those sectors. However, in recent years other gas utilities and large commercial and industrial gas users have identified RNG as a critical resource for their decarbonization goals and targets and have begun to enter the market and buy RNG under both medium term (5 years) and long term (10 years+) contracts. NW Natural has internal RNG origination resources and has maintained active project origination and development efforts for several years. These activities and our annual RFP process for RNG will continue to help the company identify cost-effective RNG resources in the future. NW Natural continues to be able offer longer term contracts than most other market participants, and its high credit rating allows it to be viewed as a highly low-risk offtaker/purchaser of RNG by RNG project developers and owners.

[122] The results of these reports were presented at one of NW Natural's Technical Working Group #3. For more information, please see TWG 3, https://www.nwnatural.com/about-us/rates-and-regulations/resource-planning

NW Natural responded to concerns from stakeholders that there is not sufficient RNG to meet its goals.[123] In fact, just 1/50th of the updated ICF estimate of the total amount of RNG available in the US would be about 132 million MMBtu, which is nearly twice the total demand of gas by NW Natural sales customers today. While there has been healthy growth in the RNG market in recent years, there is still much more RNG that can be developed than what is already developed.

The costs for RNG reflect the production costs, including financing costs, the capital costs of equipment, the ongoing operating expenses, and development costs such as legal and permitting. The cost of RNG on a $/MMBtu basis is largely impacted by the size of the project. There are tremendous economies of scale in RNG production, as many of the high capital costs increase to some degree with volume, but not in a 1:1 manner. Costs for gas cleaning and conditioning equipment have increased along with all other major equipment in this inflationary period, and NW Natural will continue to evaluate how such cost increases are impacting offtake prices and the costs of RNG project development.

Renewable Natural Gas Procurement

Oregon Senate Bill 98, Washington HB 1257, the Oregon Climate Protection Program, and the Washington Climate Commitment Act all underscore the need for NW Natural to secure low carbon gases, including biofuel-based RNG and hydrogen resources. While each program takes a slightly different view of RNG definitions, cost caps, etc., NW Natural endeavors to secure resources that it believes will work within a variety of policies, regulations, and other programs. Our current assumption, for instance, is that all the RNG we have procured to date under Senate Bill 98 will also offer compliance benefits under the Oregon CPP. As noted earlier, the Oregon DEQ has stated that off-system RNG, which is typically tracked via RTCs, will qualify as a resource under the Oregon CPP.

RNG projects take several years to develop. NW Natural keeps track of projects at a variety of times in their lifespans. For instance, projects are sometimes in very early stages of development, with no definitive agreements or interconnection agreements signed, when they come to our attention. A developer may contact NW Natural about buying the RNG, and we will express interest but convey that we cannot enter true negotiations until the project has a clear pathway toward full development. NW Natural may enter non-binding letters of intent (LOIs) and non-binding term sheets with developers and project owners. Only a small number of these resources become actual contracted resources but entering into these non-binding agreements allows us to learn more about the resource, exercise our due diligence, and assess the costs and benefits of a project. This is similar to how other utility projects are assessed, where there is initial investigation/origination, targeted due diligence, and then recommendations for an investment or resource selection.

[123] See Oregon Docket UG 435, NW Natural's Reply Testimony and Exhibits: https://edocs.puc.state.or.us/efdocs/HTB/ug435htb162723.pdf

Projects must be continually evaluated and worked on, which makes it hard to put specific resources into an IRP. Typically, NW Natural must decide about whether to enter into definitive agreements within a set timeline (e.g., within 90-day exclusivity period, or in response to a formal bid process with a hard deadline). Additionally, all projects, regardless of timing or whether they are identified through the RFP process, are evaluated on the same metrics, which include incremental cost to customers, project risks, volume availability, etc.

NW Natural utilizes in-house origination resources as well as its external relationships in the industry to identify new potential RNG resoruces. An annual request for proposal process is used to evaluate multiple opportunties in the market and understand the breadth of renewable resources that might be available. Figure 6.5 and Table 6.2 summarize the 2021 RFP responses.

Figure 6.5: 2021 RFP by Feedstock

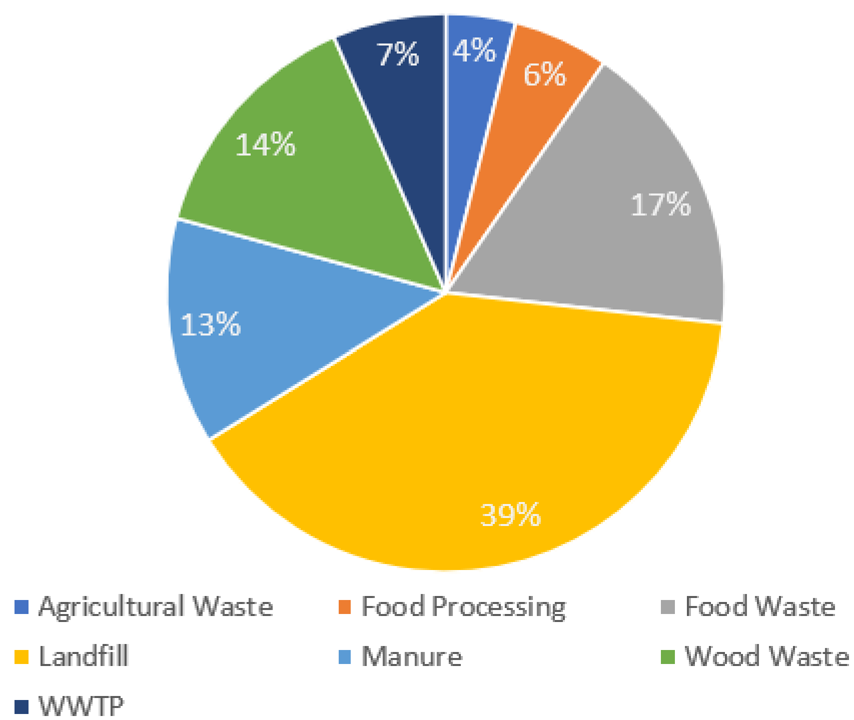


Table 6.2: 2021 RFP Responses- Summary

2021 RFP Response Summary	
Total Responses	27
Average Contract Term	14 years
Average Annual Volume of Resource	597,806 MMbtu
Bundled vs Unbundled	52% / 48%

2022 RNG RFP Procurement and Development Timeline

The 2022 RFP is NW Natural's 3rd annual RFP for RNG resources. The RFP was released on April 14, 2022, with short-listed respondents receiving notification in mid-June. Diligence was conducted on short-listed respondents June throught July and final agreement negotiations began in the third of 2022 and as noted above, NW Natural is in the midst of final negotiations with a small number of respondents and will be likely entering into multiple RNG contracts over the next several months as a result of the 2022 RFP.

Rolling Evalutations

Between rounds of RFPs, NW Natural additionally evalutates resources on a rolling basis. This includes a rolling evalutaion of other offtake resources as well as a rolling evalution of RNG development opportunities. For development opportunities, the following agreements and activities are common during NW Natural's rolling evalution process:

- Non-disclosure agreements signed to collect initial data
- Non-binding term sheets agreed to to explore economic agreements with feedstock owners, developers, project owners, etc.
- Extensive diligence processes undertaken to assess project economics and risks, including technical, legal, regulatory, financial, environmental, etc.

6.2.2 Hydrogen

Hydrogen is evaluated as a compliance resource option as it provides the needed emissions reductions for NW Natural customers. The use of hydrogen has many benefits including: its compatibility with current gas system operations, increasing the diversity of supply sources, the ability to deliver high temperature energy (critical for industrial process loads), the potential to support new vehicle fuel demand (trucking, aviation, marine), and the ability to store energy long term at a low cost.

The Hydrogen Rainbow

Hydrogen can be sourced from many sources and feedstocks, including electrolysis of water (referred to as electrolytic hydrogen or green hydrogen), gasification or pyrolysis of woody biomass, and cracking of imported ammonia. There are many types of hydrogen, and the colors represent the base source and production method, as depicted in Table 6.3. The manner in which different types of hydrogen may qualify for emissions compliance under the CPP and CCA is not entirely clear. To reflect some of the projects currently under consideration, this IRP only considers hydrogen produced through electrolysis (green hydrogen) and synthetic methane (described below) using renewably-generated electricity as a compliance resource. NW Natural is exploring all low-carbon sources of hydrogen inside and outside the region.

Table 6.3: Hydrogen Sources[124]

	Gray Hydrogen	Blue Hydrogen	Turquoise Hydrogen	Green Hydrogen	Pink Hydrogen
Process	Steam methane reforming	Steam methane reforming with carbon capture sequestration	Reforming methane into hydrogen gas and elemental (solid) carbon	Electrolysis, electricity is used to split the molecule into hydrogen and oxygen	Electrolysis, electricity is used to split the molecule into hydrogen and oxygen
Source	Methane	Methane	Methane	Renewably-generated electricity	Nuclear electricity generation

Regardless of the type of hydrogen that is produced or purchased, the hydrogen molecules can be blended into the existing pipeline and used by existing buildings, and commercial appliances. Preliminary studies and testing project a 20%, by volume, blending limit onto a combined system. In addition to the combined systems servicing homes and business, there is potential for hydrogen to have dedicated systems for large industrial processes currently relying on natural gas. These dedicated systems would flow 100% hydrogen that is completely separated from the distribution system delivering the blended hydrogen-methane gas but would provide the required energy for a large industrial customer.

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[124] Each source of hydrogen carries a carbon footprint from a lifecycle perspective. Green hydrogen carries the carbon intensity of the energy used to create the electricity and build and maintain the associated generation infrastructure, blue and turquoise sources have up- and mid-stream methane emissions or CO_2 sequestration efficiencies, etc. These carbon intensities depend on a number of design and production factors and can range from near-zero to the hundreds of grams of CO_2 per MJ of energy. The newly passed Inflation Reduction Act provides hydrogen production tax credits (PTCs) based on the carbon intensity of the gas, as measure on a lifecycle basis using the GREET software created by Argonne National Laboratory. The PTCs are highly skewed towards the lowest carbon intensities possible:
Based on carbon intensity ($0.60/kg base credit, **5x** if prevailing wages & apprenticeship requirements met):

- 0.45$kgCO_2/kgH_2$: 100% ($3.00/kg or $22/MMBtu)
- 0.45-1.5$kgCO_2/kgH_2$: 33.4% ($1.00/kg or $7.43/MMBtu)
- 1.5-2.5$kgCO_2/kgH_2$: 25% ($0.75/kg or $5.57/MMBtu)
- 2.5-4.0$kgCO_2/kgH_2$: 20% ($0.60/kg or $4.46/MMBtu)

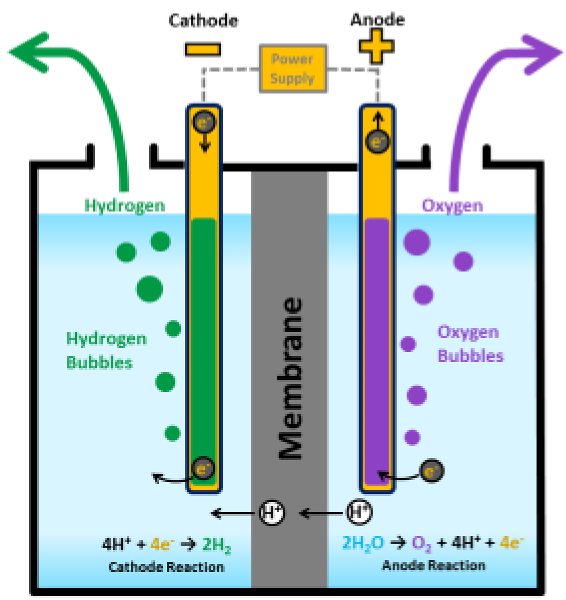
Any given hydrogen production pathway could be anywhere in this range of carbon intensities depending on the capital costs of the project. For example, electrolytic hydrogen using electricity from a coal generation plant could be on the lower end of carbon intensities using significant carbon capture infrastructure. The incentives to minimize the carbon intensity to obtain the maximize PTC are very high, and at a minimum, all hydrogen projects are expected to meet the definition of Clean Hydrogen as outlined in the Inflation Reduction Act, with the highest level being produced with emissions of 4$kgCO_2e/kgH_2$ or less.

Power-to-gas

Power-to-gas (P2G), also referred to as green hydrogen or electrolytic hydrogen, describes a suite of technologies that use electrolysis in an electrolyzer to separate water molecules into oxygen and hydrogen. P2G produces useful hydrogen that can be used as an energy source onsite (as in a fuel cell) or injected into a gas grid to produce energy that is very similar to typical natural gas. There are limitations in the amount of hydrogen that can be blended into the natural gas system, but current pilots are exploring blending up to 20% hydrogen within existing natural gas grids.[125] A discussion of P2G as a potential resource option is new to NW Natural's IRP process.

Figure 6.6 shows the basic reaction that occurs within an electrolyzer during electrolysis. An electrolyzer uses electricity to conduct this process, and if the electricity is sourced from zero-carbon resources, the entire production of hydrogen and oxygen is virtually zero-emissions.

Figure 6.6: Schematic of Polymer Electrolyte Membrane (PEM) Electrolysis



Source: U.S. Department of Energy. https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis

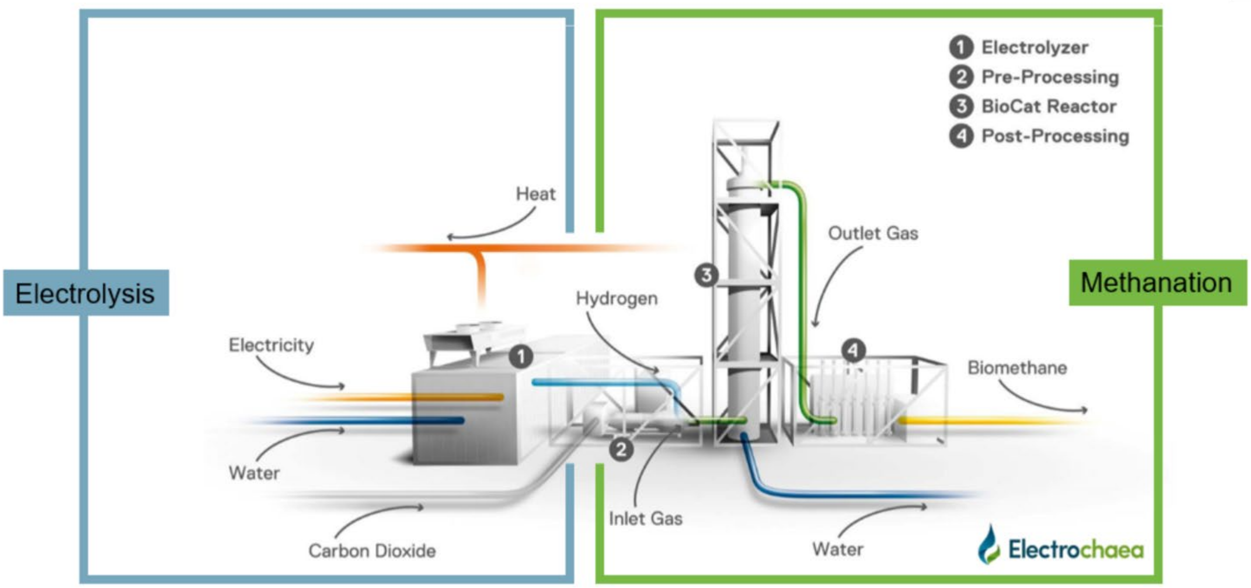
NW Natural is currently considering P2G projects that would blend hydrogen directly into the pipeline, at overall percentages likely far below 20%. NW Natural is reviewing research related to the impacts of varying percentages of hydrogen on system components and end use appliances to better understand the maximum potential of using hydrogen to meet different energy demands on our system with zero emissions.

[125] See, e.g., the HyDeploy project: https://hydeploy.co.uk/.

Synthetic Methane

Green hydrogen can be combined with waste CO_2 to produce synthetic methane (also referred to as synthetic natural gas or methanated hydrogen or power-to-X) using chemical or biological processes, as depicted in Figure 6.7. The molecule is identical to methane molecules sourced from fossil or renewable sources and can be directly injected into natural gas transmission and distribution systems. Unlike hydrogen, synthetic methane does not have a blending limit. Producing synthetic methane uses approximately 15% of the original chemical energy from the hydrogen; however, economies of scale through large production plants can decrease these costs such that they are competitive with small scale distributed hydrogen production.

Figure 6.7: Synthetic Methane Production Process



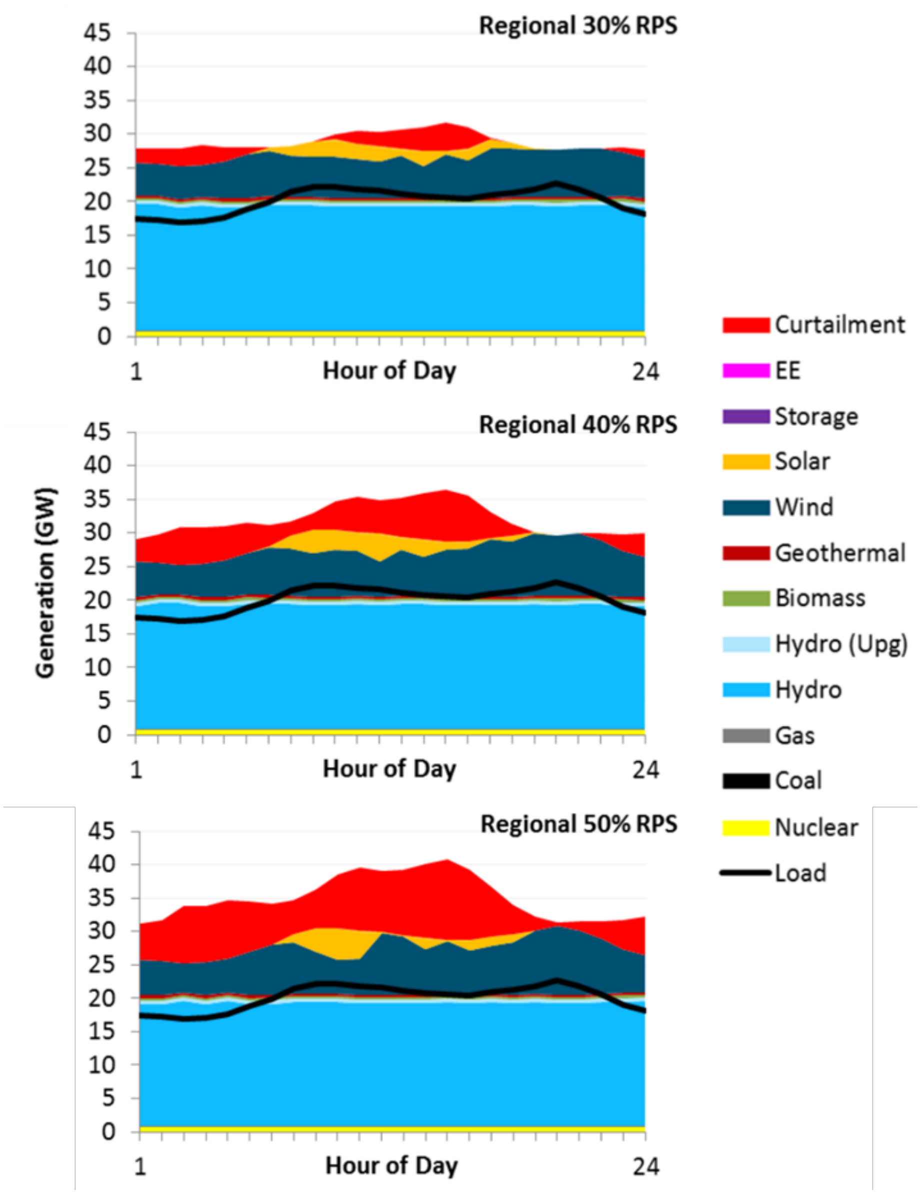
Synthetic methane does not have the energy dilution effects nor possible material compatibility effects that direct hydrogen injection has; therefore, large amounts can be produced and injected much easier as long as a suitable (i.e., low-cost and steady) waste carbon source can be found. NW Natural is pursuing synthetic methane projects where low-cost green hydrogen is available and direct hydrogen blending is not possible.

In addition, RNG projects which have low-cost electricity nearby are also being explored for synthetic methane “bolt-on” projects, as RNG has the requisite low-cost and steady waste CO_2 supply. By adding synthetic methane to RNG projects, almost twice the amount of gas can by produced at the site while leveraging the existing gas interconnect and compression infrastructure.

Power-to-gas and the Need for Seasonal Energy Storage

As renewable electricity goals and targets in the region ramp up over time, the amount of electricity that will need to be curtailed due to oversupply is expected to rise. See Figure 6.8 for one analysis of the impact of rising renewable portfolio standards on the overall amount of curtailed power.

Figure 6.8: Increasing renewable curtailment observed with increasing regional RPS goals[126]

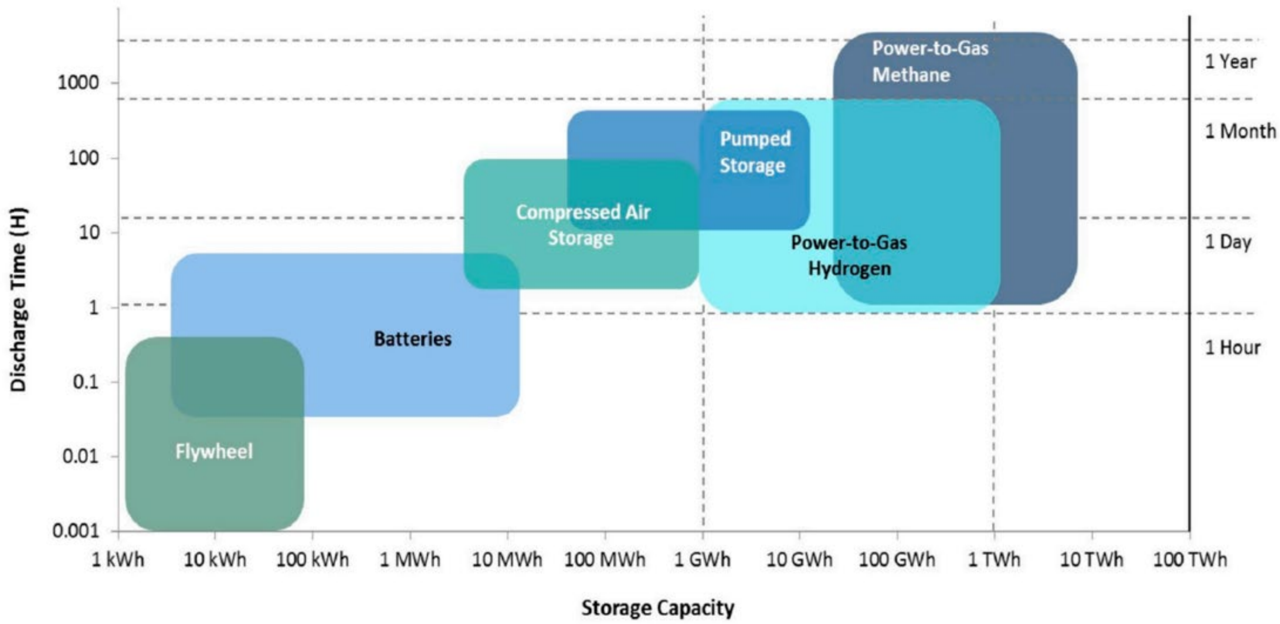


Curtailment events and the consequent energy storage needs are very different in the Pacific Northwest compared to other regions. In our region, excess generation occurs over a longer time period, and is less predictable day-to-day, due to the nature of the region's renewable resources. Thus,

[126] https://www.ethree.com/wp-content/uploads/2018/01/E3_PGP_GHGReductionStudy_2017-12-15_FINAL.pdf

shorter-duration energy storage resources, such as batteries, which are well-equipped to handle energy storage needs over the course of several hours, are less well-suited to handle the energy storage needs we will experience in our region, which will stretch over weeks or perhaps months.[127] For this reason, energy storage resources that can store energy over longer time periods are necessary.

Figure 6.9: Comparative Energy Storage Resources: Size and Duration



Source: https://www.californiahydrogen.org/wp-content/uploads/2018/01/CHBC-Hydrogen-Energy-Storage-White-Paper-FINAL.pdf

As seen in Figure 6.9, power-to-gas is one technology that can help store energy over much longer time periods than batteries and other shorter-duration energy storage resources. Hydrogen generated by excess power can be used immediately in the natural gas system, displacing natural gas purchases, and turning what would otherwise be wasted energy into usable energy. A power-to-gas system can run for days, weeks, and months at a time, providing an energy storage service to the grid for very long durations. The overall amount of energy that can be stored is dependent on the size of the natural gas system to which it is connected, and the available gas storage technologies attached to that system. In the case of NW Natural, energy can be stored and withdrawn from the existing distribution system as well as our significant underground storage resources, including Mist.

[127] See pp. xiii – xv in the Pacific Northwest Low Carbon Scenario Analysis: https://www.ethree.com/wp-content/uploads/2018/01/E3_PGP_GHGReductionStudy_2017-12-15_FINAL.pdf.

Power-to-gas Existing Technologies and Trends

There are three primary electrolyzer technologies that are available today for power-to-gas applications. These are:

- Alkaline
- Proton exchange membrane (PEM)
- Solid oxide (SOE)

Of these technologies, alkaline electrolyzers have been in operation much longer than the other two. They are also less expensive than the other technologies, and more efficient in their production of hydrogen. However, PEM technologies have advantages over alkaline electrolyzers such as faster ramp-up times and a smaller footprint. SOE technology is less developed but offers the distinct advantage of using heat as one of the inputs to generate hydrogen, so it could potentially offer a productive use for existing waste heat resources. The choice of electrolyzer depends on the situation and the way it will be operated.

Today most P2G projects are located in Europe, where P2G has been identified as a critical component of a low-carbon future. In the U.S., several demonstration projects exist, and several projects are being designed in Canada.

The Economics of Power-to-gas for the Direct-use Natural Gas System

When P2G is utilized as a supply-side resource for the direct-use natural gas system, its economics are driven primarily by technology costs (i.e., electrolyzer and methanation facility costs), the price of electricity used as a feedstock, and how often the built facility is used to produce deliverable gas. Additionally, the functional and emissions attributes of the various P2G technologies influence its relative cost effectiveness for a regional natural gas system.

A 2018 report commissioned by NW Natural found recent commercial-scale electrolyzer projects with construction costs between $500 and $1000 per kW of capability, a range consistent with other recent industry estimates. As with most emerging technologies, these costs are expected to decline through time. At a given facility cost level, the ultimate costs of hydrogen delivered to the natural gas system on a per-unit basis depends on the extent to which a built facility is utilized, often referred to as its capacity factor or utilization factor. For illustration, Figure 6.10 and Figure 6.11 isolate the impact of these two factors on the per-unit cost to produce gas. First, Figure 6.10 summarizes a range of per-MMBtu costs associated with varying facility capital costs, assuming a facility with 1 MW capability, 70% efficiency in turning electricity into gas energy, and a 20% capacity factor.

Figure 6.10: Electrolyzer Fixed Cost per MMBtu vs. Facility Capital Costs

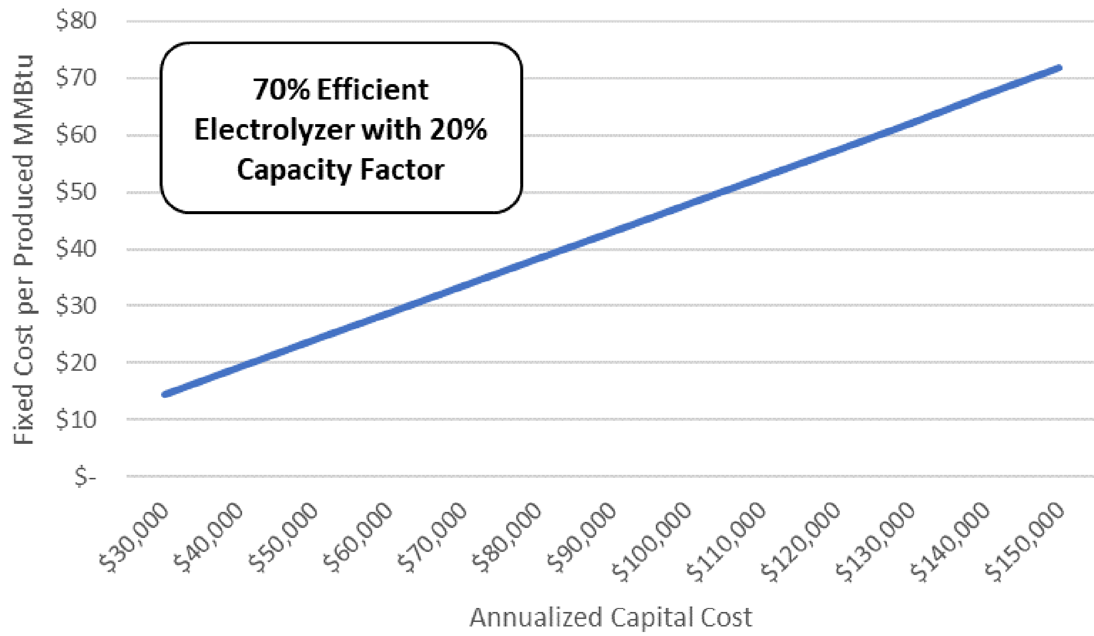
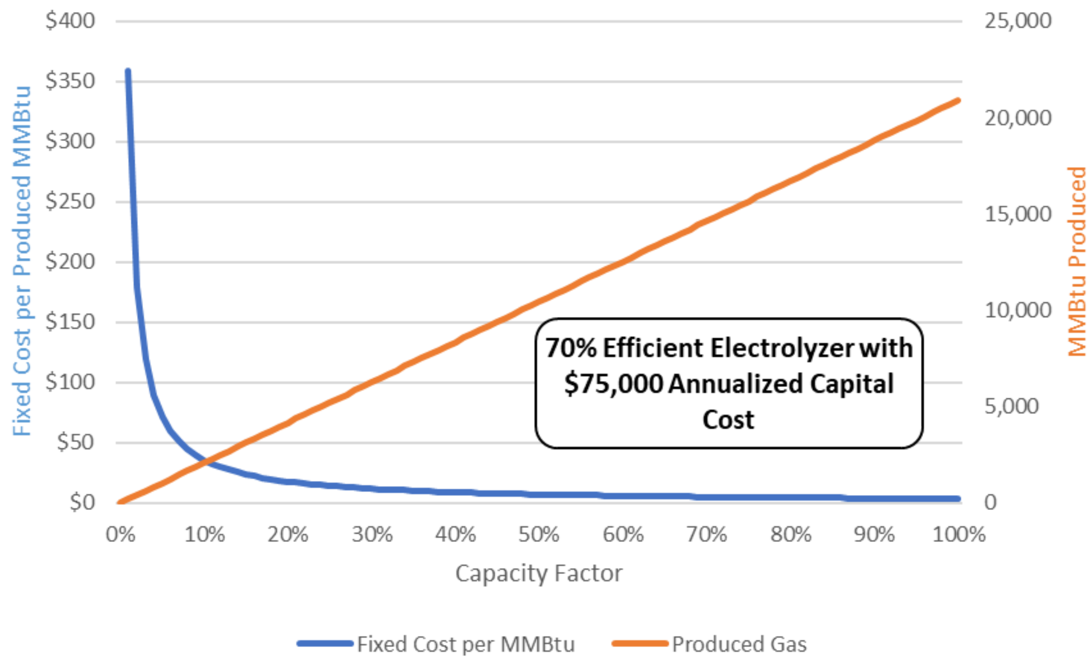


Figure 6.11 illustrates the cost impact of capacity factor on a 70% efficient 1 MW electrolyzer with a $75,000 annualized capital cost. If the facility is operated at capacity for an entire year, the capital (fixed) cost per MMBtu of produced gas would be $3.59. If the facility were operated during only half the hours of the year, this cost would double to $7.18/MMBtu.

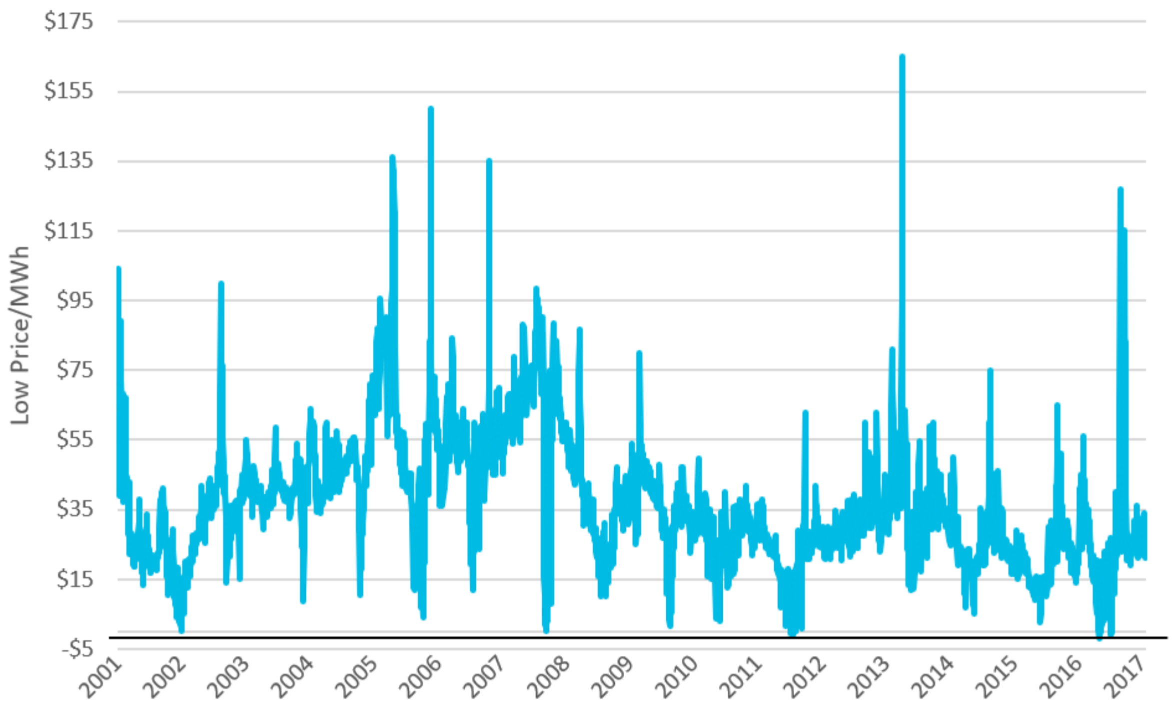
Figure 6.11: Electrolyzer Fixed Cost per MMBtu vs. Utilization Factor



While hydrogen produced by P2G technology must be blended with conventional natural gas to be used directly by most appliances, an additional conversion to methane (methanation) produces gas that is fully interchangeable with pipeline natural gas. Electrolysis may currently have more visibility in research and pilot programs in the U.S. and elsewhere, but several methanation facilities are in use in the U.S. and Europe, and the technology costs associated with this additional step in the P2G process are expected to fall over the coming decades.

For a direct-use natural gas system, P2G is essentially an opportunistic resource — by taking advantage of transitory surpluses in electricity markets, a gas utility can produce low-cost, carbon-neutral fuel for its customers. Thus, the availability of low-cost (or no-cost) electricity directly affects a P2G facility's utilization factor and overall economics. In the Pacific Northwest, electricity prices often fall to very low (and sometimes negative) levels during the spring season, as snowmelt increases hydro flows and electricity demand wanes with warming weather. At the Mid-Columbia power market, for reference, peak wholesale power prices have dropped below $0.01 per kWh on an average of roughly nine days per year over the last decade (Figure 6.12).

Figure 6.12: Mid-Columbia Trading Hub Peak Wholesale Electricity Prices, Daily Low



As the penetration of renewable generation resources increases in the region as a result of both market and policy forces, periods of curtailment (excess generation) are expected to increase in duration and frequency, and both power-to-hydrogen and power-to-methane technologies are recognized as well positioned for large scale and extended-duration storage. For NW Natural, the utilization rates of our power-to-gas facilities used for direct-use energy will likewise depend on this growing availability of low-cost electricity.

Given the opportunistic nature of P2G as a direct-use supply resource for the natural gas system, and limits on the amount of hydrogen that can be blended with conventional gas, it is worth noting that gas storage would likely play a key role in the integration of the two. At modest levels of hydrogen production, the product could be injected directly into local distribution networks; at higher levels, a combination of dispersed production/injection sites and storage would likely be used to incorporate hydrogen gas into the system.

A final but significant contributing factor in the cost-effectiveness of P2G for a natural gas utility is that its value would not be limited to that of the commodity it produces — its energy value. On-system P2G facilities would also serve as capacity resources, providing options for peak day production and delivery, and distribution system support during peak hours of the year, providing similar value to demand-side resources like energy efficiency measures.

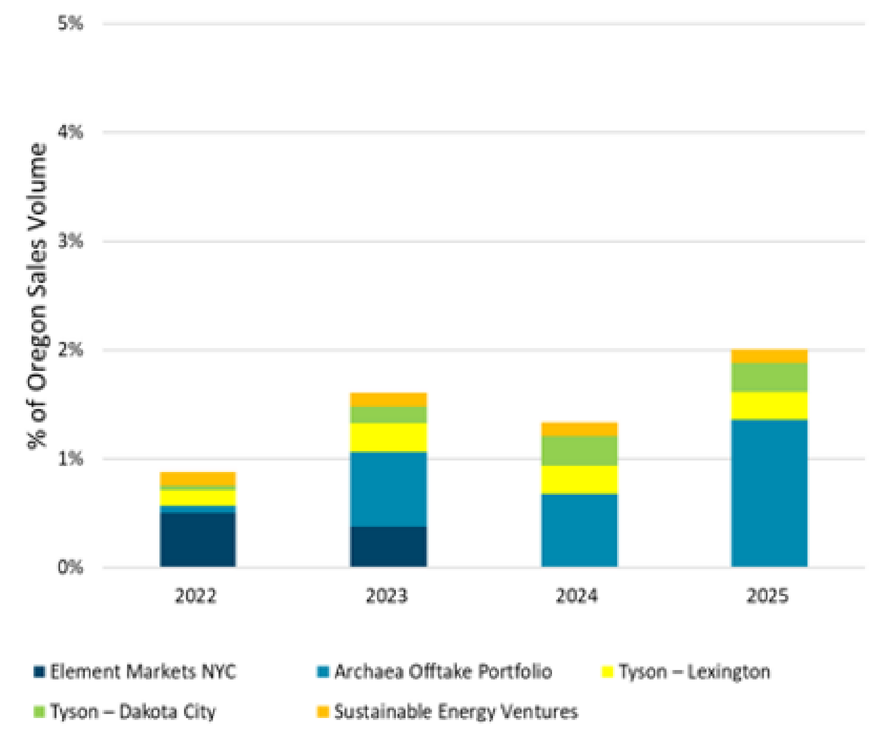
P2G is a relatively new and evolving technology, and as noted above its economics are substantially changing over time. As such, NW Natural draws from existing literature, industry reports, and internal consultants' reports for modeling purposes.

6.3 RNG and Hydrogen Evaluation Methodology

In our 2018 IRP we included the nation's first comprehensive methodology to evaluate the cost-effectiveness of low-carbon gas supply resources and sought acknowledgement of this methodology in Oregon. This request resulted in the OPUC opening a docket (OPUC Docket No. UM 2030) for review of the proposed methodology. This process resulted in a modified methodology that was approved by the OPUC to evaluate low carb gas supply resources. Also, as discussed in Chapter 2, a voluntary renewable gas portfolio standard (SB 98) passed in Oregon, and the resulting rules to implement the program included a placeholder for the evaluation methodology based upon the methodology acknowledged in the most recent IRP. NW Natural has been using this methodology to evaluate the incremental cost of potential resources to comply with climate policy in both Oregon and Washington. As we have gained experience in the RNG market we have made improvements to the methodology and greatly increased the risk evaluation portion of the tool as well as made a process that can align with the realities of the RNG market (in terms of timing and resource types). The updated methodology is included in detail in Appendix K.

Figure 6.13 shows a summary of current committed RNG resources as of March 2022. As our actual experience with RNG grows, we are able to build and refine the supply curve shown in Figure 6.14.

Figure 6.13: Summary of Current Committed RNG Portfolio- Contracted Resources by Opportunity



† For these 5 resources, the weighted risk-adjusted incremental cost is projected to be $7.38/MMbtu

‡ This graph reflects current contracted resources that are actively delivering RNG today. NW Natural has additional contracts in place for future RNG resources that are currently under development, totaling about 3% by 2025

Figure 6.14: Average Cost of RNG

†2020 and 2021 RFP responses, as well as development projects NW Natural is currently evaluating.
‡ Total production represented in chart: 35.3 million Mmbtu/year (about 49% of NW Natural's annual sales in Oregon in 2021.
♠ New RFP issued in 2022.
♦ Proposed supply tranches +/- variability:

- $14.00/Mmbtu
- $19.00/MMbtu

6.4 Current Resources

NW Natural's current portfolio of resources sufficiently meets energy and capacity requirements for customers and are on track to achieve RNG targets outlined by SB 98. This section discusses NW Natural's current resource portfolio.

6.4.1 Gas Supply Contracts

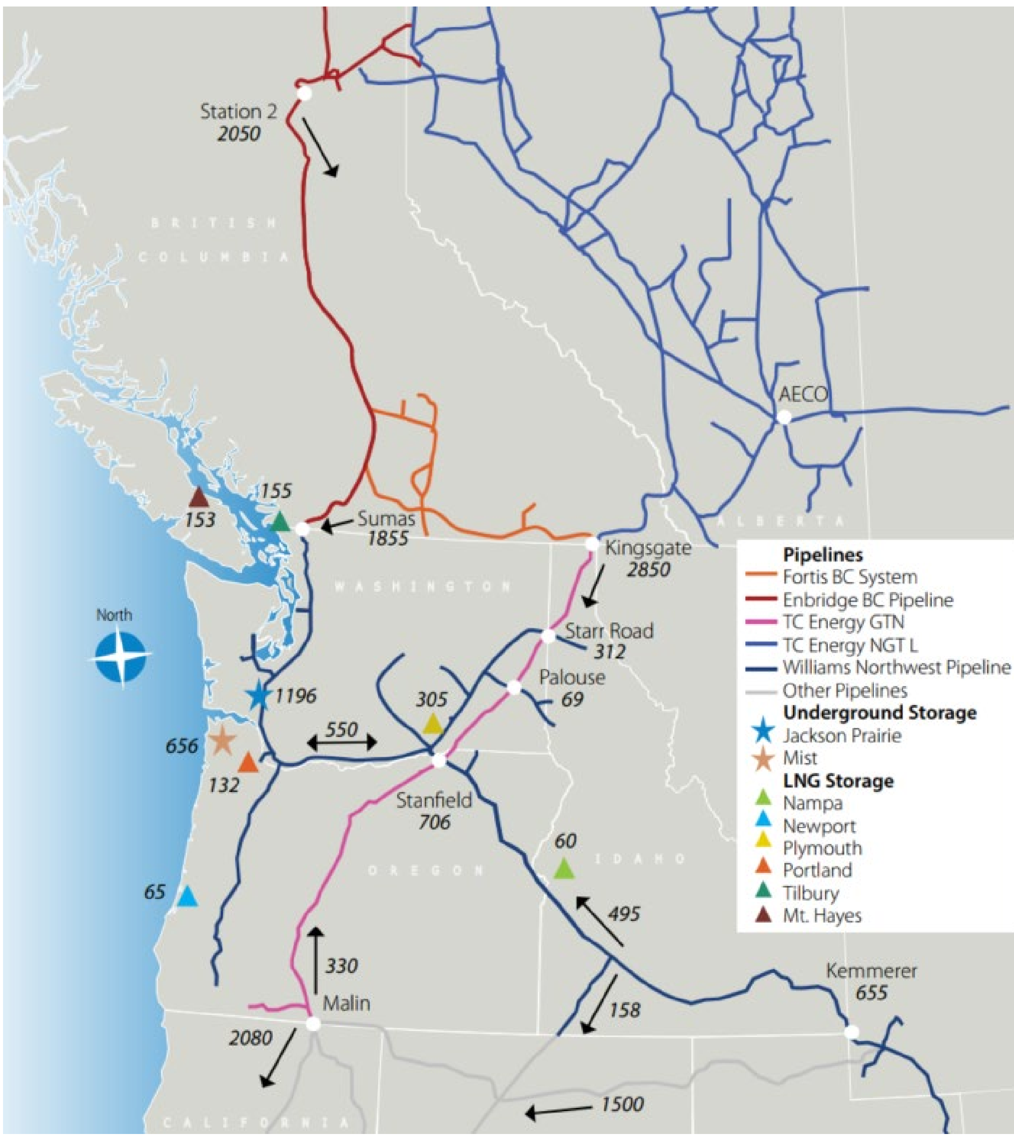
NW Natural has a portfolio of term supply contracts for each year, which are presented and reviewed in the annual purchased gas adjustment (PGA) proceedings in Oregon and Washington. The most recently approved portfolio of term contracts — for the 2021-22 PGA period — is included in Appendix E, Table E.2. Some contracts are designated using the term "Baseload Quantity," which refers to a contractual obligation for daily delivery and payment, while contracts designated as "Swing Supply" mean one party has an option to deliver or receive all, some, or none of the indicated volumes at its sole discretion.

In addition to term contracts, NW Natural buys certain gas volumes on the "spot" market, meaning the volumes, pricing and delivery points are negotiated on a real-time basis for delivery the following day or other near-term period, but no more than a month in advance. NW Natural maintains a diversified array of suppliers from whom gas can be bought on a spot or term basis.

6.4.2 Pipeline Capacity

A map showing the existing natural gas pipeline and storage infrastructure in the Pacific Northwest is shown in Figure 6.15. Total pipeline capacities in the map are shown in thousands of Dths per day (MDth/day).

Figure 6.15: Pacific Northwest Infrastructure and Capacities (MDth/day)



Source: Northwest Gas Association, 2022 Gas Outlook

Firm Pipeline Transport Contracts

NW Natural holds firm transportation contracts for capacity on Williams Northwest Pipeline (NWP), over which all of NW Natural's supplies must flow except for the small amount of natural gas that comes from on-system resources, which are less than 1% of annual purchases.

For gas sourced in the U.S. Rockies, transportation over NWP is all that is needed to bring the supplies to NW Natural's territory.

For gas sourced in British Columbia, purchases are either made directly into the NWP system at the international border (called Sumas on the U.S. side and Huntingdon on the Canadian side) or purchased in Northern British Columbia at a trading hub called Station 2. Extending northward from the international border is the T-South pipeline system (owned by and referred to as Enbridge BC Pipeline in Figure 6.15), which creates a connection between Station 2 and Sumas/Huntington. Purchases made at Station 2 first require transportation by Enbridge before reaching the Sumas/Huntington interconnection point and movement onward by NWP to NW Natural.

For gas sourced in Alberta, purchases are made at the trading hub known as AECO. Gas sourced at the AECO hub reaches the NW Natural system via four pipeline systems, three owned by TC Energy, and the fourth being NWP. Starting in Alberta with NOVA Gas Transmission Limited (NGTL or NOVA), the molecules, then travel along the Foothills pipeline in southeastern British Columbia.[128] The molecules continue south on this pipeline to the international border, at the Kingsgate point in northern Idaho, into Gas Transmission Northwest (GTN) pipeline, which extends southward and connects to NWP at Starr Road, in eastern Washington (near Spokane) and at Stanfield, in northeastern Oregon.

NW Natural has released a small portion of our NWP capacity to one customer but has retained certain heating season recall rights, discussed above as an Industrial recall option. Details of the current portfolio of pipeline transportation contracts are provided in Appendix E, Table E.3.

Since the implementation of the Federal Energy Regulatory Commission's (FERC) Order 636 in 1993, capacity rights on U.S. interstate pipelines have been commoditized, i.e., capacity can be bought and sold like other commodities. These acquisitions and releases occur over electronic bulletin board systems maintained by the pipelines, under rules laid out by FERC. To further facilitate transactional efficiency and a national market, interstate pipelines have standardized many definitions and procedures through the efforts of the industry-supported North American Energy Standards Board (NAESB), with the direction and approval of FERC. Capacity trades can also occur on the Canadian pipelines. In general, Canadian pipeline transactions are consistent with most of the NAESB standards.

Except for a small percentage of on-system supply, all the gas supplied to NW Natural customers must be transported over the NWP system, which is fully subscribed in the areas served by NW Natural.

[128] The small section of Foothills pipeline in southeastern BC is shows as a part of the NGTL system in Figure 6.13

Usage among NWP capacity holders tends to peak in a nearly coincident fashion as cold weather blankets the Pacific Northwest region. Similarly, NWP capacity that may be available during off-peak months tends to be available from many capacity holders at the same time. This means that NW Natural is rarely in a position to release capacity during high value periods of the year, and it would be unusual for capacity to be available for acquisition during peak load conditions.

Given the dynamics of market growth and pipeline expansion, NW Natural will continue to monitor and leverage the capacity release mechanism whenever appropriate, but primarily this will mean continuing to use our asset management agreement (AMA) with a third party to find value-added transactions that benefit customers.

Exposure to Sumas

About 30% of our contracts on the NWP system are sourced from Sumas. We can fill these contracts either with purchases directly at Sumas or with purchases further upstream at West Coast Station 2 (Station 2), which is a supply point where the commodity is being produced. Sumas on the other hand is a trading point where natural gas trading occurs but supplies at Sumas first must be transported there from a production source, such as Station 2. We have long-term Enbridge BC Pipeline (T-South) contracts that allow us to procure about half of the gas we need to ship from Sumas at Station 2. The other half of the supplies we ship from Sumas must be purchased directly at Sumas.

Historically, Sumas has been a high-priced, volatile trading point when compared to other trading points throughout North America. We are expecting this to be further exacerbated in 2027 when the Woodfibre LNG facility is expected to come online. Woodfibre LNG, which is being constructed in Squamish, B.C. will convert about 300,000 Dth of natural gas per day to LNG which will then be shipped overseas. Woodfibre LNG already holds the T-South pipeline capacity they need for their operations and this capacity is currently used to ship Station 2 gas down to Sumas where these supplies are sold.

When the LNG facility is operational, currently forecast to be in 2027, these supplies will be pulled from the Sumas market and used in the liquefaction process. This loss of gas supply equates to approximately 15 percent of the total available winter capacity to Sumas on the T-South system and will represent a fundamental shift in the region’s gas supply availability to serve existing demand. It will have significant adverse implications for customers relying on purchasing gas supply at Sumas unless there is an upstream pipeline expansion or another solution that would benefit the market at Sumas. In fact, if a regional peak cold weather event were to occur after Woodfibre is in service and before a solution could be found, we could possibly see supply shortages in the Pacific Northwest.

There are several pipeline solutions that are being marketed as a solution for this supply leaving the market at Sumas and NW Natural will evaluate participation in these projects as the opportunities present themselves. We will also evaluate longer-term physical purchases at Sumas or Mist Recall as solutions for the market disruption at Sumas.

Due to the expectation that Woodfibre LNG will begin operations in late 2027, thus tightening the Sumas market, we do not expect that we will be able to procure large volumes of spot gas during a cold weather event. While we are confident that gas supplies shipped on segmented capacity would flow, our ability to find these supplies will be restricted and that is why we are no longer relying on segmented capacity for a peak day starting in the 2027-28 winter, as is discussed in the segmented capacity section.

Segmented Capacity

Segmented capacity is secondary firm capacity on NWP that is deemed reliable due to the high probability that it will be available during times of peak usage. This reliability assumption is validated every IRP cycle through an analysis of NWP flow data through the Chehalis Compressor Station along the I-5 corridor. The analysis uses the prior three to five winters to validate that there is sufficient North to South capacity available as the weather gets colder. These assumptions are based on current market dynamics as the ability to schedule segmented capacity is more reliable as weather becomes colder (see Appendix E for the Chehalis compressor analysis). For more details on the process of segmentation see Chapter 6, section 3.3 in the 2018 IRP.

For many years now, NW Natural has segmented capacity and flexed the receipt and delivery points to create useful, albeit secondary, firm transportation on the NWP system. This segmented capacity flows from the north (Sumas) in a path that has not experienced constraints, during the coldest weather events in recent years. Utilizing segment capacity does not incur an additional demand charge and only incurs NWP’s variable and fuel charges in additional to the Sumas commodity costs. Because of this low opportunity cost, segmented capacity is very valuable resource for customers.

Modeling of segmented capacity began in 2014 with 43,800 Dth/day included in the analysis. Another 16,900 Dth/day of segmented capacity was subsequently created in 2016. This combined amount of 60,700 Dth/day was included in the both the 2016 and 2018 IRPs. This amount remains in the current IRP planning until 2027 when certain constraints in the Sumas market are expected to increase the risk of being able to procure spot gas on a peak day. This IRP does not rely on segmented capacity to meet peak demand starting in the 2027-2028 gas year but does allow it to be used on colder non-peak days at 30,000 Dth/day the rest of the year (see Table 6.4).

Table 6.4: Segmented Capacity Availability Assumption

Timeframe	Design Peak Day Availability	Non-Design Peak Day Availability
2022 – Oct 2027	60,700 Dth/day	60,700 Dth/day when temperature is < 40
Nov 2027 – 2050	0 Dth/day	30,000 Dth/day when temperature is < 40

6.4.3 Storage Assets

NW Natural relies on four existing storage facilities in and around our market area to augment the supplies shipped from British Columbia, Alberta and the U.S. Rockies. These consist of underground storage at Mist and Jackson Prairie, and LNG plants located in Portland and Newport, Oregon.

NW Natural owns and operates Mist, Portland LNG, and Newport LNG, all of which reside within NW Natural's service territory. Hence, gas typically is injected into storage at these facilities during warm periods and withdrawn when needed during cold periods directly onto NW Natural's system.

In contrast, Jackson Prairie underground storage is located about 80 miles north of Portland near Centralia, Washington, i.e., outside NW Natural's service territory. Jackson Prairie has been owned and operated by other parties since its commissioning in the 1970s. NW Natural contracts for Jackson Prairie storage service from NWP. Several separate contracts with NWP provide for the transportation service from Jackson Prairie to the NW Natural citygate.

Table 6.5 shows the maximum storage capacity and deliverability of these four firm storage resources.

Table 6.5: Firm Storage Resources[129]

Facility	Maximum Daily Deliverability (Dth/day)	Maximum Seasonal Storage Working Capacity (Dth)
Mist (reserved for Utility Sales Customers)	305,000	12,213,605 *
Newport LNG	64,500 *	752,500 *
Portland LNG	130,800 *	368,776 *
Jackson Prairie	46,030	1,120,288

Notes: Newport LNG tank maximum capacity currently de-rated pending results of the CO2 removal project, and the available capacity also takes into account a minimum 20% tank level needed for normal operations. Portland LNG maximum capacity currently de-rated due to seismic analysis, and the available capacity also considers a minimum 20% tank level needed for normal operations.

The Mist storage deliverability and seasonal capacity shown in Table 6.5 represents the portion of the facilities reserved for utility service. Mist began storage operations in 1989 and currently has a maximum daily deliverability of 480 million cubic feet[130] per day (MMcf/day) with peak hourly deliverability at a rate of 515 MMcf/day, and a total working gas capacity of 17.3 billion cubic feet (Bcf). These volumetric figures are converted to energy values (Dth) using the heat content of the injected gas. That heat content conversion factor had been relatively constant at 1,010 Btu/cf in prior years but has increased and stabilized at around 1,060 Btu/cf over the past several years.

Storage capacity and deliverability in excess of core needs is made available for the non-utility storage business and AMA activities. As core needs grow, existing storage capacity may be recalled and transferred for use by core utility customers, which NW Natural refers to as Mist recall discussed later in this chapter.

6.4.4 On-system Production Resources

On-system production resources produce methane and do not require upstream capacity resources. In other words, these resources produce and inject gas directly onto NW Natural's system.

[129] The numbers in this table marked with an asterisk (*) originated from volumetric units (e.g., Bcf) and have been converted to energy units (Dth) using the heat content (Btu per cf) of the applicable facility, which may differ very slightly from the assumed heat content factors used in other portions of this IRP. The other numbers in this table 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. These values based on the heat content are firm storage resources as of Nov 2021.

[130] All uses of cubic feet in this chapter assume "standard conditions" of gas measurement, i.e., temperature of 60°F and pressure of 14.7 pounds per square inch absolute.

6.4.5 Mist Production

Natural gas wells owned by a third-party in the Mist area continue to produce small quantities of low Btu gas which NW Natural purchases and blends into larger volumes of gas supplies at Miller Station. Over time these wells continue to deplete, and new wells have not been drilled for several years. Unless there is a renewed interest in exploration and production of natural gas in the Mist area, it is expected that these volumes will continue to decline over time.

6.4.6 On-system Production

Two producing RNG projects are interconnected to the NW Natural distribution system and another one is expected to come online later in 2022. Currently, NW Natural only purchases the underlying *brown gas* from these projects and does not have rights to the environmental attributes associated with this RNG. Expected volumes from these projects are still included as gas supplies in the IRP as they do provide a capacity benefit, but not a compliance benefit.

6.4.7 Industrial Recall Options

NW Natural has contracts with three industrial companies located on or near our distribution system wherein we can call on natural gas supplies if needed in the winter. The price of these contracts is tied to an alternate fuel source that the industrial company could use if we were to call on their flowing natural gas supplies. If called upon, these supplies would be delivered to NW Natural at our citygate on the industrial customers' capacity with NWP. Each contract has specific terms outlining when we can call on the capacity and at what volume. Contracts range from 1,000 Dth/day to 30,000 Dth/day.

6.4.8 Existing RNG Contracts

NW Natural has 3 renewable natural gas RTC offtake agreements and 2 development projects, one of which is currently under construction, and one that is operating (see Figure 6.16 for details). In 2021 we officially retired 148,037 RTCs from these project(s) on behalf of customers.

Figure 6.16: Current RNG Contracts

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

Renewable Natural Gas RTC (Renewable Thermal Certificates) Offtakes

NW Natural has entered into three offtake agreements to purchase RNG from operating RNG projects. Most will be delivered to Oregon customers and will be a part of the Oregon PGA, but some RNG will likely be used for other programs, such as those in Washington and future voluntary tariffs. The following are these offtake agreements:

- Offtake #1
    - Five-year term
    - About 200 Dth/day
    - Organic waste processing facility in Utah
    - Fixed price per RTC; purchase what is delivered

- Offtake #2
    - Two-year term, with option for one year extension
    - About 1,000 Dth/day
    - Wastewater treatment plant in New York plus dairy-based agricultural waste in Wisconsin
    - Fixed price per RTC; only purchase what is delivered

- Offtake #3
    - 21-year term
    - Production ranges from 500,000-1,000,000 Dth/year
    - Landfill facilities (multiple)
    - Fixed price per RTC; only purchase what is delivered; required minimums, damages for failure to deliver

Renewable Natural Gas Development

NW Natural partnered to develop RNG upgrading and conditioning facilities at the Tyson Fresh Meats facilities in Lexington and Dakota City, Nebraska.

Tyson Fresh Meats Facilities:

- Two of the largest beef processing plants in U.S.
- Beef processing and packaging; 7,000 employees across both facilities
- Lexington: newer plant (built in 1990); Dakota City: Tyson purchased in 2001 (built in 1966)
- Processes enough beef daily to feed 18 million people
- Both facilities recently received significant investment in new equipment, wastewater processing facilities, etc.
- Both facilities together expected to produce about 360,000 MMbtu/ year of RNG (about 0.5% of Oregon annual sales)

Scope of RNG Projects:

- Utilize biogas off existing lagoons
- Implement biogas flow balancing control systems
- Address and correct leaks/sources of possible oxygen intrusion
- Invest in upgrading technology (membrane/pressure-swing absorption)
- Invest in interconnection to local gas pipelines
- Buy the RNG and sell *brown gas* locally
- Retire RTCs on behalf of NW Natural customers

Figure 6.17: Tyson Lexington Skid

6.5 Future Compliance Resource Options

As 2022 is the first compliance year for Oregon and 2023 is the first compliance year for Washington, acquiring resources to meet compliance obligations is an immediate issue. This section outlines the various non-demand-side resources available to meet emissions compliance obligations.

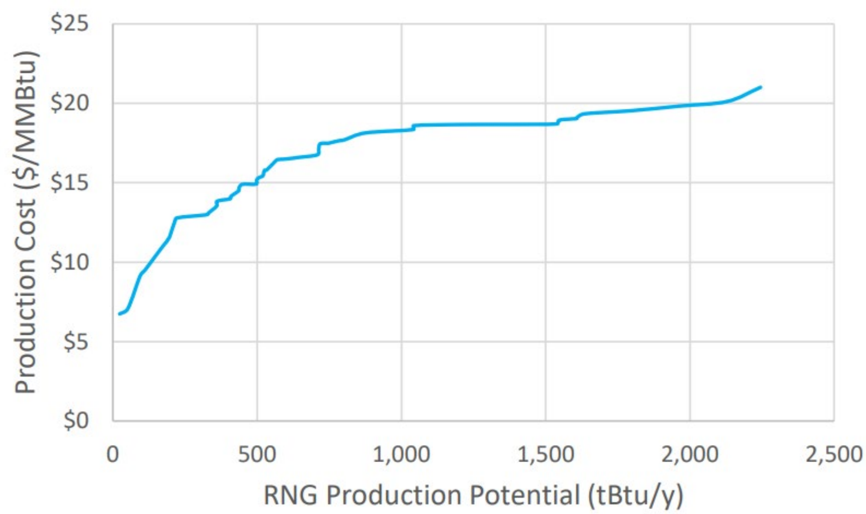
6.5.1 Biofuel RNG

As discussed in detail above and through participation in the RNG market and our annual RFP process, NW Natural maintains a deep understanding of the RNG market. Using information from ICF's AGF 2019 RNG Supply Report and NW Naturals annual request for proposal (RFP) process two RNG supply tranches are developed as a compliance resource for consideration in resource planning optimization. Each tranche represents a portfolio level set of RNG projects with a portfolio average price and associated quantities.

The 2019 ICF study evaluates the technical potential of eight feedstock options including: landfill gas, wastewater, food waste, animal manure, agricultural and forestry residues, and energy crops. The study includes a range of high and low resource potential cases and calculates both the technical potential and an estimate of supply which could be realized. ICF uses a relatively conservative approach in estimating technical potential in both resource potential scenarios. It should be noted that the technical and resource potential are developed independently of policy GHG objectives and illustrates the diversity of RNG supply options available at different price points. On the high end, the study estimated a national technical potential of 14,000 tBtu with roughly 27% or 3,800 tBtu as available for RNG supply. For reference, total US annual direct use natural gas consumption is approximately 18,000-19,000 tBtu.[131]

ICF estimated the majority of RNG produced would be available in the range of $7-$20/MMBtu as plotted in Figure 6.18. These cost estimates reflect the all-in cost to collect, clean, and deliver the RNG up to the point of injection into a common-carrier pipeline. It provides a minimum price point estimate, which RNG developers would need to recoup their costs.

Figure 6.18: Combined RNG Supply Curve in 2040[132]



In addition to the study done by ICF, NW Natural also uses information gathered through our annual RFP for RNG resource acquisition and the prices offered for 2020 and 2021 RFP responses as well as the costs for development projects currently being evaluated (see Figure 6.14 for details).

Since the current RNG market is nascent, dynamic, and these specific resources are not always available throughout the planning horizon, a traditional supply curve would be inappropriate for the IRP. Instead, NW Natural uses a two-tiered portfolio approach for the IRP. The maximum amount of RNG available to NW Natural is 75% of our customers' population weighted share of the national RNG supply potential, estimated by the ICF study. The total amount of RNG available to NW Natural is then split into two traches based on the supply curve as illustrated by Figure 6.19.

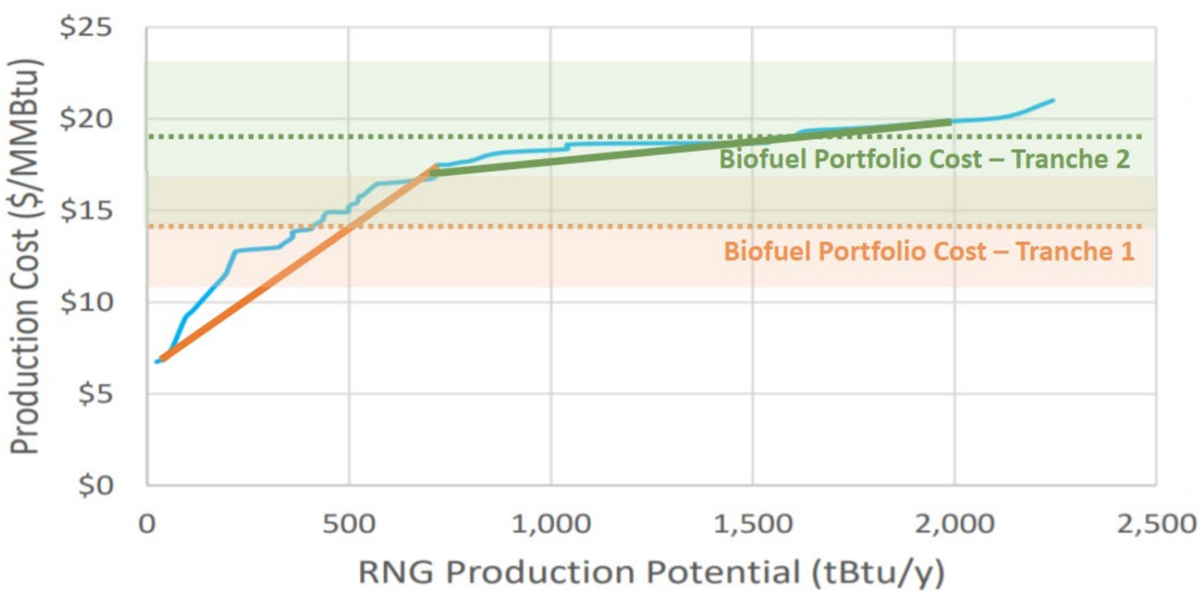
[131] Excludes gas for electric generation and natural gas used in vehicles. Source: https://www.eia.gov/energyexplained/natural-gas/use-of-natural-gas.php#:~:text=The%20United%20States%20used%20about,of%20U.S.%20total%20energy%20consumption.

[132] Source: *Renewable Source of Natural Gas: Supply and Emissions Reduction Assessment*. American Gas Foundation Study Prepared by ICF, 2019.

Tranche 1 (orange in
Figure 6.19) represents 1/3 of the total RNG resource available to NW Natural. This is approximately 13 million MMBtu annually. Additionally, most of Tranche 1 represents larger, nearer term projects, such as landfills and can be acquired for a portfolio cost of $14/MMBtu (+/- $3/MMBtu in stochastic simulation).

Tranche 2 (green in
Figure 6.19) represents the remaining 2/3 of the resource available to NW Natural, approximately 27 million MMBtu total annual production. This tranche would likely consist of longer term and higher cost projects, such as a new-build solid waste/food digester. Tranche 2 can be acquired for a portfolio cost of $19/MMBtu (+/- $5/MMBtu in stochastic simulation).

Figure 6.19: Biofuels Supply Curve and Tranche 1 & 2 Portfolio Cost[133]



6.5.2 Hydrogen and Synthetic Methane

As discussed in earlier in this chapter, hydrogen can be blended onto the existing system up to 20% by volume and there is potential for dedicated hydrogen systems for large industrial applications. Between the combination of a blended system and the potential for dedicated systems, this IRP uses a 20% of all deliveries by state limitation for hydrogen that can be used for compliance. The use of hydrogen for an LDC to serve its customers is in its infancy and this limitation is uncertain. Therefore, the limitation on hydrogen as a percentage of deliveries is treated as uncertain in the risk analysis of the IRP.

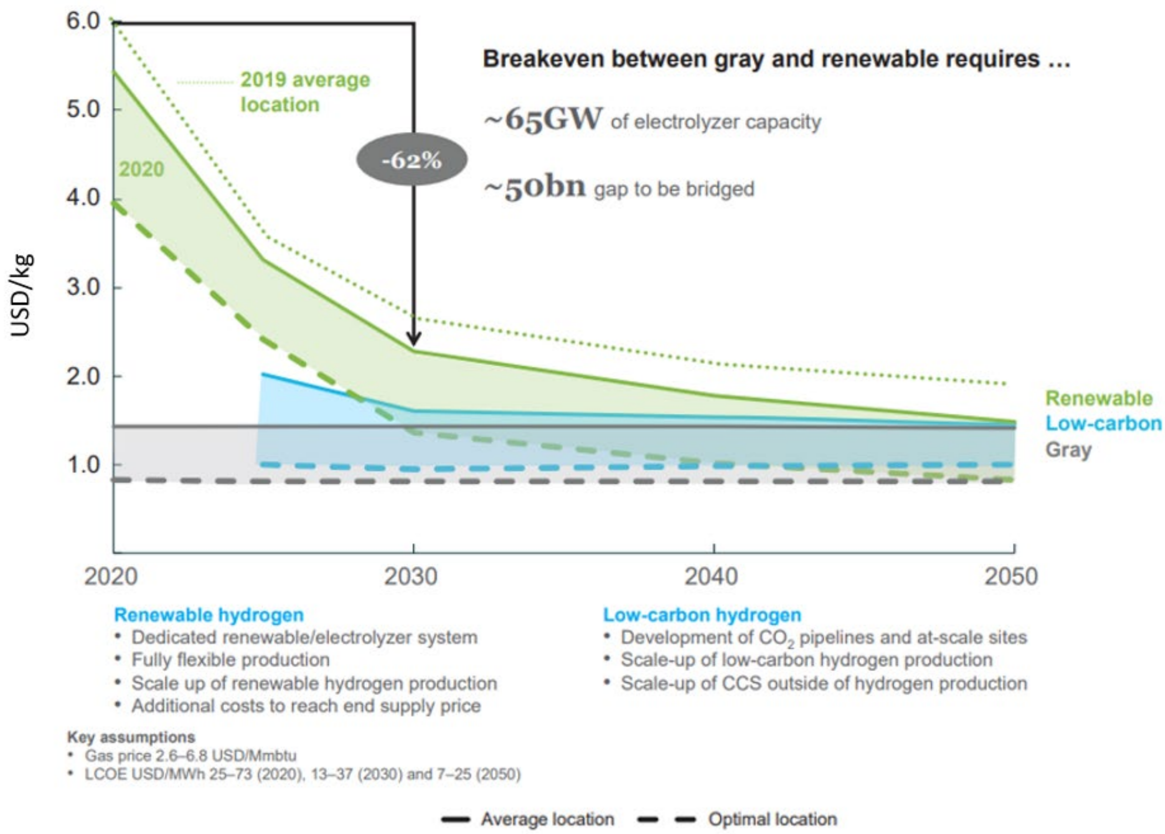
[133] Supply Curve (Blue Line) Source: "Renewable Source of Natural Gas." American Gas Foundation Study Prepared by ICF (2019). RNG supply potential adjusted for update in "Net Zero Emissions Opportunities for Gas Utilities." American Gas Association Prepared by ICF (2022).

Currently, hydrogen sourced from natural gas with carbon capture, low-carbon hydrogen, is the lowest cost resource. Renewable sources are becoming increasingly economically viable and are predicted to lower the production cost of hydrogen over the planning horizon. Specifically, the cost of renewable hydrogen is expected to be on par with the cost of low-carbon hydrogen by 2030, as depicted in Figure 6.19. This decrease in cost is driven by three factors:

1. A forecasted decline in off-peak electricity prices as more renewable generation is available during low demand periods, both at the daily and seasonal level.
2. A decrease in the capital costs of electrolyzer technology as the production of electrolyzers starts benefiting from economies of scale.
3. Capacity factors of hydrogen production at individual hydrogen facilities increase, which spread the fixed capital costs across more hydrogen volumes.

The cost for renewable hydrogen will be highly dependent on the cost of electricity, the growth of renewables and projected overbuild of wind and solar, the share of available biofuel RNG for hydrogen production, and the costs of electrolyzer technology. Due to these factors, the costs of electrolytic hydrogen are expected to decline.

Figure 6.20: Production Cost of Hydrogen[134]



Source: Hydrogen Insights Report 2021; Hydrogen Council, McKinsey & Company

Hydrogen costs are modelled based on the *Hydrogen Insights Report 2021* shown in Figure 6.20. Given the reasons already discussed, hydrogen from renewables is expected to have a relatively steep cost decline in the near term. This rate of cost decline will not continue indefinitely, and the economics will at some point in the future temper the cost decline, like the cost declines seen in wind and solar technology and application. We model the cost of hydrogen starting at roughly $23/MMBtu with higher rate of decline through until 2030 where it pivots to a slower trajectory, but still decreases to roughly $5/MMBtu by 2050. In addition to the forecasted decrease to the prices of hydrogen due to the economics, a hydrogen production tax credit could reduce costs further and help make hydrogen a low-cost resource in the nearer term. This cost trajectory and the potential for a tax credit is uncertain and analyzed as such through the risk analysis.

[134] Multiply USD$/kg$H_2$ by 7.43 to get USD$/MMBtu.

Synthetic methane is another potential compliance resource. Hydrogen, regardless of the feedstock used to produce it, can be combined with waste CO_2 to create synthetic methane. However, the IRP models only synthetic methane created from renewable hydrogen. The synthetic methane molecule is identical to the methane molecules sourced from fossil or renewable sources and can be directly injected into natural gas transmission and distribution systems. Due to this fact, synthetic methane does not have a blending limit and is modelled as a non-bounded quantity.

Producing synthetic methane uses approximately 15% of the original chemical energy from the hydrogen; however, economies of scale through large production plants can decrease these costs such that they are competitive with small scale distributed hydrogen production. Synthetic methane also does not have the energy dilution effects nor possible material compatibility effects that direct hydrogen injection has; therefore, large amounts can be produced and injected much easier as long as a suitable (i.e., low-cost and steady) waste carbon source can be found. NW Natural is pursuing synthetic methane projects where low-cost renewable hydrogen is available and direct hydrogen blending is not possible.

The cost of hydrogen is the primary cost component for creating synthetic methane, but additional costs are determined by the additional capital costs of the methanation equipment and the cost of waste CO_2. We model the costs of synthetic methane through all scenarios and simulations as the price of hydrogen plus an additional adder. This adder starts at $7/MMBtu and decreases over the planning horizon, but the primary driver of the cost decline for synthetic methane is the decline in the cost of hydrogen. We note that this adder for synthetic methane above the price of hydrogen is uncertain and is analyzed in the risk analysis.

6.5.3 Community Climate Investments (CCIs)

As was discussed in Chapter Two, CCIs are a unique compliance tool developed by DEQ specifically for the CPP. These tools were designed to focus on funding emission reduction projects benefitting underrepresented communities. CCIs are projected to be available by the first demonstration of compliance. Per the rule making, the price of CCIs will be set at $71/ton for the first compliance period and raise over time. Use of CCIs as a compliance instrument is limited to 10% of the compliance demonstration during the first compliance period (2022-2024), 15% during the second compliance period (2025-2027), and 20% during the subsequent compliance periods (2028-2050).

6.5.4 Tradable Emission Allowances

Discussed in further detail in Chapter 2, rules are being developed by the Washington Department of Ecology to implement a cap on carbon emissions. Mechanisms for the sale and tracking of tradable emissions allowances are included in that rule making. Long term, the program is intended to link with similar programs in other states/jurisdictions, such as California. The cap-and-invest program works by setting a limit on greenhouse gas emissions in state, and then lowering that cap over time. The program baseline is set at average covered entity greenhouse gas emissions from years 2015-2019. Reductions from this baseline are set at 45% by 2035, 70% reduction by 2050 and 95% by 2050.

NW Natural will be assigned some free allowances over the planning horizon but will be required to hold total allowances equal to the company's covered Washington customer's emissions. This will likely require the utility to purchase allowances at the quarterly allowance auctions. As NW Natural is a relatively small participant in the allowance market, the utility should be able to purchase as many allowances as needed.

6.5.5 Offsets

The CCA allows covered parties to purchase offsets up-to 5% of their emission within the first compliance period. An additional 3% of offsets can be purchased for project on tribal lands. For a total of 8% in the first compliance period (2023-2026). This decreases to 4% of offsets and 2% for projects on tribal lands, total 6% for all subsequent compliance periods. NW Natural is an active participant in the offset market through the Company's Smart Energy Program. We used pricing data from our internal subject matter experts to develop a price forecast for these offsets.

6.5.6 Compliance RNG Resources and Compliance Instruments Comparison

Compliance RNG resources and compliance instruments can be used to meet emissions compliance in both Oregon and Washington. Each type of compliance resource has various quantity limitations, purchasing options, and can be acquired at various costs. Table 6.5 lists the various options that NW Natural can acquire and a summary of their short-term flexibility to help fill in the gap for emissions obligations, which may arise due to year-over-year changes in weather.

Table 6.5: Long-term Compliance vs Short-term Flexibility

Emissions Compliance Options	Long-term Compliance Option	Short-term Compliance Flexibility
Energy Efficiency	✓	
Development RNG	✓	
RNG offtake from existing project	✓	✓
Development Hydrogen	✓	
Development Synthetic Gas	✓	
Community Climate Investments*	✓	✓
Banking	✓	✓
Allowance Trading Auction**	✓	✓
Bilateral Allowance Trading*	✓	
Offsets**	✓	✓

* Only and option under Oregon Climate Protection Program
** Only and option under Washington Cap-and-Invest

We make a distinction between 1) RNG compliance resources, which are ultimately tied to a specific amount of low carbon or zero carbon gas and 2) compliance instruments, which are tied to a specified quantity of emissions which can be deducted from the Company's overall obligation. The costs and quantity limitations for RNG compliance resources employed in the resource planning optimization model are summarized in Table 6.6.[135]

Table 6.6: Renewable Natural Gas Costs and Volumes

Resource	Bundled Price ($/MMBtu)			Volumes Available		
	10th Percentile	Reference	90th Percentile	10th Percentile	Reference	90th Percentile
Biofuels RNG Tranche 1	$10.50	$14.00	$16.50	-50%	11 Million Dth : Oregon 2 Million Dth : Washington	100%
Biofuels RNG Tranche 2	$14.00	$19.00	$24.00	-50%	24 Million Dth : Oregon 3 Million Dth : Washington	100%
Hydrogen				10% Combined	20% combined blending and dedicated systems by state	40% Combined
2022	-20%	$23.00	40%			
2050	-50%	$5.00	70%			
Synthetic Methane				Unlimited		
2022	-20%	$30.00	40%			
2050	-50%	$9.00	70%			

These RNG compliance resources are likely to be longer-term commitments, either through offtake agreements or project development. Therefore, we model these resource options as long-term decisions that if selected as a least cost resource remain throughout the rest of the planning horizon. For example, if the model were to select a hydrogen resource in 2022 for 10 MMBtu per year when the cost of hydrogen is $23 per MMBtu, it incurs a cost of $230 per year for the remainder of the planning horizon, even though the costs of hydrogen decline over time.

To align with the legislation for both Oregon's CPP and Washington's CCA, we model compliance resources from RNG, hydrogen and synthetic methane as having zero anthropogenic carbon dioxide, which is the prevailing approach for evaluating the emissions from biogas-based resources in a combustion-based regulatory framework. This essentially means that each MMBtu or RTC of RNG, hydrogen, or synthetic methane selected in the resource planning optimization model (PLEXOS®) avoids the combustion of one MMBtu of conventional gas in terms of emissions compliance.[136] The PLEXOS® model has the flexibility to assign different carbon intensity scores to different resources if NW Natural's emissions were reported and regulated using a lifecycle accounting basis. NW Natural

[135] Note that the table shows a bundled price, but we subtract out the average price of gas when inputting the costs into the model.

[136] There is a small difference between Oregon and Washington for the carbon intensity score for conventional gas. Washington HB 1257 requires that the IRP account for assumed upstream emissions and results in slightly higher CI score for conventional gas. We account for this difference in the PLEXOS® model.

follows the current guidance on greenhouse gas reporting at the federal and state level in its evaluation of the emissions benefits of RNG, hydrogen, and synthetic methane.

The PLEXOS® model has the flexibility to assign difference carbon intensity scores to difference resources. NW Natural follows the direction of CPP and CCA policies and models carbon intensity scores for RNG that align with these policies in the IRP.

Compliance instruments (CCI, tradable allowances, and offsets) are far more flexible resources to meet emissions obligations. We model these resources as options that can be purchased as needed in each compliance period of the CPP and CCA. As NW Natural is small participant in the tradable allowance market, we do not put any limitations on the amount of the allowances the Company is able to purchase. To align with Washington HB 1257 language to use the SCC for planning, we use the maximum of the SCC and our allowance price forecast to price the tradable allowances in PLEXOS®.[137] This ensures that other compliance resources will be selected if they are ever lower cost than the SCC and required to meet the Company's emission obligation in Washington. This is used for resource selection, but when discussing rate impacts in Chapter 7, we use the allowance price forecast. Quantity limitations on CCIs and offsets are specified by rules for the CPP and CCA. Compliance instrument's costs and volumes are summarized in Table 6.7.

[137] Note that in the Reference Case the SCC is higher than the allowance price forecast over much of the planning horizon. Only in the last few years does the forecasted allowance price increase above the SCC. The allowance price is uncertain and is treated as uncertain in the risk analysis.

Table 6.7: Compliance Instrument Costs and Volumes[138]

Compliance Period	Reference Case Cost		Reference Case Volumes
	$/Metric Tons CO2e	$/Dth	
Oregon : Community Climate Investments (CCI)			
2022-2024	$109	$5.79	10% of OR compliance period deliveries
2025-2027	$112	$5.89	15% of OR compliance period deliveries
2028-2031	$115	$6.10	20% of OR compliance period deliveries
…..	…..	…..	
2049-2051	$135	$7.17	
Washington : Tradable Allowances			
	Max(SCC,Allowance Price Forecast)		No Quantity Limits for NW Natural
2023	$82	$5.11	
2050	$120	$7.63	
Washington : Offsets			
2023-2026	$12	$0.63	8% of WA compliance period deliveries
2027-2030	$16	$0.86	6% of WA compliance period deliveries
…..	…..	…..	
2047-2050	$91	$4.83	

Figure 6.21 and Figure 6.22 shows the reference case price paths for the compliance resources over the planning horizon for Oregon and Washington, respectively.

[138] Prices to vary within a compliance period. The prices indicated are the prices at the start of the compliance period indicated.

Figure 6.21: Reference Case Oregon Compliance Resource Bundled Price Paths

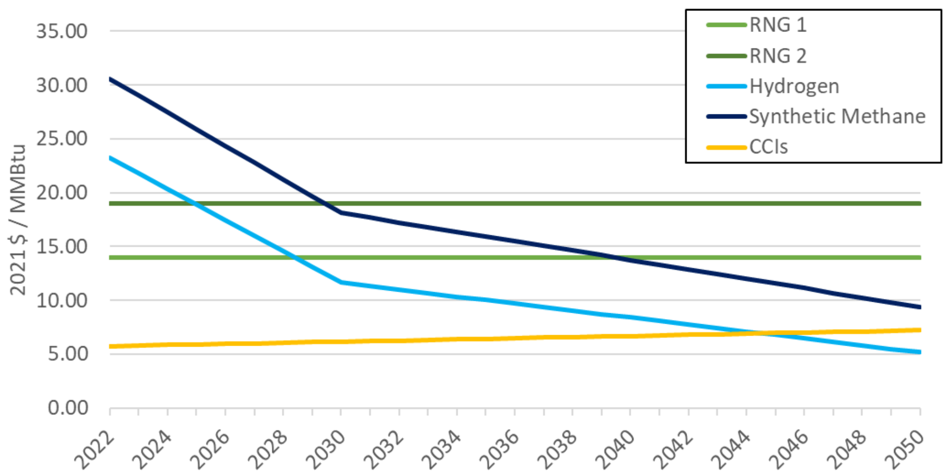
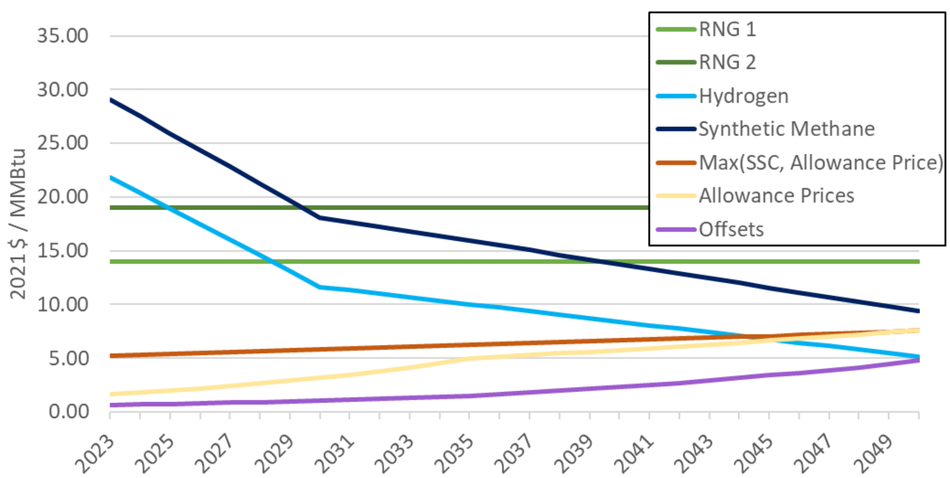


Figure 6.22: Reference Case Washington Compliance Resource Bundled Price Paths



6.6 Future Capacity Resource Options

NW Natural considers additional gas supply resource options including Mist recall, further Mist expansion, and the acquisition of new interstate pipeline capacity. The primary alternatives are described in more detail below.

6.6.1 On-system Production for Capacity

RNG and Hydrogen projects located within NW Natural service territory can inject molecules directly onto the system and provide energy to the system without needing upstream or storage capacity resources. NW Natural is applying for project approval of a 1MW hydrogen electrolyzer using the Senate Bill 844 voluntary emissions reduction program. The electrolyzer would produce approximately 4,300MMBtu of hydrogen to be blended into the natural gas distribution system. This is a small amount of energy that does not significantly impact supply side resource planning today; however, the learnings will be used to enable much larger scale projects connected directly onto NW Natural's system in the coming years.

As we better understand the costs and availability of these utility-scale projects, future IRPs will be able to evaluate them as a potential capacity resource option but are not being considered for capacity in this IRP. Depending on the economics, on-system production resources could be selected as an emissions compliance resource and the value of being on-system and providing capacity is included in the cost evaluation.

6.6.2 Mist Recall

In addition to the existing Mist storage capacity currently reserved for the core utility sales customers (see Table 6.7), NW Natural has developed additional capacity in advance of core customer need. This capacity currently serves the interstate/intrastate storage (ISS) market but could be recalled for service to NW Natural's utility customers as those third-party firm storage agreements expire.

Mist is ideally located in NW Natural's service territory, eliminating the need for upstream interstate pipeline transportation service to deliver the gas during the heating season. Due to its location, Mist is particularly well suited to meet load requirements in the Portland area, which can then free up other capacity resources to meet incremental system requirements.

There are three practical considerations that apply to Mist recall:

1. Recall decisions to transition capacity to the utility portfolio are made roughly a year prior to the core utility's forecasted capacity need. On or about May 1, NW Natural wants to start filling any recalled storage capacity over the summer months to have the maximum inventory in place by the start of the following heating season. Working backwards from May 1, ISS customers need advance notice to empty their gas inventory accounts if their capacity is going to be recalled by NW Natural. NW Natural informs the ISS customer of a recall before the heating season if their contract will not be renewed. Accordingly, we have established the prior summer as the time at which operationally we must make our recall decisions. This timeline is depicted in Figure 6.23.

Figure 6.23: Mist Recall Decision Timeline

Summer This Year	Winter Season	Next Year
Core recall decision made Inform applicable ISS customer(s) if contract will not be renewed	Applicable ISS customer(s) empty inventory if contract is terminating	Core recall is effective May 1 Core injections spring/summer/fall Core withdrawals available Nov. 1

2. Mist ISS contracts are of various durations. While limiting Mist ISS contracts to 1-year terms would maximize the capacity available for recall each year, it also would limit ISS revenues, which utility customer's share in a portion of those revenues. Accordingly, ISS contracts have staggered start dates and durations that create a profile of capacity available for recall that increases over time, in effect mirroring expectations of rising resource requirements.
3. Recalls are rounded (up or down) to the closest 5,000 Dth/day of deliverability. This is done to simplify the administration of recalls and the marketing of ISS service but are modelled as a completely divisible product in the resource planning optimization model discussed in Chapter 7. For scale, 5,000 Dth/day is roughly 0.5% of the current resource stack daily deliverability. The ability to recall Mist in such small increments is a very valuable property that allows customers pay for a capacity resource as needed.

6.6.3 Newport Takeaway Options

As previously mentioned, the daily deliverability of the Newport LNG facility provides 60 MMcf/day (64,500 Dth/day when adjusted for heat content) of system capacity under design peak conditions. This is due to pipeline infrastructure limitations flowing gas out from the central coast back towards Salem. However, the Newport LNG facility has the equipment and permitting necessary to vaporize and deliver up to 100 MMcf/day. To match the pipeline takeaway capability to Newport vaporization capacity of 100 MMcf/day, infrastructure additions would be needed on the Newport to Salem pipeline, known as the Central Coast feeder and other related pipelines. This would provide an incremental 40 MMcf/day (43,000 Dth/day). The 2018 IRP identified a three phased approach that could be done separately and sequentially at various costs to achieve the full 40 MMcf/day of incremental takeaway capability.[139]

1. Newport Takeaway 1 – would increase the maximum pressure rating of 40 miles of the Central Coast Feeder, adding 15 MMcf/day (16,125 Dth/day) at an estimated cost range of $7-16 million.

2. Newport Takeaway 2 –would add a new compressor station near Lincoln City, Oregon, adding 13 MMcf/day (13,975 Dth/day) at an estimated cost of roughly $29-66 million.

3. Newport Takeaway 3 – would boost the Lincoln City compressor horsepower, add another new compressor station to the west of Salem, and make piping improvements between Salem and Albany, all to add 12 MMcf/day (12,900 Dth/day) at an estimated cost of roughly $39-86 million.

The physical gas flow would require that these three improvement projects would have to be undertaken sequentially in the above order. If this were not the case, selection of these projects would

[139] The 2016 IRP and the 2014 IRP evaluated a similar single project call the Christensen Compressor project.

still proceed in this order due to the increase costs of each phase (Table 6.17) for an apples-to-apples cost comparison for resource capacity).

6.6.4 Mist Expansion

The storage currently in service at Mist for core customers, the capacity already developed for future Mist recall that currently serves the ISS market, and the capacity recently developed as North Mist for PGE, collectively do not exhaust the Mist gas field's storage potential. That is, other Mist production reservoirs remain that could be developed by NW Natural into additional storage resources. The primary impediment in doing so is not geological, but the challenges associated with developing new pipeline capacity to move additional gas from a new Mist storage reservoir(s) to NW Natural's load centers.

A Mist expansion project could be developed for core customer use, which would involve 100 MMcf/day (rounded to 106,000 Dth/day) of maximum delivery capacity coupled with a maximum storage capacity of around 4.0 billion cubic feet (4 Bcf, or 4.24 million Dth). Any Mist Expansion would require new compressor stations, additional wells, pipelines and associated infrastructure. If shown to be a least cost least risk resource a Mist expansion would be developed exclusively for utility use.

While design of a new storage facility itself is relatively straightforward, a larger consideration is transporting the stored gas to NW Natural's load centers during the heating season — the "takeaway" pipeline(s). With exhaustion of all available Mist recall capacity, the existing primary takeaway pipelines from Mist will be at their maximum capacities and incapable of transporting additional gas during the heating season.

A Mist expansion project involves expanding the storage capacity and sharing the pipeline constructed for PGE northbound from Mist to the Kelso-Beaver Pipeline (KB Pipeline) and onto NWP's system near Kelso, Washington. NW Natural would contract with NWP for transport to NW Natural's load centers.

The analysis assumes NWP is willing to offer a storage-related transportation service on its mainline, and on the NWP's Grants Pass Lateral (GPL) moving upstream of Molalla, on a firm basis and at a cost reflective of similar offerings that have occurred in the recent past.

NW Natural estimates the investment cost of a Mist expansion with 100 MMcf/day of deliverability and roughly 4 Bcf of storage capacity to be in the range of $150 to $240 million.[140]

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[140] A regulatory concern has been raised in the past regarding the utility's direct movement of gas stored at Mist out of Oregon to serve our load centers in Washington; specifically, the concern involves the potential violation of NW Natural's Hinshaw Exemption with FERC. However, preliminary legal analysis has indicated that a viable structure could be created to make this arrangement work without adversely impacting NW Natural's Hinshaw Exemption.

6.6.5 Upstream Pipeline Expansion

NW Natural holds existing contract demand and gate station capacity on: 1) NWP's mainline serving our service areas from Portland to the north coast of Oregon, Clark County in Washington, and various small communities located along or near the Columbia River in both Oregon and Washington; and 2) GPL serving our loads in the Willamette Valley region of Oregon from Portland south to the Eugene area, as well as the central coast (e.g., Lincoln City, Newport) and south coast (e.g., Coos Bay) areas. Therefore, consideration of incremental NWP capacity, separately on the mainline and on the GPL, is a starting point for NW Natural's assessment of incremental interstate pipeline capacity in this IRP.

Since NW Natural effectively is interconnected only to NWP, a subscription to more NWP mainline capacity traditionally has been a prerequisite to holding more upstream capacity of equivalent amounts (e.g., from GTN). There could be exceptions when market dynamics indicate some advantage to holding more or less upstream capacity. For example, as upstream pipelines continue to expand into new supply regions and/or to serve new markets, an evolution of trading hubs may occur; opening up the more liquid trading points while others fade into disuse. The construction of an LNG export terminal in the Pacific Northwest or British Columbia and/or the construction of a new pipeline transporting Arctic gas (either from Alaska or the Mackenzie Delta) are examples of market developments that could cause NW Natural to reconfigure or add to our upstream pipeline contracts. Under these market conditions, it may be beneficial to hold transportation capacity upstream of NWP leading to these new supply points and trading hubs.

The timing for new regional pipelines will be driven by the growth in regional gas demand. From NW Natural's perspective, new regional pipelines could improve gas system resiliency and enhance reliability, which may be particularly important given the convergence and interdependencies of the electric and gas systems. Some proposed projects could provide the additional benefit of mitigating Sumas price risks potentially arising from future British Columbia LNG export terminals. By comparison, meeting regional demand growth via incremental NWP expansions from Sumas essentially "doubles down" on an existing pathway and, at the same time, is a potential lost opportunity to protect customers from a risk management perspective.

In this IRP, NW Natural has evaluated the potential acquisition of interstate pipeline capacity via an expansion of the NWP system between Sumas and Portland. This incremental NWP capacity from Sumas is designed to serve only NW Natural's load growth needs. Accordingly, it would have a relatively small scale and would not benefit from the economies of scale from an expansion built to serve the whole region.[141] Having a NW Natural specific expansion as any option enables the IRP to select the resource at the point in time when customers would be need.

The acquisition of incremental pipeline capacity spans a wide range of lead times. It would be dependent on the length of regulatory permitting times, and the time required to construct the

[141] Such as in the case when a pipeline expansion is being proposed and an open season is held to solicit interest from perspective customers.

required facilities, which could include restrictive periods due to environmental considerations. A pipeline expansion for NW Natural from Sumas to Portland is restricted from being selected for at least 5 years in the resource planning optimization model.

6.6.6 Portland LNG

Portland LNG was constructed by Chicago Bridge & Iron (CB&I) and commissioned in 1968 as one of the first LNG utility facilities used for LNG liquefaction, storage, and LNG vaporization for supplemental winter supply.

The Portland LNG facility's nominal capacity includes:

- One single containment LNG storage tank with a capacity of 175,000 barrels (7,350,000 gallons) of LNG
- One flow-by-expander liquefaction cycle with a net LNG liquefaction capacity of 2.15 MMCFD (26,000 gpd)
- A net of 15.06 MMCFD tail gas is sent to the distribution system from pretreatment, LNG liquefaction, and vapor recovery operations during LNG liquefaction mode
- Three submerged combustion vaporizers (SCVs) have a combined peak send-out capacity of 120,000 MCFD at 400 psig (130,800 Dth/day after adjusting for the heat content of the gas)
- One LNG truck loading bay using LNG tank pumps with a 506 gpm max rate

Due to its location, Portland LNG is a critical resource for meeting our customer's peak needs in the Portland Metro Area. As mentioned above, Portland LNG is considered an 'on-system' gas supply resource. Gas is typically placed into storage at this facility during off-peak periods, which is also known as 'liquefaction' (for the LNG facilities). When needed, this on-system resource does not require further transportation on the NW Pipeline interstate pipeline system, but rather uses vaporization from the LNG facility to supply gas directly to NW Natural's system. Portland LNG's central location and proximity to Portland makes it a valuable peaking resource.

Portland LNG needs investment to keep the facility operational and a reliable option to serve customers during cold weather events. NW Natural conducted a comprehensive alternatives analysis to evaluate the options for customers relative to the Portland LNG facility, including demand side management strategies as well as different levels of investment in the facility and options for maintaining reliable service if it were to be taken out of service and decommissioned. The additional demand response or energy efficiency beyond the current demand response and energy efficiency projects were deemed not viable options to replace Portland LNG daily deliverability as a capacity resource. This is due both to the fact that this resource is needed as a system capacity resource and to the timing of the resource need. Thus, the facility investments and the alternatives considered are summarized in Table 6.8.

Table 6.8: Portland LNG Alternatives

Alternative		Sub-Option	Feasible beyond 2027?	Cost of Service	Modeled Option in PLEXOS®
1	Keep Portland LNG Facility	A- Replace Cold Box and upgrade pre-treatment system	Yes		
		B- Replace Cold Box and keep existing pre-treatment system	Yes		✓
		C- Keep existing Cold Box and pre-treatment system	No	N/A	
2	Decommission Portland LNG and enhance Mist takeaway capabilities	A- North Pipeline	No	N/A	
		B- Middle Pipeline	Yes		✓
		C- South Pipeline	No		
3	Decommission Portland LNG and enhance Northwest Pipeline takeaway capabilities		Yes		✓
4	Decommission Portland LNG and complete no replacement alternative		Highly Unlikely		✓

How each of these alternatives was developed and assessed for feasibility and their associated costs is described in the next sections.

Alternative 1- Keep Portland LNG Operational

As mentioned above, the Portland LNG Plant is a liquified natural gas production and storage facility located in Portland, Oregon. The Portland LNG Plant serves as a winter peak shaving facility to address gas supply and system pressure needs on the coldest winter days. This facility in NW Portland is ideally located to assure reliable gas service to Portland area customers and support the rest of NW Natural's system resources under peak demand conditions. The facility provides 130,800 Dth/day of capacity to NW Natural's system and needs investment in a new Cold Box to continue operating as a capacity resource.

Many of the components within the Portland LNG plant are beyond their expected design life and the Portland LNG liquefaction rate has been reduced from its original design capacity due to both age and gas composition changes. Over the last several years NW Natural has engaged LNG industry experts including Braemar, CHIV, and Sanborn Head and Associates (SHA) to assess various options to the liquefaction technology to be considered in the broader IRP. In consultation with SHA the Company uses an approach focused on upgrading critical components which would extend the facility's useful life without requiring a complete replacement of the liquefaction system. SHA performed three studies that looked at modifying the existing liquefaction system, replacing the Cold Box, and a list of other improvements to extend the life of the Portland LNG plant. The reports are summarized as follows:

- Cold Box Replacement FEED Report, Portland LNG Facility
- Pretreatment System Evaluation, Portland LNG Facility
- Facility Assessment Report, Portland LNG Facility

Using the reports from SHA, NW Natural outlined three different scenarios for improving the Portland LNG facility and providing the best value to our customers. Those scenarios are outlined in detail in the following sections.

Replace the Cold Box and upgrade the pre-treatment system

Portland LNG Cold Box

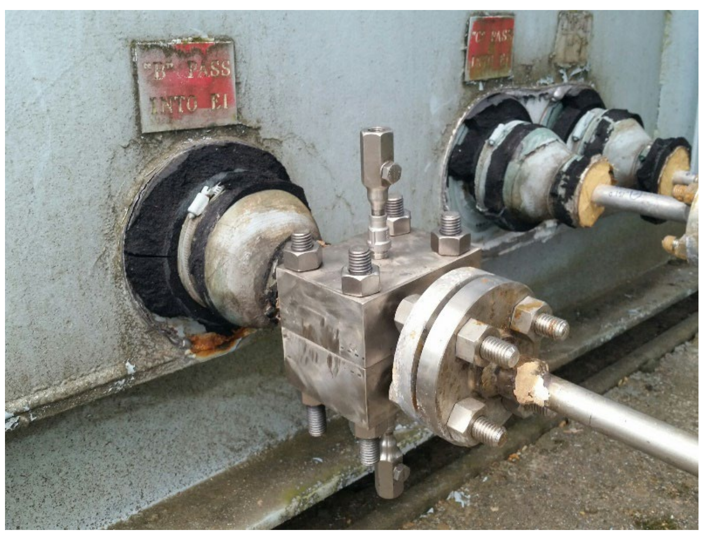
The current Cold Box at Portland LNG is 54 years old. This places it well past its design life and it is currently showing signs of performance issues. Without an investment in the Cold Box the Portland LNG facility would not be able to liquify natural gas to be ready to be withdrawn during a peak event. This investment is critical for the Portland LNG plant to remain in NW Natural's capacity resource stack and is modelled in resources planning optimization model (PLEXOS®) as an option for selection in 2027. Without the Cold Box investment, the Portland LNG facility becomes unavailable. Figure 6.24 shows the existing Portland LNG Cold Box.

Figure 6.24: Portland LNG Cold Box

Over its 54-year life span the Portland LNG Cold Box has developed several natural gas leaks between its outer casing and interconnecting piping. Figure 6.25 shows pitting on the aluminum pipes that has led to holes and leaks on the Cold Box. These leaks have been temporarily remediated using a specialty pipe clamp (Figure 6.26) that encapsulates the hole. However, it is suspected that more leaks exist within the Cold Box itself and cannot be remediated. These leaks derate the capacity of the Cold Box and lead to operational issues. Additionally, the Cold Box is an older design that is purged with natural gas, whereas modern Cold Box designs are purged with nitrogen.

Figure 6.25: Aluminum Pitting

Figure 6.26: Aluminum Pitting Clamp



Sanborn & Head conducted a FEED study to evaluate the Cold Box, assess the replacement effort, and create a cost estimate for the project. SHA outlined the following reasons to replace the Portland LNG Cold Box and summarized them in their FEED Study.

Safety – The Cold Box is purged with natural gas and constantly bleeds, creating an atmosphere around the Cold Box that consistently registers at least 0.5% gas concentration (10% LEL). The new Cold Box will be purged with nitrogen, an inert gas which improves the area safety and offers opportunity for leak detection within the Cold Box.

Fouling of the Cold Box Heat Exchanger Passes – Process modelling identified poor performance as a result of a temperature imbalance between the Cold Box heat exchanger passes. This may be due to loss of heat transfer due to a coating of contaminants within the heat exchanger passes or leaks between passes. Due to the repeated plugging of the heat exchanger passes given the recent history of the feed gas composition exceeding the design capacity of the upstream pretreatment system, contaminant coating may be permanent, and it is possible leaks have developed due to the added stress on the walls.

Age – The existing Cold Box heat exchanger design is outdated. Modern heat exchangers, when operated per manufacturer requirements, are less prone to failure than the older designs. Should one of the heat exchangers fail, repair may not be possible depending upon the severity of the failure causing significant downtime for the liquefier since new heat exchangers have a lead time of at least 1 year without including specification and installation. As identified above, it is possible the heat exchangers already have pass to pass leaks which leads to the belief the equipment has reached the end of its useful life and failure may be imminent.

Temperature Rating – The existing Cold Box heat exchanger maximum temperature rating is 100 °F. This limits liquefaction operation to days when the ambient temperature does not exceed 75-80 °F based upon the current configuration of the E-4 feed cooler and the F-2 water/glycol cooling supply loop. Based on local historical TMY2 ambient temperature data, liquefaction operation may be limited to 90% of the liquefaction season from April 1 through October 1 and as low as 77% of the time in August. The new Cold Box will be rated for 150 °F, mitigating the ambient temperature limit concerns.

In addition to a thorough review of the Cold Box, Sanborn & Head also reviewed what it would take to replace the Portland LNG facility pretreatment system. SHA reviewed several different options to improve the pretreatment system including an option of a total replacement. The pretreatment system replacement options are summarized in the following section.

Pretreatment System

Except for the hot oil heating system, the pretreatment equipment is reaching the end of its useful life and requires system upgrades and/or replacements to improve the safety and availability of the system. The pretreatment system at Portland LNG primarily consists of two original mole sieve dryers D-1 and D-2, and two original CO_2 adsorbers A-1 and A-2. Dryers D-1 and D-2 are internally insulated vessels, designed with an internal bed to contain the molecular sieve for removing water, mercaptans, and other sulfur compounds. The internal bed includes supports, liner, seals, and screens that are designed to support the sieve, prevent gas from bypassing the sieve through the insulation, and prevent sieve carryover. The molecular sieve has not been changed in over 10 years and is more than likely due for replacement. Due to reported sieve carryover, it is suspected that there is some internal support or screen damage. D-1 and D-2 are shown in Figure 6.27.

Figure 6.27: D-1 & D-2

Absorbers A-1 and A-2 are internally insulated vessels, designed with an internal bed to contain the molecular sieve for removing CO_2. The internal bed includes supports, liner, seals, and screens that are designed to support the sieve, prevent gas from bypassing the sieve through the insulation, and prevent sieve carryover. The molecular sieve was changed in 2016. Due to reported sieve carryover and process upsets, it is suspected that there is some internal support or screen damage. A-1 and A-2 are shown in Figure 6.28.

Figure 6.28: A-1 & A-2

Due to the increased CO_2 in the feed gas today as compared to the original design of 0.4 mol% CO_2, the pretreatment system performance does not meet the performance requirements of the existing liquefaction system. Excessive CO_2 in the liquification stream cannot be removed by the Dryers and Adsorbers and results in solid CO_2 within the Cold Box. Solid CO_2 causes plugging of the Cold Box passes during liquification and affects the system availability as the liquefier must be shut down and derimed when plugging occurs.

The existing pretreatment system can remove CO_2 at concentrations up to 0.4 mol% CO_2 in the incoming gas stream. However, the incoming gas frequently has concentrations of CO_2 up to 0.6 mol% and as high as 1 mol% CO_2. This increase marks a change in the composition gas coming to the plant, and a change in treatment methods at the gas production sites that NW Natural cannot control. With these conditions the existing pretreatment system fails to adequality remove CO_2 leading to CO_2 plugging, deriming and plant operations shutdown. The proposed replacement pretreatment system can remove CO_2 up to 1 mol% while still maintaining an LNG production of 2.15 MMSCFD, which is the original design capacity. The cost estimate to replace the Cold Box and the whole pretreatment system is shown in Table 6.9.

Table 6.9: Replace Cold Box and Pretreatment System

Project	Cost
Cold Box Replacement Cost	$11,235,000
Pre-treatment Replacement Cost	$17,300,000
Total:	$28,535,000

Replace the Cold Box and keep the existing pretreatment skid

Sanborn and Head also provided an option for NW Natural in which the Cold Box is replaced but the overall pre-treatment system is not. In this scenario SHA did recommend small, incremental improvements to the pretreatment system to extend its life and increase the safety and reliability of the pretreatment system. These improvements will benefit plant operations and safety but will not improve the LNG production rate of the plant. When CO_2 mol% is higher than 0.4 the plant will temporarily fall below the production rate of 2.15 MMSCFD. The improvements and their costs are summarized in Table 6.10.

Table 6.10: Pretreatment Improvement Cost Estimates

Pretreatment improvement	Cost
Switching valve replacement	$1,300,000
Instrument and controls upgrade	$310,000
E4 relief valve sizing	$10,000
Remove sulfur blimp V-1	$210,000
Replace molecular sieve material in the dryer	$140,000
Replace molecular sieve material in the CO_2 adsorbers	$140,000
Total	$2,110,000

Pretreatment Switching Valves

As the pretreatment system cycles between vessels for adsorption, regeneration heating, and regeneration cooling, switching valves are required to allow for the flow path to be directed properly, prevent clean bed contamination, and controlled pressurization. Pneumatically actuated ball valves are utilized for the switching valves. The valves are standard ball valves. NWN personnel have noted that multiple pretreatment switching valves do not seal completely. This is a common problem with standard quarter turn ball valves in this service due to the seal rubbing and the sieve dust that can break down the seal. Orbit rising stem ball valves, commonly used in modern systems, use a tilt and turn design as they reduce seal rubbing and increase the longevity/reliability of the valve. It is proposed to replace the switching valves that are reported to leak and have unreliable open-closed limit switches.

Pretreatment System Instrumentation and Control

The pretreatment system control is performed by the Facility PLC control system, including dryer and adsorber bed switching, regeneration, flow control, temperature control, and alarms. The HAZOP workshop completed under the Facility Assessment Report identified several findings and recommended enhancements to the existing process controls and interlocks to improve the process safety, if the existing pretreatment systems are maintained.

Sulfur Blimp V-1

The sulfur fuel blimp (V-1) acts as an averaging chamber for the regeneration gas outlet to control the mercaptan spikes in the off-gassing of the pre-treatment sieve. The vessel is only utilized for one hour of the 12-hour dryer cycle, at which time, the regen tail gas is discharged to the 57# system instead of the 85# system. The vessel was originally heat treated to minimize sulfur stress corrosion. As the tank is 50+ years old, the tank should be removed from service or inspected to insure it is fit for service.

E4 Relief Sizing, Mole Sieve Replacement

SHA recommends that the E4 relief valve sizing be verified and possibly replaced if not adequate. SHA also recommends that the mole sieve material in both the dryers and CO_2 adsorbers be replaced. Replacing the mole sieve material was previously identified by NW Natural and budgeted for execution.

Before SHA evaluated any of these options NW Natural had already made plans to execute some of the above line items, including the replacement of the switching valves, upgrades to the instrumentation and controls, and replacement of the mole sieve material. Those improvements are currently being executed under other projects.

With an upgraded Cold Box the plant is predicted to operate safely and reliably for another 15-20 years. The cost estimate to replace the Cold Box and keep the existing pretreatment system is shown in Table 6.11.

Table 6.11: Replace the Cold Box and Keep the Pretreatment System

Project	Cost
Cold Box Replacement Cost	$11,235,000
Pretreatment incremental improvements	$2,110,000
Total:	$13,345,000

Keep the existing Cold Box and the pretreatment systems

The third and final option for Portland LNG evaluated by the SHA team was to keep the existing Cold Box and the existing pretreatment system. If NW Natural continued on this route at a minimum SHA recommends that that the incremental improvements outlined in the previous section be executed. As stated in the above section these incremental improvements will not improve the production of LNG at the plant and the PLNG plant will be susceptible to reduced production and line plugging at CO_2 mol% higher than 0.4%.

If the Cold Box is not replaced, it is anticipated that eventually a failure will occur that would stop production permanently or for an extended period until the Cold Box was replaced. Given the lead time, inclusive of planning, purchasing, permitting, delivery, and construction of a new Cold Box; it is risky to continue to rely on the current Cold Box until failure. A failure of the current Cold Box could lead to managing through 1 or 2 winters seasons without gas from Portland LNG available for a peak event or even as a regional resiliency capacity resource. In the event of a failure of the current Cold Box, the plant would be maintained in a safe condition until the Cold Box replacement was completed.

The cost estimate to keep the Cold Box and the incremental costs required for the existing pretreatment system is shown in Table 6.12.

Table 6.12: Keep the Existing Cold Box and Incremental Improvements to Existing Pretreatment System

Project	Cost
Keep the existing Cold Box	$0
Pretreatment incremental improvements	$2,110,000
Total:	$2,110,000

SHA also performed a facility assessment report that summarizes other recommend improvements to the Portland LNG facility outside of the Cold Box and the pretreatment systems. These upgrades to the plant are intended to increase the life of Portland LNG and improve both safety and operations at the plant. These upgrades are included in the *Facility Assessment Report* for the Portland LNG Facility and included in the appendix of this IRP. These improvements are intended to be executed regardless of which pathway allows for Alternative 1 – Keep Portland LNG Operational.

Option for Inclusion in PLEXOS®

In collaboration with SHA, NW Natural examined several potential pathways for Alternative 1 – Keep Portland LNG Operational. Of these pathways, the option to replace the Cold Box and keep the existing pretreatment system, was the least-cost least-risk pathway in order keep Portland LNG operational and is one of the four high-level alternatives modeled in PLEXOS® as a capacity option for selection.

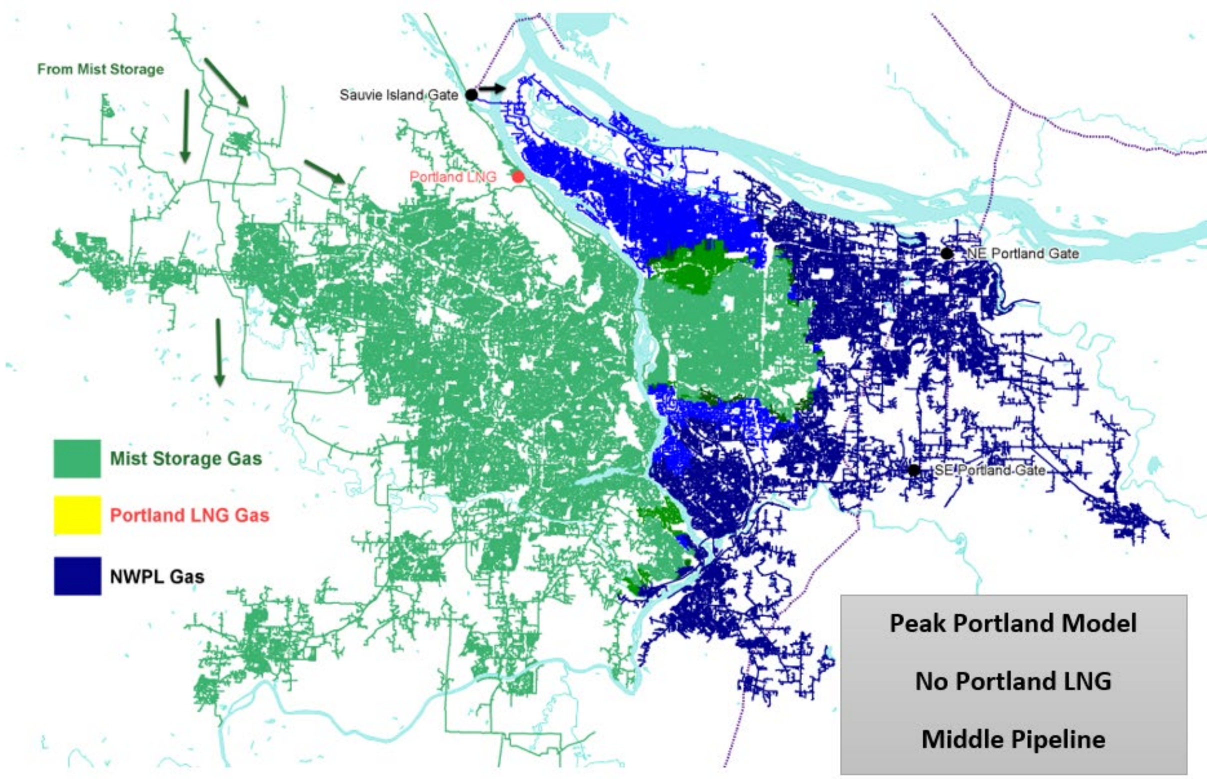
Alternative 2-Decommission Portland LNG and Enhance Mist Takeaway Capabilities

One option to reliably serve firm customer demand on the Portland system without Portland LNG is to install a new pipeline that delivers more Mist gas into Portland. This alternative includes recalling the necessary Mist deliverability to meet system capacity requirements (130,800 Dth/day for full replacement).

The evaluated alternative includes decommissioning Portland LNG and installing a new high-pressure pipeline to support core customers on the distribution system. The proposed high-pressure pipeline, known as the Middle NWN system pipeline, would deliver Mist gas to the East and North Portland replacing Williams and Portland LNG gas. The Middle NWN system pipeline would provide a connection from the 24- inch South Mist Pipeline to the high-pressure system serving Portland. This direct connection would boost pressures in the area with Mist Gas, allowing NW Natural to serve peak demands in Portland if Portland LNG is decommissioned.

Figure 6.29 illustrates the supply distribution after the Middle NWN system pipeline is installed. The green areas represent Mist gas, while the dark blue areas show gas delivered from Williams Pipeline. The lighter blue regions represent a blend of Mist gas and Williams gas. The image shows that the footprint of Mist gas extends further to the East and North Portland with the Middle NWN system pipeline in service.

Figure 6.29: Portland LNG Gas Flow Diagram with Middle Pipeline No LNG



NW Natural conducted an extensive evaluation on the feasibility for the delivery of natural gas supplied from the Mist, Oregon storage facility to meet peak usage demands of the East Portland Region.

NWN's technical team performed system modeling and determined potential options for delivering gas supply from Mist to the Portland, Oregon area by constructing a new natural gas pipeline from the existing South Mist Pipeline Extension (SMPE 24- inch pipeline) to a large transmission pipeline in the Portland, Oregon area. As a result of the modeling the NWN technical team identified the following the three route corridors:

1. Mountaindale Road to Highway 30 Corridor (North Corridor)
2. Scholls to Barbur Corridor (Middle Corridor this also refers to the middle pipeline mentioned above)
3. Wilsonville to Stafford Corridor (South Corridor)

The Southern Corridor was eliminated as an option due to the high risk and costs associated with the installation of a new pipeline under the Willamette River. NW Natural retained HDR and Associates to conduct further analysis of the North Corridor and Middle Corridor. The North Corridor had initially five potential routes evaluated which was later reduced to three, while the Middle Corridor had only one.

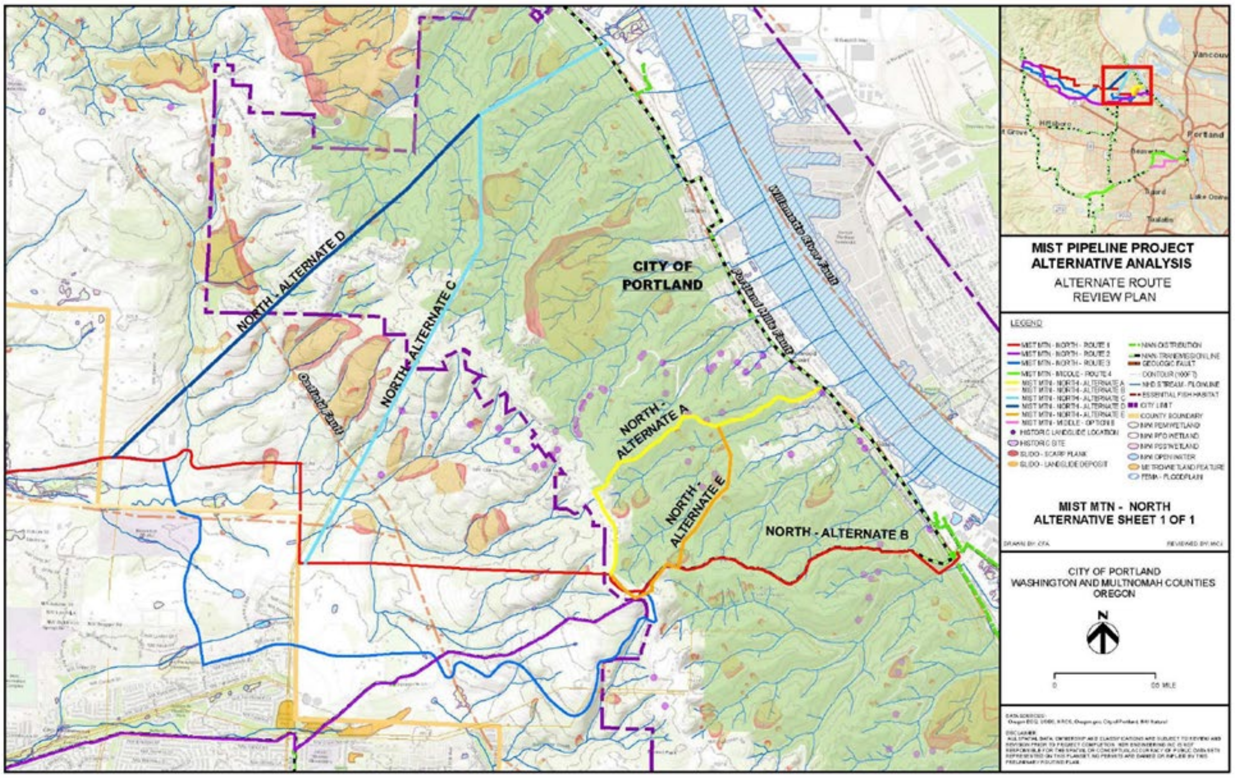
A Phase I evaluation was conducted for three routes of the North Corridor and one route for the Middle Corridor that included the following:

- Natural resources impact
- Rare, threatened, and endangered species
- Proposed mitigation strategies
- Additional environmental considerations
- Geological review
- Land Acquisition
- Permitting
- Constructability, and
- Construction, Operations and Maintenance Costs.

North Corridor

NWN's modeling concluded that the Northern Corridor would require a new 20–inch steel gas pipeline with a 720 PSIG MAOP. The alignments all start at the City of Portland along Hwy 30 and head west northwest to Mountaindale Rd. The first identified obstacle to manage is the City of Portland's Forest Park. Forest Park is a public municipal park that stretches more than 8 miles north and south in length and has over 5,100 acres of property. Five alternatives were identified for analysis and field investigation during the desktop analysis. Figure 6.30 illustrates the five alternatives.

Figure 6.30: North Corridor Route Options



Each alternative was selected to best utilize existing features and infrastructure within Forest Park to minimize the impact to the area. Alternatives A and E are aligned with ridge lines that follow existing water utility easements and hiking trails. Alternatives C and D parallel existing Bonneville Power Administration high voltage easements. Alternative B parallels an existing NWN 16" gas pipeline that runs along the ridgeline Firelane Road 7.

During the field investigation each alternative was further investigated to determine which crossing point would be used. Alternatives A and E looked very promising initially, but the trails and water line easement utilized would require significant land disturbance and clearing just to prepare the site for construction. Alternatives C and D parallel BPA right-of-way (ROW) but unfortunately after conversation with NWN staff being within the BPA ROW would not be feasible from a permission standpoint. This would force the pipelines to have extensive side hill cut conditions for the entire crossing of Forest Park. This would not only increase the impacts to the park but also put the pipeline in additional risk to slope failure in an already unstable area due to the soil conditions and steep slopes. Alternative B that parallels the existing pipeline was much more promising as a crossing location for Forest Park. Due to the historic disturbance of the existing pipeline being built along the pipeline the alternative already lends itself to a usable working space that has an existing NWN easement that is 40 feet wide.

The combination of the existing easement and the use as a fire lane has kept large trees from growing within the easement. There is a significant overhang of canopy and ground vegetation along the easement that would need to be cleared for construction to commence. At the conclusion of the field review the HDR/NWN team identified this as the primary crossing location for Forest Park. Furthermore, because of this determination all Northern Corridor routes utilize this crossing and only deviate once the proposed route hits Skyline Drive. The remaining Northern Corridor analysis starts at Skyline Drive and proceeds to Mountaindale Road. HDR proposed three routes that had specific differences in each.

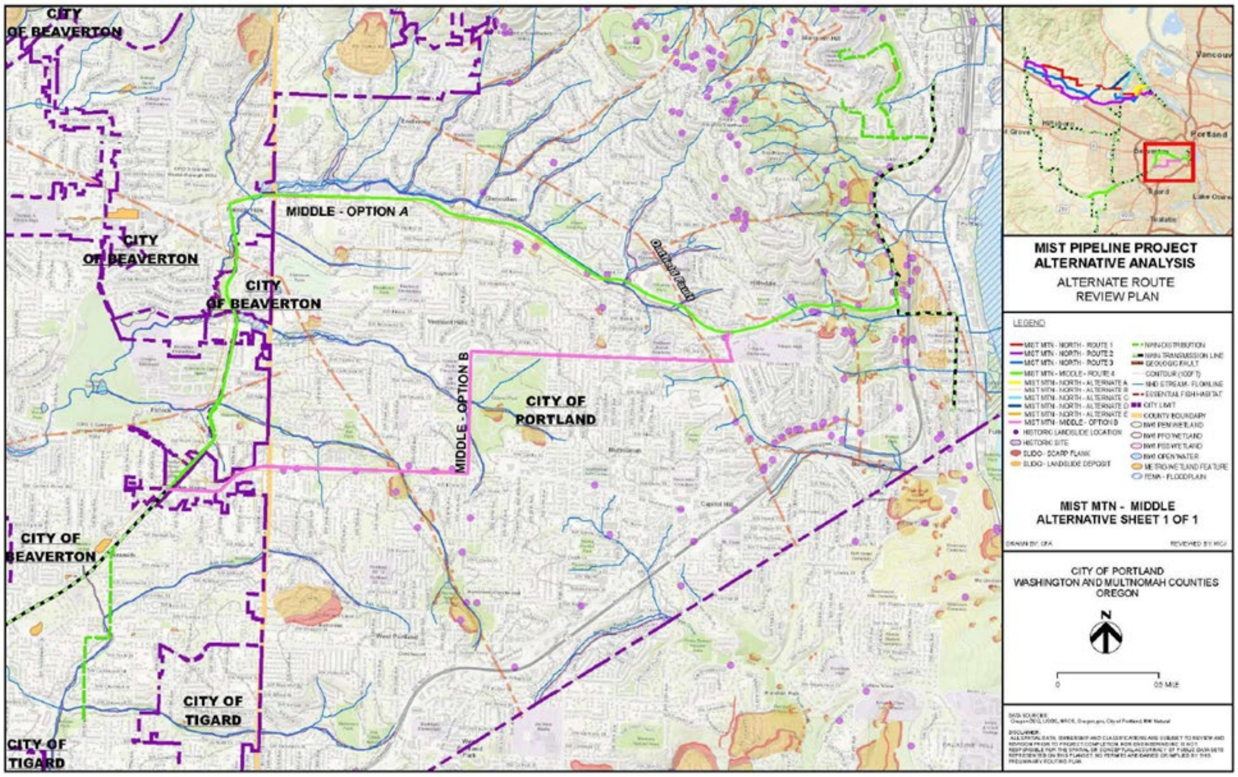
1. Route 1: Greenfield with large portions in open country undeveloped property (Red) – 16.3 mile
2. Route 2: Existing Easement which follows the alignment of NWN’s 16 inch pipeline (Purple) - 16.8 miles
3. Route 3: Roadway with all work being within or immediately adjacent to the roadway (Blue) – 16.8 miles

Middle Corridor

NWN’s modeling concluded the Middle Corridor[142] would require two new 16-inch steel gas pipelines with the western pipeline operating 720 PSIG MAOP and the eastern pipeline operating at 400 PSIG MAOP. The separation is because an existing 12-inch gas main will be utilized as a bridge between tie-ins. The east side is urban and will require all work to be completed within the roadway. The west side becomes more rural as you continue west but still has significant development along the route. In the East section, HDR looked at two options as shown in Figure 6.31. The Middle Corridor would require a total of 8.4 miles of new pipe. A regulator station will be required near the east side of the route to drop the pressure down to 400 PSIG prior to connecting to the existing 16-inch main.

[142] This is referred to as the Middle pipeline above.

Figure 6.31: Middle Corridor Route Options



Due to the findings of the Phase I Analysis, two routes were selected for a more thorough analysis. Those include Route 3 (Blue Route) from the Northern Corridor and Route 4 from the Middle Corridor.

The main advantage of Route 3 is that NWN can take advantage of the public ROW along the existing network of roadways and only need to secure temporary easements for additional workspace. This will significantly reduce costs for ROW and speed the process for initiating fieldwork during design. The overall permitting risk is moderate, but by using additional avoidance and minimization strategies, it is believed that risk can be mitigated.

Route 4 has the advantages of less permitting risk, fewer trenchless crossings, less ROW to purchase, and half the construction time and cost. Public discontent should also be limited to traffic pattern impacts during construction and not as much long-term environmental damage or spreading development concerns. For the reasons above, the Middle Corridor Route 4 was selected as the alternative to model in PLEXOS®.

In Phase 2, HDR developed more specific route avoidance measures to further mitigate impacts, a route-specific risk matrix for each route, 10% alignment drawings, schedules, and a more specific total incurred cost for each route. A summary of the findings is in Table 6.13.

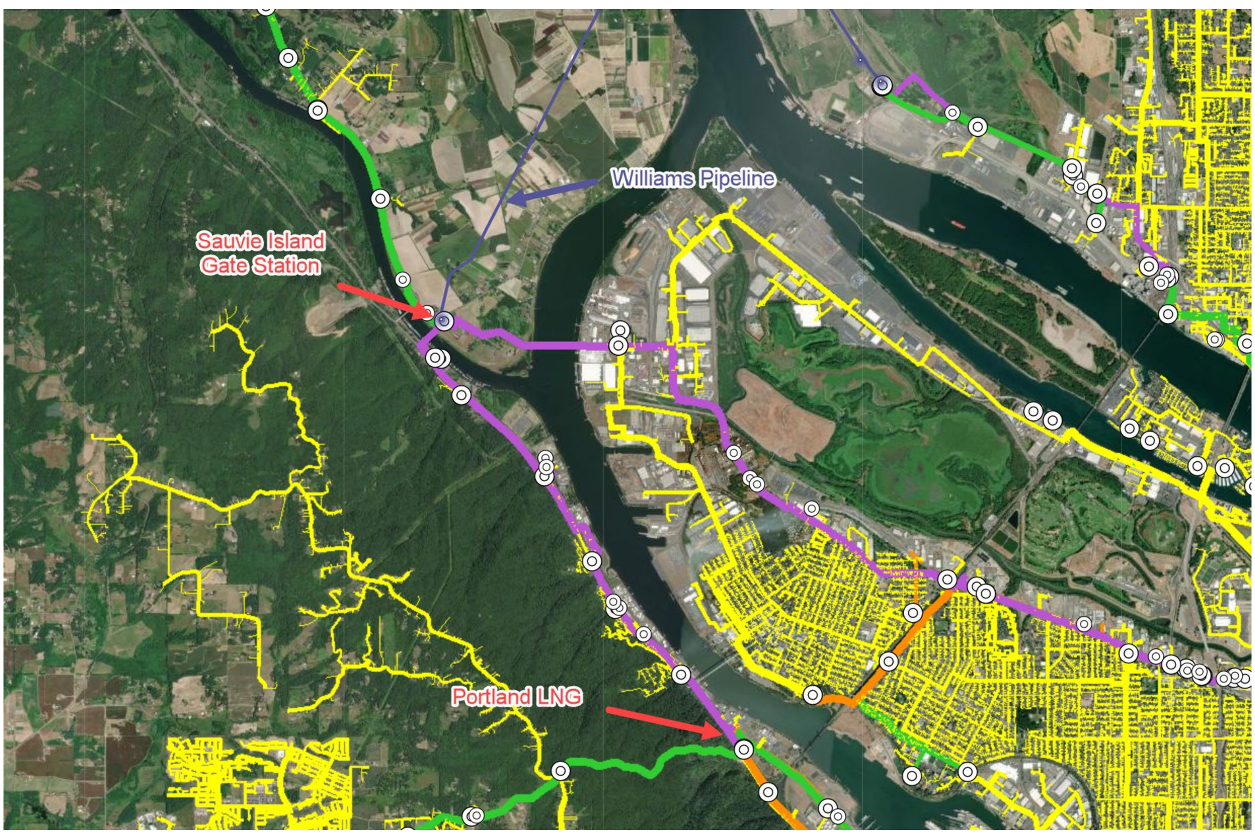
Table 6.13: Phase 2 Results

Route #	Length (miles)	Overall Permit Risk			Number of Trenchless Crossings	Total ROW to Procure		Total Project Duration	Total Installed Cost ($)
		Local	State	Federal		Temp (ac)	Perm (ac)	Days	
3 - North Corridor	16.8	Moderate	Low	Low	8	31.74	0.36	1,025	$127,336,000
4 - Middle Corridor	8.4	Low	Low	Low	2	15.4	0	984	$76,145,000

Alternative 3– Decommission Portland LNG and Enhance NWP Takeaway Capabilities

As shown in Figure 6.32, Sauvie Island Gate Station and Portland LNG feed the same high-pressure system. Provided that there is adequate pressure and flow rates, Sauvie Island Gate Station and Portland LNG are hydraulically interchangeable. Meaning gas from Sauvie Island Gate Station can substitute vaporized gas from Portland LNG because they can supply the same area.

Figure 6.32: Portland LNG Gas Flow Diagram



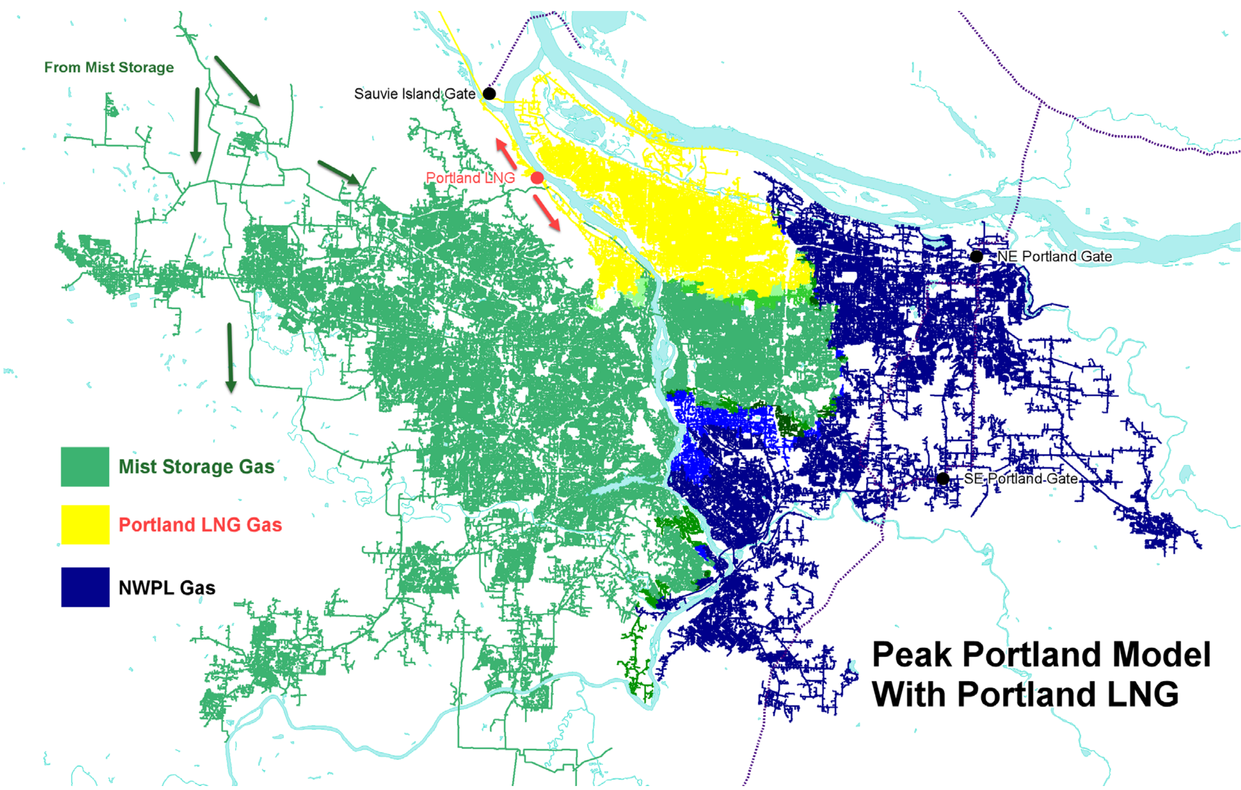
Synergi™ Gas was used to model the volume of gas required from Sauvie Island Gate with Portland LNG offline. The results of the modeling run indicated that NW Natural would require an incremental 38,000 th/hr at Sauvie Island Gate Station to serve firm customers during peak hour conditions. NW Natural approached Williams NW Pipeline to identify the requirements to increase the capacity of the Sauvie Island Gate Station by 38,000 th/hr. Williams NW Pipeline identified an expansion that would allow NW Natural to take more supplies off Sauvie Island Gate Station. Synergi™ modeling results show that we can serve firm customers in Portland if with an interstate pipeline looping option on Williams NW Pipeline that feeds into the Sauvie Island Gate Station.

Alternative	Installation Cost	Additional Resources Required
Interstate Pipeline Looping	$87 Million	Mist Recall

Alternative 4- Decommissions Portland LNG and Complete No Replacement Alternative

During a peak event, the gas being withdrawn from Portland LNG supports the pressures on the distribution system serving North Portland (see yellow area in Figure 6.33).

Figure 6.33: Portland LNG Gas Flow Diagram With LNG



Without Portland LNG, alternative supplies would need to be sourced from either Mist or NWP to replace the LNG gas in the northern portion of Portland. Without a pipeline project, Mist gas would not have adequate pressure to serve the void left by Portland LNG. Additionally, without an expansion on NWP, NW Natural could not take the necessary supplies from Sauvie Island Gate Station to replace the Portland LNG gas. The lack of a reliable supply sources means that there would be unserved demand in the Portland area shown in yellow in Figure 6.33.

Using 2022 forecasted demands, the Synergi™ model does not solve after disabling Portland LNG and limiting the Sauvie Island Gate flows to the current capacity. The unsolved model results from not having adequate supplies to meet demands on the system. During extreme conditions, the lack of supplies would cause system pressures to drop to a point where gas service could be lost to thousands of firm customers.

A Synergi™ analysis was used to determine the maximum firm demand the system could serve if Portland LNG were decommissioned and no other system reinforcement projects were constructed. For this analysis, the Williams supplies were fixed to their current capacities and load was reduced until Synergi™ was able to solve. The model solved after firm demands were reduced by approximately 16% from 2022 forecasted peak demands. This suggest that firm sales peak demand would need to be below 830,000 Dth/day to decommission Portland LNG and not need one of the other alternatives discussed above.

Portland LNG and segmented capacity are the two capacity resources, which fall off the capacity resource stack within the planning horizon. Without these resources, NW Natural has 800,000 Dth/day of capacity. 30,000 Dth/day of Mist Recall would still be required to fill the gap if peak demand were to decline to a point where Alternative 4 is a viable option. We impose a constraint into our resource planning optimization model (PLEXOS®), where Alternative 4 is not available if it selects more than 30,000 Dth/day of Mist Recall.

6.6.7 Capacity Resource Comparison

NW Natural uses cost-of-service modeling, which captures the capital costs, operation and maintenance costs, taxes, construction and overhead, and all other estimated costs associated with an option over the planning horizon. Using the cost-of-service modeling, each option has a present value revenue requirement. These costs become an input into the resource planning optimization model, and they are incurred when a capacity option is selected.

Table 6.14 lists the capacity options, costs in terms of dollars per Dth per day, the daily deliverability, and the years each option is available for selection. These are fixed costs that are incurred everyday throughout the planning horizon if a capacity resource is selected. Note that only Mist Recall is a non-binary option, and the model can select as much Mist Recall as needed in each year. All other options must be selected at the full amount. The model must select the Portland LNG Cold Box or one of the alternatives discussed Section 6.6.6 in the year 2027.[143] While the Cold Box could fail between now and 2027, the year 2027 was selected as this was the earliest timeframe any of the other alternatives could feasibly be constructed. Once an option is selected it remains in the resource stack and incurs the cost for the rest of the planning horizon.[144]

Table 6.14: Capacity Resource Cost and Deliverability

Capacity Resource	Cost ($/Dth/day)	Daily Deliverability (Dth/day)
Mist Recall	$ 0.09	As needed Max : 203,800
Newport Takeaway 1	$ 0.14	16,125
Newport Takeaway 2	$ 1.00	13,975
Newport Takeaway 3	$ 1.41	12,900
Mist Expansion	$ 0.62	106,000
Upstream Pipeline Expansion	$ 2.12	50,000
Portland LNG - Cold Box	$ 0.06	130,800
Interstate Pipeline Looping Plus Required Mist Recall	$ 0.39	130,800†
Middle Corridor NWN System Pipeline Plus Required Mist Recall	$ 0.35	130,800‡

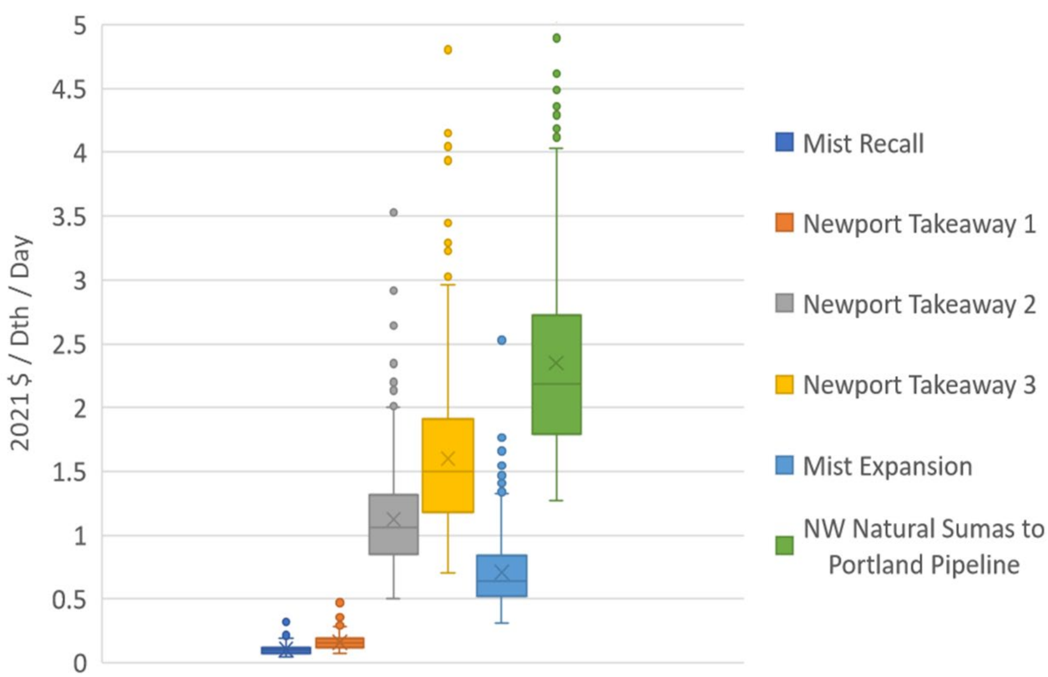
Notes: Pipeline options are available for selection November 1st of year; storage options are available for selection May 1st in each year. Newport Takeaway options must occur sequentially.
† Pressure modeling shows that with this option would allow for additional Mist takeaway and would increase the max Mist Recall to 240,492 Dth/day. 130,800 is used in this table for a direct comparison to the deliverability enabled by the Cold Box alternative.
‡ Pressure modeling shows that with this option would allow for additional Mist takeaway and would increase the max Mist Recall to 204,422 Dth/day. 130,800 is used in this table for a direct comparison to the deliverability enabled by the Cold Box alternative.

[143] This includes a object in the PLEXOS® model that represents the decommission Portland LNG and complete no replacement alternative.
[144] The only exception to this assumption is the Interstate Pipeline Looping option. This option is an agreement with Williams NW Pipeline that would be if chosen in 2027 would be paid off over the course of 20-years, therefore payments would cease in 2048.

6.6.8 Capacity Resource Cost Uncertainty

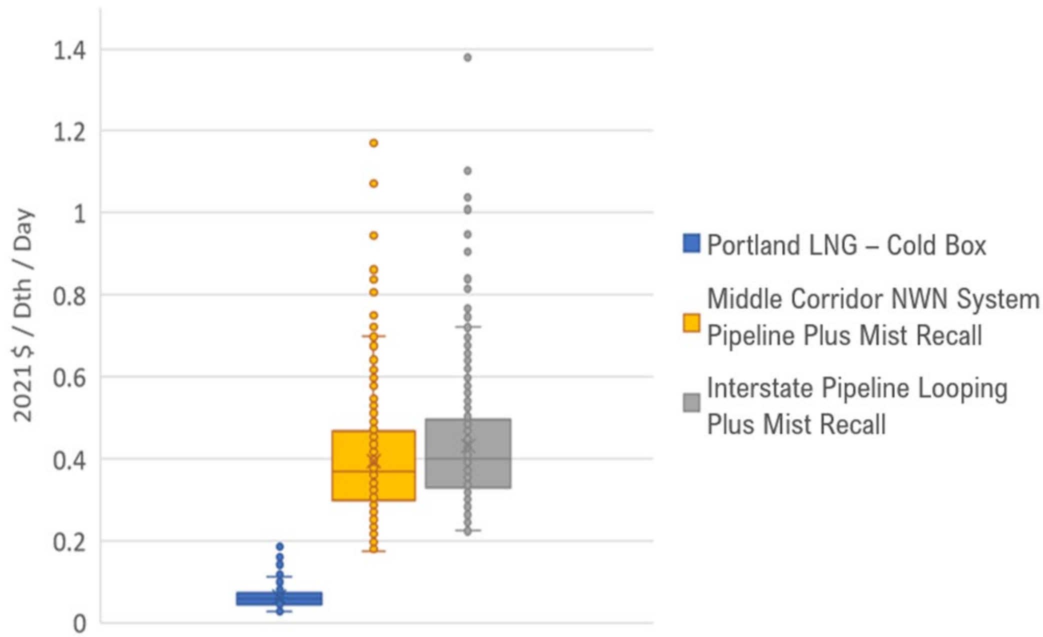
Just like natural gas prices, the price for RNG, the price for hydrogen, and the cost for methanation, the fixed costs for capacity resource options are also uncertain. Many of these costs are associated with construction, material, and labor costs, which can all vary both together and independently; however, since these capacity resources are specific to the natural gas sector, the labor and material costs are likely highly correlated. Additionally, the risk associated with the costs for these capital-intensive resources is not symmetrical with the potential for a much higher, albeit low-probability, over-all project cost. To simulate these fixed costs, we use a log-normal distribution in a Monte Carlo simulation for each capacity resource along with a correlation coefficient to account for correlation across all resources.[145] Figure 6.34 and Figure 6.35 shows the magnitude and range for the capacity resources options considered in resources optimization modelling discussed in the following chapter.[146]

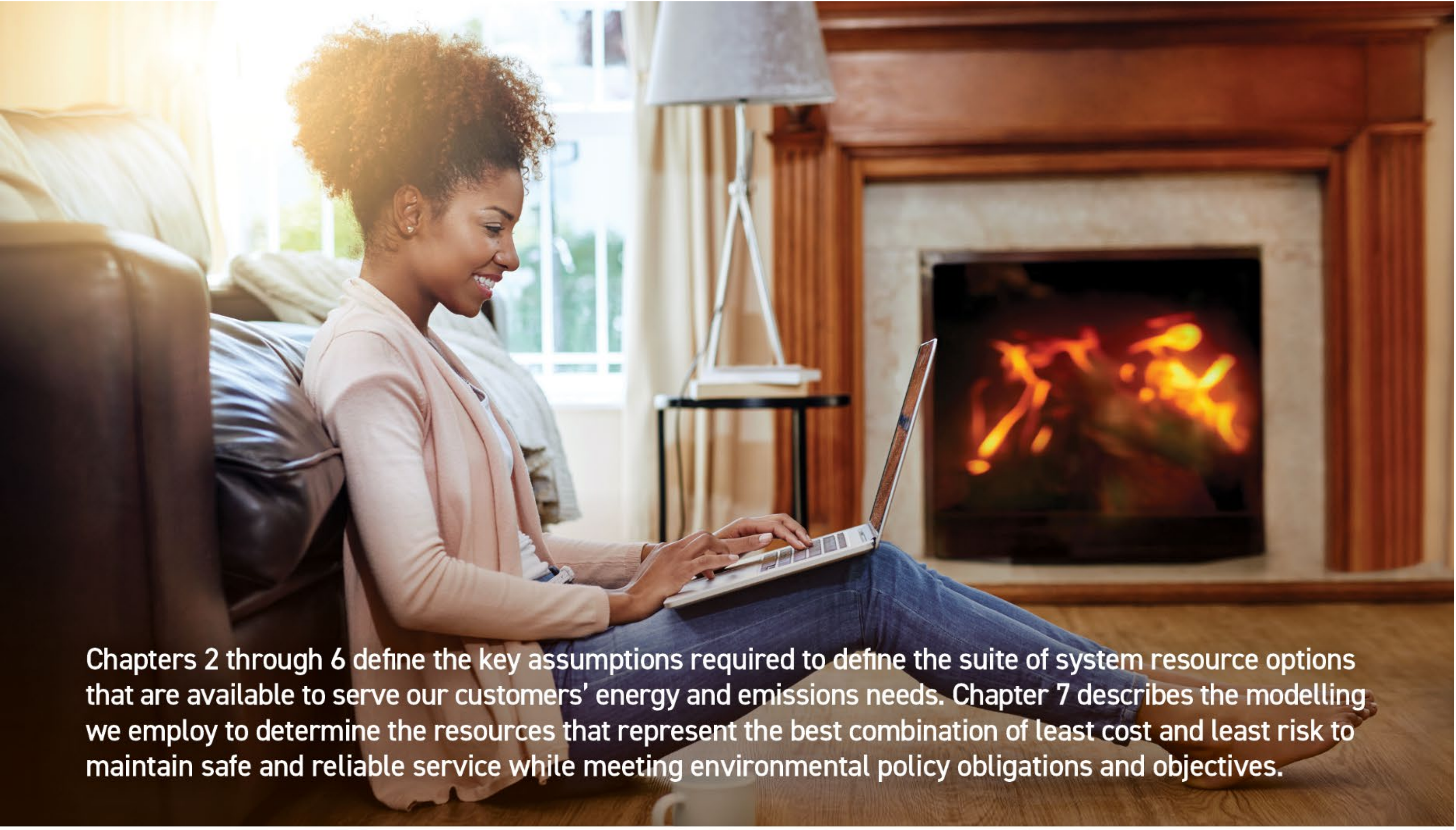
Figure 6.34: Box and Whisker Plot for Capacity Resources



[145] See Appendix F for technical details for capacity resource cost simulation.
[146] Please note the difference in X- axis scale between the two figures

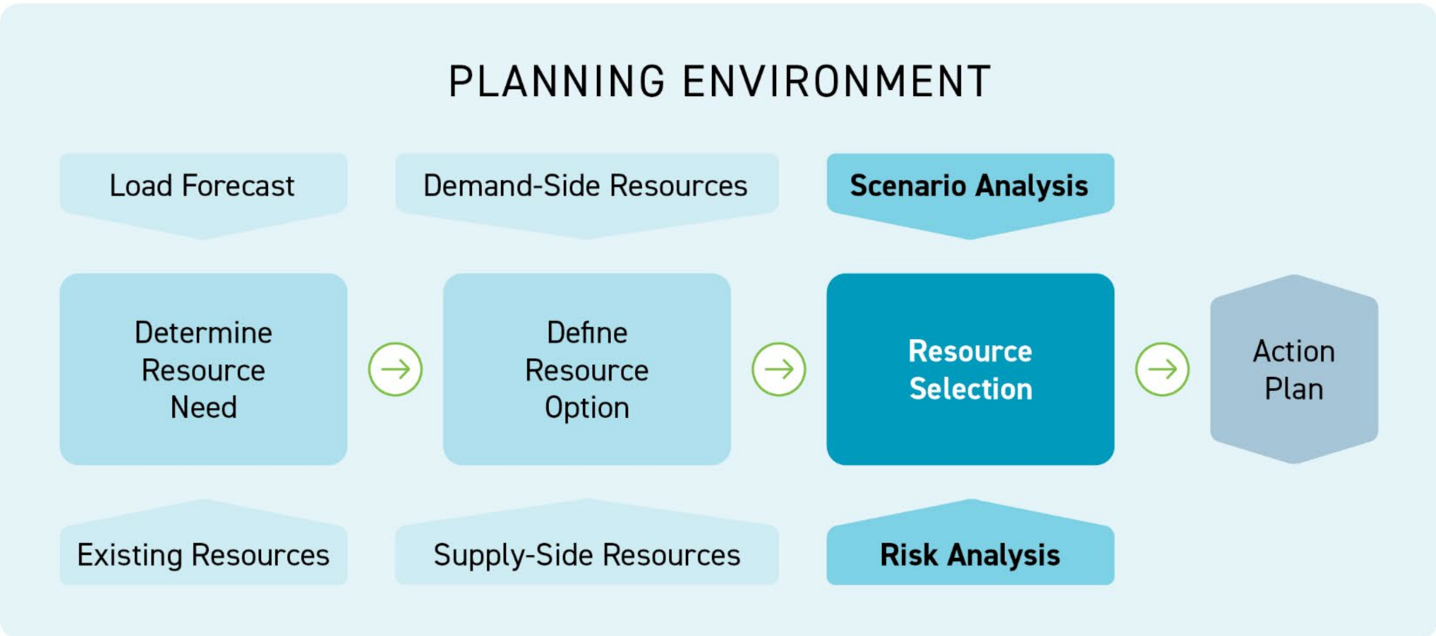
Figure 6.35: Box and Whisker Plot for Portland LNG Alternatives





Chapters 2 through 6 define the key assumptions required to define the suite of system resource options that are available to serve our customers' energy and emissions needs. Chapter 7 describes the modelling we employ to determine the resources that represent the best combination of least cost and least risk to maintain safe and reliable service while meeting environmental policy obligations and objectives.

7 | System Resource Portfolio Optimization and Results



7.1 Least Cost Least Risk Portfolio Selection – Overview

The IRP is the Company's primary tool to evaluate near-term resource decisions over a long-term planning horizon and understand how those decisions would be viewed under a wide range of circumstances. Some of these near-term decisions involve investments in long lived assets or signing long term contracts, such as an RNG off-take agreement. Understanding the long-term planning outcomes under a variety of futures allows a robust evaluation of any near-term system resource decisions formed within the Action Plan of this IRP. The complex optimization modeling and the results discussed in this chapter help develop system resources Action Plan Items that will be low regret decisions on behalf of customers.

System resource planning must acquire the appropriate mix of resources with the best combination of cost and risk to meet three primary requirements:

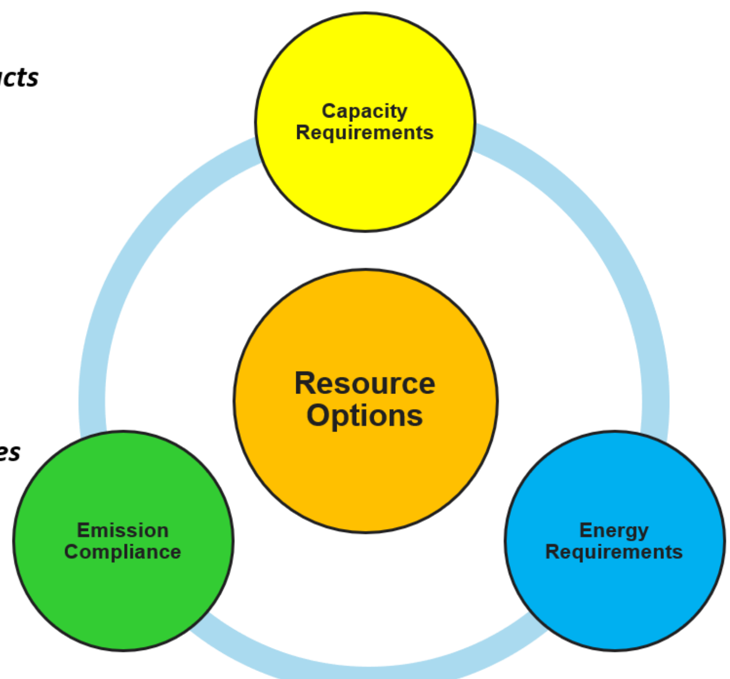
1. Emissions reduction requirements, emission compliance following the rules of the CPP in Oregon, and the CCA in Washington.
2. Capacity requirements, being able to reliably serve customers during a design peak cold event when loss of customer service due to resource constraints occurs at the same time when it is the most dangerous time for customers to lose service.
3. Annual energy requirements, having the resources to reliably serve customers throughout the year.

Figure 7.1: System Resource Planning Requirements and Options

Supply-side Options
Natural gas, RNG, or hydrogen supply contracts
Interstate/interprovincial pipeline capacity
On-system production resources
Underground storage
Above-ground LNG storage
Industrial recall options
Citygate deliveries

Compliance Resource Options
Bundled RNG or hydrogen
Unbundled environmental attribute purchases
Qualified compliance instruments

Demand-side Options
Energy efficiency
Demand response



Resource options offer very different emissions, capacity, and energy contributions. Additionally, resource options all vary in costs, availability, and timing. For example, NW Natural's Newport LNG facility provides a significant amount of capacity, but limited amount of total energy before being completely emptied. On the other hand, upstream pipeline capacity with conventional gas purchases can provide 365 days of both capacity and energy, some of which is needed during the summer to fill NW Natural's storage facilities. Off-system purchases of RNG help meet emission compliance, but do not provide either capacity or energy to the system, whereas an on-system RNG can help meet all three requirements.

Due to the complexity of varying resources and resource requirements, NW Natural must implement an optimization software called PLEXOS® to solve for the least cost mix of resources that complies with emission obligations, while reliably serving customers each day over the planning horizon (2022-2050). Scenario and Monte Carlo simulation is used in the risk analysis to develop the least cost least risk near-term actions for system resources in the Action Plan.

Chapters 2 through 6 lead up to this chapter by discussing all the key load and resource components that become the inputs into the PLEXOS® modelling software. The rest of Chapter 7 discusses the PLEXOS® model, capacity resources needed, a break-out of compliance resources by scenario, and an overview of risk analysis.

7.2 Resource Planning Optimization Model (PLEXOS®)

PLEXOS® implements a mixed integer program (MIP) algorithm, which triangulates a least cost solution of resource acquisition and dispatch that minimizes net present value of total system costs over a specified planning horizon. PLEXOS® is owned and licensed by Energy Exemplar and is a completely new tool for NW Natural's IRPs.[147] The software provides superior flexibility and software technical support over the previous optimization tool used for prior NW Natural's IRP.[148] Most importantly, upgrading to the PLEXOS® software allows NW Natural to implement quantity constraints on emissions and have different the carbon intensities across resources, both critical for modeling compliance with the CPP and CCA.

The software operates by using sophisticated *Operations Research* techniques and algorithms (e.g., linear and non-linear programming) to solve a constrained optimization mathematical problem. Constrained optimization problems start with an *objective function*. The objective function for PLEXOS® is mathematically represented as:

[147] NW Natural only licenses the gas module for PLEXOS®. PLEXOS® has additional modules, such as electric and water, that can be linked for co-optimization of systems. Even after a year of modeling within the gas module, NW Natural is still learning about the full capabilities of the software and may be able to introduce further complexity into the model for future IRPs.

[148] The previous software (SENDOUT) had linear limitations on resource acquisition. The mixed integer program (MIP) algorithm in PLEXOS® are more complex, but allow for integer-based decisions, such as a binary build or not build decisions.

$$Minimize \sum NPV(Cost_t)\ \forall\ daily\ costs\ t = [2022 - 2050]$$

Contextually, this means that model solves for a solution that minimizes the summed net present value (NPV) of all costs incurred each day in the planning horizon; from 2022 through 2050. The algorithm does this by adjusting selection variables, also known as decision variables, but is constrained based on the inputs and parameters of the model. These constraints represent real world limitations, for example daily maximum withdrawal capability from Mist storage. Table 7.1 provides a high-level list of the decision variables and constraints in NW Natural's IRP PLEXOS® model.

Table 7.1: Decision Variables and Constraints

Decision Variable	Constraints
➢ Daily purchases for compliance resources (RNG, hydrogen, synthetic methane) and compliance instruments (CCI, allowances, offsets) ➢ Daily selection of quantity and location to purchase and ship conventional gas ➢ Daily Mist, Jackson Prairie, Portland LNG and Newport storage operations (injections and withdrawals) ➢ Annual acquisition of capacity resources required to serve demand	➢ All demand is served in each load center ➢ NW Natural meets emissions compliance in both Oregon and Washington ➢ Pipeline constraints and costs ➢ Storage constraints and costs ➢ Supply purchasing constraints and costs ➢ Compliance and capacity resource acquisition constraints and costs ➢ Costs are discounted at a rate equal to the Company's real after-tax weighted cost of capital

At its core, the PLEXOS® software is used to create a nodal model that links objects together. Objects can represent, but are not limited to, gas supply contract, gas pipelines, gas storage, and gas demands. Figure 7.2 shows a simple PLEXOS® model with two supply contracts, three pipelines, one storage facility, and two demand areas. All objects can only be connected to other objects through "*node"* objects. Emissions constraints can be placed on any single node or group of nodes. In this simple example there is a constraint placed on all gas flowing from Supply 1 and Supply 2 gas contracts.

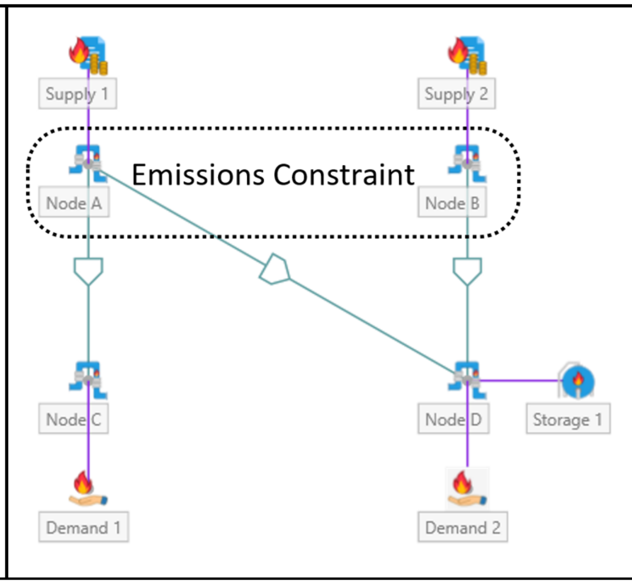
Figure 7.2: PLEXOS® Simple Model Example

In this simple model gas can be purchased from:

- "Supply 1" and put into the system at "Node A"; ***or***
- "Supply 2" and put into the system at "Node B"

3 Pipelines are modeled as directional and

- connect Node A to both Node C and Node D; ***and***
- connect Node B to only Node D
  - Gas from Supply 1 can serve both Demand 1 and 2 and inject into Storage 1
  - Gas from Supply 2 can serve only Demand 2 and inject into Storage 1
  - Gas withdrawn from Storage can only be used to serve Demand 2



For each object numerous properties can be assigned. Additionally, these properties can be dynamic, in other words changing over the planning horizon. Table 7.2 shows seven properties assigned to a single object representing our upstream Foothills pipeline contracts. Properties that are dynamic require a data file with dates and values for a specified time interval (day, month, or year).

Table 7.2: Object Properties Example

Object	Property	Value	Data File	Units
Foothills Pipeline	Max Flow Day		Pipeline MDQ	MMBtu
Foothills Pipeline	Is Bidirectional	No		-
Foothills Pipeline	Flow Charge		Pipeline Variable Charge	$/MMBtu
Foothills Pipeline	Reservation Charge		Pipeline Demand Charge	$/MMBtu/month
Foothills Pipeline	Reservation Volume		Pipeline MDQ	MMBtu
Foothills Pipeline	Loss Rate		Pipeline Fuel Rate	%
Foothills Pipeline	Entitlement Type	Net		-

This IRP is the first NW Natural IRP to implement a PLEXOS® model and the Company built this model from the ground up. Objects in the model include, but are not limited to:

- existing upstream pipeline capacity,
- existing storage facilities,
- existing conventional gas purchasing hubs,
- existing RNG offtake agreement and developments,
- existing on-system production resources,
- future potential capacity resources options,
- future potential compliance resources options and,

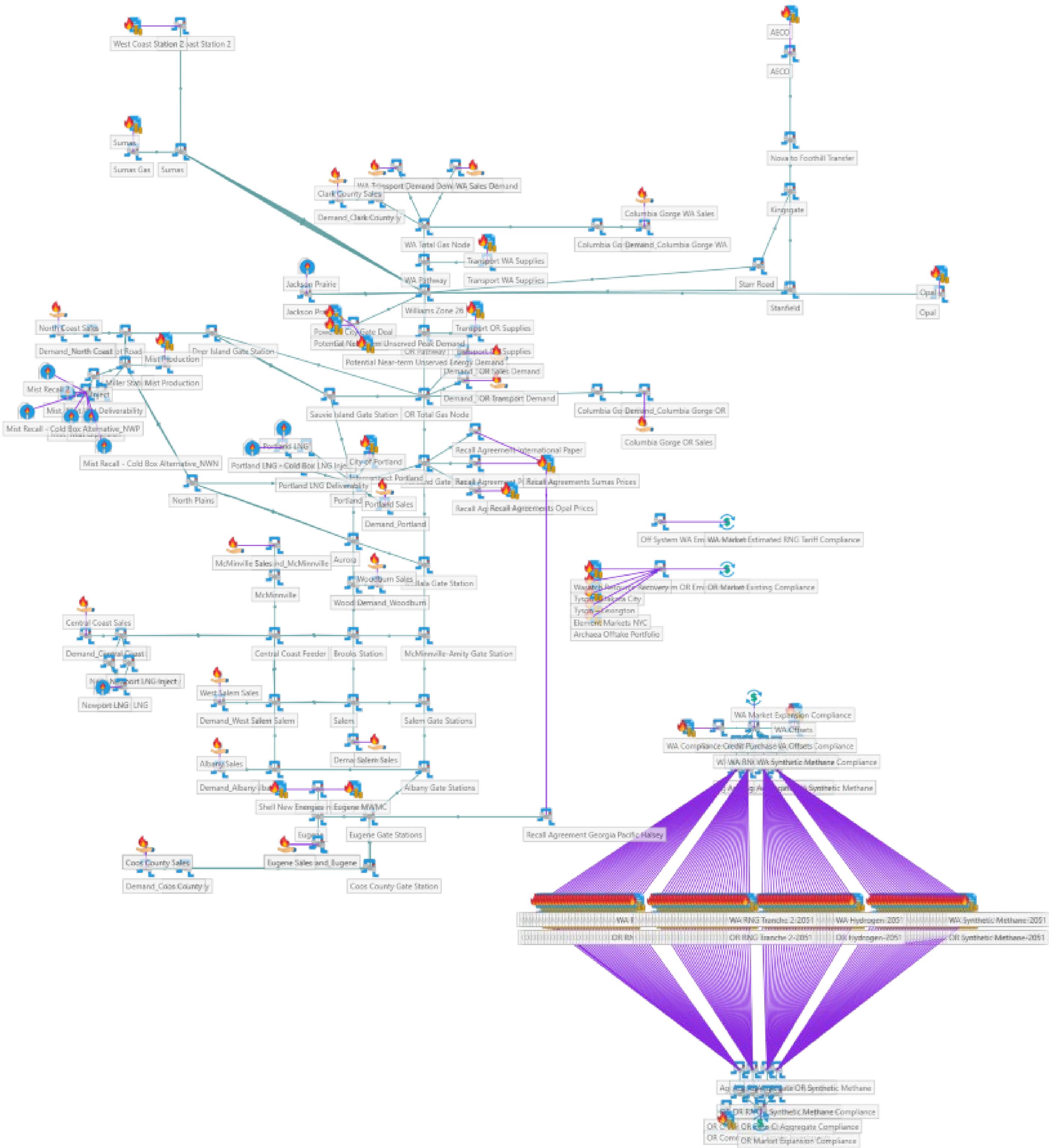
- state specific daily demand by service type (i.e., firm vs interruptible)

In addition to the required properties for each object in the model (example shown in Table 7.2), user defined constraints are developed to ensure that:

- emissions compliance across two separate states,
- least cost qualifying resources are acquired to meet SB 98 targets,
- total cumulative RNG contracts are quantity limited by state,
- hydrogen is less than a specified blending limit by state,
- CCI acquisitions are quantity constrained within each Oregon compliance period,
- offsets are quantity constrained within each Washington compliance period,
- the sequential construction of the potential Newport Takeaway projects,
- potential pipeline resources are selected in November,
- potential storage resources are selected in May and,
- one of the four high-level Portland LNG Alternatives is selected with access to the appropriate level of Mist Recall in May 2027.

This extensive modeling has created a much more complex nodal system model as illustrated by Figure 7.3.

Figure 7.3: 2022 IRP PLEXOS® Model Topography

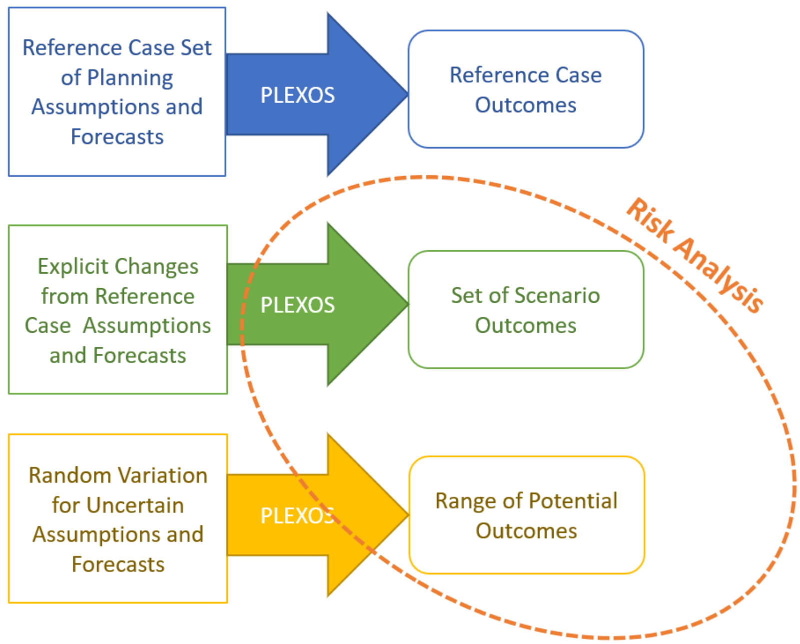


The PLEXOS® model uses the information discussed in chapters 2 through 6. This includes demand forecast, resource options, price forecasts, compliance obligations, etc. Given these inputs, the cost minimization algorithm of the model has perfect foresight of the future and optimizes the resource selection and dispatch across time accordingly. In other words, it can choose to inject into storage in one period to avoid paying high costs in the future.

Unlike the PLEXOS® model, resource planners do not have perfect foresight and face a lot of uncertainty and risk across several factors. Our risk analysis varies the key input component in the mode to understand these risks. An overview of the risk analysis is discussed in the following section.

7.3 Risk Analysis Overview

Unlike previous IRPs, this IRP does not define or select a particular scenario as a base case. Instead, we define a reference case (see Chapter 2, Section 7) and numerous "what-if" scenarios where uncertain key demand and supply inputs are explicitly or stochastically modified in-contrast to the Reference Case. The PLEXOS® takes in all the information and produces a least cost solution for the whole planning horizon. This solution includes, but is not limited to, daily purchases of conventional gas, annual low-GHG supply resource contract decisions, daily storage operations, and capacity resource investments, along with the emissions and costs associated with each of components. The primary output is a least cost resource portfolio that is dynamic through time.



7.3.1 Scenario Analysis Overview

Our risk analysis includes two approaches to testing resource selection. The first approach is to view the world through a specific set of circumstances, known as scenarios. The benefit of using scenarios is it allows stakeholders to understand the implications for resource planning given a specific set of circumstances, for example aggressive building electrification, which can be a bookend set of circumstances. Each scenario makes a few significant deviations from the reference case to understand the implication of that change. For example, Scenario 7 examines the impact of a federal policy aimed at reducing the costs of RNG and Hydrogen. How the future ultimately unfolds will not be a single scenario, but likely a combination of all scenarios.

In addition to the Reference Case, we developed nine other scenarios for the risk analysis. To reference a specific scenario throughout the IRP, we assign numbering and labels to each scenario as shown in Table 7.3. Table 7.3 provides a high-level summary of all the inputs for each scenario. Detailed descriptions of the inputs, outputs, and the reason for a scenario are included as comprehensive standalone sections for each scenario later in this chapter.

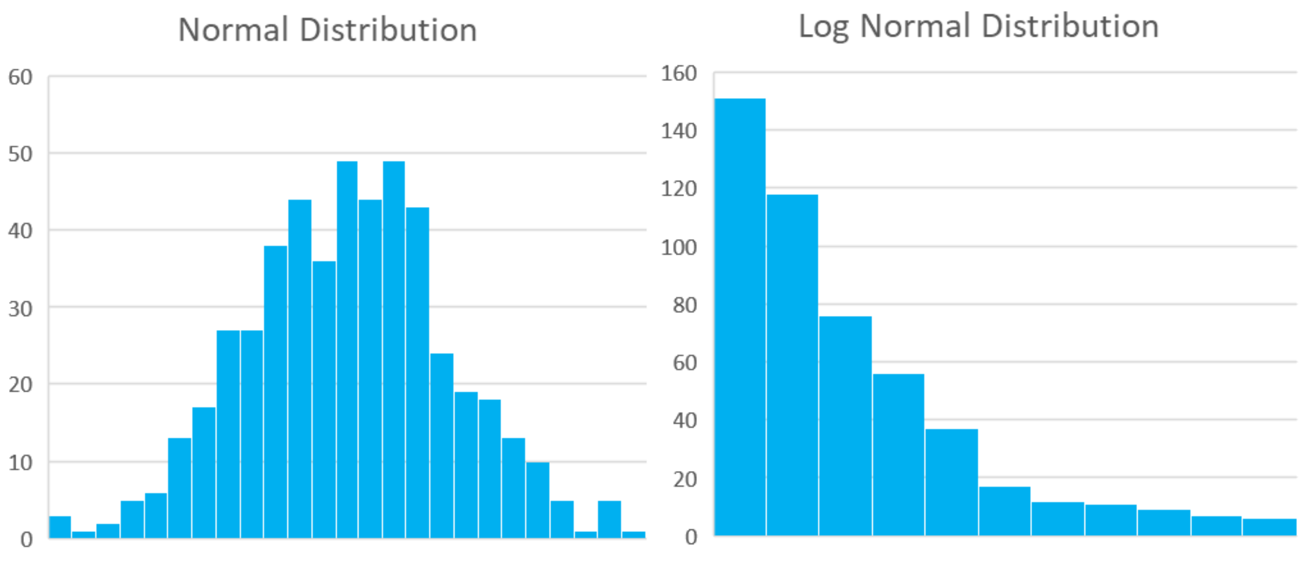
Table 7.3: 2022 IRP Scenarios

	2022 IRP Scenarios- Summary Version	Reference (Trend Continuation) Case	1 Balanced Approach	2 Carbon Neutral by 2050	3 Dual-Fuel Heating Systems	4 New Direct Use Gas Customer Moratorium in 2025	5 Aggressive Building Electrification	6 Full Building Electrification	7 RNG and H2 Production Tax Credit	8 Limited RNG Availability	9 Supply-Focused Decarbonization
Demand-Side	Weather	Climate change adjusted expected ("normal") weather in each year									
	Customer Growth	Current expectations				No New Customers After 2025			Current expectations		
	Space and Water Heating Equipment	Current EE expectations	Moderate gas powered heat pump and hybrid heating adoption		All residential and commercial space heating becomes hybrid heating by 2050	Moderate gas heat pump and hybrid adoption for existing customers	High electrification of existing residential and commercial load by 2050	Full electrification of existing residential and commercial load by 2050	Moderate gas heat pump and hybrid heating adoption		No gas powered heat pumps and low levels of hybrid heating
	Industrial Use Efficiency		Consultant projection	High sensitivity	Consultant projection		60% Electrified by 2050	90% Electrified by 2050	Consultant projection		
	Building Shell Improvement		Energy Trust projection	Energy Trust high sensitivity projection	Ajusted Energy Trust projection				Energy Trust projection		
Supply-Side Assumptions	Conventional Gas	Expected pricing in each month									
	Capacity Resources	All capacity resources available at expected cost									
	Renewable Natural Gas	Expected availability and cost		Higher availability and expected cost	Expected availability and cost				High avail and low cost to customers	Low availability and high cost	Expected availability and cost
	Hydrogen	20% Energy maximum (blended and dedicated) and expected cost		40% Energy maximum and expected cost	20% Energy maximum and expected cost				30% energy max and low cost to customers	12% energy max and high cost	35% max and expected cost
	Synthetic Methane	No energy max and expected cost							No energy max and low cost to customers	No energy max and high cost	No energy max and expected cost
	OR- CCIs	Costs and limits defined in CPP rule									
	WA- Allowances & Offsets	Higher of social cost of carbon or California allowance projection in each year									

7.3.2 Monte Carlo Simulation Analysis Overview

The second approach for risk analysis uses stochastic Monte Carlo simulation. Monte Carlo simulation is often used synonymously with stochastic simulation. It is a technique to randomly draw a value from a defined distribution. Figure 7.4 provides an example of a Monte Carlo simulation for 500 draws from a normal distribution and a log normal distribution.

Figure 7.4: Monte Carlo Example - 500 Draws



There is no single distribution or simulation process that is used for the inputs listed in Table 7.4. Some simulations are more complex than others. Some simulations must incorporate critical cross-input or cross-time correlations. For example, the gas price simulation must incorporate both correlation across purchasing hubs and correlation across time. If gas prices increase at AECO they are likely to see a similar increase at Sumas. Also, if markets are facing a high gas price environment in 2027, they are likely to face similar conditions in 2028. To account for these two components, the gas price simulation relies on historical data, both at annual and monthly levels to define the distribution for the gas price Monte Carlo.

How some inputs vary is likely not tied to how other uncertain inputs vary, such as the cost of Mist Recall and Portland's weather. However, some inputs are likely to be correlated. For example, construction cost increases are likely to impact all resources that involve construction and temperature in Oregon and Washington are likely to move together. The co-dependence, or correlation across stochastic simulations (a.k.a. draws) is modeled for known or likely correlated inputs.[149]

NW Natural generates 500 draws for uncertain inputs. Independent inputs are randomly matched to a single draw, whereas correlated inputs are simulated together and matched appropriately to the same draw. While more draws will always be preferred to less draws, computational limits start becoming an

[149] The term draw refers to a random "draw" selected from a defined distribution for uncertain inputs, known as a random variable in statistics

issue at this high threshold of draws. Additional computational costs, both money and time, must be balanced with adding incremental simulation runs.[150] The 500-draw threshold was selected as a sufficient number of random pairings of inputs to produce an adequately wide range of resource portfolio outcomes for a risk analysis and still be able to solve a least costs portfolio for each draw.[151]

Due to the uncertainty of the future, we employ Monte Carlo simulations for numerous factors that are inputs into the PLEXOS® model. Table 7.4 lists the key inputs for which we simulate 500 draws. Most inputs, such as the price for hydrogen or daily temperatures in Portland, are dynamic and change throughout the planning horizon. For dynamic inputs, a dynamic path over the planning horizon is simulated for 500 draws.

Table 7.4: Stochastic Variables for Risk Analysis

Stochastic Variables		
Demand Drivers - Weather Daily Temperatures By Load Center: *Albany, Astoria, Coos Bay, The Dalles, Eugene, Lincoln City, Portland, Salem, Vancouver* - Customer Growth Rates - Growth Moratorium Start Dates - Customer Losses - Gas Heat Pump Penetration - Hybrid Heating Penetration - Building Shell Improvements - Industrial Energy Efficiency	**Supply Costs and Prices** - Price of Conventional Natural Gas By hub: *AECO, Opal, Sumas West Coast Station 2* - Price of RNG Tranche 1 - Price of RNG Tranche 2 - Price Path of Hydrogen - Cost Adder and Path for Methanation - Allowance Prices - Offset Prices **Supply Availability** - Max Allowable Hydrogen Blend - Max Annual Quantity of RNG Tranche 1 - Max Annual Quantity of RNG Tranche 2	**Capacity Resource Costs** - Mist Recall - Newport Takeaway 1 - Newport Takeaway 2 - Newport Takeaway 3 - Upstream Pipeline Expansion - Mist Expansion - Portland LNG Alternative Portland LNG - Cold Box Middle Corridor Mist Takeaway Williams NWP Enhancement

7.4 Scenario Results

The results of the scenarios discussed throughout the IRP are provided in the following subsections. The key input assumptions and key results of each scenario are compiled as a standalone "booklet" to be able to see how all the key parts fold into the results. The results of the scenarios can then be compared against one another. Each scenario requires compliance with the Oregon Climate Protection Program and the Washington Cap-and-Invest program.

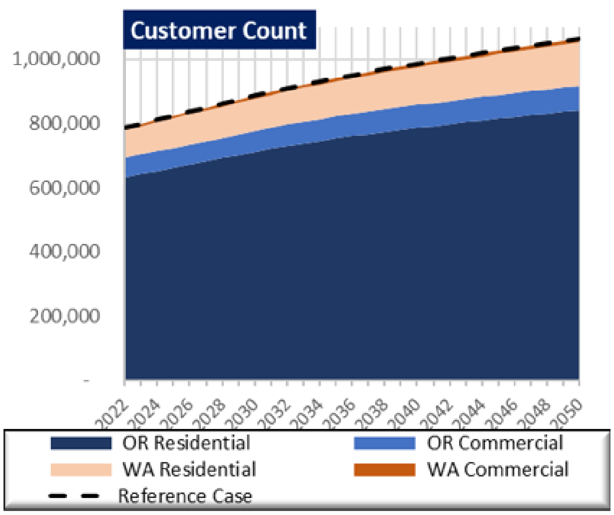
[150] To complete the risk analysis, NW Natural subscribed to 160 computer cores for a 2-month period. Even with this access to additional computer cores the model takes roughly 5 days to complete all 500 draws and significantly more time to troubleshoot and QC the model.

[151] One of the benefits of moving to PLEXOS® is the ability to optimize the resource selection for each individual draw. Due to the limitations of the previous software, prior IRPs ran Monte Carlo simulation of only costs and demand for a fixed resource portfolio. PLEXOS® has the flexibility to input simulations for any key assumption, forecast or constraint and will optimize resource selection for that specific draw. PLEXOS® still has the capability to analyze how a fixed resource portfolio with perform across varying inputs, forecasts, or constraints.

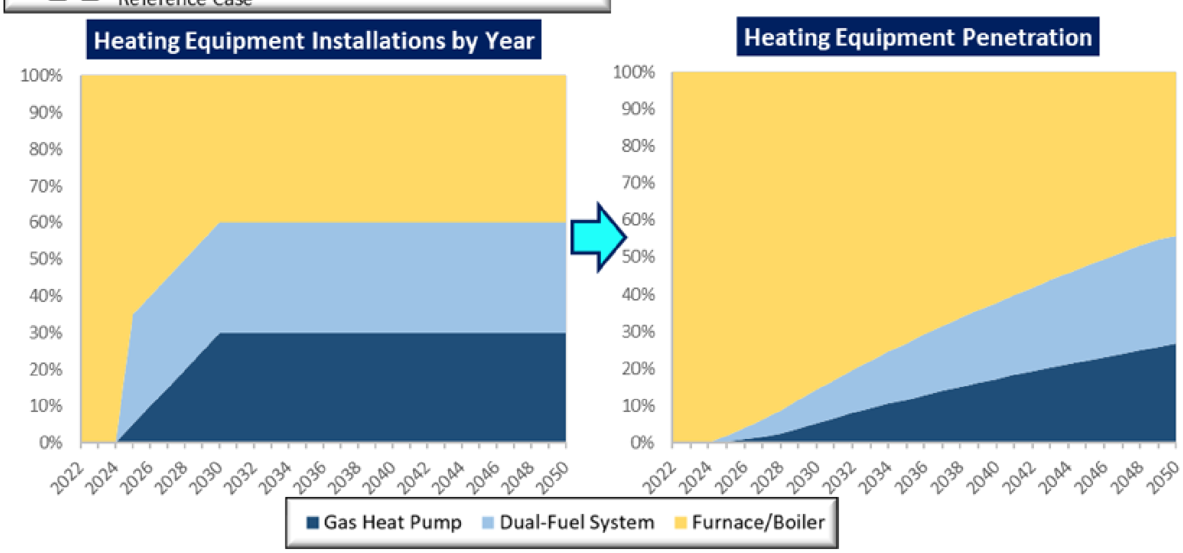
7.4.1 Scenario 1-Balanced Decarbonization

Scenario 1 – Balanced Decarbonization

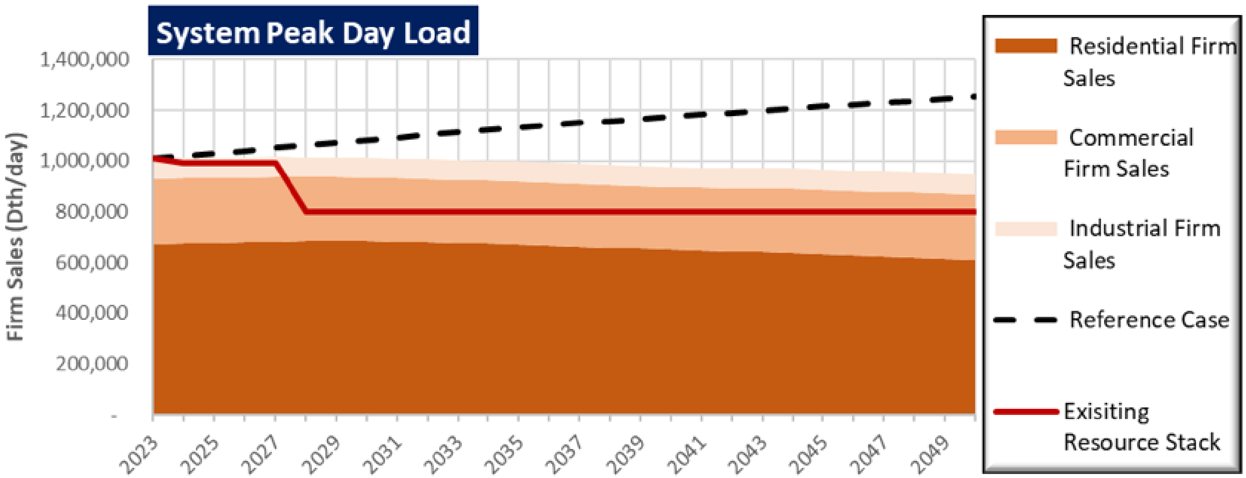
Scenario 1 represents what NW Natural considers to be a balanced approach to meeting the emissions compliance obligation of Oregon's Climate Protection Program (CPP) and Washington's Cap-and-Invest program. Customer growth is based upon historical trends. It uses the energy efficiency forecasts provided by Energy Trust of Oregon for sales customers and AEG for transport customers. It also deploys a moderate amount of both natural gas heat pump technology for space and water heating and dual-fuel heating systems (electric heat pump with natural gas supplemental/backup heat). It uses our best estimate of the availability and cost of biofuel RNG and a conservative estimate of the amount of renewable hydrogen that is either blended into our system or deployed in pure hydrogen to some customers (20% of deliveries in energy terms). Key assumptions in the other scenarios are varied to be able to compare against Scenario 1.

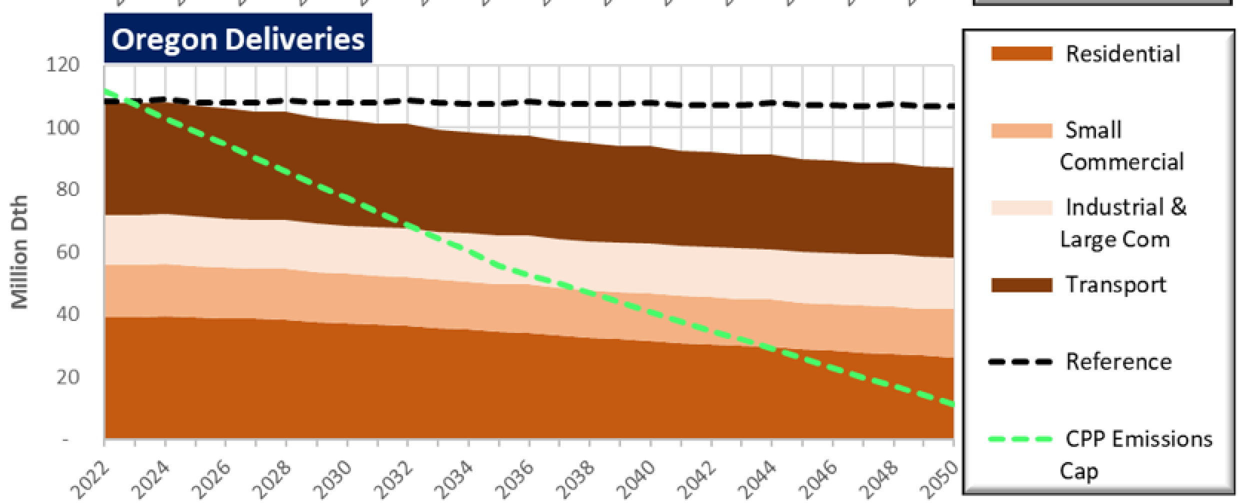


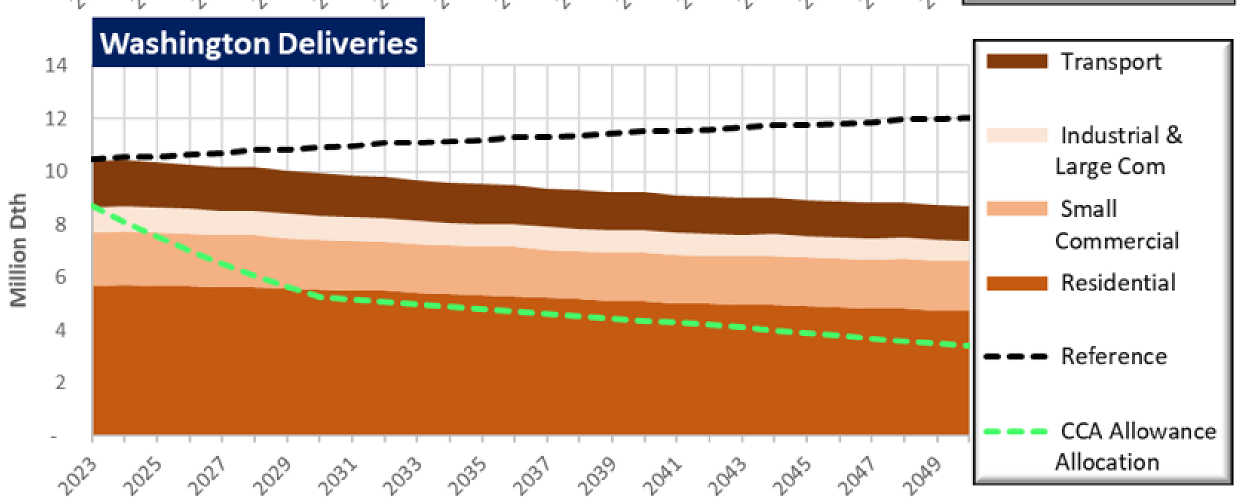
Demand-Side Assumptions	
Sales Customer Energy Efficiency	Energy Trust of Oregon projection of savings, at $5.06/therm of first year savings
Transport Customer Energy Efficiency	Applied Energy Group projection of savings at $1.79/therm of first year savings
Gas Heat Pump Cost	$4,000 total cost to utility for a residential heating system, $13,000 for a Commercial heating System; $1600 for residential water heater
Dual-Fuel System Costs	Net cost of $400 to utility



Scenario 1 – Balanced Decarbonization







Scenario 1 – Balanced Decarbonization

Capacity Resource Options

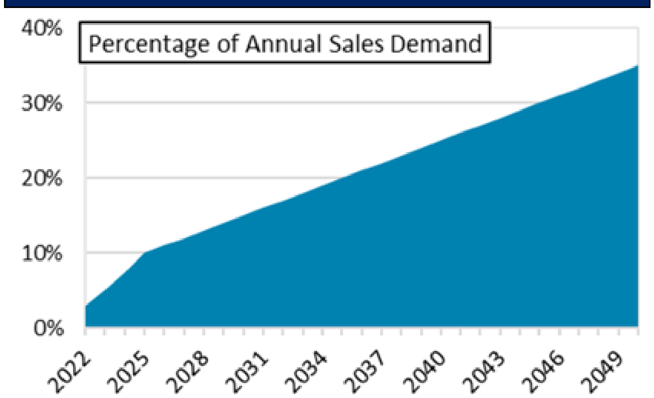
Capacity Resource	Cost ($/Dth/day)	Daily Deliverability (Dth/day)
Mist Recall	$ 0.09	Max: 203,800
Newport Takeaway 1	$ 0.14	16,125
Newport Takeaway 2	$ 1.00	13,975
Newport Takeaway 3	$ 1.41	12,900
Mist Expansion	$ 0.62	106,000
Upstream Pipeline Expansion	$ 2.12	50,000
Portland LNG - Cold Box	$ 0.06	130,800
Interstate Pipeline Looping Plus Required Mist Recall	$ 0.39	130,800
Middle Corridor NWN System Pipeline Plus Required Mist Recall	$ 0.35	130,800

Compliance Resource Options

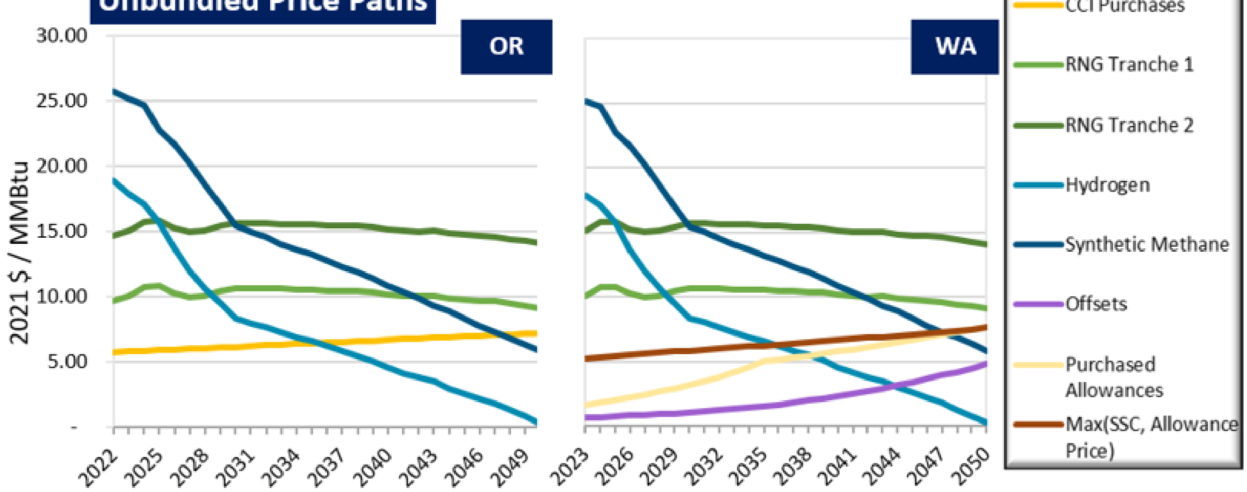
Quantity Available

Option	Limit
RNG Tranche 1	13,000,000 Dth / year
RNG Tranche 2	27,000,000 Dth / year
Hydrogen	20% of Deliveries by Energy
Synthetic Methane	Unbounded
CCIs	OR Compliance Period 1: 10% OR Compliance Period 2: 15% OR Compliance Period >=3: 20%
Allowances	Unbounded
Offsets	WA Compliance Period 1: 6% WA Compliance Period >=2: 8%

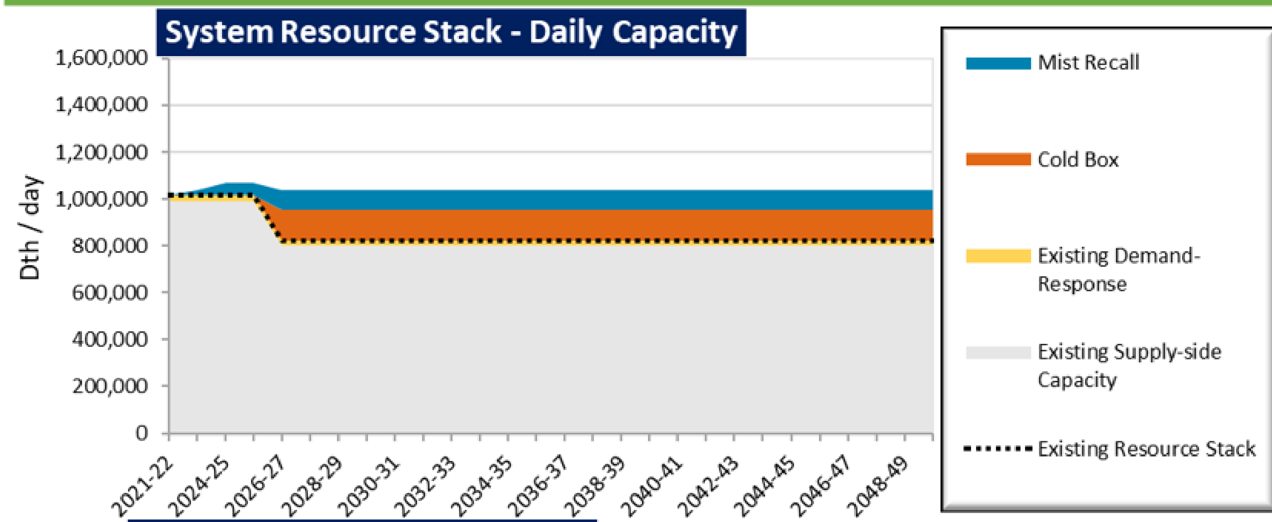
OR SB 98 / WA HB 1257 RNG Targets

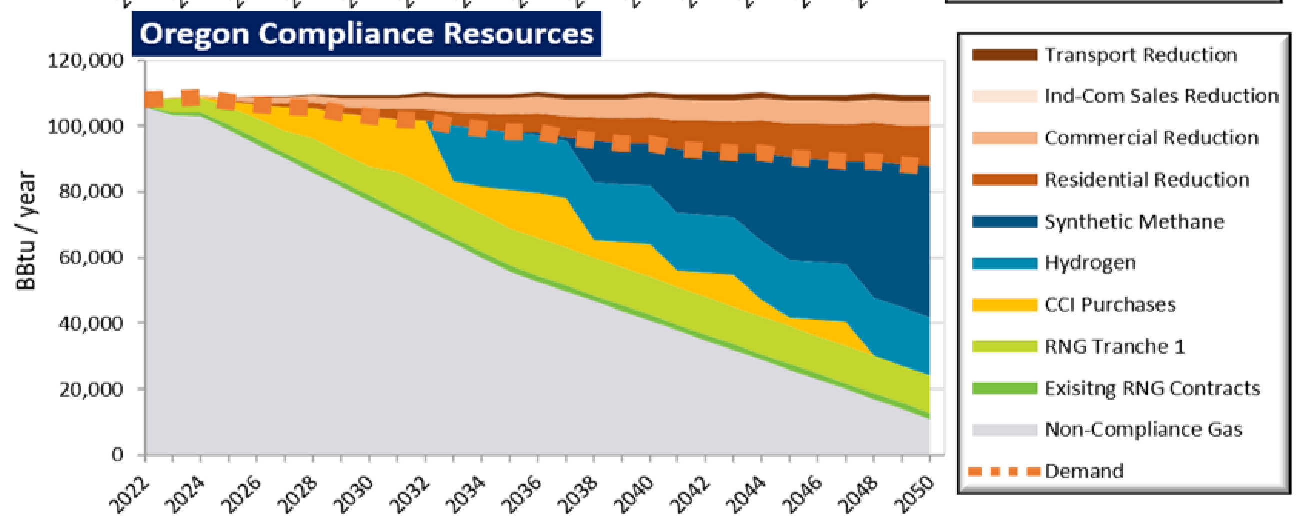


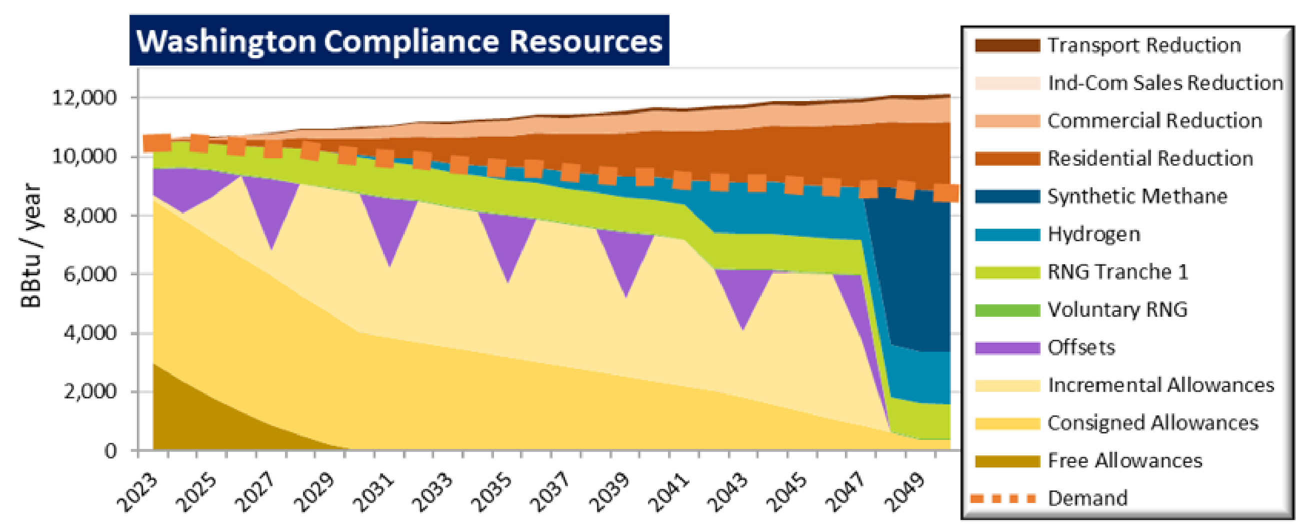
Unbundled Price Paths



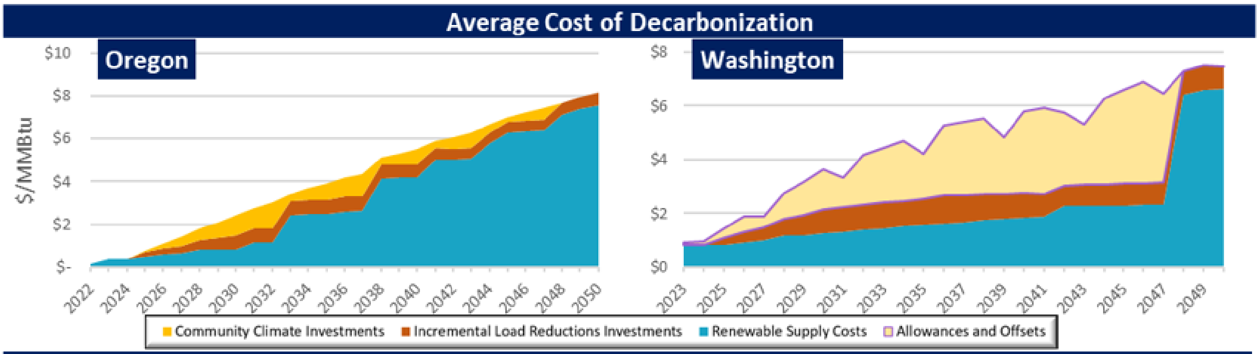
Scenario 1 – Balanced Decarbonization

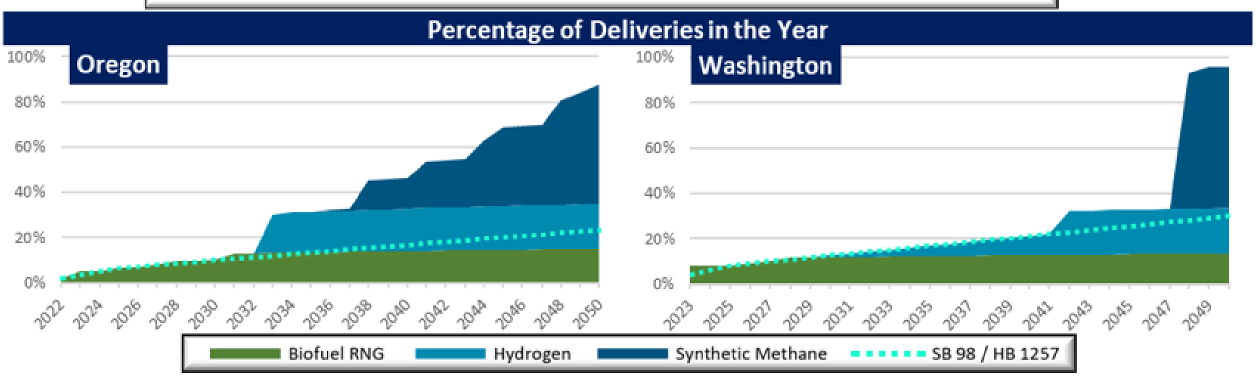


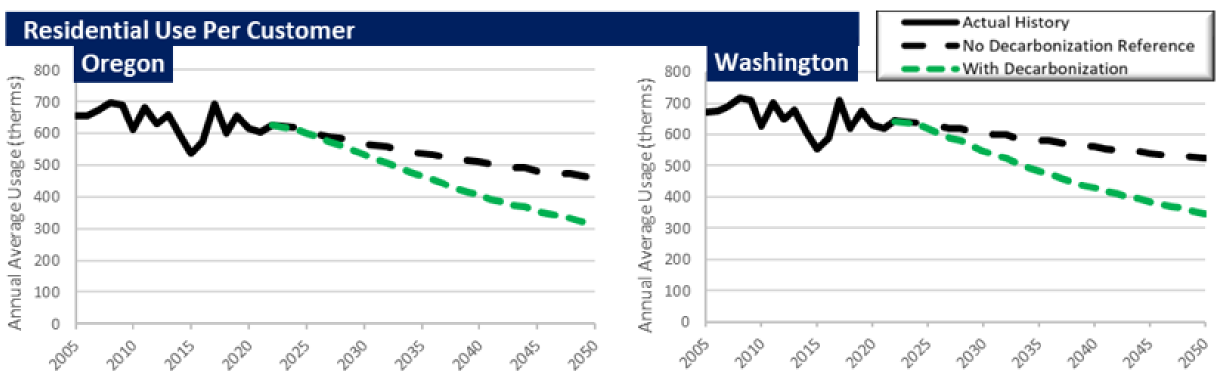


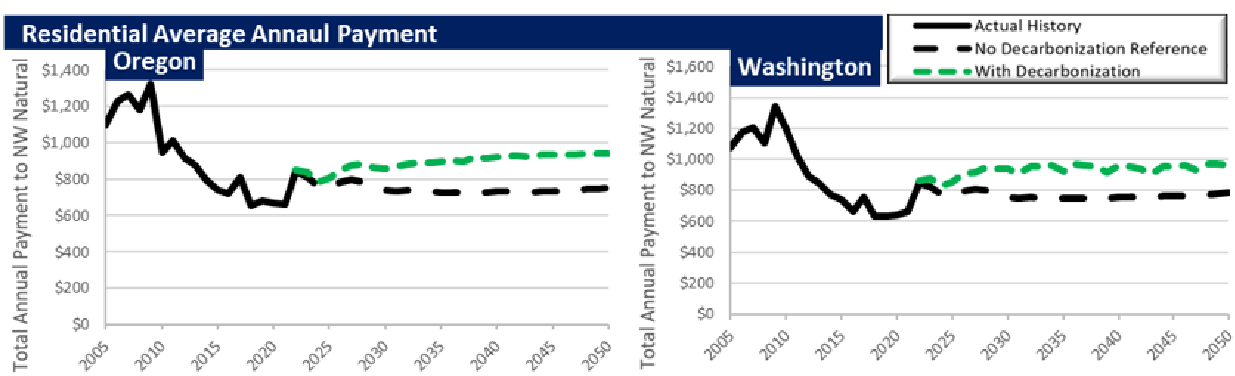


Scenario 1 – Balanced Decarbonization









Scenario 1 – Balanced Decarbonization

Capacity Takeaways

- Replacing Portland LNG Cold Box shown as least cost solution
- Additional capacity needs served by Mist Recall, with a total recall of 85,000 Dth with the last recall occurring in 2027

Oregon Emissions Takeaways

- Meeting RNG targets for SB 98 represents most of the needed emissions reduction for the first compliance period of the Climate Protection Program; small amounts of Community Climate Investments (CCIs) may be purchased to meet additional requirements depending on weather and other conditions
- Biofuel RNG and CCIs represent the marginal compliance activity in the near- to medium-term, transitioning to renewable hydrogen for blending or dedicated delivery starting in 2032, and then transitioning to synthetic renewable natural gas in 2038
- Renewable supply represents roughly 90% of deliveries in 2050, which is equivalent to roughly ¾ of current gas deliveries in Oregon. Biofuel RNG deliveries represent roughly 10% of current load in 2050
- Decarbonization action to comply with SB 98 and the CPP results in residential gas utility bills being 16% higher in 2030 and 25% higher in 2050 than in a world without these policies

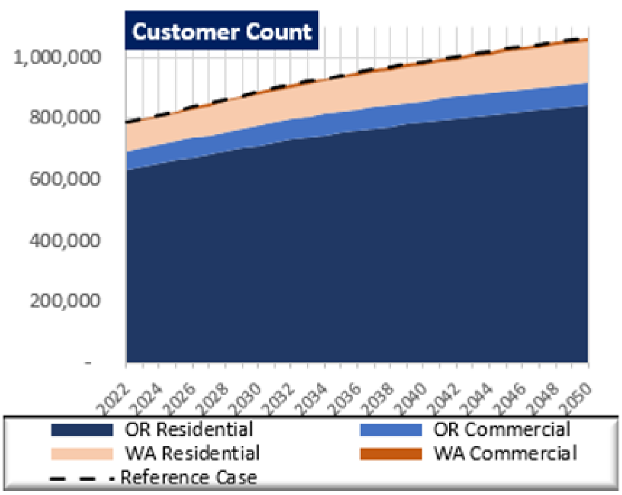
Washington Emissions Takeaways

- Delivering RNG for HB 1257 and utilizing offsets represents the bulk of net near term compliance with Cap-and-Invest, with allowance purchasing filling in any gaps
- Renewable supply represents roughly 20% of deliveries in 2040 and 95% of deliveries in 2050
- Complying with HB 1257 and Cap-and-Invest results in residential gas utility bills being 25% higher in 2030 and 22% higher in 2050 than in a world without these policies

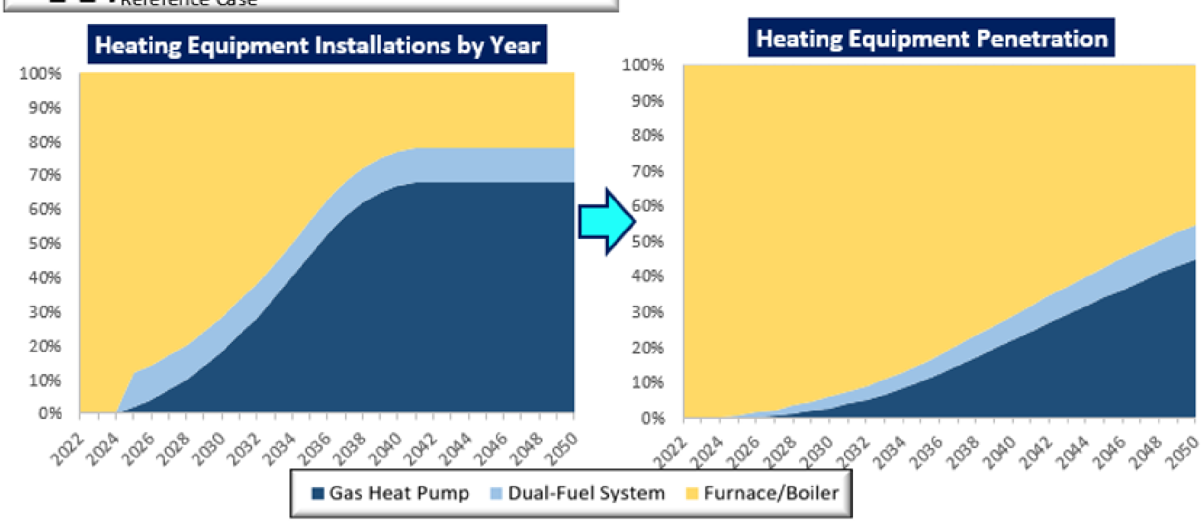
7.4.2 Scenario 2- Carbon Neutral

Scenario 2 – Carbon Neutral

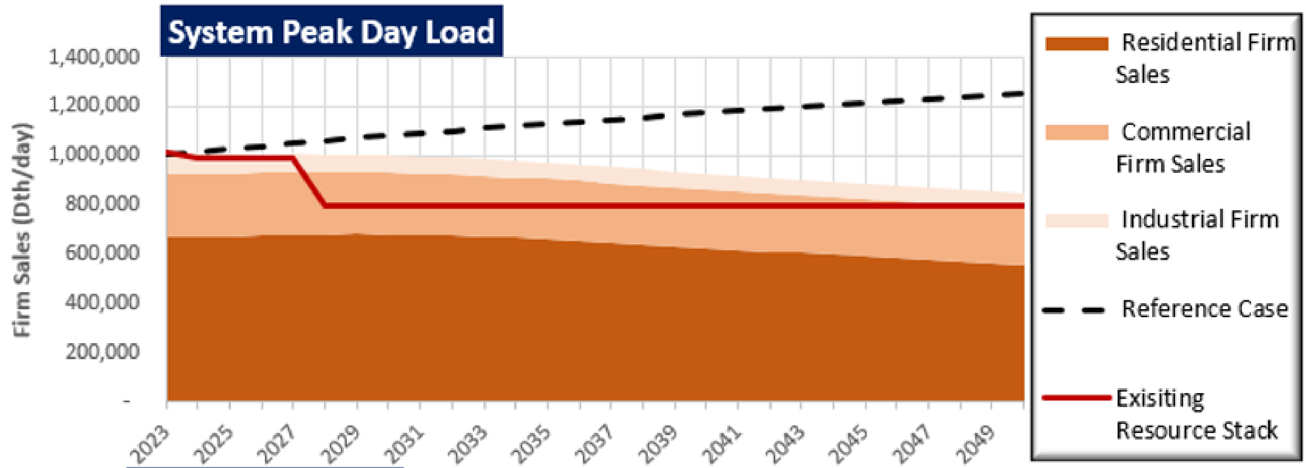
Scenario 2 is the scenario meant to help answer the question “What if NW Natural reduced emissions faster and further than is required by the OR CPP and WA CCA programs?” As such, it is the only scenario that does not use NW Natural’s emissions cap in Oregon’s CPP program or expected activity to comply with Washington’s Cap-and-Invest program as the constraint for emissions. It deploys a requirement that NW Natural’s emissions are zero in 2050 without the use of offsets or compliance instruments (like CCIs in OR or emissions allowances in WA). It assumes customer growth based upon historical trends. In order to meet this more aggressive emissions target it deploys a more aggressive deployment of existing Energy Trust EE programs and expected transport schedule EE programs than Scenario 1. It also assumes a more aggressive penetration of natural gas heat pump technology for space and water heating. While the costs of the modeled renewable supply options are the same as Scenario 1, Scenario 2 allows for more RNG and pure hydrogen to be blended or dedicated to some customers.

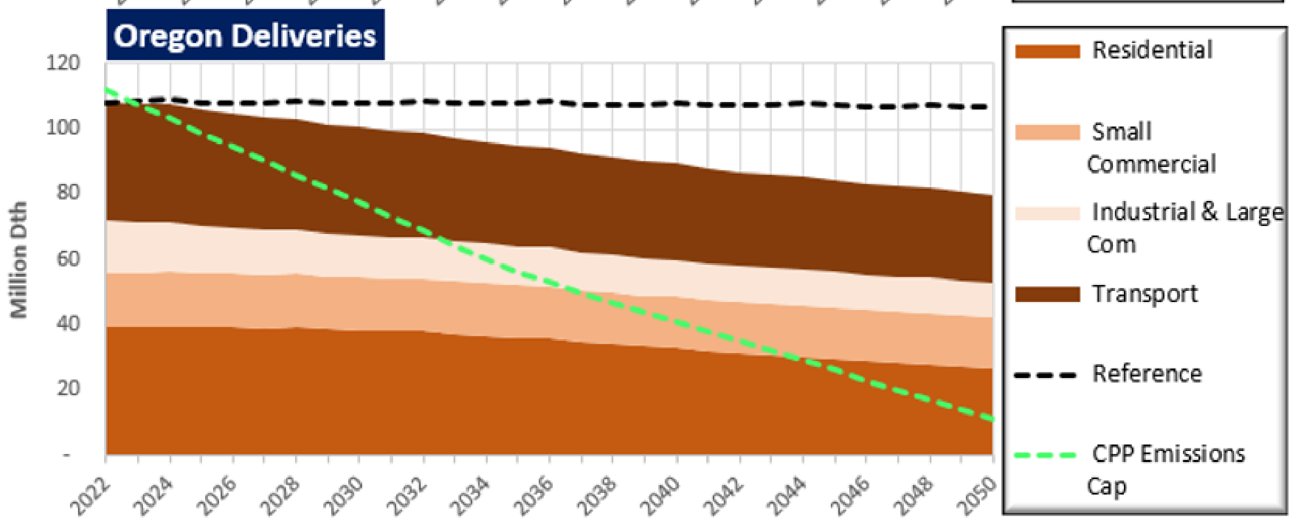


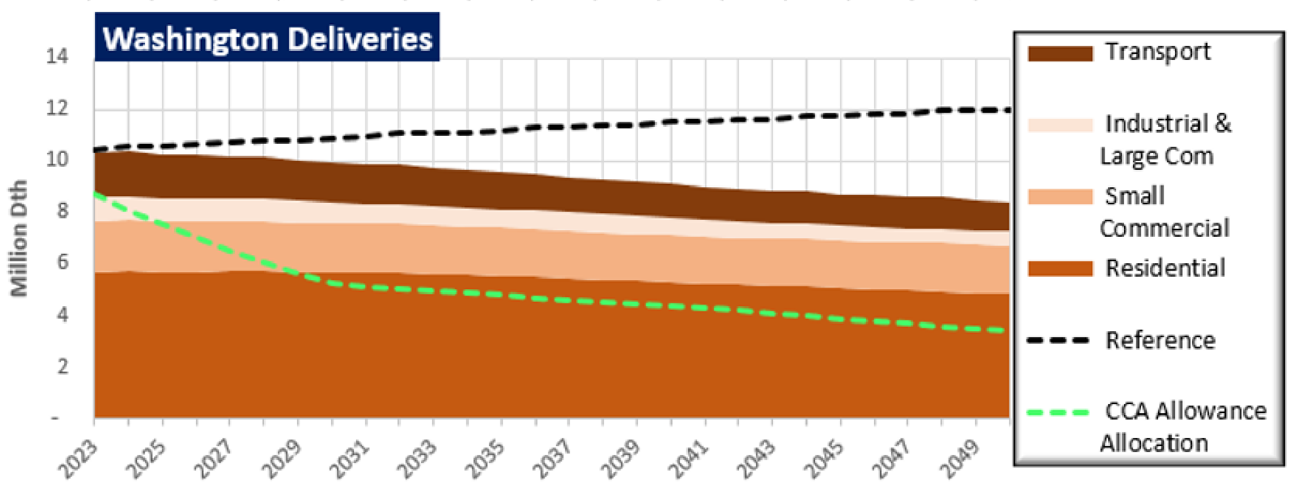
Demand-Side Assumptions	
Sales Customer Energy Efficiency	15% more than ETO projection at $5.06/therm of first year savings
Transport Customer Energy Efficiency	30% more than Applied Energy Group projection of savings at $1.79/therm of first year savings
Gas Heat Pump Cost	$4,000 total cost to utility for a residential heating system, $13,000 for a Commercial heating System; $1,600 for residential water heater
Dual-Fuel System Costs	Net cost of $400 to utility



Scenario 2 – Carbon Neutral







Scenario 2 – Carbon Neutral

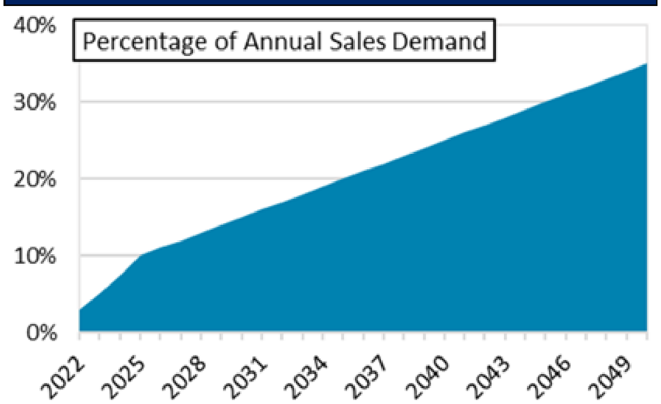
Capacity Resource Options		
Capacity Resource	**Cost ($/Dth/day)**	**Daily Deliverability (Dth/day)**
Mist Recall	$ 0.09	Max: 203,800
Newport Takeaway 1	$ 0.14	16,125
Newport Takeaway 2	$ 1.00	13,975
Newport Takeaway 3	$ 1.41	12,900
Mist Expansion	$ 0.62	106,000
Upstream Pipeline Expansion	$ 2.12	50,000
Portland LNG - Cold Box	$ 0.06	130,800
Interstate Pipeline Looping Plus Required Mist Recall	$ 0.39	130,800
Middle Corridor NWN System Pipeline Plus Required Mist Recall	$ 0.35	130,800

Compliance Resource Options

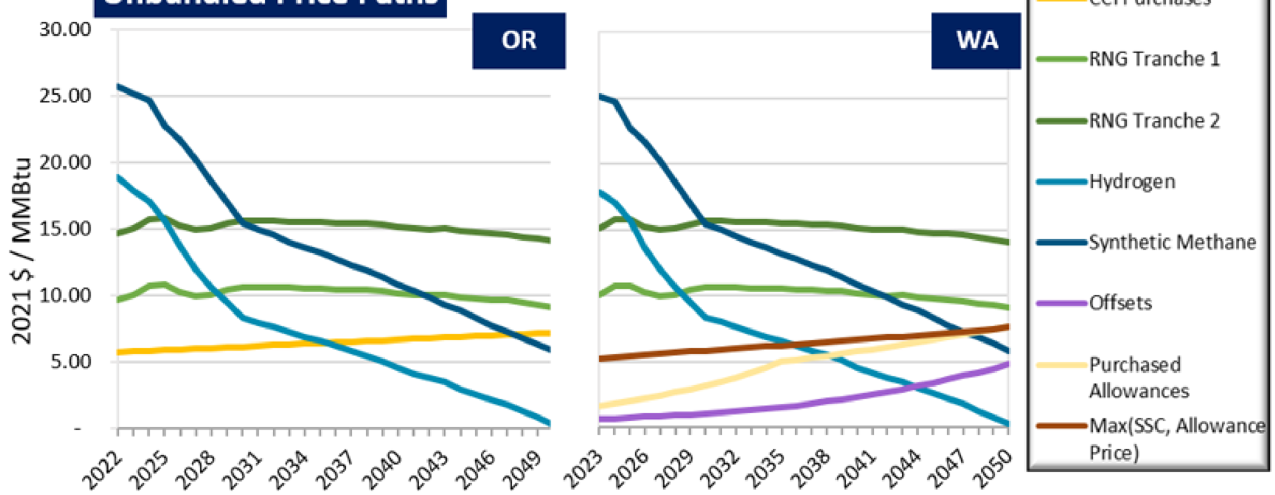
Quantity Available

Option	Limit
RNG Tranche 1	15,000,000 Dth / year
RNG Tranche 2	35,000,000 Dth / year
Hydrogen	40% of Deliveries by Energy
Synthetic Methane	Unbounded
CCIs	OR Compliance Period 1: 10% OR Compliance Period 2: 15% OR Compliance Period >=3: 20%
Allowances	Unbounded
Offsets	WA Compliance Period 1: 6% WA Compliance Period >=2: 8%

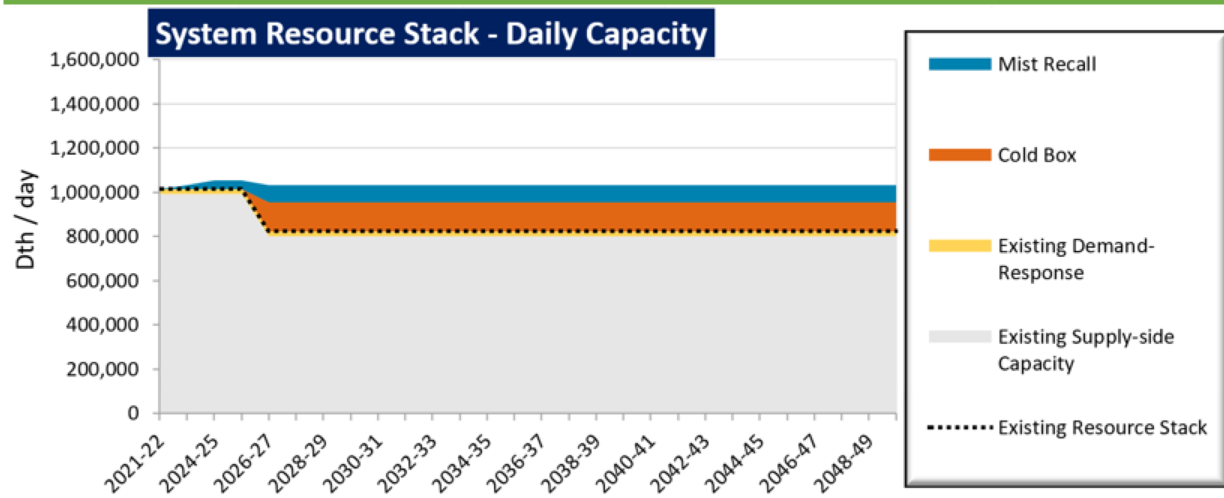
OR SB 98 / WA HB 1257 RNG Targets

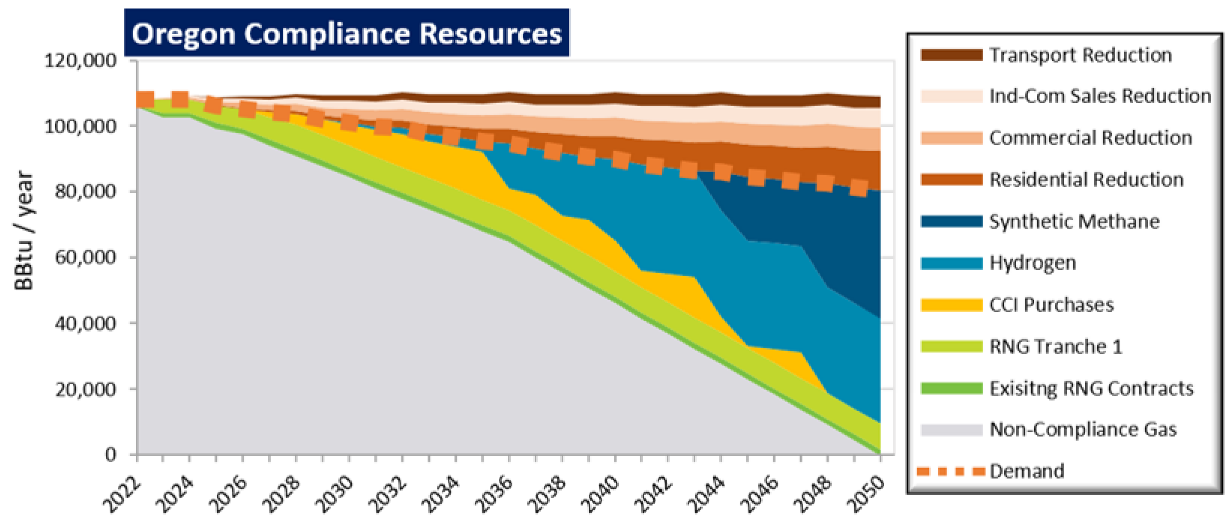


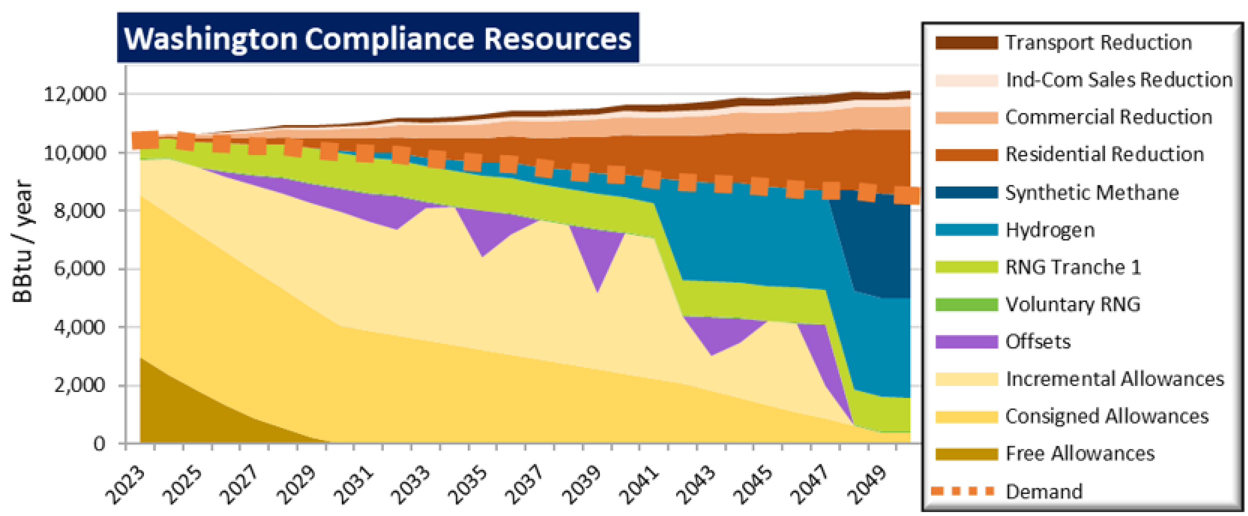
Unbundled Price Paths



Scenario 2 – Carbon Neutral

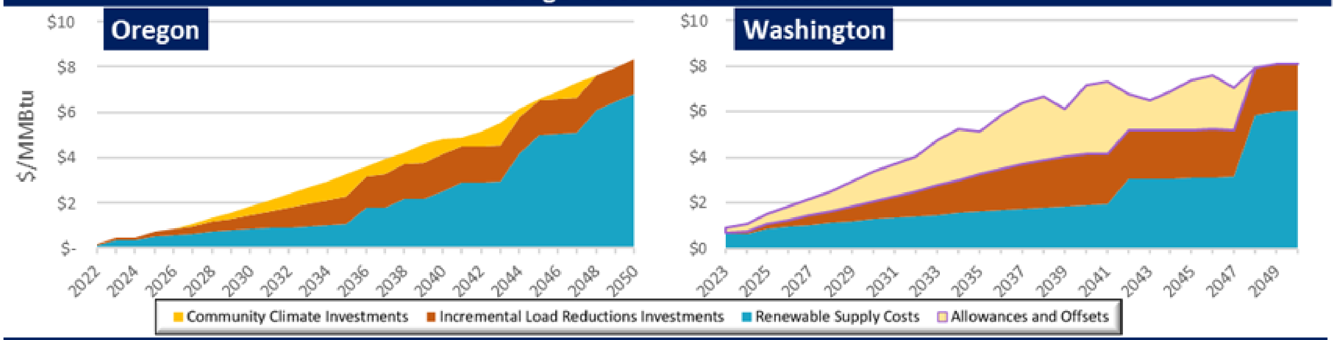




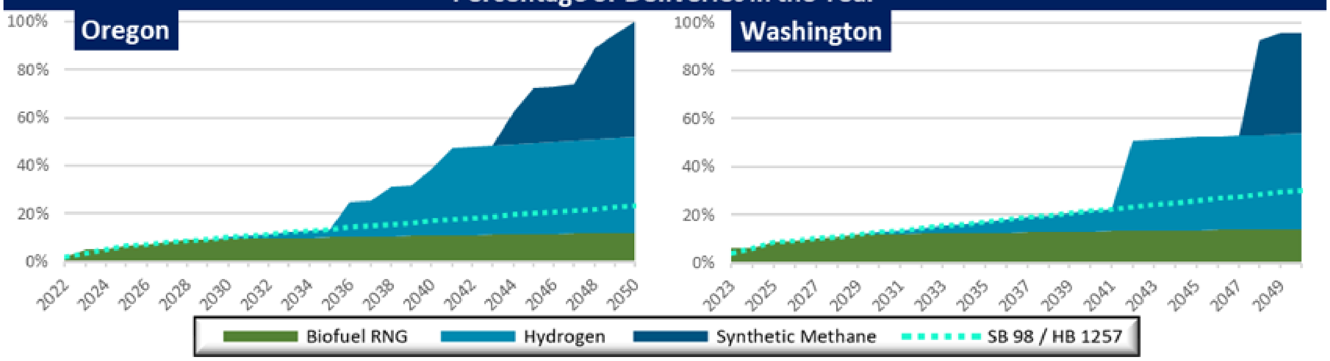


Scenario 2 – Carbon Neutral

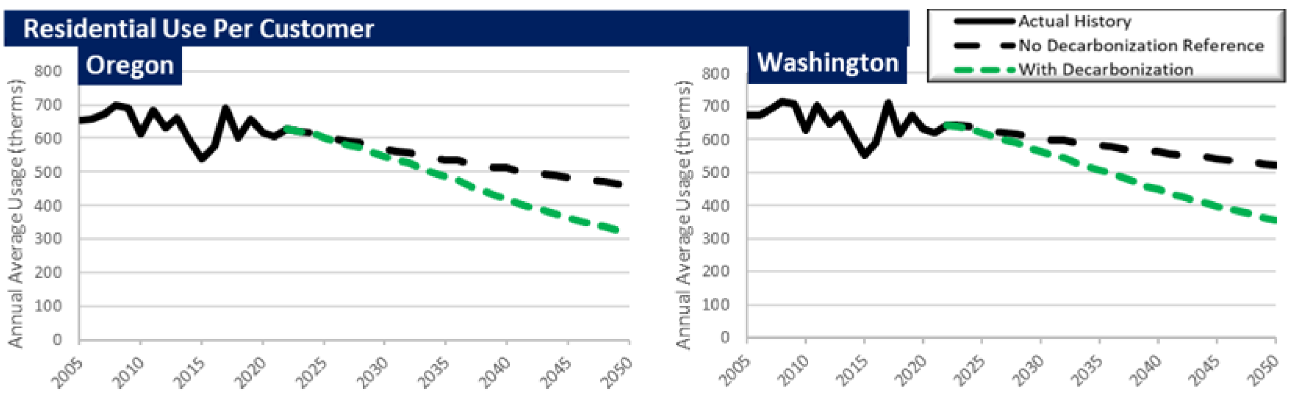
Average Cost of Decarbonization



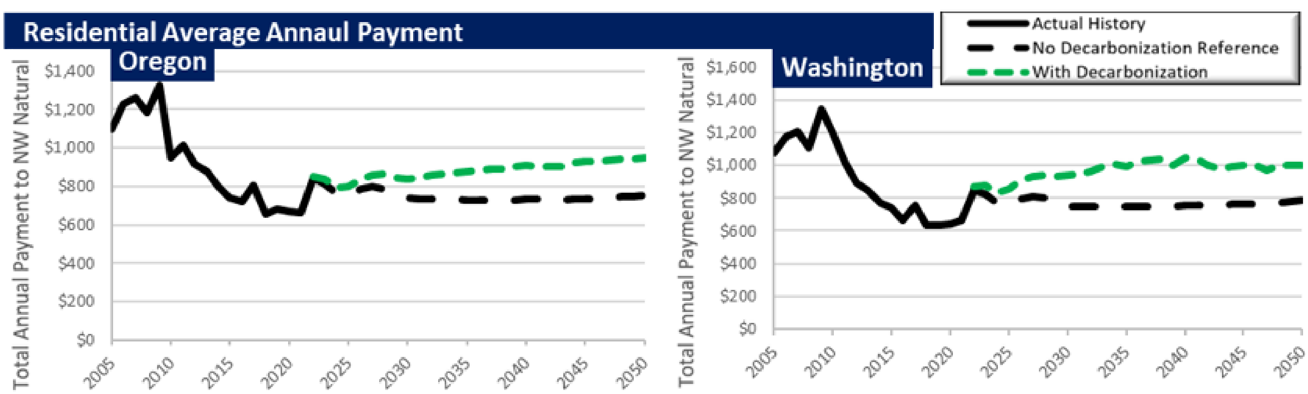
Percentage of Deliveries in the Year



Residential Use Per Customer



Residential Average Annaul Payment



Scenario 2 – Carbon Neutral

Capacity Takeaways

- Replacing Portland LNG Cold Box shown as least cost solution
- Additional capacity needs served by Mist Recall, with a total recall of 80,000 Dth with the last recall occurring in 2027

Oregon Emissions Takeaways

- Meeting RNG targets for SB 98 represents most of the needed emissions reduction for the first compliance period of the Climate Protection Program; small amounts of Community Climate Investments (CCIs) may be purchased to meet additional requirements depending on weather and other conditions
- Biofuel RNG and CCIs represent the marginal compliance activity in the near- to medium-term, transitioning to renewable hydrogen for blending or dedicated delivery starting in 2033, and then transitioning to synthetic renewable natural gas in 2036
- Renewable supply represents 100% of deliveries in 2050, which is equivalent to roughly ¾ of current gas deliveries in Oregon. Biofuel RNG deliveries represent roughly 10% of current load in 2050
- Decarbonization action to comply with SB 98 and the CPP results in residential gas utility bills being 13% higher in 2030 and 26% higher in 2050 than in a world without these policies

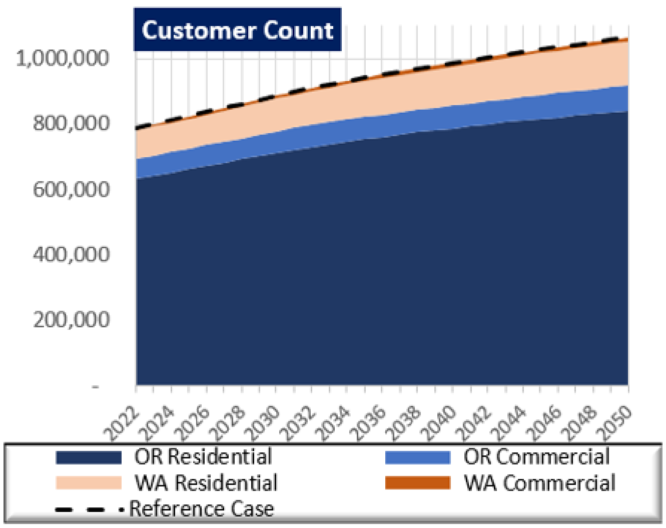
Washington Emissions Takeaways

- Delivering RNG for HB 1257 and utilizing offsets represents the bulk of net near term compliance with Cap-and-Invest, with allowance purchasing filling in any gaps
- Renewable supply represents roughly 20% of deliveries in 2040 and 95% of deliveries in 2050
- Complying with HB 1257 and Cap-and-Invest results in residential gas utility bills being 25% higher in 2030 and 27% higher in 2050 than in a world without these

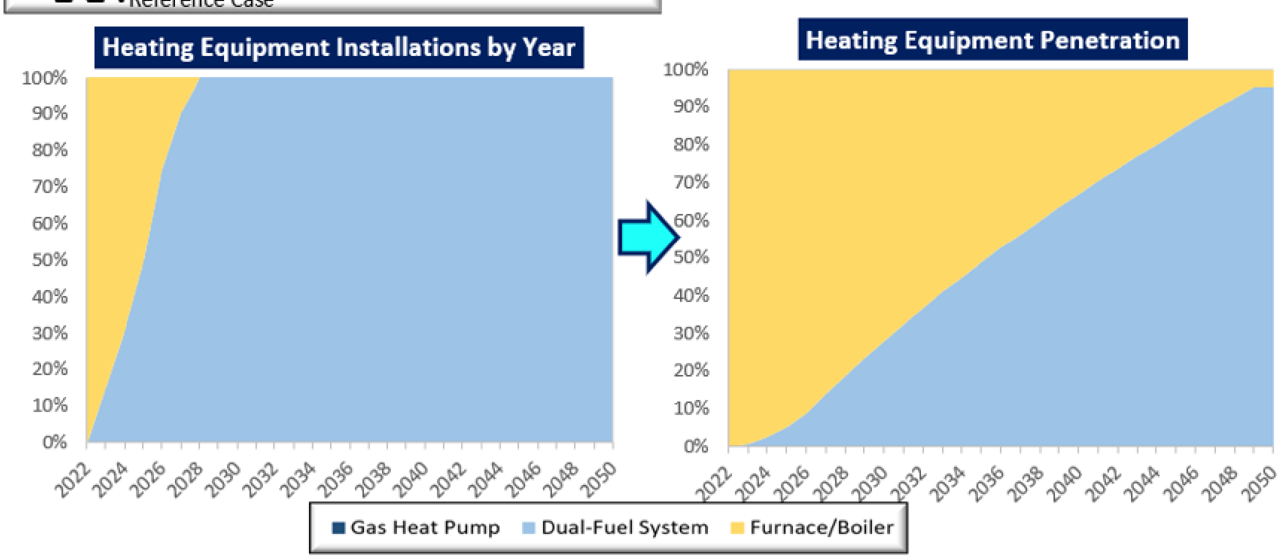
7.4.3 Scenario 3- Dual-Fuel Heating

Scenario 3 – Dual-Fuel Heating

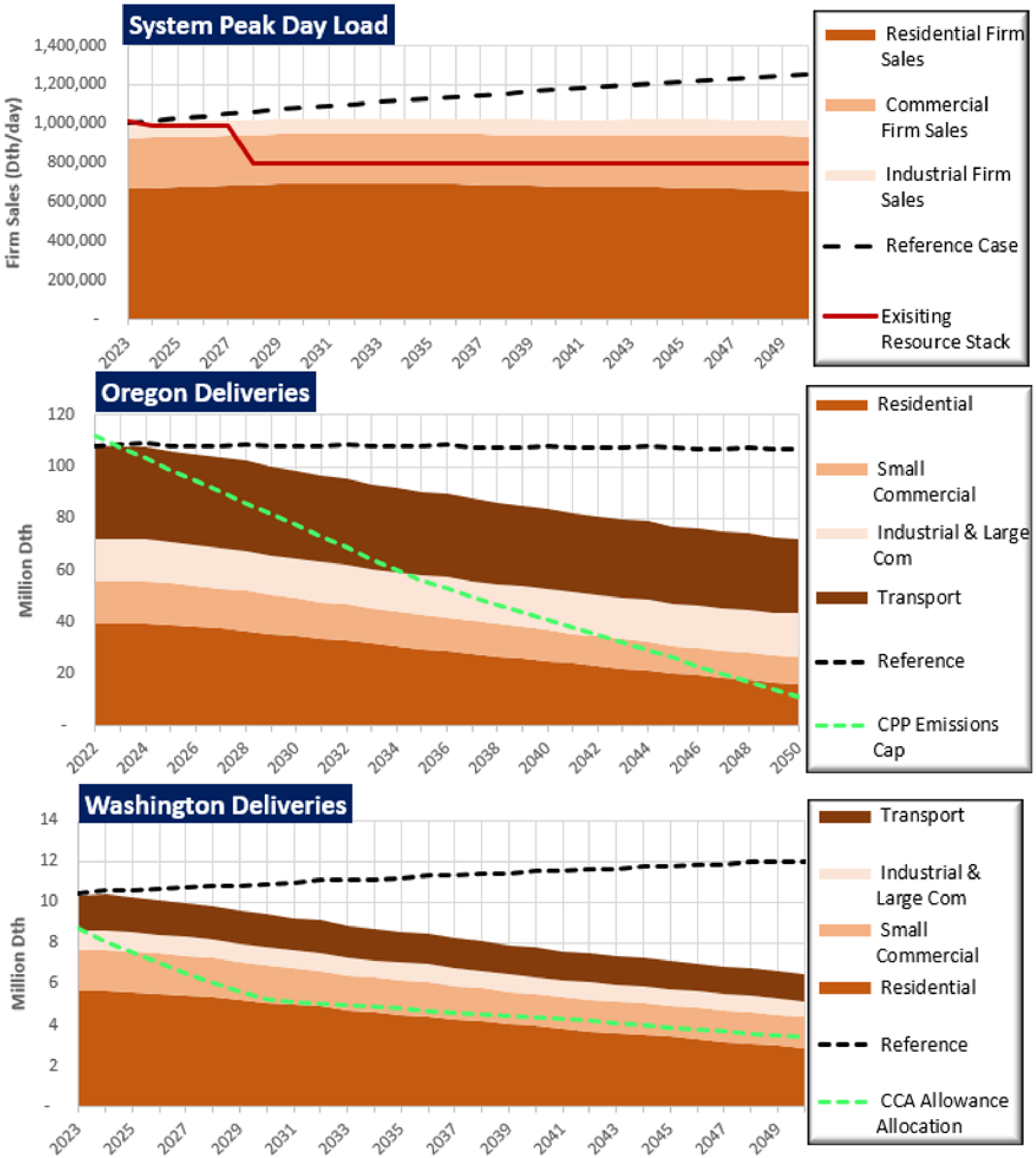
Scenario 3 helps to answer the question "What could it mean for gas utility customers if dual-fuel heating (an electric heat pump supplemented by a gas furnace during cold events) becomes the primary equipment to meet heating need in NW Natural's service territory?" It utilizes the same customer growth and supply-side assumptions as Scenario 1, but assumes that by 2028 all heating equipment installations (replacement of existing equipment reaching the end of its life as well as installations in newly constructed buildings) that would be natural gas heating in the reference case become dual-fuel systems, such that by 2050 dual-fuel heating systems predominate in NW Natural's service territory.



Demand-Side Assumptions	
Sales Customer Energy Efficiency	Energy Trust of Oregon projection of savings, at $5.06/therm of first year savings
Transport Customer Energy Efficiency	Applied Energy Group projection of savings at $1.79/therm of first year savings
Gas Heat Pump Cost	$4,000 total cost to utility for a residential heating system, $13,000 for a Commercial heating System; $1,600 for residential water heater
Dual-Fuel System Costs	Net cost of $400 to utility



Scenario 3 – Dual-Fuel Heating



Scenario 3 – Dual-Fuel Heating

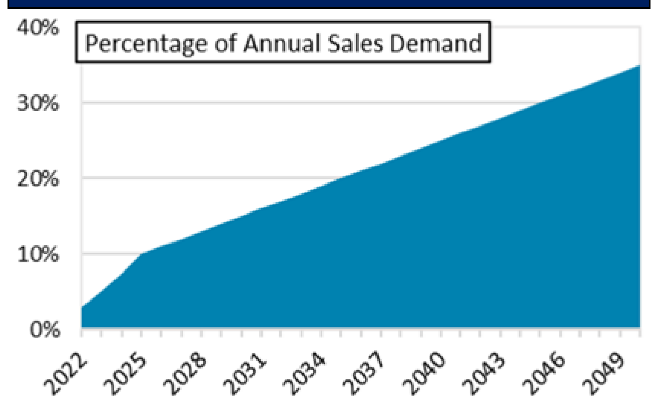
Capacity Resource Options		
Capacity Resource	**Cost ($/Dth/day)**	**Daily Deliverability (Dth/day)**
Mist Recall	$ 0.09	Max: 203,800
Newport Takeaway 1	$ 0.14	16,125
Newport Takeaway 2	$ 1.00	13,975
Newport Takeaway 3	$ 1.41	12,900
Mist Expansion	$ 0.62	106,000
Upstream Pipeline Expansion	$ 2.12	50,000
Portland LNG - Cold Box	$ 0.06	130,800
Interstate Pipeline Looping Plus Required Mist Recall	$ 0.39	130,800
Middle Corridor NWN System Pipeline Plus Required Mist Recall	$ 0.35	130,800

Compliance Resource Options

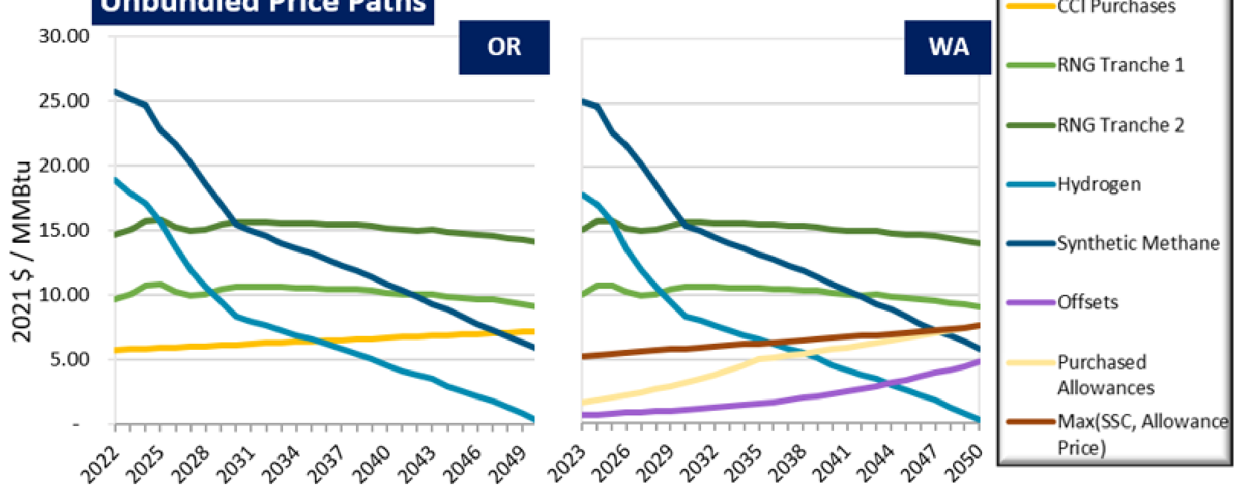
Quantity Available

Option	**Limit**
RNG Tranche 1	13,000,000 Dth / year
RNG Tranche 2	27,000,000 Dth / year
Hydrogen	20% of Deliveries by Energy
Synthetic Methane	Unbounded
CCIs	OR Compliance Period 1: 10% OR Compliance Period 2: 15% OR Compliance Period >=3: 20%
Allowances	Unbounded
Offsets	WA Compliance Period 1: 6% WA Compliance Period >=2: 8%

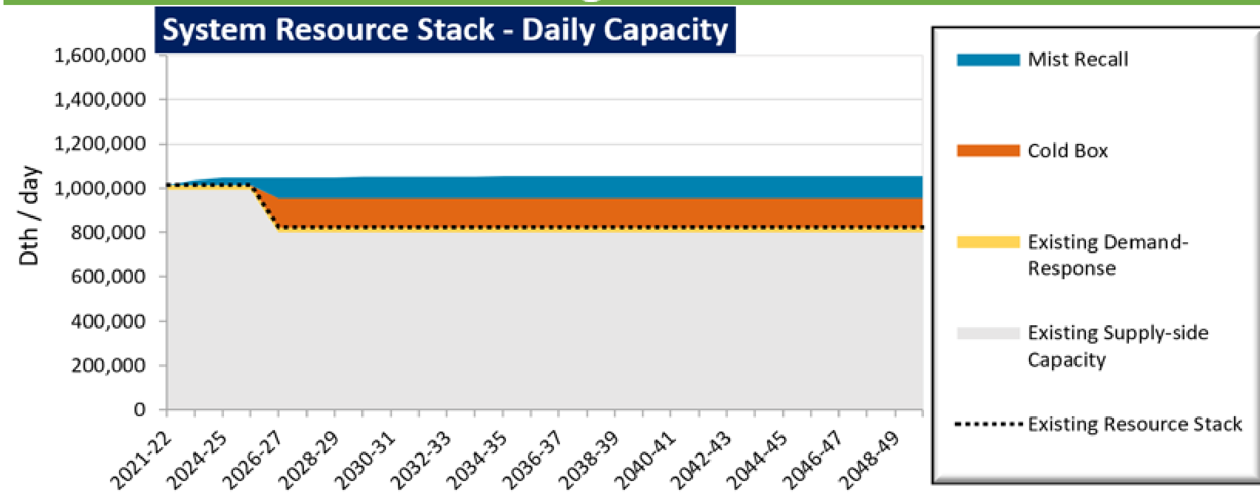
OR SB 98 / WA HB 1257 RNG Targets

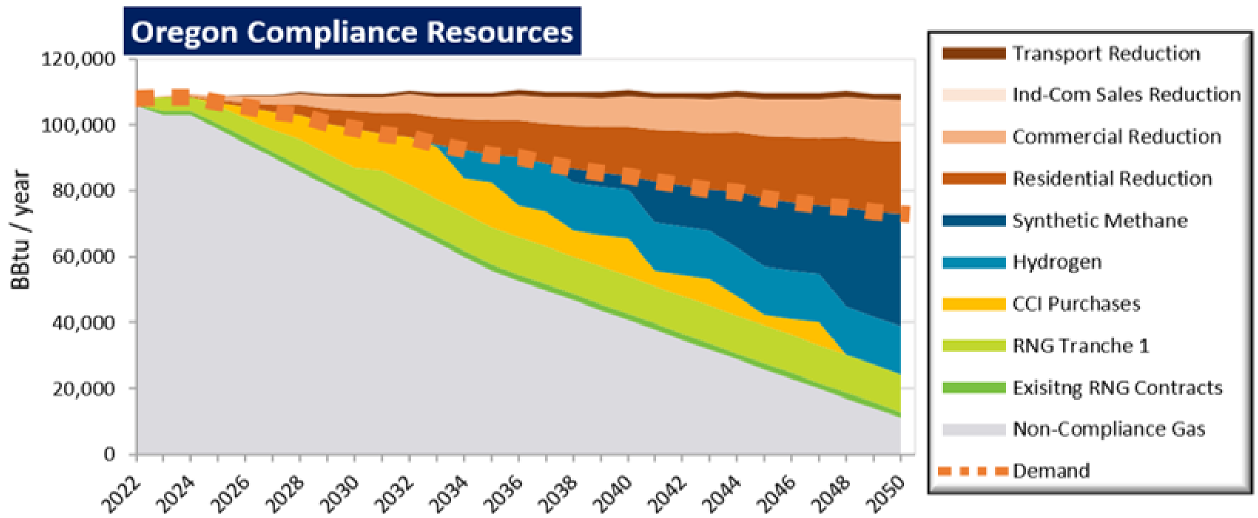


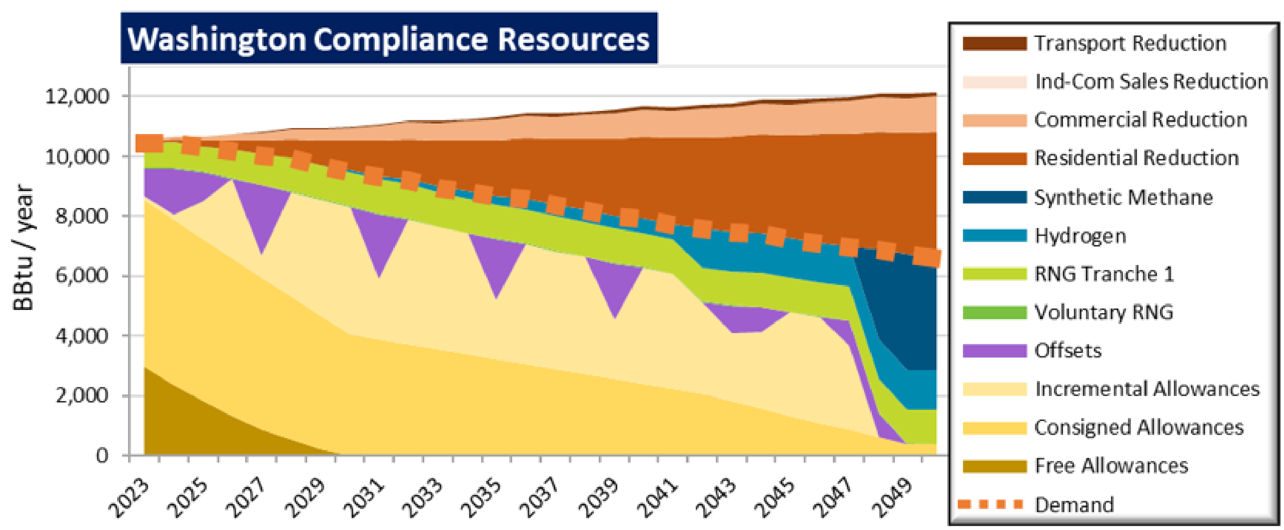
Unbundled Price Paths



Scenario 3 – Dual-Fuel Heating

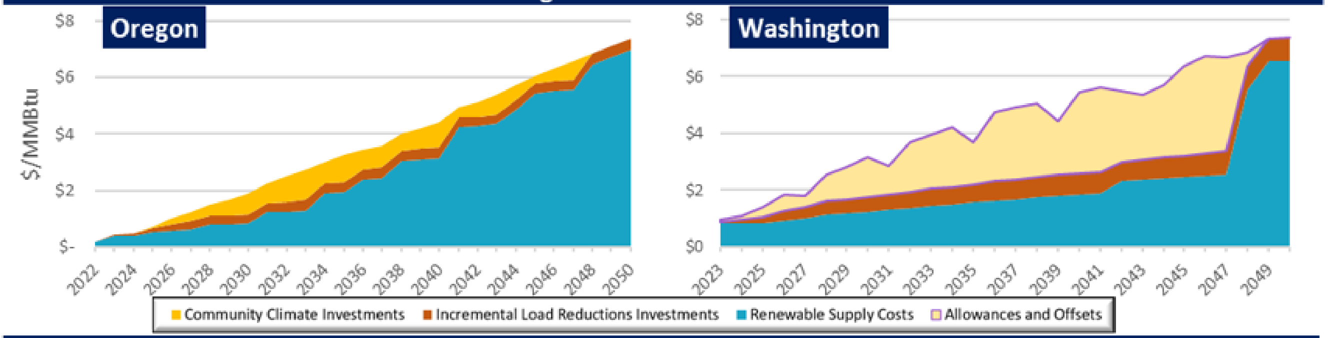




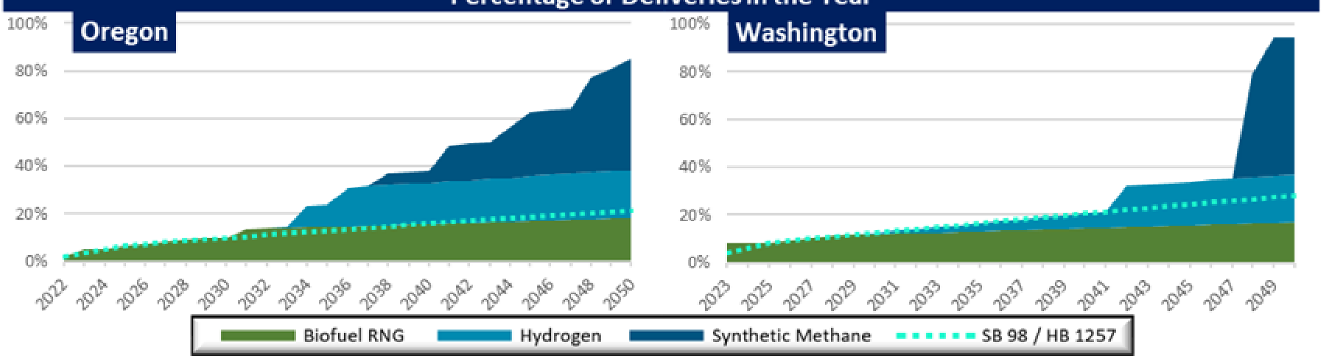


Scenario 3 – Dual-Fuel Heating

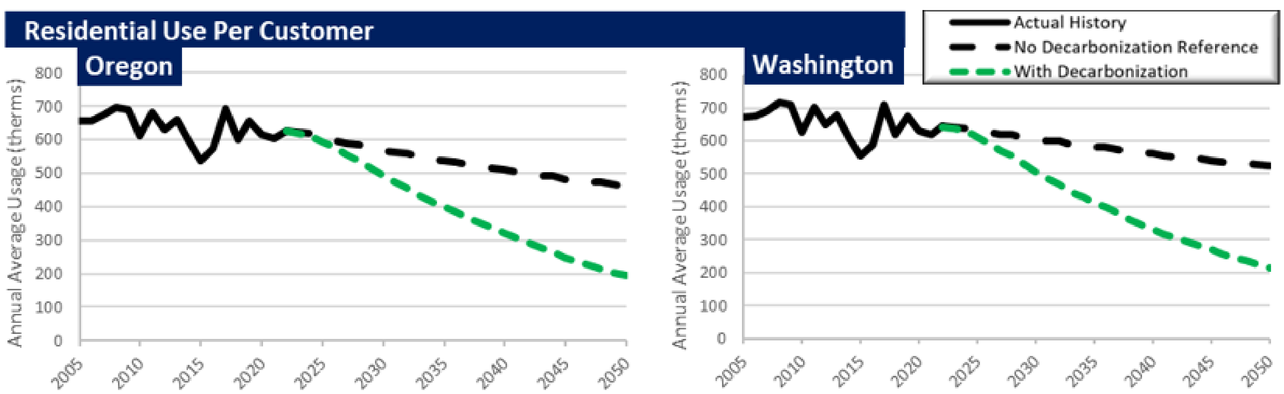
Average Cost of Decarbonization



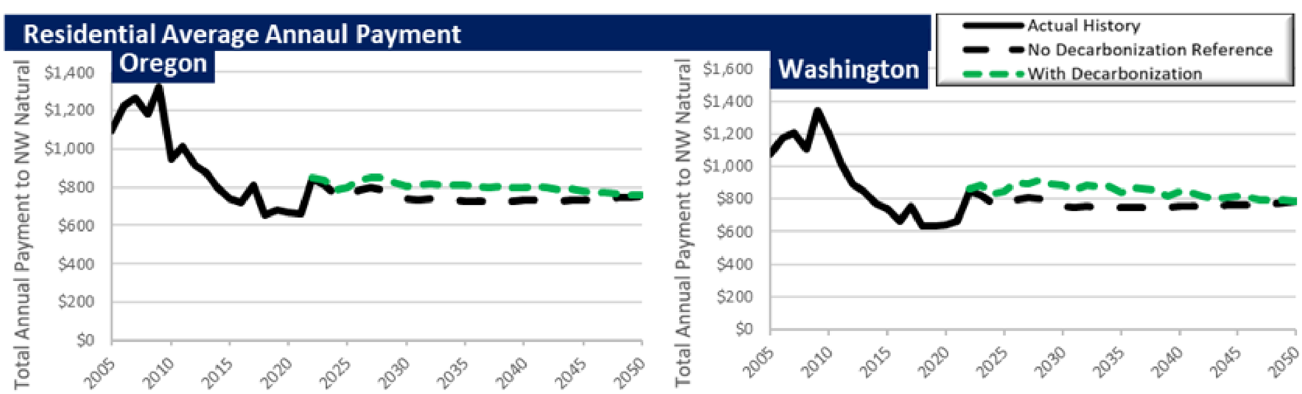
Percentage of Deliveries in the Year



Residential Use Per Customer



Residential Average Annaul Payment



Scenario 3 – Dual-Fuel Heating

Capacity Takeaways

- Replacing Portland LNG Cold Box shown as least cost solution
- Additional capacity needs served by Mist Recall, with a total recall of 100,000 Dth with the last recall occurring in 2035

Oregon Emissions Takeaways

- Meeting RNG targets for SB 98 represents most of the needed emissions reduction for the first compliance period of the Climate Protection Program; small amounts of Community Climate Investments (CCIs) may be purchased to meet additional requirements depending on weather and other conditions
- Biofuel RNG and CCIs represent the marginal compliance activity in the near- to medium-term, transitioning to renewable hydrogen for blending or dedicated delivery starting in 2033, and then transitioning to synthetic renewable natural gas in 2038
- Renewable supply represents roughly 85% of deliveries in 2050, which is equivalent to roughly over half of current gas deliveries in Oregon. Biofuel RNG deliveries represent roughly 10% of current load in 2050
- Decarbonization action to comply with SB 98 and the CPP results in residential gas utility bills being 9% higher in 2030 and 1% higher in 2050 than in a world without these policies. However, this figure can be misleading as most of the heating needs that would otherwise be served by natural gas are served by electricity, so gas service cost per unit of energy served is far greater than in Scenario 1. The cost of heating overall for a customer would need to include estimates of electric service relative to other options

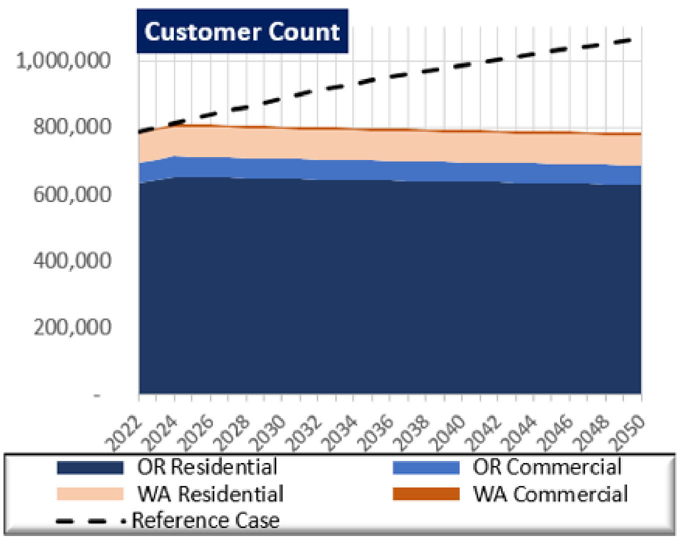
Washington Emissions Takeaways

- Delivering RNG for HB 1257 and utilizing offsets represents the bulk of net near term compliance with Cap-and-Invest, with allowance purchasing filling in any gaps
- Renewable supply represents roughly 20% of deliveries in 2040 and 95% of deliveries in 2050
- Complying with HB 1257 and Cap-and-Invest results in residential gas utility bills being 17% higher in 2030 and 1% lower in 2050 than in a world without these policies. However, this figure can be misleading as most of the heating needs that would otherwise be served by natural gas are served by electricity, so gas service cost per unit of energy served is far greater than in Scenario 1. The cost of heating overall for a customer would need to include estimates of electric service relative to other options

7.4.4 Scenario 4- New Customer Moratorium

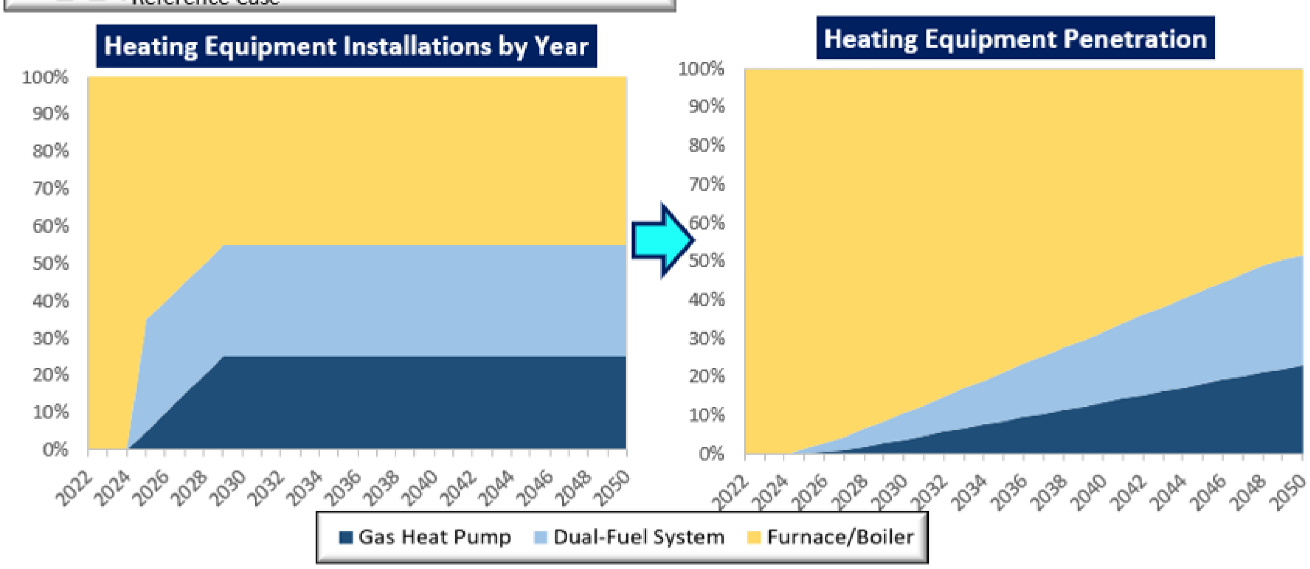
Scenario 4 – New Gas Customer Moratorium

Scenario 4 helps to answer the question "What would be the implications if policy prohibited new customers from connecting to the natural gas grid?" It deploys the same demand and supply-side resource option assumptions as Scenario 1, but assumes that no new customers connect to the gas system starting in 2025. This reduces much of the energy efficiency deployed via Energy Trust programs given that much of the expected savings over the planning horizon come from new construction and conversions.

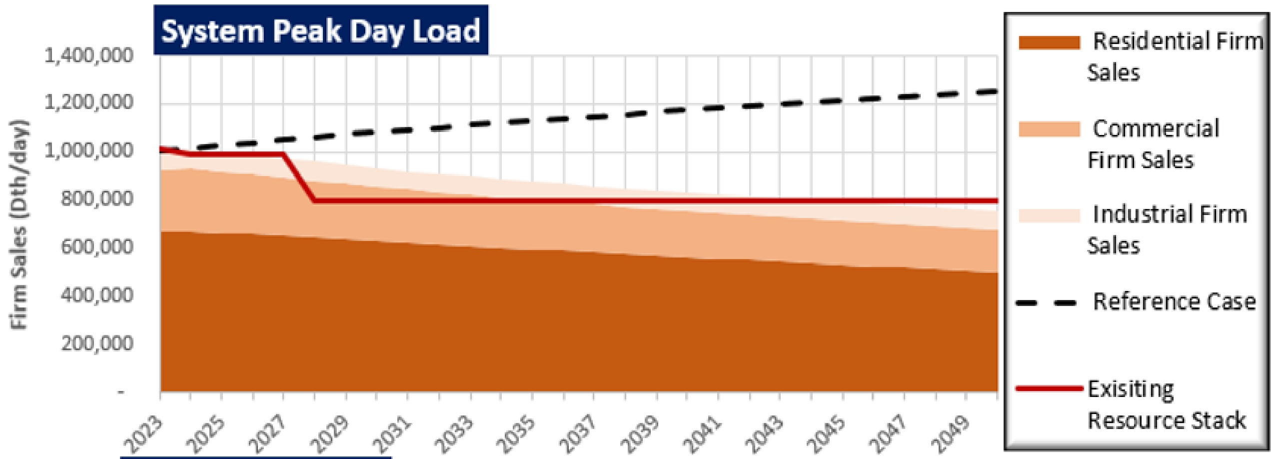


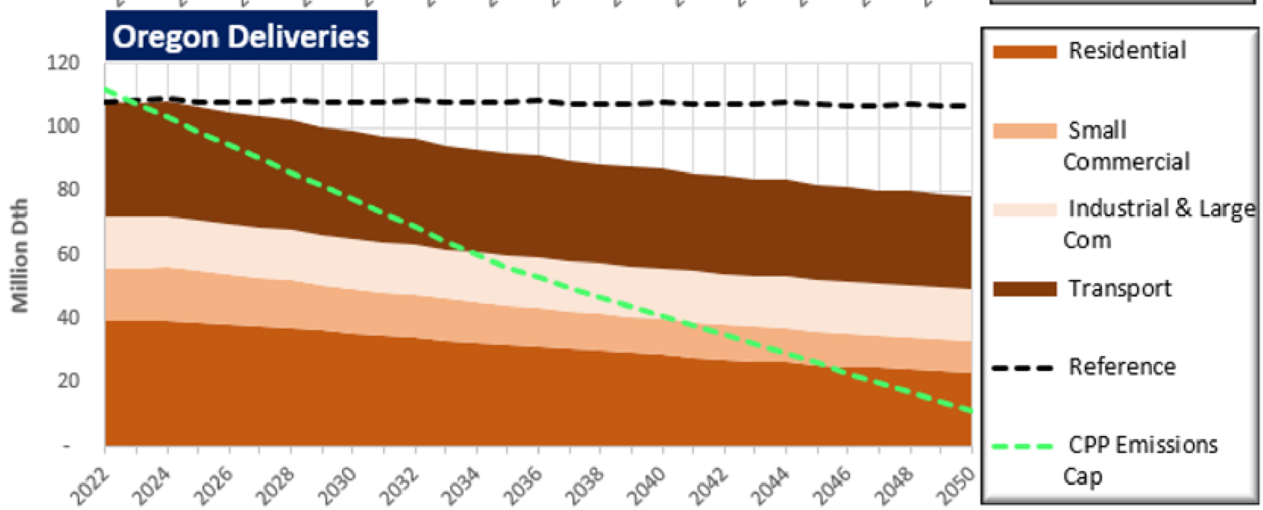
Demand-Side Assumptions

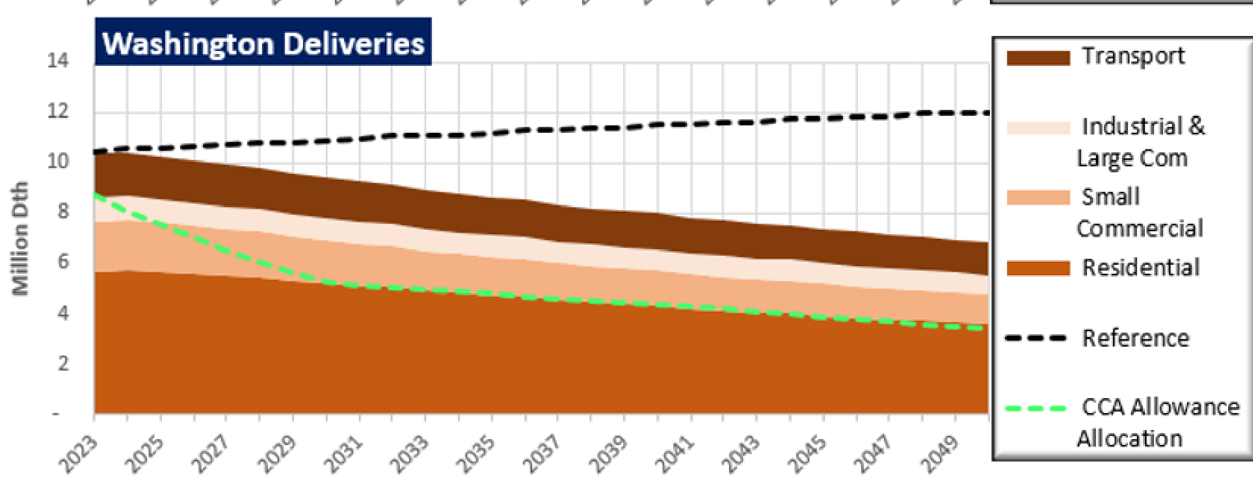
Sales Customer Energy Efficiency	ETO projection for existing customers at $5.06/therm of first year savings. Expected savings from new buildings are not achieved as new customers are not added.
Transport Customer Energy Efficiency	Applied Energy Group projection of savings at $1.79/therm of first year savings
Gas Heat Pump Cost	$4,000 total cost to utility for a residential heating system, $13,000 for a Commercial heating System; $1,600 for residential water heater
Dual-Fuel System Costs	Net cost of $400 to utility



Scenario 4 – New Gas Customer Moratorium







Scenario 4 – New Gas Customer Moratorium

Capacity Resource Options

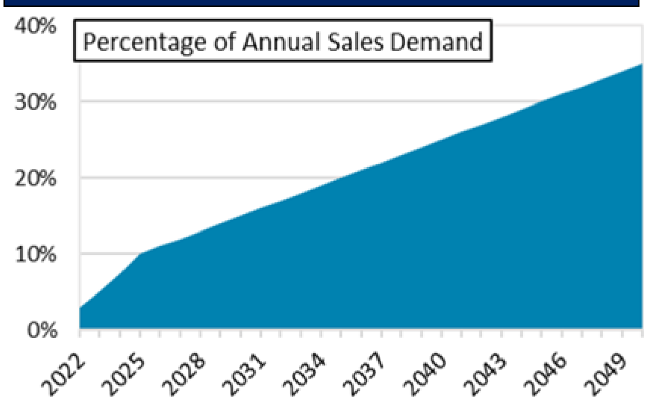
Capacity Resource	Cost ($/Dth/day)	Daily Deliverability (Dth/day)
Mist Recall	$ 0.09	Max: 203,800
Newport Takeaway 1	$ 0.14	16,125
Newport Takeaway 2	$ 1.00	13,975
Newport Takeaway 3	$ 1.41	12,900
Mist Expansion	$ 0.62	106,000
Upstream Pipeline Expansion	$ 2.12	50,000
Portland LNG - Cold Box	$ 0.06	130,800
Interstate Pipeline Looping Plus Required Mist Recall	$ 0.39	130,800
Middle Corridor NWN System Pipeline Plus Required Mist Recall	$ 0.35	130,800

Compliance Resource Options

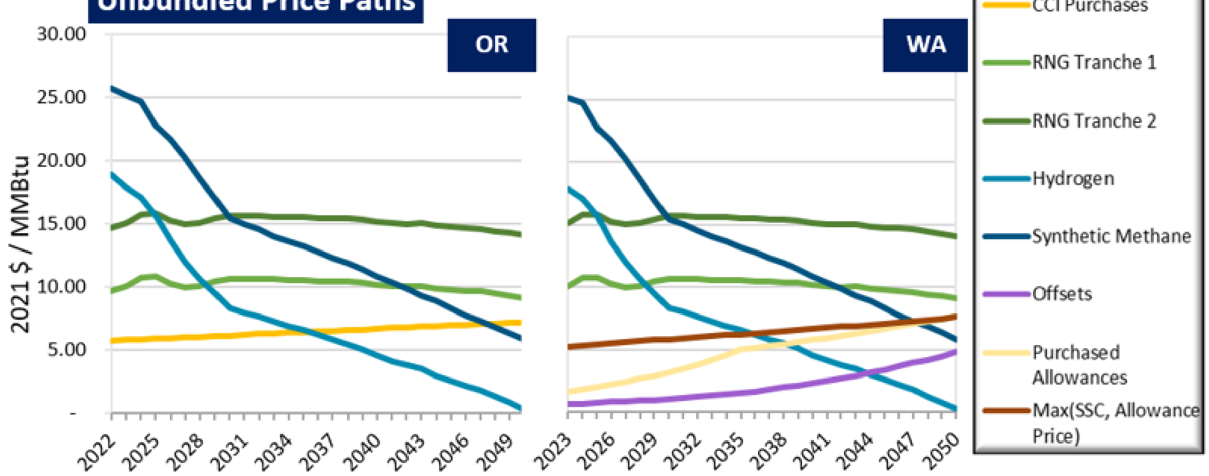
Quantity Available

Option	Limit
RNG Tranche 1	13,000,000 Dth / year
RNG Tranche 2	27,000,000 Dth / year
Hydrogen	20% of Deliveries by Energy
Synthetic Methane	Unbounded
CCIs	OR Compliance Period 1: 10% OR Compliance Period 2: 15% OR Compliance Period >=3: 20%
Allowances	Unbounded
Offsets	WA Compliance Period 1: 6% WA Compliance Period >=2: 8%

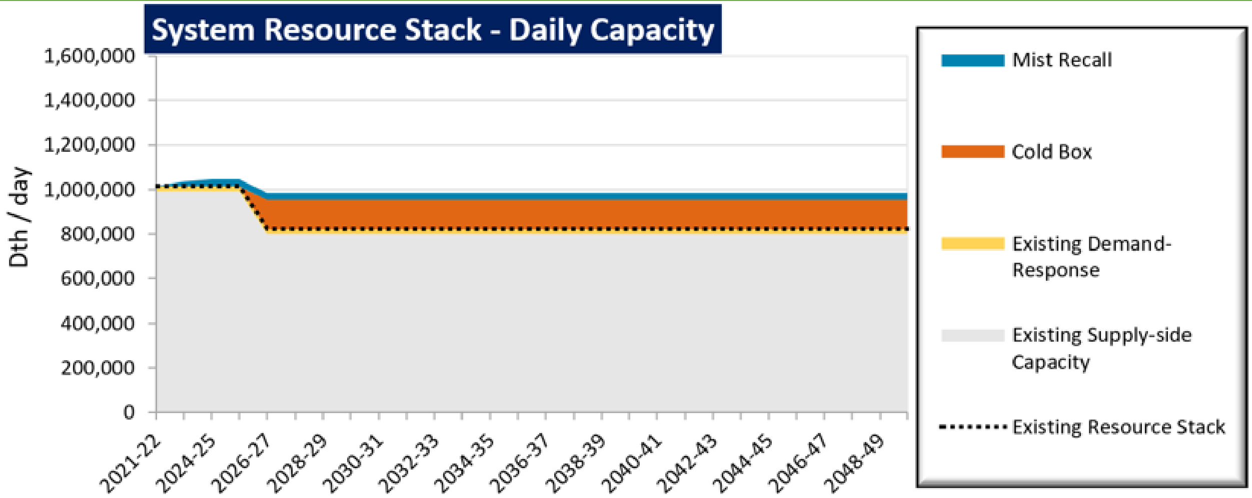
OR SB 98 / WA HB 1257 RNG Targets

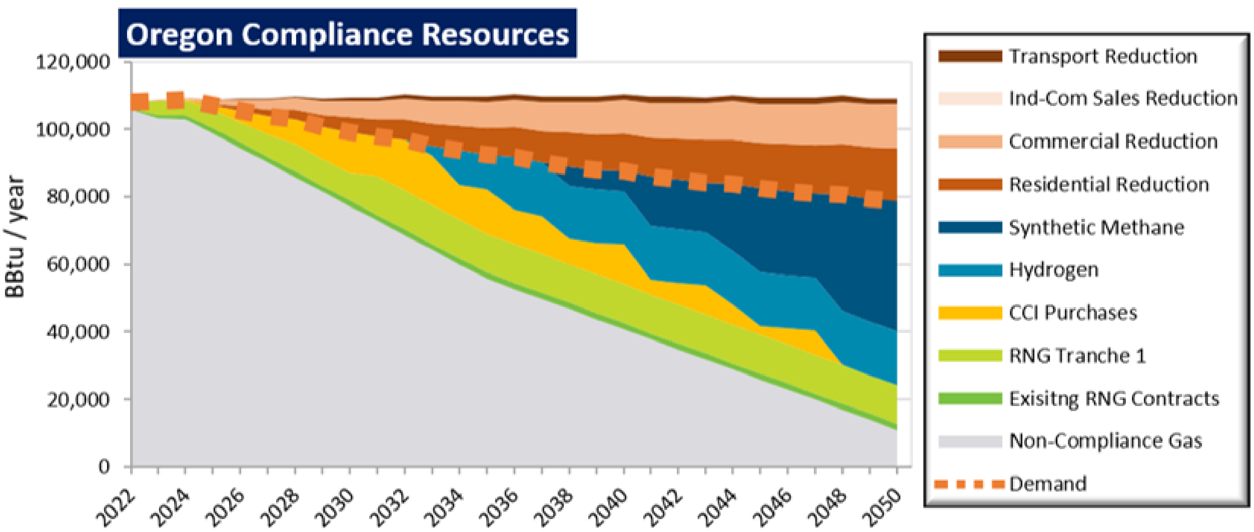


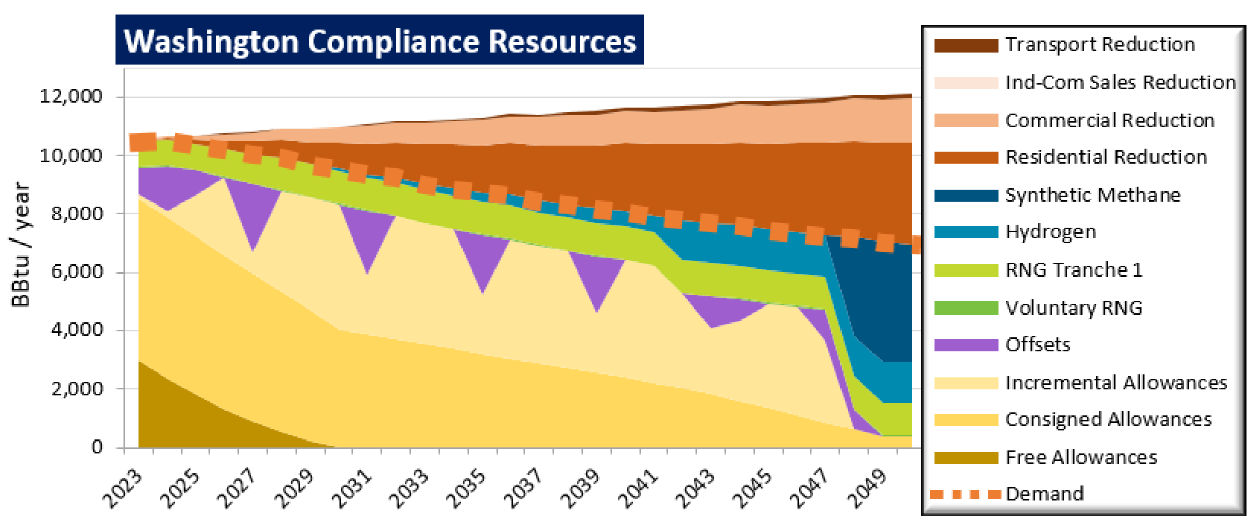
Unbundled Price Paths



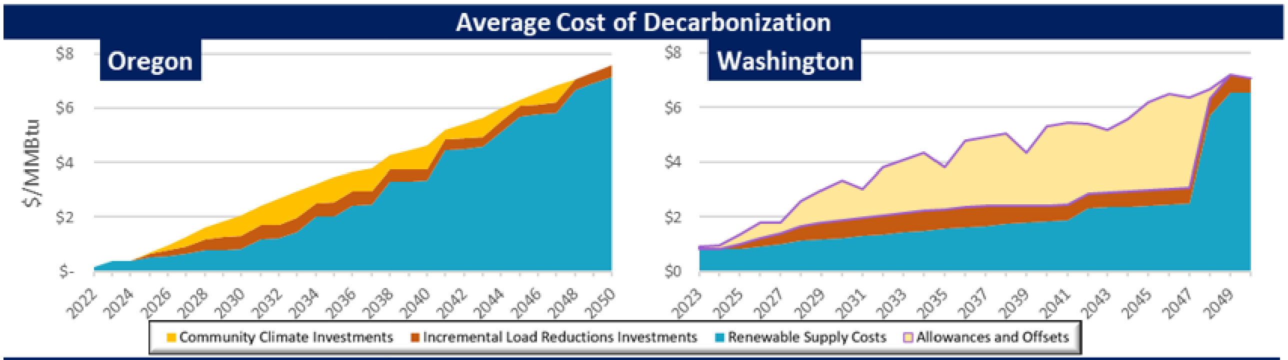
Scenario 4 – New Gas Customer Moratorium

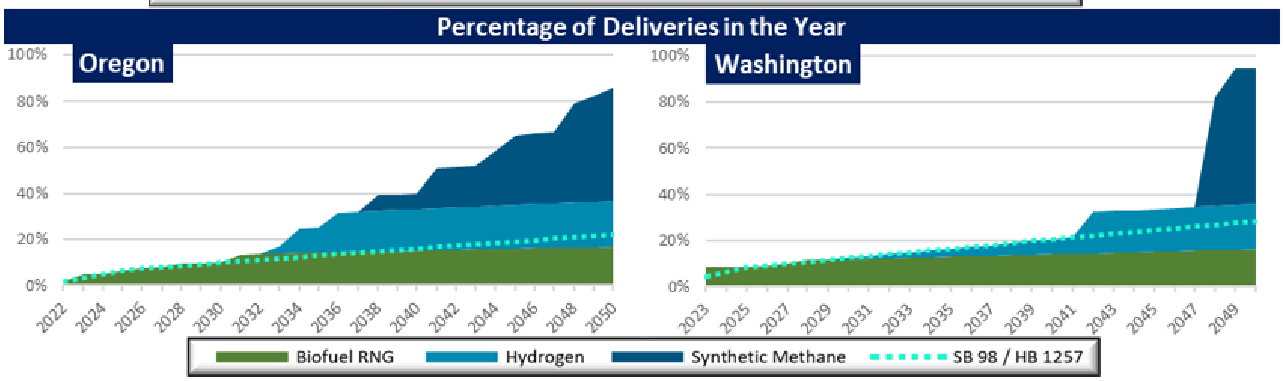


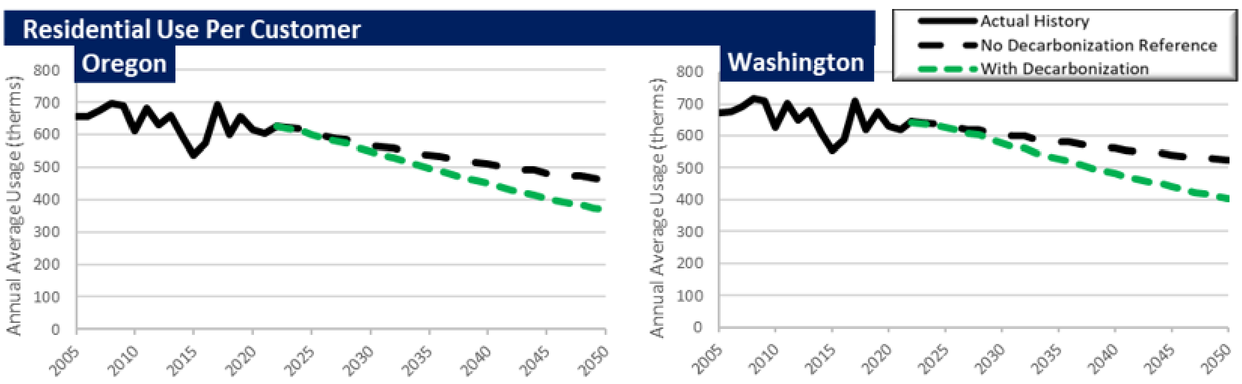


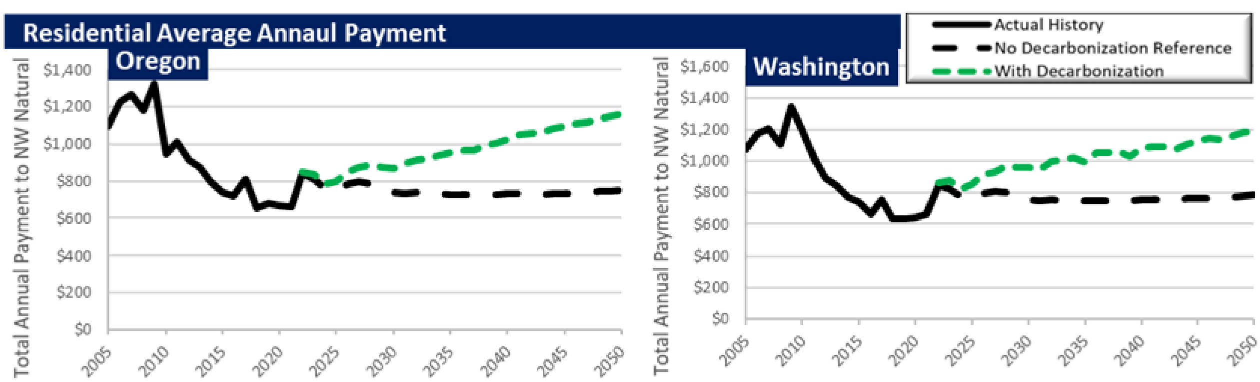


Scenario 4 – New Gas Customer Moratorium









Scenario 4 – New Gas Customer Moratorium

Capacity Takeaways

- Replacing Portland LNG Cold Box shown as least cost solution
- Additional capacity needs served by Mist Recall, with a total recall of 30,000 Dth with the last recall occurring in 2025

Oregon Emissions Takeaways

- Meeting RNG targets for SB 98 represents most of the needed emissions reduction for the first compliance period of the Climate Protection Program; small amounts of Community Climate Investments (CCIs) may be purchased to meet additional requirements depending on weather and other conditions
- Biofuel RNG and CCIs represent the marginal compliance activity in the near- to medium-term, transitioning to renewable hydrogen for blending or dedicated delivery starting in 2033, and then transitioning to synthetic renewable natural gas in 2038
- Renewable supply represents roughly 85% of deliveries in 2050, which is equivalent to roughly 2/3 of current gas deliveries in Oregon. Biofuel RNG deliveries represent roughly 10% of current load in 2050
- Decarbonization action to comply with SB 98 and the CPP results in residential gas utility bills being 18% higher in 2030 and 54% higher in 2050 than in a world without these policies

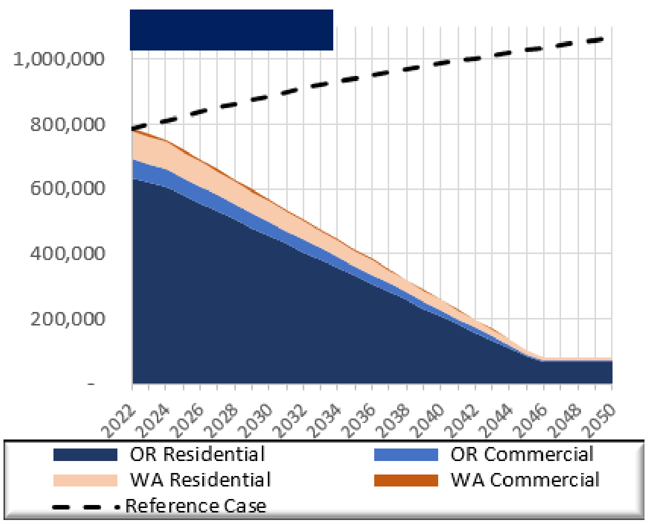
Washington Emissions Takeaways

- Delivering RNG for HB 1257 and utilizing offsets represents the bulk of net near term compliance with Cap-and-Invest, with allowance purchasing filling in any gaps
- Renewable supply represents roughly 20% of deliveries in 2040 and 95% of deliveries in 2050
- Complying with HB 1257 and Cap-and-Invest results in residential gas utility bills being 28% higher in 2030 and 51% higher in 2050 than in a world without these policies

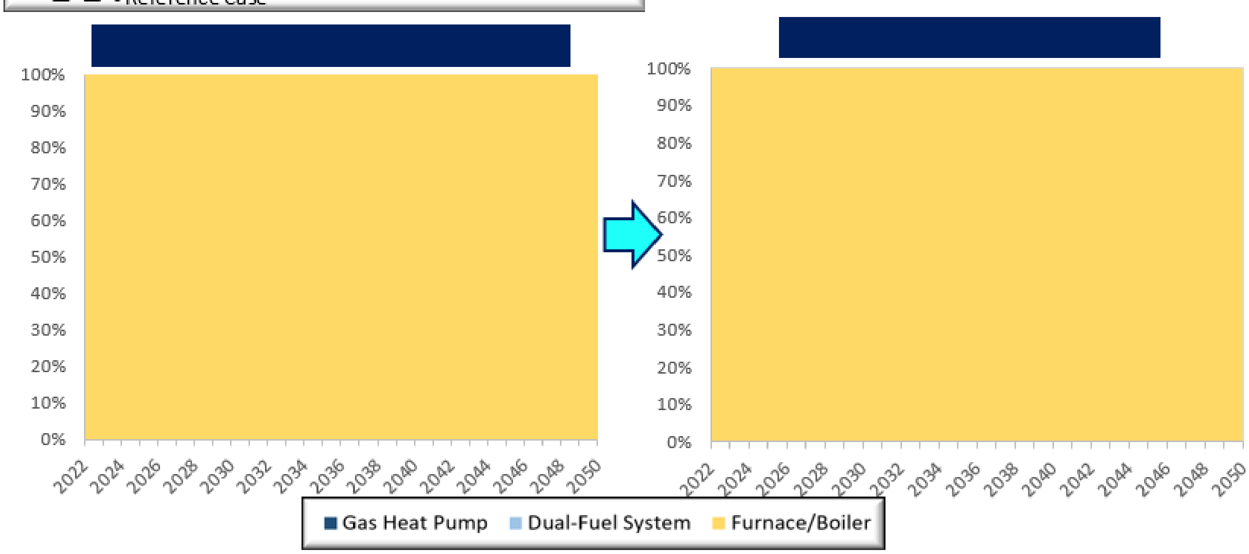
7.4.5 Scenario 5- Aggressive Building Electrification

Scenario 5 – Aggressive Building Electrification

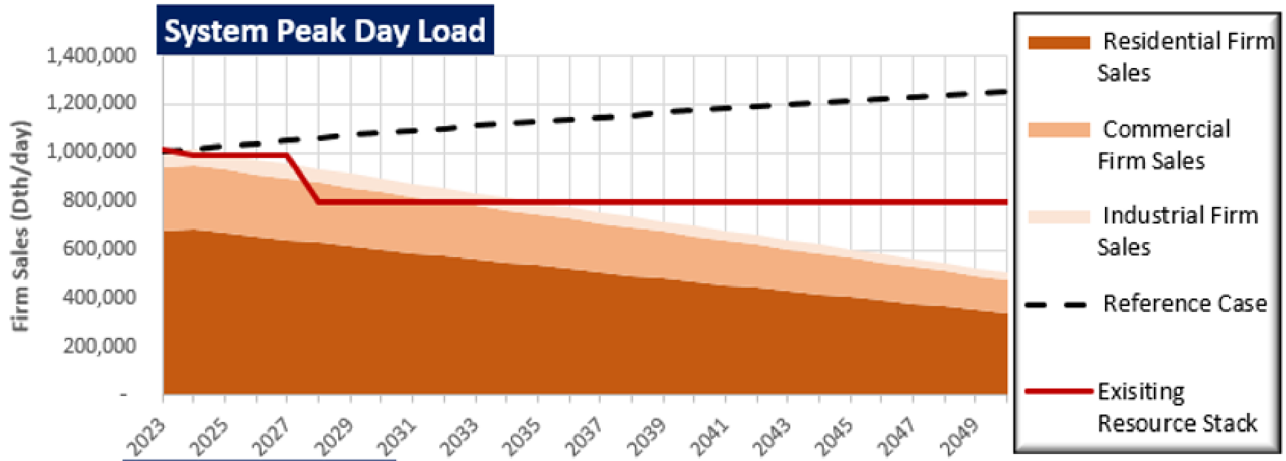
Scenario 5 helps to answer the question "What would it mean if policy prohibited new customers from connecting to the natural gas grid and many existing customers also left the gas system to electrify?" Scenario 5 assumes the same cost and availability of renewable supply as Scenario 1 but assumes no new customers are added to the system starting in 2025, and that half of the customers who replace their existing gas heating equipment in a given year choose to electrify their homes upon that decision and leave the gas system.

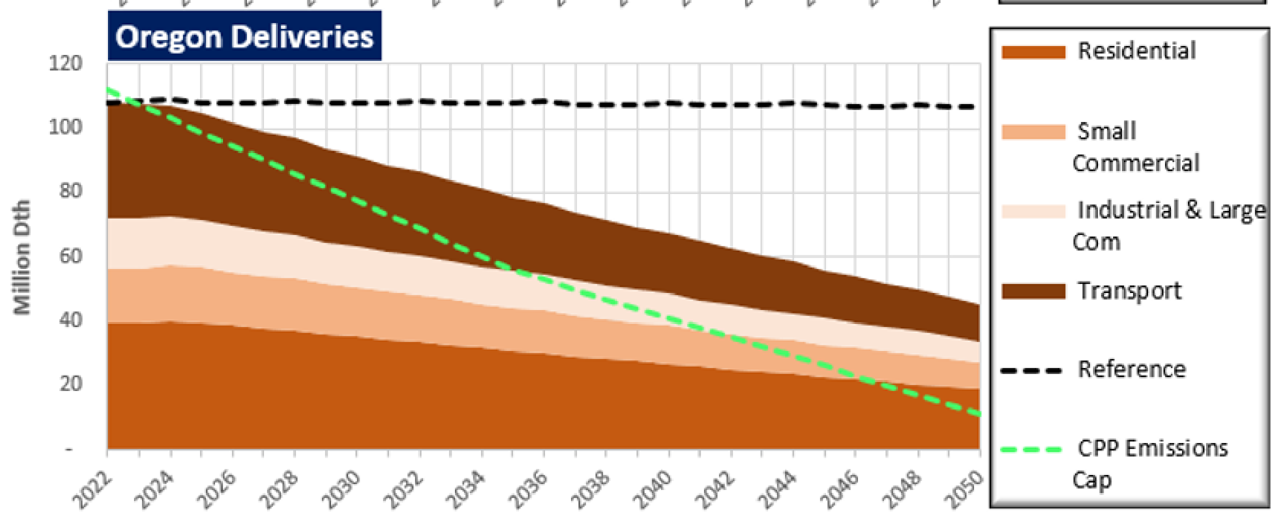


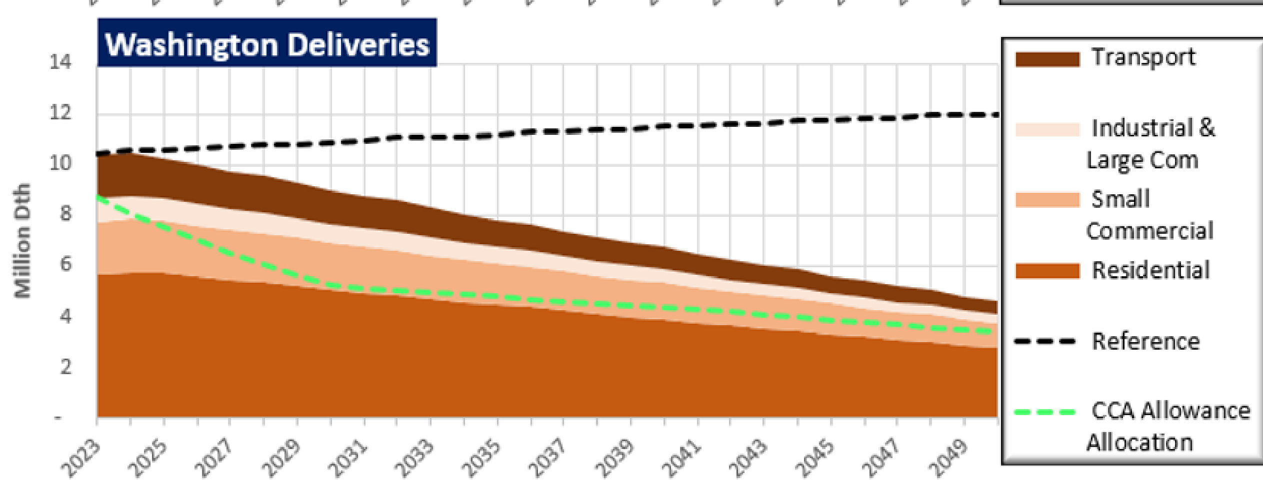
Demand-Side Assumptions	
Sales Customer Energy Efficiency	Gas energy efficiency programs are halted as they are not required to meet emissions goals and cross-subsidize electric customers
Transport Customer Energy Efficiency	
Gas Heat Pump Cost	No Gas Heat Pumps Installed
Dual-Fuel System Costs	No Dual-Fuel System Installed



Scenario 5 – Aggressive Building Electrification







Scenario 5 – Aggressive Building Electrification

Capacity Resource Options

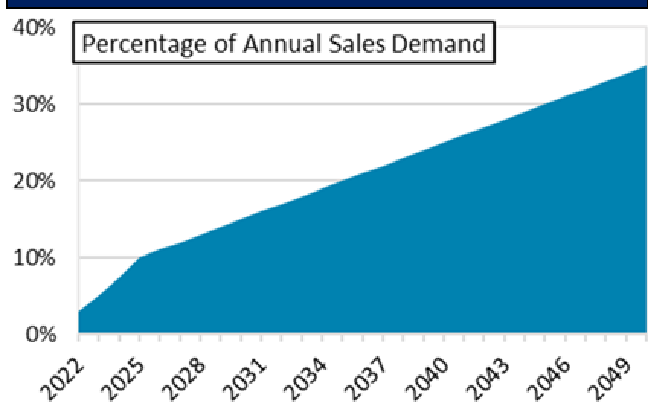
Capacity Resource	Cost ($/Dth/day)	Daily Deliverability (Dth/day)
Mist Recall	$ 0.09	Max: 203,800
Newport Takeaway 1	$ 0.14	16,125
Newport Takeaway 2	$ 1.00	13,975
Newport Takeaway 3	$ 1.41	12,900
Mist Expansion	$ 0.62	106,000
Upstream Pipeline Expansion	$ 2.12	50,000
Portland LNG - Cold Box	$ 0.06	130,800
Interstate Pipeline Looping Plus Required Mist Recall	$ 0.39	130,800
Middle Corridor NWN System Pipeline Plus Required Mist Recall	$ 0.35	130,800

Compliance Resource Options

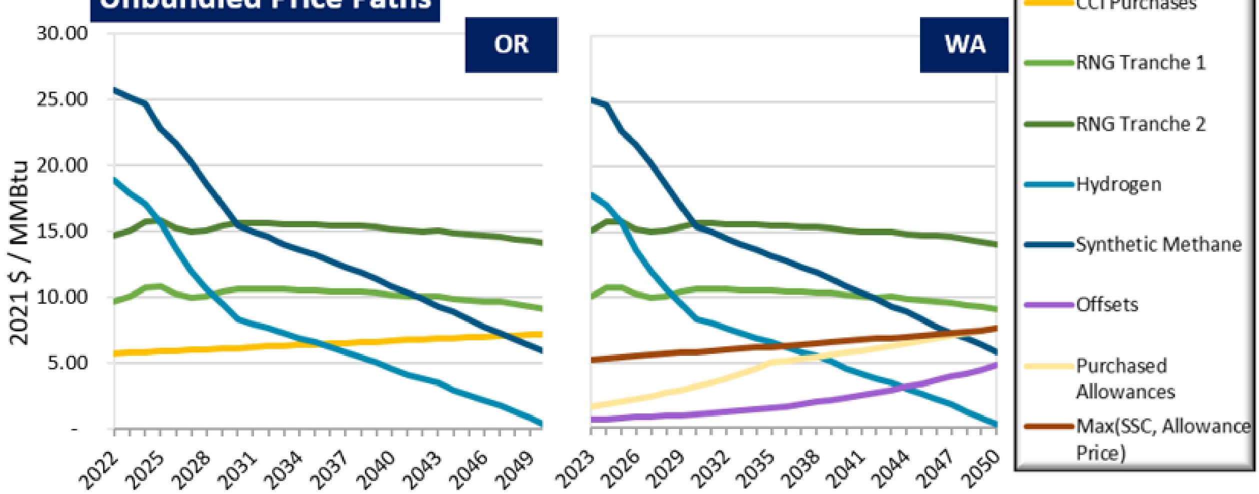
Quantity Available

Option	Limit
RNG Tranche 1	13,000,000 Dth / year
RNG Tranche 2	27,000,000 Dth / year
Hydrogen	20% of Deliveries by Energy
Synthetic Methane	Unbounded
CCIs	OR Compliance Period 1: 10% OR Compliance Period 2: 15% OR Compliance Period >=3: 20%
Allowances	Unbounded
Offsets	WA Compliance Period 1: 6% WA Compliance Period >=2: 8%

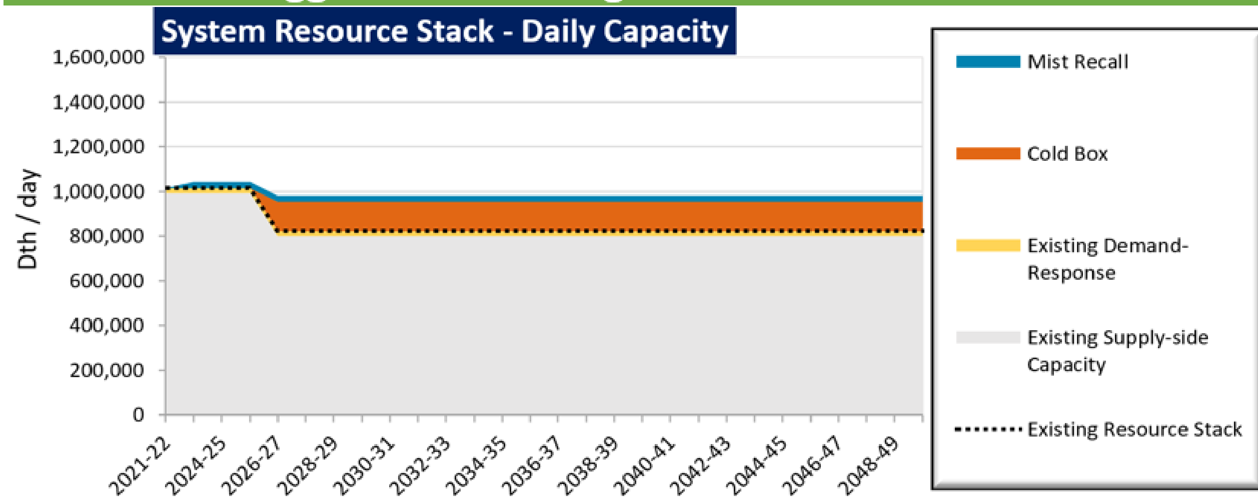
OR SB 98 / WA HB 1257 RNG Targets

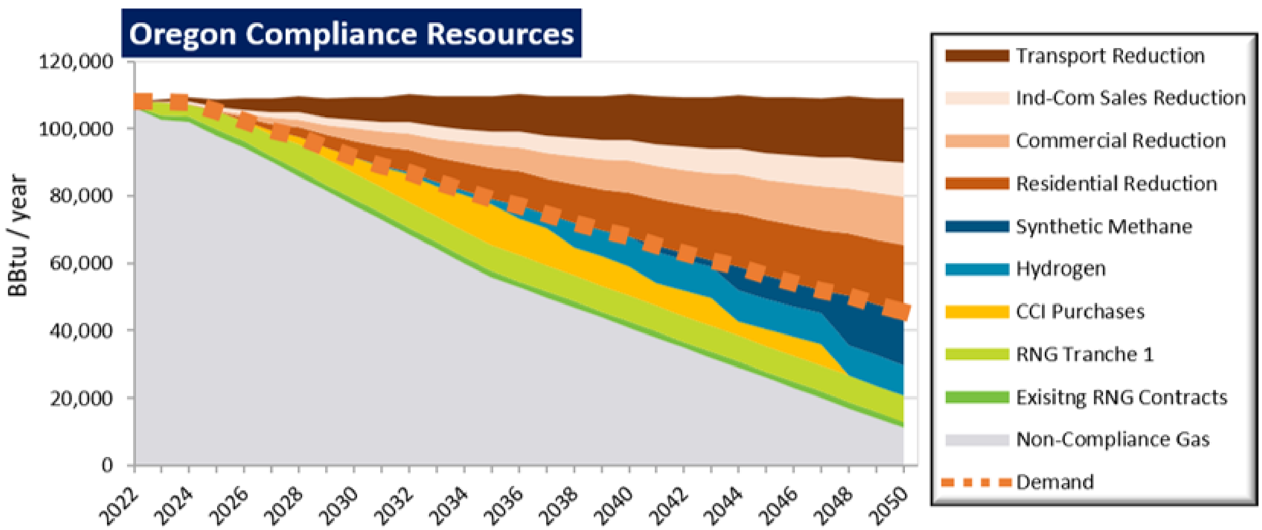


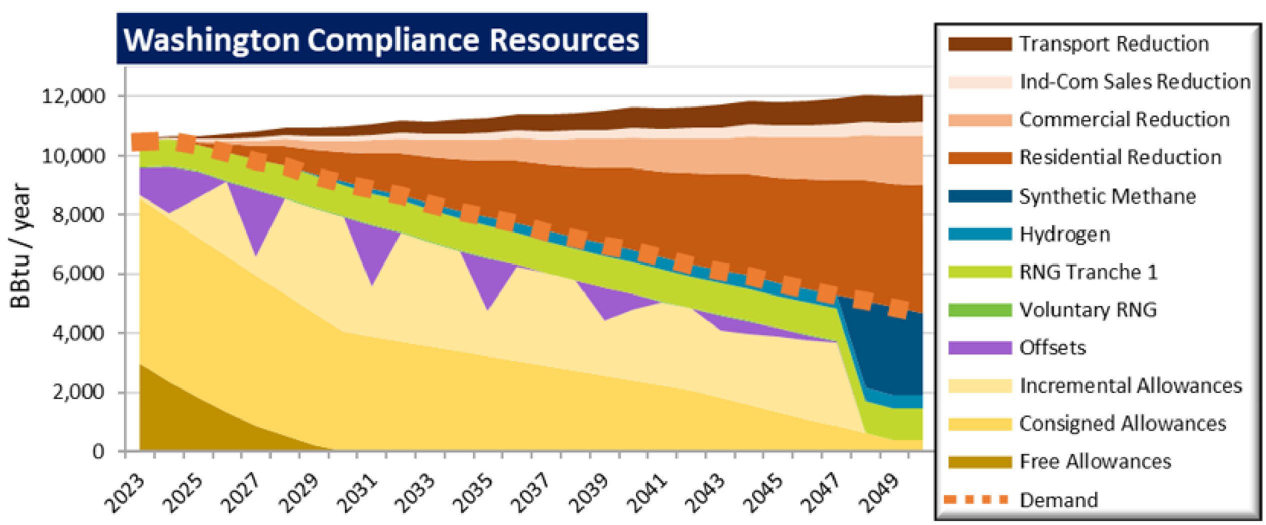
Unbundled Price Paths



Scenario 5 – Aggressive Building Electrification

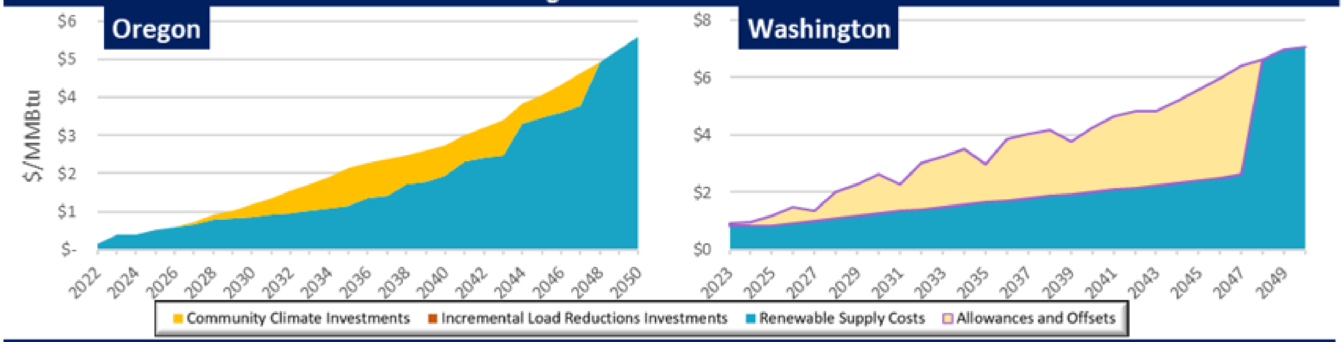




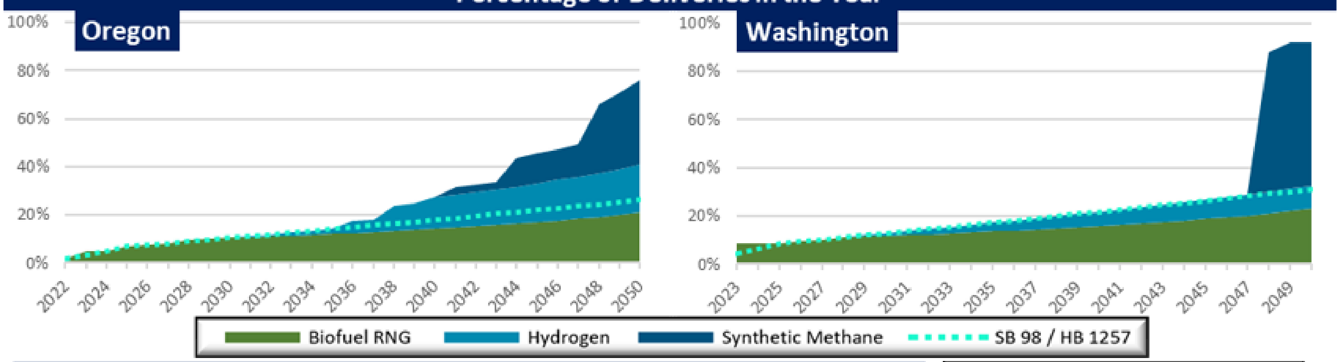


Scenario 5 – Aggressive Building Electrification

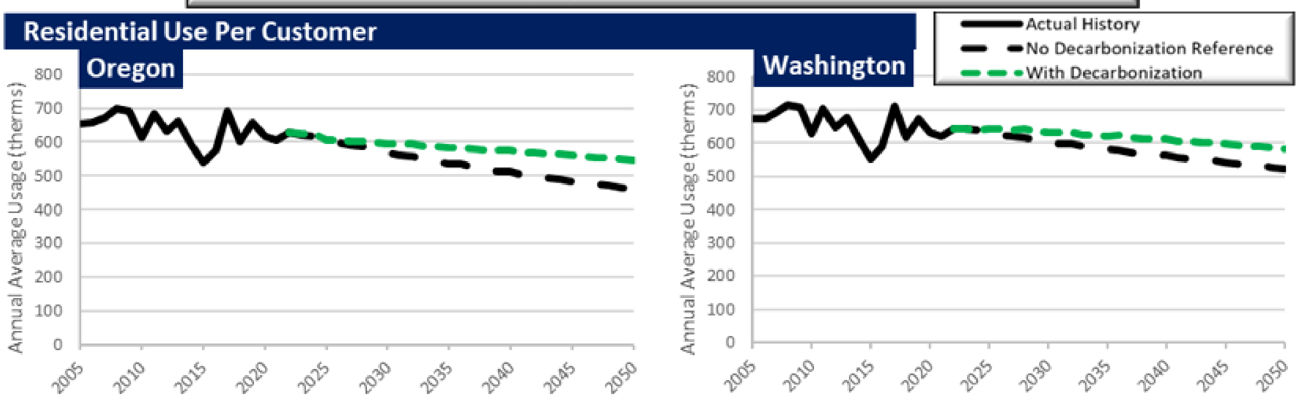
Average Cost of Decarbonization



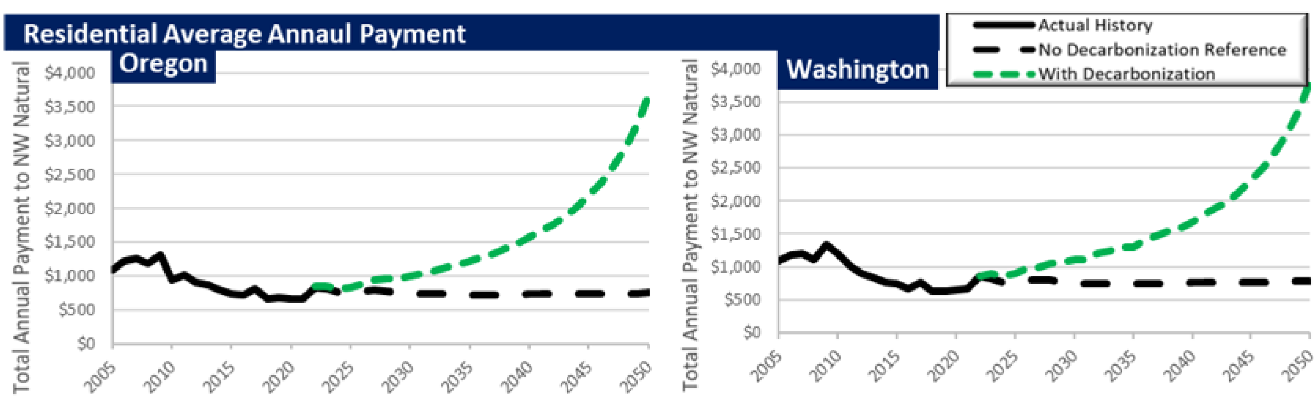
Percentage of Deliveries in the Year



Residential Use Per Customer



Residential Average Annaul Payment



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Scenario 5 – Aggressive Building Electrification

Capacity Takeaways

- Replacing Portland LNG Cold Box shown as least cost solution
- Additional capacity needs served by Mist Recall, with a total recall of 30,000 Dth with the last recall occurring in 2023

Oregon Emissions Takeaways

- Meeting RNG targets for SB 98 represents most of the needed emissions reduction for the first compliance period of the Climate Protection Program and far less compliance action is needed due to falling loads
- Renewable supply represents roughly 75% of deliveries in 2050, which is equivalent to roughly 1/3 of current gas deliveries in Oregon. Biofuel RNG deliveries represent roughly 7% of current load in 2050
- Compared to non-electrification scenarios far less decarbonization action is needed from NW Natural to comply with SB 98 and the CPP.
- Customers who remain on the gas system experience 34% higher rates in 2030 and 387% higher in 2050 due to spreading of fixed costs across less energy use

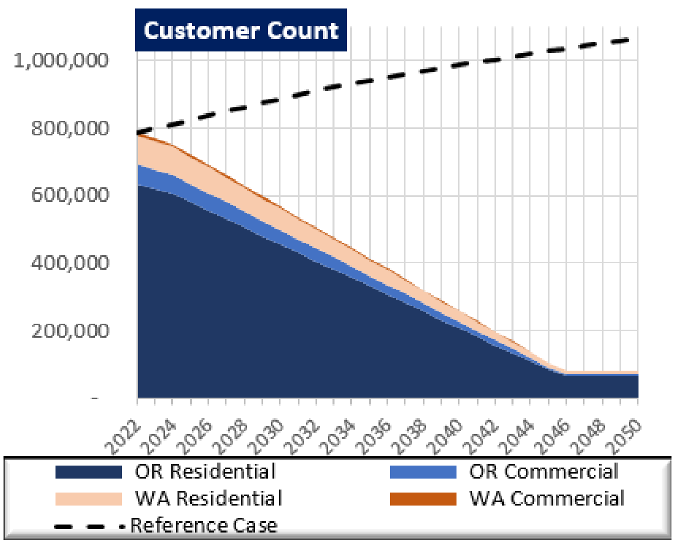
Washington Emissions Takeaways

- Delivering RNG for HB 1257 and utilizing offsets represents the bulk of net near term compliance with Cap-and-Invest, with allowance purchasing filling in any gaps
- Renewable supply represents roughly 20% of deliveries in 2040 and 90% of deliveries in 2050
- Customers who remain on the gas system experience 47% higher rates in 2030 and 383% higher in 2050 due to spreading of fixed costs across less energy use

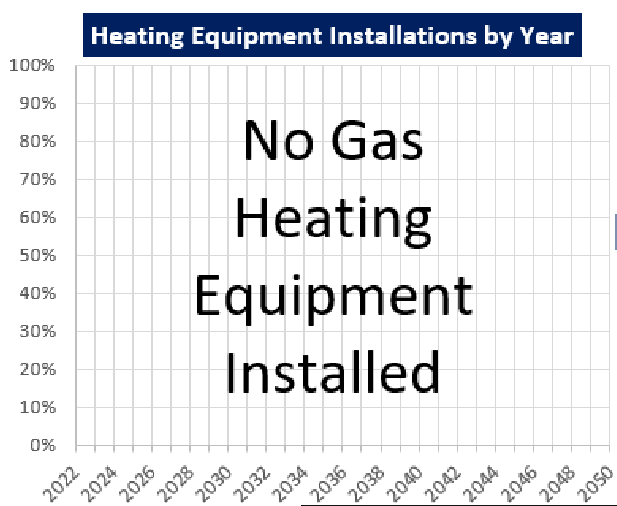
7.4.6 Scenario 6- Full Building Electrification

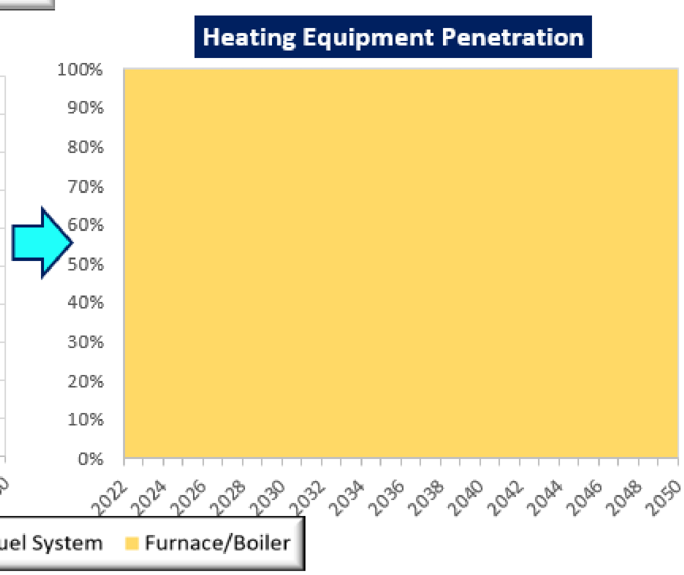
Scenario 6 – Full Building Electrification

Scenario 6 helps to answer the question "What would it mean if a policy were implemented that required homes and businesses to leave the gas system when they replaced their heating equipment?" This scenario represents the bookend of what the implications could be if the most extreme electrification policy were implemented. While rendered largely moot by the electrification assumption, this scenario assumes the same availability and cost of renewable resources as Scenario 1.

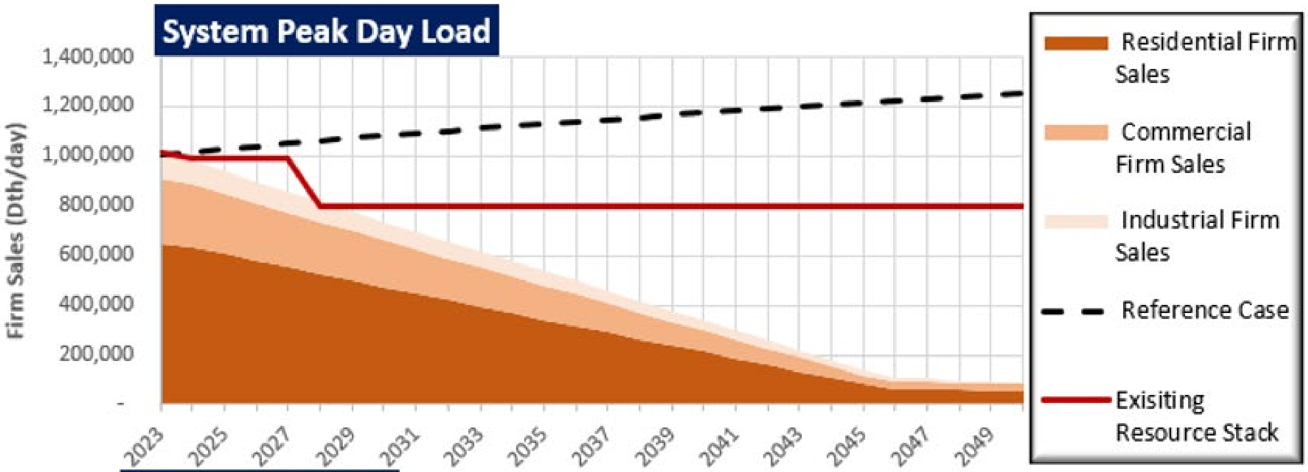


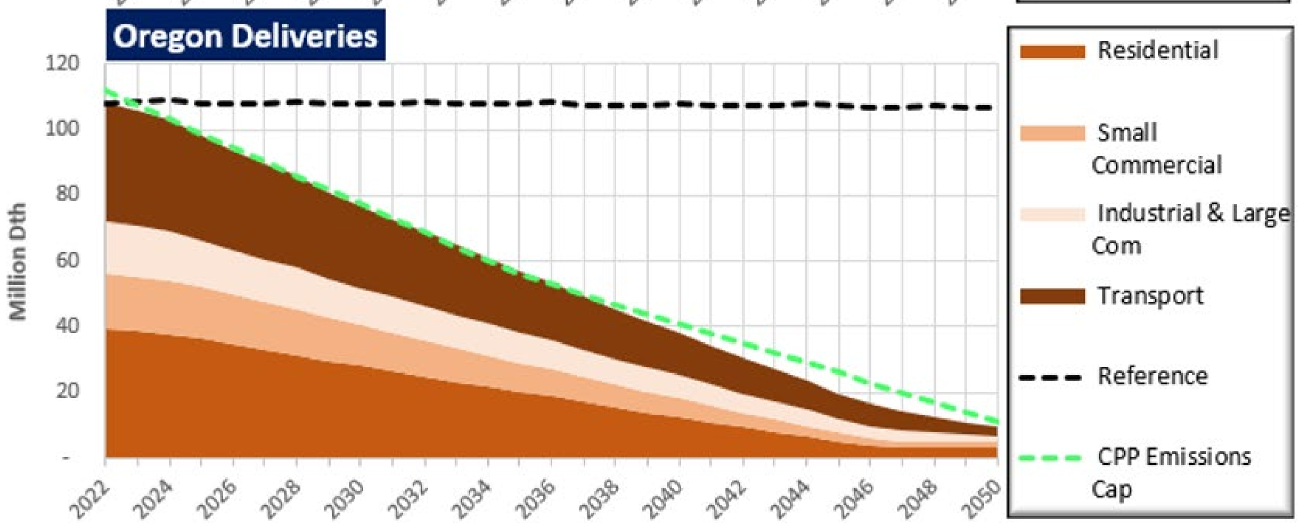
Demand-Side Assumptions	
Sales Customer Energy Efficiency	Gas energy efficiency programs are halted as they are not required to meet emissions goals and cross-subsidize electric customers
Transport Customer Energy Efficiency	
Gas Heat Pump Cost	No Gas Heat Pumps Installed
Dual-Fuel System Costs	No Dual-Fuel System Installed

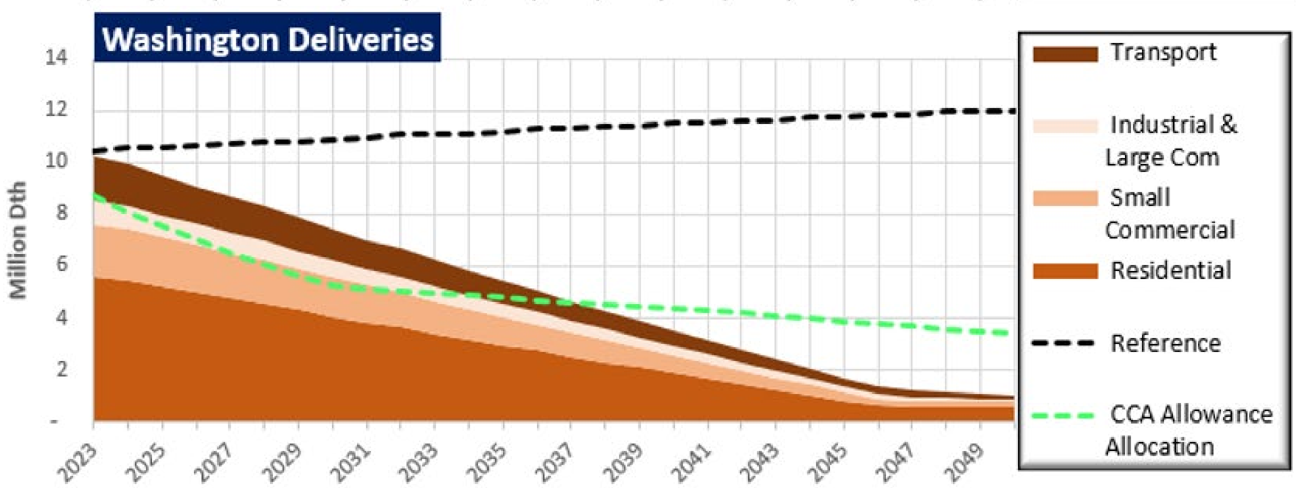




Scenario 6 – Full Building Electrification







Scenario 6 – Full Building Electrification

Capacity Resource Options

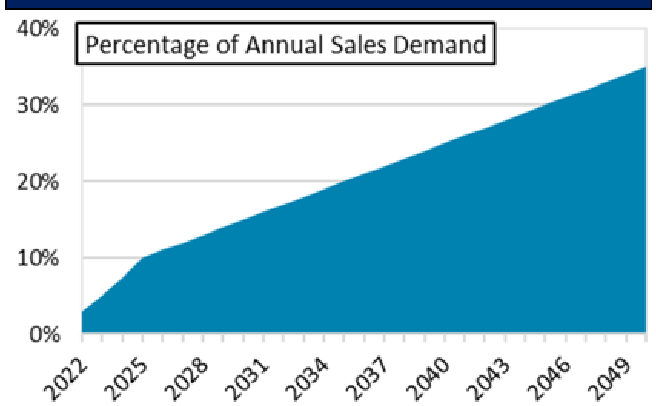
Capacity Resource	Cost ($/Dth/day)	Daily Deliverability (Dth/day)
Mist Recall	$ 0.09	Max: 203,800
Newport Takeaway 1	$ 0.14	16,125
Newport Takeaway 2	$ 1.00	13,975
Newport Takeaway 3	$ 1.41	12,900
Mist Expansion	$ 0.62	106,000
Upstream Pipeline Expansion	$ 2.12	50,000
Portland LNG - Cold Box	$ 0.06	130,800
Interstate Pipeline Looping Plus Required Mist Recall	$ 0.39	130,800
Middle Corridor NWN System Pipeline Plus Required Mist Recall	$ 0.35	130,800

Compliance Resource Options

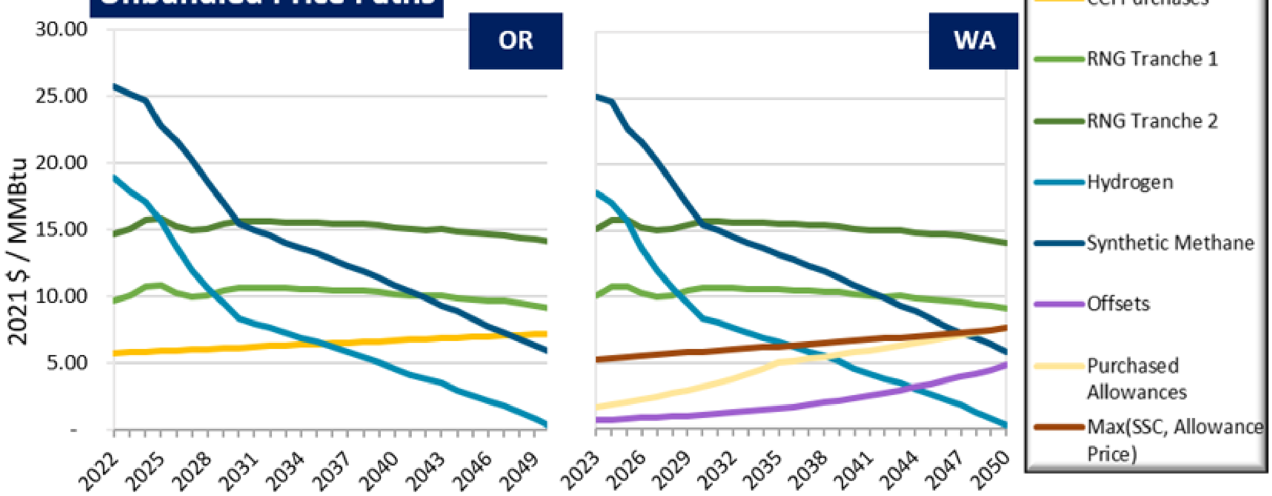
Quantity Available

Option	Limit
RNG Tranche 1	13,000,000 Dth / year
RNG Tranche 2	27,000,000 Dth / year
Hydrogen	20% of Deliveries by Energy
Synthetic Methane	Unbounded
CCIs	OR Compliance Period 1: 10% OR Compliance Period 2: 15% OR Compliance Period >=3: 20%
Allowances	Unbounded
Offsets	WA Compliance Period 1: 6% WA Compliance Period >=2: 8%

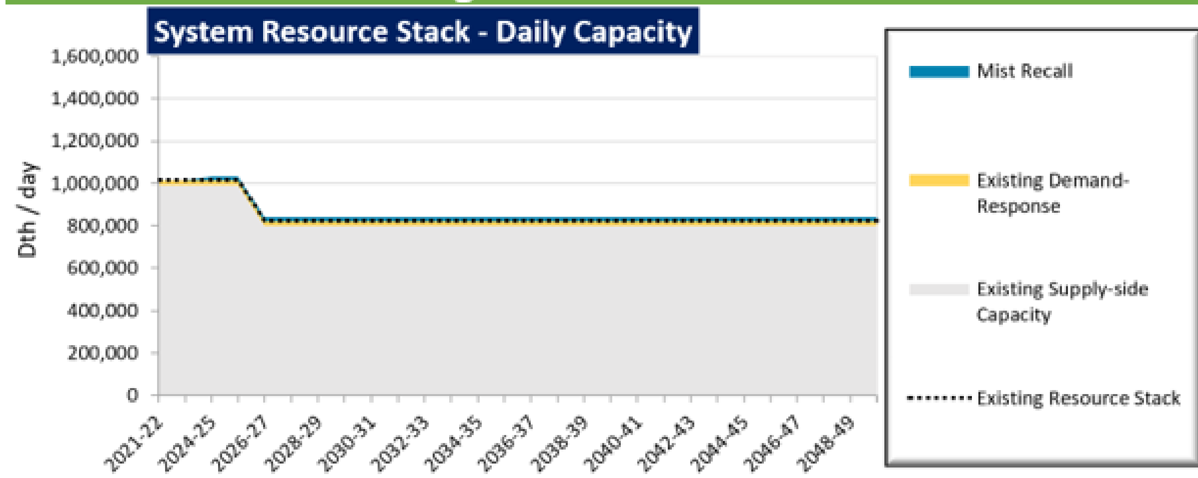
OR SB 98 / WA HB 1257 RNG Targets

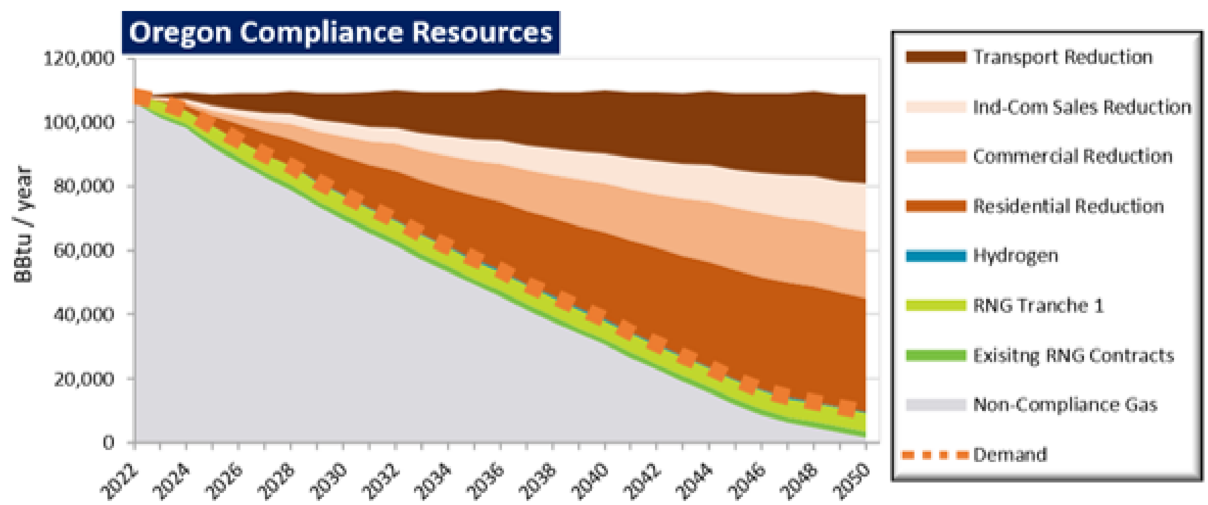


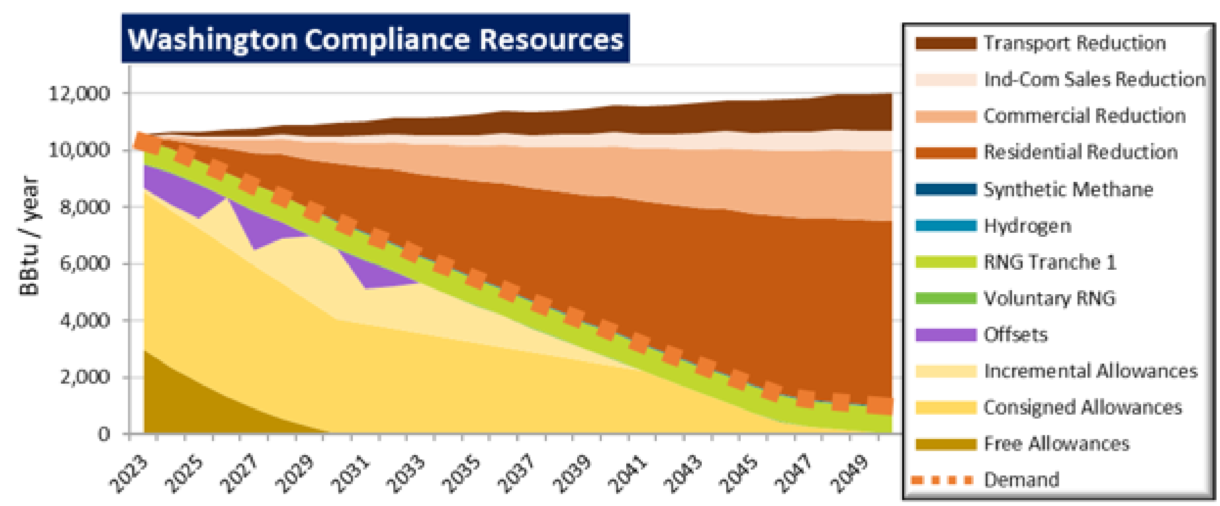
Unbundled Price Paths



Scenario 6 – Full Building Electrification

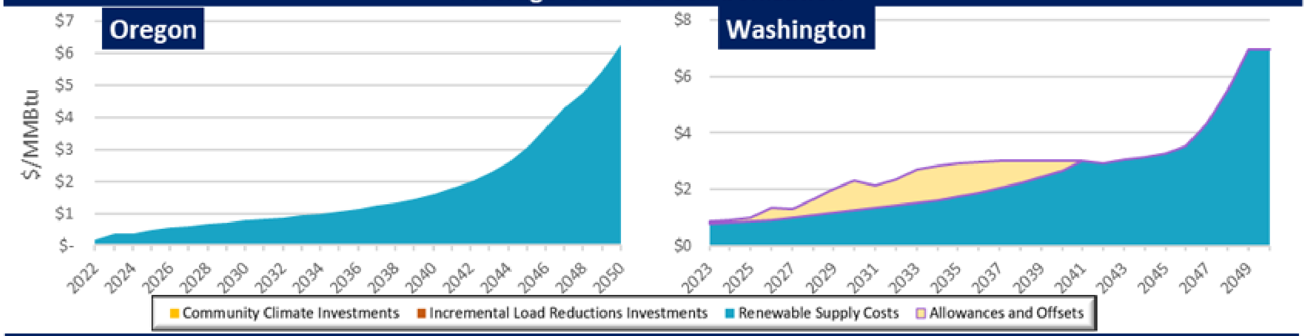




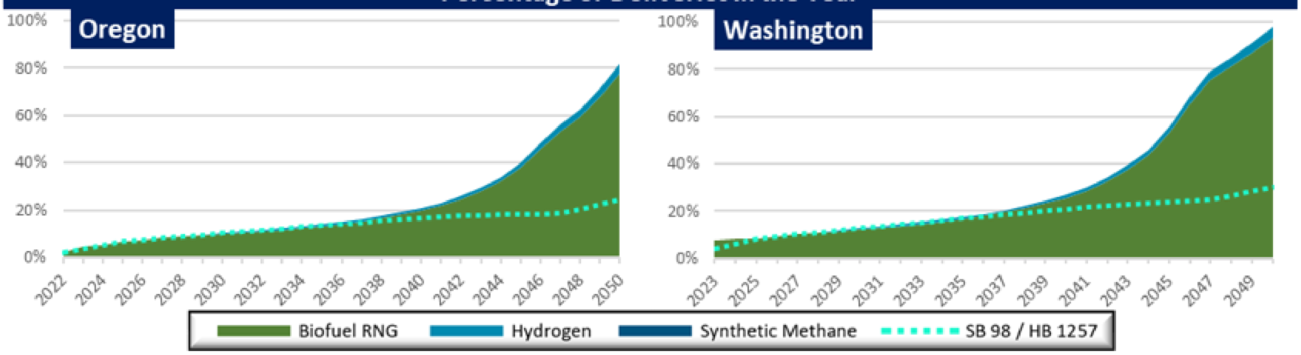


Scenario 6 – Full Building Electrification

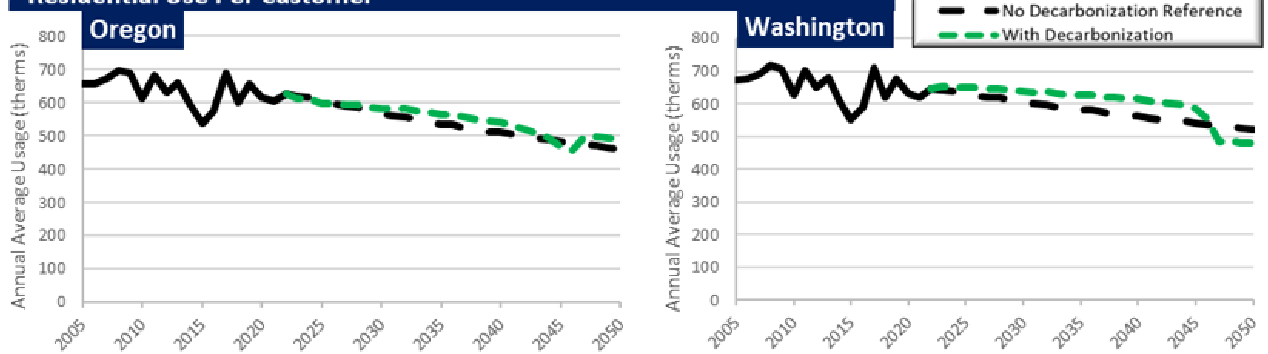
Average Cost of Decarbonization



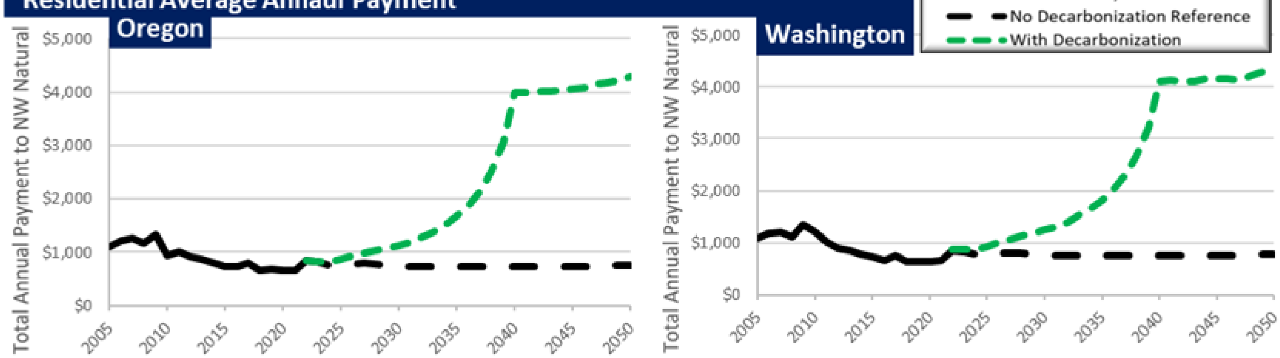
Percentage of Deliveries in the Year



Residential Use Per Customer



Residential Average Annaul Payment



Scenario 6 – Full Building Electrification

Capacity Takeaways

- Neither the Portland LNG Cold Box, the Central Pipeline, nor the Interstate Pipeline Looping project were selected
- Additional capacity needs served by Mist Recall, with a total recall of 20,000 Dth with the last recall occurring in 2025

Oregon Emissions Takeaways

- Meeting RNG targets for SB 98 represents most of the needed emissions reduction for the first compliance period of the Climate Protection Program and far less compliance action is needed due to falling loads
- Renewable supply represents roughly 80% of deliveries in 2050, which is equivalent to roughly 1/3 of current gas deliveries in Oregon. Biofuel RNG deliveries represent roughly 6% of current load in 2050
- Compared to non-electrification scenarios far less decarbonization action is needed from NW Natural to comply with SB 98 and the CPP.
- Customers who remain on the gas system experience 51% higher rates in 2030 and 468% higher in 2050 due to spreading of fixed costs across less energy use

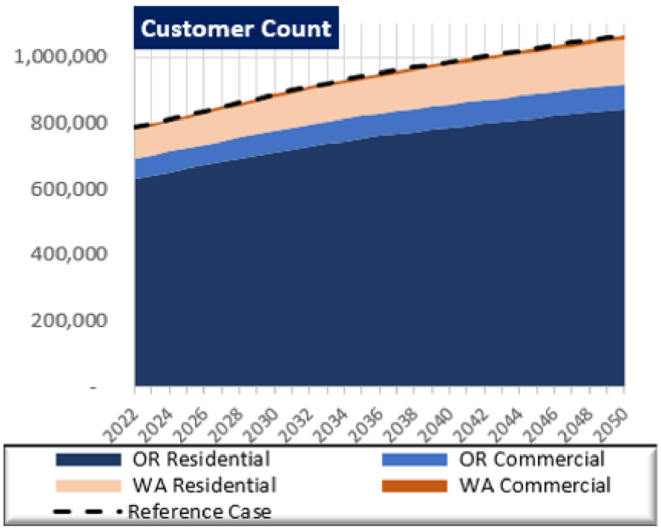
Washington Emissions Takeaways

- Delivering RNG for HB 1257 and utilizing offsets represents the bulk of net near term compliance with Cap-and-Invest, with allowance purchasing filling in any gaps
- Renewable supply represents roughly 30% of deliveries in 2040 and 100% of deliveries in 2050
- Customers who remain on the gas system experience 65% higher rates in 2030 and 448% higher in 2050 due to spreading of fixed costs across less energy use

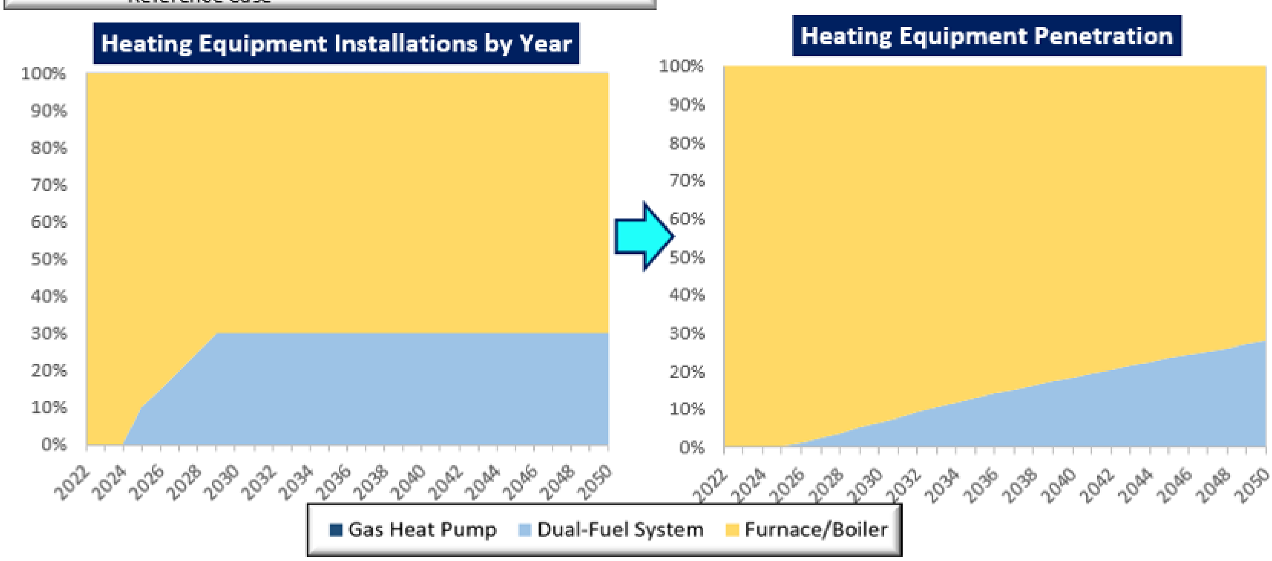
7.4.7 Scenario 7- RNG & H_2 Federal Policy Support

Scenario 7 – RNG and H2 Policy Support

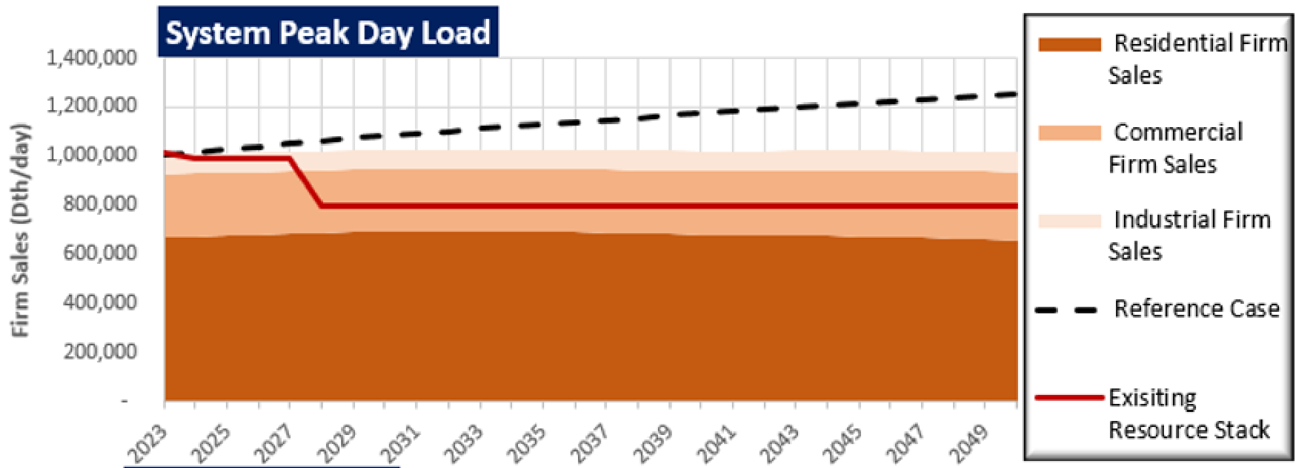
Scenario 7 answers the question "What would it mean if there were federal policy support for renewable natural gas and renewable hydrogen that reduced the cost of these resources to gas utility customers?" This scenario assumes a federal production tax credit of 30% for RNG and H2 similar to policies to support renewable electricity generation. It is assumed that this reduction in the price of these resources also results in a moderate increase in the availability of biofuel RNG. The customer growth demand-side resource assumptions in this scenario are the same as Scenario 1.

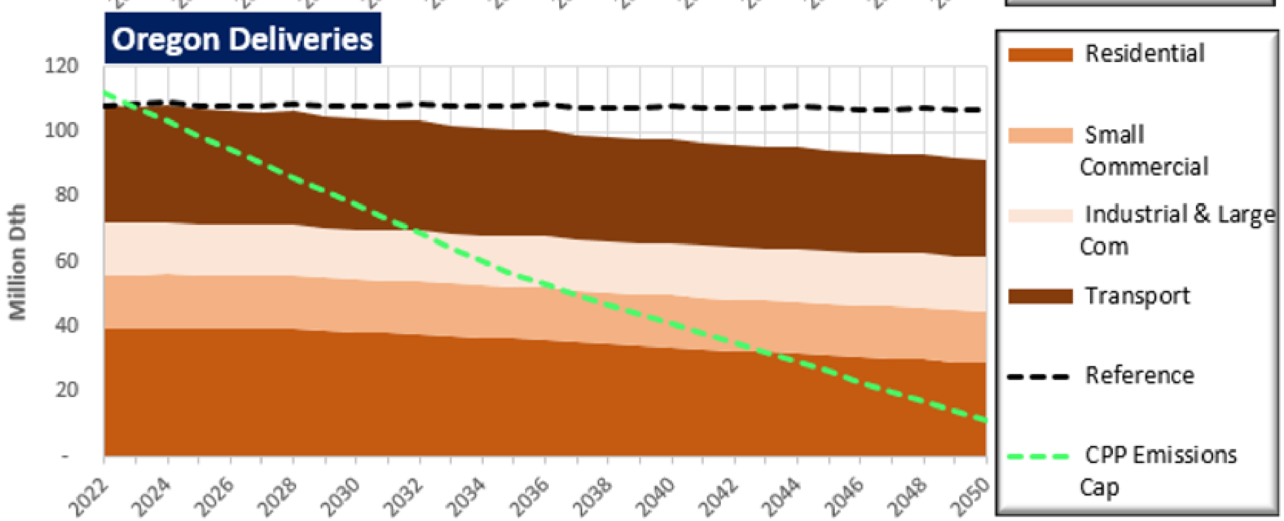


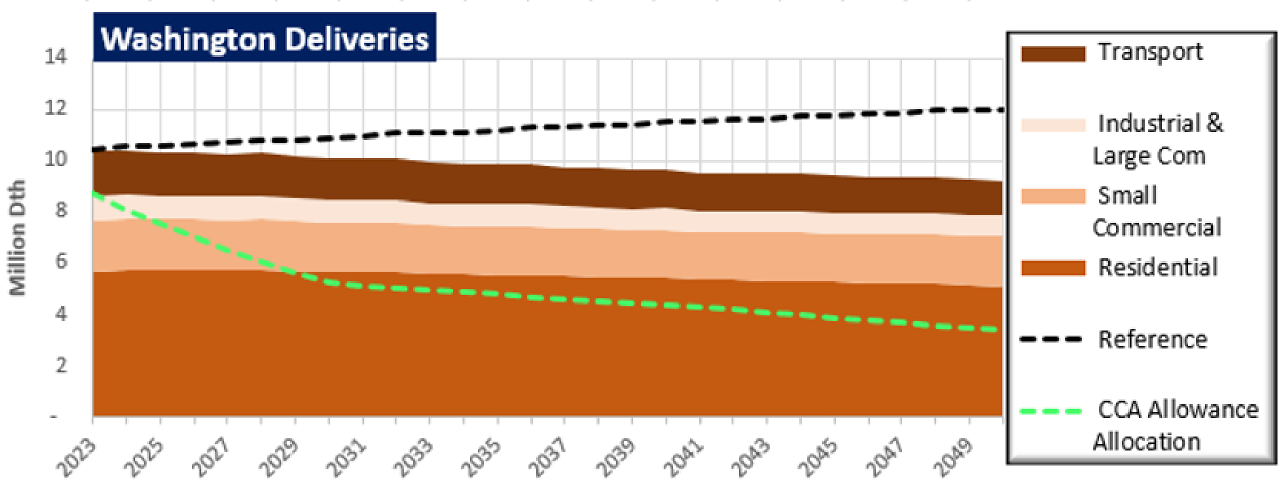
Demand-Side Assumptions	
Sales Customer Energy Efficiency	Energy Trust of Oregon projection of savings, at $5.06/therm of first year savings
Transport Customer Energy Efficiency	Applied Energy Group projection of savings at $1.79/therm of first year savings
Gas Heat Pump Cost	$4,000 total cost to utility for a residential heating system, $13,000 for a Commercial heating System; $1,600 for residential water heater
Dual-Fuel System Costs	Net cost of $400 to utility



Scenario 7 – RNG and H2 Policy Support







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Scenario 7 – RNG and H2 Policy Support

Capacity Resource Options

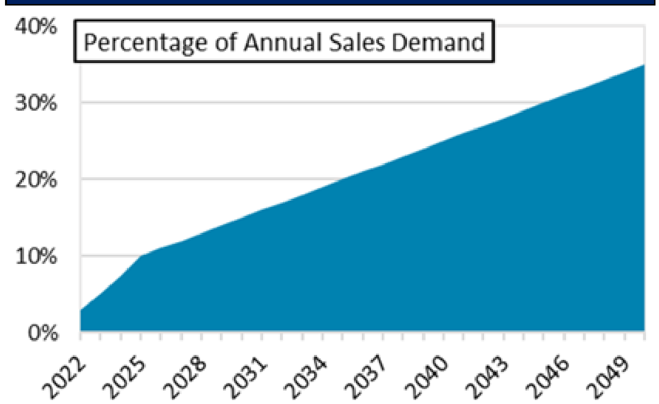
Capacity Resource	Cost ($/Dth/day)	Daily Deliverability (Dth/day)
Mist Recall	$ 0.09	Max: 203,800
Newport Takeaway 1	$ 0.14	16,125
Newport Takeaway 2	$ 1.00	13,975
Newport Takeaway 3	$ 1.41	12,900
Mist Expansion	$ 0.62	106,000
Upstream Pipeline Expansion	$ 2.12	50,000
Portland LNG - Cold Box	$ 0.06	130,800
Interstate Pipeline Looping Plus Required Mist Recall	$ 0.39	130,800
Middle Corridor NWN System Pipeline Plus Required Mist Recall	$ 0.35	130,800

Compliance Resource Options

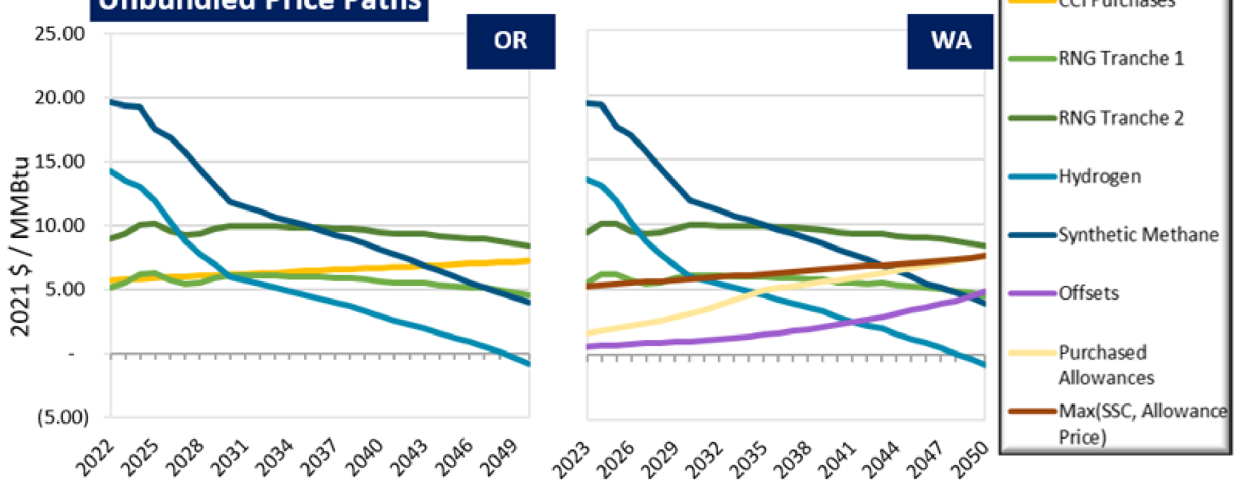
Quantity Available

Option	Limit
RNG Tranche 1	17,000,000 Dth / year
RNG Tranche 2	35,000,000 Dth / year
Hydrogen	30% of Deliveries by Energy
Synthetic Methane	Unbounded
CCIs	OR Compliance Period 1: 10% OR Compliance Period 2: 15% OR Compliance Period >=3: 20%
Allowances	Unbounded
Offsets	WA Compliance Period 1: 6% WA Compliance Period >=2: 8%

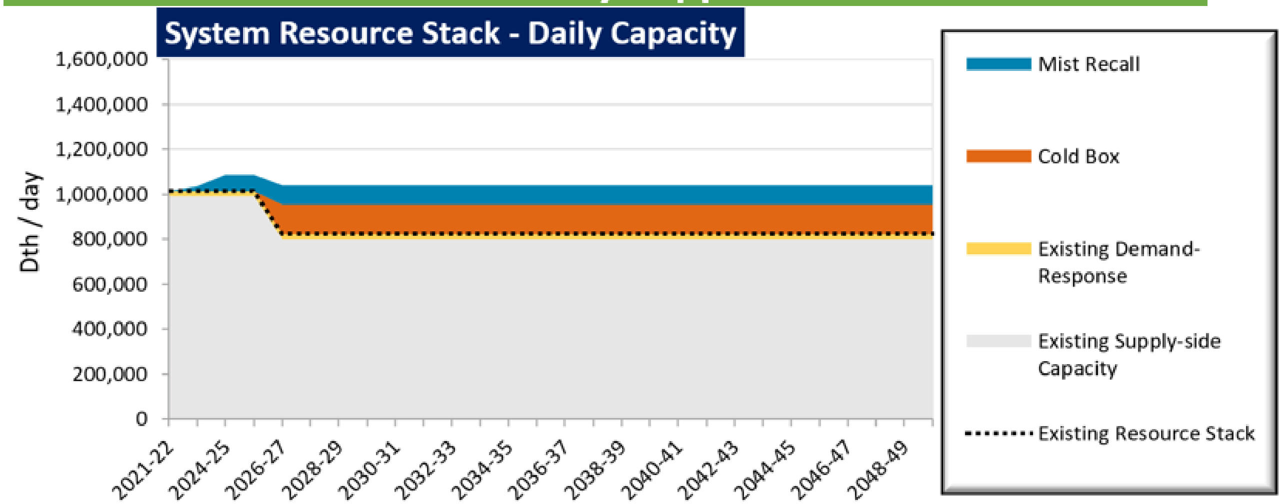
OR SB 98 / WA HB 1257 RNG Targets

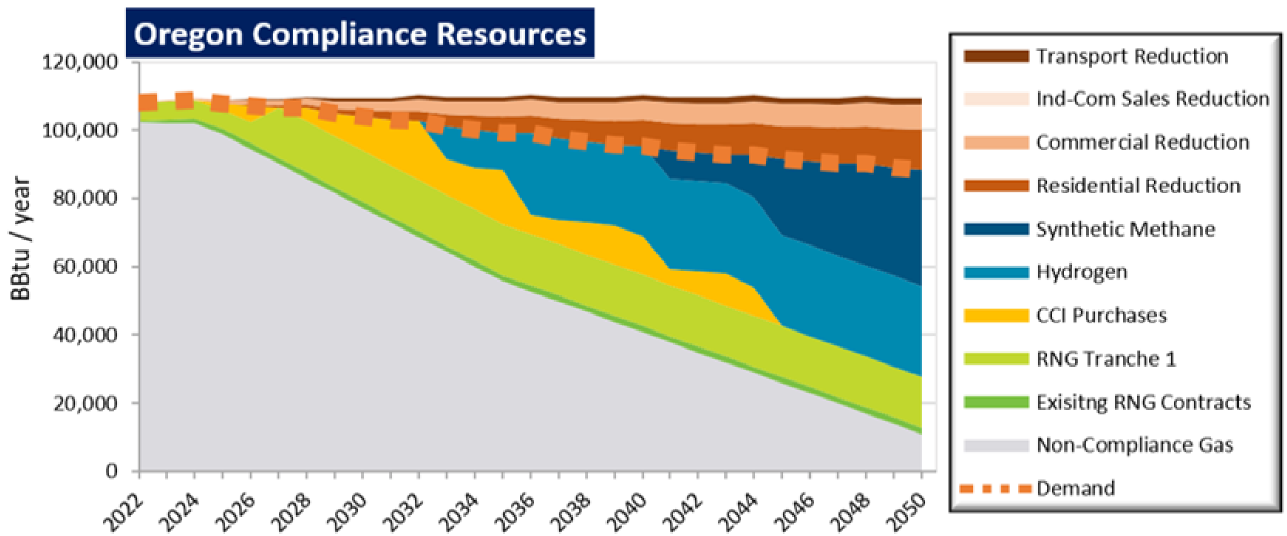


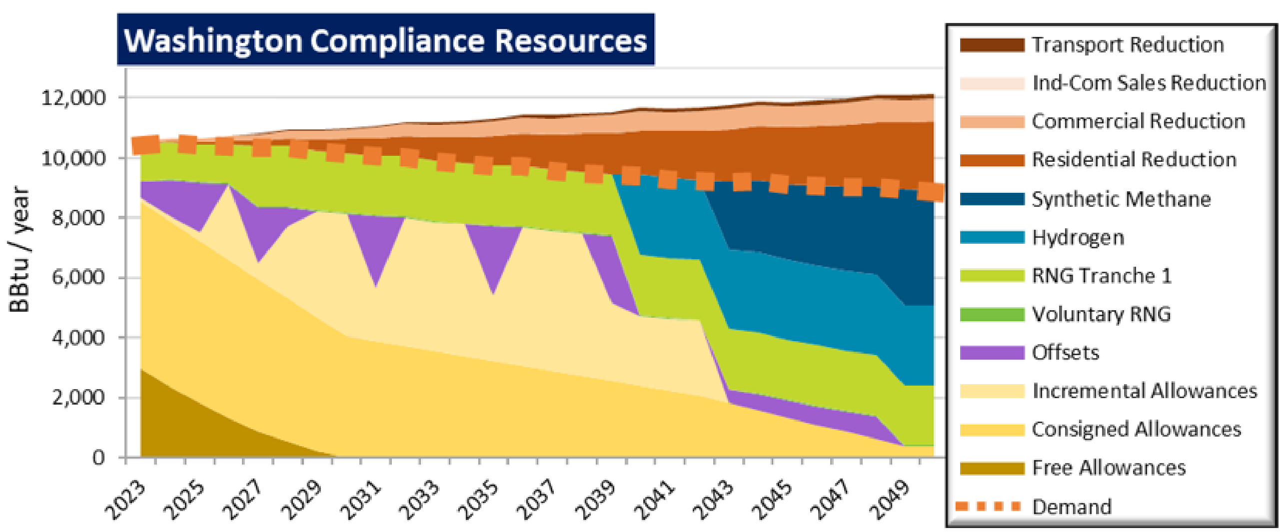
Unbundled Price Paths



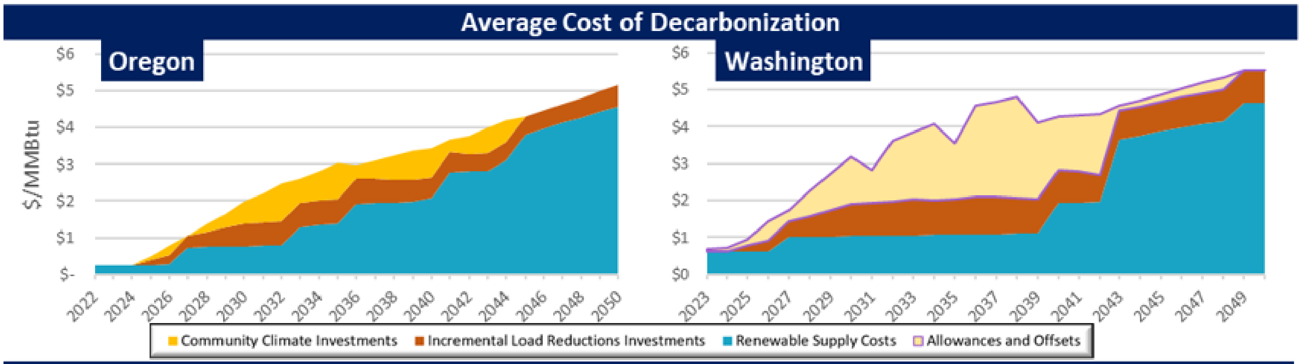
Scenario 7 – RNG and H2 Policy Support

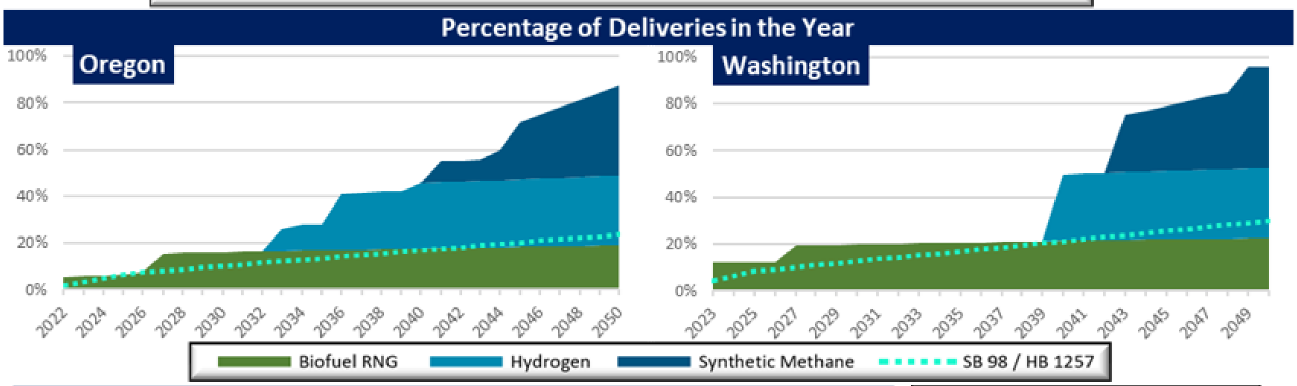


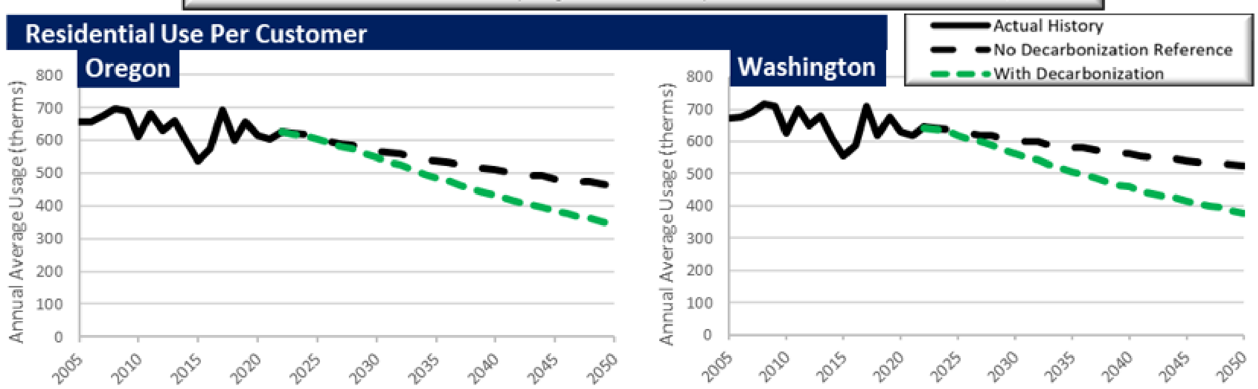


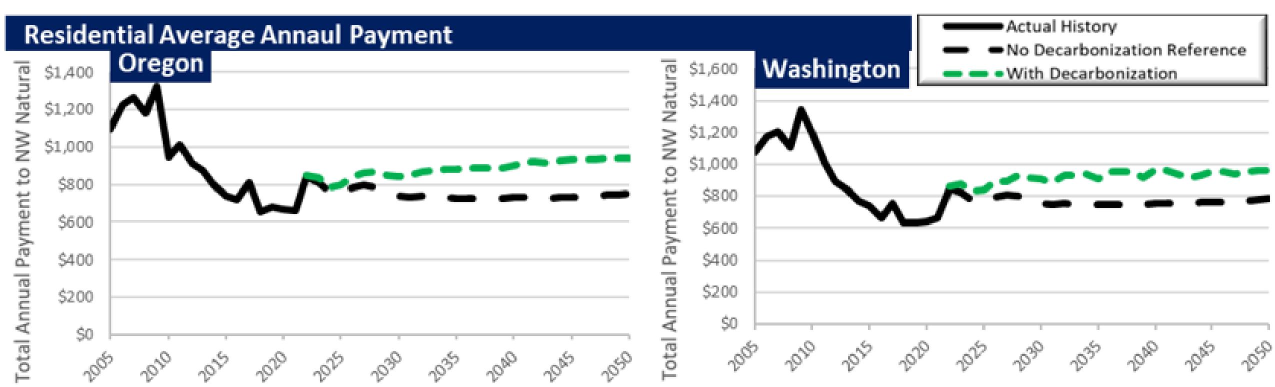


Scenario 7 – RNG and H2 Policy Support









Scenario 7 – RNG and H2 Policy Support

Capacity Takeaways

- Replacing Portland LNG Cold Box shown as least cost solution
- Additional capacity needs served by Mist Recall, with a total recall of 85,000 Dth with the last recall occurring in 2027

Oregon Emissions Takeaways

- Meeting RNG targets for SB 98 represents most of the needed emissions reduction for the first compliance period of the Climate Protection Program
- Biofuel RNG represents the marginal compliance activity in the near- to medium-term, transitioning to renewable hydrogen for blending or dedicated delivery starting in 2033, and then transitioning to synthetic renewable natural gas in 2041
- Renewable supply represents roughly 85% of deliveries in 2050, which is equivalent to roughly 2/3 of current gas deliveries in Oregon. Biofuel RNG deliveries represent roughly 14% of current load in 2050
- Decarbonization action to comply with SB 98 and the CPP results in residential gas utility bills being 14% higher in 2030 and 25% higher in 2050 than in a world without these policies

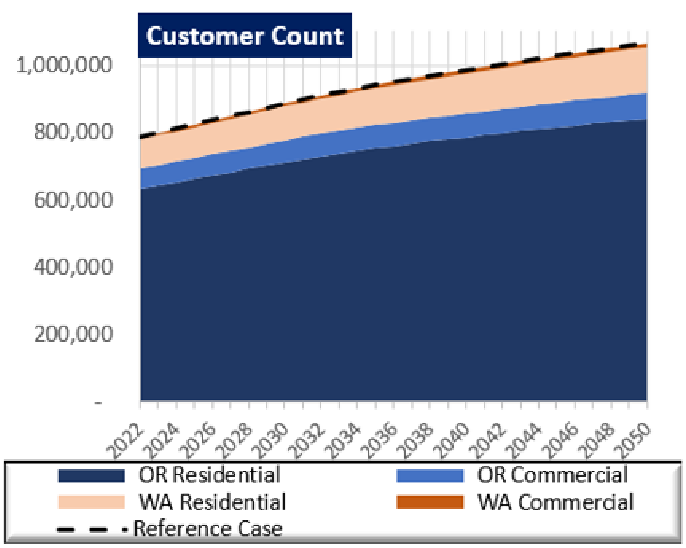
Washington Emissions Takeaways

- Delivering RNG for HB 1257 and utilizing offsets represents the bulk of net near term compliance with Cap-and-Invest, with allowance purchasing filling in any gaps
- Renewable supply represents roughly 50% of deliveries in 2040 and 95% of deliveries in 2050
- Complying with HB 1257 and Cap-and-Invest results in residential gas utility bills being 21% higher in 2030 and 22% higher in 2050 than in a world without these policies

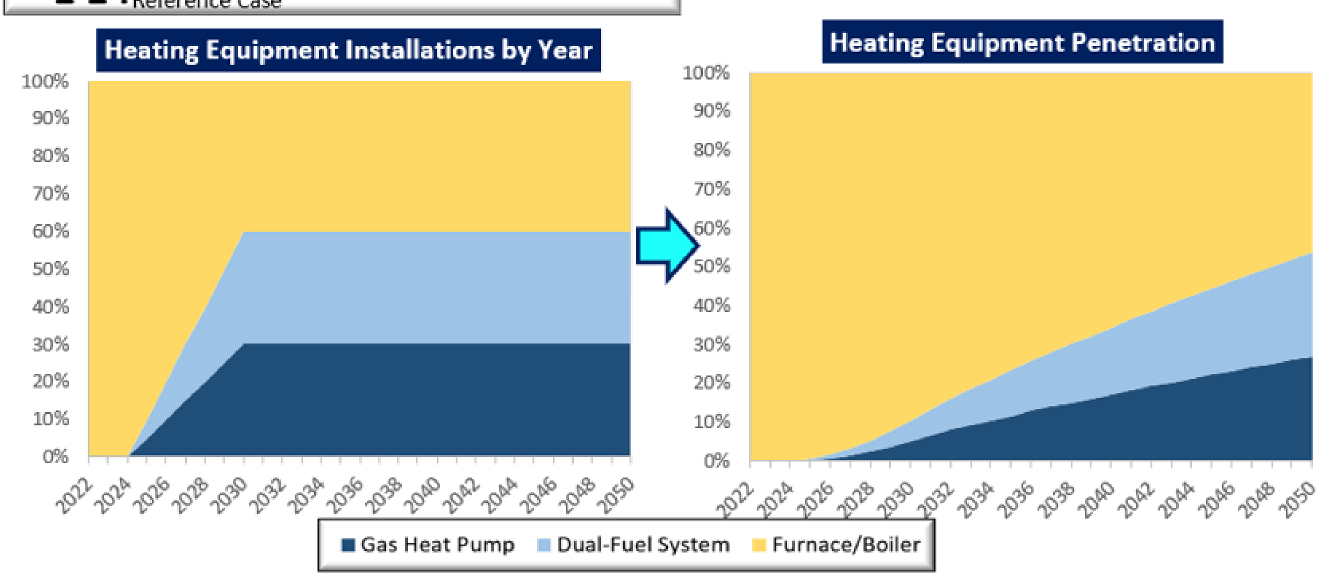
7.4.8 Scenario 8- Limited RNG Availability

Scenario 8 – Limited RNG

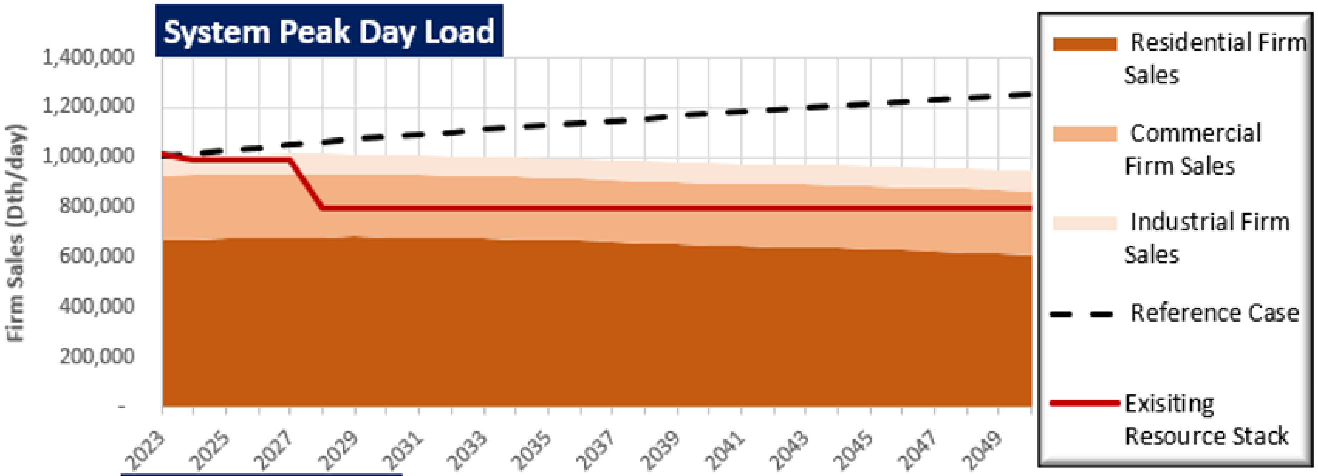
Scenario 8 helps to answer the question "What are the implications if biofuel RNG is less plentiful and more expensive than expected?" This scenario assumes a low resource potential for biofuel RNG (roughly half of the resource assumed in Scenario 1) at a higher cost than can be seen in current markets, and that less hydrogen can be delivered to customers via a combination of blending and dedicated delivery to some customers. Customer growth and demand-side resource assumptions in this Scenario are the same as Scenario 1.

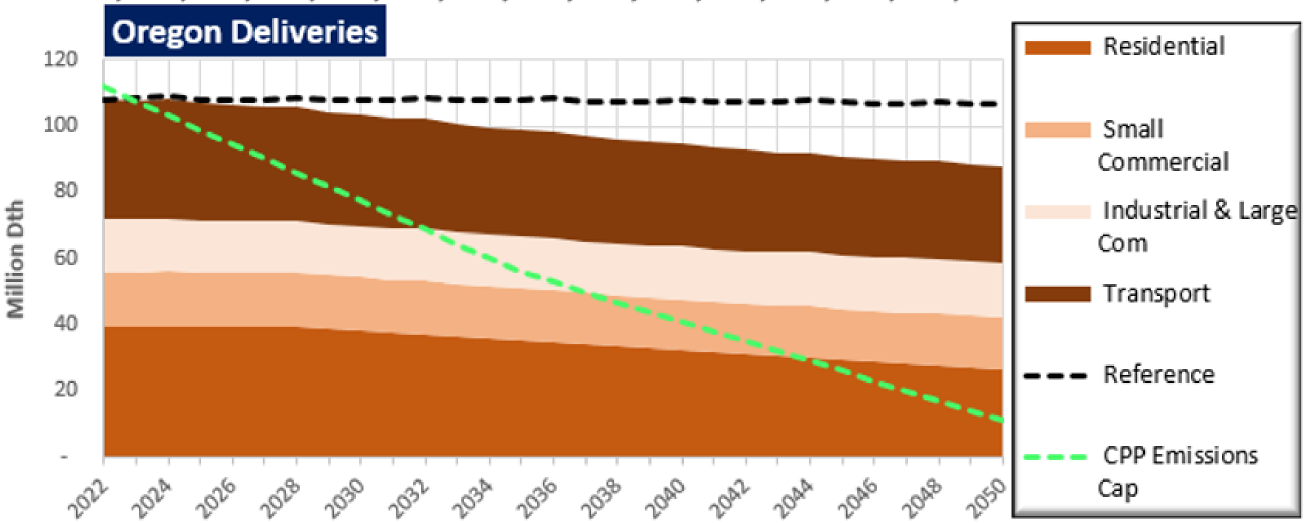


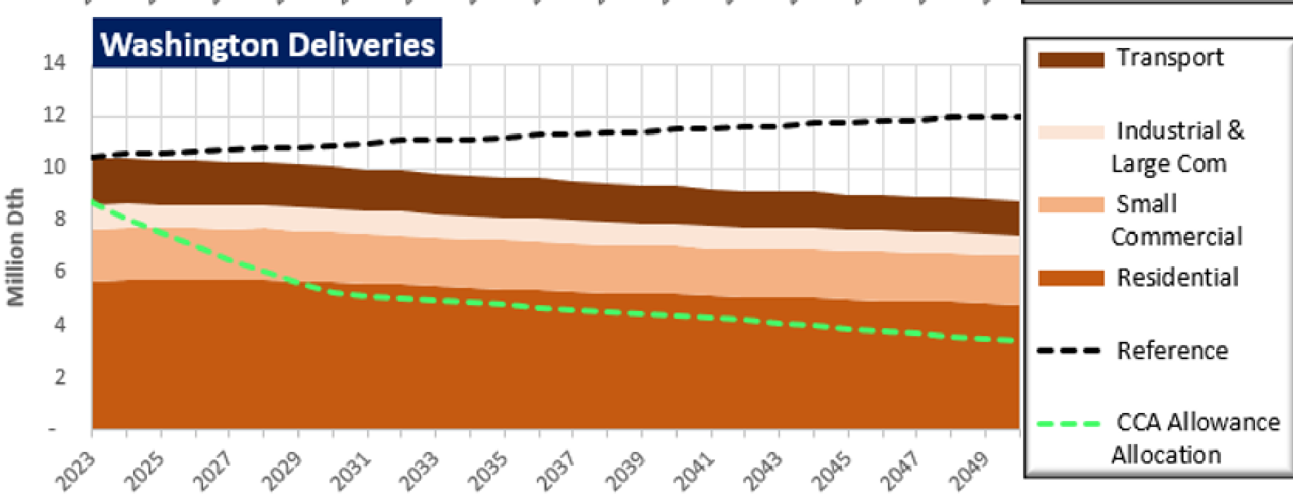
Demand-Side Assumptions	
Sales Customer Energy Efficiency	Energy Trust of Oregon projection of savings, at $5.06/therm of first year savings
Transport Customer Energy Efficiency	Applied Energy Group projection of savings at $1.79/therm of first year savings
Gas Heat Pump Cost	$4,000 total cost to utility for a residential heating system, $13,000 for a Commercial heating System; $1,600 for residential water heater
Dual-Fuel System Costs	Net cost of $400 to utility



Scenario 8 – Limited RNG







Scenario 8 – Limited RNG

Capacity Resource Options

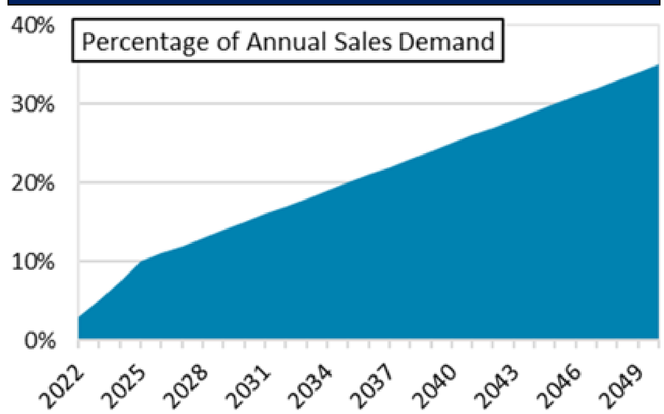
Capacity Resource	Cost ($/Dth/day)	Daily Deliverability (Dth/day)
Mist Recall	$ 0.09	Max: 203,800
Newport Takeaway 1	$ 0.14	16,125
Newport Takeaway 2	$ 1.00	13,975
Newport Takeaway 3	$ 1.41	12,900
Mist Expansion	$ 0.62	106,000
Upstream Pipeline Expansion	$ 2.12	50,000
Portland LNG - Cold Box	$ 0.06	130,800
Interstate Pipeline Looping Plus Required Mist Recall	$ 0.39	130,800
Middle Corridor NWN System Pipeline Plus Required Mist Recall	$ 0.35	130,800

Compliance Resource Options

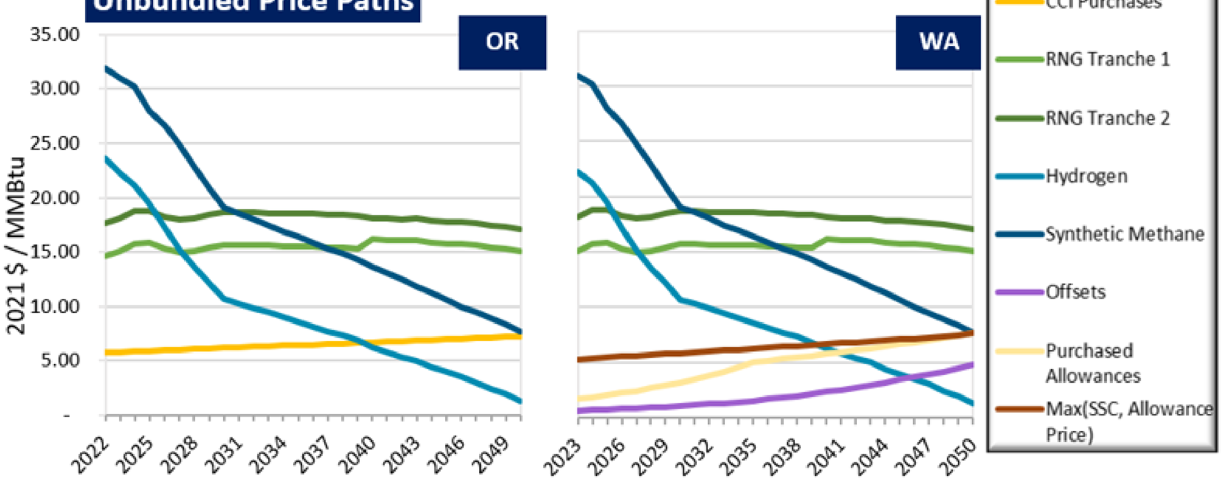
Quantity Available

Option	Limit
RNG Tranche 1	8,000,000 Dth / year
RNG Tranche 2	13,000,000 Dth / year
Hydrogen	12% of Deliveries by Energy
Synthetic Methane	Unbounded
CCIs	OR Compliance Period 1: 10% OR Compliance Period 2: 15% OR Compliance Period >=3: 20%
Allowances	Unbounded
Offsets	WA Compliance Period 1: 6% WA Compliance Period >=2: 8%

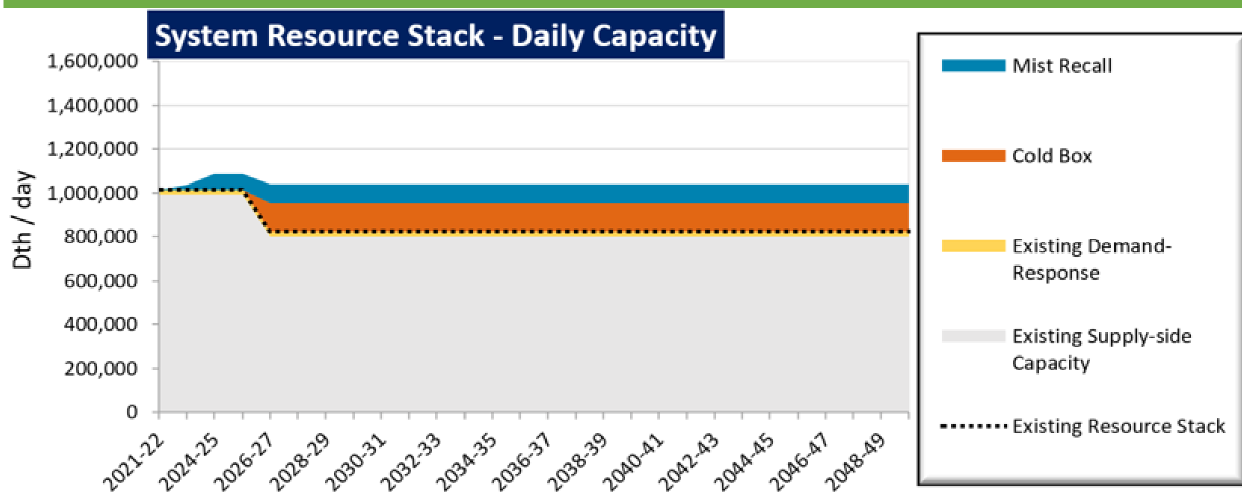
OR SB 98 / WA HB 1257 RNG Targets

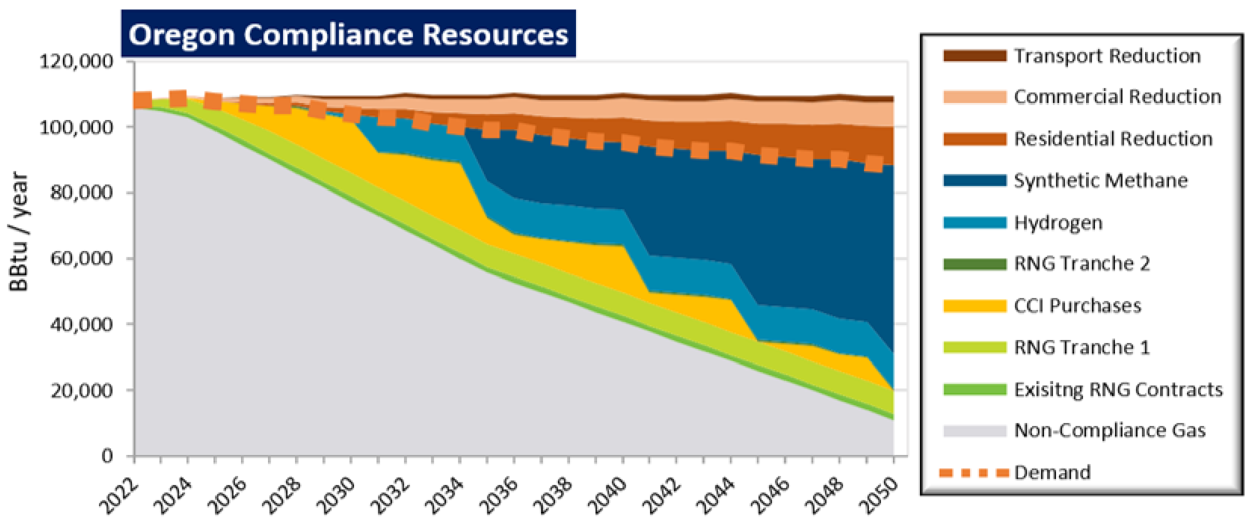


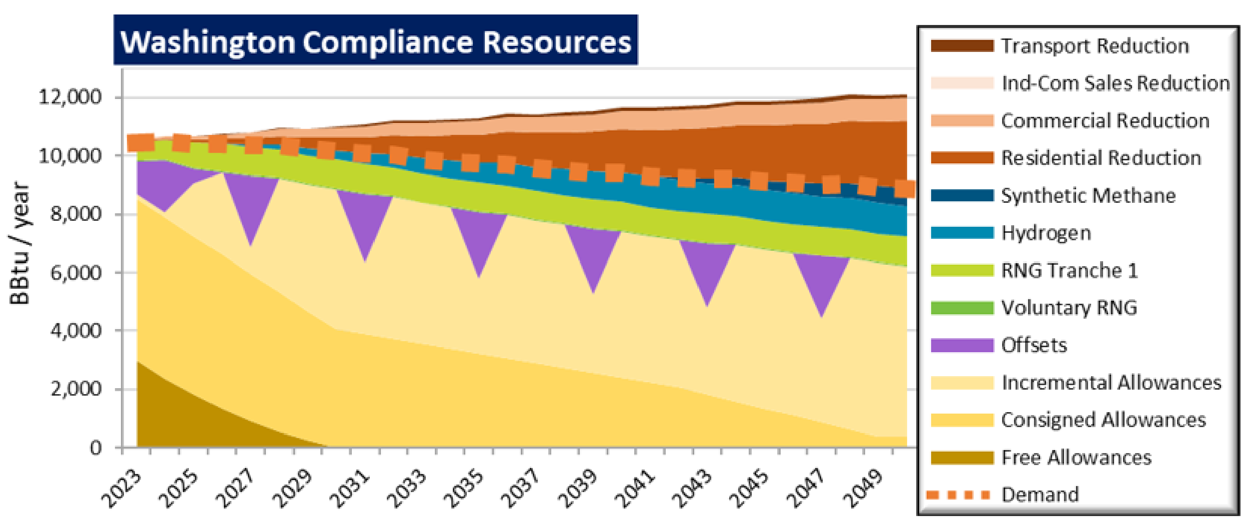
Unbundled Price Paths



Scenario 8 – Limited RNG

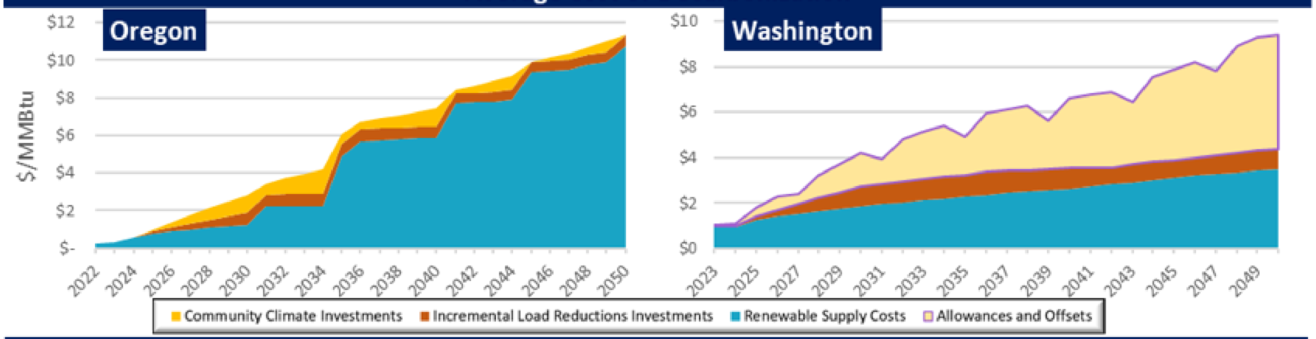




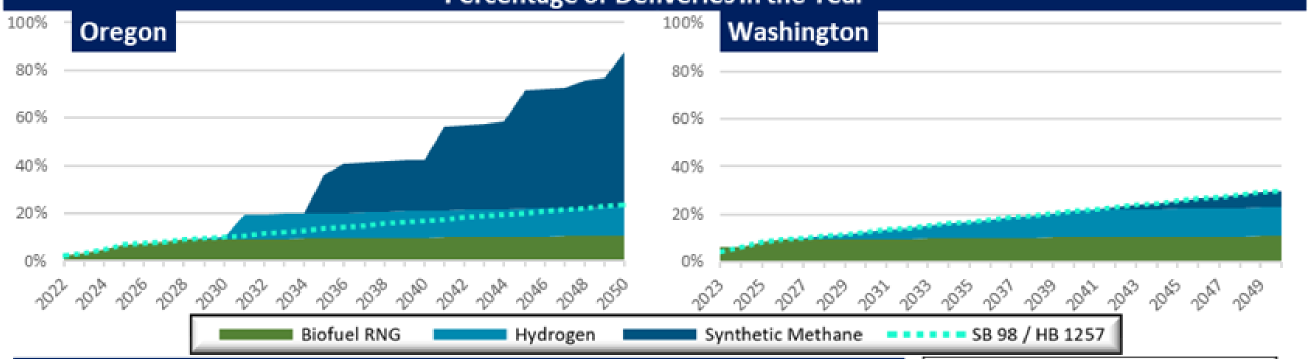


Scenario 8 – Limited RNG

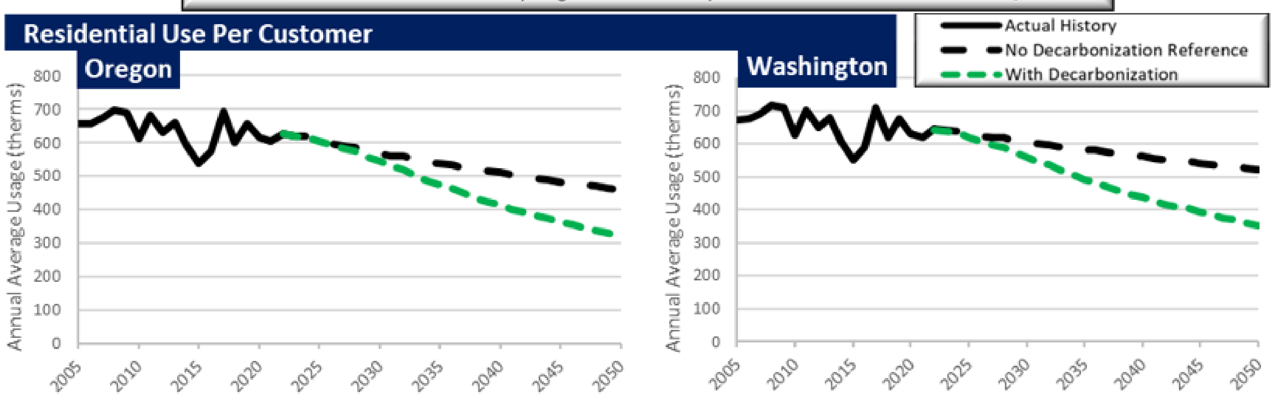
Average Cost of Decarbonization



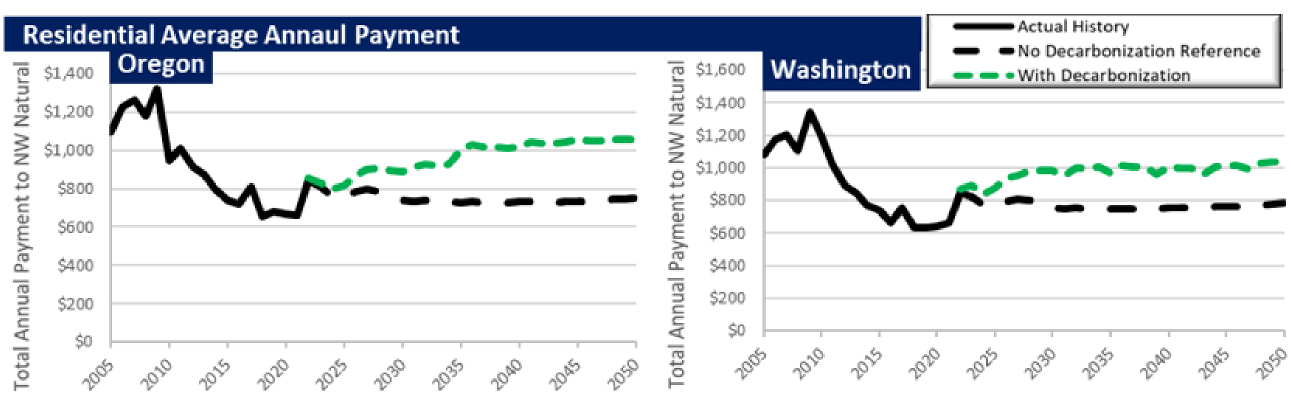
Percentage of Deliveries in the Year



Residential Use Per Customer



Residential Average Annaul Payment



Scenario 8 – Limited RNG

Capacity Takeaways

- Replacing Portland LNG Cold Box shown as least cost solution
- Additional capacity needs served by Mist Recall, with a total recall of 85,000 Dth with the last recall occurring in 2027

Oregon Emissions Takeaways

- Meeting RNG targets for SB 98 represents most of the needed emissions reduction for the first compliance period of the Climate Protection Program; small amounts of Community Climate Investments (CCIs) may be purchased to meet additional requirements depending on weather and other conditions
- Biofuel RNG and CCIs represent the marginal compliance activity in the near- to medium-term, transitioning to renewable hydrogen for blending or dedicated delivery starting in 2029, and then transitioning to synthetic renewable natural gas in 2035
- Renewable supply represents roughly 90% of deliveries in 2050, which is equivalent to roughly ¾ of current gas deliveries in Oregon. Biofuel RNG deliveries represent roughly 7% of current load in 2050
- Decarbonization action to comply with SB 98 and the CPP results in residential gas utility bills being 21% higher in 2030 and 40% higher in 2050 than in a world without these policies

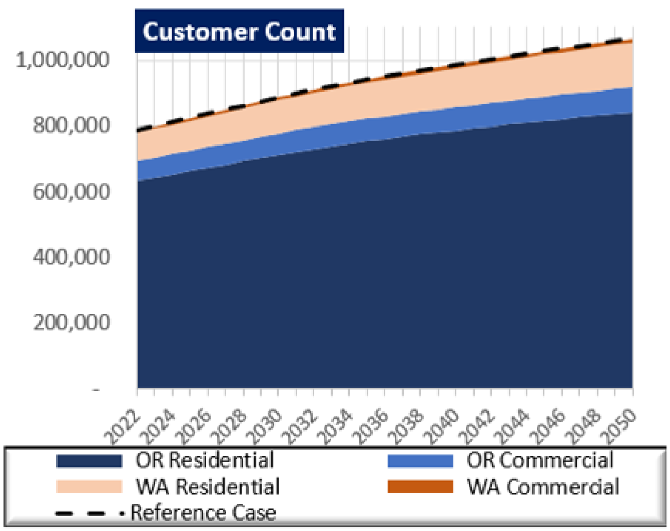
Washington Emissions Takeaways

- Delivering RNG for HB 1257 and utilizing offsets represents the bulk of net near term compliance with Cap-and-Invest, with allowance purchasing filling in any gaps
- Renewable supply represents roughly 20% of deliveries in 2040 and 30% of deliveries in 2050
- Complying with HB 1257 and Cap-and-Invest results in residential gas utility bills being 31% higher in 2030 and 31% higher in 2050 than in a world without these policies

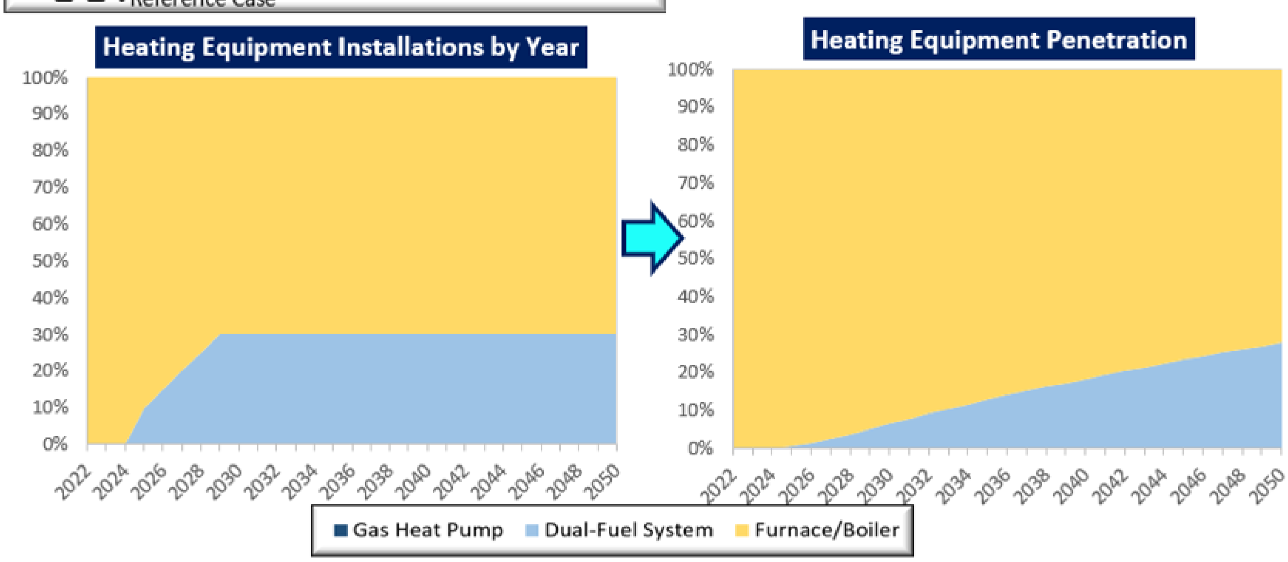
7.4.9 Scenario 9- Supply-Focused Decarbonization

Scenario 9 – Supply-Focused Decarbonization

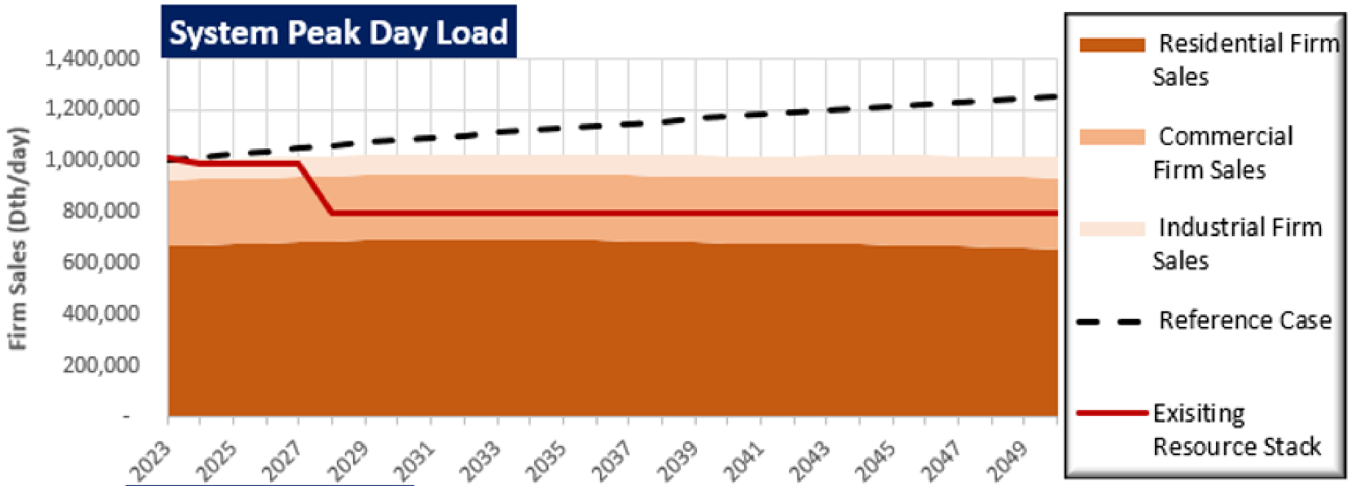
Scenario 9 helps to answer the question "What would it mean if less load can be reduced than is expected?" This scenario assumes less energy efficiency can be achieved than Scenario 1 and assumes that natural gas heat pump technology never becomes available in NW Natural's service territory. This assumption results in a great need for renewable supply to meet the emissions requirements of the OR-CPP and WA-CCA programs. It assumes the same customer growth and price and availability of renewable supply sources (RNG, H2) as Scenario 1.

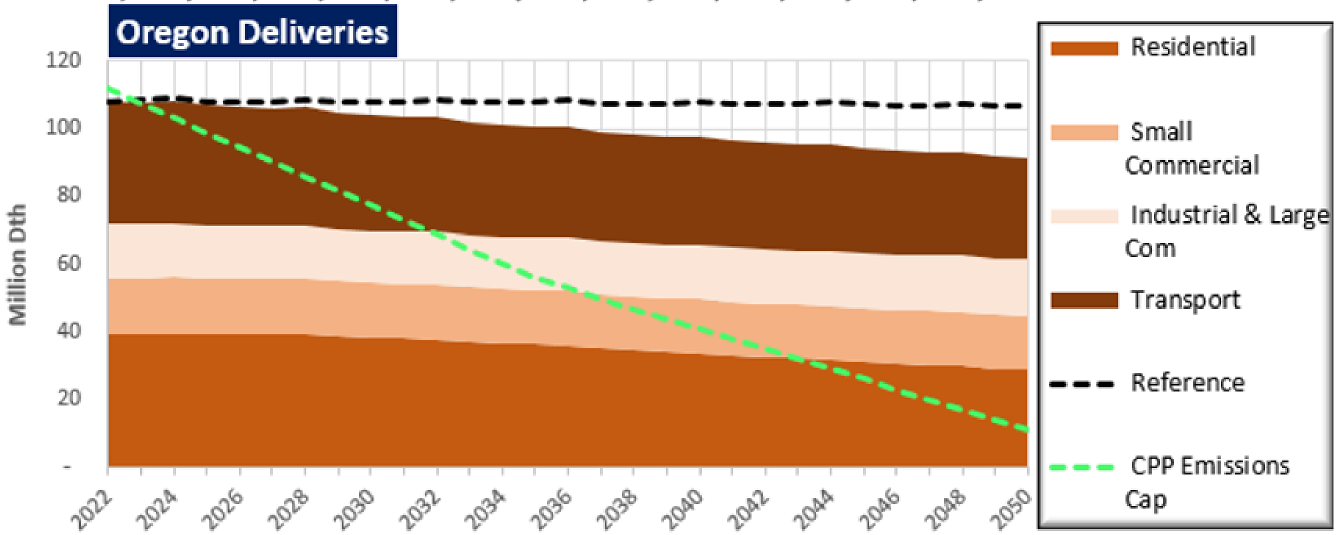


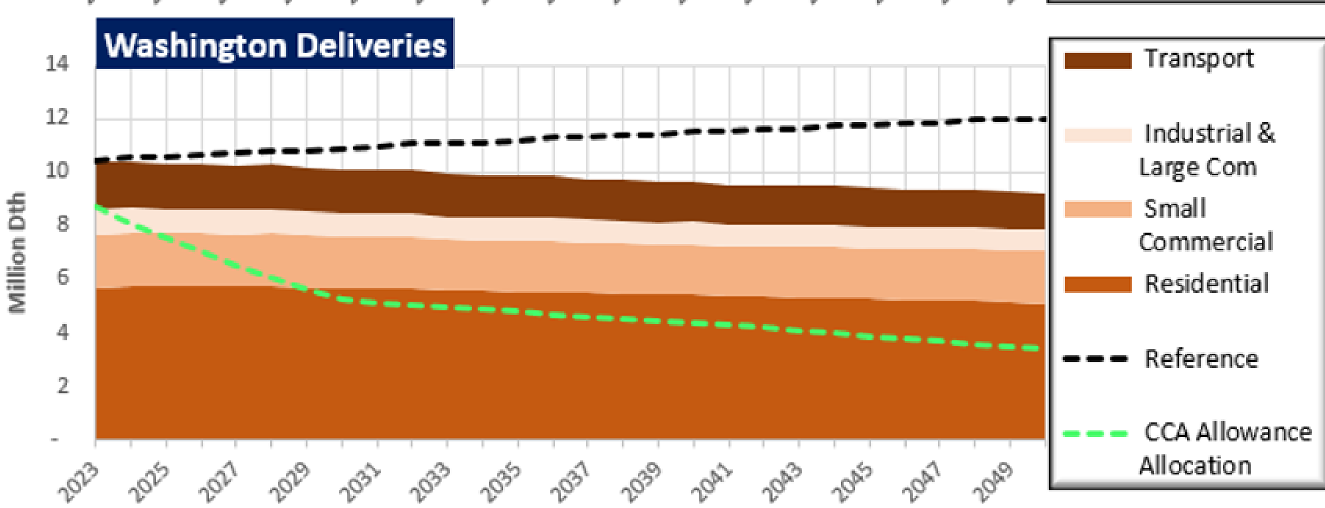
Demand-Side Assumptions	
Sales Customer Energy Efficiency	Energy Trust of Oregon projection of savings, at $5.06/therm of first year savings
Transport Customer Energy Efficiency	Applied Energy Group projection of savings at $1.79/therm of first year savings
Gas Heat Pump Cost	$4,000 total cost to utility for a residential heating system, $13,000 for a Commercial heating System; $1,600 for residential water heater
Dual-Fuel System Costs	Net cost of $400 to utility



Scenario 9 – Supply-Focused Decarbonization







Scenario 9 – Supply-Focused Decarbonization

Capacity Resource Options

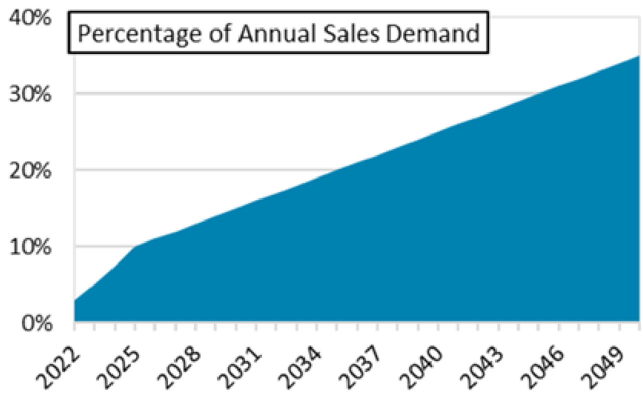
Capacity Resource	Cost ($/Dth/day)	Daily Deliverability (Dth/day)
Mist Recall	$ 0.09	Max: 203,800
Newport Takeaway 1	$ 0.14	16,125
Newport Takeaway 2	$ 1.00	13,975
Newport Takeaway 3	$ 1.41	12,900
Mist Expansion	$ 0.62	106,000
Upstream Pipeline Expansion	$ 2.12	50,000
Portland LNG - Cold Box	$ 0.06	130,800
Interstate Pipeline Looping Plus Required Mist Recall	$ 0.39	130,800
Middle Corridor NWN System Pipeline Plus Required Mist Recall	$ 0.35	130,800

Compliance Resource Options

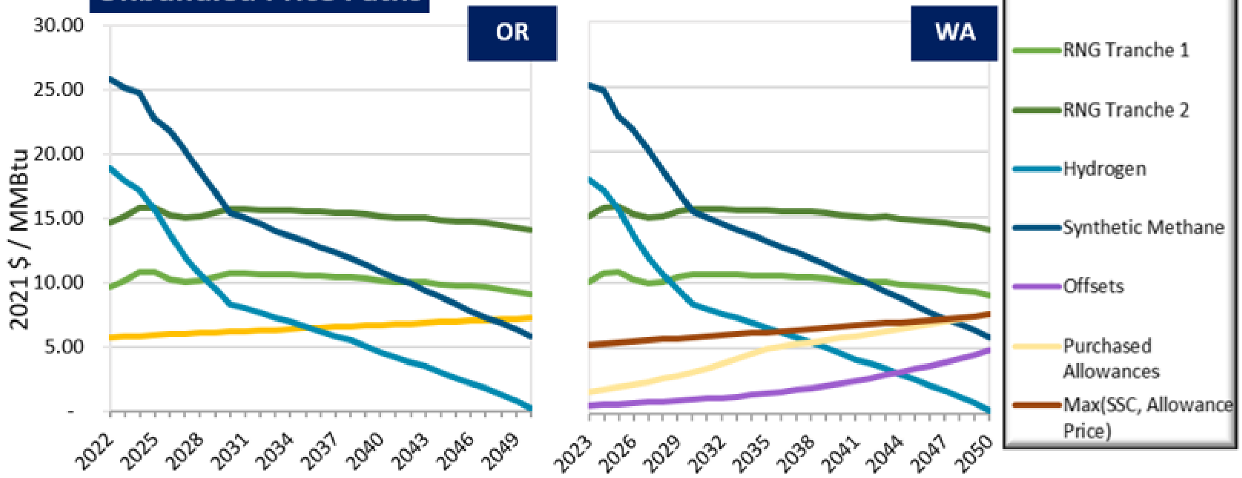
Quantity Available

Option	Limit
RNG Tranche 1	13,000,000 Dth / year
RNG Tranche 2	27,000,000 Dth / year
Hydrogen	35% of Deliveries by Energy
Synthetic Methane	Unbounded
CCIs	OR Compliance Period 1: 10% OR Compliance Period 2: 15% OR Compliance Period >=3: 20%
Allowances	Unbounded
Offsets	WA Compliance Period 1: 6% WA Compliance Period >=2: 8%

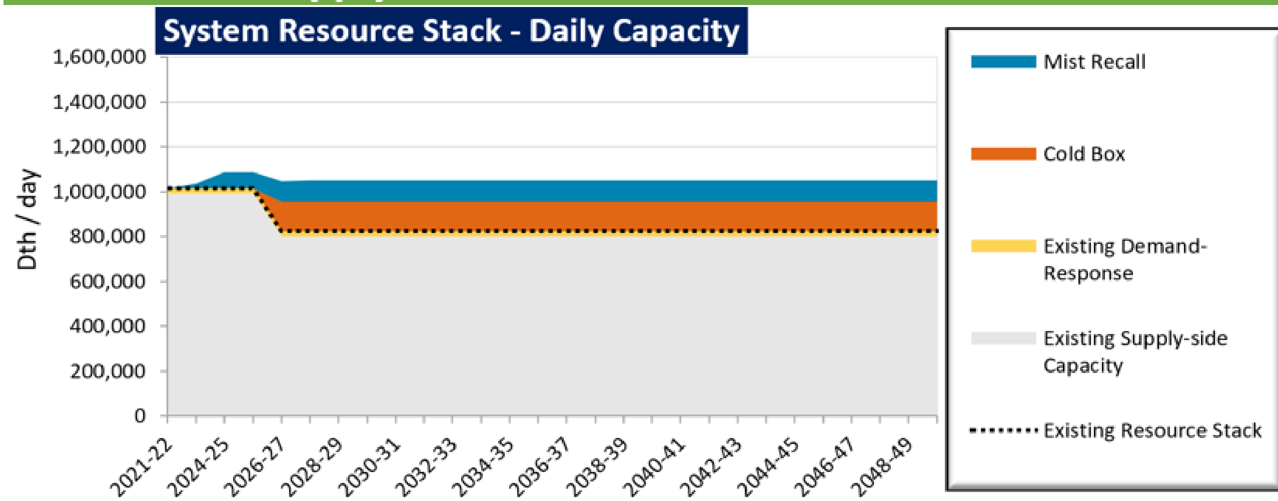
OR SB 98 / WA HB 1257 RNG Targets

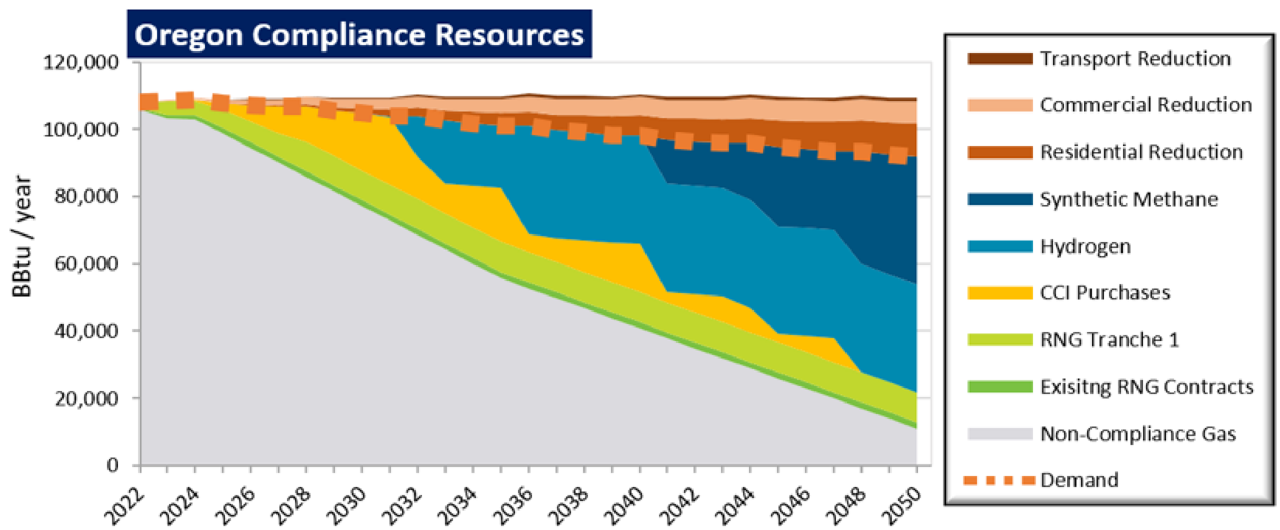


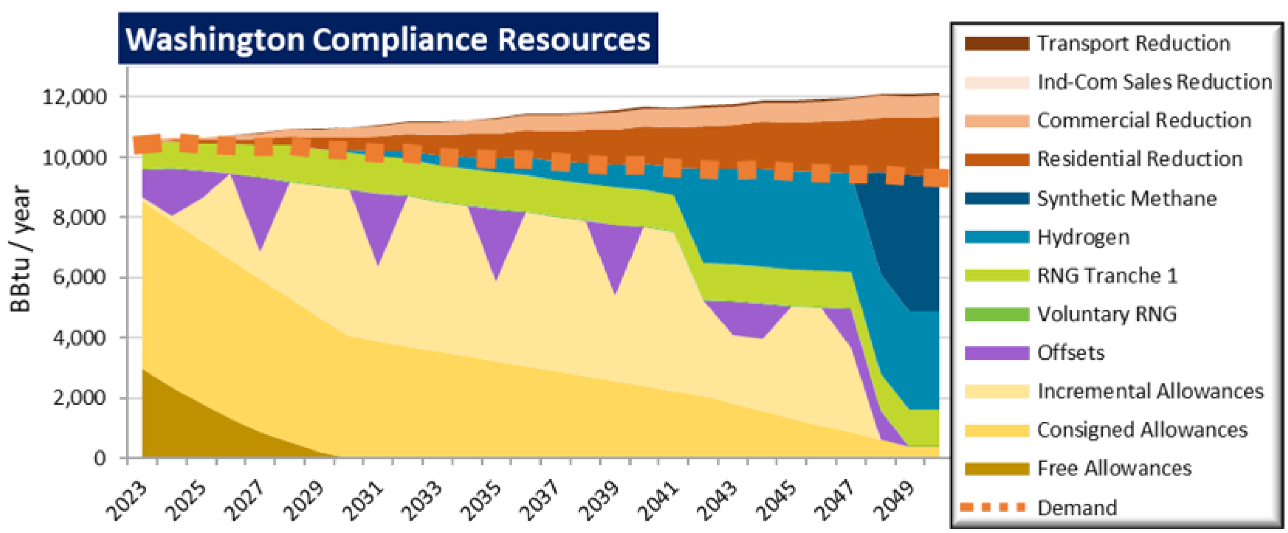
Unbundled Price Paths



Scenario 9 – Supply-Focused Decarbonization

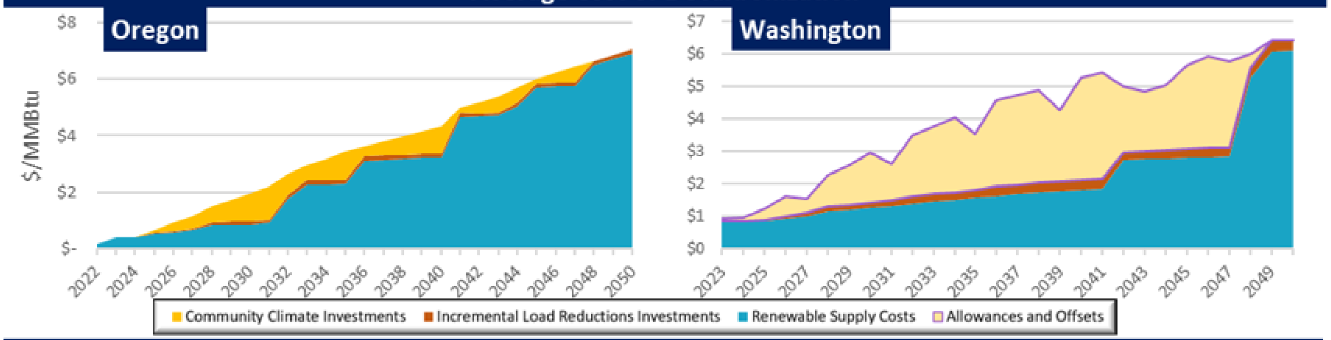




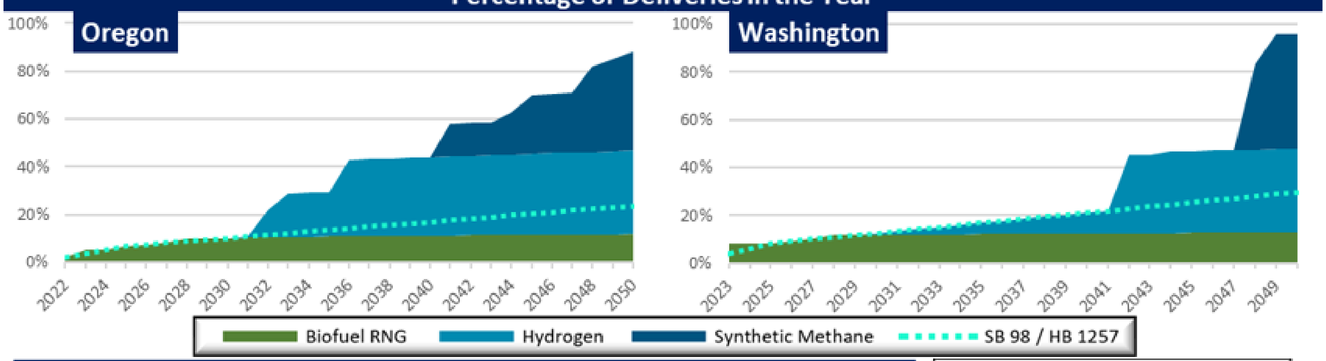


Scenario 9 – Supply-Focused Decarbonization

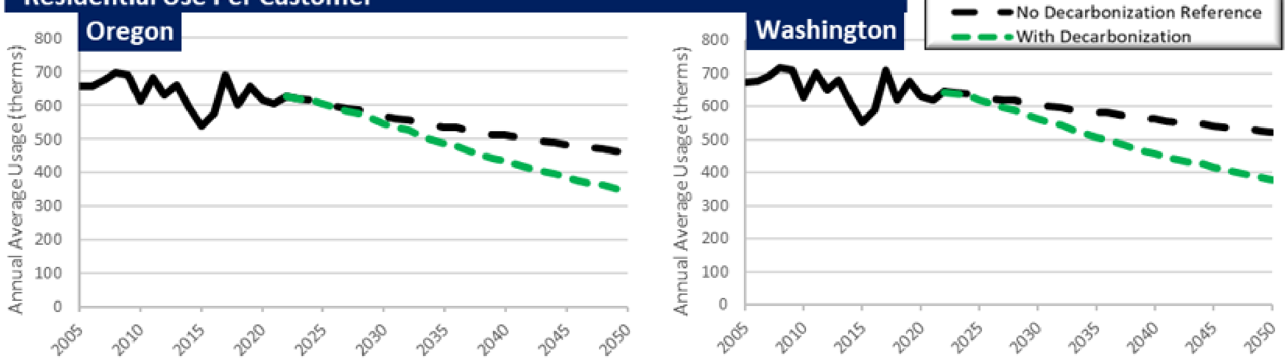
Average Cost of Decarbonization



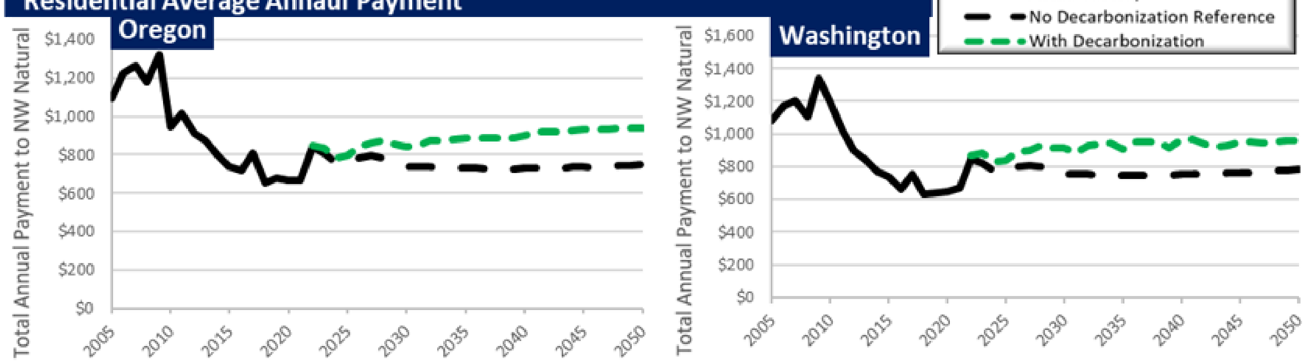
Percentage of Deliveries in the Year



Residential Use Per Customer



Residential Average Annaul Payment



Scenario 9 – Supply-Focused Decarbonization

Capacity Takeaways

- Replacing Portland LNG Cold Box shown as least cost solution
- Additional capacity needs served by Mist Recall, with a total recall of 100,000 Dth with the last recall occurring in 2031

Oregon Emissions Takeaways

- Meeting RNG targets for SB 98 represents most of the needed emissions reduction for the first compliance period of the Climate Protection Program; small amounts of Community Climate Investments (CCIs) may be purchased to meet additional requirements depending on weather and other conditions
- Biofuel RNG and CCIs represent the marginal compliance activity in the near- to medium-term, transitioning to renewable hydrogen for blending or dedicated delivery starting in 2031, and then transitioning to synthetic renewable natural gas in 2041
- Renewable supply represents roughly 90% of deliveries in 2050, which is equivalent to roughly ¾ of current gas deliveries in Oregon. Biofuel RNG deliveries represent roughly 8% of current load in 2050
- Decarbonization action to comply with SB 98 and the CPP results in residential gas utility bills being 14% higher in 2030 and 25% higher in 2050 than in a world without these policies

Washington Emissions Takeaways

- Delivering RNG for HB 1257 and utilizing offsets represents the bulk of net near term compliance with Cap-and-Invest, with allowance purchasing filling in any gaps
- Renewable supply represents roughly 20% of deliveries in 2040 and 95% of deliveries in 2050
- Complying with HB 1257 and Cap-and-Invest results in residential gas utility bills being 21% higher in 2030 and 22% higher in 2050 than in a world without these policies

7.5 Scenario Results Takeaways

In all the scenarios, the expected volumes from SB 98 and HB 1257 RNG – of which biofuels are shown as the lowest cost option – make up a significant amount of the needed compliance action in the first compliance periods (CPP:2022-2024, CCA:2023-2027). Similarly, in Oregon CCIs are used to fill in any gaps not served by SB 98 targets in the term, and that NW Natural is not expected to bump up against CCI limits in the CPP until the period around 2030. Since the amount of RNG needed to achieve SB 98 targets varies by scenario due to differences in load (SB 98 targets are a percentage of sales load), higher load scenarios show more SB 98 RNG and lower load scenarios show smaller amounts SB 98 RNG, though the difference is small given that load cannot change materially from current levels by the end of 2024. Also, even in scenarios with aggressive load reductions going forward, the amount of RNG that aligns with near-term SB 98 targets would be able to be utilized for compliance (i.e., not "wasted" in terms of compliance needs). Furthermore, over the first compliance period it is not anticipated that RNG or clean hydrogen would be cheaper than CCIs, making a strategy of purchasing compliance needs in excess of SB 98 a robust option. This strategy is further supported by the flexible nature of CCIs, where they can be purchased for any of the three years compliance period in any of those three years.

Also, when looking across scenarios at compliance with the CPP there is a consistent trend in expected emissions compliance resources through time. In the near-term biofuel RNG is the cheapest option and is used to meet SB 98 targets, whereas renewable hydrogen is expected to become the incremental resource starting around 2030, and once blending limits are reached around 2040, synthetic methane (or methanated renewable hydrogen) becomes the cheapest resource, expected to become cheaper than CCIs and WA allowances in later years in the planning horizon.

For compliance with the Washington Cap-and-Invest program the results show offsets are expected to be the lowest cost compliance option, and if compliance offsets can be procured at prices seen in today's market, they should be acquired to the maximum amount and used for compliance. There is still work that needs to be done to understand what offsets might be available on tribal lands and what they might cost, but if these can be procured at a price lower than the expected price of allowances they would also be acquired for compliance. Allowance purchases show as the lowest cost option to fill in the remaining compliance need over the first compliance period (2023-2027), even if allowance prices are at the price ceiling currently detailed in the draft rule. As such, a strategy of purchasing allowances in the quarterly auction adjusting in real time to load expectations and weather over the compliance period is a strategy that is robust across scenarios.

7.6 Monte Carlo Outcomes

The scenarios provide key insights into how a particular set of inputs can change the outcomes of resource planning. In fact, many key inputs, such as weather, are held constant across all the scenarios to isolate impacts from other key demand-side or supply-side inputs. While the scenario results are very informative, it is certain that the future will not mimic any single scenario. We know that weather will fluctuate from one year to the next, key demand drivers are subject to policy changes, efficiency and technology gains will ebb and flow, and prices and availability for all resources will rise and fall. Therefore, we generate 500 Monte Carlo draws for the key uncertainties as discussed earlier in this chapter (Table 7.4).

The PLEXOS® model imports data files containing these 500 draws for demand, resource prices, and uncertain quantity limitations. The model produces a unique solution for each draw.[152] While the simulation for the inputs has been discussed throughout the IRP, this section presents the outcomes from the PLEXOS® solutions.

7.6.1 Capacity Resource Acquisitions

Table 7.5 summarizes the capacity resource acquisitions across all draws. As anticipated, Mist Recall is the marginal capacity resource selected in the near-term for 99% of the draws. Mist Recall has been the marginal capacity resource for NW Natural for several IRPs now as Mist Recall is relatively cheap capacity and comes with additional storage capacity, which provides ancillary benefits for customers. Given the demand simulations and their implications on peak day demand, only 4% of the draws require an additional capacity resource beyond Mist Recall. In other words, Mist Recall is sufficient to meet customer peak energy requirements over the planning horizon.

Table 7.5: Capacity Resource Monte Carlo Acquisition Summary

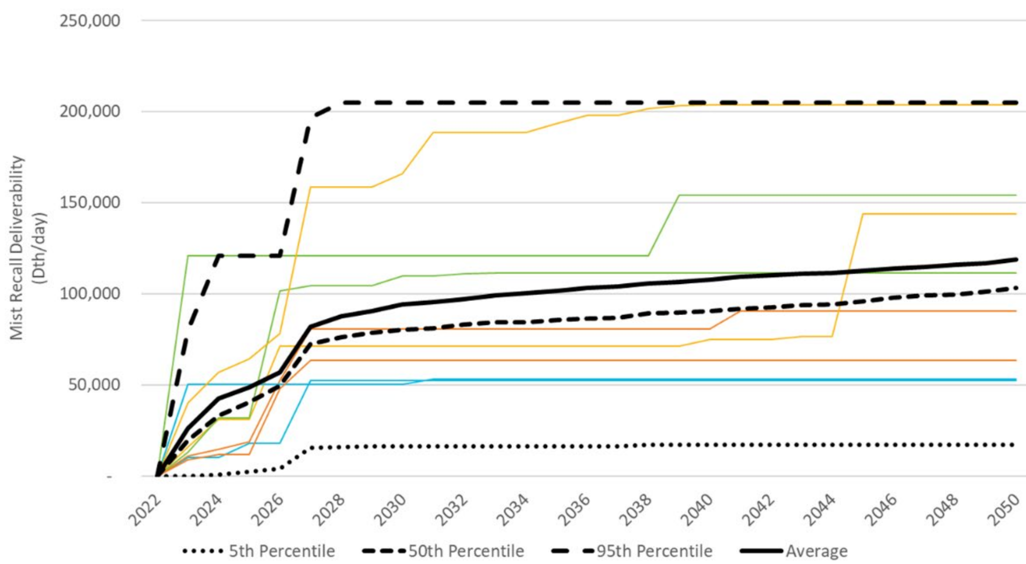
Capacity Resource	Number of Draws where Resource is Selected	If Selected Average Year
Some Mist Recall	496	2023
All Mist Recall	144	2036
Mist Expansion	17	2037
Newport Takeaway 1	21	2036
Newport Takeaway 2	9	2044
Newport Takeaway 3	6	2046
Interstate Pipeline Capacity	3	2043
Portland LNG Cold Box	500	2027†

† Portland LNG Cold Box or an alternative must be selected in 2027

[152] These solutions are not a single data point, but contain a lot of daily data for the system, such as daily conventional gas purchases, daily storage operations, annual capacity resource acquisitions, compliance resources acquisitions, upstream pipeline capacity factors, daily demand, etc…

NW Natural's resource stack is *storage heavy* relative to most other gas LDCs. If the ratio of storage assets to pipeline capacity contracts becomes too lopsided, resource acquisitions could be driven by energy requirements. In other words, given the daily maximum deliverability of pipeline capacity and injection limitations of the storage facilities, there is a threshold where there are simply not enough days in the year to fill up storage capacity as needed to serve load the following winter. As the other resources are generally not selected until after Mist Recall is exhausted, these results suggest that the Company is still well under that storage to pipeline capacity ratio threshold. Figure 7.5 summarizes the results for Mist Recall across the Monte Carlo draws.

Figure 7.5: Monte Carlo Mist Recall Acquisition



From Scenario 6 – *Full Building Electrification*, we see that under reference case prices and costs, Alternative 4 (*Decommission Portland LNG and Complete No Replacement Alternative*) is a least cost and viable solution. Scenario 6 is a bookend case where every piece of natural gas end-use equipment (furnaces, stoves, water heaters, etc.) is replaced with electric appliances beginning today. However, using the 500 simulations, which mixes and matches variation in weather, demand trajectories, and resource costs, 100% of the draws select Alternative 1, keep Portland LNG operational by investing in a new Cold Box.

7.6.2 Compliance Resource Acquisitions and Purchases

Variation in year-over-year weather, uncertainty in the long-term trajectories for demand, the availability of RNG, uncertainty in the limits of hydrogen, and changes in the costs for compliance resources all impact the amount and timing of compliance resource acquisitions. Figure 7.6 summarizes least cost portfolios of RNG compliance resources across all the Monte Carlo draws. Figure 7.7 summarizes the least cost purchases of compliance instruments (CCIs, allowances, and offsets) for compliance with the CPP and CCA.

Figure 7.6: Monte Carlo RNG Compliance Resource Acquisition

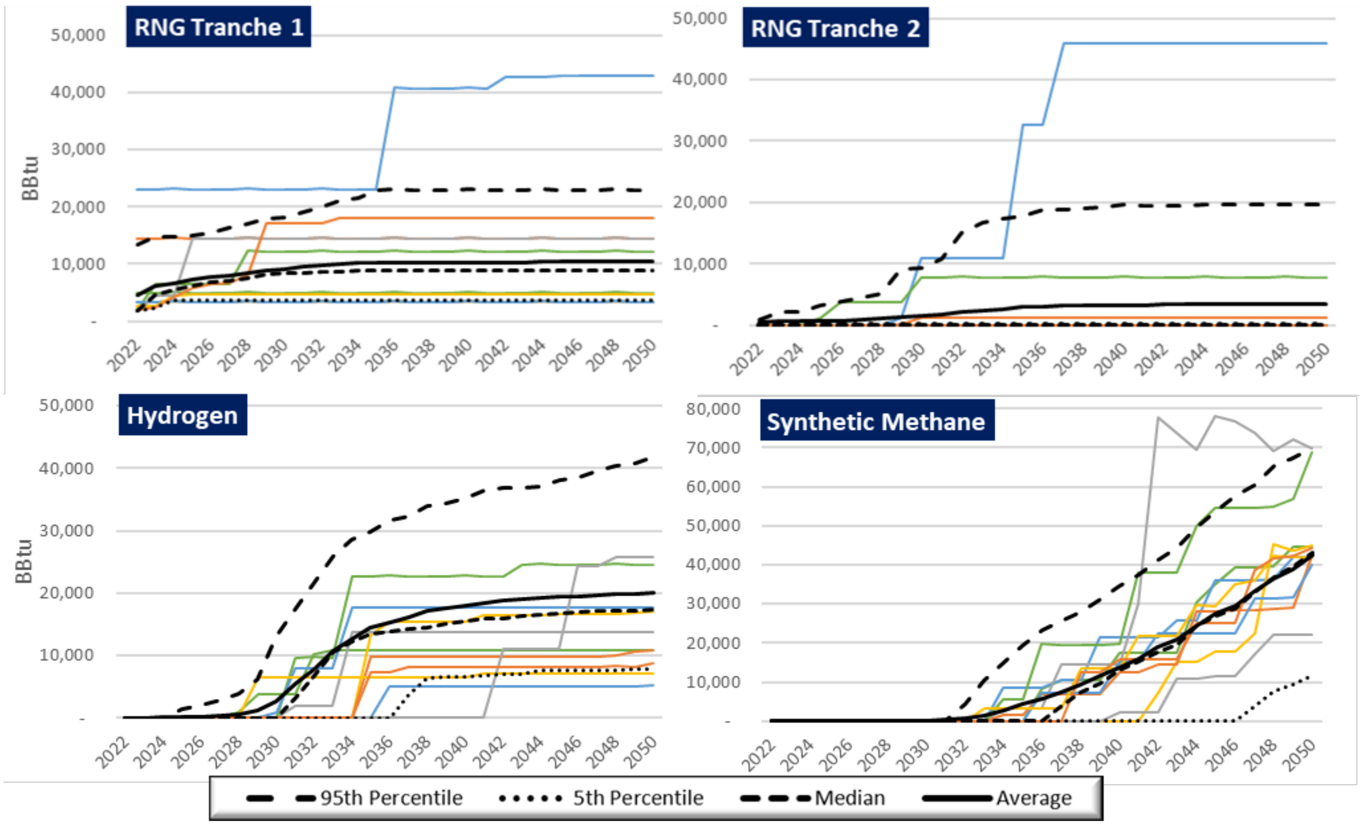
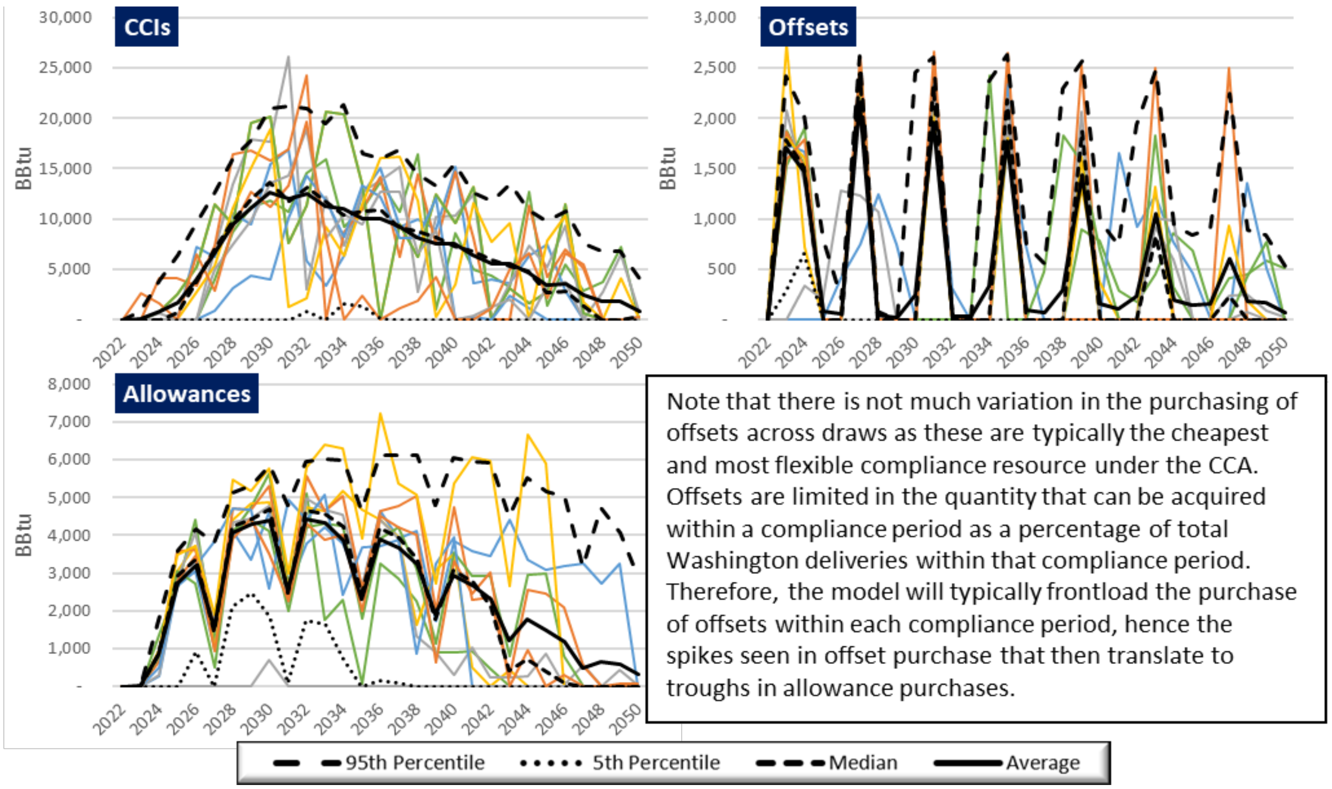


Figure 7.7:Monte Carlo Compliance Instruments Purchases



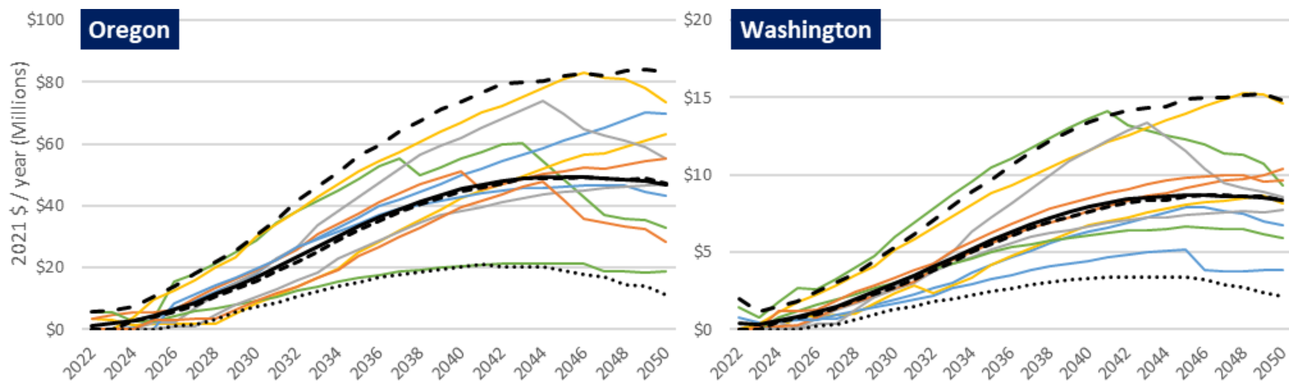
From these results, where the resource planning optimization model selects an average of roughly 5 million Dth of RNG Tranche 1 in the near-term over 500 potential different futures. Hydrogen becomes a significant part of the compliance strategy in the future, but rarely is it selected prior to 2028. Synthetic Methane sees a similar result but is never selected in any draw prior to 2031. Resources that would be represented by the costs and quantities of RNG Tranche 2, generally are not ecumenical over the planning horizon. Of course, NW Natural will be conducting IRPs every few years and as the RNG and hydrogen markets mature we will update cost and availability information as the future unfolds.

Compliance instruments, CCIs, offsets, and allowance purchases are relatively flexible compared to RNG acquisitions and can be used to *fill-in* compliance gaps due variations in weather from one compliance period to the next. Due to this flexibility instruments are often frontloaded or backloaded within a compliance period. This presents as a less smooth and more jagged purchasing strategy relative to the RNG compliance resources. Note that CCIs and allowance purchases see a *hump* shape over the planning horizon. Purchases of these instruments ramp up in the planning horizon but begin to drop off in the future.

7.6.3 Demand Reduction Investments

Demand reduction investments represent incremental investments relative to the reference case that are used for complying with emissions reduction policy. These investments may include incentivizing hybrid heating systems, gas-fired heat pumps, or expanding existing or planned energy efficiency programs.

Figure 7.8: Demand Reduction Investment Totals

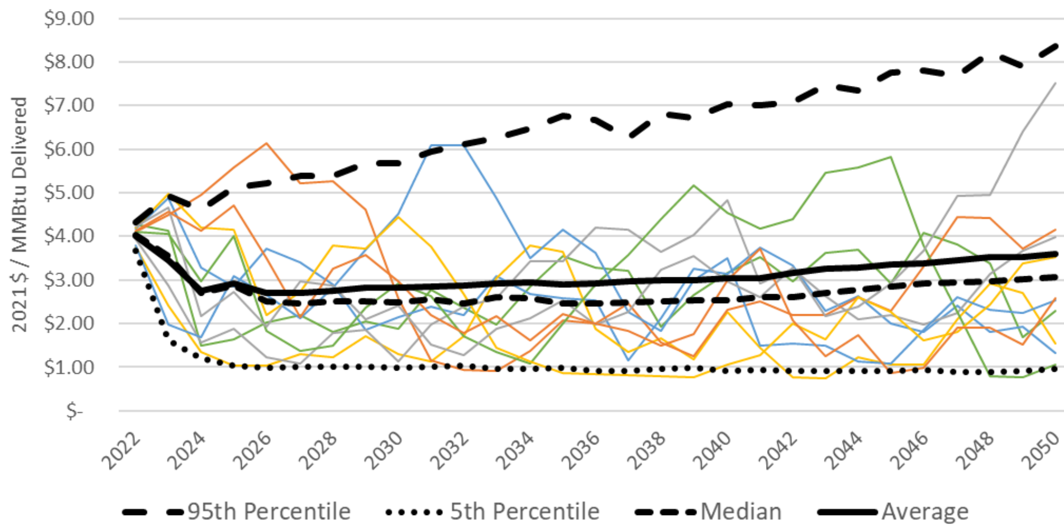


7.6.4 Weighted Average Cost of Gas

The overall gas price environment is stochastic over time, but prices at individual hubs are also stochastic.[153] When NW Natural purchases gas on the behalf of customers, there are variable shipping costs associate with each MMBtu purchased be depending on where the gas bought and what upstream pipelines it must travel along to reach NW Natural service territory. The PLEXOS® model solves the optimal purchasing portfolio or dispatch of gas contracts inclusive of these variable charges. The total dollar amount spent on gas and variable charges in a year divided by the total MMBtus purchased is the weighted average cost of gas (WACOG). Figure 7.9 summarizes the WACOG that is the output of the PLEXOS® optimization across all resources.

[153] See Chapter 2 for details about natural gas price uncertainty.

Figure 7.9: Monte Carlo WACOG



7.6.5 Weighted Cost of Decarbonization

By looking the quantity of the individual resources acquired that decarbonize the gas system and multiplying those quantities by their respective costs, the Monte Carlo simulation provides the insight into the potential range of costs to decarbonize. We can bucket these costs into three distinct groups, costs from RNG resources acquired, costs from compliance instruments and costs from demand reduction investments. The weighted costs of decarbonization (WACOD) is calculated to summarized the resources that are in these three buckets as illustrated by Figure 7.10, Figure 7.11, and

Figure 7.12. The total WACOD for each state is the sum of these buckets, shown by Figure 7.13.

Figure 7.10: Monte Carlo WACOD from Renewable Compliance Resources

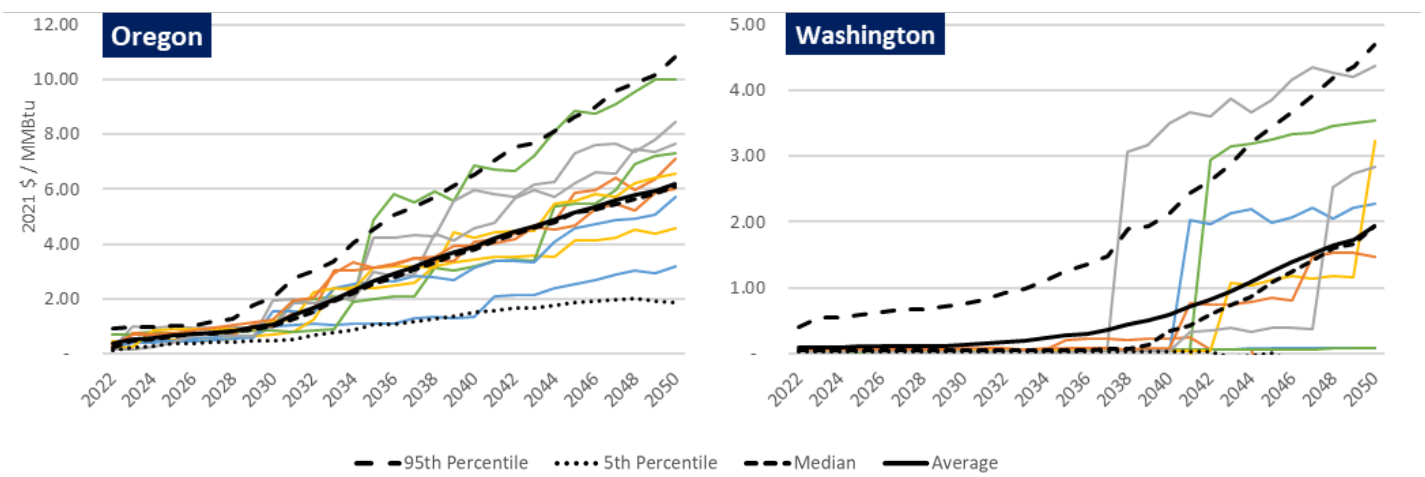


Figure 7.11: Monte Carlo WACOD from Compliance Instruments

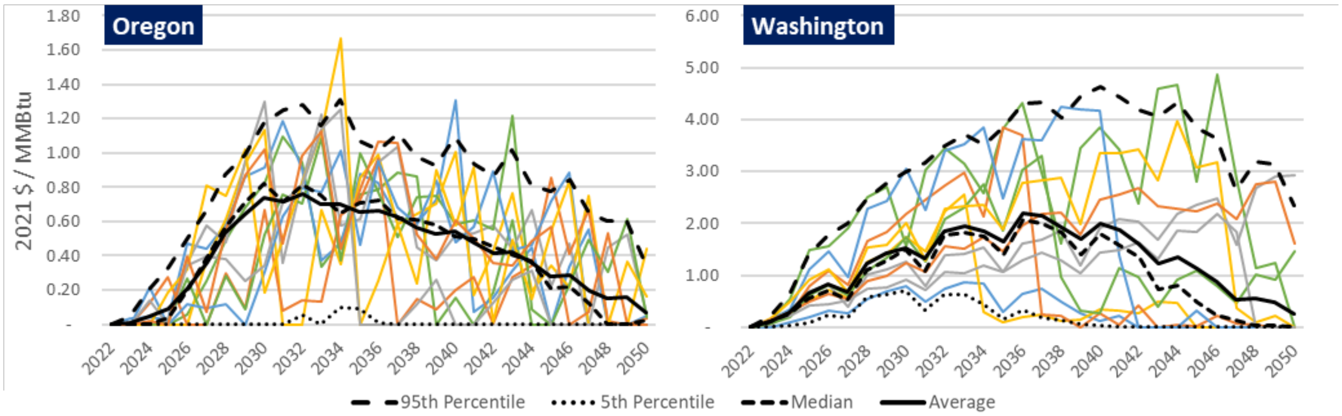


Figure 7.12: Monte Carlo WACOD from Demand Reduction Investments

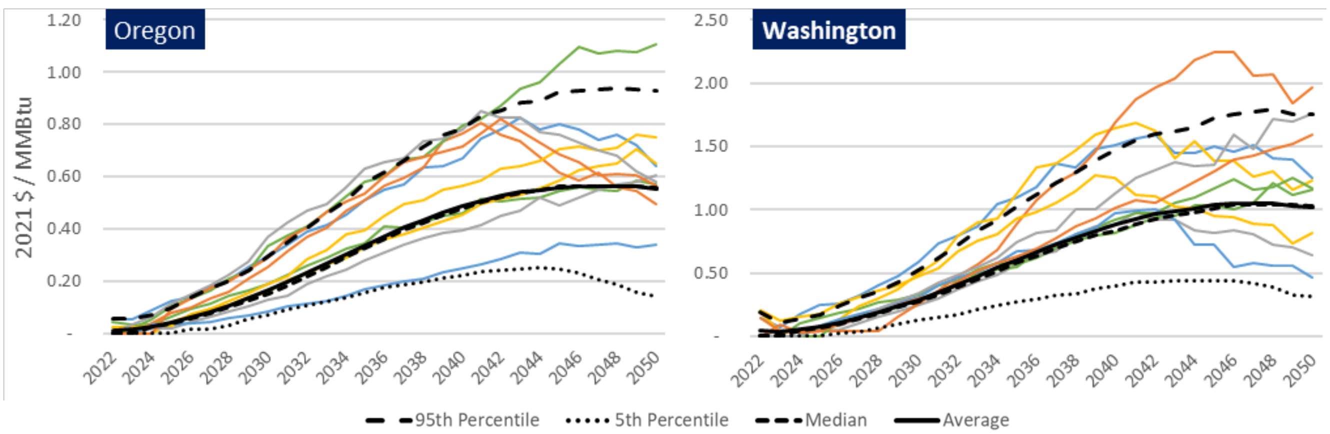
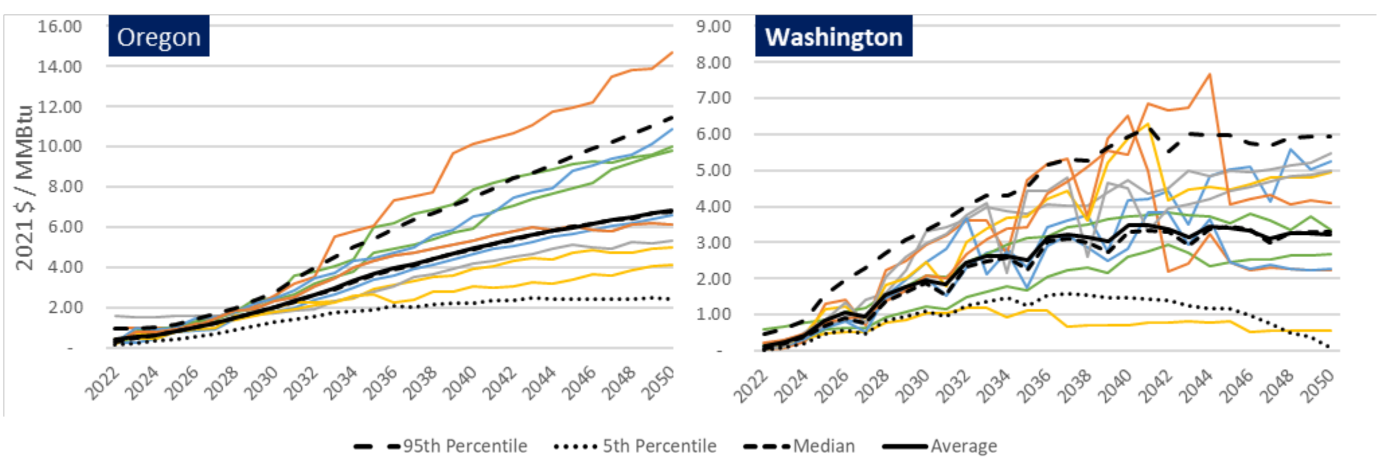


Figure 7.13: Monte Carlo Total WACOD



7.7 Preferred Portfolio and Analyzed Risk

This section has been added as an addendum to the 2022 IRP in response to stakeholder comments to further clarify the nuances of a preferred portfolio in comparison to an expected resource acquisition path. To provide structure for this clarification, we propose a set of definitions to clarify critical terms used in the IRP.[154]

Scenario – a set of specific model input assumptions that describe one potential future over the planning horizon. Scenario input assumptions focus on a small sub-set of input assumptions to stress test the impact to resource acquisition from changes in targeted assumptions (e.g., extremely high levels of electrification). See Table 7.36: 2022 IRP Scenarios for a summary of these input assumptions.

Monte Carlo Draw – a single set of input assumptions that are simulated through a stochastic process that describe one potential future over the planning horizon**.** This IRP simulates 500 sets of input assumptions and uses the PLEXOS® tool to optimize resource selections for each of the 500 draws.

Sensitivity – a variation or several variations of additional input assumptions that were not a part of the focused subset for a given scenario. If input assumption values from the scenario are within the range of the values produced from the Monte Carlo stochastic simulation, then given enough Monte Carlo draws, approximate results for a sensitivity can be obtained from the Monte Carlo results.

Portfolio – the least cost portfolio of system capacity resources and system compliance resources acquired over the planning horizon as an output of demand-side management modeling and the PLEXOS® cost-minimization modeling. A portfolio is a least-cost output for each scenario and Monte Carlo draw. Note that a single portfolio is only a least-cost portfolio (i.e., not least-risk) for the given inputs into the least-cost modeling.

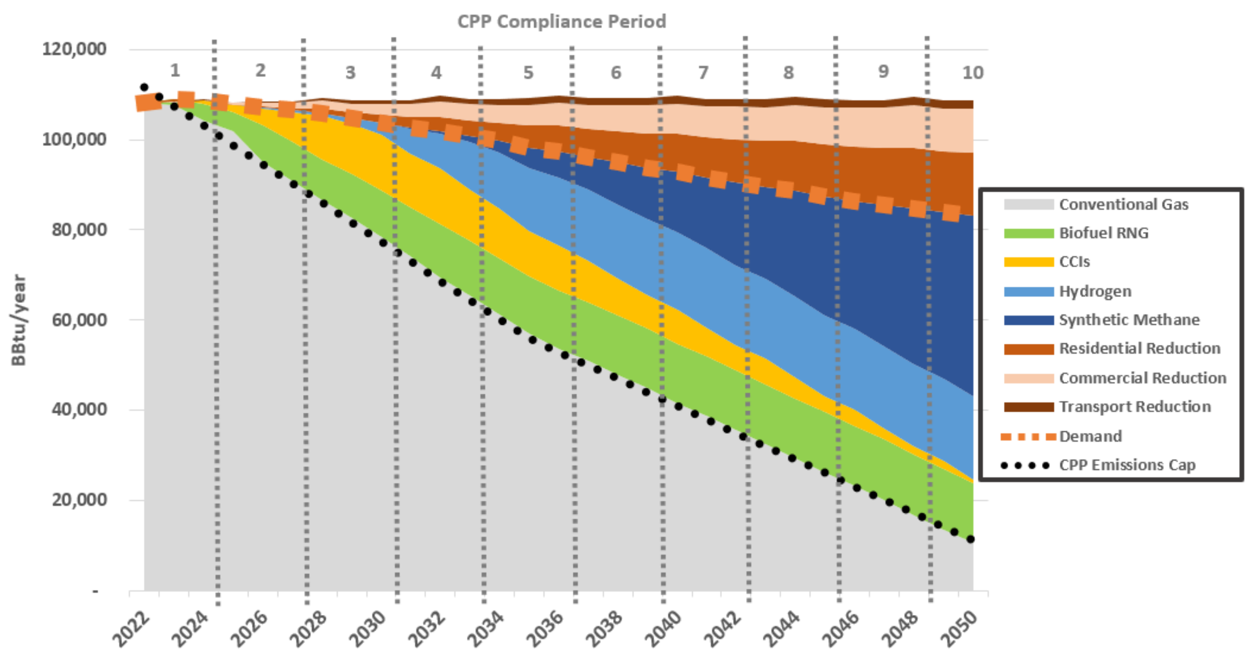
7.7.1 Oregon Preferred Compliance Portfolio

To account for uncertainty in the current environment and avoid selecting a single scenario and the corresponding set of scenario input assumptions upon which to base expected resource acquisitions, the average result across the 500 Monte Carlo stochastic simulations process represents the middle- and long-term preferred portfolio for environmental compliance by state. The load associated with the preferred portfolio is the state specific average of the 500 draws that is shown in Figure 3.40. This load is derived from a combination of electrification, customer-funded investments in incremental energy efficiency measures, and emerging technology deployment (see Figure 3.37 and Figure 5.26 for the Monte Carlo of customer count forecasting and total deliveries, respectively). These load forecasts are then input into the PLEXOS® model to determine the lowest cost combination of emissions reducing gas supply resources (i.e., biofuel RNG, hydrogen, and synthetic methane as shown in Figure 7.6) and

[154] These definitions are set in context of how NW Natural defines each term for this IRP and may be defined differently by other stakeholders or in other forums.

compliance instruments (CCIs) for each stochastic draw. The average of the results across these 500 draws for each emissions reducing gas supply resource and for CCIs represents the amount of the resource in NW Natural's preferred portfolio for environmental compliance with SB 98 and the CPP in the middle and long-term. For example, the average hydrogen acquisition shown in the bottom-left graph of Figure 7.6 represents the amount of hydrogen in the preferred portfolio.[155] The preferred portfolio combines these averages across the Monte Carlo simulation process for each resource and is shown in Figure 7.14:

Figure 7.14: Oregon SB 98 and CPP Compliance Preferred Portfolio



As such, the preferred portfolio accounts for risk by recognizing that more or less of each of the compliance resources could be deployed through time depending on relative costs, availability, and external factors like levels of electrification. Note that the preferred portfolio is distinct from the reference case and from each of the nine Scenarios discussed in this chapter, though its results are informed by all of these Scenarios as they were used to help define the distributions that drive the results of the Monte Carlo process.

While the average result across the stochastic risk analysis for each compliance resource makes up the preferred portfolio for the medium-and long-term, the results of the stochastic process are assessed for risk slightly different in the near-term period. The near-term period is defined as the period covered in the Action Plan that requires action before anticipated resolution of the next IRP; for this IRP that is through the year 2025. The near-term preferred portfolio also utilizes the Monte Carlo results but

[155] Noting that Figure 7.6 shows the acquisition for both Oregon and Washington, where the preferred compliance portfolio is state specific and the average across results across the Monte Carlo draws for Oregon represents the amount in Oregon's preferred portfolio for environmental compliance.

applies a risk-averse strategy relative to emissions reducing gas supply while accounting for uncertainty in demand for the first compliance period of the CPP (years 2022 through 2024).

In the near-term all 500 draws utilize the Energy Trust of Oregon forecast (see Action Item 4) and small amounts of varying energy efficiency savings from a new expected program for transport schedule customers (see Action Item 6). These energy efficiency forecasts along with varying amounts of customer additions or losses across draws are combined with the biggest source of variation in load (and subsequently potential emissions) in the near-term: weather.

In the long-term the number of customers and their equipment choice is the primary driver of variation in load. However, given that large changes from the current customer count cannot materialize over a short timeframe, year-to-year variation in weather is the primary driver of load uncertainty in the near-term. This variation in load across draws results in varying amounts of RNG acquired to meet SB 98 targets in each draw as well as varying amounts of CCIs to fill an any additional need for CPP compliance in the first and second compliance periods. In the vast majority of draws, biofuel RNG is selected as the resource to meet SB 98 targets in the near-term. Given the requirements of the CPP program and NW Natural's current emissions profile, in most draws the RNG acquired to meet SB 98 targets also represents the majority of incremental emissions reduction[156] activity required to meet CPP compliance in the first compliance period.

Table 7.6 shows the distribution of load resulting from the Monte Carlo process on weather, customer counts, electrification, and energy efficiency as well as the distribution of RNG and CCIs that resulted from the resource optimization modeling completed in PLEXOS® to satisfy SB 98 targets and CPP compliance across stochastic draws:

Table 7.6: Oregon Short-term Preferred Portfolio Development

Figures in Dth		Average	5th Percentile	10th Percentile	90th Pecentile	95th Percentile
2023	Sales Load	72,837,981	68,459,380	69,560,982	76,510,298	77,155,353
	Transport Load	36,033,359	35,863,203	35,894,043	36,174,137	36,205,421
	RNG	1,116,000	1,116,000	1,116,000	1,116,000	1,116,000
	CCIs	-	-	-	4,041,034	5,334,371
2024	Sales Load	72,720,165	68,152,609	69,099,053	76,099,162	77,311,682
	Transport Load	35,872,897	35,534,141	35,595,538	36,153,167	36,215,449
	RNG (5% of Sales)	3,636,008	3,407,630	3,454,953	3,804,958	3,865,584
	CCIs	1,862,049	-	-	5,352,366	6,566,542
2025	Sales Load	72,446,324	67,451,596	68,584,585	76,387,887	77,103,329
	Transport Load	35,392,122	34,881,412	34,984,774	35,791,213	35,919,295
	RNG (6% of Sales)	4,346,779	4,047,096	4,115,075	4,583,273	4,626,200
	CCIs	4,692,287	-	654,905	8,796,447	9,597,046

[156] in addition to ongoing energy efficiency programs for sales customers and expected programs for transport schedule customers.

Considering the results above and that 1) CCIs provide covered parties in the CPP program flexibility in how and when they can be acquired for compliance, and 2) if SB 98 targets are acquired there is no risk in needing more CCIs than are allowed by the CPP program for compliance in the first compliance period (Action Item 7), a risk-averse approach can be deployed in terms of how to set SB 98 RNG acquisition targets and ensure compliance with the CPP. With this background, and to align with the realities of acquiring RNG, the preferred portfolio of the period covered by the Action Plan takes the 10th percentile of RNG across the Monte Carlo draws and rounds up to the nearest 100,000 Dth (resulting in Action Item 5). This approach is a low regret path forward in the current environment given that 1) there is little risk that too much RNG will be acquired relative to SB 98 targets, 2) a rounded number can be used for the RNG acquisition target, and 3) CCIs can be purchased as needed to fill in compliance gaps as necessary depending on the load that materializes. This results in the near-term preferred portfolio for compliance in Oregon being 3.5 million Dth of RNG in 2024 and 4.2 million Dth of RNG in 2025. By taking a risk-adverse approach, we are lowering the potential of acquiring more emissions reductions from biofuel RNG (and incurring more costs) than could ultimately be required for compliance in the first compliance period.

Chapters 2 through 7 focus on ensuring that we have enough resources to get enough energy on our gas grid every day of the year. Chapter 8 is like its own mini IRP and discusses how we determine needs and options to distribute that gas on so each customer can be served reliably during any weather we could reasonably expect.

8 | Distribution System Planning

8.1 Introduction

Distribution System Planning is an IRP unto itself. It requires a very similar process of identification of needs at the distribution level, identification of resources on both demand-side and distribution supply-side, and then a risk-adjusted resource selection. Some of the unique aspects of distribution system planning include:

- Demand: Forecast peak hour usage for the area in question net of demand-side actions
- Supply: Model distribution system based on actual pipeline alignments and specifications
- Modeling: Use of different software/modeling tools to simulate system under peak conditions and/or use field measurements during cold periods
- Apply system planning criteria to identify areas of concern before planning criteria are exceeded – Ongoing field monitoring of pressures and customer growth informs which areas to investigate

As discussed in TWG No. 5, Distribution System Planning, NW Natural is transitioning from a “just-in-time” distribution system planning process based upon measured criteria violations to a forward-looking distribution system planning process, which will anticipate criteria violation further into the future. Moving from a “just-in-time” to a forward-looking distribution system planning process allows NW Natural to incorporate more non-pipeline demand-side solutions as viable options as these projects take longer to implement and produce reliable peak load reductions. This transition was initiated with NW Natural’s Geographically Targeted Energy Efficiency (GeoTEE) pilot and has been a lengthy transition over several years. Once complete and implemented, the process will continue to evolve and improve as we collect more data and adapt to changes in customer usage profiles.

With the transition to a forward-looking distribution system planning process, NW Natural is improving its system modeling. A key component of the system modeling is incorporating a Customer Management Module (CMM) into the Company’s pressure system modeling software, Synergi™. CMM provides a link between NW Natural’s Geographical Information System (GIS), Customer Information System (CIS), and Synergi™ and is discussed in detail in Section 8.3.2. Incorporating this significant improvement across NW Natural’s entire service territory is expected to be completed by the end of 2023.

NW Natural’s engineering department annually reviews and updates a 10-year plan for larger projects. The 10-year plan provides budgetary forecasts and a company-wide vision and prioritization to the distribution system planning process and the process itself is discussed in more detail below. The 10-year plan outlines potential improvements for the system, from which NW Natural selects projects from for inclusion in the IRP based on estimated cost, system prioritization needs, supply implications, as well as timing considerations related to the IRP. With the system process improvements with CMM underway but not yet complete, NW Natural is not including the 10-year plan with the 2022 IRP as the completion of the CMM improvement could significantly change the prioritization of projects on the current 10-year plan. Improvements in pressure modeling may indicate areas under observation that are more of a concern or, vice versa, indicate that constrained areas are not as critical as previously modeled. Upon the completion of new Synergi™ models, NW Natural will file a 10-year plan through an IRP Update. We note here that the single distribution system project put forth in the action plan for this IRP is in an area already incorporating the CMM module. Due to the improved modeling, NW Natural was also able to remove another distribution system project that had previously been identified for evaluation in the IRP.

The rest of this chapter discusses NW Natural's distribution system planning process and includes an overview of our needs assessment process and tools including our improved engineering and computer modeling methods that allow for more forward-looking distribution system planning. This is followed by a discussion about our distribution system resources, both existing and future options in addition to pipeline and non-pipeline solutions. The chapter concludes with the identification and discussion of a distribution project included in the action plan.

8.2 Distribution System Planning Process

NW Natural's distribution system planning process ensures that NW Natural:

- Operates a distribution system capable of meeting firm service customers' peak hour demands
- Minimizes system reinforcement costs by selecting the most cost-effective alternative
- Plans for future needs in a timely fashion
- Addresses distribution system needs related to localized customer demand

The goals of distribution system planning are to identify any shortfalls of the distribution system to meet the needs of current firm service customers' gas needs under peak hour conditions[157] and for any new projects, either demand-side or supply-side projects, will be able to serve both current and future firm service energy services. Distribution system planning identifies operational problems or constrained areas in the Company's service territory and develops solutions to address those weaknesses on the system. By knowing where and under what conditions pressure problems may occur, NW Natural can incorporate necessary projects into annual budgets and project planning thereby avoiding costly reactive and potential emergency solutions.

NW Natural collaborates with marketing departments, large customer account representatives, construction crews, external economic development and planning agencies, energy efficiency program administrators and, engineering design and construction firms to develop feasible and reliable solutions. Typical *pipeline* solutions include various forms of reinforcement, replacement, or expansion of NW Natural's distribution system facilities. *Non-pipeline* solutions can be either supply-side

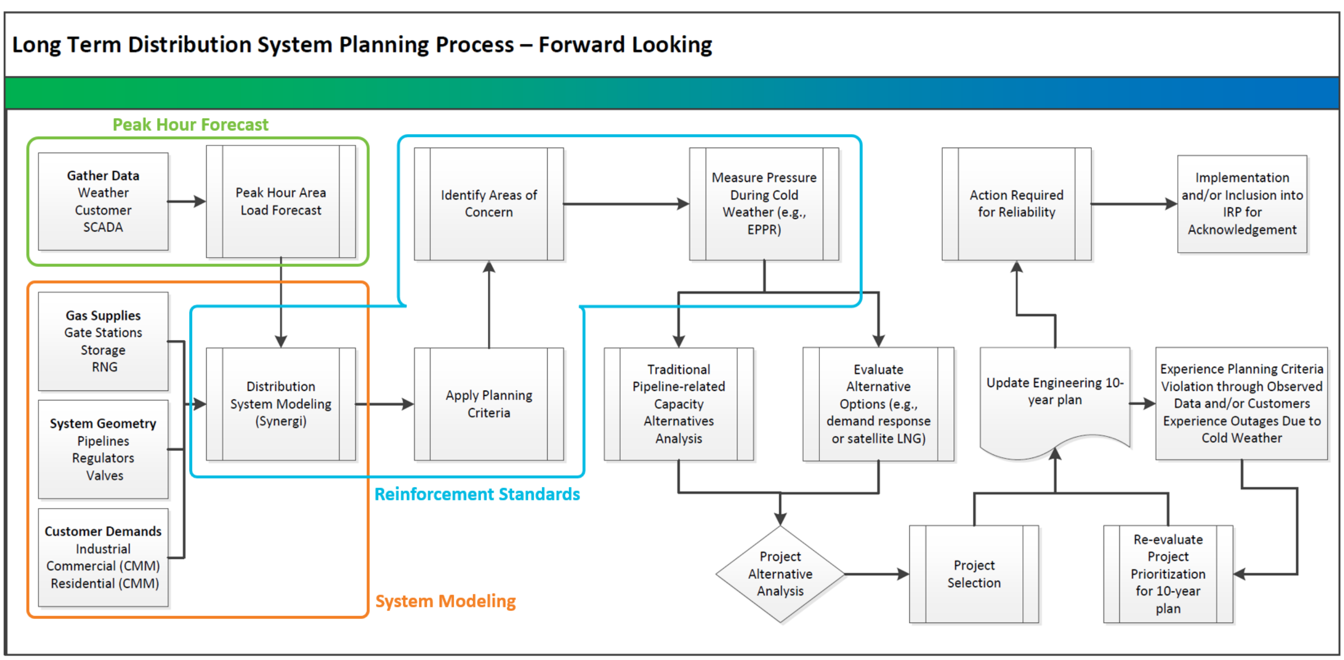
[157] NW Natural uses a peak hour standard for distribution system planning, as usage by firm service customers over a 24-hour period in colder weather has a diurnal pattern that includes an hour in which use is maximal. NW Natural discussed its peak hour standard with stakeholders in the fifth Technical Working Group meeting.

solutions, for example deployment of a mobile CNG supply vehicle, or demand-side solutions, for example geographically targeted interpretability agreements. The costs, timing and reliability varies across each of these options for distribution system planning and the suite of these options is discussed later in this chapter.

Ultimately, distribution system planning follows the same process as the planning for our system resources (see Chapter 8 cover page). The first step requires determining resource need. This starts with forecasting customer peak hour demand, determining potential distribution system constraints based on the existing system, analyzing potential solutions, and assessing the costs and risks of viable alternatives. Planning is ongoing and integrates the requirements associated with known public works projects, customer growth, and other aspects into NW Natural's construction forecasts.

Distribution system planning uses a pressure modeling software, Synergi^{TM}, to model pressure dynamics of actual pipe placement, specifications, and geographic location; along with peak hour usage estimates for the area in question (net of expected energy efficiency savings and demand response resources). Essentially this simulates the system under peak conditions; calibrates this simulation with actual field measurements during cold periods; and applies system planning criteria to identify areas of concern before such planning criteria would be violated by realized peak conditions. Figure 8.1 presents a flow diagram for the distribution system planning process.

Figure 8.1: Distribution System Planning Process



As discussed in the introduction section of this chapter, NW Natural develops a 10-year distribution system plan that outlines areas of the distribution system under observation. These areas are being monitored based on distribution system modeling under peak conditions, where system reinforcement standards are nearing violation.[158] In addition to identifying areas for cold weather observation, the 10-year plan outlines the best (i.e., least-cost least-risk) pipeline solution for each geographic area being monitored[159]. For simplicity, the company prioritizes areas into near-term, medium-term, and long-term evaluations.

Near-term - For areas facing a near-term potential criteria violation (1-to-3-year timeframe), NW Natural completes a planning process that documents the system modeling process and modeling results, identifies the best feasible pipeline solution, estimates the associated high-level cost estimates, and includes an analysis of non-pipeline alternatives, which we discuss later in this chapter.

Medium-term - For areas being monitored that are forecasted to need some action within a 4-to-7-year timeframe NW Natural develops viable pipeline project designs, preliminary modeling documentation, preliminary schedule, and high-level cost estimates.

Long-term - For areas on our radar for needing some action within the 8-to-10-year timeframe NW Natural develops preliminary modeling documentation and a high-level cost estimate for potential pipeline solutions. Project planning associated with issues having this timeframe for resolution is at the conceptual level only and discussion of such projects would not typically included be included in an IRP unless significant investments are indicated.

Depending on the scope, magnitude of the investment, or the lead time needed to implement a pipeline solution; any project on the 10-year plan may be included for a full IRP evaluation. Generally, this happens to be the higher priority near-term violation areas being monitored. However, regardless of the lead times needed implement a distribution system solution (either demand-side or supply-side), detailed cost and risk assessments, along with a robust alternatives analysis are conducted for any solutions that would be included into an IRP Action Plan.[160]

8.2.1 Forecasting Peak Hour Load

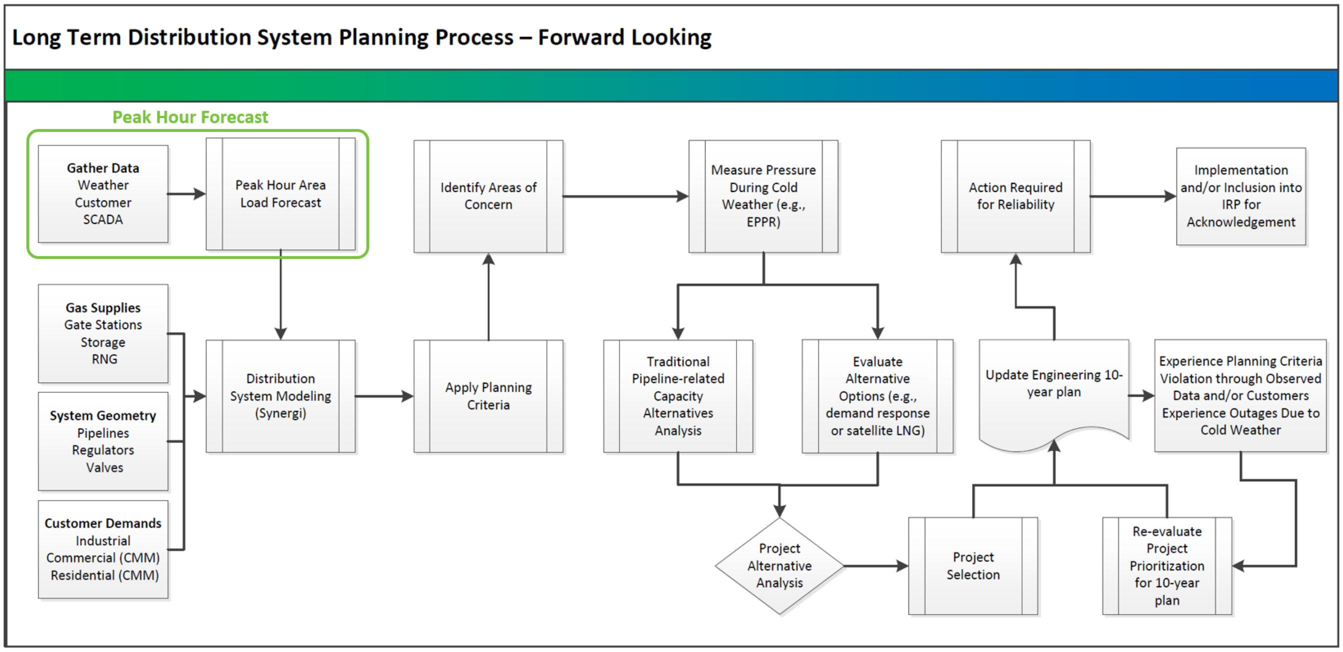
As can be seen in

Figure 8.2, determining peak hour load/demand is a critical part of distribution system planning as it establishes the minimum criterion for meeting customer needs. Firm service peak hour load

[158] See Chapter 8, section 8.3.3 for a discussion of system reinforcement standards.
[159] As explained later in this chapter, this also signals an analysis of non-pipeline alternatives as well.
[160] The burden is on NW Natural to decide which projects are brought through the IRP as action items for consideration.

predictions are the standard which must be met by the Company's distribution system capacity resources for each area of our system.

Figure 8.2: Distribution System Planning Process – Peak Hour



Just as NW Natural's peak day load forecast informs our system capacity resource planning, geographically specific peak hour load forecasting provides an input into distribution system planning. Peak hour forecasts augment the daily system load model process with forward-looking, statistically derived forecasts of hourly load in specific areas of NW Natural's service territory. NW Natural included peak hour load forecasts in its 2016 IRP process,[161] redefined its peak planning standard for both peak day and peak hour forecasts in the 2018 IRP and has applied the same peak planning standard in the 2022 IRP. NW Natural monitors, updates, and works to improve NW Natural's peak load forecast models and aspires to synchronize and adapt its peak hour load modeling process to optimally support an overall transition to a fully forward-looking distribution system planning process.

8.2.2 Estimating Peak Hour Load

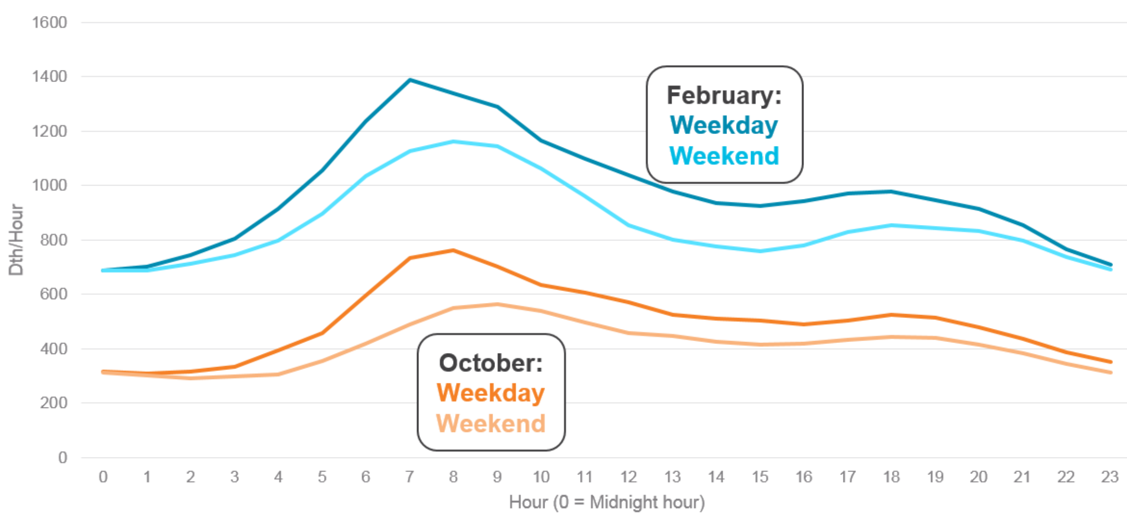
The peak hour modeling methodology generally follows that of the peak day forecasts while incorporating more granular geographic and time dimensions. Regression analysis is used to establish the statistical relationships between measured firm sales and firm transportation load in a given area with local weather variables—temperature, wind, sunshine, source water temperature, and snow depth—as well as customer counts, day of the week, holiday occurrences, and time trends. Because distribution system planning involves relatively small geographic areas, peak hour load forecasts use

[161] See Chapter 3 and Appendix C in NW Natural's 2016 IRP.

similarly localized input data—weather and customer counts, for example. These regression models also derive historical relationships between hourly geographic load and global variables (such as holiday occurrences) that do not vary across locations.

One of the primary differences between peak hour and peak day models is the presence of time-of-day effects. The intraday load shape of the natural gas system typically exhibits an early morning peak followed by a midday taper, before a smaller peak in the late afternoon (see Figure 8.3 as an example). The morning peak is dependent on the day-of-the week and is typically lower and later in the day on weekend days.

Figure 8.3: Hood River Area Intraday Load Shapes



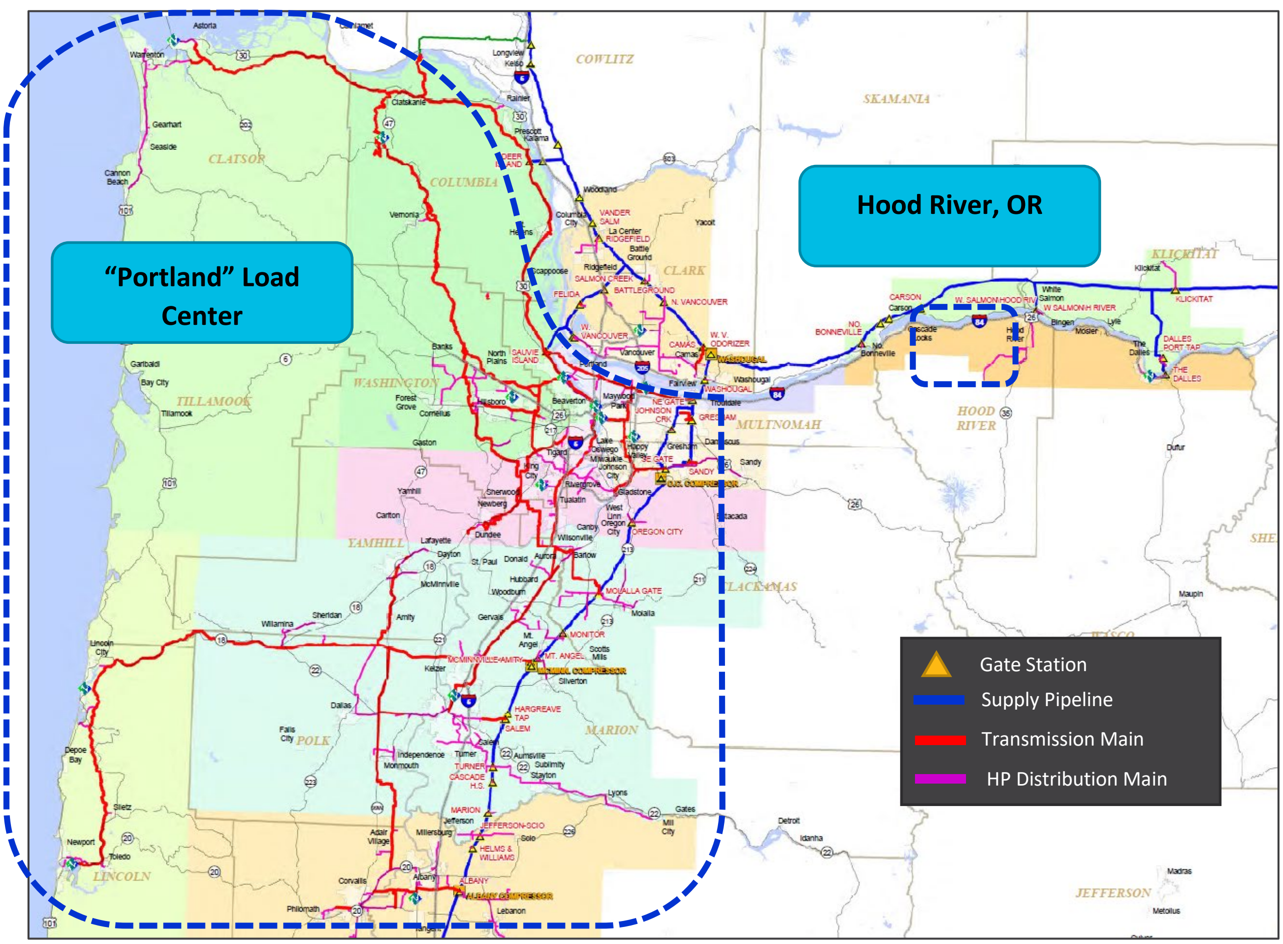
Temperature alters hourly effects, as it does the effects of other weather variables.[162] When temperatures stay cold on average throughout the day—on dark, wintry days in February, for example—the intraday load shape is less pronounced than one during the shoulder season, when midday high temperatures diverge further from nighttime lows and space heating needs fluctuate more substantially. To capture these nuanced dynamics, peak hour load models incorporate effects that are specific to the hour and day of the week (i.e., 72 indicator variables for each hour of a weekday, Saturday, and Sunday), which interact with temperature.

The second unique feature that differentiates peak hour load from peak day load is the narrower geographic relevance of the former concept. Whereas load on a peak day defines the resource capacity required to ensure that adequate gas resources be delivered on NW Natural's system, the ability to deliver gas to customers at any moment depends on very specific segments of NW Natural's distribution system, as outlined earlier in this chapter. Thus, area-specific hourly load and granular weather data is required in place of the system-level inputs of the peak day model. Although gas

[162] For a full discussion of load forecasting variables and their interactions, please see Chapter 3, Resource Needs.

demand must be met in any given instant, the time dimension granularity is constrained to hourly due to data limitations.[163] The geographic granularity of peak hour modeling is constrained by the availability of data. For example, the area served downstream of the Hood River, Oregon, gate station Figure 8.4 represents a “system within a system” along a single distribution main, where hourly flow measured at the gate station can be isolated from the rest of NW Natural’s distribution system. In contrast, customers in the broader Portland, Oregon, metropolitan area draw gas past multiple SCADA meters at receipt points that also serve other areas of the distribution system (as distant as Salem, Oregon), making it impossible to isolate the hourly load of just those customers within a given neighborhood within the metro area.

Figure 8.4: Hood River and Portland, Oregon, Distribution Systems



At this time, most of NW Natural’s distribution system is oriented and metered more like the Portland metro area than like Hood River. Hood River’s internal interconnectivity, while necessary and beneficial

[163] High frequency meters for customers on interruptible or transportation rate schedules record hourly flows. Additionally, weather data is at best available on an hourly frequency. Hourly data is sufficient for the needs of the distribution system planning process.

from an operations standpoint, limits the ability to isolate small areas for econometric load forecasting. A summary of peak hour load standards and latest available forecast for the feasible portions of the NW Natural distribution center follows in the next section.

8.2.3 Peak Hour Loads

Generally, the isolatable areas within NW Natural's distribution system are at least as large as (and often larger than) its constituent load centers. However, there are smaller areas for which econometric load forecasting is feasible, such as the area served by the Hood River gate. Forecasts are thus defined by the narrowest possible geography from which hourly data is obtainable. Table 8.1 summarizes the broad areas for which econometric peak hour load forecasting is currently feasible; smaller exceptions are omitted. Note that several load centers are subsumed by a functionally interlinked "Portland" area.

Table 8.1: Areas with a Peak Hour Load Forecast

Area	Description
Vancouver load center	NW Natural's service areas in Clark County Washington
"Portland"	NW Natural service areas in Benton, Clackamas, Clatsop, Columbia, Lincoln, northern Linn, Marion, Multnomah, Polk, Washington, and Yamhill counties in Oregon
Eugene load center	NW Natural's service areas in Lane and southern Linn counties in Oregon
Columbia River Gorge-OR load center	NW Natural service areas in Hood River and Wasco counties in Oregon
Columbia River Gorge-WA load center	NW Natural service areas in Skamania and Klickitat counties in Washington
Coos Bay load center	NW Natural service areas in Coos County Oregon

The conditions that produce peak hour loads across NW Natural's system clearly vary by location, necessitating area-specific peak hour planning standards. Analogous with the statistically based approach of NW Natural's peak day planning standard,[164] an area's peak hour is defined by the level of firm resources that provide a 99% probability of meeting the highest firm hourly load in a gas year. Once area-specific relationships between hourly flow and its driver variables are estimated, they are applied to the area-specific peak planning standard, producing a benchmark that is incorporated into a forward-looking distribution system planning process.

8.3 Distribution System Planning Tools and Standards

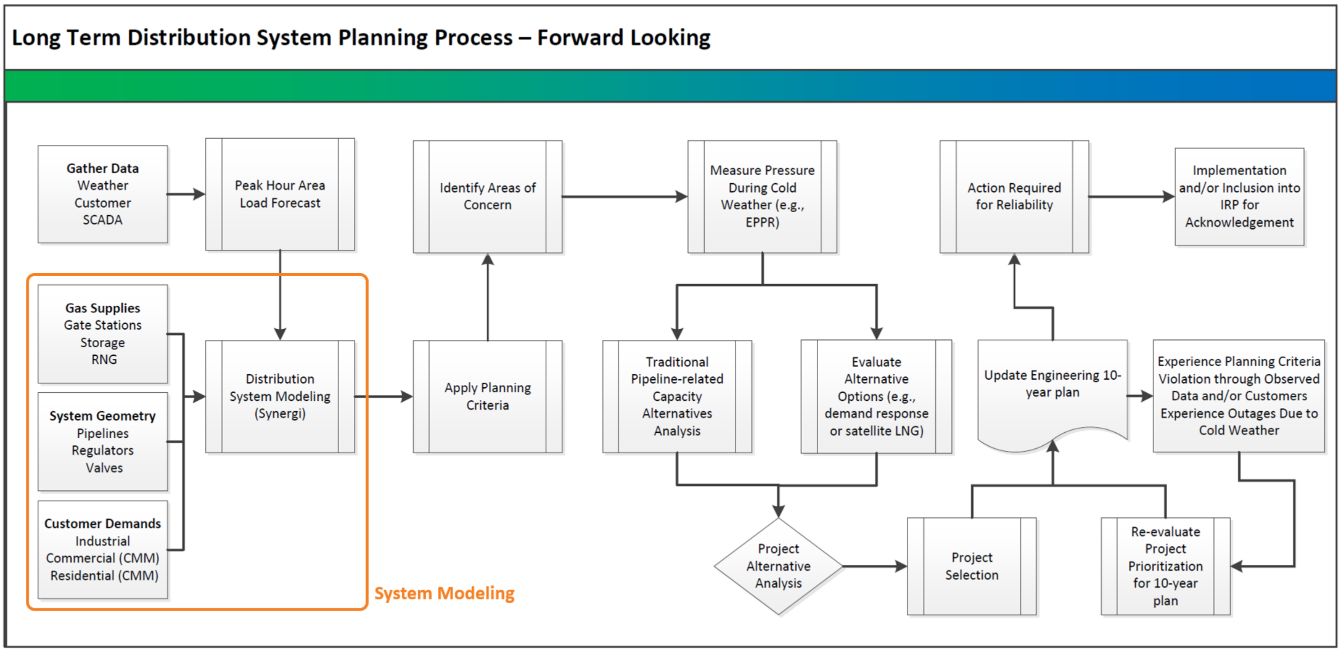
8.3.1 System Modeling

As shown in

[164] See Chapter 3 - Resource Needs for a detailed discussion of NW Natural's peak day planning standard.

Figure 8.5, system modeling is an important part of the distribution system planning process. Modeling allows accurate simulation of different aspects of NW Natural's system, from the receipt of natural gas from supplies, through NW Natural's pipeline networks, to customer locations.

Figure 8.5: Distribution System Planning Process – System Modeling



As is shown in

Figure 8.6, a Synergi Gas™ model contains detailed information regarding a specific portion of NW Natural's system, such as pipe size, length, pipe roughness, and configuration; customer loads; source gas pressures and flow rates; regulator settings and characteristics; and more. The model is based on information from NW Natural's Geographical Information System (GIS) for the piping system configuration and pipe characteristics; from the Customer Information System (CIS) for customer load sizing; and from the Supervisory Control and Data Acquisition (SCADA) system for large customer loads, system pressures, and supply flows and pressures.

Figure 8.6: Data Used in Synergi™ Models

Supply

- Gate Station Supplies (SCADA)
- Storage Facility Supplies (SCADA)
- Pressure Data (SCADA)

Pipeline Network

- Pipe Network Topology and Pipe Attributes (GIS)
- Customer Location (GIS)
- Field As-Built information
- Operating Parameters – Regulator Setpoints, Valve Status, etc.
- Cold Weather Pressure Survey
- Electronic Portable Pressure Recorders (EPPR)

Demand

- Largest Customer Demands (SCADA)
- Large Customer Demands (Industrial Billing)
- Residential and Commercial Demands (Billing Data)

Synergi™ uses mathematical flow equations and an iterative calculation method to evaluate whether the modeled system is balanced. A Synergi™ model shows flows and pressures at every point in the modeled system and, when balanced, the relationship between flows and whether pressures at all points in the modeled system are within tolerances specified by NW Natural's engineering staff. A properly designed Synergi™ model has pressure and flow results closely corresponding with those of the observed actual physical system. As with models used in other contexts, Synergi™ models rely on assumptions about the actual system, and therefore modeling results may vary from actual results. Synergi™ models are a representation of the actual system and the outputs of these models are a static snapshot of expected system conditions under the provided data.

NW Natural will occasionally run a field data collection process called a Cold Weather Survey to collect system pressures during cold weather conditions. Additionally, NW Natural has approximately a dozen Electronic Portable Pressure Recorders (EPPR) which are sited at locations with suspected low pressures. EPPR data includes pressure and temperate reads summarized in hourly intervals. NW Natural uses both EPPR data and Cold Weather Survey pressure data to validate Synergi™ modeled results.

Synergi Gas™ software simulates gas pipeline operations and does not have the ability to perform automated pipeline route selection. Automated route selection for pipeline construction would require data with quality and coverage that are not available at this time. Instead, system planners perform an iterative process incorporating multiple economic, geologic, and infrastructure factors to draft the least cost, feasible route option. An identified route is further refined through field validation and right-of-way acquisition considerations.

Synergi™ simulation capability allows NW Natural to efficiently evaluate distribution system performance in terms of stability, reliability, and safety under conditions ranging from peak hour delivery requirements to both planned and unplanned temporary service interruptions. Synergi™ modeling allows NW Natural to evaluate various scenarios designed to stress test the system's response to alternative demand forecasts, future demand forecasts, emergency situations, new customer demands, customer growth, non-pipeline alternatives, and much more.

8.3.2 Customer Management Module (CMM)

In 2021, NW Natural completed the implementation of the Customer Management Module (CMM). CMM provides a link between NW Natural's Geographical Information System (GIS), Customer Information System (CIS), and Synergi Gas™. CMM is created by DNV, which is the same developer who produces the Synergi Gas™ software. In summary, CMM provides the ability to:

- Import each customer's billing data from CIS and calculate a per customer demand based on daily temperature
- Update customer information such as rate schedule, status (active or inactive), and changes in forecasted consumption
- Assign each customer's load to the closest appropriate facility

Using historical billing, temperature data, and NW Natural GIS systems CMM can tie individual customer demands to their specific geographic location in the model. Previous modeling methods utilized area-specific averages for residential and small commercial customers. For example, residential customers in the Portland metropolitan area were previously assigned the same demand in the Synergi Gas™ models, whereas CMM allows customer-specific usages for each customer in the model based on historical consumption. In short, the benefit of CMM is that it accurately models local system pressures based on historical customer specific usage, rather than localized averages.

Beyond geographically locating customers, the CMM also connects to the CIS system and allows NW Natural to update customer information seamlessly in the Synergi models, including whether customers are identified as active or inactive and their service type (firm vs interruptible). Identifying customer status and rate schedule allows NW Natural to model active customers on the system. Firm customers are included in peak models, whereas interruptible customers are assumed to be curtailed during extreme conditions. The connection to the CIS system provides updates to add or remove demand based on whether the customer is assigned a firm or interruptible rate schedule. CMM allows NW Natural to generate new demands from real-time data if a customer changes their status or service type.

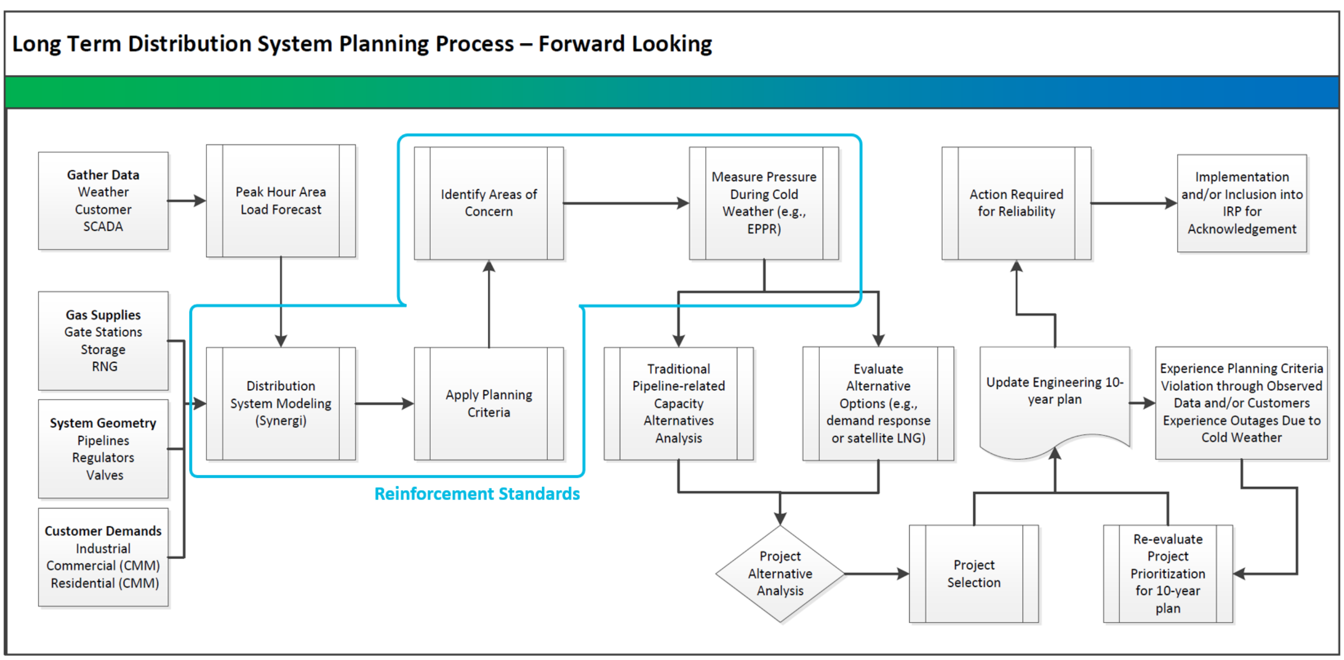
The modeling software requires that customer demands be properly assigned to the correct location in the gas distribution system. When demands are accurately assigned to the correct position in Synergi Gas™, it allows modelers to evaluate localized system pressure conditions. Previous models do not utilize the same coordinated system as the GIS system. CMM based models are required to have the same coordinate system as the GIS system. This requirement makes it mandatory for new models to be developed in order to take advantage of CMM features.

For computational purposes, these CMM models are split geographically across NW Natural's service territory.[165] As mentioned earlier in this chapter, NW Natural is still in the process of developing these models. Model creation using CMM data was prioritized based on locations that were identified to have near-term needs. The distribution planning project introduced later in this chapter was modeled using CMM. NW Natural is in the process of updating all Synergi models to incorporate the benefits provided by CMM.

8.3.3 System Reinforcement Standards

As shown in Figure 8.7, system reinforcement standards are a required component of the distribution system planning process. The standards are based on multiple indicating suboptimal conditions such as a pipeline nearing peak capacity, a regulator near failure, or customers not being served with adequate pressure or volume. The system reinforcement standards represent trigger points indicating systems under stress and in need of imminent attention to reliably serve customers.

Figure 8.7: Distribution System Planning Process – Reinforcement Standards



Transmission and high-pressure distribution systems (systems operating at greater than 60 psig[166]) have different characteristics than other components of NW Natural's distribution system, and design

[165] Previous Synergi™ models were also spilt up geographically across the service territory.
[166] Pounds per square inch gauge: a standard measure of pressure within a pipeline facility.

parameters associated with peak hour load requirements differ as well. System reinforcement parameters for these systems include:

- 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
- Considering minimum inlet pressure requirements for proper regulator function in addition to total pressure drop for pipelines that feed other high-pressure systems
- 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)
- Being identified in the IRP associated with supply requirements or needs

The system reinforcement parameters associated with peak hour load requirements for distribution systems that are not high pressure (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
- 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)

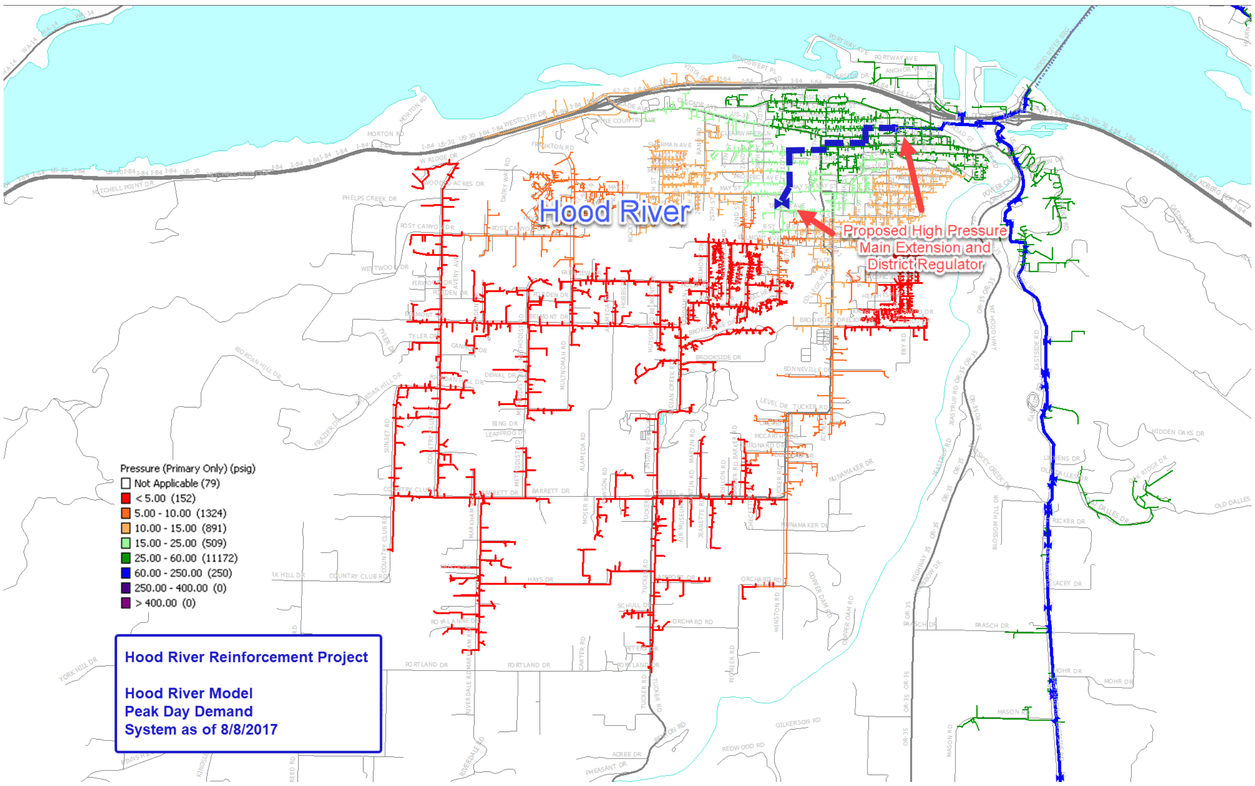
8.3.4 Identification of Distribution System Needs

Accurate modeling and forecasted level of peak hour demand combine to indicate how the distribution system would operate on a peak hour. The system reinforcement standards are then applied to the model results to identify specific areas of NW Natural's system that need reinforcement. Such areas are typically much smaller than the load center in which they are located. In the following example, and as shown in Figure 8.8, an area of the Class B distribution system[167] in Hood River is forecasted, by modeling, to experience low system pressures or outages on a peak hour. This modeling was validated in January of 2017 when several customer outages occurred in the Hood River area under non-peak conditions. Areas with pressure below 10 psig are indicated in orange and red colors, while areas with more satisfactory pressure are indicated with shades of green. Note that the Hood River Class B distribution system is located within the Columbia River Gorge-Oregon load center, is served by a

[167] Class B systems are those operating at 60 psig or less.

single gate station on Northwest Pipeline (NWPL) and is not connected to other parts of NW Natural's distribution system.

Figure 8.8: Illustration of Hood River Area Pressure Issues



8.4 Distribution System Resources

8.4.1 Existing Distribution System

NW Natural's gas distribution system consists of approximately 14.6 thousand miles of transmission and distribution mains, of which approximately 87% are in Oregon with the remaining 13% in Washington.[168]

NW Natural's Oregon service area includes 39 gate stations[169], approximately 954 district regulator stations and 2 renewable natural gas (RNG) production sites. NW Natural owns and operates two liquefied natural gas (LNG) storage plants and the Mist underground storage facility in Oregon, which are discussed in Chapter 6. NW Natural's Washington service area includes 15 gate stations and approximately 78 district regulator stations.

168 Coos County Pipeline located in Oregon consists of approximately 86 miles of transmission main. Coos County Pipeline is operated by NW Natural on behalf of Coos County.

169 Gate station values for both Oregon and Washington include all upstream pipeline interconnections, including farm taps.

NW Natural maintains two large compressed natural gas (CNG) trailers, each with a 100 Dth capacity rating, a liquefied natural gas (LNG) trailer rated at 900 Dth capacity, and assorted small CNG trailers rated below 10 Dth capacity. These trailers can be used for short-term and localized use in support of cold weather operations, or while conducting pipeline maintenance procedures.

8.4.2 Geo Current and Future Distribution System Planning Resources

Similar to system planning, alternatives for both demand-side and supply-side are evaluated. Distribution System Planning Resource Options can be seen in Table 8.2.

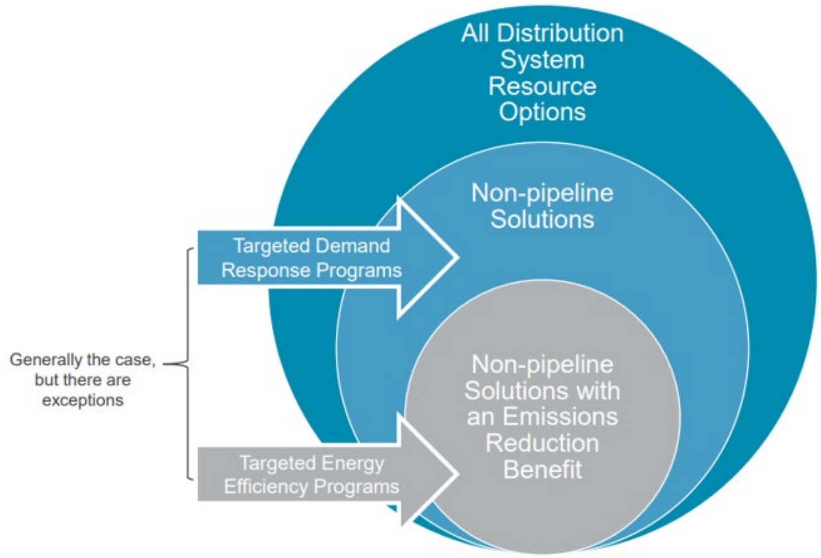
Table 8.2: Distribution System Planning Alternatives

Distribution System Planning Alternatives (not all options are possible or applicable in all situations)				Option Currently Considered for Cost-Effectiveness Evaluation
Supply-Side Alternatives	Pipeline Related Capacity Options		Loop existing pipeline	✓
			Replace existing pipeline	✓
			Install pipeline from different source location into area	✓
			Uprate existing pipeline infrastructure	✓
			Add or upgrade regulator to serve area of weakness	✓
			Gate station upgrades	✓
			Add compression to increase capacity of existing pipelines	✓
	Non-Pipeline Solutions	Distributed Energy Resources (DER)	Mobile/fixed geographically targeted CNG storage	✓
			Mobile/fixed geographically targeted LNG storage	✓
			On-system gas supply (e.g. renewable natural gas, H2)	✓
			Geographically targeted underground storage	✓
Demand-Side Alternatives		Demand Response	Interruptible schedules (DR by rate design)	✓
			Geographically targeted interruptibility agreements	✓
			Geographically targeted Res & Com demand response (GeoDR)	
		Energy Efficiency	Peak hour savings from normal statewide EE programs	✓
			Geographically targeted peak-focused energy efficiency (GeoTEE)	

As shown in both Table 8.2 and Figure 8.9, non-pipeline solutions as distribution resource planning options can be both supply-side and demand-side resources. These solutions must reliably serve customers by helping to either serve or reduce load during a peak event and are evaluated for cost effectiveness along-side other solutions. Often non-pipeline solutions are associated with DSM solutions, but to be clear this is not the case. As shown in Table 8.2 and Figure 8.9, some non-pipeline solutions are supply-side options, for example geographically targeted CNG deployment, whereas other options are demand-side options, for example geographically targeted interruptible agreements.

The purpose of any non-pipeline solution is aimed at serving or reducing peak load in an area and should not be considered a means for emissions reduction.[170]

Figure 8.9: Purpose of Non-pipeline Solutions



Supply-side Options – Pipeline-related Resources

Once NW Natural identifies a distribution system issue, in addition to demand-side alternatives, the Company considers multiple traditional pipeline solutions for addressing the issue. These traditional pipeline solutions may include:

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

The objective is to identify the most efficient, least cost, least risk solution for the identified issue. NW Natural validates the identified solution with models and field testing to verify effectiveness.

Having adequate pressure on the distribution system is crucial for reliably delivering gas to customers. Traditional pipelines are included in the alternative analysis as a solution to improve system pressures in areas with low pressures by installing new distribution pipelines or uprating existing distribution pipelines.

[170] Often GeoTEE is mis-conveyed as a solution for emissions reductions. While GeoTEE could provide emission reductions as a secondary impact, this will already be taken into consideration for a cost-effectiveness evaluation of GeoTEE as a distribution system planning option when comparing to the other distribution system options.

Pipelines

One option to remediate low pressures is installing new distribution pipelines to increase the capacity of a distribution system. The proposed distribution pipeline would transport higher pressure gas to areas with weak pressures. A distribution pipeline system reinforcement increases pressures in weak areas, lowering the potential for customer outages.

NW Natural completes pipeline feasibility studies to develop potential pipeline projects to address low pressure areas. The selection criteria include distribution pipeline distance, operating pressure, material, pipeline diameter, load type, and existing network architecture. The three major types of distribution pipeline installations related to system reinforcements are provided below:

1. Distribution Pipeline Extensions – Installation of gas distribution pipeline using a new alignment. A new distribution pipeline delivers higher pressure gas to an area of need, increasing the pressure and reliably of a distribution system. Depending on the relative operating pressures this could also include pressure regulation and overpressure protection equipment.
2. Distribution Pipeline Replacements – Replacing an existing pipeline with a new pipeline. Typically, the replacement distribution pipeline is larger in diameter than the original distribution pipeline, which reduces the pressure drop across the alignment.
3. Distribution Pipeline Looping – A new distribution pipeline that is constructed parallel to an existing distribution pipeline. The looped mains are tied-in, decreasing the flow on the original pipeline, which reduces pressure drop along the original pipeline.

NW Natural considers alternative characteristics for a pipeline solution to the identified issue as a first step in developing supply-side solutions. These alternative characteristics include the path a pipeline solution might take, the size of the pipe, the material used in the pipe, and the probable methods—or combination of methods—of pipeline construction. The feasibility study incorporates all three scenarios as well as these alternative characteristics. The least cost option is provided as an input in the alternatives analysis to address an area in need.

Uprating

Typically, the cost of uprating a portion of a distribution system is generally less than installing a new pipeline. Uprating pipelines is another form of increasing the capacity of a distribution system by operating at a higher Maximum Allowable Operating Pressure (MAOP). Before an uprate can be executed, a pipeline system must comply with Local and Federal Regulations. The uprating effort may include, but is not limited to, key activities such as reviewing records, pressure testing, replacements, field verification, inspections for all pipes and components on the portion of the distribution system being uprated, multiple leakage surveys before, during and after the pressure uprate process. Not all pipelines are eligible to be uprated, a system may have design limitations that prevent a distribution system pipeline from operating at a higher MAOP.

Table 8.3 shows the capacity for a five-mile, six-inch steel pipeline for varying operating pressures. The table shows that a pipeline operating at 600 psig has approximately six times more capacity than a pipeline operating at 100 psig. A major benefit of uprating is that incremental capacity can be provided through existing distribution pipelines by safely operating them at higher pressures.

Table 8.3: Pipeline Uprate Capacity Example

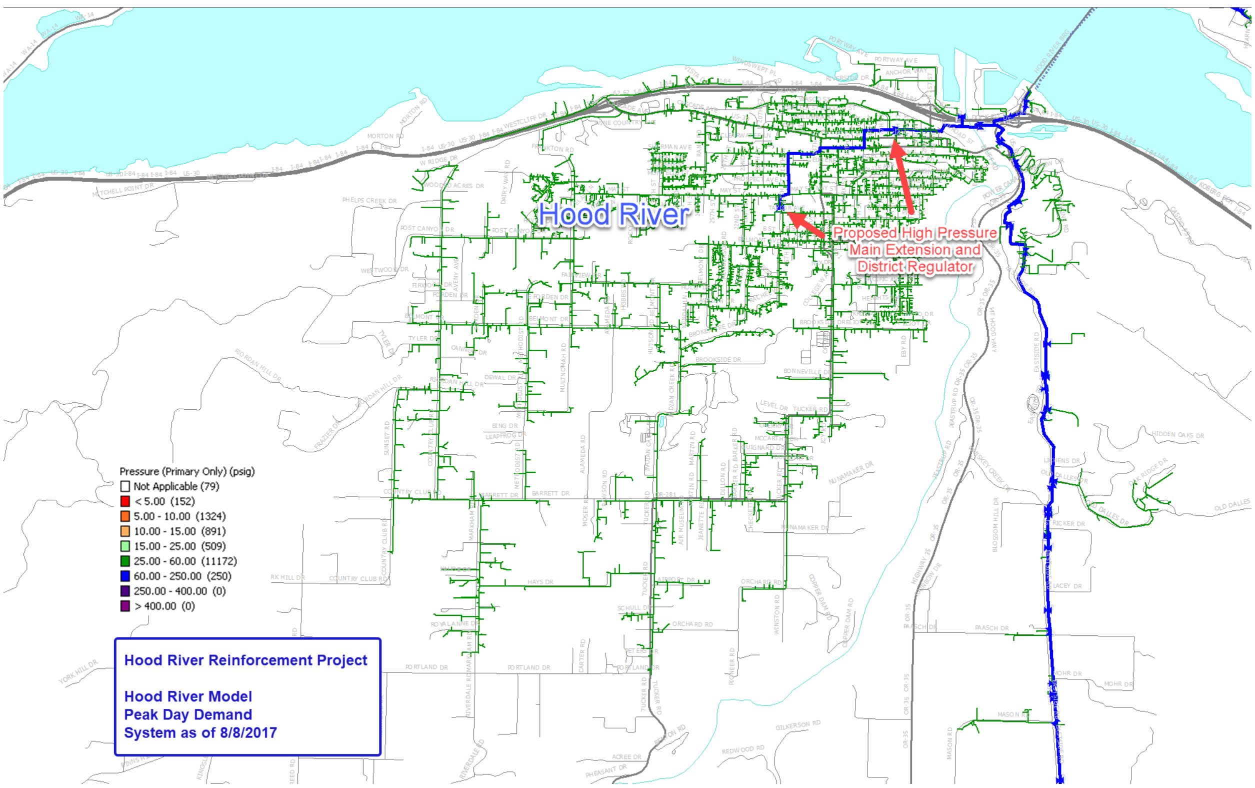
Starting Pressure (psig)	Ending Pressure (psig)	Pipeline Capacity* (th/hr)
100	60	1,820
200	120	3,569
300	180	5,341
400	240	7,163
500	300	8,956
600	360	10,800

*Pipeline Capacity Identified by 40% Pressure Drop

In the Hood River example discussed in earlier in this section (8.2), the weakness in the existing system centered around a single point of gas feed from the northeast. This created system bottlenecks, as nearly all gas required by customers must go through a very small number of pipes. The final solution extended the existing high-pressure distribution main on Cascade Street and 6th Street. A new district regulator was installed on the end of the high-pressure main extension reducing the pipeline pressure drop through the bottleneck pipelines in the north. The result was that the system pressures overall were greatly improved (note the red areas in Figure 8.8 are green in

Figure 8.10). Effective pipeline routes from the south could have been constructed, but the construction would have been much longer than the identified solution which avoided a costly river crossing.

Figure 8.10: Illustration of Hood River Area Pressure Issues and Resolution



Supply-side Options - Non-pipeline Resources

Non-pipeline supply-side options may be an option when customer demands grow beyond the capacity of the pipeline which currently serves this system. Instead of addressing weak areas with pipeline system reinforcement projects, non-pipeline alternatives are also assessed and include augmenting the capacity of the existing pipeline with a local peaking asset and the use of geo-targeted demand-side management means for reducing the local demand on peak, amongst other possible solutions, in lieu of traditional pipeline solutions. Essentially, non-pipeline supply-side options introduce a new source of gas into a constrained area of the system, thereby propping up pressure in the area to address reliability concerns. The next sections discuss supply side non-pipeline solutions.

GeoRNG

On-system RNG interconnections are a form of distributed resources that can help maintain reliability within NW Natural's distribution system. A strategically located RNG interconnection on NW Natural's system could have a similar impact in a constrained area of the distribution system as any targeted demand-side option. The additional RNG supply would be injected directly onto a weak area of the system which can help avoid or delay a pipeline reinforcement project. The likelihood of an RNG facility providing the biogas needed in the perfect location as a specific alternative to a specific pipeline reinforcement project is small, but possible. Additionally, if more on-system RNG interconnections are developed, then the aggregate of the on-system RNG injections could result in pipeline reinforcement projects that never materialize.

Satellite Storage

A satellite storage facility delivers locally stored gas to the nearby customers, which temporarily reduces the volume of gas that flows on the existing upstream pipeline. Satellite storage works in tandem with existing pipelines to serve customer demand during very cold or peak demand conditions. Unlike the pipeline options, which provide permanent pressure benefits, satellite storage plants are peak shavers which are designed to be dispatched during extreme weather. The satellite storage has a limited supply of gas on site based on the size of the facility and is usually difficult to replenish under peak conditions. Two common types of satellite storage are Liquefied Natural Gas (LNG) and Compressed Natural Gas (CNG).

1. Satellite LNG Facility – LNG is natural gas that has been cooled to a liquid state reducing its volume by about 600 times. A satellite LNG facility is a tank that stores liquified natural gas along with the associated pumping, vaporization, meter, control, fire protection, standby power and odorization systems until the energy is required during peak or emergency conditions. Withdrawal rates are determined by the tank size, vaporizing equipment capacity, and the quantity of gas that can be absorbed by customers and local piping. A satellite LNG facility does not typically include a liquefaction process. LNG is generally brought in via tank trucks or occasionally trains.
2. Satellite CNG Facility – CNG is natural gas that is compressed to less than 1% of the volume it occupies at standard atmospheric pressure. The natural gas is stored in compressed form until dispatched to a lower pressure pipeline system. The storage facility is refilled during non-peak periods when system pressures are not a concern. These facilities normally have compressors to increase the pressure of the gas coming from the pipeline.

The option to site a CNG or LNG storage facility depends on many parameters including cost, flow rates capability, volume, commodity source, permitting requirements and tank size. Typically, the option between LNG and CNG facilities is determined by how much gas is required to serve an area. The biggest advantage of LNG storage is that the total storage capacity is greater than CNG storage. A satellite LNG facility can sustain an area experiencing low pressures for a longer duration. Both options generally require acres of land, and both processes can be noisy, limiting siting and increasing costs to remediate noise generation.

Liquefied natural gas (LNG), compressed natural gas (CNG), underground storage, and propane air facilities have all been used successfully for peaking in various parts of the country. CNG applications do not scale very well and quickly become cost prohibitive. Potentially viable underground storage structures are extremely rare and very expensive to develop. Propane air presents a risk of injecting oxygen into natural gas pipelines and producing a combustible mixture and is a safety risk NW Natural is hesitant to take. NW Natural's experience with LNG as a viable peaking asset facilitates assessment of a satellite LNG facility as an alternative to traditional pipelines. NW Natural has historically utilized mobile CNG and LNG as an emergency or best-efforts measure to support firm customers. Mobile solutions for natural gas delivery have significant risk, capacity, security, and siting issues, and a high cost per therm delivered. Thus, NW Natural routinely examines satellite LNG facilities in the alternatives analysis process and whereas other peaking assets may be considered if deemed appropriate.

Demand-side Resources

Demand-side management (DSM) comes in many forms, but all DSM distribution system resources focus on reducing the peak hour demand within a specific area on NW Natural's system and thereby delaying or avoiding the need for a pipeline reinforcement project or any other supply-side solution.

Lead Times for Non-pipeline Solutions

A primary benefit of moving to a more forward-looking distribution system is to allow for better use of non-pipeline solutions. The early identification of distribution system issues as discussed above is necessary to go beyond supply-side options. More specifically, Figure 8.11 shows the value of the known time component associated with a supply-side solution but also the chunkiness of using this just-in-time supply side solutions.

Figure 8.11: Just in Time Supply-side Solutions

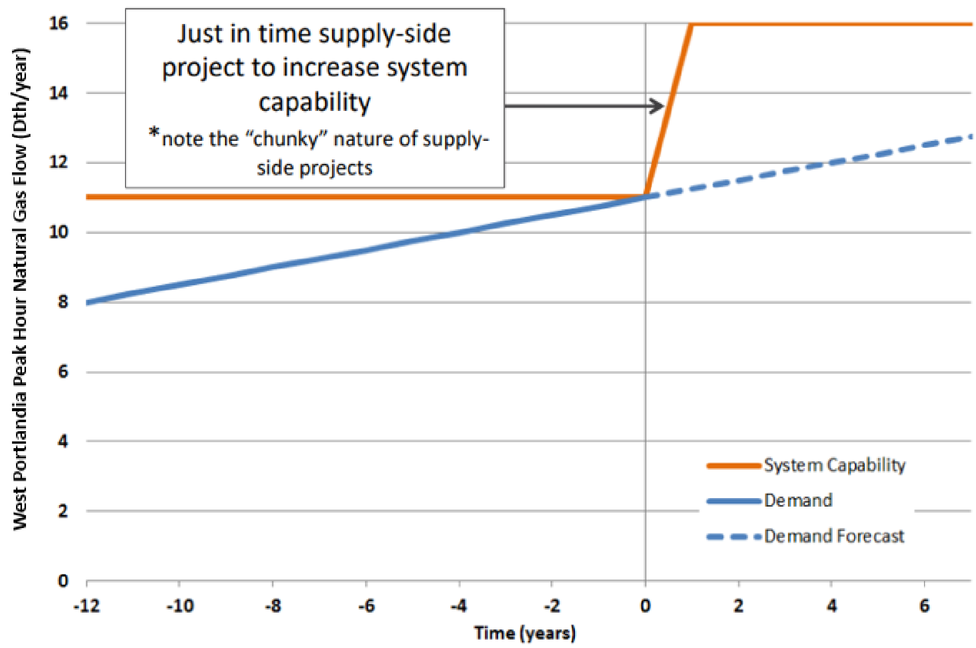
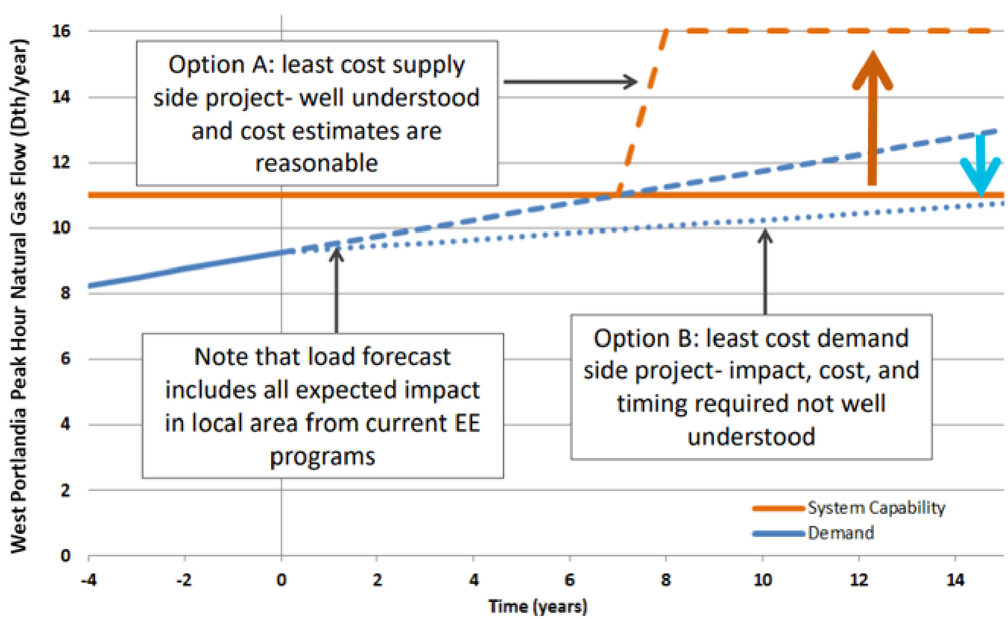


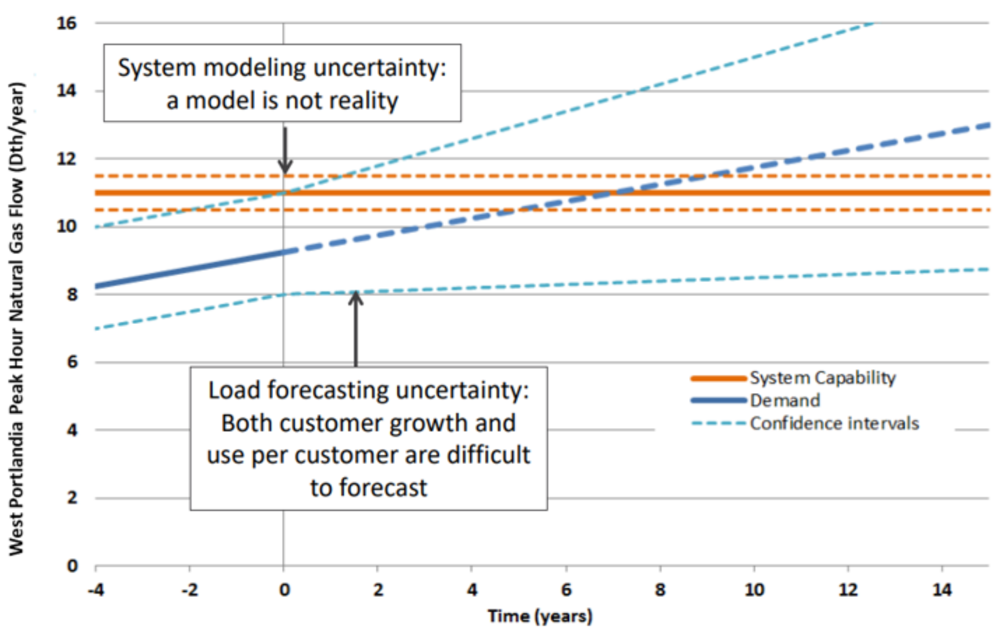
Figure 8.12 shows the timing needed for a demand-side non-pipeline solution.

Figure 8.12: Timing for Demand-side Non-pipeline Solution



As shown in Figure 8.13, the timing needed for demand-side projects is not well understood and there is still quite a bit of uncertainty. This is one of the reasons NW Natural is currently piloting an innovative non-pipeline alternative known as GeoTEE or **Geo**graphically **T**argeted **E**nergy **E**fficiency. Partnering with Energy Trust of Oregon, one of the key objectives of this pilot is to develop the data and ability needed to construct a peak hour energy efficiency supply curve for any given geographic area so that it can be compared for cost-effectiveness against other distribution system capacity options. GeoTEE is discussed in detail below.

Figure 8.13: Distribution System Planning with Uncertainty



Geographically Targeted Interruptible Agreements

NW Natural currently has many large interruptible customers who can be curtailed upon formal notice from NW Natural. This is one form of demand-side management. Another demand-side approach is to contractually arrange for voluntary service curtailment by large firm service customers within the area impacted. NW Natural begins the assessment of this alternative by examining historical loads of current large non-residential firm service customers in the area of influence for the proposed pipeline solution. If the estimated peak hour usage by these customers could be of sufficient volume to defer (or eliminate) the need to implement a supply-side solution, NW Natural would conduct additional analysis regarding whether customer-specific geographically targeted interruptible agreements[171] could be negotiated with these customers. Other demand-side management alternatives may be considered for future projects as new technologies and capabilities evolve. If the alternatives analysis indicates that a more effective and lower cost equivalent solution may be available, the proposed project will be revised to reflect the best alternative. The next sections discuss demand-side non-pipeline solutions.

GeoTEE

GeoTEE stands for **Geo**graphically **T**argeted **E**nergy **E**fficiency, and it is a non-pipeline solution to distribution capacity constraints.[172] More specifically, GeoTEE is defined as savings from offerings that are distinctive to certain locations within a state to achieve additional savings specifically from customers that contribute to the peak load of an area where the distribution system is experiencing weakness and a supply-side project is projected to be needed to meet local peak demand. Geographically targeted DSM savings can be obtained from DSM programs with measures not being offered in other areas of the state or from programs that intensify/accelerate the deployment of measures available elsewhere but different from what is offered in the state at large. Given the current method for evaluating DSM cost-effectiveness, special consideration must be given to the design and deployment of a geographically targeted DSM program to meet the economic/cost-effectiveness criteria.

Specifically, GeoTEE is designed to be achieved by either "accelerating" or "enhancing," or accelerating *and* enhancing, DSM offerings:

"Accelerated" DSM is defined as savings acquired by speeding up the deployment of measures that meet current Energy Trust cost-effectiveness requirements based on statewide avoided costs in an area with location specifically targeted marketing and/or increased incentives. In other words, accelerating DSM is acquiring savings that would be eventually achieved through statewide operations but faster in the locality in question.

[171] NW Natural also refers to such agreements as "localized interruptibility agreements."

[172] For more information on GeoTEE, please refer to NW Natural's 2016 IRP, Chapter 6, Section 7, https://www.nwnatural.com/about-us/rates-and-regulations/resource-planning

"Enhanced" DSM is defined as savings obtained from measures that do not meet current Energy Trust cost-effectiveness requirements based on statewide avoided costs but are cost-effective if location-specific avoided costs[173] are used to represent the value of achieving peak hour savings from DSM in the area that is experiencing a distribution system weakness. In other words, enhancing DSM is savings that are cost-effective based on local avoided costs but are not cost-effective under current statewide avoided costs.

Accelerated and/or Enhanced DSM will be required in a geographically targeted area to achieve the required peak hour savings since the "business as usual" process for acquiring conventional DSM savings is already accounted for in the peak hour distribution system planning that shows additional DSM is needed to address the peak hour demand. The demand-side options to evaluate against supply-side options to address weaknesses in NW Natural's distribution system will be referred to as "geographically targeted DSM via accelerated and/or enhanced offerings" or "Targeted DSM" for short. Allowing for Targeted DSM to be a viable option is breaking new ground for LDCs operating in the region and requires major changes to the way NW Natural plans distribution system upgrades and the way Energy Trust evaluates cost-effectiveness and deploys its programs.

Additionally, like supply-side options, if multiple enhanced *and/or* accelerated DSM programs are projected to be cheaper than the best supply-side option, the lowest cost option of the demand-side options would be selected and deployed to meet the best combination of cost and risk planning standard for addressing resource acquisitions.

As part of our 2016 IRP, we proposed the following action item:

Work with Energy Trust of Oregon to further scope a geographically targeted DSM pilot via accelerated and/or enhanced offerings ("Targeted DSM" pilot) to measure and quantify the potential of demand-side resources to cost-effectively avoid/delay gas distribution system reinforcement projects in a timely manner and make a Targeted DSM pilot filing with the Oregon Public Utility Commission in late 2017 or early 2018.

The Public Utility Commission of Oregon (OPUC) acknowledged this item in Order No. 17-059 dated February 21, 2017.[174]

On April 17, 2019, NW Natural filed an update to its 2018 Integrated Resource Plan[175] that included its GeoTEE pilot filing. It also noted at that time that while the filing of the pilot was delayed, the actual pilot was still on schedule.

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[173] Inclusive of the expected costs of the potential supply-side distribution enhancement.

[174] The Washington Utility and Transportation Commission does not acknowledge specific action plans but did acknowledge that NW Natural's 2016 IRP compliance with WAC 480-90-238in their letter dated December 19, 2016.

[175] https://edocs.puc.state.or.us/efdocs/HAH/lc71hah134047.pdf

The objectives of the pilot include:

(1) Develop the data and ability needed to construct a peak hour energy efficiency supply curve for any given geographic area so that it can be compared for cost-effectiveness against other distribution system capacity options.
(2) Determine whether GeoTEE represents a socially desirable tool to serve LDC customers if it shows the potential to be a cost-effective capacity resource in some situations.
(3) Explore and discuss with key stakeholders the appropriate funding mechanism for future GeoTEE projects should they show as a potentially cost-effective way to address distribution system weaknesses.

Figure 8.14: GeoTEE Phases

To achieve these objectives the pilot is being conducted in Cottage Grove and Creswell, Oregon and using various phases. The phases and anticipated timing are shown in Figure 8.14.

As of this writing, Phase One with increased marketing and outreach has been completed along with Phase Two which involved increased incentives but still within the current cost-effective parameters. Phase Three with the incentives increased even further by applying local avoided costs values for cost effectiveness screening is currently underway and will continue through August 2022. Upon completion of Phase Three, and as shown in Figure 8.14, the reporting and evaluation of the pilot will begin.

Geo-Targeted Demand Response (GeoDR)

Demand response (DR) has proven an effective way for utility companies to balance their supply and demand and prevent service interruptions through extreme weather events. When geographically targeted, DR can help lower peak demand, improve service reliability, and avoid or defer the need for distribution system expansion in the geo-targeted service areas. As discussed in Chapter 3, NW Natural already relies upon substantial demand response resources in the form of interpretability to manage peak loads and save capacity resource costs on its distribution system, where roughly 9% of would-be peak load can be interrupted during peak events. This existing DR resource comes from large commercial and industrial customers, and the cost of serving peak load, on average, is comparatively high. In addition to the DR resources enrolled under the interruptible rate programs, NW Natural commissioned the Brattle Group to explore the potential and opportunities of the technology-enabled DR resources for both Oregon and Washington customers served by the Company. With this exploration as our guide, the Company is proposing to scope a residential and small commercial demand response program to supplement our existing program for large commercial and industrial customers. This exploration will provide the Company with information about cost-effective technologies and program concepts for the customers. The potential emerging technologies under evaluation include Wi-Fi smart thermostats for shaving space heating demand and controlling devices for shaving water heating demand during peak hours for the residential and small commercial customers. The Company is committed to exploring in more detail the program design, to determine if a particular pilot program in an infrastructure constrained area can be successfully implemented.

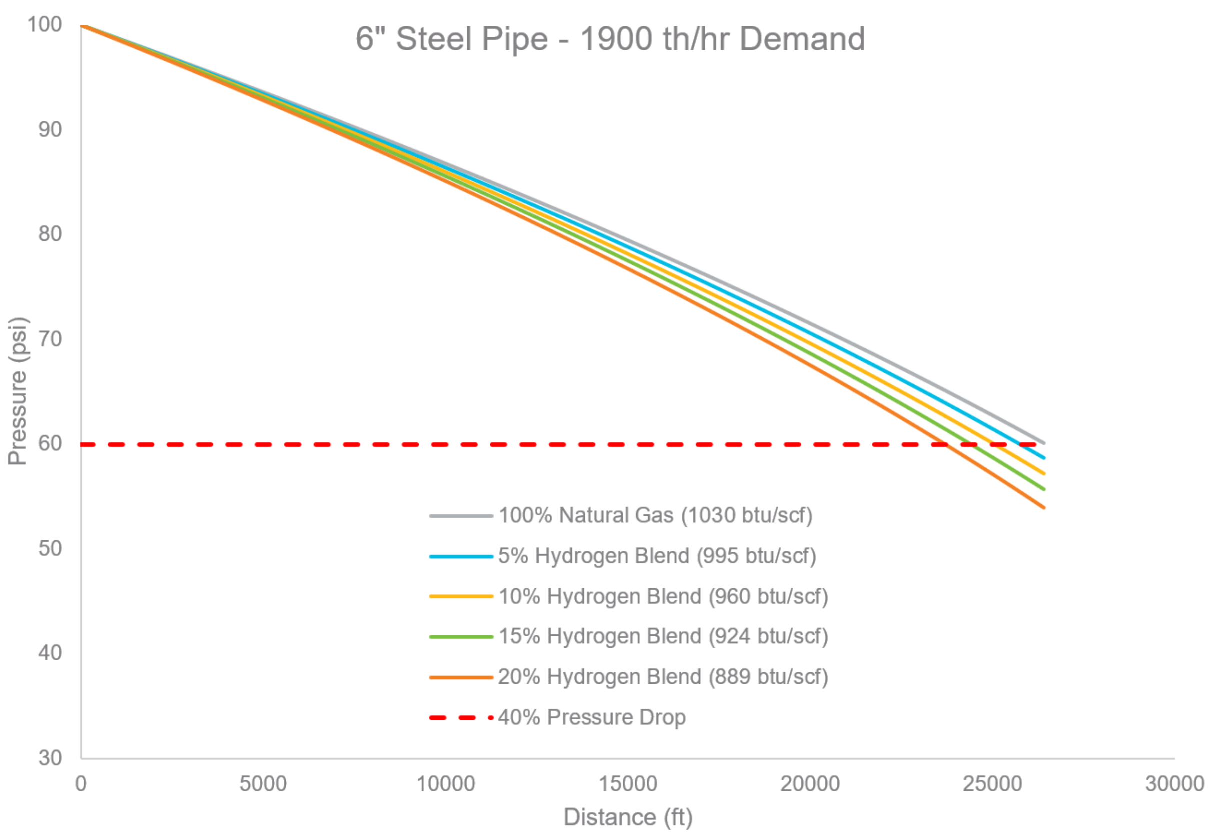
Hydrogen Blended with Natural Gas on the Distribution System

As was discussed in prior sections of the IRP, blending hydrogen into an existing natural gas system has benefits related to emission reductions. Injecting hydrogen into a natural gas stream does not improve pressures on a gas distribution system, and hence is not presented as an option in NW Natural's alternative analysis. In fact, blending natural gas with hydrogen reduces system pressures because it raises the volume of gas required to deliver to customers.

The British thermal units (Btu) Value for gas is defined as the amount of energy release by a unit volume when combusted. NW Natural measures Btu values per a standard cubic foot (Btu/scf). Btu Value on NW Natural's system typically ranges from 985 Btu/scf to 1155 Btu/scf. The Btu Value of hydrogen is approximately 325 Btu/scf. When hydrogen is blended with natural gas, the energy content of the gas stream is lowered because the Btu Value of hydrogen is approximately 1/3 that of natural gas. Btu Value is an important attribute on pipeline system because it determines the volumes of gas required to serve energy needs. Consumption on a natural gas network is determined by the amount of energy consumed, typically expressed in therms or Btus. If the energy needs remain constant while the Btu Value decreases, then it requires a higher volume of gas to meet the same energy demand. Higher volume of gas required equates to additional pressure drop along a pipeline system.

Figure 8.15 illustrates the pressure drop for natural gas compared to hydrogen blends. The graph shows that the pressure drops across a pipeline are proportional to the volume of hydrogen injected into the natural gas stream. Natural gas without hydrogen has less pressure drop than the hydrogen blends because it has a higher Btu Value. As more hydrogen is injected into the gas stream, more pressure drop occurs on the pipeline because the blend has a lower BTU Value. The main takeaway of Figure 8.15 is that it shows that hydrogen blending makes a distribution system with low pressures even weaker.

Figure 8.15: Hydrogen Blending Pressure Drop



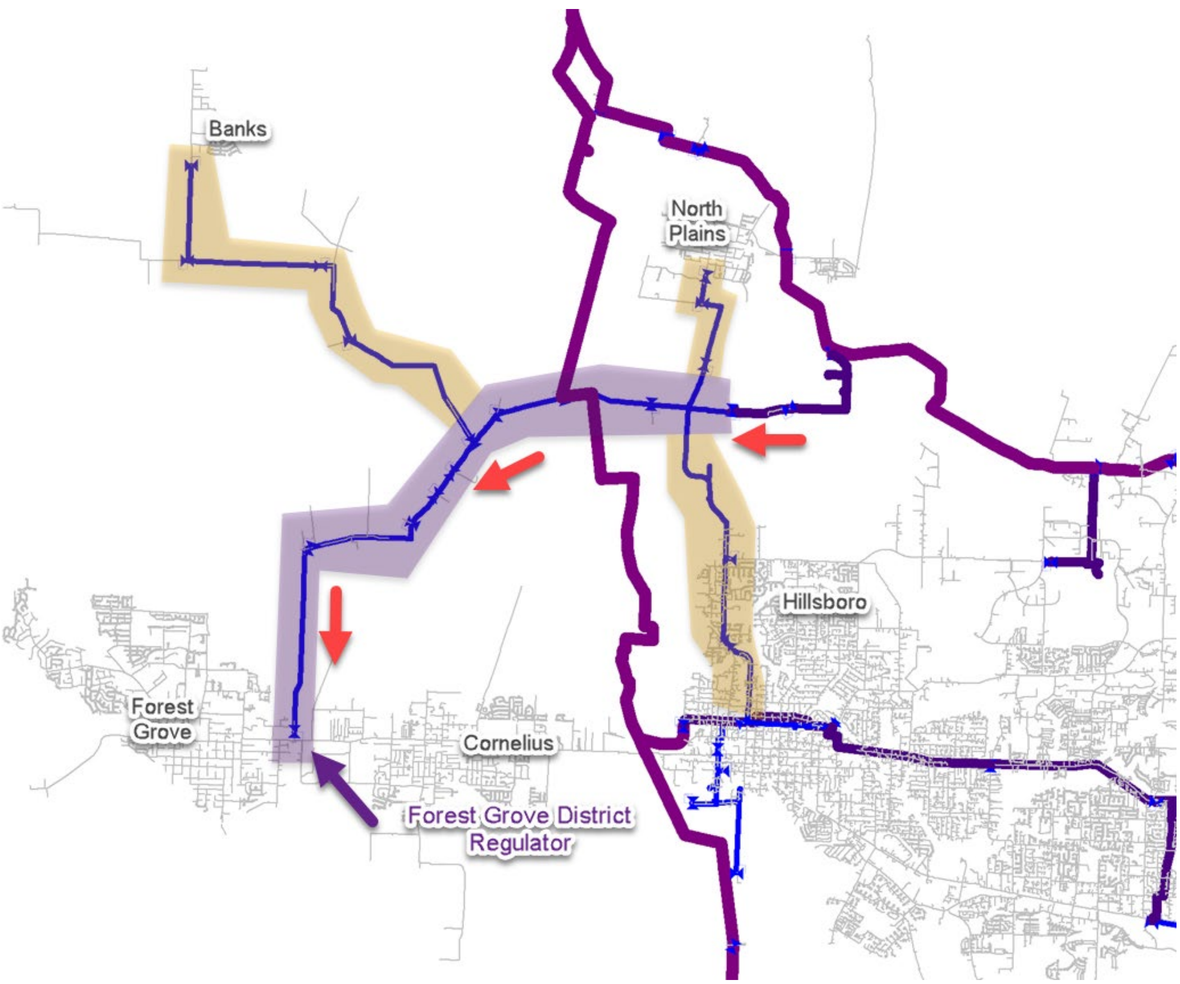
8.5 Distribution System Projects – 2022 IRP Action Item

This section describes a proposed distribution system project, which addresses an area of identified weakness within the distribution system.

8.5.1 Forest Grove Feeder Uprate

The Forest Grove Feeder (also known as the McKay Creek Feeder) is the primary supply pipeline for the western portion of the Portland metropolitan area. Customers in the communities of Hillsboro, Cornelius, Forest Grove, North Plains, and Banks are supplied by this pipeline. The Forest Grove Feeder is fed from the 720 MAOP Rock Creek Feeder and South Mist Feeder and has historically operated at 175 MAOP. Most of this pipeline was constructed in 1989 and other sections were installed in 1994. The segment that serves Banks was installed in 1997. Significant demand growth has occurred in this area and modeling results indicate that this pipeline is operating beyond its design capacity during extreme conditions. The Forest Grove Feeder is shown in Figure 8.16. The section of the Forest Grove Feeder that is operating over the original design capacity is indicated by the purple polygon.

Figure 8.16: Forest Grove Feeder System Identification

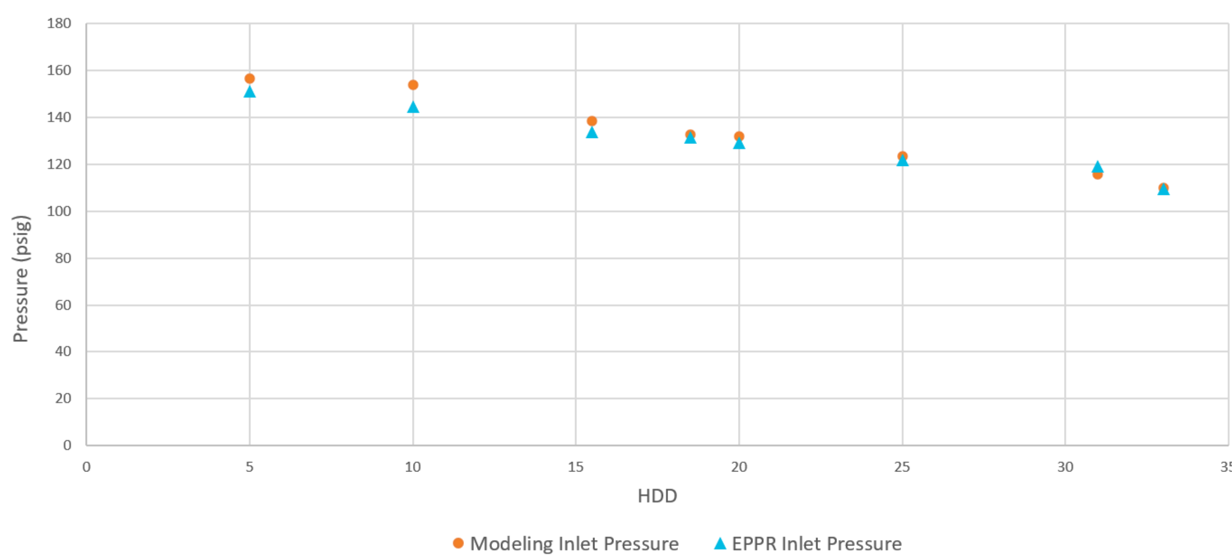


8.5.2 Customer Management Module (CMM)

For the following analysis, residential and commercial customer demands for Cornelius, Forest Grove, North Plains, and Banks were imported using CMM.

Nine data points collected between 2020 to 2022 were used to measure the variances between actual pressure reads from data extracted from an Electronic Portable Pressure Recorders (EPPR) sited at the inlet of the Forest Grove district regulator and the Synergi Gas™ model results. Because curtailments were not issued during the sample period, all interruptible customers remained enabled in Synergi Gas™ models for these data points. Figure 8.17 illustrates the difference between EPPR reads and the Synergi Gas™ model results. The average percent difference for the nine samples is 1.8%. This validation provides supporting data that CMM is producing demands that resemble actual consumption for residential and commercial customers.

Figure 8.17: Forest Grove District Regulator Inlet Pressure - CMM vs EPPR



8.5.3 Analysis

Peak hour analysis assumptions:

- Supplies set at peak hour
    - Customer demands set at Peak Hour
    - Largest customers estimated based on high frequency meter data (SCADA, Industrial Billing System)
- Commercial and residential customers peak hour demand estimated based on CMM Interruptible customers off as requested at peak hour
- Modeled System Configuration and Customers as of August 2021

During peak conditions, a severe pressure drop occurs on the last segment of the Forest Grove Feeder, which is approximately 5.3 miles of 6” steel pipeline operating at 175 MAOP. To force the model to solve during peak conditions, the Forest Grove district regulator had to be bypassed. Bypassing is performed in the model when regulators do not have sufficient inlet pressure to operate correctly. In field operations, bypassing a district regulator is typically performed by an operator who physically opens a valve that connects the district regulator inlet piping to the outlet piping. When bypassing occurs, gas does not flow through the regulator, avoiding pressures losses from the regulator. Figure 8.18 displays the model results for the Forest Grove area. Even with the Forest Grove district regulator bypassed, model results indicate customers may experience outages during a cold event. Customer connected pipes shown in red are those that may experience outages during extreme weather. During a peak hour event, the pressure drop in this segment of the pipeline is so high that Synergi Gas™ provides infeasible solutions. Infeasible solutions occur when the piping network is running out of pressure.

Figure 8.18: Existing System Peak Model

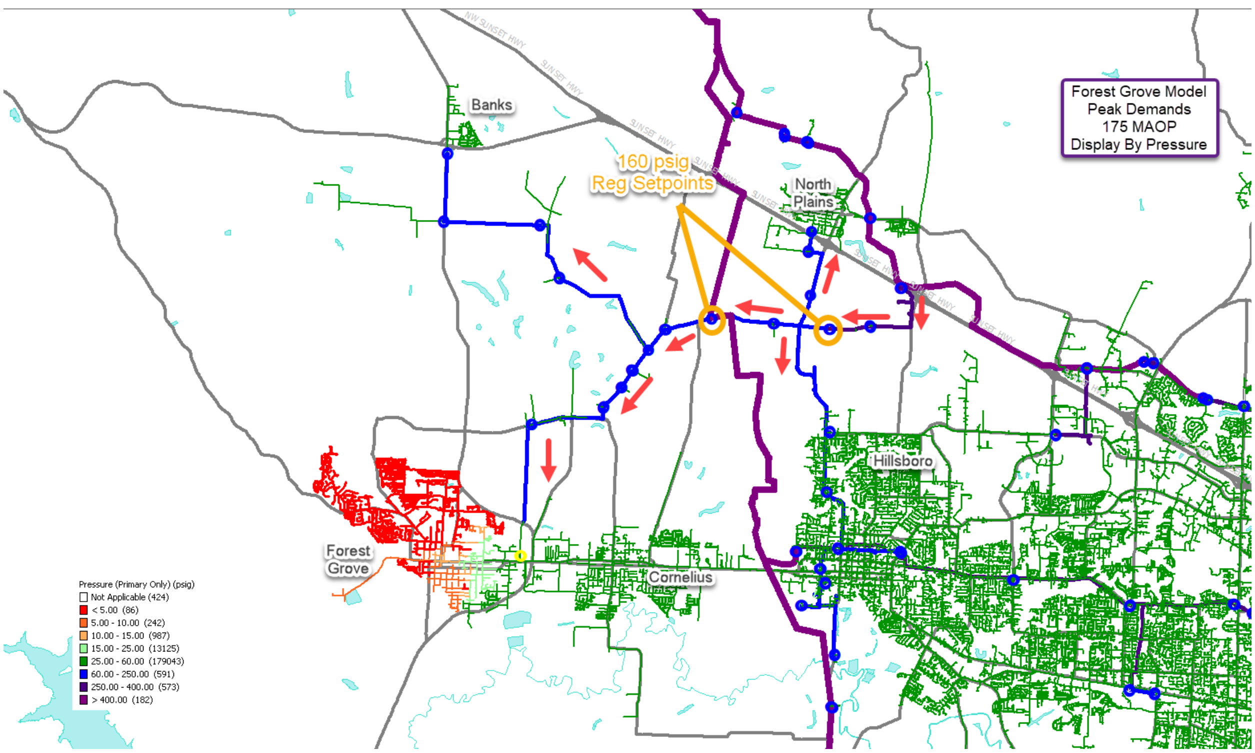
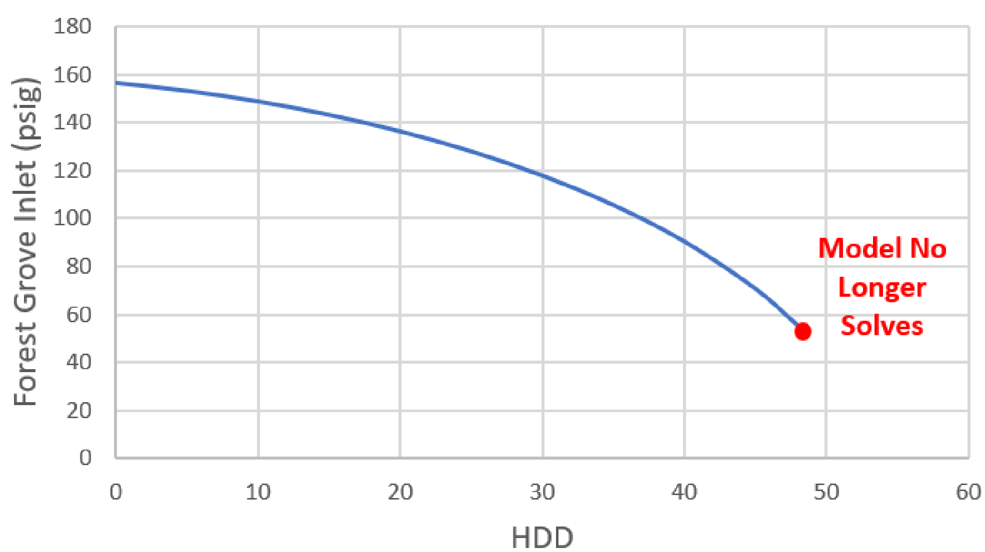


Figure 8.19 shows Synergi Gas™ results for the Forest Grove district regulator inlet pressures against various Heating Degree Days (HDDs). As the weather gets colder, the Forest Grove district regulator inlet pressure decreases. The graph illustrates that the relationship between pressure and capacity is nonlinear. The nonlinear relationship means that as demands are added in Forest Grove, the system becomes more sensitive to pressure loss. The graph terminates at 49 HDD. At 49 HDD, the model does

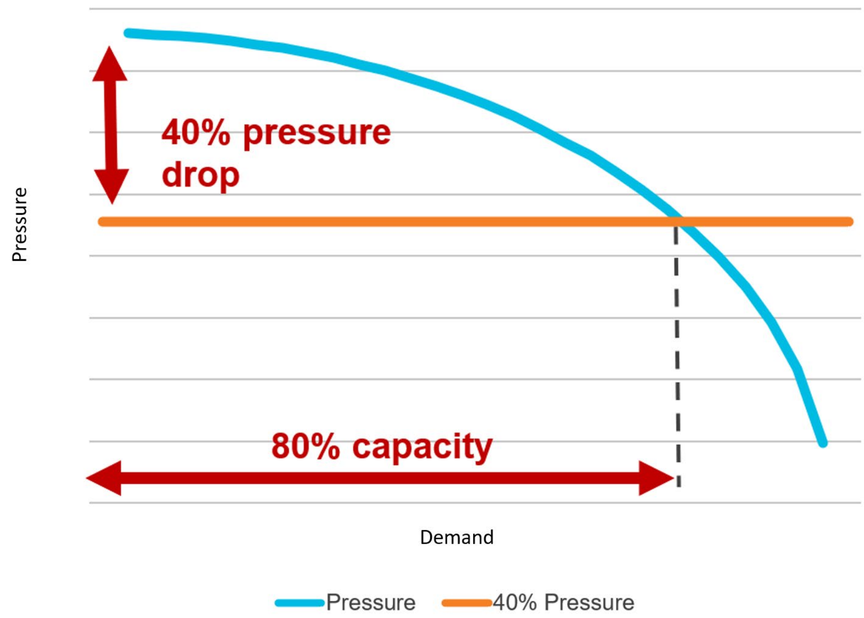
not solve because of insufficient inlet pressure to the Forest Grove district regulator. Regulators require adequate inlet pressure to operate properly and deliver gas to downstream customers, which is typically 25 psig higher than the outlet pressure.

Figure 8.19: Forest Grove District Regulator Inlet Pressure Over Various Temperatures



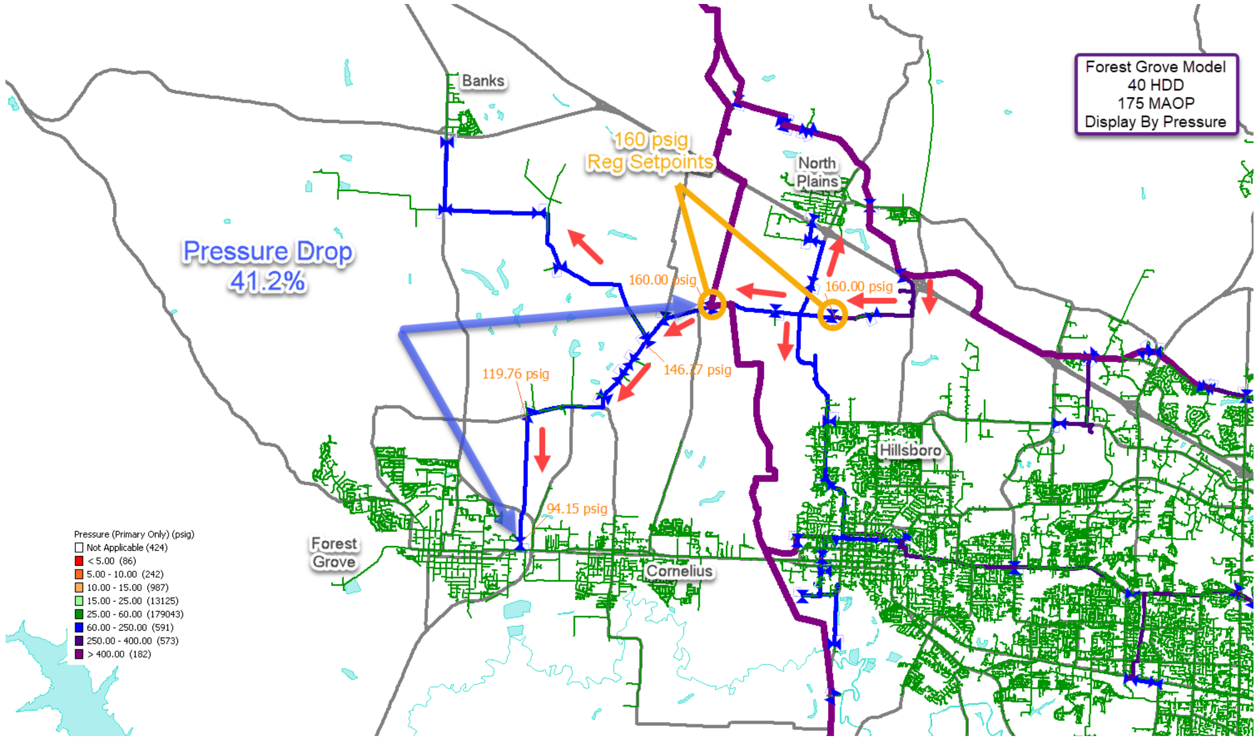
As mentioned in earlier in this Chapter, NW Natural's high pressure reinforcement criteria include addressing pressure drops that exceed 40% from the source to the end of the system. A system with a pressure reduction of 40% equates to an 80% level of capacity utilization. Small increases in demand from weather or growth can lead to outages when pipelines operate above 80% capacity. As shown in Figure 8.20, increases in demand from colder weather or growth increases the probability of outages when pipelines operate above 80% capacity as pipeline pressure decreases rapidly.

Figure 8.20: Pressure Drop Vs Demand



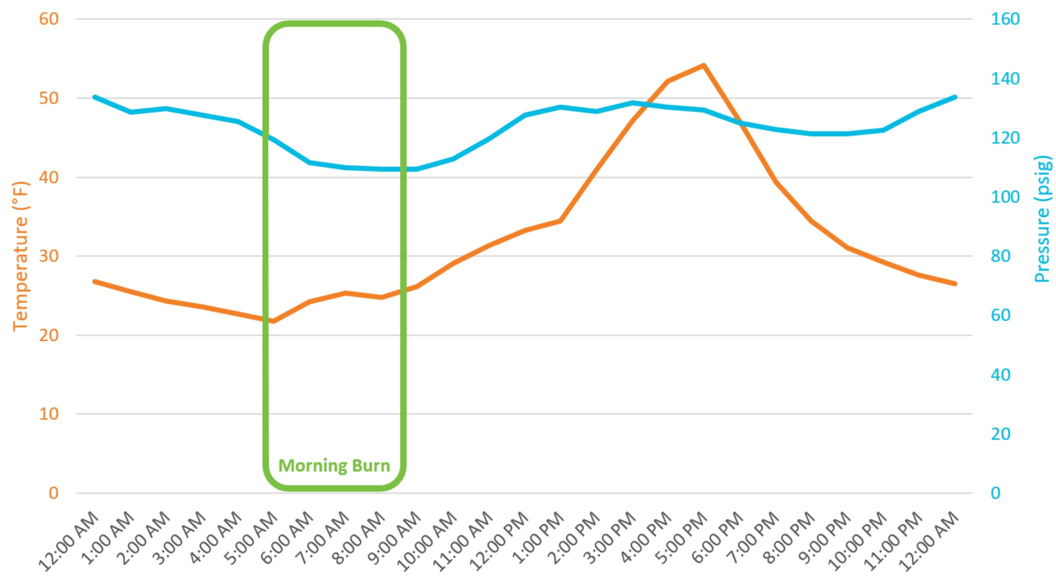
As displayed in Figure 8.21, the model results indicate that an average temperate of 25°F would cause the pressures on the Forest Grove Feeder to drop by over 40%. This area experiences a cold event with an average daily temperature less than 25°F about once every 3 years. The last cold event occurred in January of 2017.

Figure 8.21: 40% Pressure Drop for the Existing System



NW Natural began collecting EPPR pressure data in November 2020. During the sample period, the highest pressure drop occurred on February 23, 2022. Data retrieved from the EPPR revealed that the Forest Grove district regulator inlet pressure fell below 109 psig while the district regulators feeding the Forest Grove Feeder were set to 160 psig. Although the pressure drop was not greater than 40%, the pressure reads were within 1% of the modeled value of 110 psig. The EPPR case temperature during this day revealed that Forest Grove average daily temperature was 32°F. Figure 8.22 shows the recorded pressures and temperatures during the February 23, 2022, event. One area highlighted in Figure 8.22 is the morning burn. The morning burn is defined as the peak usage hour when businesses open, and where gas use increases as customers cook, adjust thermostats, and use hot water as they prepare for the day.

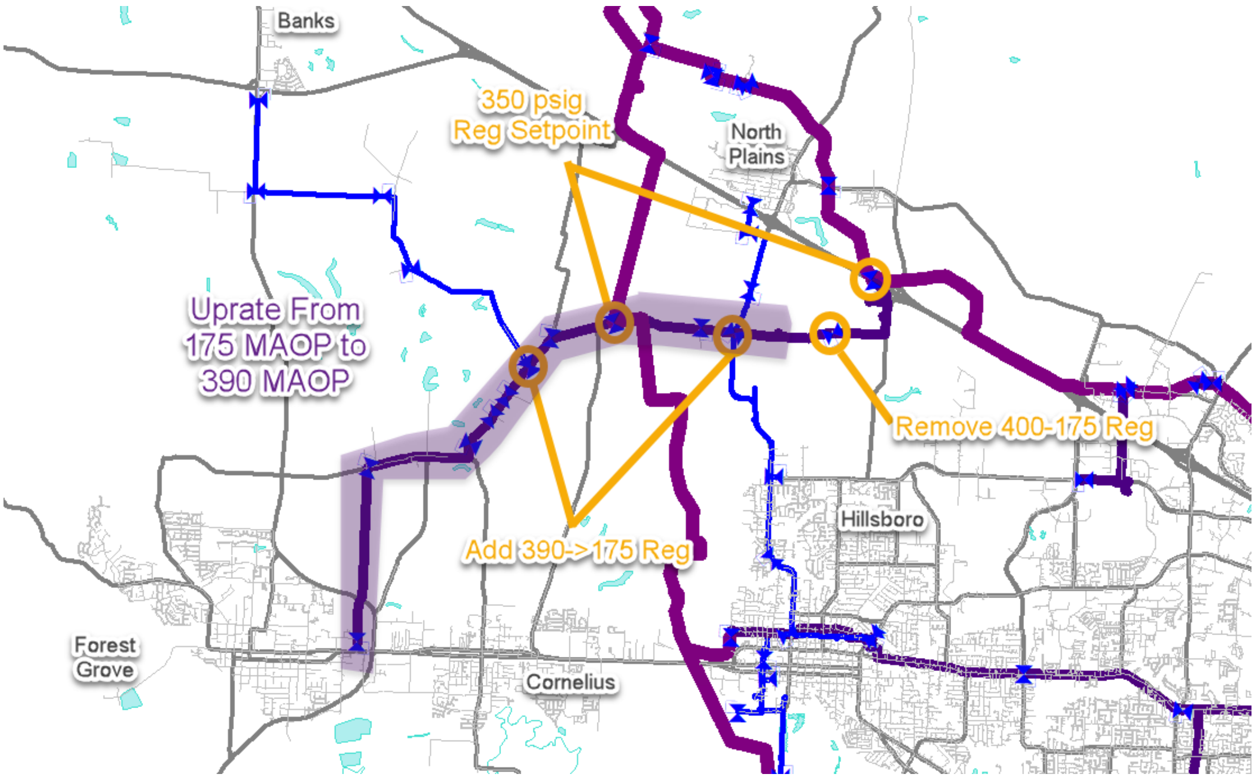
Figure 8.22: EPPR Data - February 23, 2022



The high pressure main on the Forest Grove Feeder was originally tested to allow a pressure uprate to an MAOP higher than the current 175 MAOP. As a general rule, the easiest and least expensive way to increase the capacity of a pipeline is to increase its operating pressure. Uprating a portion of the Forest Grove Feeder to an MAOP of 390 psig increases the capacity of this pipeline to deliver gas reliably to Forest Grove. The 175 MAOP laterals to Banks, North Plains, and Hillsboro do not have capacity constraints and would remain at their current 175 MAOP. Two new 390 to 175 district regulators must be installed to isolate these laterals from the newly uprated feeder. An existing 400 to 175 district regulator would be removed. All other district regulators and service regulators along the newly uprated line would be certified to operate at the new MAOP.

Figure 8.23 shows the modifications required for the high-pressure system to uprate the pipeline.

Figure 8.23: Proposed System Reinforcement



As depicted in Figure 8.24, under peak conditions, the inlet pressure at the Forest Grove district regulator would be 303 psig with the Forest Grove Feeder Uprate in place. The corresponding pressure drop across the high-pressure system is 13.4% (based on upstream regulator setpoint of 350 psig), which is below the 40% pressure drop criterion to identify weak high-pressure systems. The model results show that pressure on the Forest Grove low-pressure system would be above 5 psig with the uprated pipeline. With the reinforcement in place, the Forest Grove Feeder would have adequate capacity to serve demands in the area.

Figure 8.24: Uprated System Peak Model

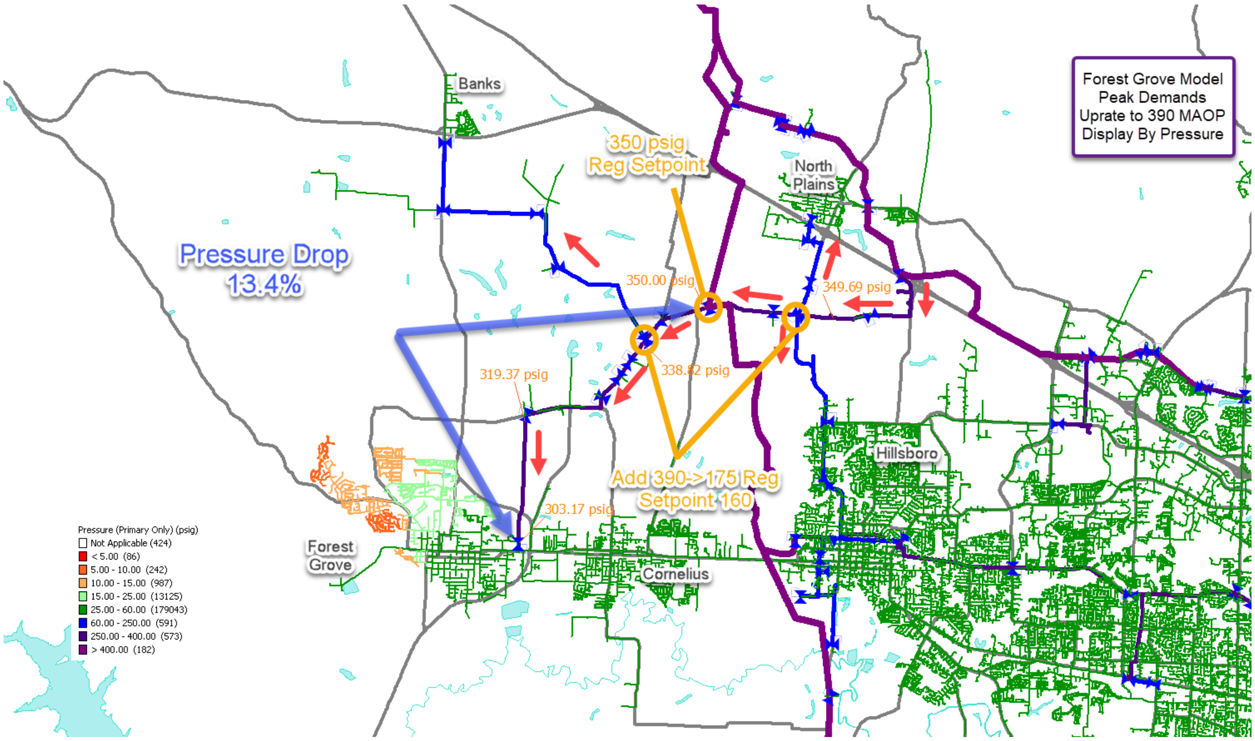
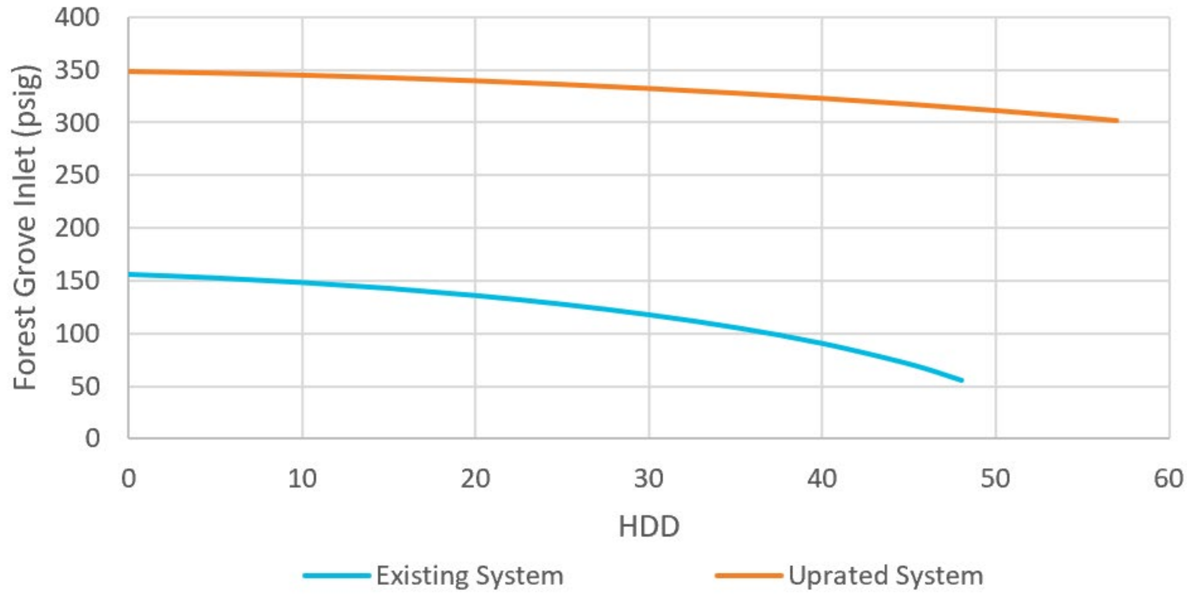


Figure 8.25 shows the pressures "before" and "after" the improvement. The "before" curve is the existing system applying current peak demands with interruptible customers disabled. The existing system curve shown in blue stops at 49 HDD because we do not have adequate inlet pressure at the Forest Grove district regulator for the model to solve. The "after" curve is the model results of the uprated system using existing demands with interruptible customers disabled. The difference between the curves captures the pressure benefits from the uprate.

Figure 8.25: Pressure Improvement



8.5.4 Uprate Scope

The items below would have to be completed in order to safely operate the Forest Grove Feeder at 390 MAOP:

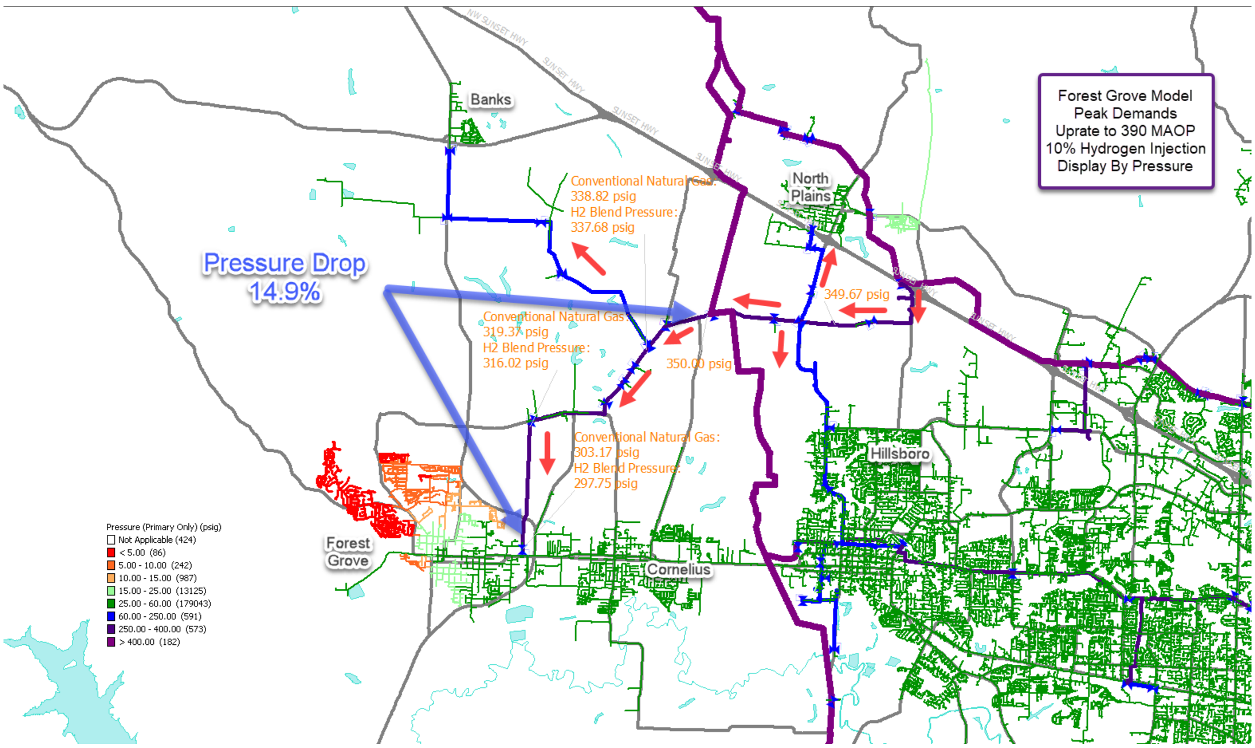
- Uprate approximately 6.3 miles of high-pressure main from an MAOP of 175 to an MAOP of 390
- Potentially uprate/replace 12 service regulator inlets
- Potentially uprate/replace 4 district regulator inlets
- Abandon 1 district regulator
- Install 2 district regulators

8.5.5 Hydrogen Compatibility

NW Natural is seeking opportunities for blending hydrogen with natural gas to lower carbon emissions. Hydrogen blended with conventional natural gas lowers the BTU values of the gas on a pipeline system. Lower BTU value gas requires higher volumes to serve the same demand because each volumetric unit of gas contains a smaller amount of energy. The higher volume of gas required to serve the same demand increases velocities in the pipeline, resulting in increased frictional losses and higher pressure drops compared to gas with higher BTU values.

Because the pressure loss across a pipeline would be higher for hydrogen blends, the existing system could not receive a hydrogen blend without further worsening the inlet pressure of the Forest Grove district regulator. Synergi Gas™ was used to model the implications of introducing hydrogen blends into the Forest Grove Feeder after uprating the pipeline from an MAOP of 175 to an MAOP of 390. The model results compare the pressures at the inlet of the Forest Grove Feeder for conventional natural gas with a gas blend that includes 10% hydrogen by volume. Model results show that flowing conventional natural gas during a peak event would cause the inlet pressure at the Forest Grove district regulator to be 303 psig. Comparatively, with hydrogen blended gas, the pressure at the inlet of the Forest Grove district regulator would be 298 psig. If a hydrogen blend were introduced onto the Forest Grove Feeder, the proposed uprate of the system would satisfy existing <u>and</u> future peak demands on the Forest Grove Feeder. Figure 8.26 shows the Synergi Gas™ model results for the 10% by volume hydrogen model run.

Figure 8.26: Uprated System Peak Model with 10% Hydrogen Blend



8.5.6 Project Alternatives

In addition to the tradition pipeline solution, NW Natural considered targeted interruptible schedule agreements by estimating the technically potential load savings from large firm industrial loads in the affected area switching to interruptible service. Even with all firm industrial loads curtailed in the model, Synergi Gas™ results demonstrate that the 175 MAOP system will continue to experience a greater than 40% pressure drop during peak hourly conditions indicating that there is insufficient technical potential available.

NW Natural also considered a satellite LNG Facility. The estimated cost to site LNG facility to serve affected area was estimated to cost significantly higher than pipeline uprate. Capital costs alone were estimated to be over $15 million dollars. Thus, this alternative was not considered further.

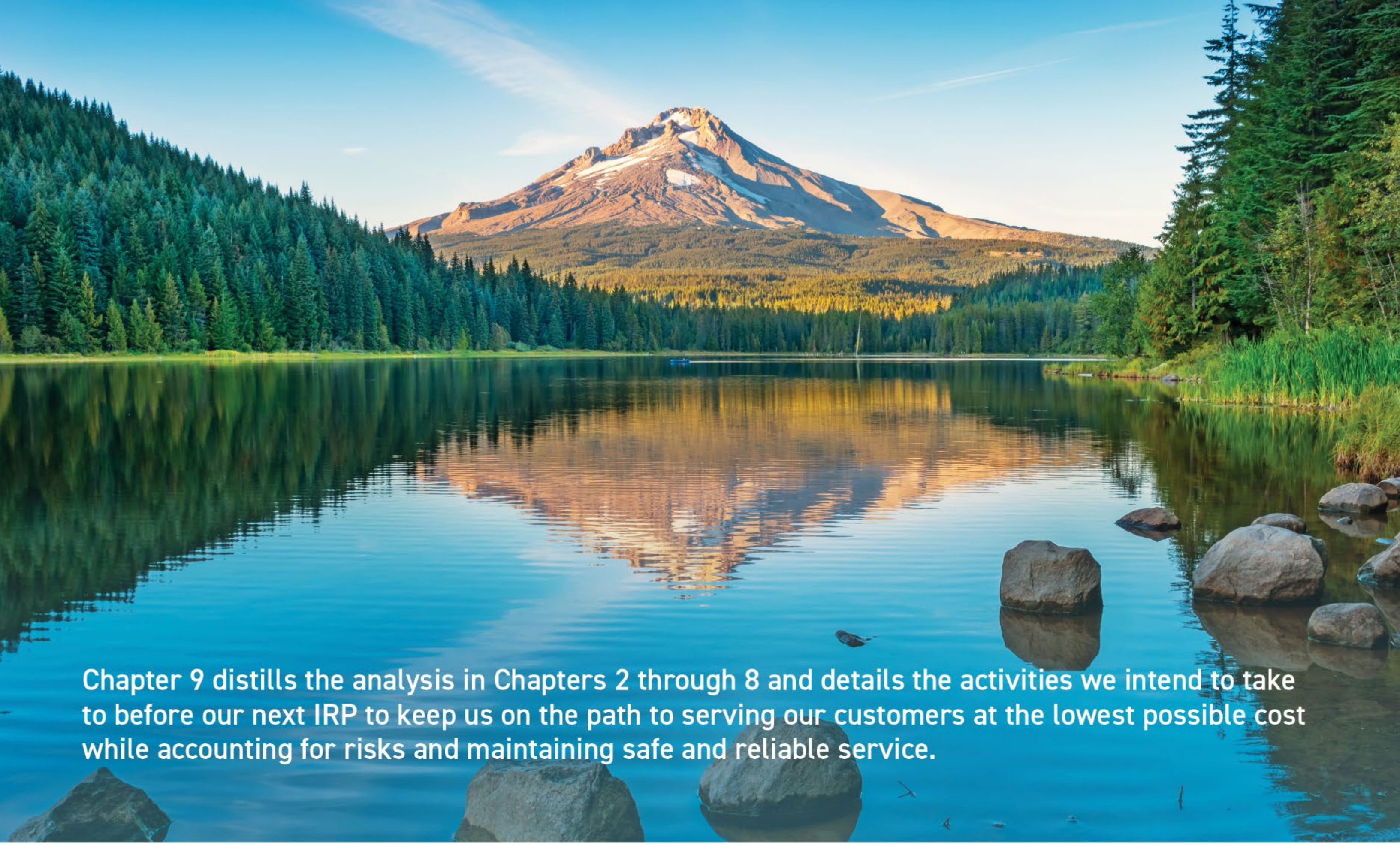
Lastly, NW Natural also considered geographically targeted RNG/Synthetic Methane but the site was not conducive to a cost-effective RNG interconnection project. RNG supplies typically originate from landfills, digesters, wastewater facilities, farms, and other waste management operations and thus one of these RNG-producing facilities would have to be in the area of need.

The Forest Grove Feeder Uprate shown in Table 8.4 is the sole project which will have an action item for which NW Natural is requesting acknowledgement by the Public Utility Commission of Oregon. Following NW Natural's final investment decision, this project will be implemented between 2024 and 2025.

Estimated costs for this project are stated in 2022 dollars and do not include construction overhead. A project's estimated cost may change over time, as it moves from a conceptual design to its final engineering specification. Additionally, both updated cost estimates and the actual cost of a project when constructed may differ from preliminary cost estimates due to actual inflation (cost escalation) differing from projected inflation, i.e., differences due to changes in the real price of a project between the preliminary cost estimate to a refined cost estimate to actual cost.

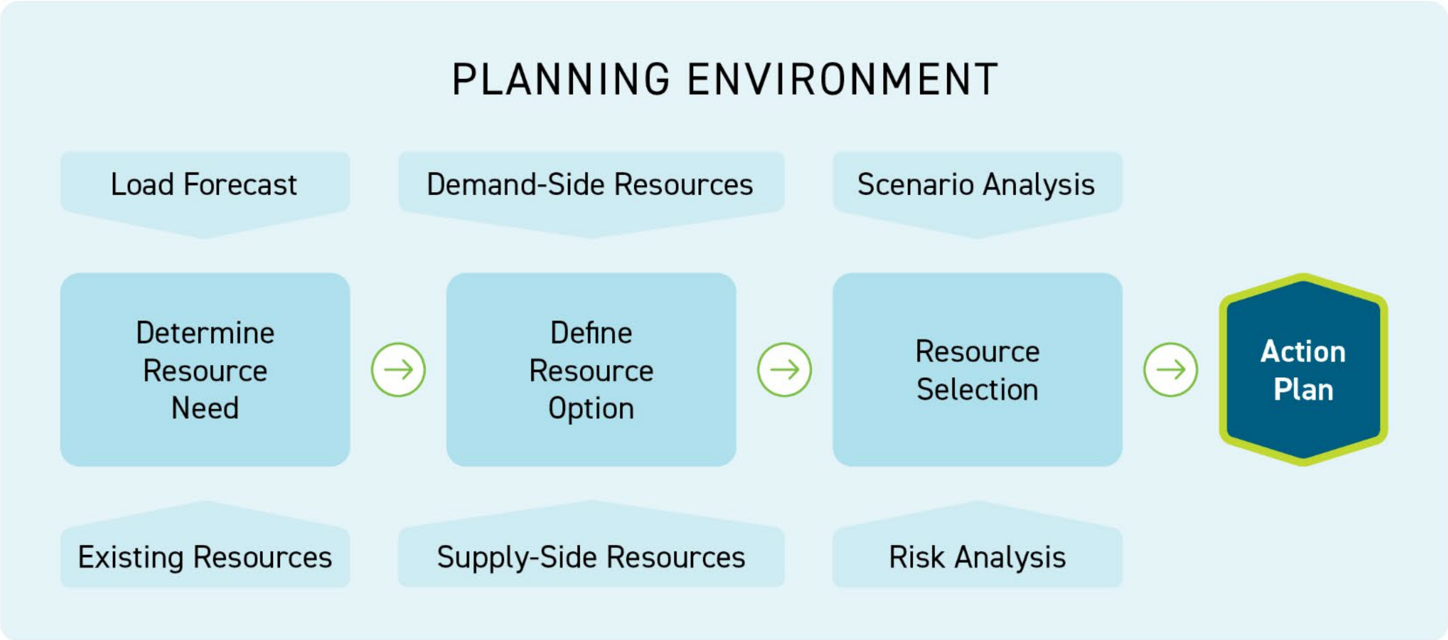
Table 8.4: Distribution System Project

Project	Schedule	Estimated Cost (Millions of $2021)	Estimated PVRR (Millions of $2021)
Forest Grove Feeder Uprate	2025	$3.0 - $6.2	$3.0 -$7.0



Chapter 9 distills the analysis in Chapters 2 through 8 and details the activities we intend to take to before our next IRP to keep us on the path to serving our customers at the lowest possible cost while accounting for risks and maintaining safe and reliable service.

9 Action Plan



9.1 Action Plan

The Action Plan turns the results of the IRP analysis into discrete near-term activities that represent the best combination of least cost and least risk over the IRP planning horizon. The action items in this Action Plan are robust in regard to a wide range of potential future outcomes and therefore all represent low regret ways to move forward in the current environment.

Capacity Resource Action Items:

1. Acquire 20,000 Dth/day of deliverability from either recalling Mist, a city gate deal, or a combination of both for the 2023-24 gas year. Based upon updated load forecast in upcoming IRP updates recall Mist capacity as required for the 2024-25 and 2025-26 gas years.
2. Replace the Cold Box at the Portland liquified natural gas (LNG) facility for a targeted in-service date of 2026 at an estimated cost of $7.5 to $15 million.
3. Scope a residential and small commercial demand response program to supplement our large commercial and industrial programs and file by 2024.

Oregon Emissions Compliance Action Items:

4. Working through Energy Trust of Oregon, acquire 5.7 – 7.8 million therms of first year savings in 2023 and 6.7 – 8.9 million therms of first year savings in 2024, or the amount identified by the Energy Trust board.
5. In Oregon, to achieve SB 98 targets, seek to acquire 3.5 million Dths of renewable natural gas (RNG) in 2024 and 4.2 million Dths of RNG in 2025, representing 5% and 6% of normal weather sales load in 2024 and 2025.
6. Work with Energy Trust of Oregon, the Alliance of Western Energy Consumers and other stakeholders to develop energy efficiency programs for transportation schedule customers by 2024.
    - While this item is a part of our compliance strategy, NW Natural is not asking for acknowledgment from the OPUC of this item as we are already pursuing this action.
7. In Oregon, purchase Community Climate Investments representing any additional Climate Protection Plan (CPP) compliance needs for years 2022 and 2023 in Q4 2023 and for year 2024 in Q4 2024 based upon actual emissions to ensure compliance with the 2022-2024 compliance period.

Distribution System Action Item:

8. In Oregon, uprate the Forest Grove Feeder (also known as the McKay Creek Feeder) to be in service for the 2025 gas year at an estimated cost of $3.0 to $7.0 million.

Washington Emissions Compliance Action Items:

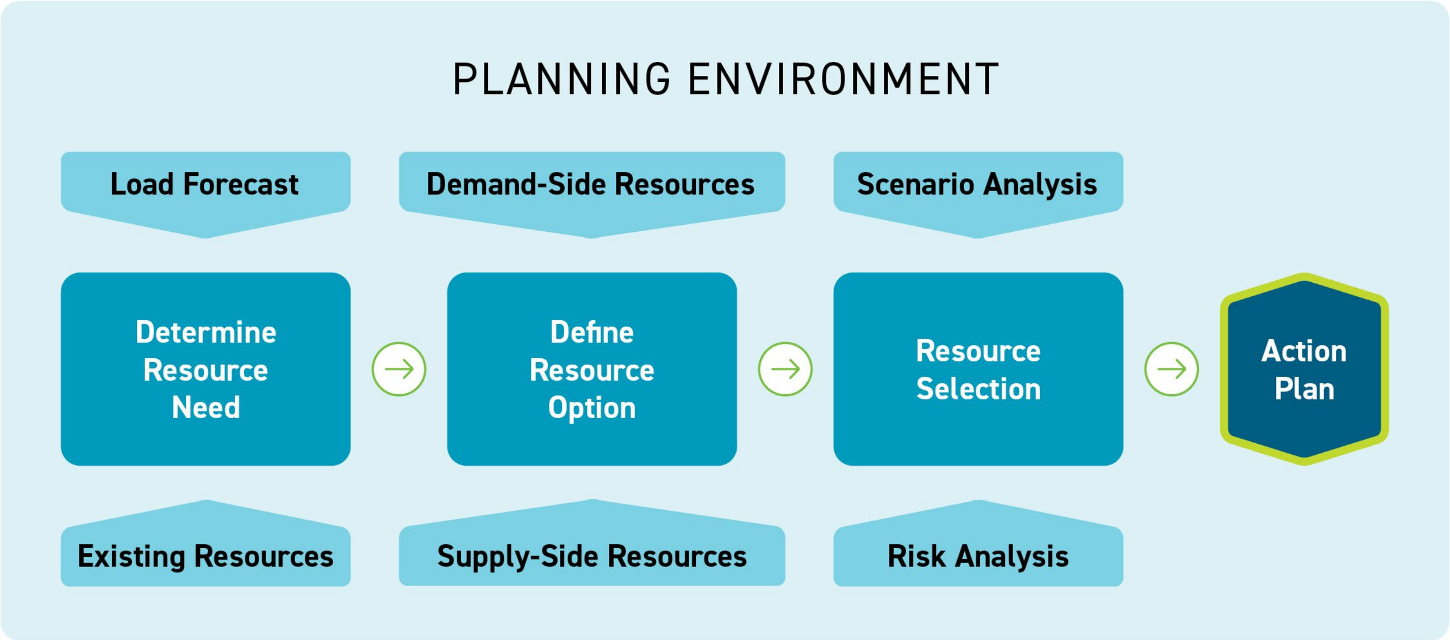
9. In Washington, acquire carbon offsets compliant with the Climate Commitment Act’s Cap-and-Invest program for 5% of expected weather emissions in year 2023 and 2024. Seek to acquire additional offsets representing 3% of expected weather emissions allowed for CCA compliance

on tribal lands, and if they can be acquired for a lower price than the program allowance price floor for years 2023 and 2024, acquire these offsets.

10. In Washington, to support HB 1257, seek to acquire 600,000 Dths of renewable natural gas (RNG) in 2024 and 800,000 Dths of RNG in 2025, representing 6% and 8% of normal weather compliance gas in 2024 and 2025.
11. In Washington, purchase emissions allowances equal to emissions at an estimate of the 95th percentile of need for annual compliance net of voluntary RNG, carbon offsets, and freely allocated but not consigned allowances.
12. Working through Energy Trust of Oregon, acquire 275,000-370,000 therms of first year savings in 2023 and 276,000-310,000 therms of first year savings in 2024, or the amount approved through WUTC Biennial Energy Efficiency Plan.
13. Work with Energy Trust of Oregon, the Alliance of Western Energy Consumers and other stakeholders to develop energy efficiency programs for transportation and industrial sales schedule customers by 2024.

Public involvement and input are essential to the development of our IRP. This chapter discusses how NW Natural involved the public through stakeholder workshops, meetings for the public, and other means of communication.

10 Public Participation



10.1 Public Participation

Public involvement and input are essential to the IRP development. In accordance with guidelines from both Oregon and Washington and to encourage an open and transparent process, the public is encouraged to attend IRP workshops and meetings, and to submit comments during public comment periods.

In the current state, the public can find information about the IRP and associated activities on the NW Natural website site, under the About Us > Resource Planning Page. This page includes multiple drop-down menus which house a description of the IRP process, current IRP working groups and how to contact the IRP team, current and previous IRPs, and a letter from the CEO. As indicated on the website, members of the public, including community-based organizations and advocacy groups, can contact the IRP team and request to be included in the IRP distribution list by contacting IRP@nwnatural.com. All meetings are open to all members of the public and any member of the public can request to be added to the distribution list. The IRP distribution list is utilized to announce IRP related activities including Technical Working Groups (TWGs), and to provide invitations to virtual meetings. For the 2022 IRP Meeting for the Public, NW Natural additionally utilized a registration link through the website, whilst also providing an announcement via the distribution list. The Meeting for the Public is described in more detail in Section 10.3.

NW Natural is invested in increasing effective participation in its IRP process and will continue to seek out and implement process improvements. As noted in Chapter 2 as well as later in this chapter (see Section 10.4), the IRP process was the impetus for the creation of NW Natural's inaugural Community and Equity Advisory Group (CEAG). Feedback provided thus far on participation activities in the 2022 IRP has been recorded (see Appendix J) and NW Natural looks forward to working with stakeholders on applying such feedback in its next IRP process.

10.2 Technical Working Groups

The Technical Working Group (TWG) is an integral part of developing NW Natural's resource plans. During this planning cycle, NW Natural worked with representatives from Oregon Public Utility Commission (OPUC) of Oregon Staff; Washington Utilities and Transportation Commission (WUTC) Staff; Citizens' Utility Board of Oregon; Energy Trust of Oregon; Alliance of Western Energy Consumers (AWEC); Washington's Office of the Attorney General; Northwest Gas Association; Northwest Energy Coalition; Green Energy Institute at Lewis & Clark Law School; Enbridge Pipeline; Fortis BC; Avista; Cascade Natural Gas; Puget Sound Energy; and other stakeholders.

NW Natural held seven TWG meetings and one meeting for the public as part of its 2022 IRP process. Prior to the 2022 IRP TWG series, NW Natural held two supplemental TWGs pursuant to Oregon Public Utility Commission Order No. 21-013 in Docket LC-71. Due to COVID-19, all meetings were held virtually. NW Natural saw an increase in the number and diversity of participants utilizing virtual platforms. Below is a brief summary of each meeting.

Supplemental TWG No. 1, Load Considerations – September 29, 2021
Held virtually via Microsoft Teams. NW Natural reviewed modeling tools used within load forecasting and discussed with stakeholders the potential implications to modeling and forecasting from recent policies enacted in Oregon and Washington. Stakeholders were asked to provide feedback to NW Natural regarding key demand-side inputs needed for end-use load forecasting.

Supplemental TWG No. 2, Emission Considerations – December 9, 2021
Held virtually via Microsoft Teams. NW Natural used the first portion of this supplemental TWG to allow stakeholders that opportunity to ask questions related to NW Natural's presentation through UM 2178, Natural Gas Fact Finding Per EO 20-04.

During the second half to the TWG, NW Natural presented the modeling challenges and considerations created by emissions compliance policies in both Oregon and Washington. TWG participants discussed challenges and potential solutions utilizing the tools available. Feedback was requested from stakeholders on additional thoughts to modeling challenges.

TWG No. 1, Planning Environment and Environmental Policy – January 14, 2022
Held virtually via Microsoft Teams. During the first half of TWG No. 1, NW Natural provided an introduction to NW Natural. During this introduction, the IRP team reviewed, at a high-level, gas purchases, customer types and rate schedules, emissions context, system capacity resources, and distribution system planning options. This portion of the TWG also included NW Natural's view on the scope and role of the IRP, the regulatory basis for IRP process, IRP timelines, least cost-least risk considerations, and the interplay of the parts within the planning environment which culminate in the Action Plan. The IRP team additionally provided updates on actions since the 2018 IRP and 2018 IRP Update, and new challenges for the 2022 IRP.

The second portion of the TWG was dedicated to the Planning Environment and Scenario Development. The IRP team reviewed changes in the policy landscape which impact the IRP in either or both Oregon and Washington. The team discussed with stakeholders the challenges associated with new policies and the compliance mechanisms associated with each. Lastly, the IRP team reviewed the development of scenarios and types of analysis within such scenarios. Scenario analysis used in the 2018 IRP was reviewed and draft scenarios for the 2022 IRP were presented. TWG attendees discussed draft scenarios and provided initial feedback during the presentation. Stakeholders were provided further time to provide feedback on scenarios with feedback requested back to the IRP team by February 4, 2022.

TWG No. 2, Load Forecasting – February 11, 2022
Held virtually via Microsoft Teams. NW Natural discussed the goals, purpose, and framework within which load forecasts are developed, including the differences in the 2022 IRP compared to previous years. The TWG focused on understanding several concepts about load forecasting including (1) when

forecasting there is a trade-off between model parsimony and accuracy/precision (2) historical trends establish our reference case, which is a key starting point for understanding how structural changes to customer growth and stock turnover of end-use equipment impact overall demand (3) the importance for peak planning in IRPs and the trade-off of between costs for reliable service and the risks of resource constraints during an extreme cold event and (4) load uncertainty and an overview of stakeholder feedback on draft scenarios as well as a preview of the draft load forecasts within such scenarios.

Each part of load forecast modeling was reviewed with detailed discussion related to each section including the differences between the types of load forecasts; residential and commercial customer count and use per customer (UPC), and industrial, large commercial, and compressed natural gas (CNG). This discussion included accounting for impacts from energy efficiency and total sales and transportation loads. NW Natural also reviewed the reference case for the expected weather load forecast and the design weather load forecast (inclusive of a cold event and peak day load forecast).

Lastly, NW Natural gave an overview of stakeholder feedback on draft scenarios presented in TWG No. 1 as well as a preview of the draft load forecasts within such scenarios.

TWG No. 3, Supply-Side Resources – March 28, 2022
Held virtually via Microsoft Teams. The first portion of this TWG was dedicated to reviewing feedback received from stakeholders on the 2022 IRP scenarios and NW Natural's stochastic modeling to account for uncertainty in load scenarios. The remainder of the TWG focused on supply-side resources.

During the presentation on supply-side resources, the IRP team discussed the differences and overlap between gas supply capacity and distribution capacity resources; existing supply-side resources and an overview of conventional market fundamentals; Portland LNG; and RNG and hydrogen resources. The team went into a detailed discussion of Portland LNG's contribution to serving current load and its requirements to serve including an overview of the required Cold Box to continue operations at Portland LNG, and an overview of alternatives to the Cold Box to maintain reliable service for current peak day operations.

Lastly, ICF reviewed and discussed the availability of RNG and hydrogen resources at a national level. The IRP expanded upon this review with a discussion of the policy environment and markets for RNG and hydrogen, as well as current NW Natural projects. The IRP team also briefly reviewed NW Natural's methodology for evaluating the incremental cost of RNG resources.

TWG No. 4, Avoided Costs and Demand-Side Resources– April 13, 2022
Held virtually via Microsoft Teams. The first portion of the TWG focused on understanding several concepts about Avoided Costs. The IRP team reviewed what avoided costs are; principles of and standard industry approaches to avoided costs; applications of avoided costs in cost-effectiveness

evaluations, as well as the components of avoided costs and their associated resource option application; energy and environmental related avoided costs including CPP and CCA compliance costs and calculating GHG price components; Risk Reduction Value and commodity price risk reduction costs; and infrastructure and capacity avoided costs including their relation to peak load and peak savings. NW Natural also shared avoided cost results by end-use for both OR and WA.

The second portion of the TWG focused on OR And WA Conservation Potential Assessments (CPAs) and emerging technologies. Energy Trust of Oregon (ETO) presented a section on OR CPA for Sales Customers, including forecast results. Applied Energy Group (AEG) presented a section on WA CPA for Transport Customers, including draft conservation potential results. The IRP team reviewed the WA CPA for sales load completed by AEG in 2021 and presented results for CPA for WA Transport Customers also conducted by AEG in 2021. GTI gave a presentation on thermal (gas) heat pumps and the status of new technologies coming to the market for residential and/or commercial customers. Finally, NEEA spoke to market transformation and the partnerships between various organization which can accelerate the adoption of emerging technology.

TWG No. 5, Distribution System Planning– April 25, 2022
Held virtually via Microsoft Teams. The IRP team reviewed distribution system planning (DSP) processes, modeling, and standards as they are applied within the IRP process. This includes the deployment of both “pipeline” and “non-pipeline” solutions. The Technical Working Group focused on (1) peak hour demand including that the design of system is based on peak hour customer demand and how weather is a major driver, and (2) non-pipeline solutions and the criteria they must meet in order to be an alternative distribution system resource, and (3) distribution system planning objectives.

During the discussion of DSP objectives, NW Natural reviewed meeting peak hour requirements, addressing localized system needs, and choosing the cost-effective alternative while accounting for risk. Points of consideration included that NW Natural’s DSP is in a transition from a “just-in-time” planning process to a forward-looking planning process and that this transition is assisted by the improvements in system modeling through the Customer Management Module (CMM) project. Tools for system modeling and planning such as SCADA, and Synergi™, as well as reinforcement standards were also reviewed in detail.

Lastly, NW Natural discussed alternative analysis, the Geographically Targeted Energy Efficiency (GeoTEE) pilot, and the proposed Forest Grove Feeder system reinforcement project based upon principles and modeling as discussed.

TWG No. 6, Low Carbon Gas Evaluation Methodology and Emissions Compliance Mechanisms – June 1, 2022
Held virtually via Microsoft Teams. The first portion of the TWG focused on low carbon gas, (i.e., RNG) evaluation methodology, beginning with a review of IRP related activities and policies since filing the

2018 IRP update, as well as the evolution of NW Natural's evaluation methodology and key terminology related to low carbon/ renewable resources. The IRP team then reviewed and discussed:

- Project types of low-GHG resources including the differences between bundled and unbundled purchases
- Application of avoided costs, utilizing examples to illustrate the various types of costs avoided such as Transport, Compliance, Infrastructure, and Capacity
- How the cost of RNG is evaluated against conventional gas and the calculations used
- An in depth look at the components within the cost calculations and evaluation methodology
- Accounting for risk and uncertainty, including the tools and calculations utilized; NW Natural accounts for two main types of risk in its RNG methodology - Market and Policy

The second portion of the TWG was dedicated to reviewing PLEXOS®, the system resource planning model. The IRP team discussed how the model incorporates new policies including emissions compliance, as well as previously accounted for inputs such as weather and climate change, and the social cost of carbon. The IRP team then led stakeholders through modeling examples and a demonstration of NW Natural's complex model within the modeling software.

TWG No. 7, Portfolio Results and Actions – September 8, 2022
Held virtually via Microsoft Teams. During the first portion of the TWG, NW Natural reviewed which topics were covered in the previous six TWGs as they apply to the IRP process. NW Natural spoke to the risk analysis and discussed scenario vs simulation analysis including the importance of each in determining resource decisions. The team also discussed feedback from stakeholders on the draft IRP and provided scenario results for both Oregon and Washington. Scenario analysis was broken into three categories: Capacity Planning, Energy Planning, and Emissions Planning. In discussing the scenarios and results, NW Natural responded to some of the stakeholder feedback from the draft IRP and how the team is applying the feedback to the final IRP including clarifying its use of the terms "reference case" and "business-as-usual case" and where assumptions were adjusted.

The second portion focused on the Monte Carlo simulations- inputs and outputs, and the Action Plan. During this time, stakeholders and NW Natural held a robust discussion regarding the Monte Carlo draws and reviewed each action item individually with time allowed for open questions and discussion. NW Natural additionally held an open Q & A with the remaining time left in the workshop. Stakeholders provided thoughtful feedback throughout the TWG, of which NW Natural has considered.

Appendix G contains the (virtual) attendance lists for each TWG meeting.

10.3 IRP Draft Release and Meeting for the Public

The public is made aware of the IRP draft release through announcements on the NW Natural website and via a bill insert sent to all NW Natural customers. The Company additionally invited customers to participate in the resource planning process by hosting a Meeting for the Public on the evening of July 18, 2022. A bill insert notice, sent to all customers beginning on May 24, 2022, informed customers about the IRP process, draft release, welcomed customers to submit feedback, and invited customers to attend the Meeting for the Public. Appendix H contains a copy of the bill insert notice that was sent out to all customers.

Meeting for the Public
Held virtually via Zoom during evening hours on July 18, 2022. NW Natural customers were notified and invited to a Meeting for the Public workshop via a bill insert notice as well as a posting on the Resource Planning page of NW Natural's website. For this meeting, NW Natural utilized a registration link which contained a field for questions and comments with the intent to understand the type of discussion participants were interested in.

During this workshop, NW Natural provided an overview of the company; described the IRP process and addressed how people can get involved and/or learn more; answered such questions as: How much gas will our customers use? How much energy can we save through conservation? Where will NW Natural get its gas supply?; and presented the draft Action Plan. Attendees were especially interested in understanding the modeling scenarios, how disparate utilities (i.e., a gas utility and a water utility) may or may not coordinate on resource planning and distribution projects, understanding RNG and Hydrogen, and energy conservation relative to commercial and industrial growth in the region.

10.4 Community and Equity Advisory Group

The Company's IRP process was the driving force behind the formation of NW Natural's inaugural Community and Equity Advisory Group (CEAG). NW Natural recognized particular communities and customer groups have historically not been included or engaged in the resource planning process. The Company additionally recognized that many issues related to resource planning intersect with other areas of operations and community needs. Thus, the CEAG has been formed to advise the Company on various programs and processes, including, but not limited to, the resource planning process. Members of the CEAG are recruited from community-based organizations representing historically underrepresented voices in the energy planning environment. Member organizations are compensated for participation in the CEAG. NW Natural held a grounding meeting with member organizations and a Diversity, Equity, Inclusion, and Belonging (DEIB) facilitator on June 30, 2022, and will be holding its first CEAG meeting with all members at the end of September 2022.

Though the timing of the 2022 IRP and standing up the inaugural CEAG did not fully align, NW Natural expects the CEAG will assist with increasing and improving upon current public participation in its future IRPs.