DRAFT

2013

Integrated Resource Plan

UG-120417

NW Natural®

Forward Looking Statement

This planning document contains forward-looking statements. Forward-looking statements include statements concerning plans, objectives, goals, strategies, future events and other statements that are other than statements of historical facts. NW Natural's expectations, beliefs and projections are expressed in good faith and are believed to have a reasonable basis. However, each such forward-looking statement involves uncertainties that could cause the actual results to differ materially from those projected in such forward-looking statements.

All subsequent forward-looking statements, whether written or oral and whether made by or on behalf of NW Natural also are expressly qualified by these cautionary statements. Any forward-looking statement speaks only as of the date on which such statement is made. New factors emerge from time to time and it is not possible for NW Natural to predict all such factors, nor can it assess the impact of each factor or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements.

The forecasts and projections included in this document have been developed for the purposes of integrated resource planning and should not be used for investment decisions. Disclosure of this information or use of the information for investment purposes could constitute a violation of federal securities laws.

NW Natural®

Table of Contents

CHAPTERS

APPENDICES

NW Natural®

Chapter 1: Executive Summary

NW Natural®

I. Introduction and Background

A. Introduction

This Executive Summary provides an overview of NW Natural's key findings in its 2013 Integrated Resource Plan (IRP) and includes a multi-year action plan. The Washington Utilities and Transportation Commission (WUTC) requires NW Natural to develop a long-term resource plan every two years. The IRP defines the mix of natural gas supply and demand side measures designated to meet expected future demand and reliability requirements at the lowest reasonable cost to the utility and its ratepayers.

B. Description of NW Natural

NW Natural is a 154 year old natural gas local distribution and storage company headquartered in Portland, Oregon, which serves more than 685,000 customers in Oregon and Washington. 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 60% of the customers reside in the Portland area, with another 10% in Vancouver, Washington. Residential customers comprise roughly 90% of the customer base.

C. Regulatory Guidelines

The requirements for Integrated Resource Planning in Washington established in Washington Administrative Code (WAC) 480-90-238 can be broadly summarized in the following seven actions:

1) Examine a range of demand forecasts;
2) Examine all feasible means of meeting demand;
3) Treat supply-side and demand-side resources consistently;
4) Describe the Company's long-term plan for meeting expected load growth;
5) Describe the Company's plan for resource acquisitions between planning cycles;
6) Take uncertainties in planning into account; and
7) Involve the public in the planning process.

II. Principal Conclusions

A. Natural gas supply

The introduction and proliferation of relatively low-cost production from shale gas over the last several years has been a transformational event for the industry. The industry has shifted from a situation of supply concern, high prices, and a perceived need to import LNG to a situation of abundant supply, low prices, and discussion of the potential to export LNG.

Natural gas customers have benefitted from the dramatic reduction in prices. In Washington, NW Natural's average residential customer bill has decreased by 34% since 2009. This abundant supply has also translated into lower forecasted long-term natural gas prices. Consequently, the expected cost of serving future demand estimated in this IRP is considerably lower than in previous IRPs prepared over the last several years.

The gas supply and demand outlook is never static. For example, low prices have driven down the number of drilling rigs exploring for natural gas. The consensus view is that the current low price levels are likely not sustainable. Among other factors, the potential of additional environmental regulation creates future price risk. Consequently, today's market appears to be a good time to acquire long-term natural gas supplies and lock-in the relatively low prices available today. For this reason, the Company continues to evaluate the possibility of investing in long-term natural gas reserves incremental to its 2011 acquisition, which is applied only to its Oregon gas portfolio.

Because the economic benefits of these types of transactions are deal and timing specific, the Company did not attempt to evaluate them as a generic supply side option in this IRP. The economics of any further investments would need to be evaluated based on the specifics of the transaction relative to the natural gas forward price curve at that time. Nevertheless, it may be constructive for the Company in a future IRP update to develop long-term hedging parameters that would provide guidance for prospective gas reserve acquisitions and support the regulatory review process. NW Natural expects that the current discussions with and investigations by Staff at the WUTC in relation to gas LDC Purchased Gas Adjustment filings also may be relevant to any future acquisitions, since they would function as a hedge against future price changes.

Price volatility within individual years will continue due to weather variability and other short-term factors. This IRP has not attempted to address the Company's short-term hedging plan. Shorter-term gas supply and hedging activities are addressed in the Company's annual Gas Acquisition Plan, as discussed further in Chapter 3.

B. Natural gas demand

NW Natural's load forecast has historically been driven primarily by residential customer growth. This growth is a function of the health of the local economy and housing market, as well as the relative attractiveness of natural gas versus alternate heating fuels (electricity, oil, etc.) to spur home fuel conversions. As a result of the housing market crash and the economic recession and slow recovery, NW Natural's annual customer growth has fallen to 1% or below over the last four years. The Company's updated base case load forecast is commensurately lower than in preceding IRPs.

However, this traditional market view is incomplete in that it does not reflect the likely stimulus to natural gas demand from the transformational shale gas supply event. Because of the lag time for major capital investments, this demand response has not yet caught up with supply. Nationally, this demand stimulus is expected to show up in three primary sectors —power generation, industrial, and transportation (e.g., natural gas vehicles or "NGVs"). Until now, these sectors have not been primary drivers in the Company's load forecast.

To address this anticipated demand response, the Company has prepared two Emerging Markets sensitivity cases —Medium and High. These are included to ensure that the resource plan has sufficient adaptability to respond to this potentially higher rate of load growth. Compounding the forecasting uncertainty is that customers in these sectors may or may not look to NW Natural for their supply arrangements as compared to directly handling supply themselves.

C. DSM cost-effectiveness

A key issue arising during this IRP is that the cost-effective DSM potential has decreased due to lower natural gas prices and as a result of actual verified DSM measure performance being lower than previously assumed. While the Company has had to remove certain non-cost effective measures from its offerings, it is still able to offer cost effective programs. The Company continues to monitor the cost effectiveness of it programs and consider ways of reducing delivery costs as a means for offsetting lower avoided costs.

D. Reliability risk analysis

The Company's current resource mix is dependent for 80% of its peak day supplies on two resources —Northwest Pipeline (NWP) and Mist Storage. About one-third of its on-peak supplies are dependent for transportation on NWP through the Columbia River Gorge. This high resource concentration leaves the Company's customers particularly vulnerable to probabilistic resource forced outage events in cold weather.

The Company conducted a reliability analysis in this IRP which examined two basic resource approaches to resolving the problem:

1) Resource redundancy—primarily through increased reliance on Mist Storage recall combined with more modest amounts of new capacity from a cross-Cascades pipeline and satellite LNG.

2) Resource diversity—pipeline diversification via replacing a portion of the NWP Gorge capacity with capacity from a new cross-Cascades pipeline.

Of the two approaches, the resource diversity approach projects to be the lowest cost resource path for addressing reliability given NW Natural's current position. It also has additional benefits that have not been fully quantified in this analysis: a) decreased single resource dependency, b) lower system reserve margin requirements, c) supply optionality, and d) greater expandability to serving higher load growth from Emerging Markets.

E. Distribution System Planning

The Company includes in this IRP a high level presentation of its distribution system planning in order to be more transparent and to capture projects that may be viewed as significant to delivering gas to load centers within the Company's distribution service area. The Company reasoned that, while the traditional IRP analysis determines what resources are necessary to bring gas to the citygate, that resource is only useful if it can be delivered to the area needing it. Only distribution projects meeting the following two criteria are presented in this plan:

1) High pressure transmission projects required to move gas supplies to the Company's discrete load centers (as compared to moving gas within the load center); and

2) Any major system reinforcement project over $10 million.

Specific projects meeting these criteria are identified in this IRP in Chapter 7.

F. Preferred Resource Plan

The Company's preferred resource plan is designed to achieve the following three criteria:

1) Meet base case forecasted system load growth over the next 5 years with Mist Recall;

2) Support development of a cross-Cascades pipeline project to strengthen reliability and diversify the Company's resource base; and

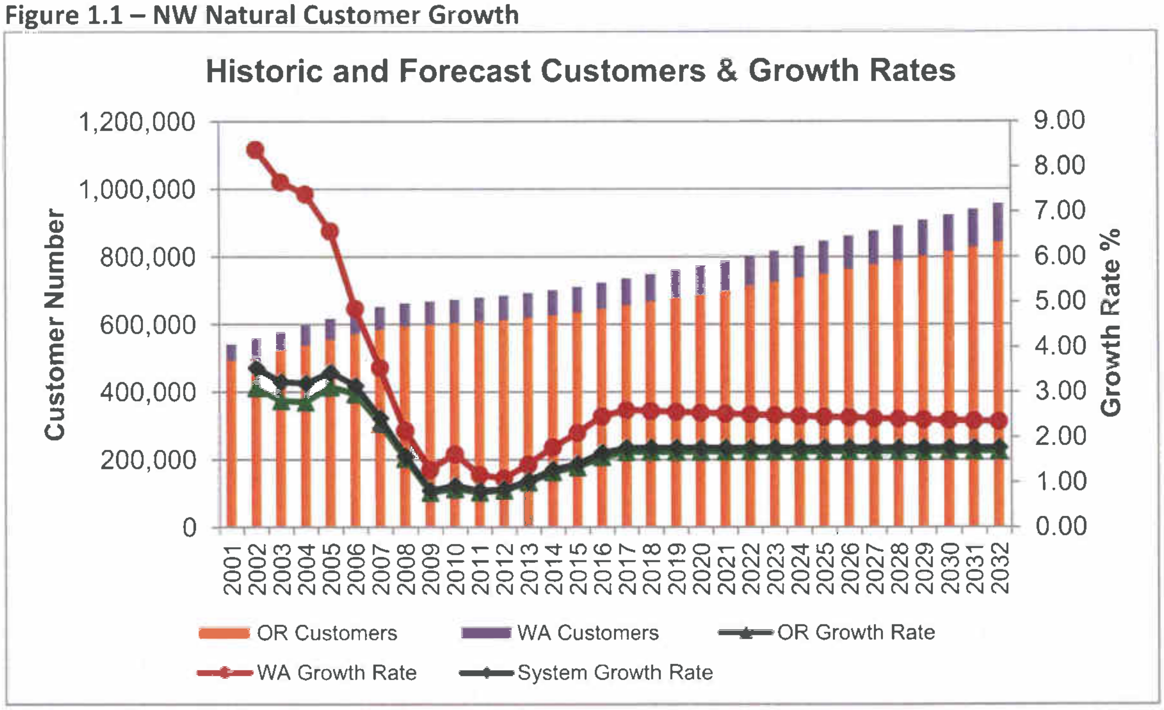
3) Be prepared to meet potentially higher load growth from Emerging Markets through a mix of additional Mist Recall and cross-Cascades pipeline capacity.

III. Demand Forecasts

A. Customer Forecast

The customer forecast is the starting point for the demand forecasting process. The following table shows historic and projected customer growth for Washington and Oregon. The forecast shows a gradual recovery in the housing market and customer growth beginning in 2013 and leveling off in 2017. Even with this recovery, the forecasted customer growth is not expected to reach the historic levels experienced prior to the "Great Recession." Load growth within the Company's Washington service area has in recent years exceeded that in Oregon, which can be attributed to lower market penetration in Washington as compared to Oregon and a large number of new housing developments being built in the greater Vancouver area. We continue to forecast this relative trend between the two states.

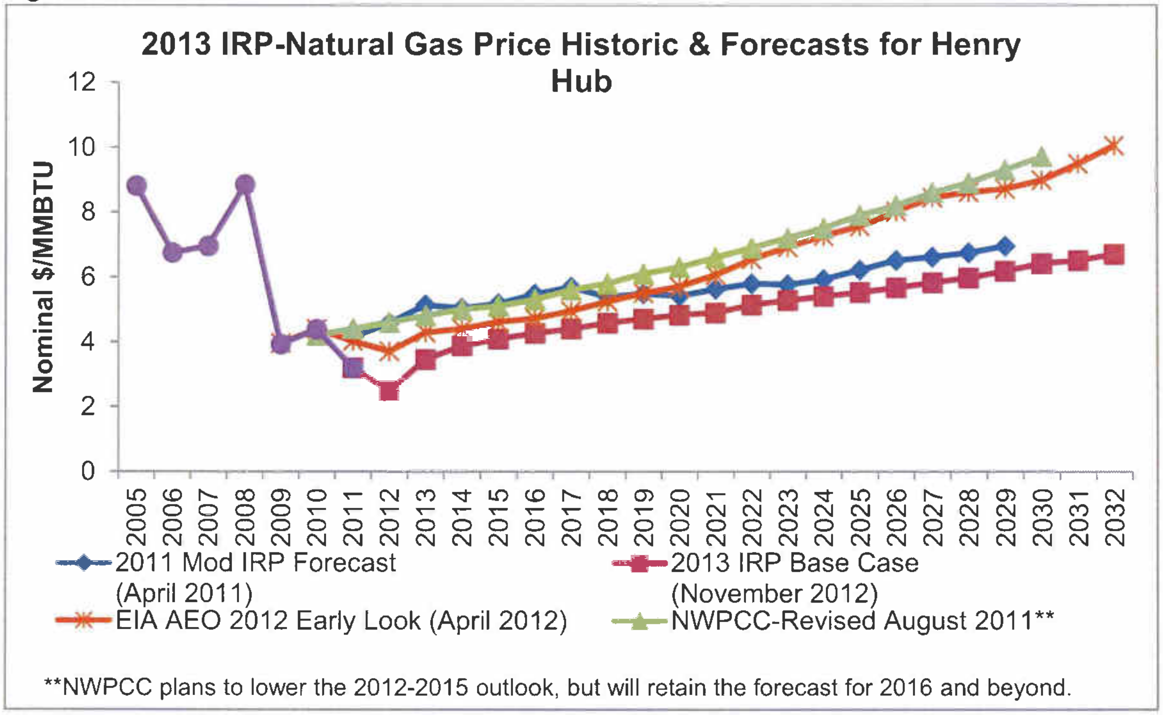
Figure 1.1 – NW Natural Customer Growth



B. Natural Gas Price Forecast

The second step in the load forecasting process is to consider projected changes in natural gas prices. The chart below shows the Company's updated price forecast relative to its 2011 Modified IRP as well as compared to two forecasts from outside public sources—EIA and NWPCC. In the short-term, forecasted prices are considerably lower in reflection of the current market over-supply. As previously mentioned, the Company does not expect these current low prices to be sustainable and forecasts some price recovery beginning in 2013. The long-term price forecast is just slightly below 2011 projections.

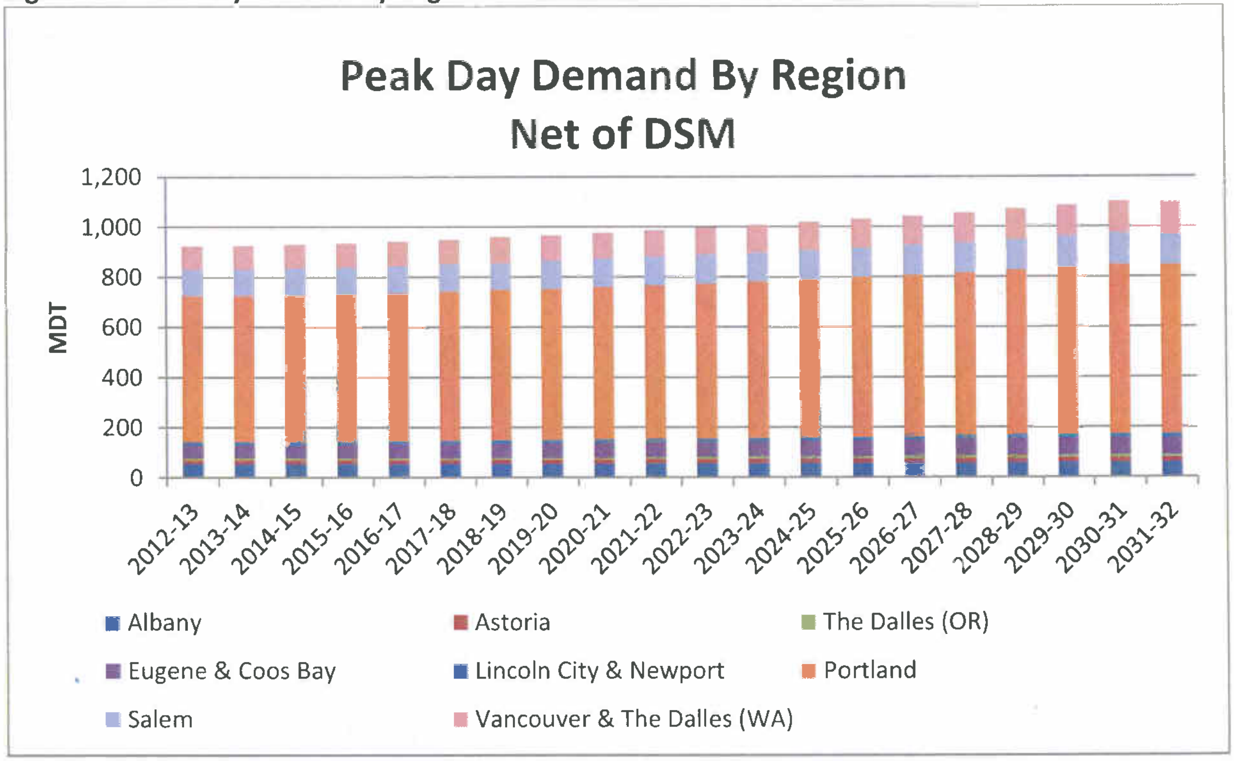
Figure 1.2 Natural Gas Forecasts



C. Load Forecast

After considering forecasts in customer growth, natural gas prices, use per customer and DSM savings, peak demand is forecasted to by grow on average by 0.84%/year. The chart below shows load composition by region.

Figure 1.3 Peak Day Demand by Region



D. Demand Sensitivity Cases

The following four demand forecast sensitivity cases were considered:

- Low Customer Growth
- High Customer Growth
- Medium Emerging Markets
- High Emerging Markets

The two customer growth sensitivity cases look at the traditional demand drivers. They produce an overall customer growth of 1.5% for the low case and 2% for the high case. Correspondingly, peak day demand for the low case grows by an average of 0.8% and 1.3% for the high customer growth case. These cases have a larger impact on peak day demand than on annual energy requirements due to the relatively low load factors associated with residential and smaller commercial customers.

The two Emerging Markets sensitivity cases examine the potential local impact from the primary natural gas demand growth segments forecasted at a national level—power generation, industrial, and transportation. These introduce more uncertainty into the demand forecast. Historically, these sectors have not been key growth drivers. The Emerging Markets cases have a more significant impact on annual energy requirements than on peak day demand due to the relatively high load factors and/or counter-cyclical usage patterns associated with these sectors. For example, based on typical driving patterns, gas consumed in the transportation sector is expected to be higher during the summer months rather than the winter heating season.

The forecasted impacts on annual energy requirements and peak demand associated with these sensitivity cases are shown on the charts below.

Figure 1. 4 – Forecast Annual Demand

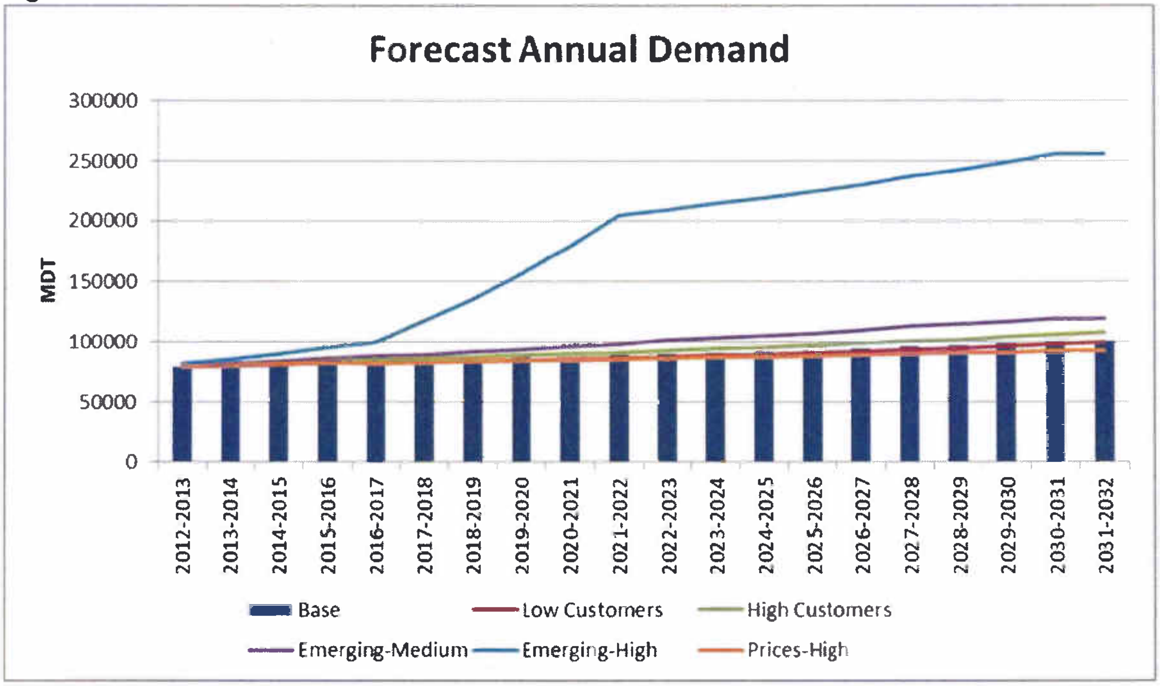
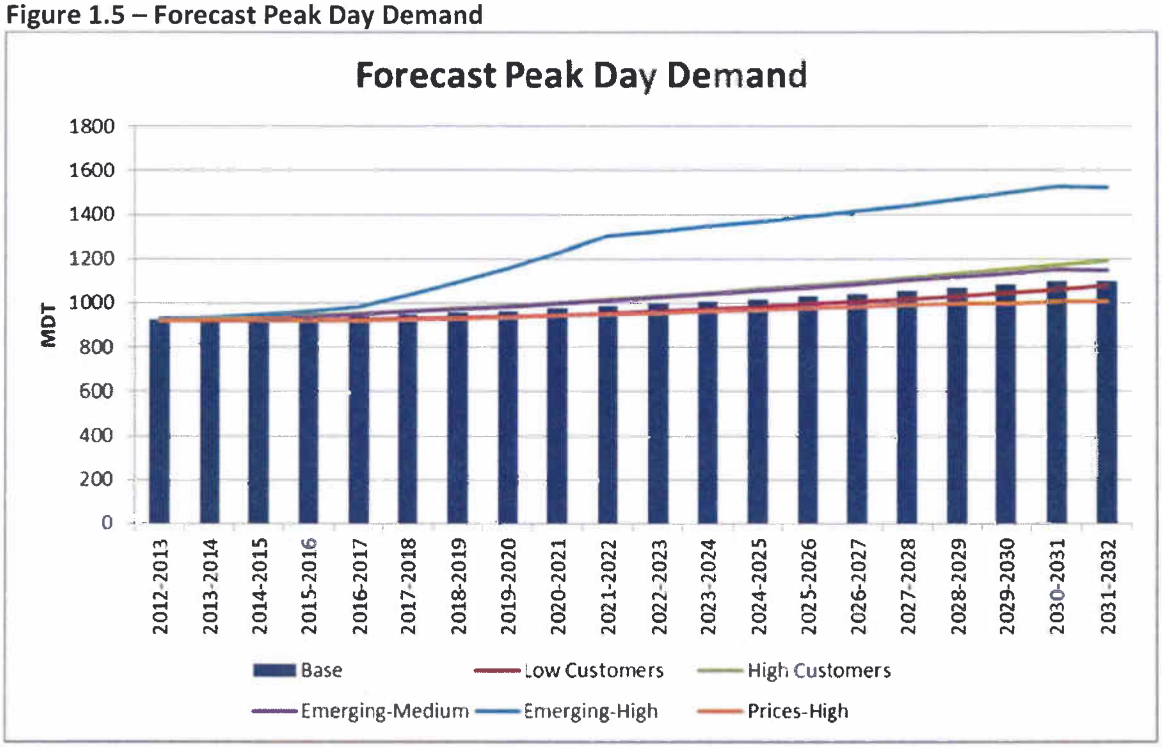


Figure 1.5 – Forecast Peak Day Demand



IV. Supply-Side Resources

A. Existing Resource Base

Currently, about 50% of the Company's peak day supply-side resources are off-system and delivered by NWP. About 32% of these supplies, including Plymouth LNG, come from the east through the Columbia Gorge line. Around 18%, including Jackson Prairie storage, come from the north through the Washington I-5 corridor line.

In terms of on-system supplies, Mist storage represents about 30% of our overall supply-side resource base. Newport LNG and Portland LNG ("Gasco") make up about 19%. The small remainder is from local natural gas production in the Mist field.

B. Resource Alternatives

A number of potential alternatives were considered for meeting future demand growth and to address system reliability. These generally fall into the following main categories:

1) Mist storage recall
2) Interstate Pipeline capacity
    a) NWP mainline expansion from Sumas
    b) New cross-Cascades pipeline
    c) Ruby pipeline capacity subscription
    d) NWP Grants Pass Lateral expansion
3) NW Natural transmission
    a) Eastside (Portland) loop
    b) Newport LNG takeaway enhancement
    c) South Willamette Valley Feeder
4) Satellite LNG Storage

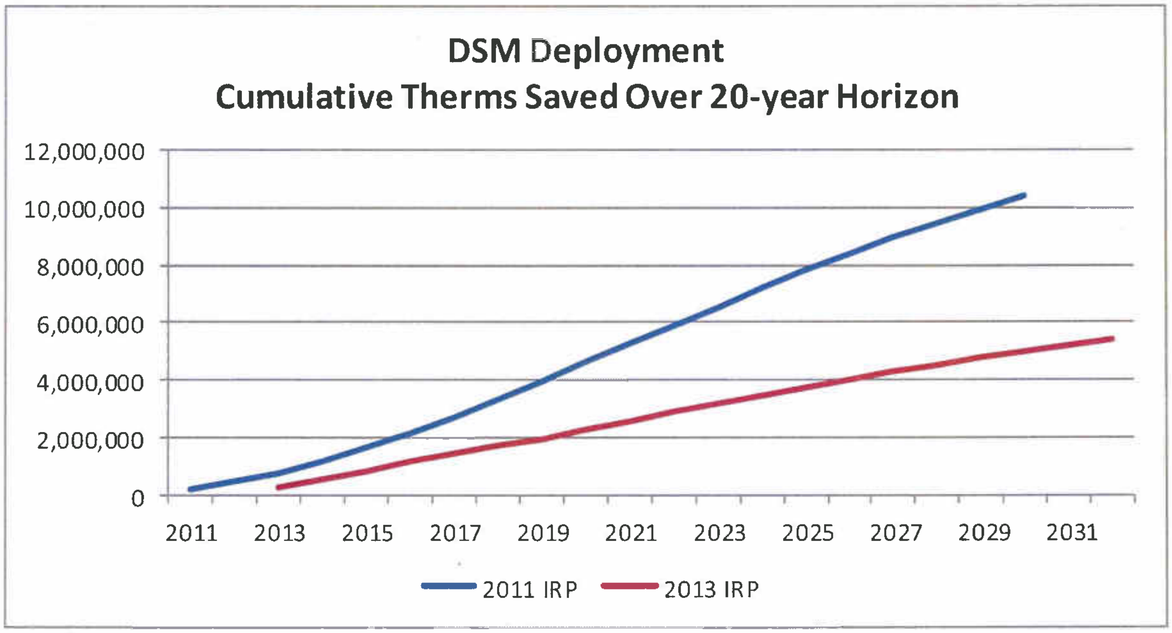
V. Demand-Side Resources

The DSM savings potential for the 2013 IRP is significantly lower than in the 2011 Modified IRP. The reduced potential is due to the following:

- Lower savings are being acquired per measure than previously assumed.
- The load forecast is down due to reduced customer growth.
- Some conservation in the previous DSM forecast has already been acquired.
- Modeling refinements have been made.
- Changes to codes and standards have reduced savings opportunities.
- Project costs are not declining.

Figure 1.6 below illustrates the difference in the DSM technical potential deployment schedule as presented in the Company's 2011 Modified IRP verses the deployment schedule identified in this plan.

Figure 1.6 – DSM Deployment in 2011 Modified IRP and 2013 IRP



A "high" DSM sensitivity case was run using targeted levels from the 2011 Modified IRP in order to determine the impact of the lower cost-effective potential identified in this IRP. The primary impact of the High DSM case is to delay the timing of Mist Recall and would result in an increase in total resource costs.

The Company will continue to deliver their DSM programs as long as they are cost effective. The WUTC is currently investigating the cost effectiveness determination of natural gas DSM programs in Docket No. WUTC UG-121207. The Company will continue to participate in this docket and will act consistently with the Commission's final ruling in this docket, whether it is to retain the status quo or to continue DSM programs even when gas prices render measures non cost effective.

VI. Resource Portfolio Analysis

A. Base Case

Traditionally, the Company's base case portfolio analysis has assumed 100% resource availability (e.g. no resource outages). Under this 100% resource availability assumption, the Company has sufficient resources through 2014-15 to serve forecasted load under design day conditions. Beginning in 2015-16, additional peak capacity is required. The most economic resource plan would be to gradually recall Mist capacity as needed to keep pace with load growth.

Table 1.2 - Base Case Resource Additions

Base Case
Cumulative Resource Additions (MDT/day)

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22
Mist Recall	5	5	8	17	24	35	44
Pipeline Capacity	1	1	1	1	1	1	1
	6	6	9	18	25	36	45

The Company considers this traditional 100% resource availability assumption to be inadequate for responsibly planning to serve customer load requirements. History demonstrates that gas resource outage events do occur. The probability of these resource outages needs to be factored into the determination of the optimal resource portfolio.

B. Reliability Risk Analysis

A new feature in this IRP is a more explicit examination of reliability and the resulting preferred resource portfolio from a risk management perspective. While the Company has previously identified the need for a cross-Cascades pipeline to diversify its resource mix, it has not previously provided an accompanying risk management analysis. As in past IRPs, the starting Base Case in this IRP assumes 100% resource availability within a deterministic optimization model. The Company's current modeling tools are limited in their ability to tackle probabilistic risk management questions such as resource availability.

To approach the risk management question, the Company created a resource outage scenario, which consists of one-time outage events at the Company's two key resources at different points of time within the 20-year planning period, as follows:

1) NWP Gorge outage
2) Mist Storage partial outage

Simulating a NWP Gorge outage is analogous in some ways to the "N-1" planning standard used by some electric utilities for transmission planning. A key distinction, however, is that electric utilities are dealing with a network of multiple transmission lines. In contrast, the Company is served by a single pipeline – NWP. This pipeline has two directional feeds into the Company's system – 1) Sumas South through the Washington I-5 Corridor and 2) from east to west through the Columbia Gorge. The Gorge event simulates an outage on the pipeline segment most sensitive to the Company.

The Mist outage event is more analogous to forced outages associated with multiple electric generation units. This is because Mist has multiple compressors and three separate transmission lines to takeaway storage withdrawals. Consequently, it was modeled as a partial outage.

This resource outage scenario was analyzed under three different winter Demand conditions:

1) Peak Design Day
2) Portland Near Peak / Valley Warmer
3) Portland Warmer / Valley Near Peak

The analysis was conducted in two steps. First, the model was left open to select resource additions that optimized least costs under these scenarios. This approach to reliability is referred to as "Resource Redundancy" – simply adding reserve margin to cover the exposed resource outages. This approach results in an extremely large amount of Mist Recall along with cross-Cascades pipeline capacity, Satellite LNG Storage and Newport LNG takeaway upgrades. Mist Recall is the primary resource in this reserve margin mix because it has lower fixed capital costs than the other options. However, this resource redundancy approach results in very large reserve margins. The reserve margin would be 31% under Peak Design Day criteria and 21% under the two Near Peak conditions criteria. This approach still leaves the Company dependent on two resources for over 80% of its gas supplies.

The second step was to rationalize the Company's pipeline capacity within the model, which is made possible by adding a new cross-Cascades pipeline option. Capacity on the new pipeline would allow the Company to turn back 77 MDT/day of existing NWP Gorge capacity. These cost savings offset and lower the net cost of adding new pipeline capacity. It also results in lower reserve margin requirements since the Company has lowered its dependence on its largest existing resource – NWP Gorge capacity. This approach is referred to as a "Resource Diversity" strategy.

Two levels of potential capacity subscription on a cross-Cascades pipeline were considered, and were priced using indicative rates provided by the Palomar pipeline sponsors:

1) 110 MDT/day, which is the minimum contract volume the sponsors have communicated is necessary from the Company; and
2) 165 MDT/day, which assumes the lower indicative rates provided by the sponsors that would result from upsizing the project.

Both the 110 and 165 cross-Cascades pipeline cases result in lower net present value optimized costs than were obtained by relying upon Mist Recall and a smaller amount of cross-Cascades capacity. The 165 cross-Cascades case has the lowest net present value (NPV) of all the outage scenarios based on the indicative rate assumptions. Because the Company would be diversifying its resource base as well as taking advantage of the three pipeline feeds currently available east of the Cascades from – a) Alberta, b) Rockies via NWP and c) Rockies via Ruby pipeline – the 165 cross-Cascades option also lowers the needed reserve margin to 23% under Peak Design Day and 13% under Near Peak conditions.

Table 1.3 - Optimized Resource Costs

Optimized Resource Costs 1-in-20 year Resource Outage Events NPV (billions of $'s)			
	Peak	Near-Peak Portland Cold	Near-Peak Valley Cold
Add Reserves with Storage (Resource Redundancy)	$7.436	$7.316	$7.338
Pipeline Rationalize – 110 (Resource Diversity)	$7.335	$7.308	$7.308
Pipeline Rationalize – 165 (Resource Diversity	$7.320	$7.290	$7.290

In considering the cross-Cascades pipeline option, the Company also evaluated two basic options for delivery of gas from the pipeline into its load centers:

a) Direct service on the cross-Cascades pipeline with deliveries at Molalla. This would require a new eastside transmission loop to deliver gas into the east Portland load center. The estimated costs of this new transmission line have been included in the analysis.

b) Service on NWP's proposed Northwest Market Area Expansion (N-MAX) project, which would bundle the cross-Cascades capacity with an expansion on NWP's existing system north of Molalla. This would enable the Company to retain the gate deliveries associated with the Gorge capacity it turned back and avoid the need for a new eastside transmission loop.

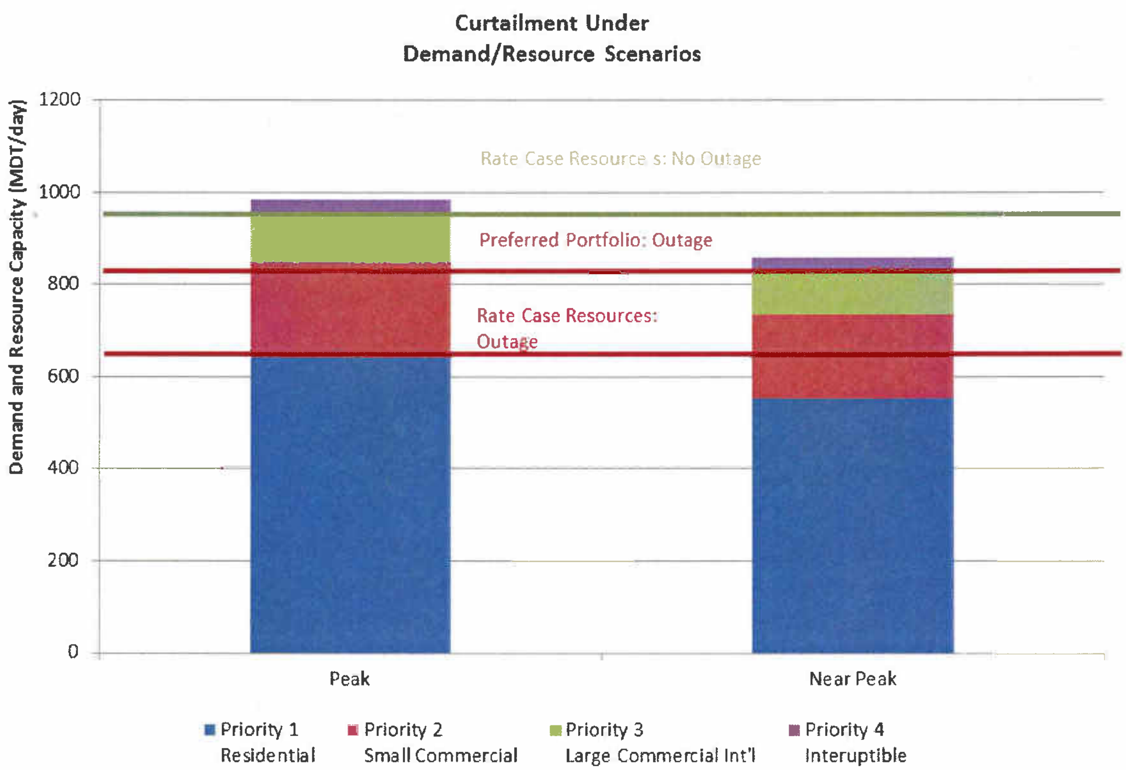
The analysis indicated the lowest cost option to be direct service on the cross-Cascades pipeline.

Interestingly, for the large amount of Mist Recall under the Resource Redundancy approach to be a viable option, an eastside transmission loop is similarly needed. This is because the ability of Mist storage gas to move to the east Portland load center is currently limited. Because this was a new conclusion in this IRP, additional engineering analysis is needed before committing to this generic option, including further investigation into possibly lower cost options for increasing the capacity to move gas from the South Mist Pipeline Extension to the east area of the Portland load center.

The chart below shows the implications to customer curtailment associated with the Base Case Resources versus the Preferred Resource Portfolio under Peak Design Day and Near Peak demand conditions. At 100% resource availability, the Base Case Resources are sufficient to meet all firm load requirements under Peak conditions. Only interruptible customers (Priority 4) would be curtailed. However, if there is a resource outage under Peak conditions, all Priority 2 and 3 customers (commercial and industrial) would face curtailment. Under near peak conditions, all Priority 3 and half of Priority 2 customers would face curtailment. In addition, there would undoubtedly be significant curtailments of Priority 1 – Residential since these customer segments are geographically comingled and some geographic segments of the system would experience more serious pressure drops than others.

In contrast, with the Preferred Portfolio, which is sized to correspond to the lower Near Peak reserve margin, only Priorities 3 and 4 would be exposed to curtailments under Peak and Near Peak demand conditions. Priorities 1 and 2 would have sufficient supplies.

Figure 1.6 - Curtailment under Demand/Resource Scenarios



From this analysis, the Company has concluded that for reliability risk management purposes, planning for Near Peak demand conditions when considering key resource forced outages is appropriate. This is analogous to an N-1 planning standard under 90/10 winter peak demand. In the Company's opinion, applying the standard to a Peak Design Day is too extreme and unnecessary in order to satisfactorily protect high priority customers from curtailment under an array of possible conditions. For comparison, the Near Peak demand used in this analysis is about 10% less than Design Day peak demand.

C. Preferred Resource Plan

There are three key dimensions to the Company's preferred resource plan:

1) Meet base case forecasted system load growth over the next 5 years with Mist Recall.
2) Support development of a cross-Cascades pipeline project to strengthen reliability and diversify the Company's resource base.
    a) Enter into a Precedent Agreement with the Palomar project sponsors to enable an open season and determine the project's economic viability.

  b) Support initiation of the critical path FERC permitting process by the project sponsors, contingent upon the results of the open season.

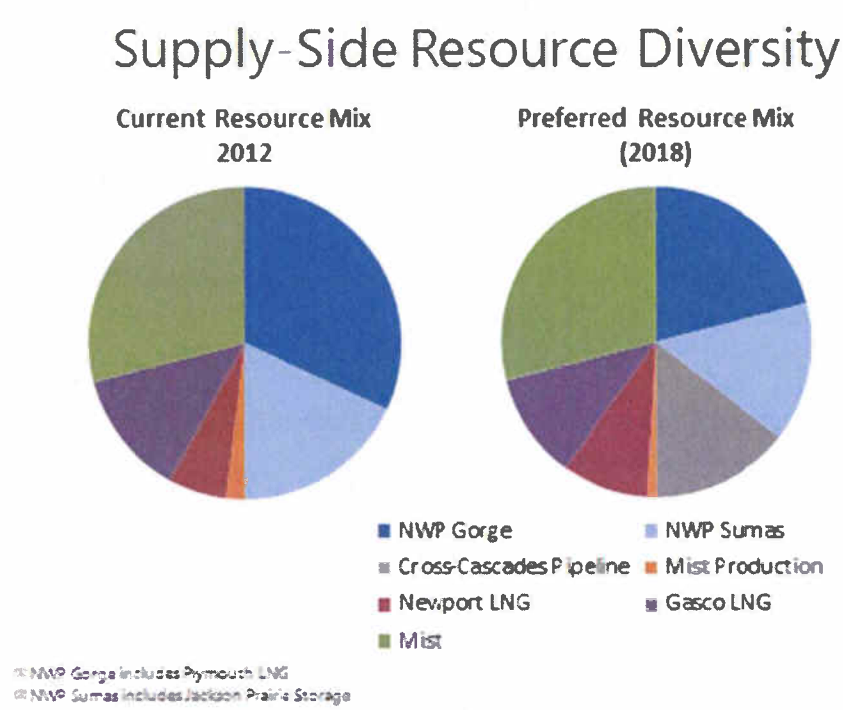
3) Be prepared to meet potentially higher load growth from Emerging Markets through a mix of additional Mist Recall and cross-Cascades pipeline capacity.

Table 1.3 Preferred Resource Plan – Resource Additions

Preferred Resource Plan
Cumulative Resource Additions/(Reductions) (MDT/day)

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22
Mist Recall	5	5	8	21	21	21	21
cross-Cascades Pipeline				165	165	165	165
Newport LNG transmission				40	40	40	40
NWP - Gorge				(77)	(77)	(77)	(77)
		5	8	149	149	149	149

The Preferred Portfolio would diversify the Company's current resource base and reduce its 80% reliance on two key resources – NWP and Mist storage. Currently, the Company is reliant for 50% of its peak design day supplies on NWP (32% through the Gorge and 18% from Sumas) and 29% from Mist. Under the Preferred Portfolio, the Company's reliance on NWP would be reduced to 36% (21% - Gorge; 15% - Sumas) while maintaining Mist at 29%. Capacity from a cross-Cascades pipeline would account for 15% of resources.



VII. Avoided Costs

The avoided costs provided from this IRP are consistent with past methodologies. They are lower in reflection of the decrease in forecasted natural gas commodity prices. Beyond a 10% adder for non-quantifiable environmental benefits, no explicit adder for regulation of greenhouse gas emissions or other environmental externalities associated with natural gas production has been included.

VIII. Distribution System Planning

One necessary change in more comprehensively including Distribution System planning in the IRP is to more explicitly include forecasted firm transportation loads, in addition to the firm sales loads that traditionally have been the focus of resource adequacy system planning. Table 1.4 below shows the addition of forecasted transportation peak day loads to the sales peak day loads.

Table 1.4 – Peak Day Design Load Requirements

Peak Design Day
(MDT/day in 2018-19)

	Firm	Interruptible
Sales Service:		
Residential	640	
Commercial	295	
Industrial	23	26
Sub-Total	$\boxed{958}$	
Transportation Service	39	76
Total	$\boxed{997}$	102

Furthermore, the analysis shifts from a macro-system look for resource adequacy to a more micro-geographic look for distribution system planning.

A. Scope Guidelines

The Company proposes using the following two criteria for determining what transmission and distribution projects should be addressed within the IRP process:

1) High pressure transmission projects required to move gas supplies to a discrete load center. (Transmission and distribution projects needed to move gas within the load center would not be included.)
2) Any system reinforcement project over $10 million.

B. Project Identification

For Washington, no project falls within the above criteria. However, detail is provided for a project that creates a new interconnection with NWP (a "gate station") in Clark County in the vicinity of Felida, along with associated distribution system infrastructure emanating from the gate station. While this "Felida Gate" project is expected to cost far less than $10 million in all, this project is a key component of the Company's plans to address existing low distribution system pressures in the area during cold weather conditions and to meet future load growth in the Clark County load center. The location of the gate station and determination of the pipeline additions were made using the Company's distribution system planning tool (SynerGEE®) as discussed in Chapter 7.

In Oregon, the Corvallis Loop project is over $10 million even though it is within the Albany/Corvallis load center. Consequently, it would fall within the IRP scope using the proposed criteria. Because the Company recently received guidance in its Oregon general rate case that may impose previously unarticulated analytical standards for distribution projects such as this, the Company has not been able to complete its full presentation of analyses of this project, and plans to address this project need in an Oregon IRP update.

This IRP includes the Mid-Willamette Valley Feeder (MWVF) as a base case committed resource. The Company had assumed its analysis of this project in the 2011 Modified IRP, coupled with other analyses that were performed outside of the IRP process, was sufficient to demonstrate the need for this project. The Public Utility Commission of Oregon Order No. 12-408 issued in the Company's 2012 rate case (UG-221), however, found that the Company had not adequately demonstrated the need for the project at this time. As a follow-up, the Company will re-assess the need for this project consistent with this feedback and provide the findings in a future IRP update.

IX. Public Involvement

The Technical Working Group (TWG) brings together professionals representing a variety of entities with an interest in the Company's IRP process. The Company reached out to a wide audience including representatives from WUTC Staff, Northwest Industrial Gas Users (NWIGU), Northwest Power and Conservation Council (NWPCC), Washington Public Counsel, Northwest Energy Coalition, and Williams Pipeline. The Company held Technical Working Group meetings on June 28, 2012, August 22, 2012 and January 30, 2013. A February 2013 bill insert will be sent to Washington customers, notifying them of the draft plan and soliciting public comments.

X. Multi-Year Action Plan

1. Demand Forecasting

    1.1 Investigate the benefit of further disaggregating the build-up of the customer forecast into more differentiated segments.

    1.2 Continue to monitor the data and sources for its customer growth projections.

    1.3 Restructure the load forecast zones to better match the distinctive load centers from a transmission and pipeline delivery standpoint.

    1.4 Continue to review national and regional supply and price forecasts and their sensitivity to environmental regulation, LNG exports and other factors.

    1.5 Further explore the demand implications from the emerging growth markets of power generation, industrial and transportation.

2. Supply-Side Resources

    2.1 Acquire resources in the near term consistent with the Base Case Resources. Specifically recall Mist storage capacity from the interstate storage account to serve the core customer needs reflected in the base case forecast.

    2.2 Support development of a cross-Cascades pipeline from a reliability risk management standpoint and to diversify the current resource portfolio. Negotiate and sign an acceptable Precedent Agreement with the Palomar pipeline sponsors and participate in their open season.

    2.3 Update and refine resource cost estimates.

    2.4 Monitor west coast LNG export project development and their potential impact on local natural gas prices.

    2.5 Evaluate Newport LNG and Portland "Gasco" LNG refurbishment alternatives and address in a future IRP.

    2.6 Develop gas supply parameters for use in evaluating potential additional gas reserves acquisitions and address in a future IRP.

3. Demand-Side Resources

    3.1 Continue existing energy efficiency programs being administered by the Energy Trust.

3.2 Explore additional energy efficiency opportunities beyond the scope of previous assessments to identify any potentially new cost-effective delivery approaches or savings areas.

3.3 Explore demand side potential from a peak capacity management perspective.

4. Resource Portfolio Analysis

4.1 Refine system analysis using restructured load center distinctive forecasts.

4.2 Investigate implications of considering a broader array of weather-sensitive peak design conditions.

4.3 Develop more statistically sophisticated approaches for probabilistically measuring reliability risk management. Explore other modeling tools to supplement SENDOUT®.

4.4 Review research studies addressing the cost of un-served demand, with a focus on differentiating the cost based on the size of curtailment and relative impact on different customer priority levels.

4.5 Evaluate costs and benefits of alternatives to a new eastside loop capable of moving gas from Molalla and/or the South Mist Pipeline Extension to the east and northwest Portland load centers.

4.6 Develop contingency plan for addressing reliability risk management should a cross-Cascades pipeline not be economically viable based on results of the open season.

5. Distribution System Planning

5.1 Reassess the costs and benefits of the Mid-Willamette Valley Feeder in serving load growth and supporting system reliability. Provide findings in a future IRP.

5.2 Complete the full presentation of analyses from the Corvallis Loop project, consistent with recent guidance received in the Company's general rate case and provide this in a future IRP.

Chapter 2: Gas Requirements Forecast

NW Natural®

I. OVERVIEW OF DEMAND FORECAST METHODOLOY

The demand or load forecast is the starting point for the IRP process. It determines the future daily sales gas supply requirements around which the resource plan is developed. Having an accurate gauge of future demand is essential for ensuring that sufficient resources are acquired in an optimal manner. Residential and commercial space heating comprise the bulk of demand on the system and both are naturally weather dependent. Therefore, it is important to note that the load forecast is designed around a severe winter, one that is much colder than normal and is augmented by a very cold peak day event. This is done to ensure the development of a resource plan that is capable of reliably serving customers under a variety of circumstances, including extremely cold weather. The load forecast is also used as the basis for determining the amount of cost-effective energy savings that is available in the Company's service territory through energy efficiency programs administered by the Energy Trust of Oregon.

NW Natural provides resource adequacy - upstream pipeline capacity, storage capacity, and the gas commodity itself – for its firm sales customers. While firm transportation customers provide for their own upstream resource adequacy needs, the Company provides them with distribution services. The load requirements of interruptible sales customers are considered only as to commodity and non-peak deliverability, because the Company does not plan for upstream pipeline or storage capacity to serve these customers during peak or near-peak conditions. The loads of interruptible transportation customers are not considered in the IRP.

The Company continues to use the same region-specific forecasts in its 2013 IRP as it used in past IRPs. The regions are defined as Vancouver & The Dalles (Washington), Albany, Astoria, Eugene & Coos Bay, The Dalles (Oregon), Lincoln City & Newport, Portland, and Salem. Each region is distinguished by unique weather, usage patterns, customer growth and resource availability. These eight regions also define the separate demand points along with supplies and distribution system connections as modeled in SENDOUT®, the Company's choice for resource planning and modeling software. In future IRPs, the Company will investigate the benefit of further disaggregating the build-up of the customer forecast into more differential segments.

NW Natural's demand forecast process is comprised of eight primary steps.

1. Customer forecast: 20-year estimate of customer counts by region and category
2. Customer usage behavior: data collection and analysis of recent usage trends by region and category
3. Load model: non-linear, statistical model fit with the independent variable of heating degree days (HDD)
4. Natural gas price forecast: monthly price forecast by supply basin or hub
5. Weather pattern and peak day development: Design weather pattern colder than 85% of winters in the past 23 years plus 3-day peak event
6. Demand forecast: the load model is implemented in SENDOUT® to integrate demand with supply side and demand side resource planning options
7. Demand scenarios: development of other potential but less likely demand outcomes
8. Forecast accuracy analysis: measure forecast performance by "backcasting" – using the load forecast model factors to predict historic use and compare the results to actual use

The demand forecasting process starts with the projection of customer growth by region and category. Next, recent usage data is collected and analyzed for customer base use and heat use behavior in response to historic weather and gas rates. The data is then used to fit the coefficients for a statistical load model for each category and region. A design weather pattern is used in combination with the load model and customer forecast to project demand over the 20-year planning horizon. This constitutes the base case demand forecast, which the Company believes is the most likely outcome for natural gas demand during a year with a severe winter. However, other customer growth and usage behavior could occur, so NW Natural also develops other, less likely demand scenarios for planning purposes. Finally, load forecast accuracy is checked against recent, actual customer usage under a variety of conditions.

II. CUSTOMER FORECAST

The customer forecast is the starting point for the demand forecasting process. The Company relies on internal business intelligence along with information from outside sources such as the Oregon Office of Economic Analysis (OEA) and the Northwest Power and Conservation Council (NWPCC) to project customer numbers across the 20-year planning horizon. The following tables display the forecast regions and categories along with the current customer mix as of December 2011.

Table 2.1 - Forecast Regions

Region	Customers – 2011	% of Total
Portland	413,232	61 %
Salem	87,994	13 %
Vancouver & The Dalles (WA)	68,301	10 %
Albany	40,191	6 %
Eugene & Coos Bay	39,882	6 %
Astoria	12,281	2 %
Lincoln City & Newport	10,097	1 %
The Dalles (OR)	5,476	1 %

Table 2.2 - Forecast Categories

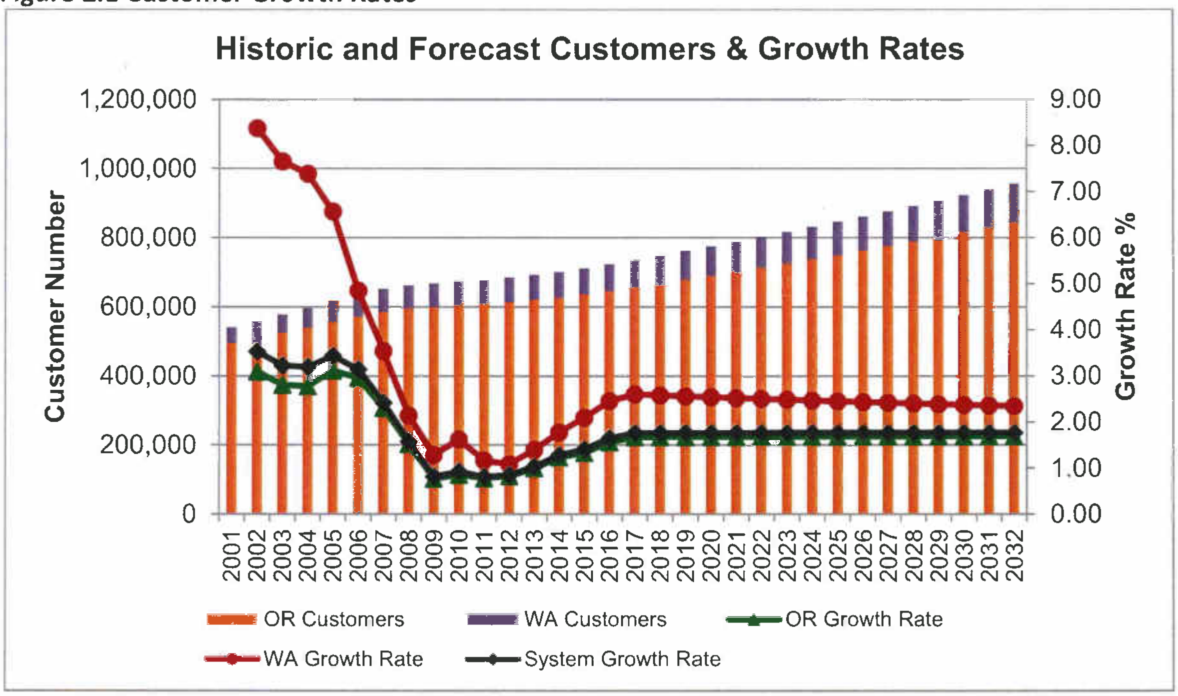
Category	Customers – 2011	% of Total
Residential Existing	615,670	90.6 %
Residential New Construction Single- Family		
Residential New Construction Multi-Family		
Residential Conversion		
Commercial Existing	62,914	9.3 %
Commercial New Construction		
Commercial Conversion		
Industrial Firm Sales Customers	585	0.1 %
Interruptible Sales Customers	151	0.0 %

In its acknowledgement of the Company's previous IRP Docket UG-100245, the Commission asked for an analysis of what drives the differential in expected growth rates between the Portland and Vancouver service territories. That analysis is included as Appendix 2.1.

A customer forecast is developed for each region and category combination – 72 in all. At the starting point of the planning horizon, all the customers fall into the existing category. Over time, the forecast growth occurs in the New Construction and Conversion categories as new customers are added.

The forecast methodology involves blending near and long term economic outlooks. Economic forces such as regional employment, housing starts, and economic leading indicators are the main factors that determine growth. According to the November 2012 OEA forecast, housing starts in Oregon had dropped by 41.7% in 2008 and 40.8% in 2009 due to the significant economic downturn. Starts were static at a positive 0.3% in 2010, and even though they improved by 6% year-over-years in 2011, they remained 37% below the number of starts recorded in 2007. The Company's customer growth rates have dropped accordingly. In 2006, the customer growth rate was over 3%. In 2011, growth had slowed to less than 1%. Going forward, customer growth is expected to crawl back to 1.8% by 2017. Overall, the average annual forecast customer growth rate over the next 20 years is 1.65%, with Washington at 2.30% and Oregon at 1.57%.[1]

Figure 2.1 Customer Growth Rates



1 As was mentioned earlier, the higher growth rate in Washington is due to a lower market penetration compared to Oregon and a large number of new housing developments being built in the greater Vancouver area.

A. Residential Customer Forecast

Customer growth in the residential sector is allocated among three separate categories:

1. New Construction Single-Family
2. New Construction Multi-Family
3. Conversions

In the forecast, all new residential customers are added to the customer base in one of these categories. Residential attrition, or loss of residential customers, is deducted from the Residential Existing customer category.

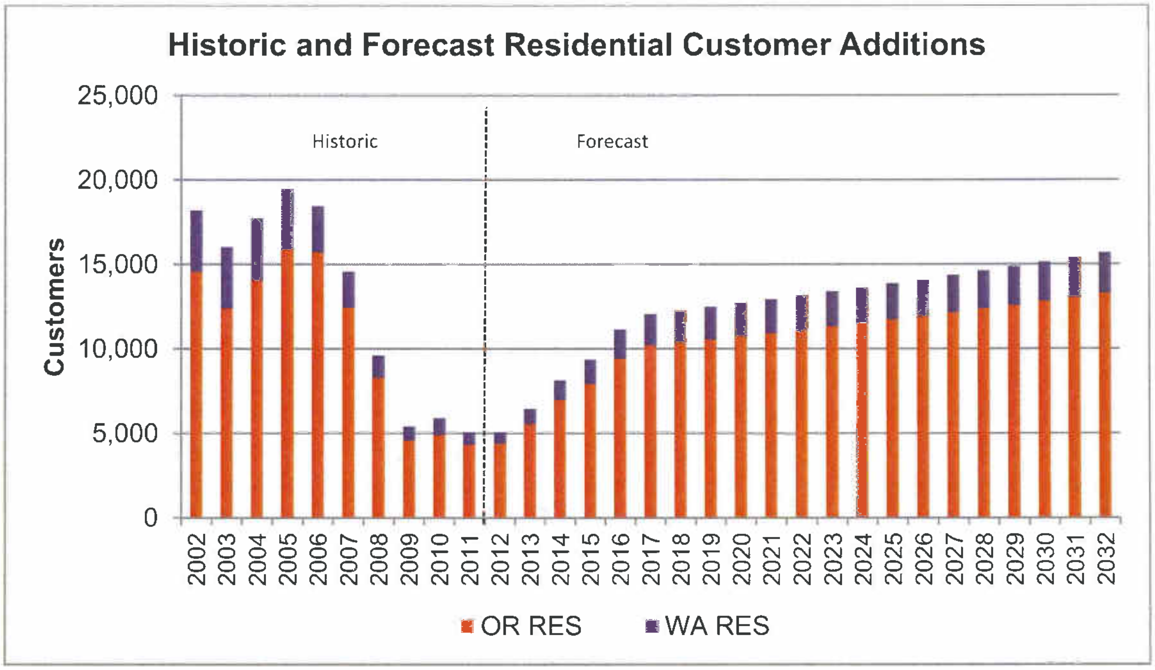
Customer projections in the new residential categories are based on historic regional growth trends, housing start forecasts, and long term population forecasts. According to the NWPCC's 6th Plan, the average annual population growth rate for Oregon is expected to slow from 1.6% historically (1985 to 2007) to a future level of 1.0% (2010 to 2030). In contrast, however, the number of occupants per household has been dropping with the result that housing stock is actually growing faster than the population.

In addition to forecasting new customer gains, NW Natural projects the number of residential customers expected to convert to natural gas from other energy sources by reviewing historical conversion activity experienced by the Company in prior years. Internal judgment is applied as well, including such factors as:

- Stock of convertible dwellings in the service area currently served by oil and other fuels
- Incentives
- Price of natural gas in relation to other energy sources
- Technology
- Marketing programs
- Economic conditions
- Cost to serve new customers

The impact of the economic recession on growth in the residential sector can be clearly seen in Figure 2.2, which shows the historical and forecast net residential customer additions by year.

Figure 2.2 - Residential Customer Additions



B. Commercial Customer Forecast

For the commercial sector, growth is concentrated in two categories:

1. New Construction
2. Conversions

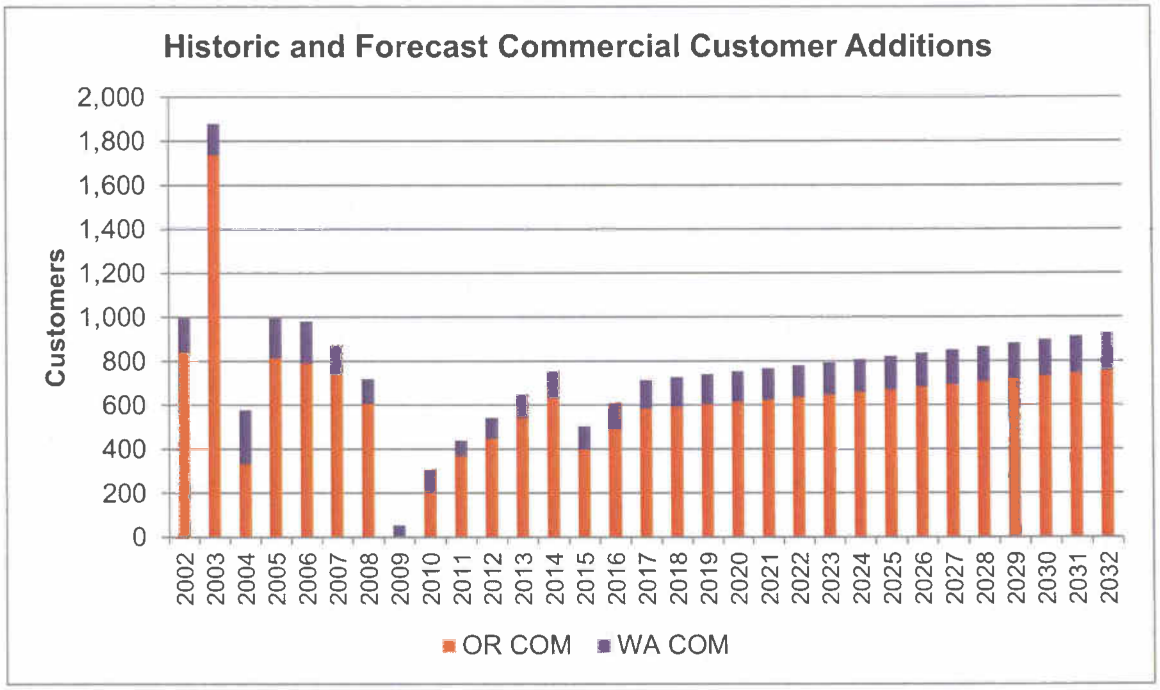
All new commercial customers are added to the customer base in one of these forecast categories. As in the residential category, attrition is deducted from the Commercial Existing customer category.

New construction forecasting for the commercial sector is based on historic patterns, economic and market indicators, and external economic forecasts from the OEA and the NWPCC.

As in the residential forecast, the Company projects the monthly number of commercial customers expected to convert to natural gas from other energy sources by reviewing historical conversion activity experienced by the Company in prior years. Similar factors are analyzed as in the residential case, but from the commercial business viewpoint.

After bottoming in 2009, growth in the commercial sector began to rebound in late 2011. Figure 2.3 shows historic and projected commercial additions.

Figure 2.3 - Commercial Customer Additions



C. Industrial Customer Forecast

The Industrial customer base, both for firm as well as interruptible customers, has recently begun to recover from the negative growth that dominated during the recession and this trend is expected to continue. Near term demand growth in the firm sales industrial category is expected to originate more from a higher use per existing customer than new customer additions. The economic slump had caused plants and factories to cut back on shifts and consume less natural gas across the region. As the economy rebounds and natural gas maintain its competitive price advantage, it is expected that the use per customer will continue to rebound, and new customers will be added.

D. Customer Scenarios

NW Natural believes the base case customer forecast and the resulting base case demand forecast to be the most likely outcome from a planning standpoint. The Company also has evaluated resource planning around other potential demand outcomes, or scenarios. Scenarios provide alternative demand projections resulting from alterations to the base case forecast assumptions. Demand scenarios also act as limits to the base case forecast by setting a floor and a ceiling on expected load. Two alternative demand scenarios have been developed around customer growth.

1. Low Growth Case: lower core customer growth due to continued slow economic recovery.
2. High Growth Case: higher core customer growth resulting from a sharper than expected economic rebound.

The customer forecast scenarios were developed by altering the base case residential and commercial customer addition values. Figure 2.4 presents the system wide customer growth rates for the scenarios. Figures 2.5 and 2.6 display the resulting customer outcomes by state.

Figure 2.4 - Scenario Growth Rates

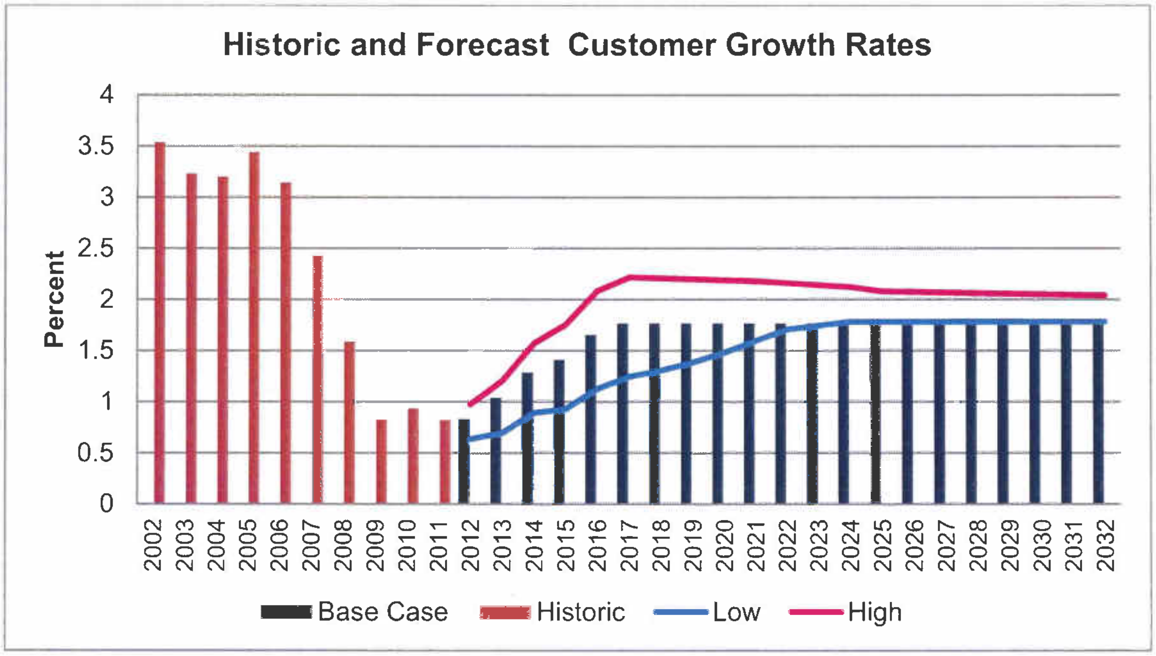


Figure 2.5 - Oregon Customer Forecast

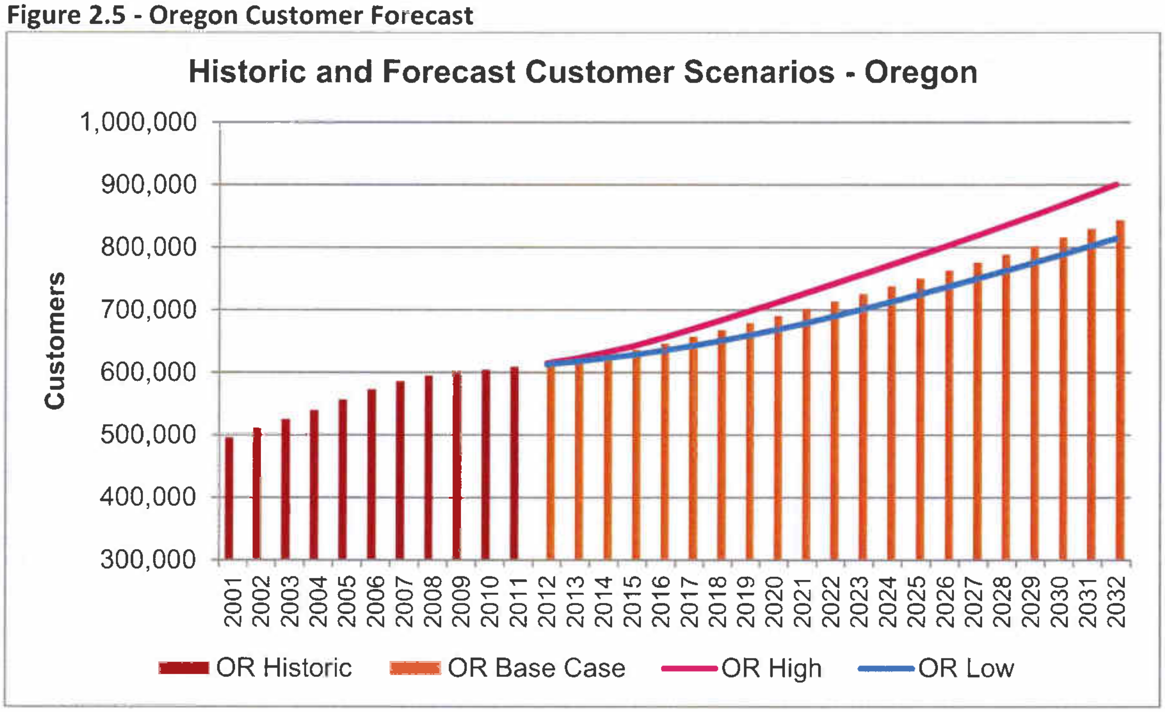
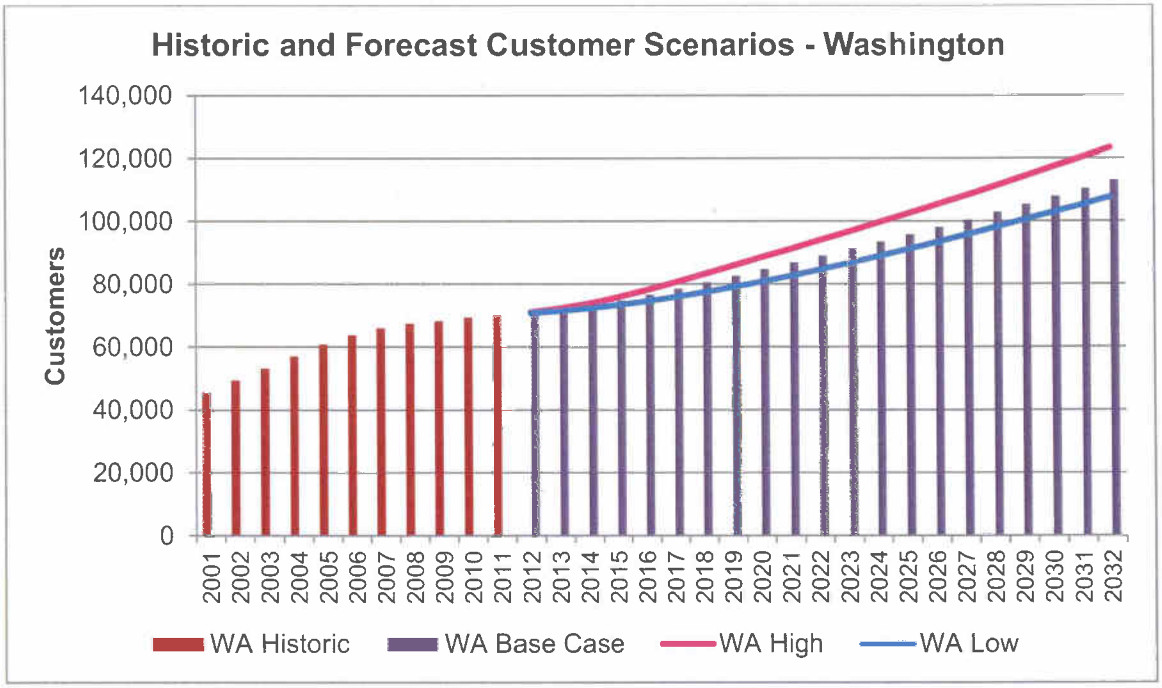


Figure 2.6 - Washington Customer Forecast



III. LOAD FORECAST MODEL

The next step in the demand forecast process is to combine historic natural gas use behaviors with the forecast customer numbers in each category. Historic billing cycle data is collected by category and region and is matched up with temperature data. Temperature data is available for each region on a daily basis; however, customer usage by region and category is not. Detailed customer usage data is derived from billing cycle information, which is collected throughout each month on a rolling basis. Temperature data is compiled to match the billing cycles. For example, typically there are 22 billing cycles each month, i.e., one for each business day. A mid-point cycle will contain aggregated customer usage data from the first half of the current month and the second half of the previous month. A cycle at the beginning will collect usage data primarily from the previous month, while a cycle at the very end of a month will be comprised of data from that month only.

A statistical load forecast model is then fit to the data set. In addition to regional variations in climate, each region's customer base also has unique usage characteristics. For example, coastal areas may have large numbers of vacation homes and seasonal businesses whose energy usage varies more with weekends and holiday periods than seen in other regions. These differences in usage patterns and levels of use may be related to the size and age of the dwellings or businesses, as well as the efficiencies of the equipment and appliances that are in use at the location. Therefore the load forecast model is fit to each distinct combination of category and region, 72 in all.

For residential, commercial, and industrial customers, daily use is separated into two components, base load and heat load. The base load component is assumed to be constant throughout the year and is independent of ambient temperatures. Base load represents demand for uses such as water heating and cooking. Heat load represents demand for space heating. For the heat load component of the load forecast, a non-linear equation is used to model daily customer use as a function of heating degree days (HDD). The metric HDD measures the extent to which the daily mean temperature (the simple average of the high and low temperatures for the day) falls below a reference temperature, which in this analysis is 65° F.

Equation 2.1 Daily Customer Use

$$U = U_B + U_H$$

$$where$$

$$U = daily\ use\ per\ customer$$

$$U_B = \ daily\ customer\ base\ load$$

$$U_H = daily\ customer\ heat\ load$$

A. Base Load

The first step in the load model derivation involves estimation of the base load component. This is done by performing a linear regression with daily use per customer as a function of HDDs, using customer usage data from the summer months of July, August, and September. While there still may be some heating load during cool summer days, the value of the y-intercept (usage where HDD=0) provides the base load factor.

Equation 2.2 Base Load Model

$$U = c + r \times x$$

$$where\ U = daily\ use\ per\ customer\ in\ summer\ months$$

$$x = HDD\ per\ day$$

$$r = heat\ factor$$

$$c = intercept$$

$$setting\ x = 0$$

$$U_B = c = daily\ customer\ base\ load$$

B. Heat Load

For the non-summer months, the base load value is subtracted from the daily customer use data and the heat load factors are calculated. For residential and commercial customers, heat load is modeled as a non-linear function of HDDs. The function resembles an "S" Curve. That is, at low HDD values, the curve is relatively flat. As the HDD values increases (colder temperatures), load increases and the curve becomes steeper. Then, at an HDD of 45 (20° F), the load curve begins to flatten out as the coincidence factor of heating unit operations (furnaces and fireplaces) begins to converge.

Following a natural log transformation, heat load is derived by performing a linear regression fit as a function of HDD.

Equation 2.3 Heat Load Regression

$$\ln\left(\frac{W}{HDD}\right) = d + r_h \times x_1$$

$$where$$

$$W = \text{ } daily\ use\ per\ customer, decremented\ for\ base\ load$$

$$x_1 = \ln(HDD)$$

$$r_h = heat\ rate$$

$$d = intercept$$

The function is transformed back by taking the exponent of both sides, resulting in the heat load component.

Equation 2.4 Heat Load

$$U_H = (HDD) \times e^{[d + r_h \times \ln(\max(45, HDD))]}$$

$$where$$

$$U_H = daily\ customer\ heat\ load$$

In the industrial sector, heat load is modeled as a linear function of HDDs only.

C. Implementation

In order to implement the Company's load model in SENDOUT®, the non-linear load equation must be transformed into a linear function of HDD. This is accomplished by fitting two piecewise segments to the load function.

Equation 2.5 Linear Transformation

$$S = B + H \times HDD$$

$$where$$

$$S = use\ per\ customer\ per\ day$$

$$B = U_B = base\ use\ per\ customer\ per\ day$$

$$H = \frac{U_H}{HDD} = heat\ rate$$

D. Peak Day Load

The slope of the non-linear load curve increases as HDD values increase. Historically, natural gas local distribution companies have seen usage begin to flatten at very low temperatures (high HDD values). In the paper titled "Bend-Over", John Little and Jeffrey Rosenbloom[2] (Fortnightly, April 1994) found that this effect- called "bend-over" - does exist, starting at a temperature of 20° F. Customers do not continue to consume natural gas at the same rate at very cold temperatures. However, the reasons for this are not clear. One hypothesis is that in a peak day event, most of the heating appliances are running at maximum capacity and cannot consume any more gas even if temperatures continue to drop. The Company has very few data points to verify this phenomenon since its service territory has a relatively mild climate. The few existing data points do seem to indicate that a shift occurs in the load curve. Therefore, in practice the load forecast model does include a bending of the curve beginning at an HDD value of 45 (20° F). This can be seen in Equation 2.4 above.

E. Use per Customer and Price Elasticity

The delivered price may also affect the load function. If the price the customer pays for gas increases, customer use at a given HDD value is expected to drop, and vice versa. In prior IRPs the Company included a price variable to capture the customer use response to price, which can also be thought of as price elasticity. For this IRP, though, the Company has included an elasticity effect only for its high price sensitivity case. The reason for this simplification is that recent experience has not shown statistical significance of a price variable during a period of *decreasing* prices.

The American Gas Association (AGA) released a study on natural gas use and price elasticity in 2007[3]. The study analyzed residential use per customer (UPC) trends from 50 natural gas local distribution companies (LDC) from across the country. The authors found that since 1980, weather normalized use in the residential sector had been dropping about 1% per year. From 2000 to 2006, though, the decline accelerated to 2.2% per year. The driving force behind the decline in use per customer was the consistent increase of natural gas prices. The Company had seen a similar drop in use per customer during that time frame. The AGA study reported a long run price elasticity value of -0.12 for the residential sector in the Pacific region, which is the factor adopted by the Company for its high-price sensitivity case that includes a price elasticity variable.

2 "Bend-Over", John Little and Jeffrey Rosenbloom, Fortnightly, April 1994

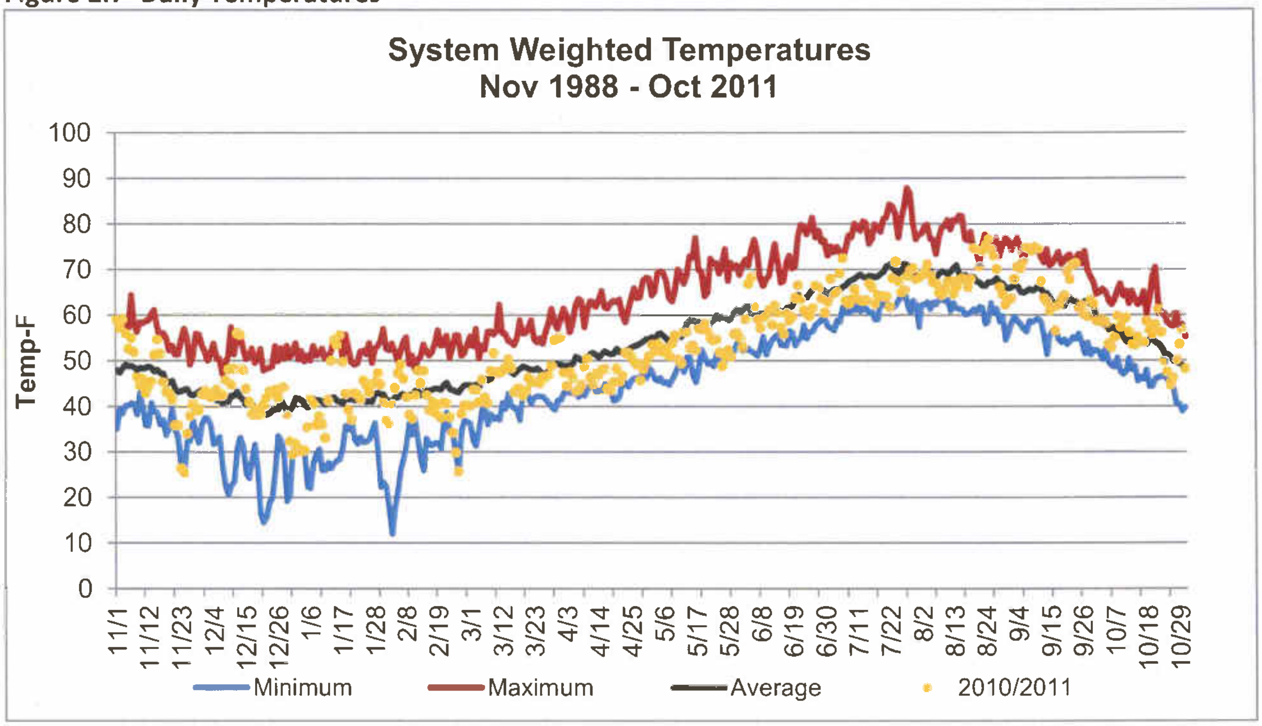
3 "An Economic Analysis of Consumer Response to Natural Gas Prices," Frederick Joutz, Robert Trost, March 2007.

IV. WEATHER

Climate plays a primary role in the demand forecast. The HDD variable in the heat load model (Equation 2.4) is a key driver of daily load, and in particular, peak day load. The Company has analyzed temperature data from its service area and designed an annual HDD pattern resulting in loads which significantly stress the system on both an annual and peak day basis. The design weather pattern is repeated in each year of the IRP so that the appropriate resources can be developed to serve customers whenever a severe winter occurs.

The Company collects and analyzes temperature data purchased from the National Oceanic and Atmospheric Administration (NOAA) for all eight regions of the service area. Figure 2.7 displays the 23-year system weighted average, minimum, and maximum temperatures along with the average temperatures from a recent gas year.

Figure 2.7- Daily Temperatures



The design weather pattern is derived from a data set containing 20 years of daily temperatures, including gas years 1991/92 through 2010/11. The daily average temperatures (T) from each region are transformed to a 65° F based HDD value by a simple conversion: HDD = max(0,65-T). The annual design pattern includes a statistically derived heating season HDD value that is calculated to be colder than 85% of the winters in the data set. The calculated HDD values are layered onto the 2000/01 heating season pattern to provide a realistic weather pattern from which to develop the supply side and demand side resource plan. The 2000/01 heating season is the period that most closely fits the 85% design for cumulative HDD. NW Natural introduced the 85% weather design standard as a scenario in its 2007 IRP. It became the design weather pattern in the Company's 2009 IRP and thereafter, as it was shown to be a good cost to risk tradeoff. A 100% design weather standard costs significantly more without offering a commensurate value in reliable service to customers.

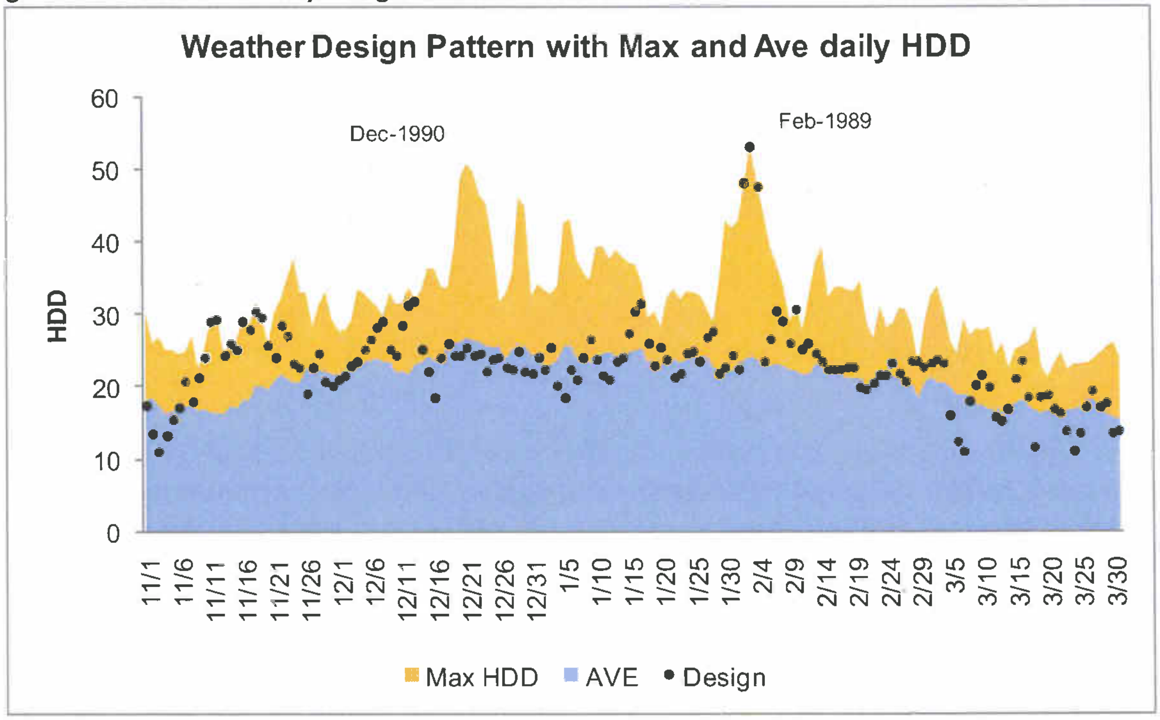
In addition to the colder than normal winter, a peak event is superimposed onto the design pattern. The actual temperature from February 3, 1989, is used for the peak planning day. On that day, the system weighted HDD value reached 53. This corresponds to an average daily temperature of 12°F. The day before and the day after the peak were very cold and were also superimposed onto the design pattern in order to capture the complete peak event.

Previously, the Company used February 3, 1989 as part of a 'coldest-in-20-year' peak day planning standard. Because there has been an absence of any meaningful extreme cold weather events in the most recent 20-year period of November 1992 through October 2012, the February 3, 1989 weather event has been retained for planning purposes. For the time being, the Company has effectively moved to a "coldest in 25 years" standard. This will continue to be reassessed, particularly given that most other LDCs use more robust peak day standards.[4]

The design pattern for the heating season is displayed in Figure 2.8, along with daily average and maximum HDD values. The Company believes that the design pattern provides a robust test for system resources. In the design pattern, the first heating month of the gas year (November) is much colder than average, and the peak weather event occurs late in the season, which results in the retention of significant supplies in storage until late in the winter in order to preserve maximum deliverability. Using this pattern, the system is stressed both at the start and toward the end of the heating season.

4 For example: Avista's 2012 Natural Gas IRP, Chapter 3, page 3.6, "Utilizing a peak planning standard of the coldest temperature on record may seem aggressive...Given the potential impacts of an extreme weather event on our customers' personal safety and property damage..., we believe it is a prudent planning standard." Intermoutain Gas Company's 2010 IRP, page 30, "Intermountain determined that the company-wide 50 year probability event...would be appropriate to use for the design weather model."

Figure 2.8 - 85% Probability Design Winter Pattern



The resulting HDD values for the design peak day and design heating season, along with normal heating seasons for each of the regions are shown below in Table 2.3.

Table 2.3 - HDD by Region

Region	Design Peak Day HDD	Design Heating Season HDD (Nov – Mar)	Average Heating Season HDD (Nov – Mar)
Albany	54.5	3,578	3,289
Astoria	50.0	3,100	3,041
The Dalles (OR)	62.0	4,116	3,891
Eugene & Coos Bay	52.2	3,586	3,267
Lincoln City & Newport	48.5	2,789	2,757
Portland	53.0	3,434	3,166
Salem	54.0	3,548	3,241
Vancouver & The Dalles (WA)	54.7	3,646	3,418

V. GAS PRICE FORECAST

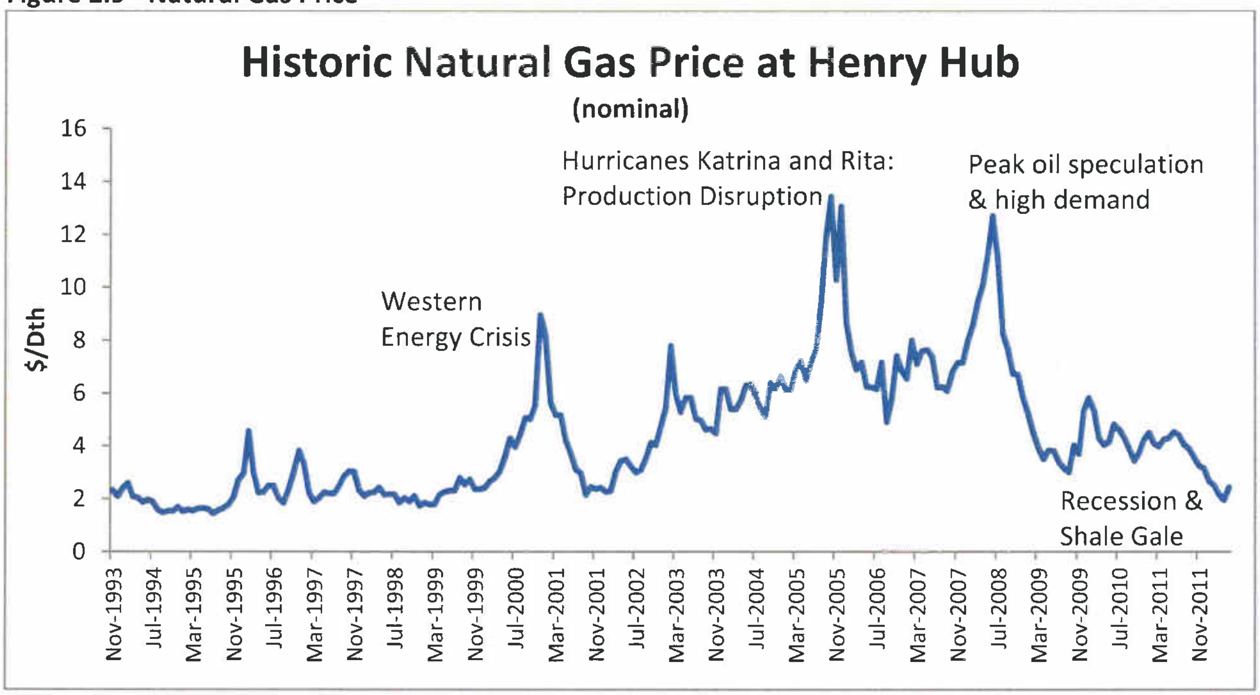
As part of the IRP process, the Company develops a 20-year natural gas price forecast by supply basin. The forecast includes a monthly price outlook for Henry Hub, Rockies (Opal), British Columbia (Sumas), Alberta (AECO) and Malin. The volatility inherent in natural gas prices makes forecasting commodity prices highly uncertain. Future gas prices are expected to be influenced by numerous factors including economic conditions, demand, power generation, potential national carbon policies, weather, and new and traditional supplies, including gas produced using more efficient extraction technologies. The Company has reviewed several public and proprietary price forecasts and has developed a base case, as well as a high and low price outlook, to represent reasonable pricing possibilities for the basins from which the Company purchases gas supplies.

A. Price Volatility

The combination of low demand and vast supplies has recently kept gas prices relatively low. Improved drilling technologies have opened up vast quantities of "unconventional" gas from shale deposits throughout North America. The economic recession that began in 2008 has continued to decrease natural gas demand. In 2009, spot prices at Henry Hub dipped below $4 per dekatherm (Dth) while Rockies and Canadian spot prices dropped below $3 per Dth. According to IHS CERA Chairman Daniel Yergin, "As recently as 2007 it was widely thought that natural gas was in tight supply and the U.S. was going to become a growing importer of gas. But this outlook has been turned on its head by the shale gale".

Figure 2.9 displays the volatile nature of natural gas prices. As recently as June 2008, prices at the Henry Hub surpassed $12 perDth. Henry Hub is the primary pricing point for the North American natural gas market. In late 2005, Hurricanes Katrina and Rita drove prices up over $13 perDth. The Western energy crisis in 2000/2001 previously spiked prices over $8. The recent drops in price have allowed the Company to cut residential rates in Washington by 24% in late 2009, 2% in 2010, 2.5% in 2011, and by about 9% in 2012.

Figure 2.9 - Natural Gas Price



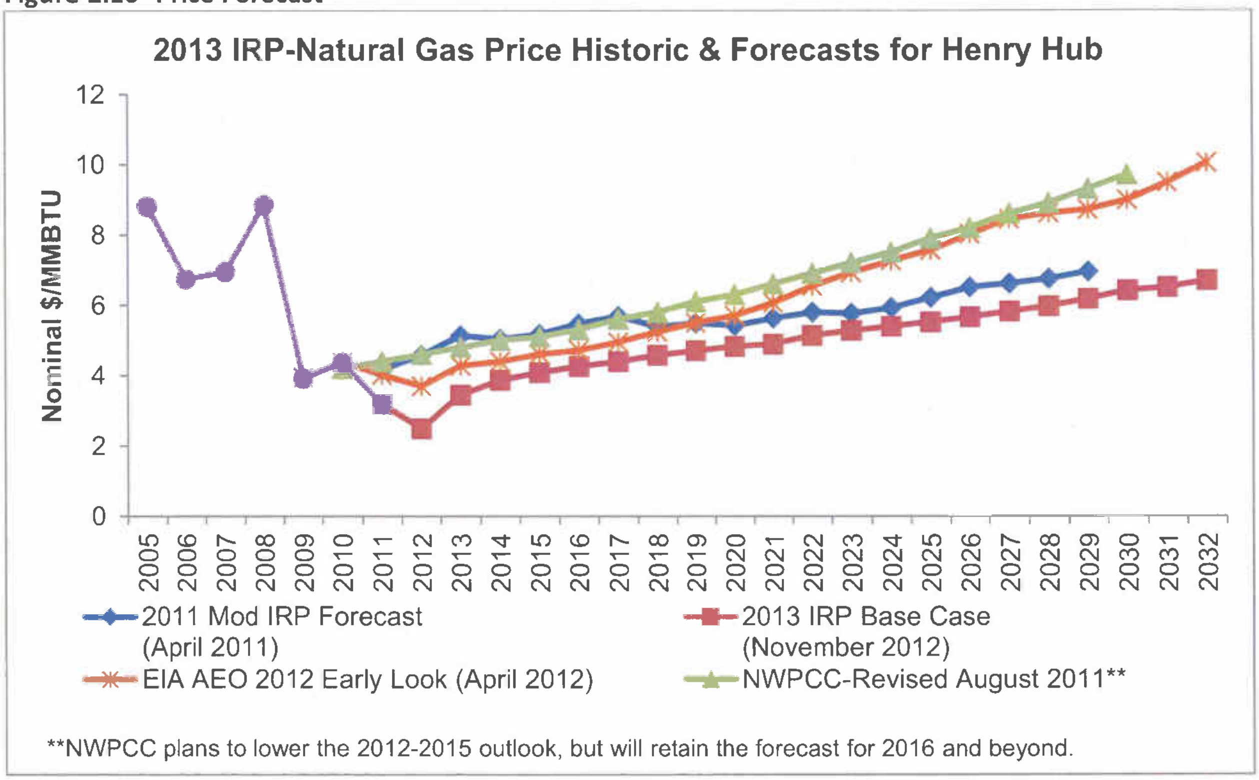
B. Forecast

The natural gas price forecast impacts the least cost planning modeling and avoided cost calculations. Further, it is used in the demand forecasts for the high price modeling scenario. The price forecast is included in the Company's SENDOUT® resource planning model and plays a strong role in determining future resource decisions. SENDOUT® determines the optimal plan for purchasing and transporting supplies to customers across the service region. Supply cost is the dominant component of avoided cost calculations; therefore the price forecast plays a significant role in estimating costs.

The price forecast offers a long term look at the natural gas market. The Company's forecast is derived from a proprietary forecast developed by a third party organization IHS CERA Inc.[5] Figure 2.10 displays the price forecast used in this IRP, along with other outlooks:

1. Modified IRP Forecast (April 2011)
2. IRP Forecast (October 2012)
3. U.S Energy Information Administration (EIA) from Dec. 2009
4. Northwest Power and Conservation Council (NWPCC) 6th Plan from 2008/2009

Figure 2.10- Price Forecast



5 The use of this content was authorized in advance by IHS CERA. Any further use or redistribution of this content is strictly prohibited without written permission by IHS CERA.

VI. Emerging Markets

The recent decrease in gas prices resulting from the transformational shale recovery methods is expected to bring about increased uses of natural gas in three or more areas. The primary markets are likely to be electric power generation, industrial processes and feedstock, and transportation. The transportation market may include local fleets and passenger vehicles, long-haul trucking, marine, and even railroad applications. Both liquefied natural gas (LNG) and compressed natural gas (CNG) facilities are expected to be required to support the new markets. An additional market that may emerge due to lower gas prices is distributed generation, where electric requirements are provided by smaller, local facilities powered by natural gas.

The Company produced three scenarios for emerging market growth, and included the lowest projection in the base model runs. Additionally, the medium and high runs were included in models specific to those scenarios. The high growth scenario is quite dramatic, including potential feedstock needs, power generation, and long-haul trucking conversions. The high case would produce annual demand for emerging markets by the end of the planning horizon that is more than twice our current load. On the same basis, the medium case would be about one-third of current load, and the lower case, which was included in the base model runs, is about ten percent of current load. The following figures show the projections for each scenario by market segment, as well as a graph comparing the total market projections of each of the low, medium, and high scenarios. MDT stands for a thousand dekatherms.

Figure 2.11- Low Emerging Market Scenario by Segment - MDT

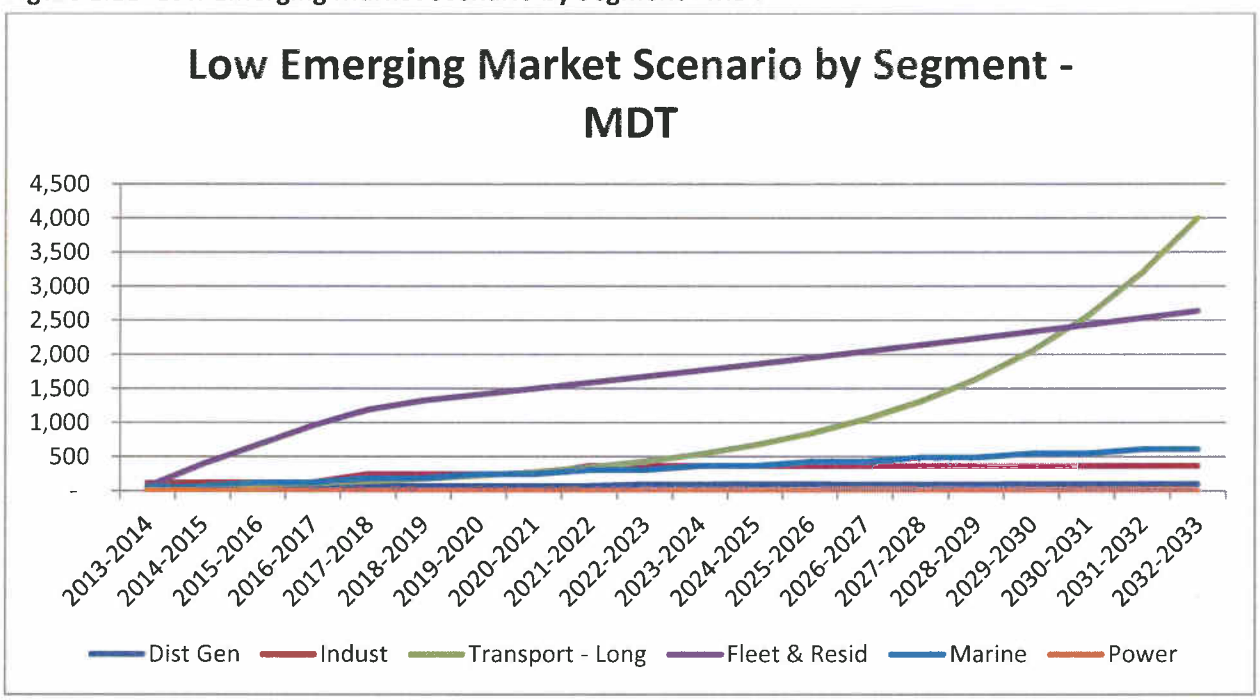


Figure 2.12 – Medium Emerging Market Scenario by Segment

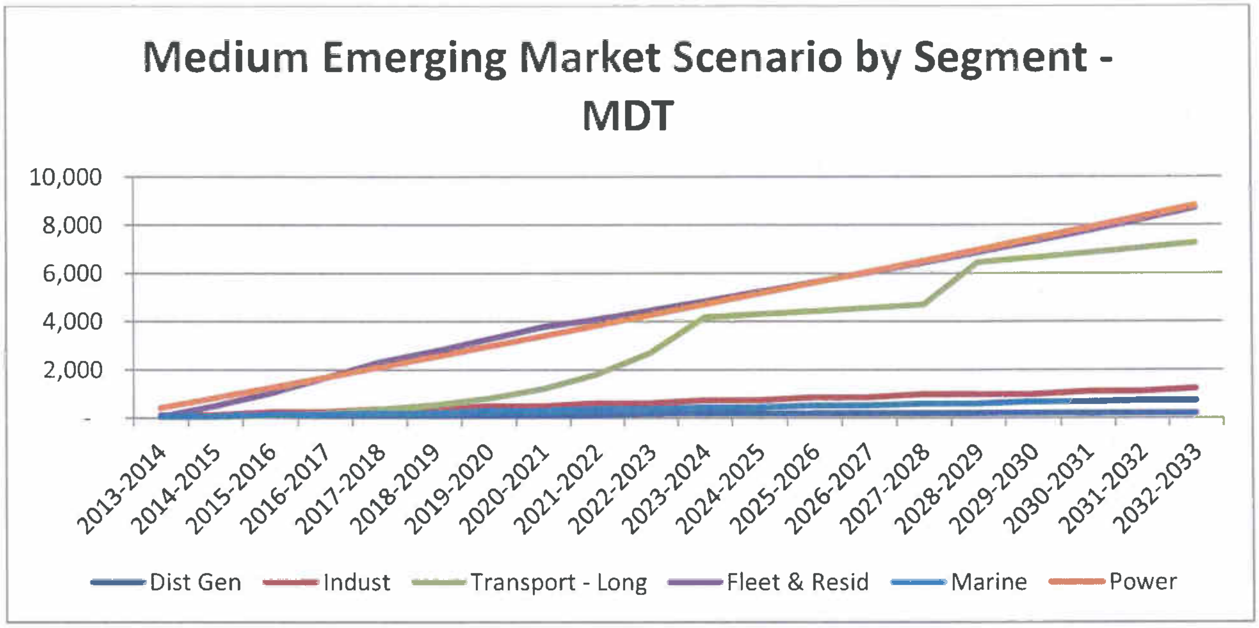


Figure 2.13 – High Emerging Market Scenario by Segment

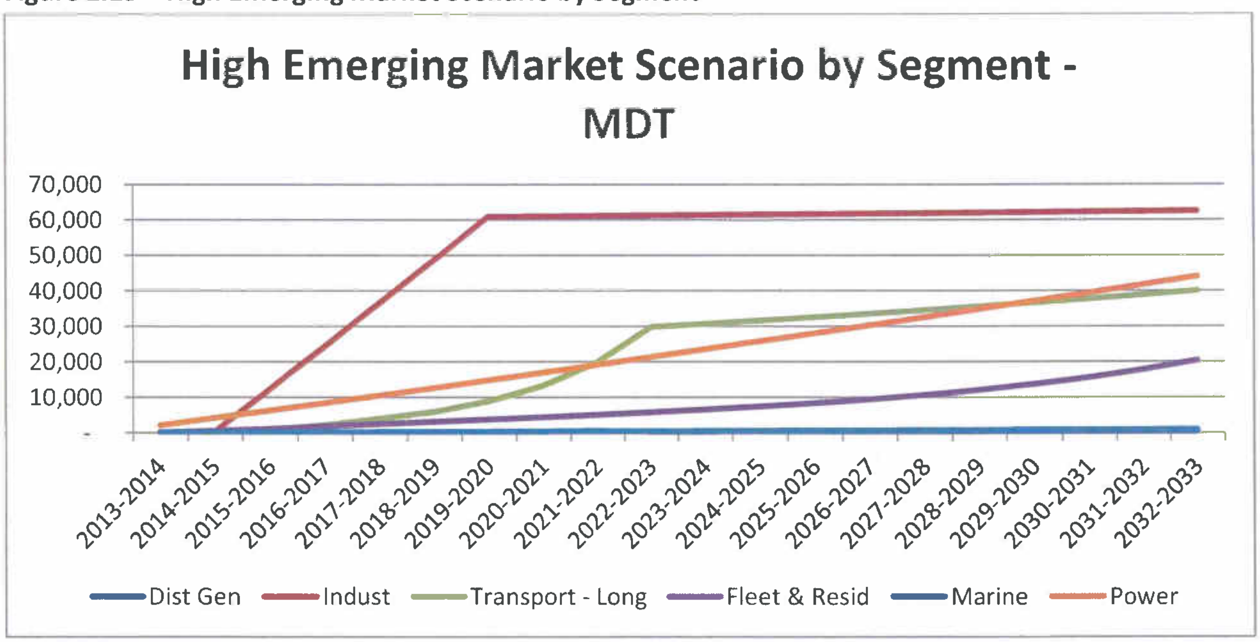
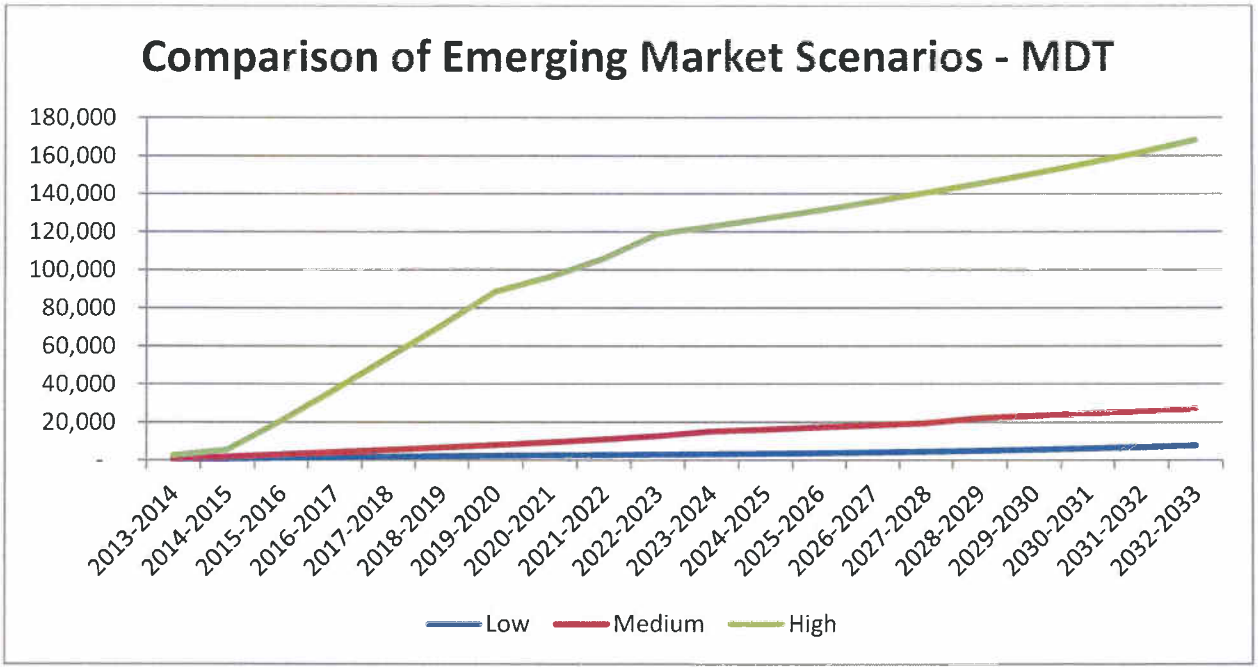


Figure 2.14– Comparison of Emerging Market Scenarios



VI. RESULTS

The primary components of the forecast – customer forecast, usage model, and weather pattern – are combined to generate a daily load forecast for each region and category.

Equation 2.6 - Daily demand

$$D = \sum_{i}^{region} \sum_{j}^{customer\ category} C(i,j) \times [U_B(i,j) + U_H(i,j)]$$

Cost effective DSM savings are forecasted and decremented from the demand. Chapters 4 and 5 provide background on how the DSM savings were estimated and integrated with the demand forecast. The end result is the daily gas requirement around which the resource plan will be developed.

A. Base Case

The planning base case provides the best estimate of future demand for a cold winter with a very cold peak day event. It is derived using the base case customer forecast, the usage factors, and the design weather pattern. The average annual load growth rate over the planning horizon is 1.27%. Excluding DSM savings, the average annual load growth is 1.49%. Peak day load is expected to grow at an average annual rate of 0.92%. Figures 2.15 and 2.16 display annual demand and peak day demand by region. MDT stands for thousand dekatherms. A value of 70,000 MDT is equivalent to 700,000,000 therms, and a value of 1,000 MDT is equivalent to 10 million therms. Figure 2.17 shows the percentage breakout of customers, and demand by category for a single year (2013-14).

Figure 2.15 - Annual Demand Base Case

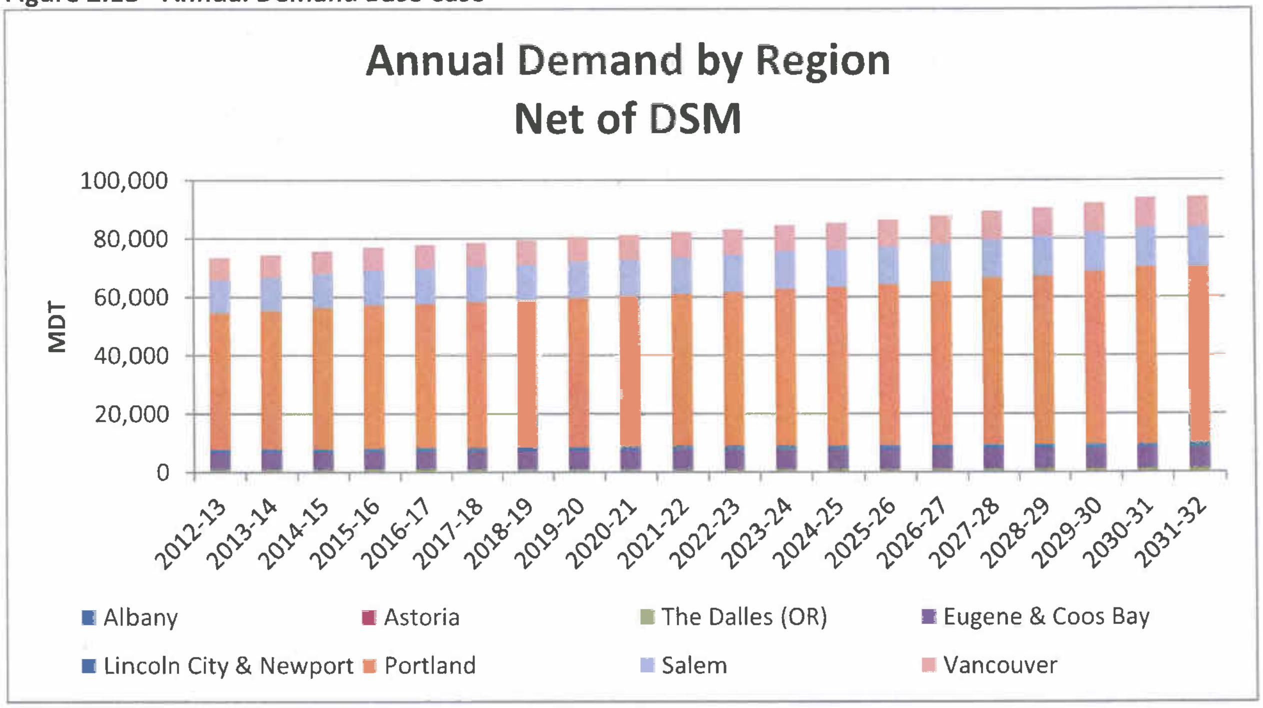


Figure 2.16 - Peak Day Demand Base Case

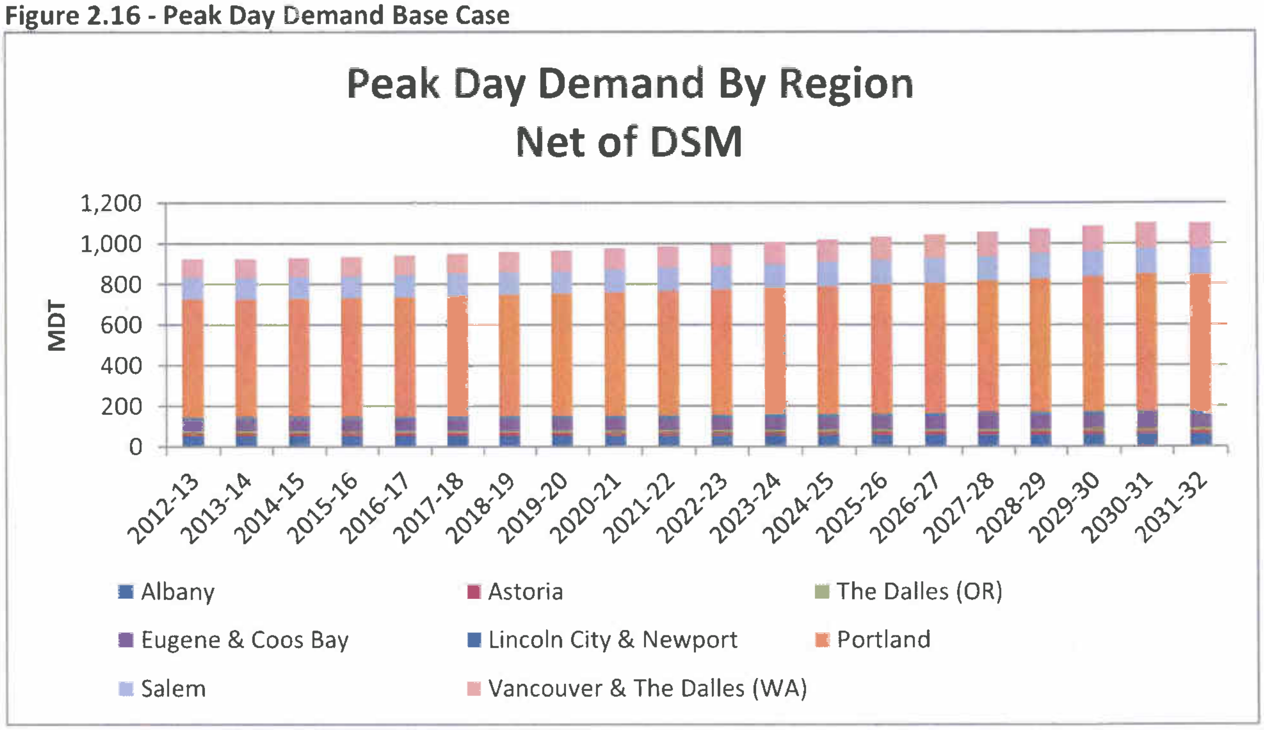
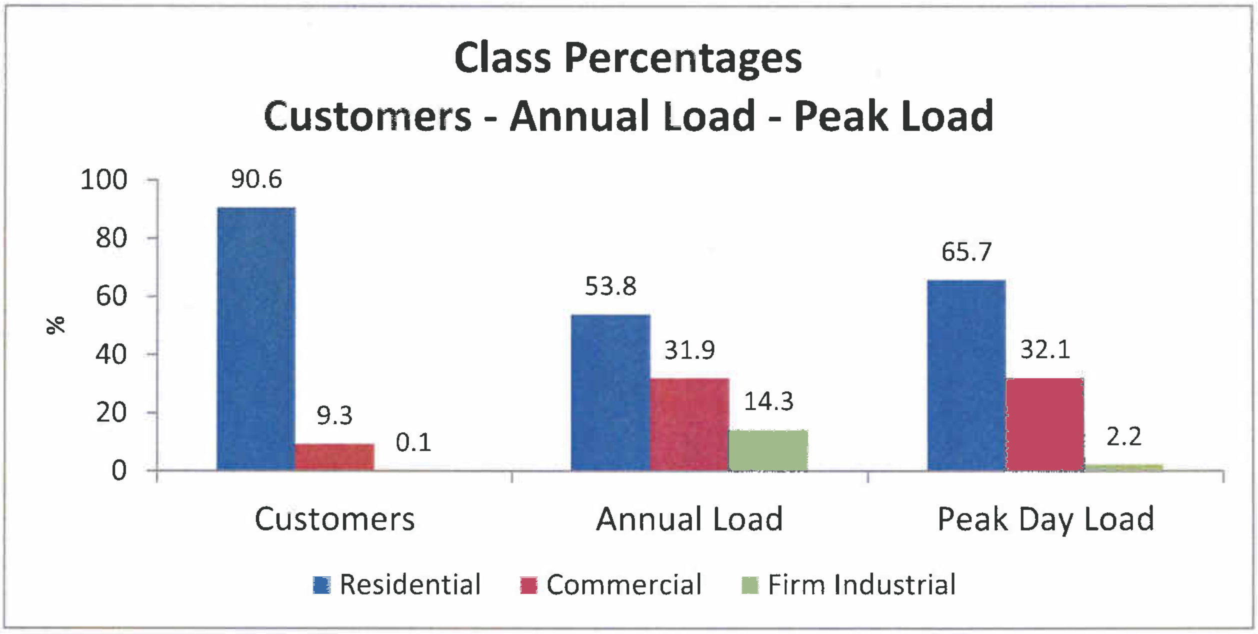
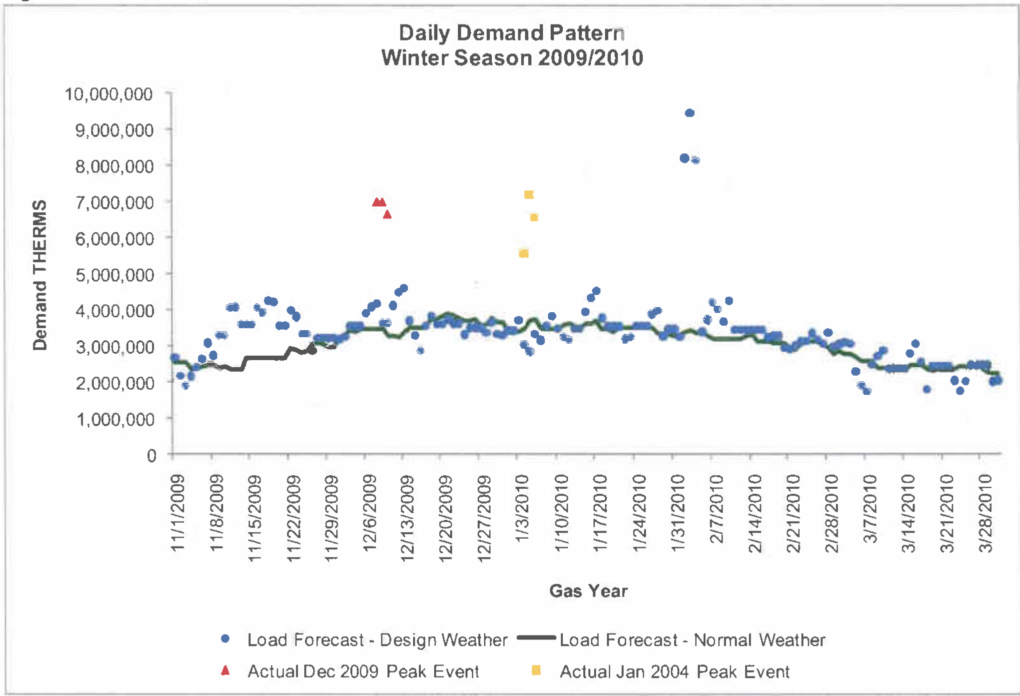


Figure 2.17 - Demand Percentages



Peak day demand is the primary driver of the IRP. High peaking demand puts a premium on storage, while large base line volumes may drive more interstate pipeline capacity. A typical daily forecast load value for a winter day in gas year 2013/2014 is 355 MDT. The forecast peak day for that gas year is 924 MDT. This is 2.75 times the load for a typical winter day. Clearly, meeting peak day load is of primary consideration for the IRP. Figure 2.16 shows the daily forecast demand for gas year 2009/2010, along with two recent historic cold winter events. The Company served its highest-ever daily firm demand (about 720 MDT) on January 5, 2004. The system weighted average temperature that day was 22°F, which corresponds to a HDD value of 43. The cold temperature was accompanied by strong winds, fog, rain and snow. More recently, on December 9, 2009, the region experienced a 44 HDD peak with calm and sunny conditions. Firm demand that day registered 698 MDT. In relation, the Company plans for a peak day of 53 HDD.

Figure 2.16 - Demand Forecast Pattern



B. Demand Sensitivities

Several demand sensitivities were developed around the base case. There are three main forecast ingredients to each demand scenario:

1. Customer Forecast
2. Customer Usage
3. Emerging Market Load Growth

For the base case, each component is derived from the Company's best estimate at the time the forecast was generated. Demand sensitivities and "world views" can be generated by mixing and matching forecast cases and run through the SENDOUT® resource model to generate and evaluate resource plans. Table 2.4 presents the demand scenarios and the components that were prepared for this IRP.

Table 2.4 – Demand Sensitivities

Case	Ave. Annual Growth Rates - % PRE-DSM			Ave. Annual Growth Rates - % POST-DSM		
	OR	WA	SYSTEM	OR	WA	SYSTEM
Base	1.45	1.84	1.49	1.24	1.61	1.27
Low Customers	1.39	1.74	1.43	1.17	1.50	1.20
High Customers	1.77	2.38	1.83	1.57	2.17	1.63
Emerging-Medium	2.39	1.87	2.35	2.21	1.64	2.16
Emerging-High	6.76	1.91	6.44	6.69	1.68	6.36
Prices-High	1.03	1.42	1.07	0.79	1.17	0.83

Table 2.5 – Overview

Case	Customer Forecast	Customer Usage Forecast	Emerging Market Forecast	Weather
Base Case	Base Case	Base Case	Base Case	Design
Low Customer Growth	Low	Base Case	Base Case	Design
High Customer Growth	High	Base Case	Base Case	Design
Medium Non-Core Growth	Base Case	Base Case	Medium	Design
High Non-Core Growth	Base Case	Base Case	High	Design
High Price Forecast	Base Case	Base Case	Base Case	Design

Table 2.4 provides a summary of the forecast results by state. The average annual demand growth rate across the 20-year horizon is shown for both pre-DSM and post-DSM calculations. The annual and peak day forecast for the base case and planning sensitivities are graphically represented in Figures 2.17 and 2.18.

Figure 2.17 - Annual Demand Scenarios

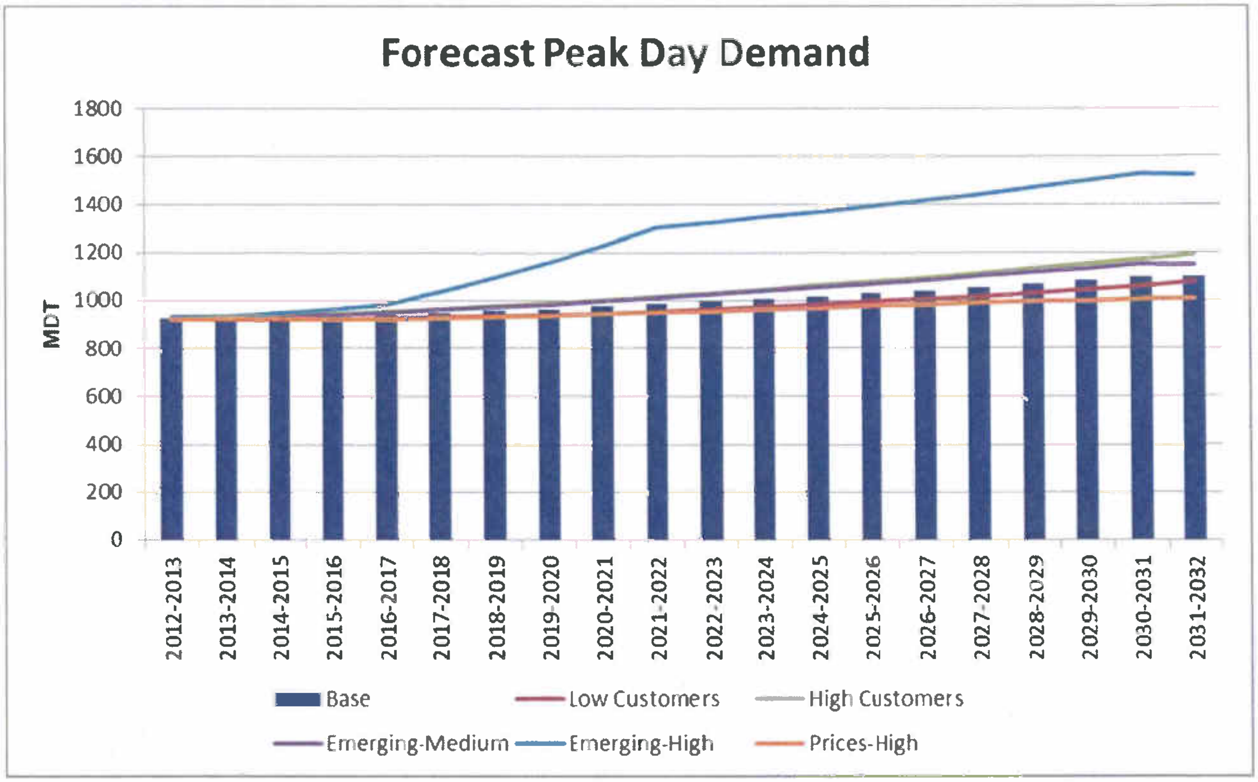
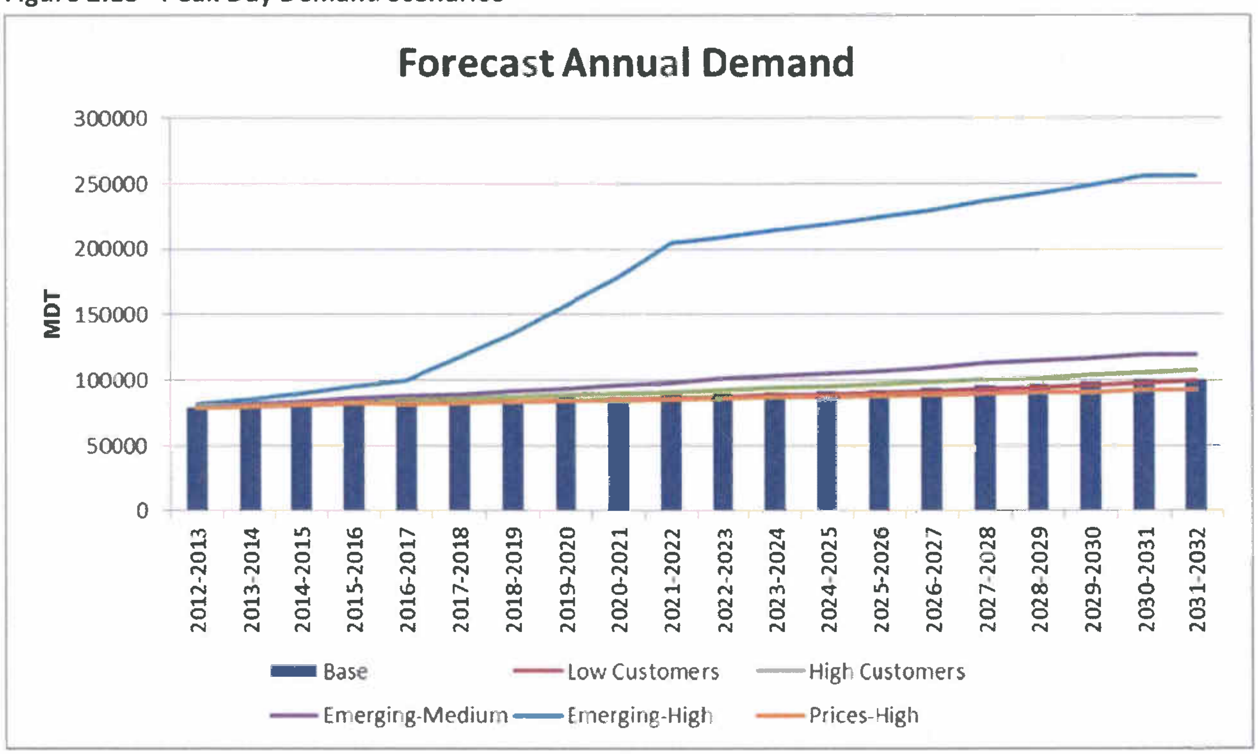


Figure 2.18 - Peak Day Demand Scenarios



VII. FORECAST ACCURACY AND PEAK DAY ANALYSIS

The load forecast model was monitored for accuracy by performing a "backcast" with two relatively recent cold weather events. The Company records actual daily gas requirements in aggregate form. The overall quantity of gas required to meet demand is measured on a daily basis along with the daily temperature; however the daily demand data is not differentiated by individual region and category. In order to measure forecast accuracy on a daily system-wide basis, the load forecast model parameters were combined with the actual customer mix, temperatures and gas rates from the time frame to calculate a forecast demand, called a "backcast". The results were compared to the actual daily "sendout," or the amount of gas the Company delivered to all sales customers to meet demand.

The two most recent cold weather peak events occurred on January 5, 2004, and December 9, 2009. Table 2.6 summarizes the weather conditions, customer numbers, actual demand and forecast demand.

Table 2.6 - Backcast

Date	Actual Firm Demand (MDT)	Forecast Model Demand	Error (MDT) & %	Customers	Res. Price per therm	HDD	Ave. Wind Speed at PDX	Weather Conditions
Monday Jan. 5, 2004	717.73	707.27	-10.46 -1.5 %	582,721	$0.91	43	24 mph with gusts to 43	Fog, Rain, and Snow
Wednesday, Dec. 9, 2009	697.97	756.90	58.93 +8.4 %	667,456	$1.39	44	2 mph	Sunny and Clear

The January 5, 2004 date represents the Company's all-time single-day record of delivered gas. Interestingly, demand on the December 9, 2009 peak date was less than the 2004 peak event, even though the temperatures were nearly identical on the two dates, and nearly 85,000 new customers had been added in the interim. It is believed that the variation in demand response was due mostly to the differences in wind and cloud cover. A small number of customer outages occurred on December 9, 2009, due to unrelated upstream equipment problems at the Jackson Prairie storage facility and at a major pipeline interconnection in eastern Oregon, but the loss of load was modest. The 2004 date was very windy with cloud cover, while the later peak event was nearly perfectly calm with sunny conditions. In addition, improvements to energy efficiency in the time gap may have played a role in the reduced demand.

Figures 2.19 and 2.20 display the "backcast" for the entire month in which the recent peak events occurred. Along with the actual and predicted demand, the average daily wind speed at PDX is plotted.

Figure 2.19 - Backcast Results for January 2004

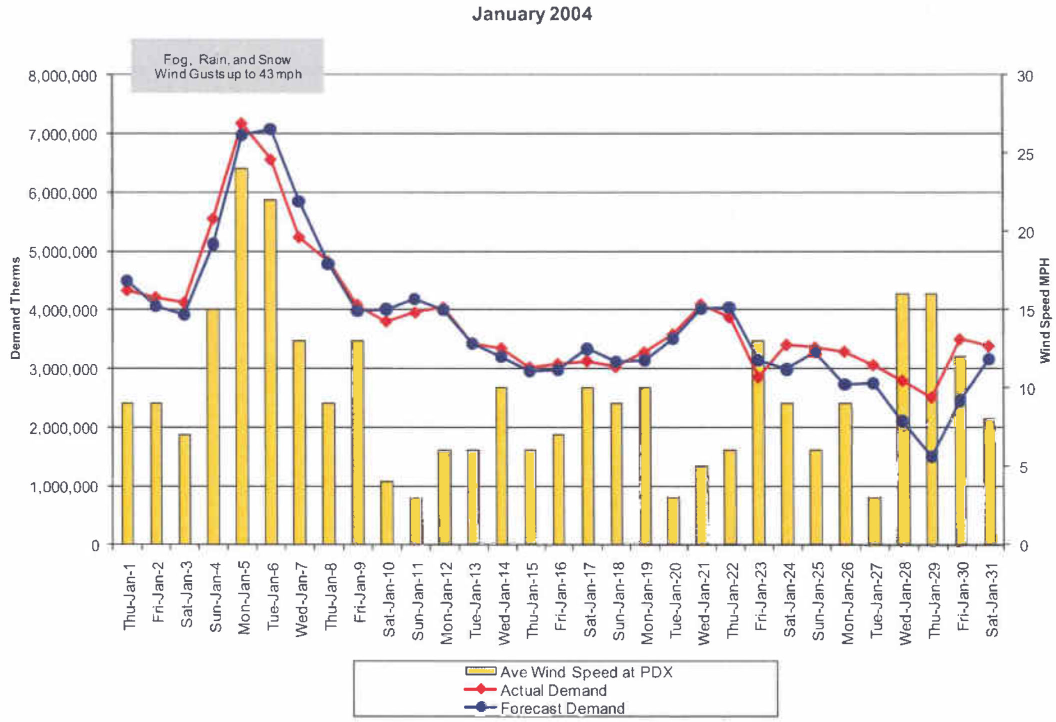
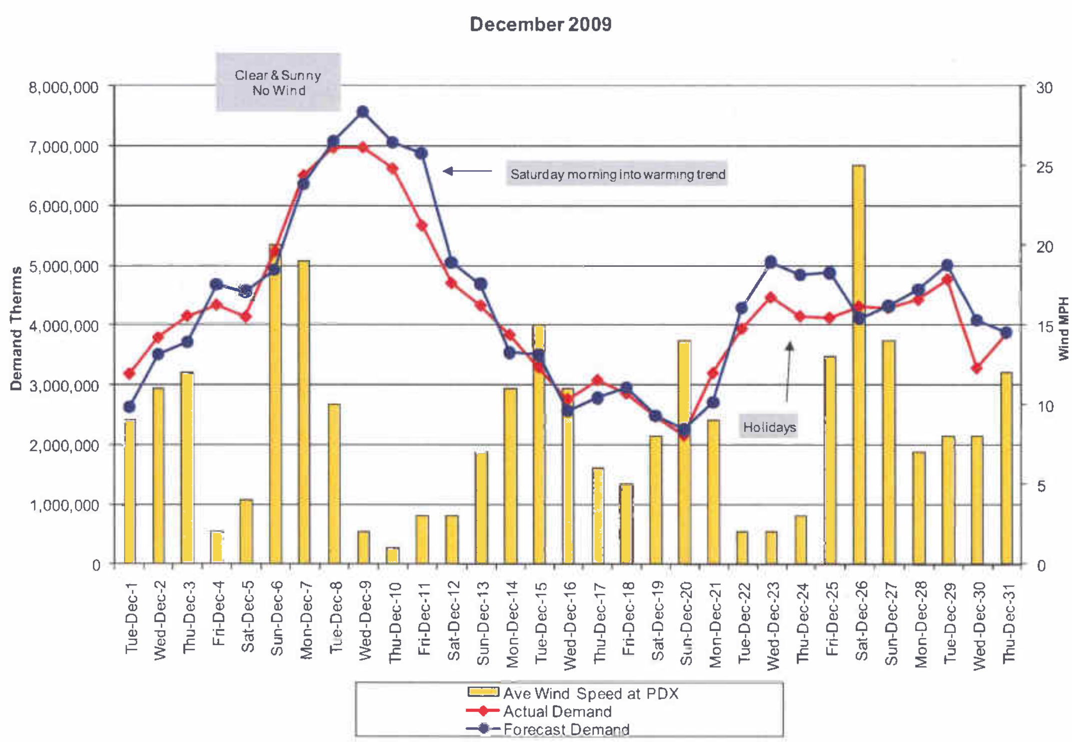


Figure 2.20 - Backcast results for December 2009



It is apparent that wind speed and cloud cover played a role in the demand response. However, wind speed and its effect on demand in combination with temperature is not currently modeled in the load forecast. This may be a topic for further study in a future IRP. Differing demand responses on holidays also contribute to load forecast error, as can be seen in Figure 2.20 in late December. Some factories, businesses and schools may be closed at various times in later December, which can result in an overestimated forecast of actual demand.

Accuracy statistics were calculated from the backcast and are listed in Table 2.7. The error computed over the entire month is shown, along with the daily mean absolute percent error (MAPE).

Table 2.7 – Accuracy Statistics

	January 2004	**December 2009**
Overall monthly error	-3,646,536	4,639,762
Monthly % Error	-3.0 %	+ 3.5 %
Daily MAPE	7.8 %	8.6 %
Peak Day % Error	-1.5 %	+ 8.4 %

VIII. KEY FINDINGS

- The current economic slump continues to affect the Company's customer growth. In 2006, growth was over 3%, while in 2009 through 2011, growth came in under 1%. The average annual customer growth over the 20-year horizon for this plan is 1.65%. Growth is expected to remain under 1.8% until 2017.
- The average annual growth in demand over the planning horizon is expected to be 1.27%, with Peak Day demand increasing at an average rate of 0.84%.
- Use per customer is expected to decline at a rate similar to recent historic rates. In the residential sector, use per customer is forecast to decline by an average annual rate of 0.20%, and in the commercial sector the average decline is forecast to be 0.40%. This is due to improving efficiency standards and the normal turnover rate of appliances, etc. This does not include any effects upward or downward of price elasticity.
- Natural gas prices are currently at historic lows in North America due to the combination of low demand and plentiful supplies. Going forward, prices are expected to slowly rise.
- NW Natural continues to plan resources around the early February 1989 peak day weather event, along with a design winter pattern that is as cold as or colder than 85% of the winters experienced in the last 20 years.

Chapter 3: Supply Side Resources

NW Natural®

I. OVERVIEW

This chapter discusses the gas supply resources that the Company currently uses to meet existing firm customer supply requirements, as well as the supply-side alternatives that could be used to meet the forecasted growth in gas requirements as described in Chapter 2. Supply-side resources include not only the gas itself, but also the pipeline capacity required to transport the gas, the Company's gas storage options, and the system enhancements necessary to distribute the gas. This chapter surveys existing and potential resources without judgment as to the resources that will be chosen. Chapter 5 describes the actual linear programming optimization process, which selects the resources that are least cost under a variety of load growth scenarios.

The gas supply planning process focuses on securing and dispatching gas supply resources to ensure reliable service to the Company's sales customers. The amount of gas needed is greatly influenced by customer behavior. Several factors can affect customer behavior and cause hourly, daily, seasonal, and annual variations in the amount of gas required. Much of this variation is due to changes in the weather. However, changes in business cycles, efficiency measures, and the price of natural gas service relative to other fuel alternatives also influence customer gas use. These behavioral factors are accounted for in the Company's gas requirements forecast and are discussed in more detail in Chapter 2.

The ability to plan for customer requirement variations while maintaining reliability of service is best accomplished by having a variety of supply resources available. The Company's current supply portfolio includes natural gas supplies contracted on a term basis or purchased on the spot (daily) market, which are transported on the interstate pipeline system, as well as storage resources, which are gas supplies purchased during off-peak periods and stored for use in either underground formations or in above-ground tanks as liquefied natural gas (LNG).[1] Both can be used as peaking resources during periods of high demand.

Another resource in the Company's portfolio is a variation on storage. It consists of recallable supply agreements with industrial customers, gas-fired electric generation plants, and gas suppliers. These recall agreements allow the Company to obtain gas supplies controlled by these parties for a limited number of days during the heating season. The alternate fuel tanks of the end-users could be thought of as the storage medium. It is up to the end-users for these gas supplies to either shut down or switch to those alternative fuels. For a variety of reasons, these recall agreements most closely resemble the Company's LNG supplies. First, there is the strict limitation on days recall is available during the heating season. Second, the delivery to or within the Company's service territory mirrors that of the Company's LNG plants and related contracts. And finally, like LNG, this is a relatively expensive resource on a pure cent per therm basis because prospective suppliers of this service expect it to be called upon during the

1 Liquefied natural gas (LNG) is natural gas in its liquid form. When natural gas is cooled to minus 258 degrees Fahrenheit (-161 degrees Celsius), it becomes a clear, colorless, odorless liquid. LNG is neither corrosive nor toxic. Natural gas is primarily methane with low concentrations of other hydrocarbons, water, carbon dioxide, nitrogen, oxygen and sulfur. During the liquefaction process, most of these other elements are removed. The remaining natural gas is primarily methane with only small amounts of other hydrocarbons. LNG weighs less than half the weight of water so it will float if spilled on water.

harshest weather, when alternate fuel costs are highest and re-supply is uncertain, and so they must include the possible cost of plant shutdowns and product loss. Most customers are simply unwilling to even consider providing such a service on a negotiated basis, and others may be too small to be of interest to the Company. However, because recall agreements can be cost-effective when looking at overall costs, the Company continues to pursue such resources where feasible.

Even though the price of natural gas is expected to increase over the next 20 years, the Company still expects its gas supply requirements to increase as its firm customer population grows. The characteristics of this load increase are a critical component of the resource selection process. For example, water heater demand is relatively constant throughout the year. Additional water heater load could be met most efficiently and economically by a resource that has relatively constant deliverability year-round -- a baseload resource. The growth in space heating requirements tends to be highly seasonal in nature. This type of load growth is best met with a combination of baseload and peaking resources. Peaking resources are designed to deliver large volumes of gas for a short duration, such as during cold weather episodes.

The possible effects of price elasticity on gas requirements have been discussed in prior IRPs and other forums. The actual extent to which price elasticity has been modeled is discussed in Chapter 2. Basic economic theory holds that when the price of a good or service increases, then all else being equal, demand for that good or service should decrease to some extent. For natural gas, this could arise from structural changes, such as the installation of higher efficiency appliances and insulating materials. Or, it could result from behavioral changes, such as turning down thermostat settings and dressing warmer. The structural changes should persist under most conditions, but the behavioral changes easily could be reversed. For example, a customer may lower his/her thermostat in response to higher prices, but during an extreme cold weather episode, raise that thermostat rather than risk frozen pipes or endure uncomfortable conditions. This may be a temporary move that has a negligible impact on annual requirements, but, in the aggregate, it could have an impact on peak day requirements.

Given these complexities, the Company has assembled a portfolio of supplies to meet the projected needs of its firm customers. At the same time, this portfolio is flexible enough to enable the Company to negotiate better opportunities as they arise. Existing contracts have staggered terms of greater than one year to very short-term arrangements of 30 days or less. This variety gives the Company the security of longer-term agreements, but still allows the Company to seek more economic transactions in the shorter term.

II. CURRENT RESOURCES

A. Pipeline Transportation Contracts

The Company holds firm transportation contracts for capacity on the Northwest Pipeline Corporation (NWP) interstate pipeline system, over which all of the Company's supplies must flow except for the small amount of local gas produced in the Mist field (currently about 2% of annual requirements). For its purchases in Alberta and British Columbia, NW Natural also holds transportation contracts on the pipeline systems upstream of NWP, namely Gas Transmission Northwest (GTN, a unit of TransCanada Pipelines Limited), TransCanada's system in southeastern British Columbia (known as Foothills), TransCanada's Alberta system (known as NGTL or Nova), Westcoast Energy Inc. (WEI, a division of Spectra Energy) and the Southern Crossing Pipeline (SCP) owned by FortisBC Inc. (formerly known as Terasen and before that BC Gas).

The Company holds all rights to all of its firm transportation contracts. Similarly, the Company has released a small portion of its NWP capacity to one customer but has retained certain heating season recall rights. Details of those contracts are provided in Table 3.1.

Table 3.1[2] - Firm Transportation Capacity as of November 2012

Pipeline and Contract	Contract Demand (Dth/day)	Termination Date
NWP:		
Sales Conversion	214,889	9/30/2018
1993 Expansion	35,155	9/30/2044
1995 Expansion	102,000	11/30/2016
Occidental Cap. Acquisition	1,046	3/31/2014
Occidental Cap. Acquisition	4,000	3/31/2025
International Paper Cap. Acquisition	4,147	11/30/2016
Total NWP Capacity	361,237	
less recallable release to -		
Portland General Electric	(30,000)	10/31/2014
Net NWP Capacity	331,237	
GTN:		
Sales Conversion	3,616	10/31/2023
1993 Expansion	46,549	10/31/2023
1995 Rationalization	56,000	10/31/2014
Total GTN Capacity	106,165	
Foothills:		
1993 Expansion	47,727	10/31/2013
1995 Rationalization	57,417	10/31/2013
Engage Capacity Acquisition	3,708	10/31/2013
2004 Capacity Acquisition	48,669	10/31/2016
Total Foothills Capacity	157,521	
NGTL:		
1993 Expansion	48,135	10/31/2015
1995 Rationalization	57,909	10/31/2015
Engage Capacity Acquisition	3,739	10/31/2015
2004 Capacity Acquisition	49,138	10/31/2015
Total NGTL Capacity	158,921	
WEI T-South Capacity	57,822	10/31/2014
Southern Crossing Pipeline (SCP)	47,343	10/31/2020

2 Notes to Table 3.1:

a. For existing contracts, the SENDOUT® model uses the pipeline rates currently paid by NW Natural.

b. The WEI and SCP contracts are denominated in volumetric units. Accordingly, the above energy units are approximations.

c. The contract demands shown for the 1993 Expansion contracts on GTN and Foothills are for the winter season (October-March) only. Both decline during the summer season (April-September) to approximately 30,000 Dth/day.

Since the implementation of 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 releases and acquisitions 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 also can occur on the Canadian pipelines. In general, Canadian pipeline transactions are consistent with most of the NAESB standards.

On the pipeline systems utilized by the Company, usage among capacity holders tends to peak in roughly a coincident fashion as cold weather blankets the Pacific Northwest region. Similarly, capacity that may be available during off-peak months tends to be available from many capacity holders at the same time. This means that the Company 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, the Company will continue to monitor and utilize the capacity release mechanism whenever appropriate, which primarily will mean continuing to post its own capacity for release during off-peak periods to benefit its customers.

B. Gas Supply Contracts

The Company's portfolio of supply contracts for the 2012-2013 heating season is indicated in Table 3.2. The contracts with near-term expiration dates will either be renegotiated or replaced prior to the next heating season. The contracts are baseloaded, meaning they have a daily delivery obligation, unless labeled as "Swing Supply," which means the Company has an option to take all, some or none of the indicated volumes at its discretion.

Table 3.2[3] - Firm Off-System Gas Supply Contracts for the 2012-2013 Tracker Year

Supply Location	Duration	Baseload Quantity (Dth/day)	Swing Quantity (Dth/day)	Contract Termination Date
British Columbia (Station 2):				
Suncor Energy Marketing	Nov-Oct	5,000		10/31/2013
TD Energy Trading	Nov-Oct	5,000		10/31/2013
Macquarie Energy Canada	Nov-Mar	5,000		3/31/2013
Powerex Corp	Nov-Mar	5,000		3/31/2013
Suncor Energy Marketing	Nov-Mar	5,000		3/31/2013
EDF Trading North America	Nov-Mar	5,000		3/31/2013
Shell Energy Canada	Nov-Mar	10,000		3/31/2013
Iberdrola Canada Energy	Nov-Mar	5,000		3/31/2013
Alberta:				
JP Morgan	Nov-Oct	10,000		10/31/2014
Husky Energy	Nov-Mar	10,000		3/31/2013
Shell Energy North America (Canada)	Nov-Mar	10,000		3/31/2013
ConocoPhillips Canada	Nov-Mar	5,000		3/31/2013
Suncor Energy	Nov-Mar	5,000		3/31/2013
Powerex Corp	Nov-Mar	5,000		3/31/2013
Cargill, Limited	Nov-Mar	5,000		3/31/2013
Iberdrola Canada Energy	Nov-Mar	5,000		3/31/2013
Rockies:				
Ultra Resources	Nov-Oct	20,000		10/31/2013
ConocoPhillips Company	Nov-Oct	5,000		10/31/2013
IGI Resources	Nov-Oct	7,500		10/31/2013

3 Notes to Table 3.2:

a. Contract quantities represent deliveries into upstream pipelines. Accordingly, quantities delivered into the Company's system are slightly less due to upstream pipeline fuel consumption.

b. Nov-Mar and Jan-Oct "Swing" contracts represent physical call options at the Company's discretion, while the Apr-Oct "Swing" contracts represent physical put options at the supplier's discretion.

Table 3.2 (continued)

Supply Location	Duration	Baseload Quantity (Dth/day)	Swing Supply (Dth/day)	Contract Termination Date
Encana Marketing (USA)	Nov-Oct	5,000		3/31/2015
Encana Marketing (USA)	Nov-Dec		7,500	12/31/2012
Encana Marketing (USA)	Jan-Oct		15,000	12/31/2015
Macquarie Energy	Nov-Mar	5,000		3/31/2013
Anadarko Energy Services	Nov-Mar	5,000		3/31/2013
Chevron Natural Gas	Nov-Mar	5,000		3/31/2013
Enserco Energy	Nov-Mar	5,000		3/31/2013
Freepoint Commodities	Nov-Mar	5,000		3/31/2013
Iberdrola Energy Services	Nov-Mar	5,000		3/31/2012
Trademark Merchant Energy	Nov-Mar		10,000	3/31/2013
Trademark Merchant Energy	Nov-Mar		5,000	3/31/2013
ConocoPhillips Company	Nov-Mar		5,000	3/31/2013
ONEOK Energy Services	Nov-Mar		5,000	3/31/2013
Trademark Merchant Energy	Apr-Oct		10,000	10/31/2013
Total Off-System Firm Contract Supply		167,500	57,500	

C. Storage Resources

The Company relies on five existing storage facilities in or near its market area to augment the supplies transported from British Columbia, Alberta and the Rockies. These consist of underground storage at Mist and Jackson Prairie, along with LNG plants located in Portland (also referred to as Gasco), Newport, and Plymouth in Washington State. The Company owns and operates Mist, Gasco, and Newport LNG, all of which reside within the Company's service territory. Hence, gas typically is placed into storage at these facilities during off-peak periods, and when needed during peak periods, these supplies do not require further transportation on the NWP system.

By contrast, others operate and own the Jackson Prairie and Plymouth facilities, which are located outside the Company's service territory. The Company has firm storage service agreements at both of these facilities along with associated NWP capacity to move those stored supplies to the Company's service territory when needed. Jackson Prairie is located north of the Company's territory near Centralia, Washington. Plymouth is located east of the Columbia Gorge, roughly 25 miles south of the Tri-Cities area.

The Company's utility customers currently receive underground storage service at Mist through the Miller Station central control and compressor facility using four depleted production reservoirs (Bruer, Flora, Al's Pool and a portion of Reichhold), collectively referred to as Mist storage. The Mist storage deliverability and seasonal capacity shown in Table 3-3 represents the portion of the present design capacity reserved for utility service. Mist currently has a maximum total daily deliverability of 519,000 Dth/day and a total working gas capacity of about 16 million Dths as contained in the above mentioned reservoirs plus three newer reservoirs (Schlicker, Busch and Meyer). Capacity in excess of core needs is made available for the non-utility storage business. As core needs grow, existing storage capacity may be recalled and transferred for use by core utility customers. The IRP models the recallable portion of the existing Mist storage capacity as an incremental resource that is discussed in Section V of this chapter.

Table 3.3 – Firm Storage Resources

Facility	Max. Daily Rate (Dth/day)
Jackson Prairie	46,030
Plymouth LNG	60,100
Mist (reserved for core)	275,000
Gasco LNG	120,000
Newport LNG	60,000

The Company also contracts on occasion for storage service in the supply basins, most typically in Alberta due to its relative abundance of merchant storage facilities. These contracts are not modeled in the IRP because they would double-count the same upstream pipeline capacity used for the Company's normal gas purchases. That is, any gas placed in supply-basin storage will use the same pipeline capacity for delivery to the Company's service territory as would normal winter purchases. The decision to contract for supply-basin storage is based on the differentials between winter and summer gas purchase prices versus the cost of the storage service, which change constantly. Accordingly, as with other commodity contracts, financial hedges, etc., the process to review supply-basin storage agreements is part of the annual Purchased Gas Adjustment (PGA) filing rather than the IRP.

D. Other Supply Resources

As mentioned previously, an additional type of resource in the Company's portfolio is a variation on storage, *i.e.*, agreements that allow the Company to utilize gas supplies delivered to the Company's service territory for a limited number of days during the heating season. These are supplies that otherwise would be consumed at industrial sites in the Company's service territory. The Company currently has three such recall arrangements, as summarized in Table 3.4 below.

Table 3.4[4] - Recallable Supply Arrangements as of November 2012

Type	Max. Daily Rate (Dth/day)	Max. Annual Recall (days)	Termination Date
Recall 1	30,000	30	10/31/2014
Recall 2	8,000	40	10/31/2015
Recall 3	1,000	15	upon 1 year notice
Total Recall Resource	39,000		

All of the above agreements provide for continuation after the termination date, if mutually acceptable. One of these deals (Recall 3) is already in its annual evergreen period. Recall 1 utilizes NWP capacity that the Company releases on a recallable basis and correlates to customer release volumes shown in Table 3.1. Should this arrangement terminate, the released NWP capacity reverts back to the Company. Recalls 2 and 3 utilize NWP capacity held by the providers of the service.

The pricing of the recallable supplies reflects the peaking nature of the service. The incremental price of any recalled supplies typically is tied to alternative fuel costs (diesel, propane, etc.), and so it would not be economic to dispatch unless weather conditions were extremely cold.

The Company also has the option of obtaining a portion of its gas requirements through a joint venture relationship with Encana Oil & Gas.

E. Joint Venture for Gas Reserves

In April 2011, the Company entered into agreements with Encana Oil & Gas (USA) Inc. (Encana), under which the Company and Encana agreed to participate in a joint venture to develop gas reserves located in the Jonah Field, located in the Green River Basin in Sublette County, Wyoming.[5] Under these agreements, the Company pays a portion of the costs of drilling in the Jonah field, and in return receives rights to the production of gas from certain sections of the field. Under the agreement, the Company has Encana market the gas for the Company, then it purchases gas at another location, applying the proceeds from the sale by Encana to the purchase costs.

The Company expects this venture will help provide its Oregon utility sales customers with long-term supplies at stable pricing over about a 30-year period. NW Natural notes, however, that it does not include the costs, or benefits, associated with this joint venture in rates for its Washington customers. Instead, NW Natural maintains two separate portfolios for Oregon and Washington (for PGA purposes), as contemplated in the WUTC's Order No. 5 in Docket No. UG-111233.

---

4 For each listed recall resource, the SENDOUT® model includes the cost the Company is currently paying for the service.

5 On April 28, 2011, the OPUC issued an order finding the Company's actions prudent in entering into a joint venture with Encana to develop gas reserves on behalf of its Oregon customers. *See* Docket No. UM 1520, Order No. 11-176

During the first 10 years of the agreement, the Company projects the volume of gas received under the transaction (or the volumes of gas to which its proceeds from the joint venture will be applied) to be approximately 8-10 percent of the Company's average annual requirements for its utility operations. It also expects its investment to result in the availability of about 93 billion cubic feet (Bcf) of gas at a highly competitive price as compared to equivalent gas supply purchase alternatives over the same term.

The joint venture with Encana serves an important role in the Company's overall portfolio because it has the attributes of both a long-term physical supply as well as a long-term financial hedge. And, rather than being limited to a duration of several years, which is the term that is normally available in financial markets, the transaction provides price stability for a portion of the Company's portfolio that is of a much longer term. As was developed in the proceeding[6] where the OPUC reviewed the Ecana transaction, the Company believes that this transaction offers customers the lowest reasonable cost available for long-term price stability with a significant expected benefit to customers relative to fixed price hedging alternatives.

In this IRP, the Encana transaction is recognized as being in effect but, for multiple reasons, the transaction does not specifically alter the modeling or analyses of supply options from what would be shown in the absence of the joint venture. The primary reason is that, as described above, the Company has flexibility under its agreements with Encana either to take gas from the joint venture at Opal or to have Encana market the gas and then apply the proceeds to purchases of gas from other locations and suppliers. This means that the Company's decisions about where to purchase gas will continue to be driven by where it can receive the lowest price for gas, rather than by the existence of the joint venture with Encana. In other words, the Company's strategy for purchasing physical supplies is expected to be the same with the Encana joint venture in place as it would be without it.

As in its 2011 Modified IRP, the Company has not specifically modeled gas acquisition options by embedding the expected price of gas under the joint venture with Encana as an available price in its models. It determined that doing so would be problematic and unhelpful. Although one of the building blocks of the IRP analysis is a price forecast applicable to commodity gas purchases, which permits a complete evaluation and comparison of different demand-side measures and supply-side resources, embedding the Encana gas supplies and associated price within that forecast would likely skew the results improperly because those prices are available under just this one transaction, which has limited volumes associated with it. If the Company were to use the price from the Encana transaction as a proxy for the marginal cost of gas, the model would not produce a realistic analysis of the options currently available for purchasing gas. Moreover, as explained above, the existence of the Encana transaction does not have an effect on the location at which the Company will purchase gas because it can always choose to apply the proceeds from the transaction to whatever purchases it makes, and it will strive to make those purchases at the lowest cost locations, regardless of the fact that it can apply proceeds from the Encana transaction to those purchases. In David Danner's (WUTC Executive Director

---

6 *See* OPUC Docket Nos. UM 1520 and UG 204.

and Secretary) letter to NW Natural, dated January 13, 2012, wherein the WUTC acknowledged the Company's previous IRP filed in Docket No. UG-100245, the Commission confirmed that NW Natural's approach to limiting the inclusion of the Encana transaction in its analyses was appropriate.

Although the joint venture with Encana does not specifically alter the resource options modeled in this IRP, the above description of the arrangement with Encana is included to ensure that it is included in future analyses if needed. That is, in some future IRP, it is possible that the Encana gas reserves transaction may need to be modeled explicitly in that IRP. For instance, modeling Encana as a resource would be appropriate if unexpected supply constraints in the Rockies caused the Company to rely on the physical supply option received under its agreement with Encana. In that unlikely case, the capacity available to the Company in the Rockies would need to be split between gas received under the Encana transaction and gas purchased under other supply contracts.

Meanwhile, the Company will continue to consider the unique aspects of the joint venture with Encana in future IRPs to ensure that its analysis is complete and that the resource decisions made in the IRP are compatible with the existence of the agreement with Encana.

Furthermore, the Company will continue evaluating the appropriate proportion of its portfolio that should be secured through arrangements like the one with Encana. As described above, such transactions offer benefits that are not likely to be secured through other traditional supply options. Future similar transactions may be desirable to both increase the percentage of the Company's portfolio that is characterized by long-term price certainty and to levelize over time the percentage of the portfolio that is secured through these arrangements.

F. Supply Diversity

The Company's upstream pipeline contracts enable it to purchase roughly one-third of its supplies from each of the major supply regions in the area: British Columbia, Alberta and the U.S. Rockies (figure 3.2). Lower liquidity in British Columbia has prompted the Company to baseload more of its supplies from this region on a year-round and winter term basis, i.e., rely less on that region for spot purchases. The Company will continue to favor spot purchases from Alberta and the Rockies due to generally lower prices. However, the mix of Rockies and Alberta gas purchases changes from year-to-year in reaction to changing market dynamics. Recent examples include -

- REX: The completion of the Rockies Express Pipeline (REX) in 2009 to move Rockies gas to markets in Illinois, Indiana, and Ohio, increased competition and prices for those supplies.
- Ruby: The Ruby Pipeline commenced service in mid-2011 from Wyoming to the California/Oregon border, providing another outlet for Rockies gas.
- Marcellus Shale: The emergence of unconventional gas supplies in the eastern U.S., combined with the economic slowdown, has displaced some of the demand for Rockies and Western Canadian supplies. At the moment, the most bearish impacts have been felt in Alberta.
- NGLs: Prices for natural gas liquids (NGLs) such as propane and butane have tended to track oil prices more closely than natural gas. As a result, drilling activity generally has shifted to regions where the natural gas is "wetter" (has more NGLs) and market access is available.

Until about four years ago, the tight nationwide balance between supply and demand resulted in lower confidence in spot markets during cold weather or other extreme load periods. Reflecting that concern, the Company's previous contracting practice was to select a minimal summer load, including storage injections, as an amount suitable for year-round baseload (take-or-pay) supply contracting. It would then fill up most of its remaining pipeline capacity with winter term (November-March) supply contracts. Some of these November to March contracts would be baseload (take-or-pay) in nature, while others would provide optionality on purchases to avoid over-contracting in the event of a mild winter. In general, spot purchases had been less than 10% of total purchases due to this heavy reliance on term contracts.

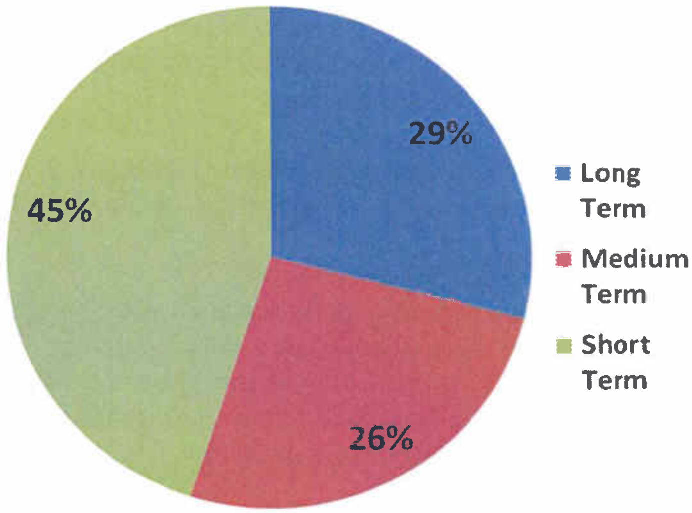
More recently, with the surge in supplies represented by shale gas, the Company has decreased its reliance on term contracts and allowed spot purchases to be much higher.

Physical gas contracting strategies for 2013-2014 that are consistent with strategies of recent years include:

- Maintain a diversity of physical supplies from Alberta, British Columbia and U.S. Rockies.
- Buy supplies at trading points with high "liquidity" in order to access the most competitively priced and reliable supplies.
- Continue to shift the source of physical supplies to the lowest-cost source region. In recent years, Rockies gas offered the best prices as production increased due to anticipation of REX and the Ruby Pipeline. Since those pipelines became fully operational, Rockies term prices have risen higher than Alberta prices. British Columbia gas typically has been priced higher than Rockies and Alberta.

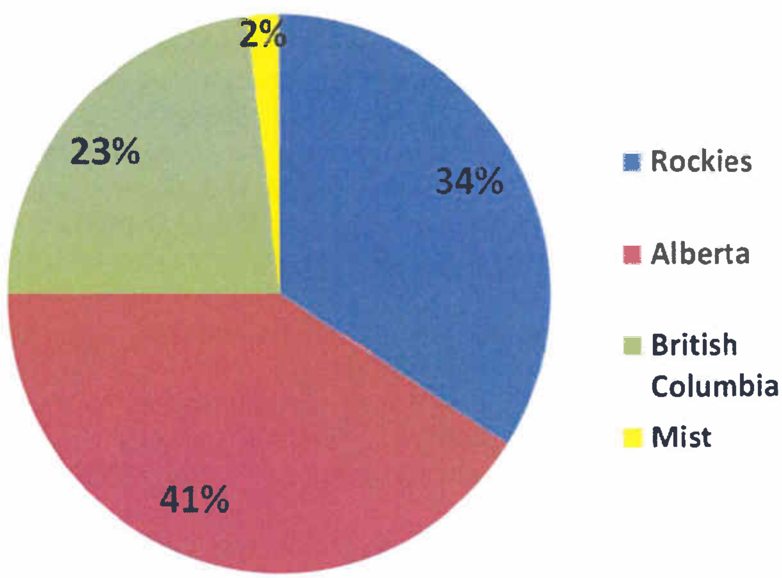
Figures 3.1 and 3.2 provide graphical representations of the Company's physical gas supply resources and diversity during 2011 (the most recently completed calendar year).

FIGURE 3.1 – Gas Supply Diversity by Contract Length for Calendar Year 2011



For Figure 3.1, Long Term means one year or longer; Medium Term is greater than a month but less than a year; and Short Term is up to a month.

Figure 3.2 – Gas Supply Diversity by Source for Calendar Year 2011



As supply contracts expire, new opportunities to re-contract supplies under different arrangements will be examined.

G. Physical and Financial Hedging

The Company provides its retail sales customers with a gas service that bundles together the gas commodity, upstream pipeline transportation, off-system contracted gas storage, and on-system gas storage owned and controlled by the Company. To accomplish this, the Company aggregates load and acquires gas supplies for its core retail customers through wholesale market physical purchases that may be hedged using physical storage or financial transactions.

Four goals guide the physical and financial hedging of gas supplies: 1) reliability, 2) lowest reasonable cost, 3) price stability, and 4) cost recovery. Section VII. B. of this chapter provides definitions of the four goals.

The use of selected financial derivative products provides the Company with the ability to employ prudent risk management strategies within designated parameters for natural gas commodity prices. The objective is to use derivative products to structure hedging strategies as defined by the Company's Gas Supply Risk Management Policies (GSRMP). All wholesale gas transactions must be within the limits set forth by those policies. This is intended to prevent speculative risk.

The Company's Gas Acquisition Strategy and Policies (GASP) Committee maintains oversight for the development and enforcement of the GSRMP. Within those policies, the Derivatives Policy establishes governance and controls for financial derivative instruments related to natural gas commodity prices including financial commodity hedge transactions.

III. LNG Process Improvement and Refurbishment Project

As mentioned above, NW Natural owns and operates two LNG peak shaving facilities. The first is in Newport, OR which consists of a 1,000,000 Dth capacity storage tank, liquefaction facilities capable of processing about 5,500 Dth per day and has a vaporization capacity of 100,000 Dth per day ("Newport"). This facility was constructed by Chicago Bridge and Iron and commissioned in 1977. The second is in Portland, OR and consists of a 600,000 Dth capacity storage tank, liquefaction facilities capable of processing about 2,150 Dth per day and a vaporization capacity of 120,000 Dth per day ("Gasco"). This facility was also constructed by Chicago Bridge and Iron and commissioned in 1969.

The facilities and major process components of these LNG plants were designed for a nominal 25 to 30 year life. Newport and Gasco are now 35 and 44 years old, respectively. NW Natural is considering a major refurbishment of each of these plants. For Newport, this includes addressing issues with the liquefaction process, including carbon dioxide (CO_2) from the incoming natural gas stream that has been very gradually collecting in the tank and settling on its floor in solid form (commonly known as dry ice).

As a storage asset specifically for peak shaving use, NW Natural requires high availability, reliability and productivity from the LNG plants. NW Natural is in the process of evaluating the options for making modifications to the plants that will enhance reliability, reduce maintenance cost and extend the operational life expectancy an additional 25-30 years.

NW Natural recently contracted the services of an engineering firm that specializes in LNG plant modifications to develop a conceptual design, cost estimate and project plan for the refurbishment of

Newport. The project scope includes a separate engineering analysis of the costs, timelines and risks associated with complete removal of the asset, as well as an engineering analysis of the effects of running Newport without removing the CO_2 or modifying the existing liquefaction or vaporization processes in any way. This study is part of our multi-year action plan and will be included in future IRPs.

IV. SUPPLY-SIDE RESOURCE DISPATCHING

The Company's Gas Supply Department utilizes SENDOUT® to perform its dispatch modeling each Fall. Based on expected conditions, this modeling provides guidance to the department in how it anticipates dispatching from various pipeline supplies and storage facilities. These economic dispatch volumes then flow into the Company's Fall Purchased Gas Adjustment (PGA) filing.

Perhaps more importantly, SENDOUT® is used to dispatch supplies to meet design peak conditions as defined through the IRP process. This leads to the creation of guidelines representing the optimal inventory levels on each day for each storage resource, under the premise that the remainder of the heating season will match design conditions. These guidelines provide insights for operational personnel as they make daily dispatch decisions throughout the heating season.

V. RECENT ACTION STEPS

The Company's most recent IRP was the 2011 Modified IRP filed in September 2011 with the Oregon PUC and acknowledged in May 2012 (OPUC Order 12-161 in docket LC 51). Its list of five action items regarding supply-side resources, along with the actions actually undertaken by the Company, is as follows:

1. *Review cost estimates, on an ongoing basis, for resources under consideration to identify potential changes in the composition of previously selected resource mixes.*

This current IRP represents the latest update of cost estimates and resource evaluations.

2. *Recall daily and annual underground storage capacity from the interstate storage gas market to core market service as needed.*

Most recently the Company recalled 10,000 Dth/day of deliverability at its Mist storage field in 2009, another 10,000 Dth/day in 2011, and 15,000 Dth/day in 2012, along with related annual storage capacity.

3. *Support development of the Palomar East Pipeline, primarily for risk management purposes in diversifying the Company's supply path options.*

The Company continues to support development of this option. It can be found in this plan more generically labeled as the cross-Cascades Pipeline.

4. *Monitor LNG terminal developments and evaluate the implications of there being an export LNG terminal in either British Columbia (Kitimat) or Oregon (e.g. Jordan Cove).*

The Company has contracted with Black & Veatch to perform a regional analysis including the impact of LNG exports from British Columbia. That study should be completed in early 2013. The probability of LNG exports from an Oregon facility continues to wane and have not been studied recently in any detail.

5. *Refine cost estimates, conduct more detailed system modeling, and investigate siting/permitting constraints on satellite LNG facilities and the specific NW Natural distribution system investments—including the Willamette Valley Feeder and Newport LNG Compressor project--identified as potential cost-effective resources in this IRP.*

Those resource options continue to be evaluated and modeled in this IRP.

VI. FUTURE RESOURCE ALTERNATIVES

Beyond the existing gas supply resources mentioned previously, the Company considers additional gas supply resource options including Mist recall, the acquisition of new interstate pipeline capacity, satellite LNG storage, and various extensions/expansions of its own pipeline system. The primary alternatives are described in more detail below and summarized in Appendix 3-2. These options will be evaluated in Chapter 5 using SENDOUT®.

A. Interstate Capacity Additions

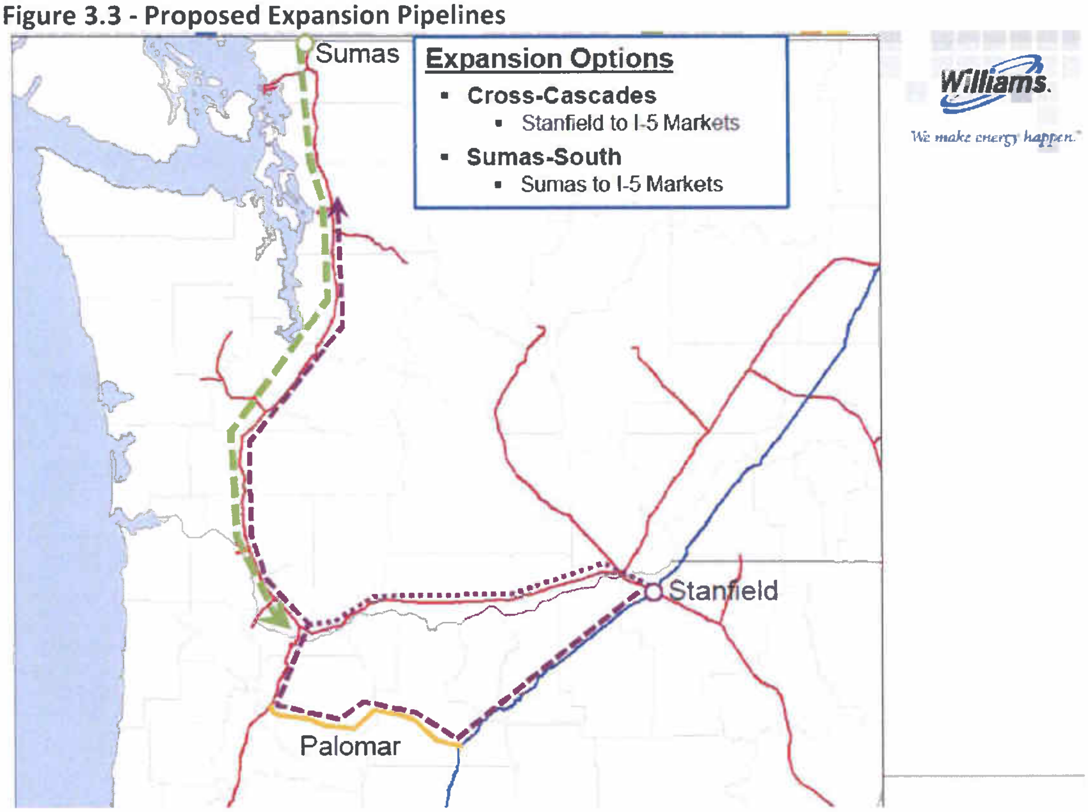
The Company holds existing contract demand (CD) and citygate station capacity on: 1) NWP's mainline serving the Company's service areas from Portland to the north coast of Oregon, Clark County in Washington, and various small communities located along or near the Columbia River in both Oregon and Washington, and 2) NWP's Grants Pass Lateral (GPL) serving the Company's loads in the Willamette Valley region of Oregon from Portland south to the Eugene area. Therefore, consideration of incremental NWP capacity, separately on the mainline and on the GPL, is a starting point for the Company's assessment of incremental interstate pipeline capacity in this IRP.

Since the Company 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 (i.e. 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 the Company to reconfigure or add to its upstream pipeline contracts. Under these market conditions, it may be beneficial to hold transportation capacity upstream of NWP leading to these new supply points.

In response to its reliance solely on NWP for delivery of interstate gas supplies, NW Natural partnered with TransCanada Corporation to form Palomar Gas Transmission LLC (Palomar). Palomar proposed to develop, build, and operate a pipeline connecting GTN's mainline north of Madras, Oregon, to the Company at Molalla. On December 11, 2008, Palomar filed an application for a certificate to build and operate the pipeline with the Federal Energy Regulatory Commission (FERC). On March 23, 2011, Palomar withdrew its original pipeline application with FERC, while stating its expectation of re-filing at a later date. Information for a new cross-Cascades pipeline project in collaboration with NWP, called Palomar/Blue Bridge, was presented in February 2011 at a public workshop jointly sponsored by the Public Utility Commission of Oregon and the Washington Utility and Transportation Commission. The information presented included new estimates for pipeline rates and service dates.

More recently, in November 2012, NWP announced the reformulation of Palomar/Blue Bridge into a new cross-Cascades project called the Northwest Market Area Expansion (N-MAX). Concurrently, NWP is soliciting interest in an expansion south from the U.S./Canadian border at Sumas to serve the proposed Oregon LNG export terminal in Warrenton, Oregon. As depicted by NWP in Figure 3.3, both of these projects could serve the Company's service territory. Of course both projects would be subject to approval by the FERC as well as numerous other Federal and State agencies, and because of these permitting processes, neither could be expected to be in service prior to 2017.

Figure 3.3 - Proposed Expansion Pipelines



From the Company's perspective, the primary benefit accruing from construction of a cross-Cascades pipeline would be to manage the risks associated with the delivery of natural gas into the region. The Willamette Valley, including the Portland metro area, is served solely by NWP. Adding a second interstate pipeline delivery corridor would assure both the security of gas supply as well as reliable gas service well into the future for core customers. As such, by interconnecting with the cross-Cascades pipeline at Molalla, the Company would be in position to consider turning back redundant NWP capacity.[7] By comparison, from a pure delivery corridor perspective, the Sumas-South project "doubles down" on an existing pathway.

As shown in Table 3.5 below, in this IRP, the Company considers the acquisition of incremental interstate pipeline capacity in several forms:

1) new NWP GPL capacity serving Salem, Newport, Albany and Eugene;
2) new NWP "mainline" capacity using the proposed Sumas-South and N-MAX projects to serve the Portland metro area, Clark County in Washington, and the Company's service territory in Washington and Oregon adjacent to the Columbia River to the east of Portland;
3) new capacity upstream of NWP mainline capacity providing access to the Rockies[8] and Alberta supply areas; and,
4) new cross-Cascades capacity directly connecting to the Company's system at Molalla.

The model also includes capacity of 12,000 Dth/day from the Rockies to Portland that was acquired in a 2008 agreement with the March Point Cogeneration Company. This vintage-priced capacity will become part of the Company's portfolio effective January 1, 2017.

The acquisition of incremental pipeline capacity spans a wide range of lead times. It is dependent on the length and success of the pipeline's open season process, regulatory permitting times, and the time required to construct the required facilities, which could include restrictive periods due to environmental considerations.

Table 3.5 - Incremental Interstate Pipeline Capacity Additions Modeled in SENDOUT®

Interstate Pipeline Segments	Contract Demand (Dth/d)	Assumed Availability
NWP Zones 12-9 (GPL)	74,000	November 2015
NWP Zones 26-12 ("mainline")	300,000	November 2015
Upstream of NWP zones 26-12:		
Sumas NWP	100,000	November 2015
Alberta-Stanfield	969,000	November 2012
cross-Cascades Pipeline	165,000	November 2018
March Point NWP capacity	12,000 Rockies to Portland	January 2017

B. Mist Storage Recall

In addition to the existing Mist storage capacity currently reserved for the core market (see Table 3.3), the Company has four reservoirs (a portion of Reichhold and all of Schlicker, Busch and Meyer) that are developed for storage services and currently serve the interstate storage market, but could be recalled for service to the Company's utility customers. Table 3.6 identifies the recallable Mist capacity and the

7 The Company has modeled a turn back of up to 77,000 Dth/day of existing NWPL capacity from Stanfield to Portland upon the availability of cross-Cascades capacity.

8 NWPL capacity upstream of Stanfield, Oregon.

year the capacity is available given current contractual commitments to interstate market customers.

Table 3.6- Mist Recall Capacity (incremental to existing capacity for utility)

Assumed	Capacity (Dth)		Deliverability (Dth)	
Availability	Increment	Cumulative	Increment	Cumulative
2013	587,522	587,522	23,530	23,530
2014	40,000	627,522	1,602	25,132
2015	2,440,000	3,067,522	97,719	122,851
2017	1,620,000	4,687,522	64,879	187,730
2018	1,430,000	6,117,522	57,270	245,000

Mist is ideally located in the Company'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 incremental load requirements in the Portland area, which is traditionally the area where the majority of the Company's firm load growth lies. Mist gas may also be directly delivered to loads westward along the Columbia River from St. Helens to Astoria, and southward to the Salem area.

C. SUPPLY SIDE INFRASTRUCTURE ADDITIONS

Supply side infrastructure additions accompany the need to increase resources to meet load growth, regardless of whether supplies come from on-system sources such as Mist, Newport, Gasco or satellite LNG storage, or from off-system sources such as the Company's numerous gate station interconnections with NWP or the new cross-Cascades pipeline . The Company's Engineering Department plans for these additions.

Two very large on-system projects directly associated with potential supply-side resources are described below. Further discussion of smaller on-system pipeline projects is provided in Chapter 7.

1. Enhancement of Pipeline from Newport

The daily deliverability of the Newport LNG plant is modeled at 60,000 Dth/day due to load and infrastructure limitations. That is, the market area currently served by the Newport LNG plant is from the town of Newport north to Lincoln City and then east to Salem, and the peak load of that area ranges up to about 60,000 Dth/day. However, the Newport plant has all the equipment and permitting necessary to vaporize and deliver up to 100,000 Dth/day. To reach this 100,000 Dth/day capability, infrastructure additions would be needed on the Newport to Salem pipeline to deliver an incremental 40,000 Dth/day (see Appendix 3-1). In addition, to connect more load centers (*e.g.*, Corvallis/Albany, Eugene) to the Newport plant, the Company would need to invest in some or all of the Willamette Valley Feeder project pipeline segments (as described in Chapter 7). The additional piping and upgrading required to reach new load centers could be quite costly due to geographical constraints. This cost, though, could be competitive as compared to a subscription to additional upstream pipeline capacity, which also would need to be accompanied by Willamette Valley Feeder project investments to serve customers increasingly distant from NWP's gate stations.

2. Eastside Loop Expansion

As previously mentioned, one potential supply resource is a new cross-Cascades pipeline connecting to the NW Natural system in the vicinity of Molalla, Oregon. Molalla is a key point because it connects with NWP and is the current terminus of the Company's South Mist Pipeline Extension (SMPE), a 24-inch high pressure pipeline serving the south and west portions of the Portland load area from both NWP and Mist storage. If a cross-Cascades pipeline also connects to the Company's system in this area, additional infrastructure would be needed to assure access to sufficient load on the eastside of the Portland metro area. Further study of the design, location, cost and timing for this additional infrastructure is contemplated in the Company's multi-year Action Plan.

The eastside of Portland is singled out because it contains a large number of customers not already capable of being served directly from Mist and/or Gasco. For the purpose of this IRP, $60 million has been assumed as a rough estimate of the cost of the new piping and related appurtenances to connect the cross-Cascades pipeline to customers on the eastside of the Portland load center. Also, the current working assumption is that two-thirds of this cost, or $40 million, is directly associated with access to supplies from the cross-Cascades pipeline. The remaining one-third, or $20 million, constitutes local distribution system reinforcements that would be needed in some form in any case to support load growth in that area of the service territory. The two-thirds/one-third allocation is the same as that used for SMPE when it was put into service in 2004, so it seems a reasonable starting point. This working assumption also will be subject to refinement as part of the Company's Action Plan study mentioned above.

C. Liquefied Natural Gas (LNG) Exports

In prior IRPs, the potential for LNG imports into Oregon resulted in various modeling efforts to simulate their impact on the Company's resource portfolio. The surge in domestic natural gas production led by unconventional (i.e., shale) developments has rendered those projects moot. Instead, there is active consideration of projects to export natural gas in the form of LNG from North America. Rather than a resource for the Company, these projects create the potential for higher commodity prices. This is especially relevant for supplies sourced from British Columbia, where at least one export project in or near Kitimat is expected by most consultants to be built. Accordingly, the modeling of LNG exports is n not part of the Company's supply scenarios, but instead one of several factors that could support the higher gas commodity price sensitivity runs.

D. Satellite Storage

Some gas utilities rely on "satellite" LNG tanks to meet a portion of their peaking requirements. LNG facilities are used as peaking resources because they provide only a few days of deliverability. The concept is that a small tank serving a remote area would be filled with LNG as winter approaches, and the site manned during cold weather episodes when vaporization is required. Since there is no on-site liquefaction process, the facility is fairly simple in design and operation. Where peaking demands are sharpest, the addition of satellite LNG could defer significant pipeline infrastructure investments.

Satellite LNG is well established in this county but generally confined to the Northeast, as indicated by this excerpt from a 2003 report issued by the U.S. Energy Information Administration:

> Of the 96 LNG storage facilities connected to the pipeline grid, roughly 57 have liquefaction capacity. Most of the remaining 39 storage facilities are located in the Northeast...where many facilities are close enough to the Distrigas import facility to receive LNG by truck. Massachusetts alone accounts for 14 satellite facilities, or roughly 40 percent of all satellite facilities in the United States. In New Jersey, which contains the second highest number of satellites, there are 5 facilities.[9]

The Company's interest in this concept has been tempered by concerns over obtaining siting and zoning approvals in our service territory. However, successful examples of satellite LNG do exist in the Pacific Northwest, including a facility that Puget Sound Energy built near Gig Harbor, Washington, as well as one built by Intermountain Gas on its Idaho Falls Lateral.

In this IRP, the Company has evaluated satellite LNG in Willamette Valley locations near Salem, Albany, and Eugene, primarily as interim resources that might delay the construction of more expensive pipeline projects and as "reserve margin" resources for reliability. The Company has modeled these resources as having the equivalent of 90,000 Dth of storage capacity and a maximum deliverability of 30,000 Dth/day for three days. The Company believes these are reasonable assumptions based on industry research of comparable facilities. At the maximum vaporization rate, this three-day resource matches well with the Company's design peak criteria.

E. Potential Future Supply Resources

In this section, the Company identifies several other potential gas supply resources that could influence the design of its future gas resource portfolio. However, at this time, these potential resources are not yet sufficiently well-defined commercially or technically to warrant inclusion in the SENDOUT® model for this IRP.

Biogas. This refers to methane produced from biomass sources including wastewater treatment plants, animal manure, landfills, woody biomass, crop residuals. If biogas is purified to the standards of the pipeline industry, it is commonly referred to as biomethane or renewable gas (RG). The American Gas Foundation (AGF) recently conducted a study regarding the technical potential for producing RG, which predicts that RG could meet 4 to 10 percent of natural gas use in the United States.[10]

While the supply is currently very small, the production of RG has the potential to provide a wide range of benefits far beyond further diversification of the Company's gas purchase portfolio. For example:

- RG can reduced greenhouse gas emissions and produce other related carbon benefits;
- Projects to generate RG could be built adjacent to existing pipelines in a manner so as to provide system reinforcement;
- Electricity from biogas can offset other forms of thermal generation; and

---

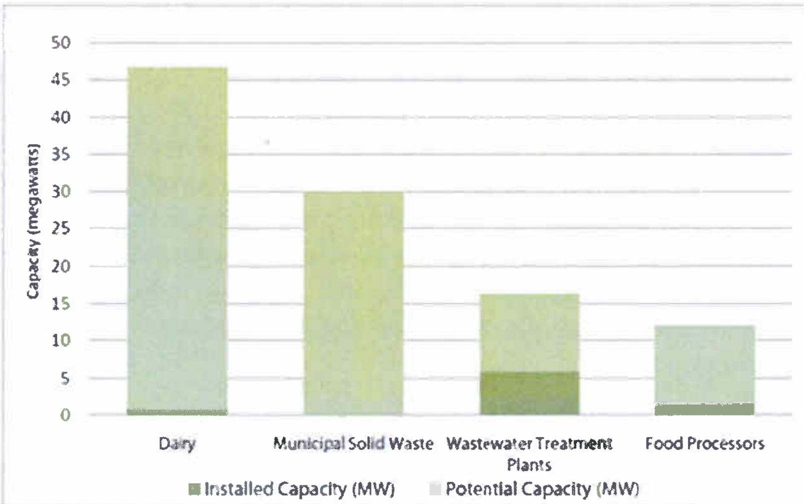
9 *See* http://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2003/lng/lng2003.pdf

10 "The Potential for Renewable Gas: Biogas Derived from Biomass Feedstocks and Upgraded to Pipeline Quality." AGF, September 2011. Total natural gas use refers to total demand in 2010 of 24 trillion cubic feet, which includes gas used for electric generation.

- RG could result in local economic investments and job creation.

A review of the potential for biogas production in Oregon was recently produced by The Energy Trust of Oregon and The Climate Trust.[11] This report found that only 8 MW of installed biogas-related electricity has been developed so far out of a potential 100 MW in the state. Figure 3.4 shows the distribution of potential biogas opportunities.

Figure 3.4 – Oregon's Unrealized Biogas Potential



An analysis recently completed for the Oregon Department of Energy reviews the use of biogas from several of the state's waste water treatment plants (WWTPs).[12] Among the findings of this report is that the RG from several of the plants may be worth more as a vehicle fuel rather than for heating or to make electricity.

To prepare itself for the potential of RG, the Company has developed gas quality standards and sampling criteria for any proposed RG facilities desiring to interconnect with and deliver gas into the Company's distribution system. One such interconnection agreement has been signed to date, but the proposed pricing for the RG (more than twice the current cost of gas delivered to the Company's system) suggests that the Company will not be the buyer for this or other RG supplies unless gas price volatility, technological advancements, or regulatory changes speed the adoption of this particular source of natural gas. For example, it would take the imposition of a carbon tax in the range of $100 per ton of CO_2 emissions to close the current gap, assuming RG would be exempt from that tax.[13]

11 "Growing Oregon's Biogas Industry: A Review of Oregon's Biogas Potential and Benefits", Peter Weisberg (The Climate Trust) and Thad Roth (Energy Trust of Oregon), February 2011.

12 "Bioenergy Optimization Assessment of Wastewater Treatment Plants", Tetra Tech Inc. for the Oregon Department of Energy, March 20, 2012.

13 Natural gas emits approximately 53 kg of CO_2 per Dth (source: "Carbon Dioxide Emissions for Stationary Combustion" posted by EIA at http://www.eia.gov/oiaf/1605/coefficients.html#tbl1). Calculation is then

Coal-bed Methane. Periodically over the years, interest had been expressed by third parties in the development of coal-bed methane reserves found in Coos County. The location of the gas at the extreme end of its service territory made this resource particularly intriguing to the Company. Some third parties did drill test wells to better ascertain the extent of these reserves, including as recently as five years ago.[14] However, the "shale gale" and its resulting reduction in natural gas prices, among other reasons, have stifled any recent interest in this potential resource.

VII. GAS SUPPLY PORTFOLIO ACQUISITION STRATEGY

A. Overview

This section provides the Company's strategies for acquiring gas supplies as described in the Company's Gas Acquisition Plan 2012-2013 (GAP). The GAP is reviewed and approved by the GASP Committee, but such plans are always subject to change based on market conditions. The primary objective of these gas acquisition plans is to ensure that supplies are sufficient to meet expected firm customer load requirements under design year conditions at a reasonable cost. Under other than design year conditions, the Company also expects to serve interruptible sales customers. The focus of the GAP is on the forthcoming gas contracting year which runs from November through the following October. However, many resource decisions are of a multi-year nature. Accordingly, a 5-year horizon is used for discussion purposes in several areas of this section.

Below are excerpts from the GAP.

B. Plan Goals

1. **<u>Reliability</u>**
   The first priority of the Company's GAP is to ensure a gas resource portfolio that is sufficient to satisfy core customer requirements under design year weather conditions as defined in the IRP. Trimming costs by compromising reliability is not acceptable.

2. **<u>Lowest Reasonable Cost</u>**
   The second priority is to acquire gas supplies at the lowest reasonable cost to customers. In so doing, the Company takes a diversified portfolio approach with gas purchases paced during the contracting season. The Company also optimizes its gas supply resource assets using a third party marketer as well as its own staff in order to lower costs with minimal risk to stakeholders.

3. **<u>Price Stability</u>**

$100/ton times 53 kg/Dth divided by 907 kg/ton = $5.84/Dth, which when added to the estimated $4.71/Dth cost of gas delivered to the Company's system in calendar 2012, would be at the low end of the $10-$12/Dth range at which RG is expected to be priced per discussions with RG developers.

14 *See* http://library.state.or.us/repository/2011/201109010951034/index.pdf

Customers are sensitive to price volatility in addition to prices. Consequently, the Company makes use of physical assets (e.g. storage), financial instruments (e.g. derivatives), as well as its investments in gas reserves to hedge price variability within the contract year and for longer-term periods.

4. **Cost Recovery**

Aside from its investments in gas reserves, the Company does not earn a return for acquiring and selling gas commodity supplies, yet the cost of these supplies typically amount to over half of the Company's total revenue stream. Accordingly, the risks associated with the payment and recovery of gas acquisition costs need to be fully addressed. On the financial hedging side, this means strong credit policies and counterparty oversight. On the legal side, this mandates scrupulous compliance to standards of conduct. Since regulatory disallowances could be devastating, maintaining trust and credibility with state regulatory bodies is imperative.

C. Relationship to the Integrated Resource Plan

The IRP contains the Company's long-range analysis of loads and resources spanning a 20-year horizon. It is prepared approximately every two years and involves considerable regulatory and public input. Because the IRP focuses on long-term decisions, it does not include many of the details that are provided in the GAP. Nevertheless, there is consistency between the GAP and the IRP to ensure that long-range decisions are reflected in current decisions, and vice versa.

D. Strategies

Gas acquisition strategies based on the Company's market outlook are summarized as follows:

- Financially and physically hedge up to 75 percent of projected gas sales volumes in accordance with decisions of the GASP Committee.

- Maximize supplies from the regions that afford the lower prices. In prior years, prices of Rocky Mountain gas were lower than prices of Canadian gas due to increased production in preparation for the REX and Ruby pipelines. Since those pipelines went into service, and with the emergence of shale gas in the eastern U.S., Rocky Mountain prices have typically been higher than Alberta but lower than British Columbia prices. Strategies will be continuously re-evaluated as market developments warrant.

- Fill storage at a pace that might present opportunities to purchase gas at times that best benefit customers.

- Maintain a diversity of physical supplies from Alberta, British Columbia and the Rockies to maximize reliability.

- Due to its relative lack of trading liquidity, continue to baseload virtually all pipeline capacity from the Station 2 trading point in British Columbia during the heating season.

E. Market Outlook

Supply increases and demand decreases have crushed prices since the highs of July 2008. Shale gas is the primary impetus for a current supply glut. Gas trapped between dense layers of the world's most prevalent sedimentary rock, shale, became economically accessible in recent years. By some estimates, there are 1,000 trillion cubic feet recoverable in North America alone, enough to supply the nation's natural gas needs for the next 45 years.

Breakeven costs continue to tumble due to advances in drilling and completion techniques. A single drill pad sometimes can be used for a dozen or more horizontal wells, lowering infrastructure costs and speeding the redeployment of drilling rigs. As a result, fewer drilling rigs are required to reach the same volume of gas as in past years.

Shale plays are situated throughout the U.S. and Western Canada. Low-cost methods of horizontal drilling have facilitated the success of shale gas recovery, and undercut the costs of vertical drilling methods used in the Rockies. As a result, drilling decreased in the Rockies while more supplies flowed east via REX, further diminishing the quantity of Rockies gas for the West.

Even more important has been the prominence or lack thereof of NGLs due to the wide spread between NGL and natural gas prices. "Wet" gas is highly sought after while "dry" gas drilling is in great decline, with Haynesville being one such example. This dynamic is likely to continue until a surplus of NGLs develops, which will then dampen the drilling enthusiasm and gradually rein in the production of associated natural gas.

Alberta supplies should continue to decrease due to depleted wells and due to the increase in gas used for oil sands production. However, those supply reductions are not likely to be felt in the West. Alberta gas transportation costs, specifically to the eastern U.S. and Canada, are higher than the transportation costs of shale gas supplies being developed in the eastern U.S. (Marcellus, Utica, etc.). Drops in Alberta supplies should be more than offset by drops in Alberta flows to the East. Alberta supplies to the West should stay level, and Alberta prices to the West are projected to stay below Rockies prices for the next several years.

The development of LNG export terminals in northern British Columbia is validating the emergence of shale gas supplies in that region. The eventual impact on B.C. gas commodity pricing will continue to be debated, but the expectation is that some increase relative to Alberta and the Rockies is likely.

VIII. EMERGENCY PLANNING

The Company uses the Incident Command System (ICS) as its emergency response methodology. The Incident Management System Plan (IMSP) documents the ICS concept and the responsibilities of those individuals responding to an emergency incident. In addition, this plan provides response alternatives and resource material for a variety of possible emergency events.

This plan is written and maintained by the Business Continuity and Corporate Security Department. Responsibility for planning and coordinating the actions of field and office personnel during emergencies such as floods, earthquakes, pandemics, or severe cold weather is designated to the Incident Command

Team (ICT). The Operations section of that team is prepared to take whatever actions are needed to prevent or minimize firm curtailments of service. This includes the operation of regulators to boost pressures, the installation of pipe to tie together sections of the Company's distribution system, the dispatching of mobile CNG and LNG tankers to handle distribution system trouble spots, curtailment notices to interruptible customers, shut-offs and light-ups of firm customers, and public announcements to reduce gas usage.

The ICT conducts periodic exercises to ensure the readiness of the team and gain experience in ICS techniques. One of the most visible uses of ICS occurred during the Y2K rollover transition period. The Company utilized Y2K as both a potential threat and an opportunity for a corporate-wide emergency readiness exercise, with over 300 employees involved in the process. More recent examples include: managing three pre-planned and one unexpected outage of the electrical power at the Company's corporate headquarters; response to a pipeline breach in one of Portland's largest transportation transfer hubs; and the re-light of hundreds of customers on the Central Oregon Coast due to a landslide. The most recent example of significance was the outage of hundreds of customers in Clark County, Washington, on December 9, 2009, due to equipment failures at the GTN interconnection to Northwest Pipeline as well as at the Jackson Prairie storage facility. These real-world examples are in addition to periodic exercises conducted with other regional agencies.

As previously described, the Company designs its resource portfolio to satisfy firm loads through a strenuous design heating season. However, design weather has not been the coldest faced by the Company. There certainly have been colder heating seasons if a longer historical perspective is taken, such as occurred in 1949/50. Also, the IRP assumes perfect foresight of the weather. This may not be important for storage supplies, which can respond to load changes very quickly, but all other supplies require some amount of prior notice for scheduling. This ranges from two hours for curtailment of interruptible sales, to a day for the transportation of most pipeline gas and the use of the recall arrangements. Finally, the IRP assumes reliable equipment behavior; i.e., nothing breaks or freezes up, even in the face of extremely cold temperatures. For the first time in an IRP, this last assumption is the subject of various scenarios modeled by the Company, as discussed in Chapter 5.

The ICT has to contend with the failure of any or all of the above assumptions in addition to the stresses on the system caused by the emergency itself. The Company's ultimate goal is an emergency management system that will allow for the continued delivery and/or restoration of gas during an emergent event in a safe and efficient manner. The Company cannot guarantee uninterrupted service at all times to all customers, but the ICT works to make customer outages during emergency events as brief as possible, with public health and safety being the ultimate priority.

IX. KEY FINDINGS

- For this planning cycle, the Company's gas supply procurement strategy will rely on the transportation of supplies priced at negotiated rates that will follow market prices on an annual, seasonal, or monthly basis.

- A portfolio of fixed price supplies is desirable because it dampens volatility and assures more stable pricing for customers.

- Similar to the recent gas reserves agreement approved at the end of April 2011,additional very long term pricing arrangements may be advantageous due to the current price regime, which reflects a stagnant economy coupled with surging supplies from shale gas.

- The Company's service territory is widespread and it is not practical to consider tying together all customers into a single integrated distribution system. Accordingly, some amount of incremental upstream pipeline capacity may be needed throughout the forecast period to serve one or more portions of the Company's system. Conversely, as the cost of upstream pipeline expansions increase, it may be cost-effective for the Company to remove bottlenecks and more fully integrate certain portions of its own distribution system.

- As approximately two-thirds of its supply can flow through a single pipeline through the Columbia Gorge, the Company seeks cost-effective resource options to improve supply path diversity, and toward this end, is supporting development of a cross-Cascades pipeline project.

- In this IRP, the Company is considering a variety of incremental gas supply resource options to serve projected load over the forecast period, including new interstate pipeline capacity, Mist recall capacity, expansion/extension of the Company's distribution system, and satellite LNG.

Appendix 4: Detailed Measure Description

Table 1: Detailed Measure Table, Residential Sector, Gas Savings, and 2032 Technical Potential

Measure Description	Program	Average Lifetime	Total Incremental Cost ($)	Total O&M Impact ($)	Gas Savings (Therms)	Level Cost ($/therm)	BCR
Low Flow Showerhead	Replace GasDHW	15	4,881,156	-74,270,571	4,240,120	($1.598)	100.00
Gas 2.20 MEF Washer	New Appl	14	5,058,467	-9,213,662	124,895	($0.611)	100.00
Gas 2.20 MEF Washer	ReplaceAppl	14	23,033,983	-41,954,874	442,334	($0.540)	100.00
Gas ETO Dishwasher	New Appl	12	2,392,903	-4,202,713	36,150	($0.430)	100.00
Gas ETO Dishwasher	ReplaceAppl	12	6,347,577	-11,148,402	74,584	($0.419)	100.00
Gas 2.46 MEF Washer	ReplaceAppl	14	47,189,994	-46,901,117	565,384	$0.006	1.51
Gas 2.46 MEF Washer	New Appl	14	22,561,657	-22,423,544	322,309	$0.007	1.46
Gas Hearth	Replace GasDHW	20	326,341	0	767,861	$0.035	15.36
Windows, replacement (U=.30)	Retro Gas	45	5,497,730	0	1,999,024	$0.159	3.46
Windows, replacement (U=.25)	Retro Gas	45	17,962,182	0	3,646,516	$0.285	1.93
NW Energy Star BOP Ducts Inside	New Gas	35	62,680,876	0	3,569,225	$0.370	1.48
AFUE 92 to condensing combo hydrocoil, Z A	New GasEquip	25	598,370	0	103,717	$0.418	1.29
NW Energy Star BOP Equip Upg	New Gas	25	169,224,943	0	11,134,457	$0.466	1.16
MH Duct Sealing, Z A	Retro Gas	20	372,230	0	39,303	$0.773	0.69
Wx insulation (ceiling, floor), Z A	Retro Gas	45	1,206,535	0	90,324	$0.774	0.71
HRV, Z A	Retro Gas	18	20,331,023	8,163,491	2,942,373	$0.841	0.63
Near Net Zero	New Gas	45	3,745,822	0	247,746	$0.853	0.65
Wx SF Ceiling Insulation, Zone A	Retro Gas	45	17,066,582	0	1,121,162	$0.882	0.62
Energy Star 0.67 EF	New GasDHW	12	1,397,755	0	176,140	$0.905	0.55
Energy Star 0.67 EF	Replace GasDHW	12	6,749,445	0	850,540	$0.905	0.55
NW Energy Star BOP Env Upg	New Gas	35	62,063,463	0	1,455,684	$0.928	0.59
MF Corridor Ventilation	New Gas	15	3,207,656	0	324,494	$0.965	0.54
MF Corridor Ventilation	Retro Gas	15	14,818,265	0	1,499,051	$0.965	0.54
Energy Star 0.67 EF after 2015	Replace GasDHW	12	23,644,542	0	2,591,183	$1.041	0.48
Energy Star 0.67 EF after 2015	New GasDHW	12	8,191,862	0	897,738	$1.041	0.48
Tankless Gas	New GasDHW	15	1,242,922	0	113,292	$1.071	0.47
Tankless Gas after 2015	New GasDHW	15	9,938,843	0	808,440	$1.200	0.42
AFUE 95 Furnace, Z A	Replace GasEquip	25	25,065,695	2,786,682	1,671,046	$1.206	0.45
Wx SF Wall Insulation, Zone A	Retro Gas	45	22,245,284	0	907,608	$1.420	0.39
Condensing Tankless	New GasDHW	15	1,278,435	0	85,831	$1.454	0.35
Wx SF Duct Sealing, Z A	Retro Gas	20	3,992,926	0	215,834	$1.510	0.35
Condensing Tankless Gas after 2015	New GasDHW	15	11,664,411	0	695,254	$1.638	0.31
Wx SF Floor Insulation, Zone A	Retro Gas	45	24,914,718	0	872,015	$1.655	0.33
Wx Air Sealing, Z A	Retro Gas	20	5,381,878	0	233,215	$1.883	0.28
Windows, retrofit (U=.25)	Retro Gas	45	167,565,079	0	4,595,254	$2.112	0.26
Windows, retrofit (U=.30)	Retro Gas	45	116,692,479	0	2,554,516	$2.646	0.21
Solar DHW (50 gal) - gas backup	New GasDHW	20	5,953,567	0	169,944	$2.859	0.17
Solar DHW - gas	Replace GasDHW	20	5,552,175	0	158,485	$2.859	0.17

Measure Description	Program	Average Lifetime	Total Incremental Cost ($)	Total O&M Impact ($)	Gas Savings (Therms)	Level Cost ($/therm)	BCR
Solar DHW - Gas after 2015	New GasDHW	20	55,562,491	0	1,424,353	$3.183	0.16
Solar DHW - gas afer 2015	Replace GasDHW	20	32,484,678	0	832,741	$3.184	0.16
Condensing Tankless	Replace GasDHW	15	13,328,338	0	397,704	$3.273	0.15
Tankless Gas	Replace GasDHW	15	25,737,466	0	756,276	$3.323	0.15
HRV, E*	New Gas	18	17,253,494	0	432,346	$3.467	0.15
Condensing Tankless after 2015	Replace GasDHW	15	69,408,585	0	1,750,303	$3.872	0.13
Tankless Gas after 2015	Replace GasDHW	15	146,622,389	0	3,466,473	$4.130	0.12

Table 2: Detailed Measure Table, Commercial Sector, Gas Savings, 2032 Technical Potential

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost ($)	Total O&M ($)	Gas Impacts (kTherms)	Levelized Cost ($/therm)	BCR
Estar Commercial Clothes Washer	Install high performance commercial clothes washers - coin op	Replace	Water Heat	10	469,179	-4,256,021	19	($7.1456)	9.64
Estar Commercial Clothes Washer	Install high performance commercial clothes washers - coin op	New	Water Heat	10	50,931	-367,793	7	($3.6797)	8.07
EStar Steam Cooker	Replace with EStar in place of conventional	Replace	Cooking	10	130,322	-331,484	17	($1.5488)	3.04
EStar Steam Cooker	Install EStar in place of conventional	New	Cooking	10	79,145	-201,062	10	($1.5335)	3.04
Efficient Estar Dishwasher	Install EStar in place of conventional	New	Water Heat	12	928,338	-4,590,636	429	($0.3306)	10.91
Efficient Estar Dishwasher	Retrofit with EStar in place of conventional	Retrofit	Water Heat	12	655,621	-3,242,052	303	($0.3306)	10.91
DHW Wrap	Insulate the surface of the storage water heater or an unfired storage tank to R-5 to reduce standby losses.	Retrofit	Water Heat	7	24,077		154	$0.0273	18.57
Estar Convection Oven	Replace with EStar in place of conventional	Replace	Cooking	12	128,829		231	$0.0638	7.84
Roof Insulation - Attic R0-30	Roof Insulation - Attic R0-30. Application: Buildings with uninsulated attics	Retrofit	Heating	45	614,465		268	$0.0825	6.68

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost ($)	Total O&M ($)	Gas Impacts (kTherms)	Levelized Cost ($/therm)	BCR
EStar Fryer	Install EStar in place of conventional	New	Cooking	8	390,327		565	$0.1077	4.68
HW Boiler Tune	Tune up in accordance with Minneapolis Energy Office protocol. Can include derating the burner, adjusting the secondary air, adding flue restrictors, cleaning the fire-side of the heat exchanger, cleaning the water side, or installing turbulators. Other modifications may include uprating the burner to reduce oxygen or derating the burner to reduce stack temperature. Note: In gas systems, excess air and stack temperatures are often within reasonable ranges, so the technical potential for this measure is limited. Combining this measure with the vent damper and power burner measures increases both applicability and cost effectiveness, and was assumed for this analysis.	Retrofit	Heating	5	10,117		22	$0.1078	4.84
Roof Insulation - Rigid R0-11	Roof Insulation - Rigid R0-11-not including re-roofing costs but including deck preparation. Application: Old buildings with flat roofs and no attics	Replace	Heating	45	3,035,273		763	$0.1249	4.41
DHW Shower Heads	Install low flow shower heads (2.0 gallons per minute) to replace 3.4 GPM shower heads.	Retrofit	Water Heat	8	93,276		114	$0.1276	3.95

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost ($)	Total O&M ($)	Gas Impacts (kTherms)	Levelized Cost ($/therm)	BCR
Hot Water Temperature Reset	Controller automatically resets the delivery temperature in a hot water radiant system based on outside air temperature. The reset reduces the on-time of the heating equipment and the occurrence of simultaneous heating and cooling through instantaneous adjustments.	Retrofit	Heating	10	1,184,393		1,117	$0.1386	3.76
DHW Condensing Tankless (repl)	Costs and savings are incremental over a Code-rated tank (combustion efficiency of 80%) for a condensing tank with a minimum combustion efficiency of 94% and an R-16 tank wrap.	Replace	Water Heat	15	3,991,752		2,414	$0.1615	3.11
Wall Insulation - Blown R11	Wall Insulation - Blown R11. Application: Old buildings	Retrofit	Heating	45	6,781,587		1,929	$0.1684	3.27
Roof Insulation - Rigid R0-22	Roof Insulation - Rigid R0-22-- not including re-roofing costs but including deck preparation and ~4" rigid.. Application: Old buildings with flat roofs and no attics	Replace	Heating	45	5,242,744		866	$0.1906	2.89

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost ($)	Total O&M ($)	Gas Impacts (kTherms)	Levelized Cost ($/therm)	BCR
Steam Balance	Single-pipe steam systems are notorious for uneven heating, which wastes energy because the thermostat must be set to heat the coldest spaces and overheating other spaces. Steam balances corrects these problems by: 1) Adding air venting on the main line or at the radiators; 2) Adding boiler cycle controls; 3) Adding or subtracting radiators. Energy savings accrue from lowering the overall building temperature.	Retrofit	Heating	15	1,006,682		460	$0.2137	2.45
Wall Insulation - Spray On for Metal Buildings	Wall Insulation - Spray On for Metal Buildings (Cellulose) Unfinished. Application: Old buildings	Retrofit	Heating	45	585,393		154	$0.2274	2.42
Estar Convection Oven	Install EStar in place of conventional	New	Cooking	12	328,133		161	$0.2333	2.14
DHW Condensing Tank (new)	Costs and savings are incremental over a Code-rated tank (combustion efficiency of 80%) for a condensing tank with a minimum combustion efficiency of 94% and an R-16 tank wrap.	New	Water Heat	15	1,989,832		775	$0.2508	2.00
Windows - Add Low E to Vinyl Tint	Windows - Add Low E to Vinyl Tint. Application: Old buildings	Replace	Heating	20	3,527,778		334	$0.2618	2.03
Roof Insulation - Blanket R0-19	Roof Insulation - Blanket R0-19. Application: Buildings with open truss unfinished interior	Retrofit	Heating	45	900,322		192	$0.2671	2.06

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost ($)	Total O&M ($)	Gas Impacts (kTherms)	Levelized Cost ($/therm)	BCR
Roof Insulation - Rigid R11-22	Roof Insulation - Rigid R11-22 2" rigid added to an existing foam roof insulation at re-roof, includes some surface prep. Application: Old buildings with flat roofs, no attics, and some insulation	Replace	Heating	45	9,917,116		1,439	$0.2676	2.06
DCV	Applicable to single zone packaged systems with large make -up air fractions either because of intermittent occupancy or because of code requirements. In most cases the outdoor air is reset to 5% or less with CO2 build-up modulating ventilation.	Retrofit	Heating	10	9,662,491		1,032	$0.2812	1.85
Roof Insulation - Blanket R0-30	Roof Insulation - Blanket R0-30. Application: Buildings with open truss unfinished interior	Retrofit	Heating	45	1,012,863		201	$0.2862	1.92
Ducts	Duct retrofit of both insulation and air sealing	Retrofit	Heating	15	3,179,785		313	$0.3061	1.71
EStar Fryer	Replace with EStar in place of conventional	Replace	Cooking	8	2,236,760		1,082	$0.3225	1.56
DHW Condensing Tankless (new)	Costs and savings are incremental over a Code-rated tank (combustion efficiency of 80%) for a condensing tank with a minimum combustion efficiency of 94% and an R-16 tank wrap.	New	Water Heat	15	2,467,392		685	$0.3519	1.43

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost ($)	Total O&M ($)	Gas Impacts (kTherms)	Levelized Cost ($/therm)	BCR
DHW Condensing Tank (repl)	Costs and savings are incremental over a Code-rated tank (combustion efficiency of 80%) for a condensing tank with a minimum combustion efficiency of 94% and an R-16 tank wrap.	Replace	Water Heat	15	3,227,410		881	$0.3575	1.41
Ozone Laundry Treatment	Ozone treatment allows use of cold water	Retrofit	Water Heat	10	379,980	-83,812	108	$0.3593	1.31
Windows - Add Low E and Argon to Vinyl Tint	Windows - Add Low E and Argon to Vinyl Tint. Application: Old buildings	Replace	Heating	20	5,517,127		461	$0.3647	1.46

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost ($)	Total O&M ($)	Gas Impacts (kTherms)	Levelized Cost ($/therm)	BCR
Roof Insulation - Attic 11-30	Roof Insulation - Attic 11-30. Application: Buildings with partially insulated attics	Retrofit	Heating	45	3,791,959		463	$0.3649	1.51
Hot Food Holding Cabinet	Install EStar in place of conventional	New	Cooking	8	741,621		294	$0.3939	1.28
DestratificationFan	Destrat fan reduces heat load	Retrofit	Heating	12	4,160,485		1,193	$0.3981	1.31
Hot Food Holding Cabinet	Install EStar in place of conventional	Replace	Cooking	8	1,453,032		564	$0.4017	1.26
Vent Damper	Install vent damper downstream of the draft relief to prevent airflow up the stack, while allowing warm air from the boiler to spill into the conditioned space as heat or into the boiler room to reduce jacket losses. This measure is most cost-effective when combined with the boiler tune up and power burner measures.	Retrofit	Heating	12	474,045		125	$0.4321	1.20
Windows - Tinted AL Code to Class 40	Windows - Tinted AL Code to Class 40. Application: New Construction	New	Heating	20	1,663,246		96	$0.4516	1.12
EStar Griddle	Install EStar in place of conventional	New	Cooking	12	426,581		105	$0.4621	1.08

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost ($)	Total O&M ($)	Gas Impacts (kTherms)	Levelized Cost ($/therm)	BCR
Combo Hieff Boiler (new)	Replace existing boiler with unit meeting OR Code requirements of 80% combustion efficiency.	New	Heating	20	769,967		131	$0.4792	1.07
DHW Hieff Boiler (new)	Replace existing boiler with unit meeting OR Code requirements of 80% combustion efficiency.	New	Water Heat	20	1,659,089		278	$0.4875	1.05
Combo Hieff Boiler (repl)	Replace existing boiler with unit meeting OR Code requirements of 80% combustion efficiency.	Replace	Heating	20	2,518,769		417	$0.4930	1.08
EStar Griddle	Replace with EStar in place of conventional	Replace	Cooking	12	608,152		137	$0.5064	0.99
Windows - Tinted AL Code to Class 40	Windows - Tinted AL Code to Class 40. Application: Old buildings	Replace	Heating	20	2,521,565		92	$0.5077	1.05
Roof Insulation - Roofcut 0-22	Roof Insulation - Roofcut 0-22. Application: Buildings with uninsulated flat roofs at reroofing time	Replace	Heating	45	8,710		1	$0.5735	0.96
SPC Hieff Boiler Replace	Install near condensing boiler. Assumed seasonal combustion efficiency of 85% over base of 80%	Replace	Heating	20	1,320,560		168	$0.6426	0.83
DHW Cond Boiler (new)	Replace with boiler using condensing or pulse technology to achieve steady-state combustion efficiencies of 89% to 94% (this analysis used 92% efficiency for savings calculations).	New	Water Heat	20	5,075,857		616	$0.6727	0.76

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost ($)	Total O&M ($)	Gas Impacts (kTherms)	Levelized Cost ($/therm)	BCR
DHW Faucets	Add aerators to existing faucets to reduce flow from 2.2 gallons per minute to 1.5 GPM.	New	Water Heat	8	40,302		9	$0.7321	0.69
DHW Recirc Controls	Install electronic controller to hot water boiler system that turns off the boiler and circulation pump when the hot water demand is reduced (usually in residential type occupancies) or can be reset to meet the hot water load. (Steel boilers also require a mixing valve to prevent water temperatures from dropping below required levels).	Retrofit	Water Heat	10	798,946		142	$0.7347	0.68
DHW Faucets	Add aerators to existing faucets to reduce flow from 2.2 gallons per minute to 1.5 GPM.	Retrofit	Water Heat	8	36,333		8	$0.7458	0 68

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost ($)	Total O&M ($)	Gas Impacts (kTherms)	Levelized Cost ($/therm)	BCR
Cond Furnace (new)	Condensing / pulse package or residential-type furnace with a minimum AFUE of 92%. Base case: AFUE 80	New	Heating	18	3,205,091		365	$0.7631	0.66
DHW Hieff Boiler (repl)	Replace existing boiler with unit meeting OR Code requirements of 80% combustion efficiency.	Replace	Water Heat	20	2,272,460		226	$0.8201	0.65
Combo Cond Boiler (new)	Replace with boiler using condensing or pulse technology to achieve steady-state combustion efficiencies of 89% to 94% (this analysis used 92% efficiency for savings calculations).	New	Heating	20	3,030,655		291	$0.8507	0.60
SPC Cond Boiler Replace	Install condensing boiler. Assumed seasonal combustion efficiency of 92% over base of 80%	Replace	Heating	20	4,894,787		450	$0.8873	0.60
Combo Cond Boiler (repl)	Replace with boiler using condensing or pulse technology to achieve steady-state combustion efficiencies of 89% to 94% (this analysis used 92% efficiency for savings calculations).	Replace	Heating	20	10,057,535		925	$0.8878	0.60
Power burner	Replace standard burner with a power burner to optimize combustion and reduce standby losses in the stack. Note: Costs and savings assume that this measure will be performed in conjunction with a boiler tune up when appropriate.	Retrofit	Heating	12	10,190,449		1,292	$0.9002	0.58
DHW Pipe Ins	Add 1" insulation to pipes used for steam or hydronic	New	Water Heat	15	412,525		44	$0.9191	0.55

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost ($)	Total O&M ($)	Gas Impacts (kTherms)	Levelized Cost ($/therm)	BCR
	distribution; particularly effective when pipes run through unheated spaces.								
Waste Water Heat Exchanger	Install HX on waste water	New	Water Heat	15	1,942,808		206	$0.9191	0.55
Windows - Tinted AL Code to Class 36	Windows - Tinted AL Code to Class 36. Application: New Construction	New	Heating	20	4,158,116		153	$0.9435	0.54
Roof Insulation - Rigid R11-33	Roof Insulation - Rigid R11-33: add 4' of insulation at reroof. Application: Old buildings with flat roofs, no attics, and some insulation	Replace	Heating	45	14,875,673		446	$0.9643	0.57
Windows - Tinted AL Code to Class 36	Windows - Tinted AL Code to Class 36. Application: Old buildings	Replace	Heating	20	6,303,914		159	$1.0610	0.50
SPC Cond Boiler (new)	Install condensing boiler. Assumed seasonal combustion efficiency of 88% over base of 75%	New	Heating	20	17,583,678		1,224	$1.1727	0.43
Windows - Add Argon to Vinyl Lowe	Windows - Add Argon to Vinyl Lowe. Application: Old buildings	Replace	Heating	20	7,845,826		510	$1.3020	0.41

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost ($)	Total O&M ($)	Gas Impacts (kTherms)	Levelized Cost ($/therm)	BCR
Rooftop Condensing Burner	Install condensing burner	New	Heating	10	15,004,953		742	$1.3302	0.39
Waste Water Heat Exchanger	Install HX on waste water	Retrofit	Water Heat	15	317,666		23	$1.3340	0.38
DHW Cond Boiler (repl)	Replace with boiler using condensing or pulse technology to achieve steady-state combustion efficiencies of 89% to 94% (this analysis used 92% efficiency for savings calculations).	Replace	Water Heat	20	8,211,654		501	$1.3365	0.40
DDC HVAC controls	Control set up and algorithm. This assumes the development of an open source control package aimed at describing scheduling and control points throughout the HVAC system, properly training operators so that scheduling can be maintained and adjusted as needed, and providing operator back up so that temperature reset, pressure reset, and minimum damper settings are set at optimum levels for the current occupancy.	New	Heating	5	24,663,193		2,695	$1.3392	0.37
Cond Unit Heater from Nat draft (replace)	Install condensing power draft units (90% seas. Eff) in place of natural draft (80% seas. Eff)	Replace	Heating	18	18,405,270		1,064	$1.5029	0.35
Computerized Water Heater Control	Install intelligent controls on the hot water circulation loops.	New	Water Heat	15	836,567		51	$1.5992	0.31

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost ($)	Total O&M ($)	Gas Impacts (kTherms)	Levelized Cost ($/therm)	BCR
Computerized Water Heater Control	Install intelligent controls on the hot water circulation loops.	Retrofit	Water Heat	15	1,114,954		65	$1.6779	0.30
Steam Trap Maintenance	Set up a in-house steam trap maintenance program with equipment, training, and trap replacement. An alternative procedure is to just pay for an outside contractor to conduct a steam survey.	Retrofit	Heating	10	1,468,427	5,651,625	519	$1.7928	0.29
Windows - Non-Tinted AL Code to Class 40	Windows - Non-Tinted AL Code to Class 40. Application: New Construction	New	Heating	20	5,433,614		255	$1.8022	0.28
Roof Insulation - Blanket R11-41	Roof Insulation - Blanket R11-41. Application: Buildings with open truss unfinished interior	Retrofit	Heating	45	2,532,156		79	$1.8256	0.30
Roof Insulation - Blanket R11-30	Roof Insulation - Blanket R11-30. Application: Buildings with open truss unfinished interior	Retrofit	Heating	45	2,250,806		65	$1.9386	0.28
Windows - Non-Tinted AL Code to Class 40	Windows - Non-Tinted AL Code to Class 40. Application: Old buildings	Replace	Heating	20	8,167,046		327	$2.0662	0.26
Windows - Non-Tinted AL Code to Class 36	Windows - Non-Tinted AL Code to Class 36. Application: New Construction	New	Heating	20	10,937,965		389	$2.3723	0.21

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost ($)	Total O&M ($)	Gas Impacts (kTherms)	Levelized Cost ($/therm)	BCR
Cond Furnace (repl)	Condensing / pulse package or residential-type furnace with a minimum AFUE of 92%.	Replace	Heating	18	22,750,568		709	$2.7899	0.19
Warm Up Control	This measure is designed to implement a shut down of outside air when the building is coming off night setback. Usually the capability for this is available in a commercial t-stat but either the extra control wire is not attached or the unit itself has not been set up to receive the signal. Cost is based on labor cost to enable this ability in existing controllers	Retrofit	Heating	10	9,184,113		398	$3.0185	0.17
Windows - Non-Tinted AL Code to Class 36	Windows - Non-Tinted AL Code to Class 36. Application: Old buildings	Replace	Heating	20	20,417,616		501	$3.3586	0.16
Windows - Non-Tinted AL Code to Class 45	Windows - Non-Tinted AL Code to Class 45. Application: Old buildings	Replace	Heating	20	5,431,086		119	$3.7902	0.14
HVAC System Commissioning	HVAC system commissioning. Includes testing and balancing, damper settings, economizer settings, and proper HVAC heating and compressor control installation. This measure includes the proper set-up of single zone package equipment in simple HVAC systems. The majority of the Commercial area is served by this	New	Heating	7	89,216,398		1,752	$5.1499	0.10

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost ($)	Total O&M ($)	Gas Impacts (kTherms)	Levelized Cost ($/therm)	BCR
	technology. Work done in Eugene (Davis, et al, 2002) suggests higher savings than the other documented commissioning on more complex systems.								
Solar Hot Water	Install solar water heaters on large use facility such as multifamily or lodging	New	Water Heat	15	7,362,902	575,776	106	$7.2914	0.07
Solar Hot Water	Install solar water heaters on large use facility such as multifamily or lodging	Retrofit	Water Heat	15	9,839,581	675,964	137	$7.4802	0.07
Cond Unit Heater from power draft (replace)	Install condensing power draft units (90% seas. Eff) in place of power draft (80% seas. Eff)	Replace	Heating	18	660,459,793		709	$80.8964	0.01
Windows - Tinted AL Code to Class 45	Windows - Tinted AL Code to Class 45. Application: Old buildings	Replace	Heating	20	570,796,700		18	$148.9149	0.00
Heat Reclaim	Large Grocery - Heat recovery to space heating. Assumes floating head control exists and must be changed to allow HR.	New	Refrigeration	18	1,902,154		293	$0.1546	3.26
Heat Reclaim	Large Grocery - Heat recovery to space heating. Assumes floating head control exists and must be changed to allow HR.	Retrofit	Refrigeration	18				na	na
Heat Reclaim	Large Grocery - Heat recovery to space heating. Assumes floating head control exists and must be changed to allow HR.	Replace	Refrigeration	18	4,411,709		638	$0.1714	2.94

Table 3: Detailed Measure Description, Industrial Natural Gas Technical Potential

Conservation Measure	Potential Savings (therm/yr)	Annual O&M Cost ($)	Levelized Cost ($/therm)	Initial Cost (k$)	BCR
Chiller heat recovery (Electronics)	63,526	$0	$1.229	$800	0.41
Combo Cond Boiler (repl)	815,993	$0	$0.637	$6,373	0.80
Combo Cond Boiler (retro)	0	$0	$1.714	$0	na
Combo Hieff Boiler (repl)	417,947	$0	$0.347	$1,775	1.46
Combo Hieff Boiler (retro)	0	$0	$1.804	$0	na
Cond Furnace (repl)	904,616	$0	$2.776	$25,716	0.18
Cond Unit Heater from Nat draft (replace)	0	$0	$1.066	$0	na
Cond Unit Heater from power draft (replace)	320,403	$0	$2.157	$7,953	0.23
Heat Recovery to HW	1,877,447	($252,385)	$0.157	$5,609	1.75
DHW Cond Boiler (repl)	448,631	$0	$0.158	$868	3.22
DHW Cond Boiler (retro)	0	$0	$0.495	$0	na
DHW Condensing Tank (repl)	365,731	$0	$0.026	$97	19.32
DHW Condensing Tank (retro)	0	$0	$0.116	$0	na
DHW Hieff Boiler (repl)	229,786	$0	$0.049	$139	10.28
DHW Hieff Boiler (retro)	0	$0	$0.386	$0	na
DHW Pipe Ins	52,213	$0	$0.020	$11	25.15
DHW Std. Boiler (retro)	7,735	$0	$0.232	$22	2.19
DHW Wrap	23,206	$0	$0.001	$0	100.00
Ducts	1,428,697	$0	$3.092	$45,233	0.16
Hi Eff Unit Heater (replace)	865,954	$0	$0.343	$3,417	1.47
Hi Eff Unit Heater (retro)	0	$0	$2.087	$0	na
HiEff Clothes Washer (retro)	5,515	($67,026)	($11.387)	$43	2.05
HiEff Clothes Washer (repl)	5,515	($67,026)	($11.387)	$43	2.05
Hot Water Temperature Reset	1,828,424	$0	$0.194	$2,709	2.56
HW Boiler Tune	1,005,623	$0	$0.179	$774	2.78
Power burner	1,482,288	$0	$1.153	$14,972	0.43
Process Boiler Controls	157,241	$0	$0.002	$2	326.50
Process Boiler Insulation	1,053,674	$1,289	$0.009	$81	67.27
Process Boiler Load Control	526,837	$0	$0.002	$10	282.97
Process Boiler Maintenance	263,419	$137	$0.001	$0	100.00
Process Boiler Steam Trap Maintenance	856,110	$31,101	$0.036	$0	100.00
Process Boiler Water Treatment	131,709	$0	$0.001	$1	606.36
Roof Insulation - Blanket R0-19	461,314	$0	$0.350	$2,426	1.48
Roof Insulation - Blanket R0-30	484,002	$0	$0.375	$2,730	1.38
Roof Insulation - Blanket R11-30	168,056	$0	$2.562	$6,470	0.20
Roof Insulation - Blanket R11-41	201,668	$0	$2.402	$7,279	0.22
Roof Insulation - Rigid R11-22 repl	454,559	$0	$0.908	$6,200	0.57
Roof Insulation - Rigid R11-33 repl	224,187	$0	$2.761	$9,301	0.19
Solar Hot Water	57,990	$0	$4.697	$3,337	0.11
SPC Cond Boiler Replace	473,441	$0	$1.111	$6,443	0.46
SPC Cond Boiler Retro	0	$0	$2.357	$0	na

Conservation Measure	Potential Savings (therm/yr)	Annual O&M Cost ($)	Levelized Cost ($/therm)	Initial Cost (k$)	BCR
SPC Hieff Boiler Replace	273,743	$0	$0.712	$2,388	0.71
SPC Hieff Boiler Retro	0	$0	$2.490	$0	na
Steam Balance (Wood Prod)	47,373	$0	$0.374	$182	1.33
Steam Trap Maint (Wood Prod)	58,559	$0	$0.648	$290	0.77
Upgrade Process Heat	202,613	($68,804)	$1.007	$2,031	0.54
Vent Damper	897,807	($68,804)	$0.482	$3,768	1.05
Wall Insulation - Blown R11	308,492	$0	$0.254	$1,175	2.05
Wall Insulation - Spray On for Metal Buildings	338,707	$0	$0.282	$1,437	1.84
Waste Water Heat Exchanger	56,597	$0	$0.700	$486	0.72
Ozone Treated Laundry	0	$0	$0.179	$0	na

Chapter 5: Linear Programming and The Company's Resource Choices

NW Natural®

I. OVERVIEW

The Company employs an analytic method utilizing linear programming to integrate the significant planning components, and to generate and evaluate long term resource plans. Linear programming (LP) is a mathematical optimization technique which solves the "general problem of allocating limited resources among competing activities in the best possible way."[1] For the IRP, the Company's LP model examines all reasonable means for acquiring demand-side and/or supply-side resources to meet growing customer demand and determines the series of resource decisions through time which results in a plan that balances reliability and cost. The LP model acts as a tool to guide the Company's resource decisions; it is not the final answer. The deterministic model makes resource decisions based on perfect knowledge of the 20-year planning horizon, including weather, demand, future resource availability, and supply prices. For example, a decision made in year five may have been informed by an event occurring in year ten. LP modeling also allows for various combinations of resources, called portfolios, to be evaluated under assorted demand scenarios and ranked according to cost.

The Company holds a license with Ventyx, an ABB company, for their gas supply planning and optimization software product SENDOUT®. This application is designed to simultaneously analyze and optimize the entire gas supply portfolio, including supply, transportation, storage assets, and conservation programs. The objective function of the LP engine within SENDOUT® seeks to minimize system costs associated with meeting daily load. The resource mix optimization module both evaluates and optimally sizes resources to meet load based on the associated fixed and variable costs of the resource. The Monte Carlo module provides risk planning analysis around hundreds of weather and price simulations. This allows portfolios to be evaluated from a probabilistic standpoint.

II. RESOURCE PLANNING MODEL INTEGRATION

Six primary components are integrated within the SENDOUT® resource planning model.

A. Demand forecast
B. Temperature pattern
C. Natural gas price forecast
D. Demand side management resources
E. Current supply side resources
F. Potential future supply side resources

A. Demand Forecast

The Company uses demand usage factors to incorporate the demand forecast into the resource planning model. The usage factors include the number of customers by region and category, as well as the customer and region specific base and heat load factors. The usage factors are used in combination with temperature data to generate an overall gas requirement for each of the eight demand centers. The methodology for the derivation of the demand usage factors was presented in Chapter 2. In addition, a high cost penalty is attached to un-served demand so that the resource model attempts to serve all demand by any means possible. For interruptible loads, the penalty is set low enough that the model is allowed to not serve this category during colder weather periods, but high enough that the model chooses to serve it otherwise.

---

1 Hillier, Fredrick S. and Lieberman, Gerald L, Introduction To Operations Research 6th Edition, McGraw-Hill, Inc., 1995, 25.

B. Temperature Pattern

A daily temperature pattern by region is required to calculate region specific demand. The temperature data is converted to heating degree days (HDDs) based on 65° F for the calculation. The Company has developed a statistically based HDD pattern, referred to as the design weather pattern, for the model. Chapter 2 outlines the development of this very cold weather pattern, which was designed to be colder than 85% of the winters that the service area has experienced in a 25-year period. In addition, the annual temperature pattern was augmented with the very cold three-day peak event from February 1989. A 20-year data set of temperatures has been included in the resource model to provide a basis for the weather portion of the Monte Carlo simulation.

In this IRP, modeling and resource planning is developed around this design winter as explained above. Should capacity become constrained in a service area for any reason, including a weather event that exceeds the Company's planning standard, the Company can balance the system by curtailing service. The guidelines for curtailment are established in Rules 15 and 16 in the Company's Washington Tariff and Rules 13 and 14 in the Oregon Tariff. These rules establish a priority for curtailment. Customers on interruptible schedules are curtailed first, followed by non-essential human needs firm sales industrial and commercial customers. The last to be curtailed are firm residential and essential human needs customers. It is not uncommon during the heating season for the Company to call a curtailment event for a portion of its interruptible customers. These customers pay lower distribution charges and they generally provide services in a sector that requires them to have a back-up energy source.

C. Natural Gas Price

A cost is associated with each unit of natural gas supply sourced in the resource model. These costs can drive planning to focus on certain low cost sources and can also allow the model to take advantage of seasonal variability. For instance, one low-cost strategy might involve purchasing gas during the summer months when prices are lower and holding the supply in a storage facility until needed to meet high winter demand. Substantial differences between summer and winter prices could, therefore, influence storage resource decisions as well as supply purchase decisions. Long term price differentials between supply basins may also drive pipeline resource decisions to steer toward the lower priced basins. The Company used the price forecast described in Chapter 2 to evaluate supply options and costs. Gas price also has a strong influence on the expected overall cost to meet customer demand across the planning horizon, since supply is typically the largest cost component of any IRP.

D. Demand side management resources

As discussed in Chapter 4, the Company worked with the Energy Trust of Oregon (Energy Trust) to generate a 20-year demand side management forecast, which estimates the cost and amount of therm savings that can be procured by providing incentives to customers for installing energy efficiency measures at their homes or other facilities. This energy savings and cost forecast was integrated into the SENDOUT® resource planning model so that DSM may offset supply side resources through time. The savings are deducted from the demand forecast with the remaining demand served by supply side resources.

DSM was implemented in SENDOUT® using the Program Totals method. In this method, DSM savings are represented by customer specific base and heat load factors. Similar to the demand forecast, base load is considered to be independent of weather while heat load is a function of the rate at which energy is saved (heat rate factor) multiplied by the HDD value. The associated costs of the DSM are represented by a total program cost as provided by Energy Trust.

Energy Trust provided the DSM forecast on an annual and state-wide basis. In order to implement the forecast into the resource model, the energy savings were allocated among the Company's eight demand regions on a monthly basis. In addition, the savings associated with the DSM defined categories were translated into the resource planning model DSM categories.

An additional "high" DSM scenario was developed and run through the resource model. This "high" case corresponds to the DSM level in the Company's last acknowledged IRP and is 217% of the DSM contained in the base case. The purpose was to understand the impact on resource costs and supply-side resource acquisition associated with continuing DSM program at these old levels as compared to the new cost-effective levels reflected in this IRP.

E. Current and future supply side resources

Following the DSM adjustments in the planning model, the remaining gas requirements for each region or demand center are met by supply-side resources. The Company's current supply-side resources are incorporated into the SENDOUT® resource planning model. These resources fall into 3 basic categories:

1. Supply
2. Transport
3. Storage

The supply category includes the gas commodity itself. In the planning model, gas may be purchased from an existing supply source or acquired through a recall agreement. The purchase cost is defined in the gas forecast. Recall agreements allow the Company to acquire limited volumes at an elevated cost and are used to augment peak day resources.

Transport involves moving the purchased supply to the demand center or to a storage facility via a pipeline. Pipelines typically have a fixed cost associated with the reservation of a specific, fixed maximum daily capacity. The amount of gas that can be moved on these pipelines is constrained to the amount of capacity that is reserved. Most pipelines upstream of the Company's system also have a variable cost associated with the quantity of supply that is actually moved along that transport path. The pipeline capacities for internal Company pipeline projects, such as the Mid Willamette Valley Feeder, are estimated based on pipe diameters and system pressure assumptions.

Gas may be transported to storage facilities where the supply is injected and held in storage until it is withdrawn to serve demand at a later date. Each storage facility is modeled to have an associated maximum physical capacity as well as individual gas injection and withdrawal rate capabilities. Storage related costs include fixed costs attached to the facility itself, carrying costs associated with the amount and value of gas that is stored over time, and variable costs related to injection and withdrawal. Storage can be a very valuable asset for meeting peak demand. Typically, the facilities are filled with supply during the summer and drawn down in the winter.

Demand may be met in the resource model in numerous ways. Each pathway, from supply source to demand center, has a specific constraint and an associated cost. The value of an LP resource planning model is that it will efficiently converge to the least cost method of serving all demand, assuming such a solution exists. As an example, suppose a unit of demand is placed on the system by a residential customer in Salem. The unit of gas may be bought in Alberta, Canada at the AECO trading hub price. This unit of gas is brought down the TransCanada Alberta pipeline system (also known as NGTL or Nova) and then the TransCanada BC system (also known as Foothills) to Kingsgate at the Canadian/U.S. border with the associated costs. From there it enters the TransCanada GTN system and is transported to Stanfield, Oregon, where it enters the NWP system. From there, it may be transported through the Columbia Gorge to the Portland area and down the Grants Pass Lateral, past the Salem city gate and onto the Company's local distribution system in Salem. Alternatively, the unit of demand might be sourced from Mist underground storage and moved down to the Salem distribution system via the North Willamette Valley Feeder. Another option is to withdraw the unit of gas from the Newport LNG facility and transport it to Salem via the Company's Central Coast Feeder, or instead, source the unit of gas from the Rockies or British Columbia and transport by another path. There are numerous ways of serving the same unit of demand, each with unique costs.

To meet growing demand, future supply side resources need to be added. Future resources fall into the same three categories – supply, transport, and storage. SENDOUT® utilizes the resource mix optimization capability to evaluate new resource options. New supply sources may become available, such as Rockies gas via the Ruby Pipeline to GTN at Malin, Oregon, on the California/Oregon border. New transportation capabilities could be explored. Additional capacity on existing pipelines could be secured over time with an additional fixed and variable cost. A new pipeline may become available, such as the proposed cross-Cascades project, which would open up new supply and transport options. Internal Company pipeline projects could be developed, with the capital costs representing the resource fixed costs. For storage, additional capacity could be added at existing facilities, or new facilities could be built with the estimated capital costs serving as the fixed cost.

Table 5.1 lists the current and future resources that are available in the resource planning model, and a discussion of key resources follows. Figures 5.1 and 5.2 display model diagrams for pipeline and supply resources, and Figure 5.3 is a model diagram for Storage and other service area resources.

Table 5.1 - Current and Future Planning Model Resources

Demand Side Management	Supply	Pipeline	Storage
Current Resources			
Implicit in current demand usage factors	US Rockies (Opal)	CD on TransCanada NOVA/BC/GTN system (TCPL & GTN)	PSE/Avista NWP's Jackson Prairie underground
	Alberta Canada (AECO)	CD on FortisBC's Southern Crossing	NWP's Plymouth LNG
	British Columbia Canada (Sumas)	CD in NWP's mainline	NWN Mist Underground
	Recall Agreements	CD on NWP's Grants Pass Lateral	NWN Newport LNG
		NWN Harrisburg River Crossing - 2010	NWN Gasco LNG
		NWN Mid Willamette Valley Feeder - 2013	
Future Additional Resouces			
Energy Trust progam deployment	US Rockies (Opal)	Incremental CD on TransCanada NOVA/BC/GTN system (TCPL & GTN)	NWN Mist Recall
	Alberta Canada (AECO)	Incremental CD on NWP's Grants Pass Lateral	NWN Satellite LNG Storage projects in the Willamette Valley
	British Columbia Canada (Sumas)	CD on cross-Cascades/NMAX Pipeline	
	Recall Agreements	NWP's Sumas South (generic from BC)	
	US Rockies at Malin (OR) via Ruby Pipeline	GTN backhaul Malin to Madras	
		NWP CD acquired from March Point Cogen. Co.	
		NWN Newport LNG Compressor Project	
		NWN South Willamette Valley Feeder	

1) DEMAND-SIDE MANAGEMENT

The savings performance from previous energy efficiency programs are assumed to be reflected in the current demand usage factors that determine the demand forecast. Future DSM savings from Energy Trust programs are deducted from demand according to the deployment forecast. For a detailed discussion on how DSM was integrated into the planning model, refer to part D earlier in this section.

2) SUPPLY

Currently, the Company sources gas from three primary pricing points: Opal to represent the U.S. Rockies; AECO in Alberta, Canada; and Station 2/Sumas in British Columbia, Canada. A limited number of recall agreements are in place for peak day options.

If the cross-Cascades pipeline is built at a future date, a new supply point option could be opened up at the terminus of the Ruby Pipeline at Malin, Oregon. Ruby connects U.S. Rockies supply with northern California via the southern Oregon hub of Malin. Gas potentially could be backhauled up the GTN pipeline to Madras and across the Cascade Mountains to the Willamette Valley. GTN already has one small firm backhaul agreement in place with one customer. See Figures 5.1 and 5.2 for model diagrams.

3) INTERSTATE PIPELINE

Cross-Cascades Pipeline

A partnership between NW Natural and TransCanada has proposed a new pipeline which would carry natural gas across the Cascades to western Oregon. The pipeline would connect to GTN near Madras Oregon, and terminate at NW Natural's service area near Molalla, Oregon, between Portland and Salem.

The modeled service date is November of 2018. Please see Figure 5.2 for the model diagram. The sponsors also have been in discussion with NWP about developing additional facilities in conjunction with the cross-Cascades pipeline to serve load along the I-5 corridor in Washington and Oregon. This project was announced in November 2012 as the Northwest Market Area Expansion (NMAX), and reflects a memorandum of understanding between the cross-Cascades sponsors and NWP to support a new pipeline path. This project serves as a proxy for a future new pipeline accessing gas to the east of the Cascades.

A cross-Cascades pipeline is ideal for several reasons: First, this particular project would be the shortest distance and least expensive option for diversifying the Company's interstate pipeline resources, so it would improve reliability from a risk management perspective. Second, there is considerable pipeline capacity available east of the Cascades, but what is needed is a link to get it into the I-5 population corridor. Finally, the project would access Rockies, Alberta and B.C. gas supplies; whereas Sumas South capacity is tied to B.C. and potential impacts of export LNG.

NWP is fully subscribed through the Columbia River Gorge. The cross-Cascades pipeline would provide parallel capacity to NWP, allow the transport of more Alberta supply to western Oregon, and also open up the ability to acquire supply from a new purchase point in Malin. In addition to cross-Cascades pipeline capacity, the Company would need to secure capacity on GTN from Stanfield to Madras, or if cost-effective, capacity on GTN from Malin to Madras.

Pipeline rates and service date assumptions for a cross-Cascades project have been sourced from the indicative rates provided by the project sponsors. For non-outage model runs, starting in 2018 the model could decide to select capacity on the cross-Cascades pipeline at a fixed daily level between 0 to 110 MDTH. For outage runs including the project, the model was set up to take 110 or 165 MDTH/day starting in November 2018, and at the same time, the model was required to turn back 77 MDTH/day of capacity on NWP through the Columbia Gorge. The estimated pipeline rates ($/DTH) for the cross-

Cascades project are greater than the vintage rate that the Company currently pays for capacity from NWP.

NWP Washington Expansion

NWP has requested that potential shippers indicate any interest they may have in a project that would expand the capacity of their mainline coming south from British Columbia. For the base case and other non-outage runs, the Company modeled the path, but Mist recall was favored as expected. For the outage runs, while the Washington expansion appears to be economically advantageous compared to a cross-Cascades path, the Company dismissed the option because it does not provide a resource diversity solution, and it also doesn't provide a supply diversity solution. Certainly, with the potential for LNG export in British Columbia, one would expect the price for Sumas gas to be higher than gas sourced from other basins.

Ruby

Ruby pipeline is a recent project connecting the Rockies supply basin to the GTN pipeline at Malin. There appears to be available capacity on Ruby, but there is also supply available at Malin. The model included the Ruby option, but because gas at Malin was forecast at a slight discount to the combination of Rockies supply and Ruby delivery, the model always chose Malin supply to access the path. In other words, Ruby was implicit in the pricing of the Rockies gas acquired via Malin.

GTN Malin / Stanfield to Madras

This resource provides capacity from Malin to Madras or Stanfield to Madras. Madras is the expected receipt point for delivery over the cross-Cascades pipeline. While the cross-Cascades pipeline would require an initial bulk subscription to a certain level of capacity because of excess capacity on GTN, it is expected that incremental capacity can be acquired at more customized levels.

Incremental Capacity on NWP's Grants Pass Lateral

NWP's Grants Pass Lateral transports supplies to the Salem, Albany, and Eugene demand centers. The pipeline is fully subscribed, but could be expanded to increase capability. The model estimates the incremental capacity to cost the same as the current NWP firm transportation (rate schedule TF-1) rate. The amount of capacity selected can be increased each year. The Company also would have additional pipeline costs associated with increased deliveries on the Grants Pass Lateral, as existing gate station takeaway capacity already is fully utilized. This resource decision is first available in November 2015, and may be resized up in each following year. See Figure 5.3 for the model diagram.

4) NW Natural High Pressure Transmission

Harrisburg River Crossing and North & Mid Willamette Valley Feeders

Three recent internal pipeline projects help to serve demand in the Company's Oregon service area. The Harrisburg River Crossing pipeline project has been in service since 2010. This was a key project improving the capability for serving current and future demand in Eugene. The 12-inch diameter pipeline crosses under the Willamette River and provides additional delivery potential of 8 MDT/day of supply to the Eugene demand center. The North Willamette Valley Feeder (NWVF) is a 12-inch diameter pipeline running from Aurora to Brooks, Oregon, linking the Portland and Salem demand centers. It carries up to 85 MDT/day down to Salem, and has been in service since 2011. The Mid Willamette Valley Feeder is a pipeline running from Salem to Albany expected to be in service on November 2014. It is a 12-inch pipeline with a capacity of 41 MDT/day The Willamette Valley Feeder is an important resource since it allows additional storage supplies from Mist, and potentially additional pipeline delivered supply from a cross-Cascades project to reach the Willamette Valley and the coast. See Figure 5.3 for the model diagram.

South Willamette Valley Feeder

The South section of the Willamette Valley Feeder is a potential future internal pipeline project. The south section (SWVF) would be built to link Albany with Eugene with a capacity of 14 MDT/day. The entire feeder, from Portland to Eugene, would serve as a supplement to NWP's Grants Pass Lateral. The earliest this section could be in place is November 2015. The modeled fixed costs represent the estimated capital costs for the project. The model has the ability to select this section at any time on or after November 2015. See Figure 5.3 for the model diagram.

Newport Compressor Project

The Newport Compressor Project is a potential new resource that would allow more Newport LNG storage supplies to reach Salem on a peak day, and potentially Albany via the Mid Willamette Valley Feeder. If the South Willamette Valley Feeder project is built, Newport LNG supplies could even reach Eugene. The Newport LNG plant has equipment already in place to allow up to 100 MDT/day of vaporization; however, system infrastructure constraints limit this flow to a maximum of 60 MDT/day. In the model, the addition of a new compressor station at Perrydale is represented by a transport link that would allow an additional 40 MDT/day to reach Salem from Newport. The estimated capital costs for such a project are modeled with a fixed cost factor. See Figure 5.3 for the model diagram.

Eastside Loop

In conjunction with a cross-Cascades pipeline, a project would be required to integrate the new source into the existing distribution system to provide delivery to the load centers. This project will also eventually be required to allow Mist storage to reach East Portland, where significant future growth is expected to occur. For the outage scenario runs, because the solution revolved around Mist recall or a cross-Cascades project the cost of the loop was ignored due to its requirement for either solution, but deltas between cases would still be valid. For the preferred path case, the cost of an eastside loop was included to show the full cost comparison to the base case excluding a cross-Cascades project. A potential action item for the next IRP is to complete more detailed analysis of the configuration and cost of potential looping projects stemming from Mist or the cross-Cascades pipeline.

4) STORAGE

Jackson Prairie Storage and Plymouth LNG Storage

The Company retains existing capacity in the two storage units on the NWP system. Their owners currently have no plans for expansions.

Newport LNG & Portland LNG

The Company's Newport LNG storage facility plays an important role in helping to serve peak day demand in the Newport/Lincoln City and Salem demand centers. The Newport LNG compressor project would allow the full potential of the LNG facility to be utilized by transporting additional supply to Salem and possibly beyond via the Willamette Valley Feeder.

The Company's Portland LNG plant (also known as Gasco) provides Portland with important peak day capacity. No opportunities for expanding Gasco's deliverability into the Portland distribution system were identified for consideration.

Mist & Mist Recall

The Company's Mist Storage facility provides a significant underground storage resource. Additional storage capacity can be recalled from the interstate storage business as a resource decision. The resource options are modeled as individual decisions through time as existing interstate storage contracts expire.

Satellite LNG Storage

The Company could build small, above-ground LNG storage facilities near the Salem, Albany, and Eugene demand centers to help serve peak day demand in the Willamette Valley. These satellite storage facilities are modeled to be incremental resource options since storage tanks could be added through time. The estimated capital costs associated with building these small storage facilities are converted to a fixed cost per MDT of deliverability for the model.

Figure 5.1 – Pipeline and Supply Model Diagram

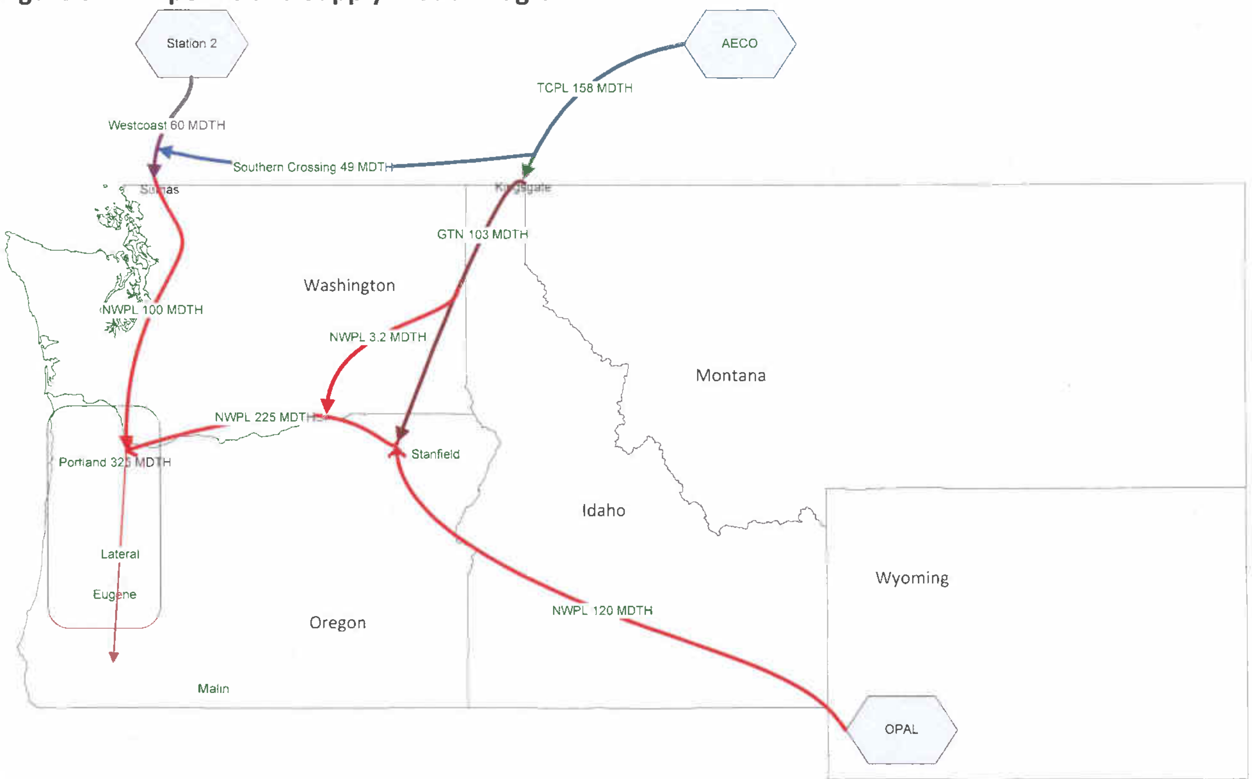


Figure 5.2 – Pipeline and Supply Model Diagram with cross-Cascades

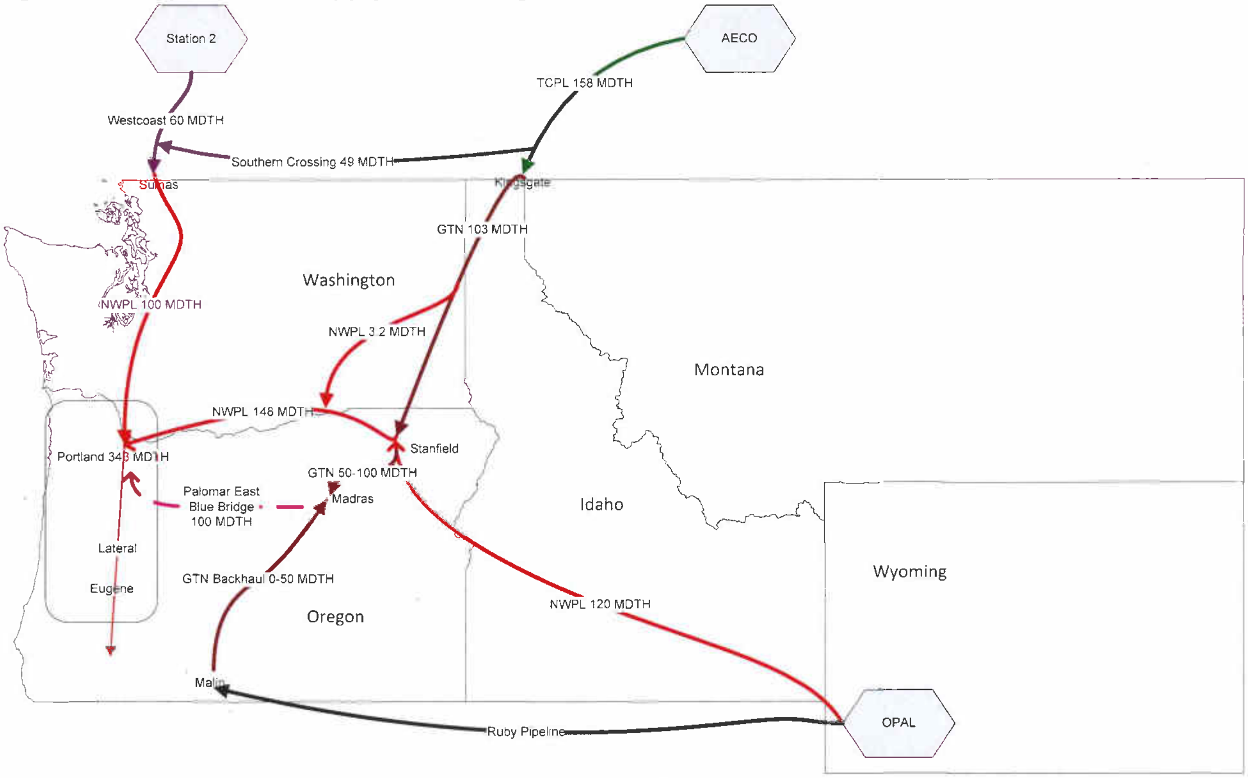
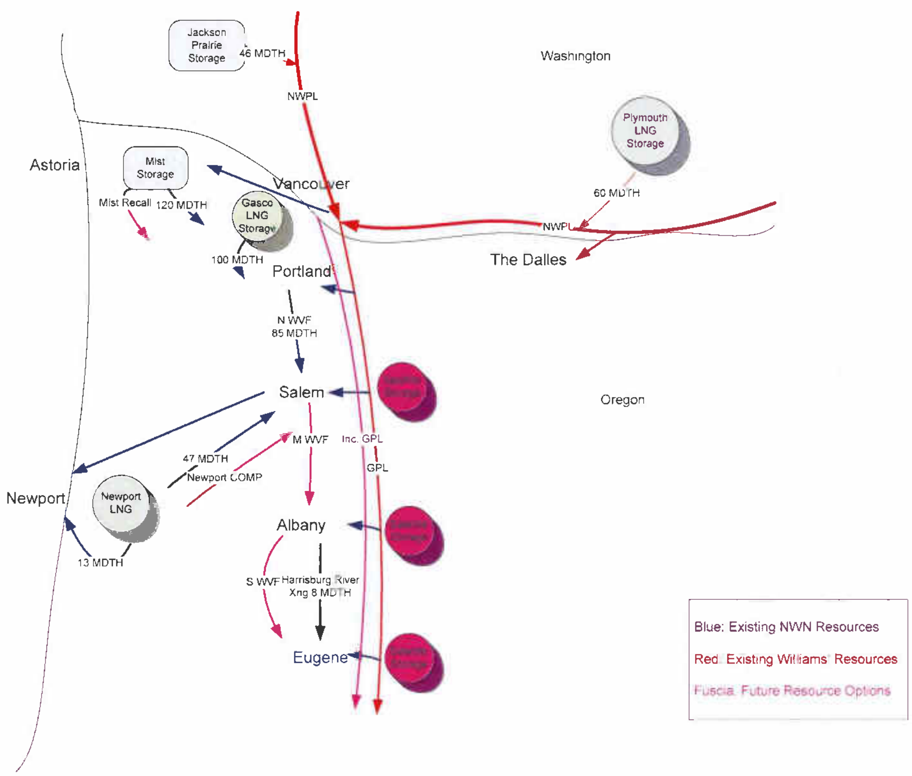


Figure 5.3 – Storage & Service Area Resources Model Diagram



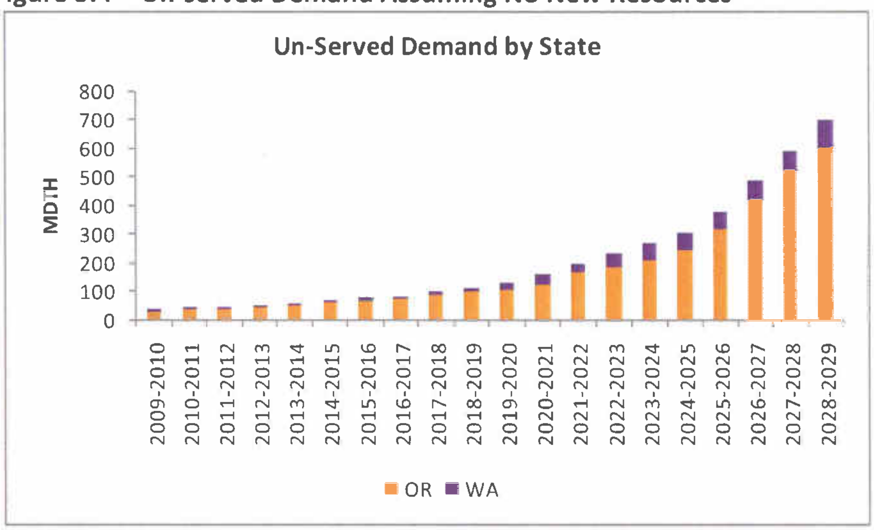
IV. RESOURCE PLANNING MODEL RESULTS

The process of running SENDOUT® includes three basis steps. First, a congruent set of model inputs must be entered into the application. These include the previously covered demand factors, weather patterns, price forecast, demand side management factors, and current resources. Next, the desired set of future resource options with individual decision factors are configured within the model. The application is then run and the output is collected. The output results include the time frame and size of the resource decisions, served and un-served demand, and the supply, transport, storage and DSM costs. Total costs are tabulated and the net present value of the cost over the 20-year horizon is calculated. The modeling process is an iterative one. Several runs are typically required for each unique set of inputs and resource portfolios.

A. No New Resources

The initial step in resource planning involves testing when new resources are required, if at all. A model run was completed in which all future incremental supply and demand side resources were excluded. The base case demand forecast and design weather were used as inputs. The model showed that all of the demand regions except for Newport/Lincoln City experienced un-served demand in each year of the planning time frame. Clearly, demand growth is large enough that new resources will need to be added to the system. Figure 5.4 displays the un-served demand through time in MDT (thousand dekatherms), broken out by state.

Figure 5.4 – Un-served Demand Assuming No New Resources



B. Planning Results with Base Case Demand and Resources

Once it has been ascertained that current resources are insufficient for meeting all projected demand, the next step is to evaluate potential new resources through SENDOUT®. Deterministic, least cost modeling was performed with the base case inputs (demand forecast, gas price forecast, design weather), around a base case resource portfolio and the results compiled.

The base case resource portfolio was assembled to represent a collection of future resource options based solely on their cost, but not based on reliability considerations. It assumes 100% resource availability under all conditions. During runs, the model was allowed to select from these resource options at specific levels and points in time. This base case resource portfolio is outlined in Table 5.2.

The resources that were selected in the base case were Mist recall during the first 15 years followed by Newport LNG deliverability and the cross-Cascades resource accessing Rockies gas at Malin in the later years.

Under the base case demand conditions and resource portfolio, Plan 1518 - Base Case produced the least cost. The alternative least cost plan if cross-Cascades is built is labeled 1540-Base with CC 165No Palomar. These two plans are very similar in resource selections and costs with the primary exception of the utilization of the cross-Cascades pipeline. In 1540, 165 MDT/day of capacity is secured on cross-Cascades starting in November of 2018, accompanied with a turn back of 77 MDT/day of the NWP mainline capacity. Least cost modeling indicates that the Plan 1540-Base with CC 165 is slightly more expensive than the least cost plan without cross-Cascades (1518) in serving base case demand. The difference in net present value over the 20-year horizon is $64 million. Table 5.2 provides a summary of the model results for these two plans.

Table 5.2 – Least Cost Modeling Results With Base Case Demand and Resource Portfolio

Table 5.2		1540 - Base w/ Cross-Cascades 165 MDT/Day		1518 - Base w/o Cross Cascades
Cost $(000) Net Present Value		$7,322,594		$7,258,215
2015/16		Mist Recall		Mist Recall
2017/18		Mist Recall		Mist Recall
2018/19		Mist Recall & Newport Delivery		Mist Recall
2018/19		Cross Cascades & GTN from Malin (NWPL & GTN turnback)		Mist Recall
2019/20		GTN from Malin		Mist Recall
2020/21				Mist Recall
2021/22				Mist Recall
2022/23				Mist Recall
2023/24				Mist Recall
2024/25		GTN from Malin		Mist Recall
2025/26		GTN from Malin & Newport Delivery		Mist Recall
2026/27		GTN from Malin		Mist Recall
2027/28		GTN from Malin		Mist Recall & Newport Delivery
2028/29		GTN from Malin		Newport Delivery
2029/30		GTN from Malin		Cross Cascades & GTN from Malin
2030/31		Mist Recall		Cross Cascades & GTN from Malin
2031/32				Cross Cascades & GTN from Malin

In the least cost model runs, all of the DSM resources were utilized. As mentioned earlier, DSM energy savings are modeled as automatic savings. Figure 5.5 displays the model output for DSM resource savings by category and state. Figure 5.6 expresses DSM savings as a percentage of demand.

Figure 5.5- DSM Savings with Base Case Demand and Resource Portfolio

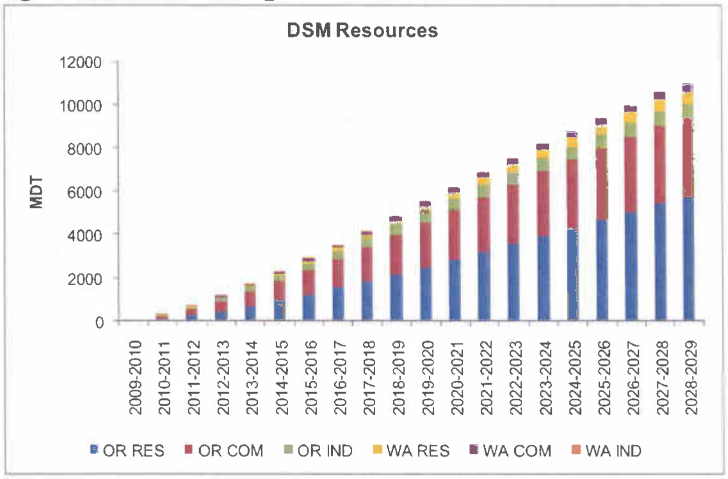
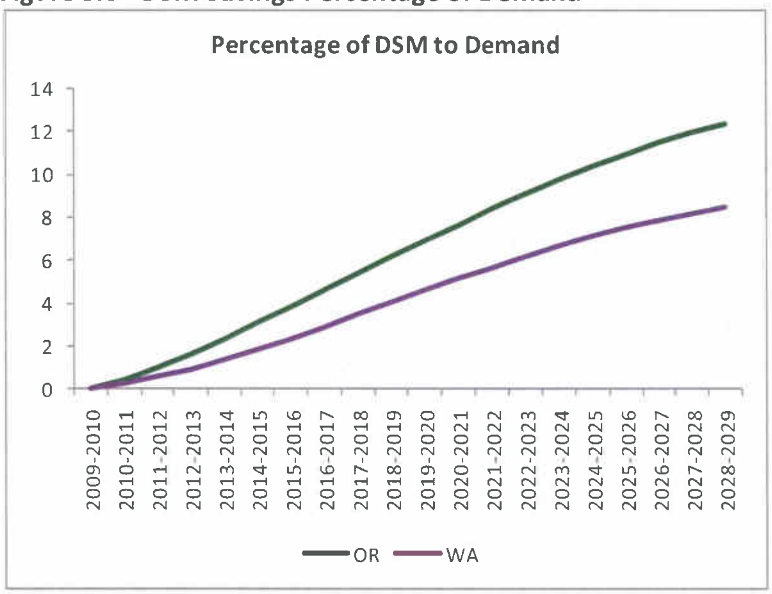


Figure 5.6 - DSM Savings Percentage of Demand



C. Reliability

Service disruptions were modeled to test the system resources for reliability. For modeling disruptions in the gorge, gas flows were reduced by the resource's capability for 3-day periods surrounding and including the 3 day peak event included in the design weather series. For modeling disruptions of Mist storage, gas flows were disrupted by 25% for existing Mist core deliverability, reflecting a reasonable level of diversity of pipeline and compression resources providing takeaway capability. Mist recall selected by the model was disrupted at 50%, where the higher percentage reflects less and less diversity of takeaway since pipeline capacity and compression are not added as more Mist recall is taken. The events were timed for the 3-day peak in early February. The peak event timing for disruptions was chosen to allow the plan to include a resource selection that would materially resolve a near worst case scenario for the Company's most exposed resources. Additionally, while that exposure exists now and in future years, the date of the gorge event was timed to coincide with what the Company believes is the first availability of a resolving resource. The service disruptions that were modeled include:

1. NWP Columbia Gorge – 2019
2. NW Natural Mist Storage – 2025

Three model runs were set up for each of 3 scenarios. First, the options were open such that the model could resolve the problem with any resource. Next, resource options included a cross-Cascades pipeline defined at 110 MDT per day with prices in line with a moderate subscription level for a new project. Finally, the resource option included a cross-Cascades pipeline defined at 165 MDT per day with prices in line with a high subscription level for a new project. In each case where the cross-Cascades pipeline was specified, the model was also set up to turn back 77 MDT/day of parallel capacity on the NWP mainline. The model results are summarized in Table 5.3.

D. Scenario Model Runs

Table 5.3 provides a summary of resource and cost results from the model runs, ranked by overall cost. Also listed are the resource options that were selected for the case as the least cost solution. Mist Storage recall is selected in all runs. The Newport LNG Compressor project was also selected in all cases Cost variation around a potential cross-Cascades pipeline was included using two possible scenarios. In the first, the cost reflected a subscription by the Company of 110 MDT/day, as well as a non-Company subscription of 190 MDT/day by other shippers, totaling 300 MDT/day. In the second, the cost reflected a subscription by the Company of 165 MDT/day, as well as a non-Company subscription of 285 MDT/day by other shippers, or a total of 450 MDT/day of pipeline capacity. The higher subscription level actually comes at a very modest cost compared to the lower level, assuming other shippers also subscribe at a higher level, since the incremental capital cost of the higher capacity project is relatively small.

In each outage scenario, the resource portfolio with the lowest overall cost included the cross-Cascades pipeline at the higher subscription level of 165 MDTH/day.

Table 5.3 –Model Runs Including Costs and Selected Resources

Run Number	Name	Cost	Cross-Cascades	Mist Recall	Newport LNG Compressor	Satellite Storage
1518	Base Case	$ 7,258,215	19	136	40	-
1540	Base with CC 165 (Preferred Path)	$ 7,322,594	165	28	40	-
1520	DSM at 2011 IRP Level	$ 7,295,075	14	66	40	-
1521	Low Customers	$ 7,122,706	27	75	40	-
1522	High Customers	$ 7,454,250	43	210	39	-
1525	High Sumas Price	$ 7,314,658	33	245	40	-
1526	High North America Prices	$ 10,471,375	9	16	40	-
1523	Medium Emerging	$ 7,895,492	43	230	40	-
1524	High Emerging	$ 12,963,701	429	188	38	-
Reliabilty Runs						
1529	Out Peak Open	$ 7,436,389	73	201	40	11
1530	Out Peak CC 110	$ 7,334,691	110	168	40	-
1531	Out Peak CC 165	$ 7,319,031	165	113	40	-
1533	Out Pre Open	$ 7,316,204	23	157	40	-
1535	Out Pre CC 110	$ 7,308,822	110	125	40	-
1536	Out Pre CC 165	$ 7,290,347	165	28	40	-
1534	Out Post Open	$ 7,338,240	28	136	40	11
1537	Out Post CC 110	$ 7,307,709	110	125	40	-
1538	Out Post CC 165	$ 7,289,159	165	28	40	-
Note: Values shown are for final year of model run (2031-2032)						

VI. Monte Carlo Simulation

The Company was unable to complete the Monte Carlo Simulation model runs prior to the filing of this draft IRP. Modeling results will be available and will be discussed at the January 30, 2013 Technical Working Group Meeting, and this section will be updated prior to the filing of the final draft.

VII. Key Findings

- Resource modeling produced a least cost Base Case resource plan to meet current and future demand. The plan's key future resource addition in the near term includes incremental Mist Storage Recall. Energy savings from DSM programs are also important.
- Modeling also generated a preferred path for resource planning that includes future capacity on a proposed cross-Cascades project. Modeling has shown that a new Cross-Cascades Pipeline could

improve service reliability and open up supply diversity options. However, there is an increased cost for such infrastructure.

- Demand Side Management (DSM) is expected to play a material role in serving future demand.

Chapter 6: Avoided Cost Determination

NW Natural

I. OVERVIEW

As part of the IRP process, NW Natural calculates a 20-year forecast of avoided costs. In this case, the avoided cost is an estimated cost to serve the next unit of demand with a supply side resource option at a point in time. This incremental cost to serve represents the cost that could be avoided through energy conservation. Therefore, the avoided cost forecast can be used as a guideline for comparing energy conservation with the cost of acquiring and transporting natural gas to meet demand. In addition, this IRP evaluates the impact that a range of environmental externalities, including CO_2 emission prices, would have on the avoided costs in terms of cost adders and supply costs. This analysis results in an expected avoided cost case – the base case, as well as a high case, and a low case.

II. Environmental Externalities

The Company's avoided cost forecast does not include a price for carbon as no viable carbon legislation is currently under consideration. Further, the third party gas price forecasters consulted by the Company are not predicting that a carbon cost will be initiated during the planning horizon of this IRP.

NW Natural's analysis, however, does includes a 10% conservation adder to account for the unquantifiable benefits of DSM, as suggested by the Northwest Power and Conservation Council.

III. Methodology

The SENDOUT® resource planning model was used to generate the avoided costs. The base case demand parameters were used as inputs, including the design weather pattern, and base case customer and gas price forecasts. The high and low natural gas price forecasts were used to generate the high and low avoided cost scenarios.

SENDOUT® contains a marginal cost report which lists the daily incremental cost to serve the next unit of demand for each demand region. The DSM functionality was turned off so energy conservation was not an option for the model; demand was served with supply side resources only. In addition to existing supply side resources, the resource options included Mist Storage Recall, Grants Pass Lateral pipeline capacity, Palomar East pipeline capacity, and satellite storage. The model determines the lowest cost method for serving the next unit of demand and computes a marginal cost. This computed marginal cost includes 1) the long term gas price forecast compiled from Intercontinental Exchange (ICE) futures and a consultant's gas price forecast; 2) Gas storage carrying costs for inventory; 3) Upstream variable transmission costs; 4) Peak related on-system transmission costs; and 5) the cost for gas used to push gas through the system.

IV. Results

Figure 6.1 charts the avoided costs resulting from the base case along with the environmental externality cost adders. The blue bars represent the avoided cost expressed in $/ DT, and the red details the 10% conservation adder.

Figure 6.1 - Avoided Cost and Environmental Externality Adders

Gas Year	Avoided Cost ($/DT)			With 10% Conservation		
	Base	High	Low	Base	High	Low
2012/13	3.51	3.79	3.22	3.86	4.17	3.54
2013/14	3.96	4.67	3.46	4.35	5.14	3.8
2014/15	4.21	5.48	3.36	4.63	6.03	3.7
2015/16	4.39	6.41	3.23	4.82	7.05	3.56
2016/17	4.5	7.36	3.05	4.95	8.1	3.36
2017/18	4.71	7.76	3.07	5.19	8.53	3.38
2018/19	4.74	7.92	3.03	5.21	8.71	3.33
2019/20	4.82	8.08	2.98	5.3	8.89	3.28
2020/21	4.86	8.21	2.96	5.35	9.04	3.26
2021/22	5.08	8.63	3.04	5.59	9.5	3.34
2022/23	5.24	9	3.12	5.76	9.9	3.43
2023/24	5.4	9.24	3.23	5.95	10.16	3.55
2024/25	5.3	9.13	3.09	5.83	10.04	3.39
2025/26	5.74	9.87	3.41	6.32	10.86	3.75
2026/27	5.98	10.23	3.53	6.57	11.26	3.88
2027/28	6.11	10.65	3.53	6.72	11.72	3.89
2028/29	6.23	11.09	3.52	6.86	12.2	3.87
2029/30	6.49	11.96	3.59	7.14	13.15	3.95
2030/31	6.93	12.72	3.87	7.63	13.99	4.25
2031/32	6.84	12.71	3.54	7.53	13.98	3.9

Figure 6.1 below graphically illustrates the base case avoided cost over the planning horizon.

Figure 6.1 - Base Case Avoided Costs

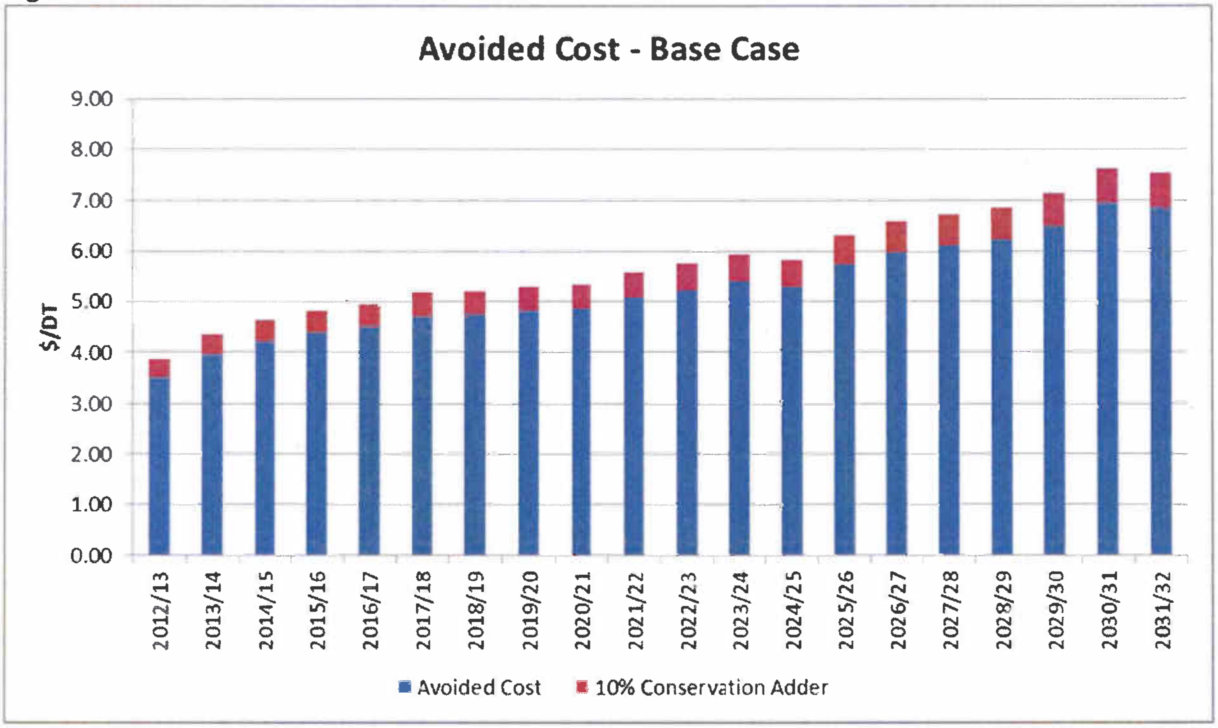


Figure 6.2 below displays the high, low, and base case cost scenarios with all costs rolled up – the avoided costs along with the 10% conservation adder. Table 6.1 lists the numerical results for costs in $/DT. Further detail around avoided costs are included in Appendix 6.

Figure 6.2 – Avoided Cost Scenarios

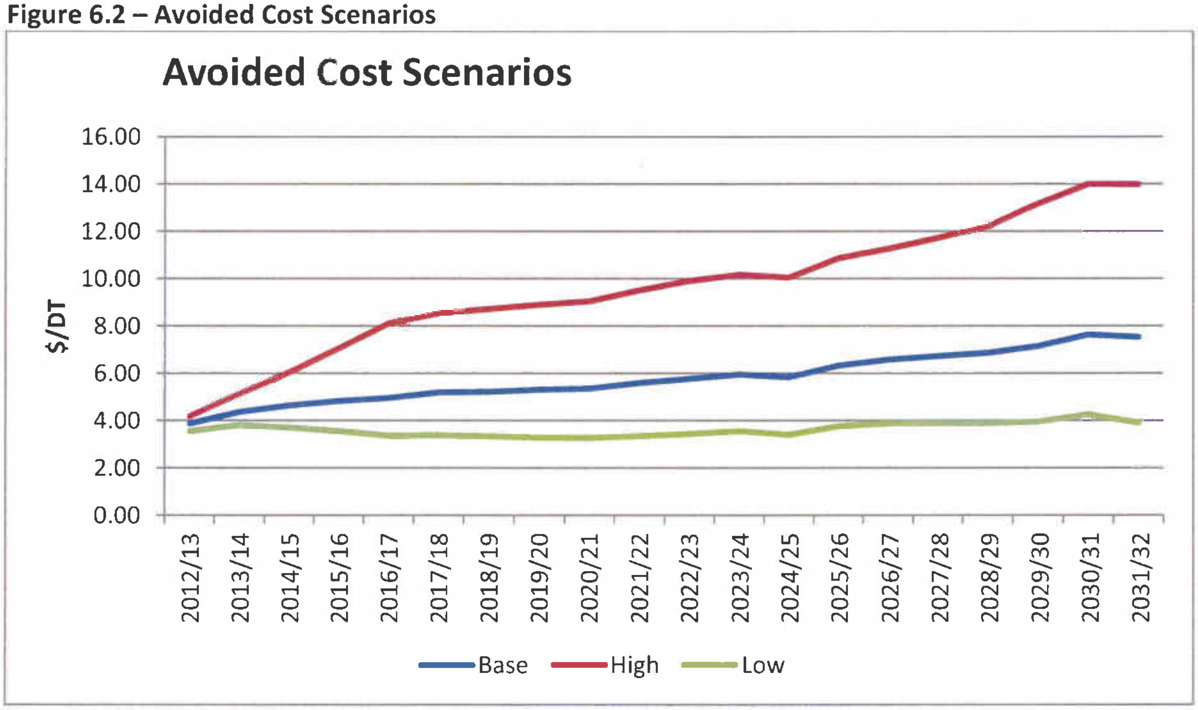


Table 6.2 - Avoided Costs

Gas Year	Avoided Cost ($/DT)			With 10% Conservation		
	OR	WA	System	OR	WA	System
2012/13	3.51	3.52	3.51	3.86	3.87	3.86
2013/14	3.96	3.96	3.96	4.35	4.36	4.35
2014/15	4.21	4.22	4.21	4.63	4.64	4.63
2015/16	4.39	4.39	4.39	4.82	4.83	4.82
2016/17	4.5	4.51	4.5	4.95	4.96	4.95
2017/18	4.71	4.72	4.71	5.18	5.2	5.19
2018/19	4.74	4.75	4.74	5.21	5.22	5.21
2019/20	4.82	4.83	4.82	5.3	5.31	5.3
2020/21	4.86	4.87	4.86	5.35	5.36	5.35
2021/22	5.08	5.09	5.08	5.59	5.6	5.59
2022/23	5.24	5.25	5.24	5.76	5.77	5.76
2023/24	5.4	5.41	5.4	5.94	5.96	5.95
2024/25	5.3	5.3	5.3	5.83	5.83	5.83
2025/26	5.74	5.75	5.74	6.32	6.33	6.32
2026/27	5.98	5.99	5.98	6.57	6.59	6.57
2027/28	6.11	6.12	6.11	6.72	6.74	6.72
2028/29	6.23	6.24	6.23	6.85	6.87	6.86
2029/30	6.49	6.5	6.49	7.14	7.15	7.14
2030/31	6.93	6.94	6.93	7.63	7.63	7.63
2031/32	6.84	6.85	6.84	7.53	7.53	7.53

The high avoided cost scenario includes the high gas price forecast (which drives up the cost of supply), and the 10% conservation adder. On average, the high case runs 63% higher than the base case. The low case, which was generated with the low gas price forecast along with the 10% conservation adder, resulted in costs being an average of 36% lower

VI. Key Findings

- Avoided costs were calculated for the base case as well as a high and a low case. This range in avoided cost could affect the amount of cost effective DSM that is achievable in future years.

Chapter 7: Distribution System Planning

NW Natural®

I. Background

As mentioned in the Chapter 1 in this and future IRPs, the Company is including a high level presentation of its distribution system planning to be more transparent and to capture projects that may be viewed as significant to delivering gas to load centers within the Company's distribution service area. Securing adequate natural gas supplies and ensuring sufficient pipeline transportation capacity become secondary issues if the distribution system is not adequately planned to deliver the gas where it is needed.[1]

II. Scope

Only distribution projects meeting the following two criteria are presented in this plan:

1) High pressure transmission projects required to move gas supplies to the Company's discrete load centers (as compared to moving gas within the load center); and
2) Any major system reinforcement or system expansion project over $10 million.

Major system enhancements meeting these criteria will be presented in detail later on in this chapter. A list of smaller projects with projected costs between $5 and $10 million dollars are provided in Appendix 7. As was mentioned in Chapter 3, projects that increase supply are referred to as Supply Side Infrastructure additions and are included in Chapter 3.

III. Nomenclature

The distribution system itself refers to all pipe owned by the Company that is downstream of the city gate. This includes both high pressure pipelines as well as distribution pressure pipelines. While Transmission Systems are considered to be those interstate pipeline systems that bring gas supply to the city gate (as discussed in Chapter 3), federal pipeline safety regulations classify mains as distribution or transmission. To avoid confusion, the Company will refer to projects meeting the criteria set forth above as HP transmission/distribution projects.

IV Overview

The goal of distribution planning is to design a distribution system to meet customers' current natural gas needs and to plan for future expansion to serve forecasted demand growth. Distribution system planning identifies potential planning problems and areas of the distribution system that require reinforcement. By knowing when and where pressure problems may occur, the necessary reinforcements can be incorporated into annual budget and distribution project planning, thus avoiding costly reactive and emergency solutions.

The Company's Engineering Department, in close collaboration with the Construction and Marketing departments, and using input from outside economic development and planning agencies, plans for the expansion, reinforcement and replacement of the distribution system. System planning takes place continuously, integrating new customer growth requirements into the Company's construction forecasts. Computer simulation modeling is used to help validate the need for and timing of specific system expansion, reinforcement, and replacement projects. Near-term (one to two-year) projects are highly likely to occur to meet specified customer delivery requirements. Mid-term (three to five-year) projects are subject to time slippage based on adjustments to the growth rate and geographic location

[1] The Company has also found this approach consistent with IRPs filed by other Washington LDCs.

of new customer requirements. Long-term (beyond five years) will tend to be general projections based on expected economic development of the region and gas supply resource acquisitions, and thus, subject to change.

The Company's distribution system planning must ensure that the Company does the following:

- operates and maintains the system in a safe and reliable manner;
- performs timely maintenance and makes the necessary reliability improvements;
- complies with all state and federal laws or regulations;
- ensures that hourly peak demands are met as well as day-to-day demands;
- plans for future needs in a timely fashion;
- addresses system needs related to localized population or demand growth; and
- ensures that the system is flexible enough to adapt to coming changes that are uncertain today such as the demand from Emerging Markets.

This planning process requires forecasting local demand growth, determining potential distribution system constraints, analyzing of potential solutions, and assessing the costs for each possible remedy.

V. Existing Distribution System

The Company's gas distribution system includes approximately 14,000 miles of distribution main pipelines, 12% of which is in Washington. The Washington service territory also includes 14 city gate stations and 85 district regulator stations.

No permanent storage facilities, compression systems, or stations are sited within the Company's distribution system in Washington. As discussed in Chapter 3, NW Natural owns two relatively large CNG trailers, each having a 1,000 therm capacity. The Company also has one LNG trailer with an 8,500 therm capacity that is occasionally deployed for short term use only, either to meet increased demand during cold weather operations or to support an area during pipeline procedures. The Company owns several smaller CNG trailers (65 therm capacity each) that are deployed for individual customers or small neighborhoods during minor pipeline procedures.

III. Distribution System Planning Methodology

A. Overview

The planning process begins with an evaluation of the system's current performance and then takes into consideration load growth and system constraints, both now and in the future. Assumptions about customer load growth are taken from the IRP demand forecasts[2] and discussions with local area management regarding main and service requests, major account representatives, developers, local trade allies, and field personnel discussions. This information is integrated with the system performance assessment for both the short and long term, and the result is a long-term planning and strategic outlook that helps to identify the best options for addressing system needs.

[2] IRP Demand Forecasts are discussed in detail in Chapter 2.

B. Computer Modeling

The Company uses the SynerGEE® software package[3] to evaluate infrastructure requirements. SynerGEE® creates a computer simulation of a pipeline system. Studies are conducted using the model to determine the response of the gas distribution system due to weather, specific load changes, supply gas changes, pressure set point changes, etc.

The SynerGEE model contains detailed information on pipe size, length, pipe roughness, pipe configuration, customer load, source gas flow rate and pressure, internal regulator settings, regulator characteristics and more information. The model uses complex mathematical flow equations and an iterative calculation method to determine when a system is in "balance". When balanced the relationship between flows and pressures at all points in the modeled system is within a tight tolerance, and the model shows flows and pressures at every point in the system. A properly designed model will show pressure and flow results in close agreement with observed conditions.

SynerGEE models utilize the NW Natural Geographical Information System (GIS) for the piping system configuration and pipe characteristics, Customer Information System (CIS) for customer load distribution, and Supervisory Control and Data Acquisition (SCADA) for large customer loads, gate flow, and gate pressure settings and key regulator pressure settings.

Once all the necessary data is in the system, SynerGEE model results are compared to actual observed conditions to validate the model. This validation process is the key to creating an accurate model.

When the SynerGEE model is validated, the performance of the distribution system can be calculated under a variety of conditions. Typically, the analysis focuses on meeting growing peak day customer demands while maintaining system stability. Gas requirements at delivery nodes are projected based on observed flow rates during recent cold weather episodes. These flow rates are then adjusted to match design peak weather conditions and the effects of customer growth. Alternative system expansion and reinforcement strategies are then evaluated in terms of system stability, cost, and the ability to meet future gas delivery requirements. This computer simulation capability allows the Company to efficiently evaluate distribution system performance in terms of stability, reliability, and safety under varying boundary conditions ranging from peak-day delivery requirements to temporary service interruptions, both planned and unplanned.

When designing new main extensions, computer modeling can help determine the optimum size of facilities for present and future needs. Undersized facilities are costly to replace, and oversized facilities incur unnecessary expenses to NW Natural and its customers.

1. Demand

Core demand typically has a morning peaking period between 7 a.m. and 8 a.m. The peak hour demand for these customers can be as much as 50% above the hourly average of the daily demand. Because of the importance of responding to hourly peaking in the distribution system, planning capacity requirements for the Company's distribution systems typically are based on peak hour demand.

---

[3] This software currently is marketed by GL Noble Denton (http://www.gl-nobledenton.com/). It previously was known as Stoner Workstation Service (SWS).

Actual system demand for various times and weather conditions are typically captured from real time SCADA information. This data is available every day. Smaller gates without SCADA have fixed outlet pressures and when modeling; these downstream loads are adjusted as appropriate for the weather conditions.

2. Modeling Scenarios

SynerGEE has a variety of features to evaluate results and to pinpoint potential solutions to correct a pressure problem. Changes can be made in the model to determine how the system would perform with a variety of enhancements. Enhancements can include increased regulator pressure, pipe looping, additional supply source, etc. The changes are entered into the model, and the model is re-balanced. A typical output is a color coded map showing system pressures. A variety of potential solutions for low pressure areas can be quickly considered to determine the short term and long term effectiveness. Once identified, the cost of each potential solution can be evaluated to select the best alternative.

NW Natural has a variety of pipeline operating pressures. The Class B system, which feeds residential and commercial customers, has a maximum allowable operating pressure (MAOP) of 60 psig. At these low pressures, there is insignificant line pack (storage within the pipe due to pressure), and changes in load cause immediate pressure changes.

In general, the industry standard for computing design capacity of a new pipeline is based on a maximum 20% pressure drop. A pressure drop of 50% from the source pressure (district regulator or gate) to the delivery point is a significant cause for concern. (A 50% pressure drop through a pipe uses 80% of available capacity. In other words, a 20% increase in load would cause pressure at the end of the pipe to be zero.) In addition to looking at the pressure drops on the pipeline from source pressure to delivery pressure NW Natural evaluates the inlet pressure to a district regulator in relation to the desired delivered outlet pressure. The differential pressure between the inlet and outlet pressure at a district regulator determines the maximum deliverable flow of the district regulator station.

Modeling allows the Company to run various scenarios to stress-test how the system will respond to varying demand forecasts and system constraints. The Company can analyze alternative solutions for meeting delivery capacity and addressing reliability issues. These alternatives can be categorized into three broad categories:

1. Add additional supply sources such as city gate, a new district regulator or a temporary CNG or LNG trailer;
2. Enhancements to the distribution system such as increased source pressure, pipeline MAOP uprate, pipe looping, pipe replacement, increased district regulator pressure.
3. Reduce load through curtailment of interruptible customers, (Conservation programs may have an ultimate impact on supply, but have not yet proven to cause significant peak load reduction in a short enough time period to provide a solution to distribution system planning efforts.)

3. Planning Results

The Company develops both short term and long term infrastructure plans based on existing load and future growth projections, system integrity considerations, and other system-impacting issues. These plans, both short term and long term, consist of proposed projects that are included in the Company's capital planning process, which are reviewed annually. The scope and needs of each project may evolve over time as new information becomes available. Actual solutions may be different based on differences in growth patterns and/or construction conditions. These annual plans are integrated into the Company's budgeting process, which also includes planning for other types of distribution capital expenditures and infrastructure upgrades.

IV. Significant HP Transmission/Distribution System Planning Projects

Currently three projects in Oregon meet the criteria mentioned at the beginning of this chapter and both are discussed below:

1. The Mid-Willamette Valley Feeder (MWVF)
   The IRP includes the Mid-Willamette Valley Feeder (MWVF) as a base case existing resource as shown in Chapter 5. The Company had assumed its analysis of this project in the 2011 Modified IRP coupled with other analyses that were performed outside the IRP process was sufficient to demonstrate the need for this project. .

2. The South Willamette Valley Feeder (SWVF)
   This project would serve to expand the Company's ability to move gas between the Albany and Eugene load centers. The cost is estimated at $58 million and the earliest in service date is currently estimated to be late 2015. Similar to the Mid-Willamette Valley Feeder, the Company received guidance that it needed to provide some additional analyses for distribution projects of this nature. The Company has not been able to complete these analyses and plans to address this project need in an Oregon IRP update. This update will be included as part of the Multi-Year Action Plan.

3. Corvallis Loop
   In Oregon, the Corvallis Loop project is over $10 million and even though it is within the Albany Corvallis load center, it would fall within the proposed IRP scope defined above. Here too, the Company plans to complete additional analysis and include it in an Oregon IRP update. This update will be included as part of the Multi-Year Action Plan.

V. Other HP Transmission/Distribution System Planning Projects

No other HP Transmission/Distribution System Planning Projects meet the criteria above. However, as this is the first time that the Company is including a chapter of this nature and due to the fact that it is a significant project for the Company's Washington service territory, the Felida Reinforcement project is discussed below.

A. Felida Reinforcement

1. Description of project

The Felida Gate project creates a new gas source in the Felida area as shown in the maps below. It consists of a new gate station on NW Pipeline, approximately one mile of high pressure piping downstream, and a new district regulator location.

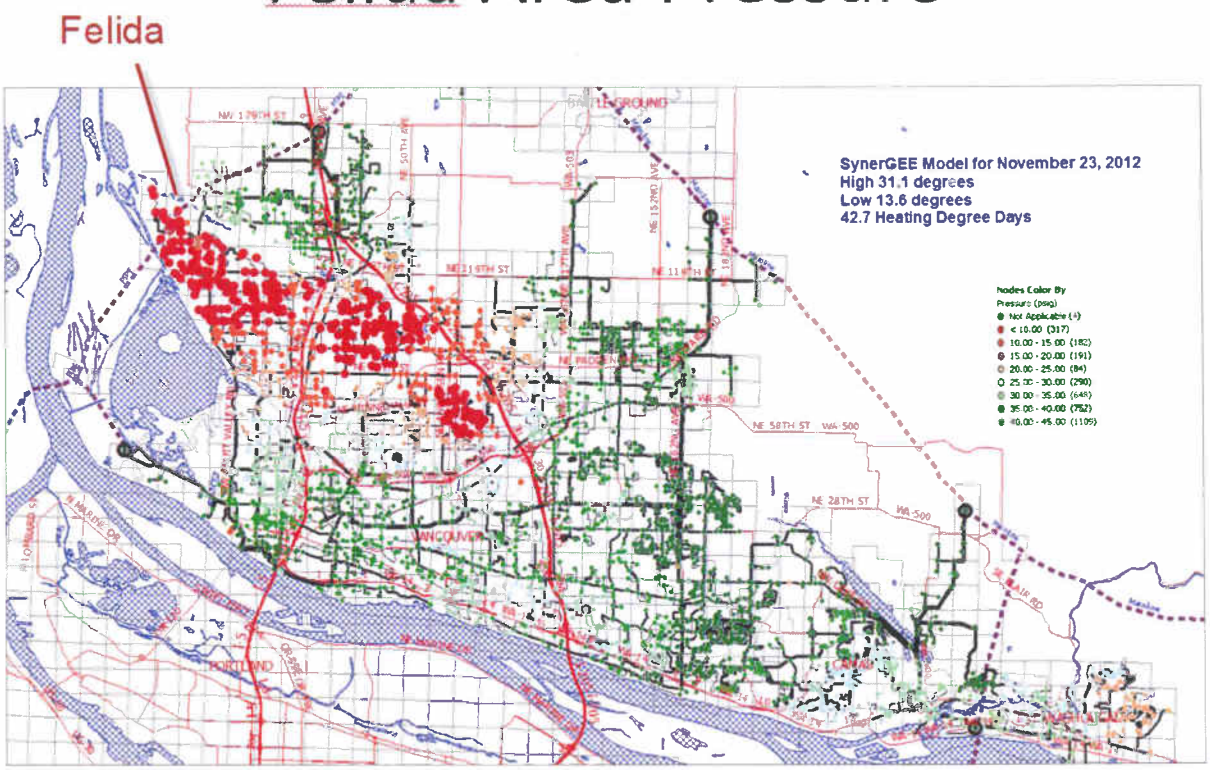
2. Purpose of project

The Felida area has a multiple year history of low pressures in winter. When low temperatures get below 15 degrees, pressures in the area drop below 10 psig. With a maximum regulator outlet pressure of 50 psig feeding the area, this is a serious drop in pressure. At a design day condition (53 HDD) pressure in the system at many services would be too low to provide gas service. NW Natural has used a large CNG Trailer (approximately 1000 therms total capacity) to provide a boost to the system for a number of years. However, this method will create sufficient pressure for only a few days at most.

This solution would not work for a long term cold weather event if the trailer could not be moved for refilling. Additionally with growth anticipated in the area, a permanent solution is needed.

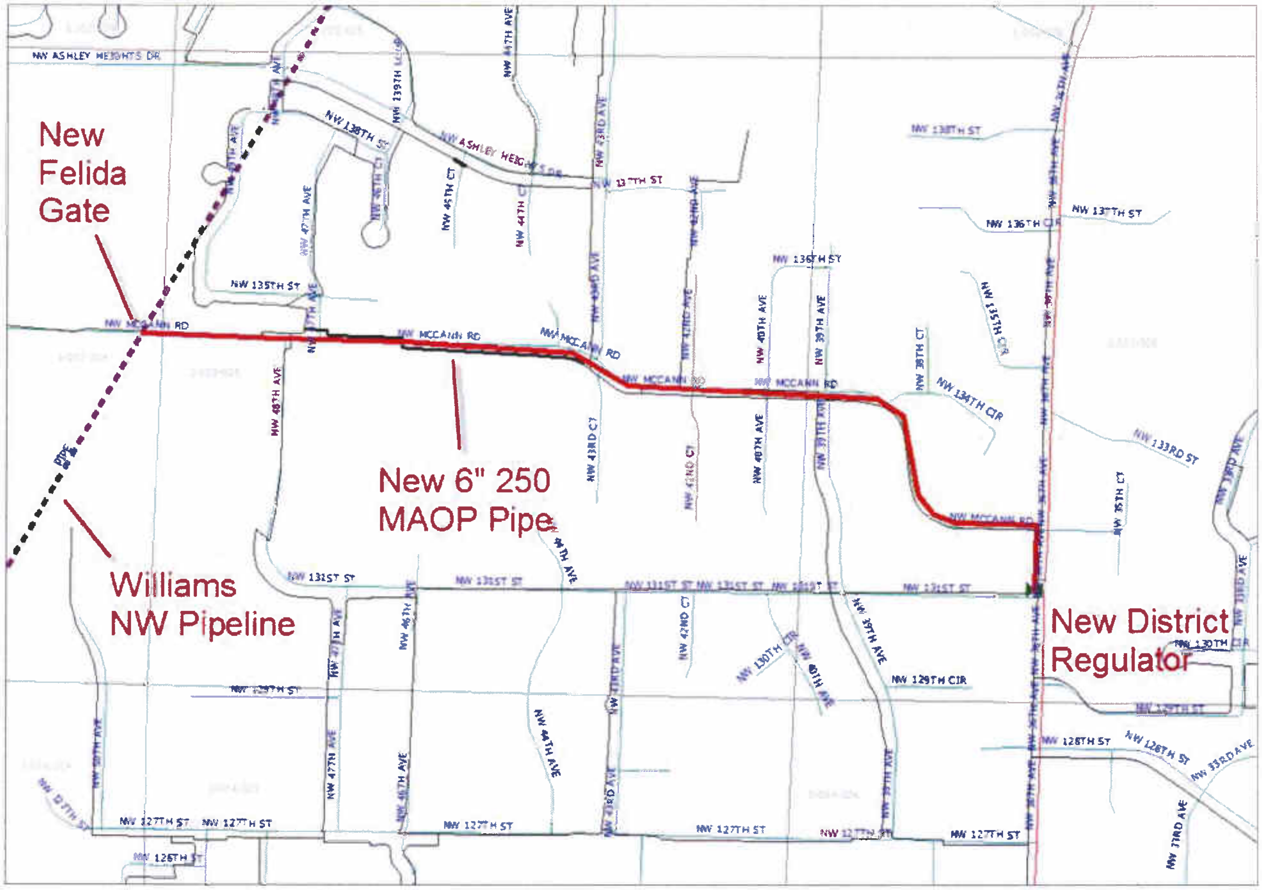
The chart below shows a SynerGEE model of the area under an observed condition on November 23, 2012. At 42.7 HDD, the red areas highlight those nodes that are under 10 psig. At 52 HDD condition, pressures at many customers would drop too low to provide gas service.

Felida Area Pressure



3. Location to existing facilities

The Felida Gate and downstream facilities are shown on the sketch below.



4. Project costs

The Felida Gate Project Cost is as follows:

• Williams NW Pipeline gate facilities	$935,000
• NW Natural Gate (telemetry, line heater)	$300,000
• 4400 feet 6" High pressure piping (including new district regulator)	$1,600,000
• Total	$2,835,000

5. Project risk

A risk analysis is performed on all projects projected to cost more than $100,000. This risk analysis looks at the following attributes that could materially impact project cost and/or timeline:

- Materials – assessing the degree and availability of non-stock specialty items involved in the project
- Easements – assessing the need for easements
- Permits – assessing the needs for and types of easements
- Ground Conditions – assessing degree of difficulty due to rocky soil
- Other Utilities – assessing the presences of other utilities in digging area
- Weather – assessing probability of rain and other weather related conditions that may negatively impact construction

- Construction Methodology - assessing the type of construction such as open trench
- Resources – assessing the availability of resources
-

Each of these attributes is evaluated as to its potential impact to the project using the following scoring:
1 – Minimal or No Impact to the project
2 – May Impact the Project
3 – Major Impact to the Project

Anything scored above a 1 has a mitigation strategy developed and the resulting score is used to calculate a contingency factor.

As can be seen below, this project has a score of 2.64.

Risk	Probability	Impact	Score (Probability x Impact)	COMMENTS (Eliminate / Mitigate)
Acquisition of Materials	3 Numerous Non-Stock or Specialty Items	2 - May Impact Project	6	Mitigate: Order parts early, determine supply for equipment that is moving and may need repairs and determine who is responsible for repairs and how long they may take.
Land Acquisition	5 Multiple Easements	2 - May Impact Project	10	Mitigate: Start work on the section that doesn't require easements.
Standard Permits	2 Permits with Minor Conditions	2 - May Impact Project	4	1200C permit and County
Special Permits	1 No Special Permits	1 - Minimal or No Impact	1	Mitigate: Avoid open cut in sensitive areas.
Environmental Impact	1 No Impacts	1 - Minimal or No Impact	1	
Ground Conditions	1 No Concerns	1 - Minimal or No Impact	1	
Utility Conflicts	2 Minor Utility Conflicts	1 - Minimal or No Impact	2	
Weather	3 Winter	2 - May Impact Project	6	Mitigate: Add time to cost estimate to cover winter work.
Construction Method	1 Open Trench	1 - Minimal or No Impact	1	
Bore Method	1 Horizontal Directional Drill	1 - Minimal or No Impact	1	
Resources	1 Resources Available	1 - Minimal or No Impact	1	
Working Hours	1 No Restrictions	1 - Minimal or No Impact	1	
Contract Availability	1 Resources Available	1 - Minimal or No Impact	1	
System Impact	1 No Impacts - Adequate Feed	1 - Minimal or No Impact	1	System reinforcement project - no impact to system during construction.
		Avg Score	**2.64**	**10**
				% Contingency

6. Selection criteria, Rationale for selection over other alternatives

No high pressure pipes are in the Felida area. The nearest active high pressure gas source is about 5 miles away to the northeast, near NW 164th Street and NE 10th Avenue. Construction of a large diameter Class B pipe or High Pressure pipe would be more expensive than construction of a new gate with downstream piping and regulator station. The location of NW Pipeline, near the low pressure area of Felida area, made a new gate the most logical alternative.

Targeted conservation resources were considered and as discussed in Chapter 4 are taken into consideration for longer term planning as are the usage of interruptible customers. However, as there are no interruptible customers in the area to curtail and DSM measures were not considered as a viable alternative due to the amount of immediate savings needed, the company believes this is the best option for addressing this system need.

7. Justification for the project schedule

In the event of a 52 heating degree day condition, the Felida area is currently at risk of service disruption. This new project will eliminate that concern. The need is immediate and thus the project is underway.

8. Project timing, Current project status

The Felida Gate facilities are currently nearing completion. The high pressure pipe downstream and the new district regulator are scheduled to be completed during 2013.

B. Other Distribution System Projects

Currently, there are no projects that meet the criteria for a smaller project (a project costing between $10 million and $5 million). However, similar to the Felida Gate Reinforcement, due to its significance to the Washington service territory and as this is the first time the Company has included this chapter, the 119th Street project has been listed.

9. Risks and Opportunities

This project plan is based on forecasted information and will be adjusted for known conditions. However, different uncertainties, while not quantifiable at this time, may have a significant impact on the spending on NW Natural's delivery systems. These uncertainties include new regulations such as proposed legislation that may be issued by the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA). Recent pipeline incidents (e.g., the San Bruno pipeline explosion in September 2010) have focused national attention on pipeline safety, including new legislation and proposed rulemaking with requirements and recommendations such as follows:

- Expanded use of excess flow valves
- Required use of automatic and remote controlled shut-off valves
- Accelerated replacement of cast iron and bare steel distribution systems
- Automated leak detection systems
- Enhanced damage prevention programs
- Improved control room monitoring and control capability

These may require additional investments in processes, infrastructure and personnel.

Additionally, shale gas has been a transformative industry event as previously discussed. From the perspective of distribution system planning, this transformation could take the form of, for example, higher usage rates per household as customers adopt more gas appliances due to the growing cost advantage of natural gas. Penetration of natural gas into the transportation (NGV) market would require a significant boost to the capacities of local distribution systems whether the fueling is done at centralized locations or at home. Lastly, with low gas prices and future increased electric demand and prices, the growth of distributed generation, such as combined heat and power (CHP) units, is also unknown but potentially significant in their implications for system reinforcements.

Chapter 8: Public Participation

NW Natural®

I. TECHNICAL WORKING GROUP

The Technical Working Group (TWG) is an integral part of developing the Company's resource plans. During this planning cycle, NW Natural worked with representatives from the Energy Trust of Oregon; Northwest Power and Conservation Council; Northwest Industrial Gas Users; Northwest Pipeline Corporation; the Washington Utilities & Transportation Commission; and the Northwest Gas Association.

The Company held two TWG meetings and has a third scheduled in early 2013. Below is a short summary of each meeting. The following pages contain more detailed summaries of each meeting including issues, both resolved and outstanding.

- <u>TWG No.1 held on June 28, 2012</u>
  NW Natural reviewed the IRP's purpose, the analysis used to determine the long term plan, the schedule for the process, NW Natural's service territory; and principal conclusions from the 2011 Modified IRP.

- <u>TWG No. 2 held on August 22, 2012</u>
  NW Natural reviewed the topics discussed and resolutions reached at the first TWG meeting. Adam Bartini of the Energy Trust provided an overview of NW Natural's current Energy Efficiency (EE) program in Washington; Lakin Garth of Energy Trust explained the process of determining the 20-year DSM potential for NW Natural's service territory; and Randy Friedman of NW Natural reviewed the mix of resources the Company uses to meet demand.

  The SENDOUT® model used for IRP modeling will optimize the supply side and demand side options presented on the basis of cost. The modeling allows for various resource combinations evaluated under assorted demand scenarios.

  Katie Gough from NW Natural explained how distribution system projects are identified, prioritized, planned, and tracked; and Glenn Carlson of NW Natural explained the use of SynerGEE® for modeling the pipelines downstream of the city-gates. This analysis is used for distribution infrastructure planning.

- <u>TWG No. 3 scheduled for January 30, 2013</u>
  NW Natural expects it will file the draft IRP by January 15, 2013. Then, on January 30, the Company will host its third and final TWG meeting, during which time the group will review the draft and discuss model results.

Appendix 8 contains the sign in sheets for each TWG meeting

II. PUBLIC PARTICIPATION

NW Natural plans on inviting its customers to participate in the resource planning process. A bill insert that informs customers of the IRP, invites comments, and announces a public meeting, will be sent to all customers in February 2013 billings. Customers will be invited to review the draft IRP and provide comments either by mail or email.

NW Natural's 2013 IRP
First TWG, June 28, 2012

Summary of Meeting

Below is a brief summary of the topics discussed at NW Naturals first TWG meeting for its 2013 IRP, held on June 28, 2012.

Review: We reviewed the IRP's purpose, the analysis used to determine the long term plan, the schedule for the process, NW Natural's service territory; and principle conclusions from the 2011 Modified IRP.

Gas Outlook: Gas supplies are up and prices are down due to the ability to fracture shale reserves and capture the gas trapped therein. Gas demand has been stagnant but may increase for:
1) Gas-Fired Generation Plants – as coal fired plants are replaced and back-up generation is built to support renewable power sources
2) Natural Gas Vehicles – as the transportation sector moves away from gasoline and diesel. Some return-to-base fleets are moving to CNG and some heavy duty trucks are moving to LNG. Passenger cars are less likely to move to natural gas.
3) Industrial Use – inexpensive gas will make it a good resource for industrial processes.
4) LNG exports – International demand coupled with cheap North American shale gas will likely increase North American exports of liquid gas.

Gas Price forecast: Gas prices are low, about $2.50 MMBtu. NW Natural's gas price forecast for its base case is developed using ICE futures and a consultant gas price outlook fundamentals forecast. The Company has developed a 20–year forecast for the following basins: Opal, AECO, Sumas, Malin, and Henry Hub.

Demand Forecast: Demand forecasts are developed for eight demand regions and nine customer classes including industrial interruptible. The weather planning standard used is 85% of coldest winter and is augmented with a peak event. Demand is based on HDDs and loads from emerging markets are included in the demand forecast.

Customer Forecast: Customer growth was about 3% prior to 2006 but has been around 1% over the last three years. The customer forecast is based on a blend of near and long term outlooks including historic trends and regional data. Residential growth is projected to be slow, while commercial growth rates are expected to decline. Industrial loads will likely remain flat. The Company is forecasting an average annual customer growth rate of 1.6% over the next 20-years.

Weather and Peak Day: The Company is using an 85% design criteria. The 2000/2001 heating season is the closest fit. The Company is also using a three-day peak event based on a February 3, 1989 peak weather day event.

Load Forecast Model: The load forecast is the synthesis of the delivered gas price forecast, the annual design weather pattern, the 3-day peak event based on February 3, 1989, and the use per customer load factors

Price Elasticity: NW Natural is not planning to use a price elasticity adjustment for its base case forecast since prices are so low. The possibility for elasticity will be handled through sensitivity studies.

Loads From Emerging Markets: The Company will assess the potential load increases from emerging vehicular transportation markets and will include a sensitivity analyses that reflects aggressive adoption rates. The Company will also track the possible new load from new gas fried generation plants.

Backcast Analysis: The Company provided a backcast of tis actual and forecast demand that demonstrated relative accuracy.

Deterministic Demand Sensitivities and Scenarios:
Sensitivities are various assumptions for individual inputs (i.e. – high price forecast, low customer growth). Portfolios are combinations of sensitivities. The Company intends to analyze the following sensitivities: base case, high customer growth demand, low customer growth demand, emerging marektet5s high growth, high price, low price, and Canadian LNG price.

Outstanding Issues

Please be prepared to discuss the following issue at the Company's second TWG.

Discussion:
We discussed four weatherization measures that are no longer cost effective (attic and wall insulation, and air and duct sealing). The Company may continue to keep these measures in its technical potential study because of the potential implications of ceasing to offer incentives on these foundational energy efficiency measures. The Company would continue to manage its program portfolio so that the sum of all therm savings acquisitions would be cost effective. The Company asked parties to consider how it should handle these measures as it prepares to finalize its DSM forecast. NWPCC and NWEC suggested the possibility of including additional adders to the avoided cost (such as a hedge value). Commission Staff may need to inform the Company if this appropriate or not since any adders may not be actual costs within the utilities current purview.

Issues Resolved

If you have questions or concerns with any of the following resolutions, please contact the Company prior to July 13, 2013; otherwise the Company will proceed with its analysis with the understanding that the following statements have been agreed upon by all parties in the process.

- NW Natural's 20-year gas price forecast for its base case will be developed using ICE futures and a consultant gas price outlook fundamentals forecast
- The weather planning standard used is 85% of coldest winter and is augmented with a peak event. The 85% coldest winter is the 2000/2001 heating season and the peak event was a 53 HDD on February 3, 1989.
- The Company is forecasting an average annual customer growth rate of 1.6% over the next 20-years.

- The Company will not use an elasticity adjustment in its base case.
- The Company will include industrial interruptible load as part of its demand forecast.
- The Company intends to analyze the following sensitivities: base case, high customer growth demand, low customer growth demand, emerging marektet5s high growth, high price, low price, and Canadian LNG price.

NW Natural's 2013 IRP
Second TWG – August 22, 2012

Summary of Meeting

Below is a brief summary of the topics discussed at NW Natural's second TWG meeting for its 2013 IRP, held on August 22, 2012.

Review: Sarah Dammen of NW Natural reviewed the topics discussed and resolutions reached at the first TWG meeting. Attendees were provided a handout summarizing the first meeting and issues resolved. This handout was also previously emailed to the group.

EE Program Summary: Adam Bartini of the Energy Trust provided an overview of NW Natural's current Energy Efficiency (EE) program in WA. The program began in late 2009 and serves approximately 70,000 customers. It offers prescriptive weatherization and equipment incentives to residential customers; prescriptive and custom incentives to commercial customers; and incentives to contractors for building new homes that meet Energy Star standards. The program is on track to acquire 214,695 therm savings in 2012.

DSM Assessment: Lakin Garth of Energy Trust explained the process of determining the 20-year DSM potential for NW Natural's service territory. The Energy Trust assesses the potential application of all known energy conservation measures within the Company's service territory based on housing stock, customer growth and load forecasts. The measures are screened for cost effectiveness, meaning the net present value of the benefits must exceed the costs. Savings from measures that are not cost effective are not included in the technical potential. The impact of revised codes and standards are factored into the DSM savings potential. The technical potential is the savings from all cost effective DSM measures. The achievable potential is 85% of the technical potential; the 15% deduction accounts for the customers who will not act on the incentive offerings. An annual deployment scenario which contemplates market penetration and assumptions regarding lost opportunities further shapes and reduces assumed DSM acquisition.

The savings potential for the 2013 IRP is significantly lower than it was for the 2011 Modified IRP. The reduced potential is due to the following: 1) lower savings are being acquired per measure than previously assumed; 2) the load forecast is down due to reduced customer growth; 3) some conservation in the previous DSM forecast has been acquired; 4) modeling refinements have been made; 5) changes to codes and standards have reduced savings opportunities; and 6) project costs are not declining.

Measures that are no longer cost effective in the residential program are ceiling, floor, and attic insulation; air and duct sealing; tankless water heaters; 0.67 EF Energy Star water heaters; and AFUE 95 furnace replacements. For the commercial program, ozone laundry treatments, HVAC controls and condensing boilers are no longer cost effective.

Supply Side Resources: Randy Friedman of NW Natural reviewed the mix of resources the Company uses to meet demand. Randy provided an overview of the system from wells to homes, provided a map of the region's local distribution companies' service territories and explained the available transportation options for bringing gas to NW Natural's service territory.

NW Natural purchases gas from British Columbia, Alberta and the US Rockies. When buying gas or hedging, the Company's policy is to achieve reliability, obtain the lowest reasonable cost, maintain price stability and ensure cost recovery. This is accomplished through a diversity of strategies: various pricing agreements are negotiated, supply contracts have staggered terms, and financial derivatives are used to further manage price. The Company has entered into long term price hedges such as its Encana deal which benefits only Oregon customers.

Transportation resources include firm contracts for capacity on NW Pipeline as well as pipeline systems that are upstream of NW Pipeline. The Sumas I-5 expansion, N-MAX/ Palomar and Fortis BC KORP/SCP Expansion – which are all possible future regional projects – were discussed, with N-MAX/Palomar the project that would directly add supply capacity to NW Natural territory.

NW Natural has off-system storage contracts at Jackson Prairie and Plymouth and on-system storage at the Company's Mist underground storage facility and its two LNG storage tanks (Newport and Gasco). Resource decisions regarding storage include how much Mist Recall the Company should use for serving its core customers and when or how should the Company take Newport LNG offline to remove the buildup of CO_2 from the tank. Current maintenance plans indicate that it may not be required to take Newport LNG offline. Further work is being performed.

IRP Modeling: The SENDOUT® model will optimize the supply side and demand side options presented on the basis of cost. The modeling allows for various resource combinations evaluated under assorted demand scenarios.

Engineering Planning Process: Katie Gough from NW Natural explained how distribution jobs are identified, prioritized, planned, and tracked. Projects may be related to public works projects, system reinforcement needs, compliance work, and customer acquisitions. Project planning is complex, requiring multiple inputs such as costs, resources, potential conflicts, and regulatory requirements. It is important to get the assumptions correct in order to properly allocate resources and funds for the term of each project.

Distribution System Modeling: Glenn Carlson of NW Natural explained the use of SynerGEE® for modeling the pipelines downstream of the city-gates. This analysis is used for distribution infrastructure planning. Hourly gas pressures are modeled to determine if the system is able to meet customer demand. If the modeling shows that the system cannot manage peak demand, actions are needed such as decreasing the load of interruptible customers, changing source pressure settings, replacing pipelines, or using temporary satellite storage. Glenn showed maps of Felida Gate and 119th Street – both of which are examples of areas where model results show the potential of low pressures which means the system needs to be reinforced to ensure reliable distribution of gas can continue in these areas.

Next Meeting: The third TWG is scheduled for October 31, 2012.

Outstanding Issues

1. NWEC asked that Energy Trust provide the complete, non-economic technical potential for DSM. The Energy Trust provides Oregon CAC members with the Oregon technical potential, achievable potential, and the potential screened per the avoided cost. Getting NW Natural's information in this same format would be helpful.

2. NWEC asked Energy Trust to explain the deployment scenario. What are the assumptions driving the deployment curve? Can we accelerate the deployment scenario so that we are doing all that is cost effective in the early years?

3. NWPCC asked if we could target DSM acquisition to an area with low pressures in order to delay an investment in distribution system enhancement.

Response:

1. For future IRPs, Energy Trust of Oregon will provide NW Natural with the technical potential, achievable potential, and the potential screened per the avoided cost, similar to what is provided to the Oregon CAC for Oregon, and ETO will also present this information to the TWG.

2. ETO develops the deployment scenario based on the best data available on items such as housing starts, number of units (e.g., SF houses/MF houses, commercial units), square footage of units, and assumptions on replacements for natural gas appliances which determines the penetration of efficient units into the market. Timing of savings from measures for new buildings (new residential or new commercial) is dictated by the real estate market and the forecast of new building (customers). Similarly, timing of deployment and savings for some measures for existing customers will depend on replacement rate. For example, the rate of furnace replacements, which is largely driven by age of existing appliances, dictates the timing for when savings can be acquired. Other measures that are clearly retrofit in nature can be done at any time within the 20 years over which the resource assessment is targeted and can be shifted forward. However acquisition is limited by program logistics. Ramping up for acquiring all retrofit measures in 1-2 years would create a bubble of activity in the marketplace. While the deployment scenarios do rely on assumptions and forecasts, there is not much that can be done in practice to advance the deployment of measures beyond the steady, manageable growth we project in the next couple years. Relying on past rates of penetration continue to be most appropriate for developing the deployment scenarios.

3. The purpose of distribution system reinforcements is to address low pressure situations to prevent service disruptions to customers during cold weather events. These distribution system projects improve the distribution of gas to customers and are not related to insufficient supply. In theory, it may make sense to target DSM to the geographic areas where we experience low pressures. However, in practice, targeting DSM to areas of low pressure is not a feasible solution to these distribution system situations. Once identified, most distribution system projects need to occur within a relatively short time frame—within one to five years. This short timeframe complicates the development and deployment of targeted DSM programs

and limits the DSM potential to address the low pressure area since there are limited opportunities for DSM deployment in the shorter time frame. In order to achieve a result that is meaningful, the vast majority of customers (thousands of customers) would need to implement very significant changes in usage simultaneously. If DSM is implemented by only a fraction of customers each year, it is unlikely that any reduction of peak load would be observed. In general the worst low pressure areas of significant size are given the highest priority for reinforcement each year. This project prioritization process allows improvements in time to ensure reliable service without excess spending. A targeted DSM approach is unlikely to change this system reinforcement project planning methodology. NW Natural continues to support pursuing DSM and believes it is appropriate to evaluate DSM relative to supply side resources as currently performed in the IRP.

Appendix 1: Regulatory Compliance

NW Natural®

In the WUTC's letter to the Company, dated January 12, 2012, wherein the Commission acknowledged the Company's 2011 Integrated Resource Plan (IRP), the Commission provided the Company with guidance on analyses and discussions it should include in its 2013 IRP. The Company addresses how its 2013 plan complies with the Commission's instructions.

- The Commission's discussion of how NW Natural's 2011 Modified Natural Gas IRP addressed the requirements for IRPs requested the Company to provide an analysis of what drives the differential in expected customer growth rates between the Portland and Vancouver service territories. The 2013 IRP discusses the results of this analysis in Section III A of Chapter 1, including that "[i]n recent history, load growth within the Company's Washington service area has exceeded that in Oregon, which can be attributed to lower market penetration compared to Oregon and a larger number of new housing developments being built in the greater Vancouver area." NW Natural includes that this difference in growth rates will continue over the planning horizon.

  The 2013 IRP specifies the jurisdictional growth rates on page 2.3 of Chapter 2 – Gas Requirements Forecast as 1.65% for the Company, 2.30% for Washington, and 1.57% for Oregon.

- The Commission's discussion encouraged the Company to provide its Lower Growth Rate Case additional consideration as it weights resource acquisition plans. As the Base Case customer growth rates in this IRP are lower than the Base Case in the prior IRP, the Company's analysis reflects such consideration. The 2011 Base Case average annual customer growth rates in the 2011 IRP were 2.70%, 1.73%, and 1.84%, respectively, for Washington, Oregon, and total Company.

- The Commission's discussion included that the Company should provide a comprehensive explanation of its level of achievable DSM savings in its Washington service territory. The current IRP discusses determination of achievable potential DSM savings on page 5 of Chapter 4. Reasons for the reduction in the overall savings potential of the measures considered in this IRP versus the prior IRP are discussed on page 2 of Chapter 4.

Appendix 2: Gas Requirements Forecast

NW Natural®

Appendix 2.19 Demand Forecast (Post DSM) – Base Case – Total Sales – MDT (Thousand dekatherms)

Year	Albany	Astoria	Dalles, OR	Eugene / Coos Bay	Newport / Lincoln City	Portland	Salem	Vancouver / Dalles, WA	System
2012-2013	4,687	1,249	969	5,766	980	46,761	11,384	7,458	79,253
2013-2014	4,736	1,248	965	5,862	982	47,355	11,543	7,553	80,244
2014-2015	4,795	1,267	995	6,015	986	48,121	11,784	7,680	81,643
2015-2016	4,871	1,274	998	6,123	993	48,964	11,983	7,839	83,045
2016-2017	4,879	1,272	997	6,205	997	49,446	12,079	7,936	83,811
2017-2018	4,896	1,278	1,000	6,269	1,005	49,974	12,161	8,059	84,642
2018-2019	4,922	1,284	1,003	6,339	1,014	50,473	12,245	8,196	85,476
2019-2020	4,962	1,298	1,011	6,434	1,027	51,233	12,400	8,363	86,727
2020-2021	4,972	1,299	1,014	6,494	1,033	51,654	12,462	8,468	87,395
2021-2022	5,004	1,306	1,018	6,569	1,042	52,267	12,558	8,608	88,373
2022-2023	5,028	1,315	1,022	6,646	1,052	52,872	12,656	8,753	89,345
2023-2024	5,083	1,330	1,032	6,757	1,066	53,793	12,819	8,940	90,819
2024-2025	5,091	1,331	1,032	6,808	1,072	54,299	12,865	9,054	91,552
2025-2026	5,124	1,340	1,038	6,897	1,083	55,103	12,972	9,206	92,764
2026-2027	5,158	1,351	1,044	6,983	1,094	55,962	13,090	9,372	94,055
2027-2028	5,214	1,367	1,055	7,105	1,110	57,127	13,268	9,580	95,826
2028-2029	5,234	1,372	1,057	7,165	1,118	57,954	13,326	9,715	96,940
2029-2030	5,271	1,384	1,065	7,263	1,131	59,115	13,449	9,893	98,569
2030-2031	5,314	1,396	1,072	7,365	1,143	60,497	13,576	10,083	100,446
2031-2032	5,327	1,400	1,075	7,386	1,146	60,691	13,618	10,109	100,751

Appendix 2.20 Demand Forecast (Post DSM) – Base Case – Firm – MDT (Thousand dekatherms)

Year	Albany	Astoria	Dalles, OR	Eugene / Coos Bay	Newport / Lincoln City	Portland	Salem	Vancouver / Dalles, WA	System
2012-2013	3,936	1,194	750	4,792	946	44,163	9,618	7,065	72,463
2013-2014	3,923	1,193	746	4,811	948	44,203	9,626	7,117	72,566
2014-2015	3,920	1,193	744	4,848	952	44,303	9,668	7,201	72,830
2015-2016	3,932	1,200	747	4,914	959	44,708	9,761	7,316	73,535
2016-2017	3,931	1,197	744	4,944	962	44,752	9,785	7,406	73,721
2017-2018	3,948	1,203	747	5,009	971	45,109	9,867	7,529	74,382
2018-2019	3,974	1,210	750	5,078	979	45,418	9,951	7,665	75,025
2019-2020	4,012	1,223	756	5,169	992	46,020	10,099	7,831	76,102
2020-2021	4,013	1,223	757	5,216	997	46,190	10,138	7,930	76,464
2021-2022	4,044	1,231	762	5,291	1,006	46,606	10,234	8,070	77,244
2022-2023	4,068	1,239	766	5,369	1,017	46,952	10,332	8,215	77,957
2023-2024	4,120	1,254	775	5,475	1,031	47,629	10,488	8,400	79,172
2024-2025	4,131	1,255	776	5,531	1,037	47,833	10,541	8,516	79,619
2025-2026	4,164	1,264	782	5,619	1,047	48,333	10,648	8,668	80,527
2026-2027	4,198	1,275	788	5,705	1,059	48,774	10,766	8,834	81,399
2027-2028	4,251	1,291	798	5,824	1,075	49,492	10,937	9,041	82,708
2028-2029	4,274	1,297	800	5,887	1,082	49,774	11,002	9,177	83,293
2029-2030	4,311	1,308	808	5,985	1,095	50,324	11,125	9,355	84,312
2030-2031	4,354	1,320	816	6,087	1,108	50,905	11,252	9,545	85,387
2031-2032	4,364	1,324	817	6,105	1,110	51,071	11,287	9,569	85,647

Appendix 2.21 Demand Forecast (Post DSM) – Base Case – Residential – MDT (Thousand dekatherms)

Year	Albany	Astoria	Dalles, OR	Eugene / Coos Bay	Newport / Lincoln City	Portland	Salem	Vancouver / Dalles, WA	System
2012-2013	2,293	636	267	2,119	430	27,185	5,368	4,667	42,963
2013-2014	2,294	641	267	2,136	435	27,308	5,400	4,707	43,189
2014-2015	2,302	647	269	2,164	440	27,452	5,459	4,776	43,510
2015-2016	2,320	659	274	2,208	448	27,849	5,555	4,869	44,182
2016-2017	2,336	665	277	2,237	454	28,007	5,614	4,954	44,543
2017-2018	2,361	677	282	2,283	464	28,384	5,707	5,057	45,216
2018-2019	2,393	689	288	2,331	474	28,691	5,802	5,171	45,838
2019-2020	2,429	705	295	2,387	486	29,210	5,939	5,302	46,753
2020-2021	2,442	712	300	2,423	493	29,442	6,004	5,385	47,200
2021-2022	2,477	725	306	2,471	503	29,841	6,105	5,497	47,926
2022-2023	2,505	738	311	2,522	514	30,161	6,208	5,612	48,571
2023-2024	2,552	756	320	2,586	527	30,728	6,348	5,755	49,571
2024-2025	2,571	764	324	2,624	535	30,966	6,421	5,849	50,055
2025-2026	2,606	778	331	2,680	545	31,415	6,528	5,968	50,850
2026-2027	2,640	792	338	2,732	557	31,797	6,646	6,099	51,600
2027-2028	2,685	810	347	2,801	571	32,375	6,796	6,257	52,642
2028-2029	2,713	822	352	2,842	580	32,661	6,876	6,365	53,211
2029-2030	2,747	837	360	2,900	592	33,129	6,993	6,501	54,059
2030-2031	2,787	852	367	2,961	604	33,617	7,112	6,646	54,945
2031-2032	2,794	855	368	2,971	605	33,741	7,137	6,663	55,132

Appendix 2.22 Demand Forecast (Post DSM) – Base Case – Commercial– MDT (Thousand dekatherms)

Year	Albany	Astoria	Dalles, OR	Eugene / Coos Bay	Newport / Lincoln City	Portland	Salem	Vancouver / Dalles, WA	System
2012-2013	1,394	540	413	2,210	447	14,909	3,568	2,117	25,596
2013-2014	1,386	534	410	2,224	445	14,885	3,560	2,132	25,575
2014-2015	1,380	528	408	2,243	443	14,889	3,556	2,150	25,599
2015-2016	1,378	523	407	2,271	443	14,931	3,562	2,173	25,689
2016-2017	1,367	515	403	2,282	440	14,863	3,540	2,184	25,593
2017-2018	1,363	509	402	2,308	438	14,879	3,538	2,207	25,645
2018-2019	1,361	504	400	2,336	437	14,917	3,538	2,234	25,727
2019-2020	1,365	501	401	2,377	438	15,026	3,556	2,271	25,934
2020-2021	1,358	494	398	2,396	436	15,002	3,540	2,292	25,916
2021-2022	1,357	489	397	2,428	435	15,046	3,543	2,323	26,020
2022-2023	1,357	484	396	2,461	435	15,100	3,546	2,357	26,136
2023-2024	1,364	482	398	2,507	436	15,232	3,568	2,402	26,388
2024-2025	1,359	475	395	2,531	435	15,227	3,556	2,428	26,406
2025-2026	1,360	471	395	2,568	435	15,302	3,563	2,466	26,560
2026-2027	1,363	467	395	2,606	435	15,384	3,569	2,505	26,724
2027-2028	1,372	465	397	2,659	437	15,542	3,595	2,556	27,023
2028-2029	1,371	459	395	2,688	436	15,566	3,588	2,588	27,091
2029-2030	1,376	456	396	2,732	436	15,669	3,600	2,633	27,297
2030-2031	1,382	453	396	2,777	437	15,781	3,613	2,680	27,519
2031-2032	1,386	454	397	2,786	438	15,834	3,626	2,689	27,610

Appendix 2.23 Demand Forecast (Post DSM) – Base Case – Firm Industrial – MDT (Thousand dekatherms)

Year	Albany	Astoria	Dalles, OR	Eugene / Coos Bay	Newport / Lincoln City	Portland	Salem	Vancouver / Dalles, WA	System
2012-2013	250	18	70	463	69	2,069	683	281	3,904
2013-2014	243	18	68	451	69	2,009	666	278	3,802
2014-2015	238	18	67	441	69	1,962	653	275	3,722
2015-2016	234	18	66	435	69	1,928	644	273	3,665
2016-2017	228	17	64	425	68	1,882	631	268	3,585
2017-2018	224	17	63	418	68	1,846	621	264	3,522
2018-2019	220	17	62	411	68	1,810	611	261	3,460
2019-2020	217	17	61	406	68	1,784	604	258	3,415
2020-2021	213	17	60	398	68	1,747	594	253	3,348
2021-2022	210	17	59	392	68	1,718	586	249	3,299
2022-2023	207	16	58	387	68	1,691	578	246	3,250
2023-2024	204	16	57	382	68	1,669	572	243	3,212
2024-2025	201	16	56	376	67	1,640	564	238	3,158
2025-2026	198	16	56	372	67	1,616	558	234	3,117
2026-2027	196	16	55	367	67	1,593	551	230	3,075
2027-2028	194	16	54	363	67	1,575	546	228	3,043
2028-2029	190	16	53	357	67	1,546	538	224	2,992
2029-2030	188	16	53	353	67	1,526	533	222	2,957
2030-2031	186	16	52	349	67	1,507	527	219	2,923
2031-2032	185	15	52	347	67	1,496	524	218	2,904

Appendix 2.24 Demand Forecast (Post DSM) – Base Case – Interruptible – MDT (Thousand dekatherms)

Year	Albany	Astoria	Dalles, OR	Eugene / Coos Bay	Newport / Lincoln City	Portland	Salem	Vancouver / Dalles, WA	System
2012-2013	740	55	216	959	33	2,340	1,740	386	6,469
2013-2014	802	55	216	1,036	33	2,538	1,889	429	6,996
2014-2015	863	73	247	1,150	33	2,815	2,087	472	7,740
2015-2016	927	73	248	1,192	33	2,944	2,193	516	8,126
2016-2017	925	73	247	1,227	33	3,013	2,236	514	8,267
2017-2018	925	73	247	1,227	33	3,013	2,236	514	8,267
2018-2019	925	73	247	1,227	33	3,013	2,236	514	8,267
2019-2020	927	73	248	1,231	33	3,023	2,243	516	8,293
2020-2021	925	73	247	1,227	33	3,013	2,236	514	8,267
2021-2022	925	73	247	1,227	33	3,013	2,236	514	8,267
2022-2023	925	73	247	1,227	33	3,013	2,236	514	8,267
2023-2024	927	73	248	1,231	33	3,023	2,243	516	8,293
2024-2025	925	73	247	1,227	33	3,013	2,236	514	8,267
2025-2026	925	73	247	1,227	33	3,013	2,236	514	8,267
2026-2027	925	73	247	1,227	33	3,013	2,236	514	8,267
2027-2028	927	73	248	1,231	33	3,023	2,243	516	8,293
2028-2029	925	73	247	1,227	33	3,013	2,236	514	8,267
2029-2030	925	73	247	1,227	33	3,013	2,236	514	8,267
2030-2031	925	73	247	1,227	33	3,013	2,236	514	8,267
2031-2032	927	73	248	1,231	33	3,023	2,243	516	8,293

Appendix 2.25 Demand Forecast (Post DSM) – Base Case – Emerging Markets – MDT (Thousand dekatherms)

Year	Albany	Astoria	Dalles, OR	Eugene / Coos Bay	Newport / Lincoln City	Portland	Salem	Vancouver / Dalles, WA	System
2012-2013	10	1	3	15	1	258	26	7	321
2013-2014	11	1	3	16	1	614	28	7	682
2014-2015	12	1	3	16	1	1,003	29	8	1,073
2015-2016	12	1	3	17	1	1,313	29	8	1,384
2016-2017	23	2	6	34	2	1,682	59	16	1,823
2017-2018	23	2	6	34	2	1,852	59	16	1,993
2018-2019	24	2	6	34	2	2,042	59	16	2,184
2019-2020	23	2	6	34	2	2,190	59	16	2,332
2020-2021	35	3	10	50	3	2,451	88	24	2,663
2021-2022	35	3	10	50	3	2,649	88	24	2,861
2022-2023	35	3	10	51	3	2,907	88	24	3,120
2023-2024	35	3	10	51	3	3,141	88	24	3,354
2024-2025	35	3	10	50	3	3,454	88	24	3,666
2025-2026	35	3	10	50	3	3,757	88	24	3,970
2026-2027	35	3	10	51	3	4,176	88	24	4,389
2027-2028	35	3	10	51	3	4,612	88	24	4,825
2028-2029	35	3	10	50	3	5,167	88	24	5,379
2029-2030	35	3	10	50	3	5,778	88	24	5,990
2030-2031	35	3	10	51	3	6,579	88	24	6,792
2031-2032	35	3	10	51	3	6,597	88	24	6,811

Appendix 2.26 Peak Day Demand Forecast (Post DSM) – Base Case – Firm – MDT (Thousand dekatherms)

Year	Albany	Astoria	Dalles, OR	Eugene / Coos Bay	Newport / Lincoln City	Portland	Salem	Vancouver / Dalles, WA	System
2012-2013	54	16	8	53	11	582	107	92	922
2013-2014	53	16	8	54	11	581	106	92	922
2014-2015	53	16	8	54	11	583	107	93	926
2015-2016	53	16	8	55	11	584	108	95	930
2016-2017	54	16	9	55	11	586	108	96	936
2017-2018	54	16	9	56	11	590	110	98	944
2018-2019	54	16	9	57	11	595	111	99	952
2019-2020	55	16	9	58	12	597	112	101	959
2020-2021	55	16	9	59	12	602	113	103	969
2021-2022	56	16	9	60	12	606	114	105	978
2022-2023	56	17	9	61	12	611	115	107	987
2023-2024	57	17	9	62	12	615	116	109	997
2024-2025	57	17	10	63	12	621	117	111	1,008
2025-2026	58	17	10	64	12	627	119	113	1,020
2026-2027	58	17	10	65	13	631	120	115	1,030
2027-2028	59	17	10	66	13	638	121	117	1,042
2028-2029	59	17	10	67	13	645	123	120	1,055
2029-2030	60	18	10	69	13	651	124	122	1,068
2030-2031	61	18	11	70	13	658	126	125	1,082
2031-2032	61	18	11	70	13	657	126	125	1,080

Appendix 2.27 Peak Day Demand Forecast (Post DSM) – Base Case – Residential – MDT (Thousand dekatherms)

Year	Albany	Astoria	Dalles, OR	Eugene / Coos Bay	Newport / Lincoln City	Portland	Salem	Vancouver / Dalles, WA	System
2012-2013	35	10	4	27	6	390	68	66	606
2013-2014	35	10	4	27	7	390	68	67	606
2014-2015	35	10	4	27	7	393	69	67	611
2015-2016	35	10	4	28	7	396	69	68	616
2016-2017	35	10	4	28	7	399	70	69	623
2017-2018	35	10	4	29	7	404	72	71	631
2018-2019	36	10	4	29	7	409	73	72	640
2019-2020	36	10	4	30	7	412	74	74	647
2020-2021	36	11	4	30	7	417	75	75	656
2021-2022	37	11	4	31	7	421	76	77	664
2022-2023	37	11	4	31	8	426	77	78	673
2023-2024	38	11	4	32	8	431	79	80	682
2024-2025	38	11	4	33	8	436	80	81	692
2025-2026	39	11	4	33	8	442	81	83	702
2026-2027	39	12	4	34	8	446	83	85	711
2027-2028	40	12	5	35	8	452	84	86	722
2028-2029	40	12	5	35	9	459	86	88	733
2029-2030	41	12	5	36	9	465	87	90	744
2030-2031	41	12	5	37	9	471	89	92	755
2031-2032	41	12	5	37	9	470	88	92	755

Appendix 2.28 Peak Day Demand Forecast (Post DSM) – Base Case – Commercial– MDT (Thousand dekatherms)

Year	Albany	Astoria	Dalles, OR	Eugene / Coos Bay	Newport / Lincoln City	Portland	Salem	Vancouver / Dalles, WA	System
2012-2013	18	6	5	24	4	180	37	24	298
2013-2014	17	6	5	24	4	180	37	24	297
2014-2015	17	6	5	25	4	179	37	24	297
2015-2016	17	6	5	25	4	178	36	25	296
2016-2017	17	6	5	25	4	177	36	25	295
2017-2018	17	6	5	25	4	177	36	25	295
2018-2019	17	6	5	26	4	176	36	26	295
2019-2020	17	6	5	26	4	176	36	26	296
2020-2021	17	6	5	26	4	176	36	26	297
2021-2022	17	6	5	27	4	175	36	27	297
2022-2023	17	6	5	27	4	175	36	27	298
2023-2024	18	6	5	28	4	175	36	28	299
2024-2025	18	6	5	28	4	176	36	28	300
2025-2026	18	5	5	29	4	176	36	29	302
2026-2027	18	5	5	29	4	176	36	29	303
2027-2028	18	5	5	30	4	177	36	30	305
2028-2029	18	5	5	30	4	177	36	30	307
2029-2030	18	5	5	31	4	178	36	31	309
2030-2031	18	5	6	31	4	179	36	32	311
2031-2032	18	5	6	31	4	178	36	32	311

Appendix 2.29 Peak Day Demand Forecast (Post DSM) – Base Case – Firm Industrial – MDT (Thousand dekatherms)

Year	Albany	Astoria	Dalles, OR	Eugene / Coos Bay	Newport / Lincoln City	Portland	Salem	Vancouver / Dalles, WA	System
2012-2013	1	0	0	2	0	11	2	2	19
2013-2014	1	0	0	2	0	11	2	2	18
2014-2015	1	0	0	2	0	11	2	2	18
2015-2016	1	0	0	2	0	10	2	2	18
2016-2017	1	0	0	2	0	10	2	2	18
2017-2018	1	0	0	2	0	10	2	2	17
2018-2019	1	0	0	2	0	10	2	2	17
2019-2020	1	0	0	2	0	10	2	2	17
2020-2021	1	0	0	2	0	10	2	2	17
2021-2022	1	0	0	2	0	9	2	1	16
2022-2023	1	0	0	2	0	9	2	1	16
2023-2024	1	0	0	2	0	9	2	1	16
2024-2025	1	0	0	2	0	9	2	1	16
2025-2026	1	0	0	2	0	9	2	1	16
2026-2027	1	0	0	2	0	9	2	1	15
2027-2028	1	0	0	2	0	9	2	1	15
2028-2029	1	0	0	2	0	9	1	1	15
2029-2030	1	0	0	2	0	9	1	1	15
2030-2031	1	0	0	2	0	9	1	1	15
2031-2032	1	0	0	2	0	8	1	1	15

Appendix 2 - Load Forecast Coefficients

Residential

	Existing Daily Baseload Factor	Existing Heat Intercept	Existing Heat Rate
Albany	0.3774	-4.4331	0.7114
Astoria	0.3488	-4.1890	0.6444
Dalles	0.3938	-4.5276	0.6525
Eugene	0.4002	-3.8605	0.5051
Newport LC	0.1662	-3.7635	0.4868
Portland	0.4465	-3.5290	0.4862
Salem	0.4074	-3.3734	0.3857
Vancouver	0.4782	-4.2299	0.6651
System	0.4407	-3.7239	0.5270

	Conv Daily Baseload Factor	Conv Heat Intercept	Conv Heat Rate
Albany	0.3018	-4.4942	0.6960
Astoria	0.2874	-4.1349	0.6044
Dalles	0.3284	-4.4560	0.5812
Eugene	0.3242	-3.7982	0.4575
Newport LC	0.2210	-4.1079	0.5170
Portland	0.2804	-3.5817	0.4666
Salem	0.2774	-3.3096	0.3517
Vancouver	0.3611	-4.0554	0.5485
System	0.3037	-3.7491	0.4962

	NC SF Daily Baseload Factor	NC SF Heat Intercept	NC SF Heat Rate
Albany	0.5357	-5.2324	0.9451
Astoria	0.5533	-4.3201	0.6891
Dalles	0.5361	-5.2811	0.8506
Eugene	0.5703	-4.1551	0.5858
Newport LC	0.3508	-4.4482	0.6692
Portland	0.6490	-3.7783	0.5760
Salem	0.5874	-3.8900	0.5368
Vancouver	0.5855	-4.4414	0.7443
System	0.6234	-3.9855	0.6101

	NC MF		
	Daily Baseload Factor	Heat Intercept	Heat Rate
Albany	0.2257	-5.5544	0.8048
Astoria	0.5351	-6.8345	1.1782
Dalles	0.3606	-6.4208	0.9908
Eugene	0.2495	-4.7040	0.4586
Newport LC	0.2679	-4.8782	0.5568
Portland	0.3687	-4.7892	0.6625
Salem	0.3909	-3.9955	0.4049
Vancouver	0.3252	-5.3474	0.7799
System	0.3621	-4.9831	0.7057

Commercial			
	Existing		
	Daily Baseload Factor	Heat Intercept	Heat Rate
Albany	2.9528	-2.4481	0.5770
Astoria	4.7070	-3.1095	0.7128
Dalles	4.1967	-2.4116	0.5099
Eugene	4.0271	-2.0349	0.4676
Newport LC	6.2701	-3.3698	0.7401
Portland	4.2317	-1.9591	0.4848
Salem	3.9081	-1.3468	0.2783
Vancouver	4.0164	-2.3610	0.5388
System	4.1822	-2.0786	0.5002
	Conv		
	Daily Baseload Factor	Heat Intercept	Heat Rate
Albany	2.3762	-3.8928	0.8333
Astoria	2.4990	-5.7561	1.3997
Dalles	2.1719	-4.4811	0.8885
Eugene	4.9736	-4.3305	1.0773
Newport LC	3.2928	-3.4989	0.8224
Portland	3.5021	-2.0763	0.3832
Salem	1.9672	-1.4754	0.1454
Vancouver	2.4270	-3.9630	0.8601
System	3.3101	-2.4856	0.4806

	NC		
	Daily Baseload Factor	Heat Intercept	Heat Rate
Albany	4.7341	-3.3805	0.9619
Astoria	2.7348	-2.1521	0.3771
Dalles	2.9895	-7.5790	1.9530
Eugene	4.2031	-2.1791	0.4827
Newport LC	5.7952	-3.5383	0.7999
Portland	6.3907	-1.7330	0.4601
Salem	3.7819	-1.3913	0.2378
Vancouver	4.1537	-2.4308	0.6077
System	5.1840	-1.9716	0.4869

Firm Industrial		
	Daily Baseload Factor	Heat Rate
Albany	124.4223	4.6770
Astoria	71.4263	0.0000
Dalles	176.3735	1.1983
Eugene	99.6153	3.5299
Newport LC	377.1642	0.0000
Portland	132.7441	4.4659
Salem	177.1909	0.7336
Vancouver	137.6775	3.5088
System	121.5720	5.8628

Interruptible		
	Daily Baseload Factor	Heat Rate
Albany	1508.1816	11.7726
Astoria	489.9587	0.0000
Dalles	642.0545	13.4164
Eugene	881.1149	11.6582
Newport LC	875.1366	0.0000
Portland	769.8753	25.6463
Salem	1155.5065	14.9430
Vancouver	969.5225	15.4594
System	1116.8697	2.7857

Appendix 2.30 Customer Use Profiles

Annual Use Per Customer at Oct 2011 Rates							
	Average Weather			Design Weather			
Residential	**Base**	**Heat**	**Total**	**Base**	**Heat**	**Total**	**Peak**
Albany | Res-Exist	137	429	566	137	486	623	9.6
Astoria | Res-Exist	126	442	568	126	481	607	10.0
Dalles | Res-Exist	142	361	504	142	402	544	6.3
Newport LC | Res-Exist	60	414	475	60	449	509	8.8
Portland | Res-Exist	161	523	684	161	588	750	9.9
Salem | Res-Exist	147	474	621	147	526	674	7.9
Eugene | Res-Exist	145	417	562	145	466	610	7.8
Vancouver | Res-Exist	173	470	643	173	525	698	9.5
System | Res-Exist	159	496	655	159	554	713	9.6
Albany | Res-Conv	110	388	498	110	439	549	8.5
Astoria | Res-Conv	105	417	522	105	454	558	9.2
Dalles | Res-Conv	120	312	432	120	346	466	5.1
Newport LC | Res-Conv	81	320	401	81	346	427	7.1
Portland | Res-Conv	102	468	570	102	527	629	8.7
Salem | Res-Conv	101	456	558	101	506	607	7.2
Eugene | Res-Conv	118	385	504	118	429	548	6.9
Vancouver | Res-Conv	132	396	528	132	440	572	7.3
System | Res-Conv	111	442	553	111	493	604	8.3
Albany | Res-NC SF	196	390	586	196	450	645	10.7
Astoria | Res-NC SF	202	444	646	202	483	685	10.7
Dalles | Res-NC SF	196	318	514	196	358	554	6.1
Newport LC | Res-NC SF	128	350	478	128	379	507	9.1
Portland | Res-NC SF	237	518	755	237	599	836	11.0
Salem | Res-NC SF	214	439	653	214	493	707	8.4
Eugene | Res-NC SF	208	395	603	208	444	652	8.1
Vancouver | Res-NC SF	214	484	698	214	544	757	10.9
System | Res-NC SF	228	486	714	228	547	774	10.4
Albany | Res-NC MF	82	186	268	82	212	294	4.5
Astoria | Res-NC MF	195	150	345	195	164	359	5.9
Dalles | Res-NC MF	132	158	290	132	179	311	3.4
Newport LC | Res-NC MF	98	166	264	98	179	277	4.0
Portland | Res-NC MF	135	246	380	135	282	416	5.6
Salem | Res-NC MF	143	268	411	143	298	441	4.9
Eugene | Res-NC MF	91	156	247	91	174	265	2.9

Vancouver | Res-NC MF	119	218	336	119	245	364	5.0
System | Res-NC MF	132	237	369	132	268	401	5.5

Commercial	Base	Heat	Total	Base	Heat	Total	Peak
Albany | Com-Exist	1068	2098	3165	1068	2351	3419	43.0
Astoria | Com-Exist	1702	1588	3290	1702	1727	3430	41.8
Dalles | Com-Exist	1518	1926	3444	1518	2128	3646	34.7
Newport LC | Com-Exist	2268	1263	3530	2268	1364	3632	40.3
Portland | Com-Exist	1530	2496	4026	1530	2806	4336	49.9
Salem | Com-Exist	1413	2628	4042	1413	2898	4312	42.5
Eugene | Com-Exist	1456	2308	3765	1456	2572	4028	43.6
Vancouver | Com-Exist	1453	2088	3540	1453	2316	3769	40.6
System | Com-Exist	1513	2375	3888	1513	2647	4160	47.1
Albany | Com-Conv	867	1064	1931	867	1216	2083	27.7
Astoria | Com-Conv	912	839	1752	912	926	1838	38.8
Dalles | Com-Conv	793	795	1587	793	896	1689	18.1
Newport LC | Com-Conv	1202	1391	2593	1202	1507	2709	44.1
Portland | Com-Conv	1278	1673	2952	1278	1861	3139	32.4
Salem | Com-Conv	718	1576	2294	718	1726	2444	22.3
Eugene | Com-Conv	1815	1421	3236	1815	1667	3483	46.2
Vancouver | Com-Conv	886	1106	1992	886	1250	2136	27.7
System | Com-Conv	1208	1498	2706	1208	1667	2875	30.1
Albany | Com-NC	1728	2609	4337	1728	3013	4741	73.6
Astoria | Com-NC	998	1569	2567	998	1704	2702	29.9
Dalles | Com-NC	1091	1074	2165	1091	1297	2388	40.2
Newport LC | Com-NC	2115	1260	3376	2115	1362	3478	42.1
Portland | Com-NC	2333	2892	5225	2333	3286	5618	58.2
Salem | Com-NC	1380	2234	3615	1380	2459	3839	37.4
Eugene | Com-NC	1534	2095	3629	1534	2338	3872	41.3
Vancouver | Com-NC	1516	2400	3916	1516	2675	4191	49.8
System | Com-NC	1892	2551	4443	1892	2840	4732	51.1

Industrial	Base	Heat	Total	Base	Heat	Total	Peak
Albany | Industrial	45414	21749	67164	45414	23633	69047	230.1
Astoria | Industrial	26071	264	26335	26071	264	26335	7.7
Dalles | Industrial	64376	6106	70483	64376	6589	70965	74.5
Newport LC | Industrial	137665	1394	139059	137665	1394	139059	40.6
Portland | Industrial	48452	20819	69271	48452	22617	71069	221.2
Salem | Industrial	64675	3994	68669	64675	4290	68964	53.0
Eugene | Industrial	36360	16436	52796	36360	17857	54217	174.3
Vancouver | Industrial	44374	27136	71510	44374	29497	73871	284.7

System | Industrial	50252	15972	66224	50252	17385	67637	320.1

Interruptible	Base	Heat	Total	Base	Heat	Total	Peak
Albany | Interruptible	550486	67131	617618	550486	71873	622359	770.3
Astoria | Interruptible	178835	4400	183235	178835	4400	183235	63.9
Dalles | Interruptible	234350	66836	301186	234350	72239	306589	737.6
Newport LC | Interruptible	319425	7859	327283	319425	7859	327283	114.1
Portland | Interruptible	281004	123654	404658	281004	133982	414987	1350.3
Salem | Interruptible	421760	78396	500156	421760	84414	506174	878.9
Eugene | Interruptible	321607	60980	382587	321607	65675	387282	683.0
Vancouver | Interruptible	407657	22710	430367	407657	23832	431489	281.3
System | Interruptible	353876	70370	424246	353876	76596	430472	1773.4

Appendix 2.1 Analysis Customer Growth Differentials by State

In its most recent acknowledgement, the Commission asked the Company to provide an analysis of what drives the differential in expected growth rates between the Portland and Vancouver service territories. That explanation as well as an explanation as to why NW Natural relies on the Oregon Office of Economic Analysis is provided below.

Explanation: The differential in expected growth rates between the Portland and Vancouver areas is explained by two elements: 1) the methodology used to allocate customer projections to service areas and 2) the difference in market share rates among service areas.

1) **Methodology used to allocate customer projections to service territories**. Once future customer additions are estimated at the system level, the expected customer additions are then allocated among service areas based on their share of recent customer additions. This methodology assures that growth trends within service areas are considered. An alternative approach would be to allocate future customer additions to service areas based on their share of customer base. This alternative approach, however, is considered to be less adequate as it does not take recent growth trends into consideration and is not used. These two methodologies may produce two different estimates. To illustrate this point, the table below shows NW Natural's residential customer base and net customer additions by State for 2011. Notice that the customer base distribution by State and the distribution of actual customer additions by State are not the same, which explain the first reason for the difference in growth rates between service areas.

	Customer Base December 2011	Customer Base Allocation by State	Actual Net Customer Additions 2011	Net Customer Additions Allocation by State
Oregon	551,038	90%	4,339	86%
Washington	64,632	10%	733	14%
Total	615,670	100%	5,072	100%

2) **Market share rates.** A second consideration when comparing customer growth rates by area is the existing market share rate by area. For instance, the same number of customer additions for a given area will produce a higher customer growth rate when its customer base or its market penetration rate is lower. As the customer base grows, the same number of additions will produce a lower customer growth rate. This fact is important as the market share estimate for the Vancouver area is significantly lower than that of the Portland area. The table below shows the 2011 residential market share estimate for these two areas.

	Estimated Residential Market Share 2011
Portland area	72%
Vancouver area	45%

The methodology used to allocate system customer projections to service areas, as well as the market share estimates by area, are elements to take into account when comparing customer growth rates among service territories. NW Natural considers that the methodology used is prudent and appropriate. The Company, however, is open to suggestions that help improve the accuracy its projections.

Use of Oregon State housing start projections for Washington State service area

Among other resources, NW Natural has been relying on the Oregon Office of Economic Analysis (OEA) in developing its customer growth projections for its Oregon and Washington service territories. The purpose of this document is to explain the reasons why NW Natural chose to use OEA data to estimate growth projections for its Washington State service area.

In 2008, the company assessed sources and methodologies to be used to project housing starts for its Washington State service area. At least four agencies were considered as possible sources for housing start projections: a) Clark County, WA, b) the City of Vancouver, WA, c) the Washington State Economic and Revenue Council (ERFC), and d) the Oregon Office of Economic Analysis (OEA).

At the time the assessment was performed, the Company found that Clark County, WA and the City of Vancouver, WA did not produce housing start projections for their service territories. On the other hand, it was found that ERFC produced housing start projections for Washington State and OEA produced housing start projections for the State of Oregon.

With that information, the Company conducted an statistical analysis to determine the historic correlation of residential new construction meters in its Washington territory with housing starts for Washington State and the State of Oregon. Based on available data at that time, the Company concluded that customer additions in its Washington territory had a better correlation with Oregon State housing starts than with Washington State housing starts. The table below provides basic details of the statistical analysis that was performed.

Housing Starts	Years	Correlation (Adjusted R square)
Washington State	1996 to 2007	0.08
State of Oregon	1991 to 2007	0.56

In addition to the statistical analysis, it was considered that the geographic proximity of the Portland Metro area to the Vancouver territory, as well as its economic influence were drivers for the higher correlation with the Oregon State housing starts.

An update to the statistical analysis was performed in 2013. The update showed that the statistical correlations with both States improved as new observations became available. It was also found that customer additions in the Washington territory have a marginally higher correlation with housing starts in Oregon. The table below shows details of this updated analysis.

Housing Starts	Years	Correlation (Adjusted R square)
Washington State	1996 to 2011	0.84
State of Oregon	1996 to 2011	0.85

The Company will continue to monitor its data and sources for its customer growth projections, and it will adjust its methodology if appropriate. NW Natural welcomes suggestions and recommendations to improve its forecasting processes.

Appendix 4: Demand-Side Resources

NW Natural®

Oregon DSM Deployment Scenario Incremental Annual Savings - THERMS

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
RESIDENTIAL																				
New Construction	68,897	86,121	120,569	189,465	315,776	430,603	516,724	574,138	574,138	574,138	574,138	574,138	574,138	574,138	574,138	574,138	574,138	574,138	574,138	574,138
Retrofit	81,586	81,586	81,586	81,586	81,586	81,586	81,586	81,586	81,586	81,586	81,586	81,586	81,586	81,586	81,586	81,586	81,586	81,586	81,586	81,586
Replace DHW	790,776	790,776	790,776	790,776																
Replace equipment	5,836	5,836	5,836	5,836	5,836	5,836	5,836	5,836	5,836	5,836	5,836	5,836	5,836	5,836	5,836	5,836	5,836	5,836	5,836	5,836
Appliances, new & replace	52,809	52,809	52,809	52,809	52,809	52,809	52,809	52,809	52,809	52,809	52,809	52,809	52,809	52,809	52,809	52,809	52,809	52,809	52,809	52,809
COMMERCIAL																				
Replace Equip	238,214	285,857	166,750	166,750	142,929	142,929	119,107	119,107	119,107	119,107	119,107	95,286	95,286	95,286	95,286	71,464	71,464	47,643	47,643	23,821
Replace Shell	189,984	197,584	121,590	121,590	121,590	121,590	121,590	121,590	121,590	121,590	121,590	121,590	121,590	121,590	121,590	121,590	121,590	121,590	121,590	121,590
Retrofit Wx	249,815	299,778	174,870	174,870	149,889	149,889	124,907	124,907	124,907	124,907	124,907	99,926	99,926	99,926	99,926	74,944	74,944	49,963	49,963	24,981
Retrofit Equip	388,020	465,624	271,614	271,614	232,812	232,812	194,010	194,010	194,010	194,010	194,010	155,208	155,208	155,208	155,208	116,406	116,406	77,604	77,604	38,802
Cooking Appliances	145,805	145,805	127,580	127,580	109,354	109,354	109,354	109,354	91,128	91,128	91,128	91,128	91,128	72,903	72,903	72,903	54,677	54,677	36,451	18,226
New Construction	38,810	42,338	45,866	49,394	49,394	52,922	52,922	52,922	52,922	52,922	52,922	52,922	52,922	52,922	52,922	52,922	52,922	52,922	52,922	52,922
INDUSTRIAL																				
Retrofit	711,883	808,958	517,733	453,016	453,016	388,300	388,300	323,583	323,583	258,866	258,866	258,866	194,150	194,150	194,150	194,150	194,150	129,433	129,433	64,717
Replacement	178,814	178,814	178,814	178,814	178,814	178,814	178,814	178,814	178,814	178,814	178,814	178,814	178,814	178,814	178,814	178,814	178,814	178,814	178,814	178,814
Residential Total	999,903	1,017,127	1,051,575	1,120,472	456,007	570,834	656,955	714,369	714,369	714,369	714,369	714,369	714,369	714,369	714,369	714,369	714,369	714,369	714,369	714,369
Commercial Total	1,250,648	1,436,985	908,270	911,798	805,967	809,496	721,891	721,891	703,665	703,665	703,665	616,060	616,060	597,835	597,835	510,230	492,004	404,399	386,173	280,343
Industrial Total	890,697	987,772	696,547	631,830	631,830	567,114	567,114	502,397	502,397	437,680	437,680	437,680	372,964	372,964	372,964	372,964	372,964	308,247	308,247	243,530
Total	**3,141,248**	**3,441,884**	**2,656,392**	**2,664,100**	**1,893,804**	**1,947,443**	**1,945,959**	**1,938,656**	**1,920,430**	**1,855,714**	**1,855,714**	**1,768,109**	**1,703,392**	**1,685,167**	**1,685,167**	**1,597,562**	**1,579,336**	**1,427,015**	**1,408,789**	**1,238,242**

Codes and Standards	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
RESIDENTIAL	372,194	938,076	1,088,382	1,087,498	1,087,498	1,087,498	1,087,498	1,087,498	1,087,498	1,087,498	1,087,498	1,087,498	1,087,498	1,087,498	1,087,498	1,087,498	1,087,498	1,087,498	1,087,498	1,087,498
Commercial	80,237	153,732	170,866	159,631	145,141	148,144	160,500	182,305	176,646	199,322	212,882	240,600	226,655	255,365	270,162	305,202	280,260	316,400	332,947	365,737
All DSM	**3,593,679**	**4,533,692**	**3,915,640**	**3,911,229**	**3,126,443**	**3,183,085**	**3,193,957**	**3,208,458**	**3,184,574**	**3,142,534**	**3,156,094**	**3,096,206**	**3,017,545**	**3,028,029**	**3,042,827**	**2,990,262**	**2,947,094**	**2,830,912**	**2,829,233**	**2,691,476**

Washington DSM Deployment Scenario Incremental Annual Savings - THERMS

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Residential																				
New Construction	16,386	17,556	18,727	21,068	23,409	23,409	23,409	117,043	117,043	117,043	117,043	117,043	117,043	117,043	117,043	117,043	117,043	117,043	117,043	117,043
Retrofit	4,579	4,579	4,579	4,579	4,579	4,579	4 579	4,579	4,579	4,579	4,579	4,579	4,579	4,579	4,579	4,579	4,579	4,579	4,579	4,579
Replace DHW	44,100	44,100	44,100	44,100	35,280	35,280	26,460	26,460	22 050	22,050	17,640	17,640	13,230	13,230	8,820	8,820	4,410	4,410	4,410	4,410
Replace equipment	5,526	6,217	6,908	6,217	5,526	4,836	4,145	4,145	4,145	3,454	3,454	2,763	2,763	2,072	2,072	1,382	1,382	691	691	691
Appliances, new & replace	2,952	2,952	2,952	2,952	2,952	2,952	2,952	2,952	2,952	2,952	2,952	2,952	2,952	2,952	2,952	2,952	2,952	2,952	2,952	2,952
Commercial																				
Replace Equip	31,417	31,417	29,569	29,569	27,721	27,721	22,177	22,177	18,481	18,481	14,785	14,785	14,785	14,785	14,785	11,088	11,088	7,392	3,696	3,696
Replace Shell	27,386	27,386	25,775	25,775	24,165	24,165	19,332	19,332	16,110	16,110	12,888	12,888	12,888	12,888	12,888	9 666	9,666	6,444	3,222	3,222
Retrofit Wx	19,324	19,324	18,187	18,187	17,050	17,050	13,640	13,640	11,367	11,367	9,093	9,093	9,093	9 093	9,093	6,820	6,820	4,547	2,273	2,273
Retrofit Equip	31,524	31,524	29,669	29 669	27,815	27,815	22,252	22,252	18,543	18,543	14,835	14,835	14,835	14,835	14,835	11,126	11,126	7,417	3,709	3,709
Cooking Appliances	1,788	1,788	1,788	1,788	1,788	1,788	1,788	1,788	1,788	1,788	1,788	1,788	1,788	1,788	1,788	1,788	1,788	1,788	1,788	1,788
Commercial New	9,010	9,829	10 648	11,468	11,468	12,287	12 287	12,287	12,287	12,287	12,287	12 287	12,287	12,287	12,287	12,287	12,287	12 287	12,287	12,287
New Constr	9,010	9,829	10,648	11,468	11,468	12,287	12,287	12,287	12,287	12,287	12,287	12,287	12,287	12,287	12,287	12,287	12,287	12,287	12,287	12,287
Industrial																				
Retrofit	16,094	18,106	20,117	22,129	24,141	24,141	24,141	24,141	24,141	24,141	24,141	24,141	24,141	24,141	24,141	20,117	16 094	8,047	8,047	8 047
Replacement	7,836	8,706	9,577	10,447	11,318	12,189	13,059	13,059	13,059	13 059	13,059	13,059	13,059	13,059	13,059	13 059	13,059	13,059	13,059	13,059
Residential Total	127,748	130,300	132,852	133,811	117,131	115,749	96,727	190,362	181,542	180,160	171,340	169,959	161,139	159,757	150,937	149,556	140,736	139,354	139,354	139,354
Commercial Total	129,459	131,097	126,285	127,923	121,473	123,111	103,761	103,761	90,861	90,861	77,961	77,961	77,961	77,961	77,961	65,061	65,061	52,161	39,261	39,261
Industrial Total	23,930	26 812	29,694	32,577	35,459	36,330	37,200	37,200	37,200	37,200	37,200	37,200	37,200	37,200	37,200	33,177	29,153	21,106	21,106	21,106
All DSM	**281,136**	**288,209**	**288,831**	**294,311**	**274,063**	**275,190**	**237,689**	**331,324**	**309,604**	**308,222**	**286,502**	**285,120**	**276,300**	**274,919**	**266,099**	**247,793**	**234,950**	**212,621**	**199,721**	**199,721**

Appendix 4: Detailed Measure Description

Table 1: Detailed Measure Table, Residential Sector, Gas Savings, and 2032 Technical Potential

Measure Description	Program	Average Lifetime	Total Incremental Cost ($)	Total O&M Impact ($)	Gas Savings (Therms)	Level Cost ($/therm)	BCR
Low Flow Showerhead	Replace GasDHW	15	4,881,156	-74,270,571	4,240,120	($1.598)	100.00
Gas 2.20 MEF Washer	New Appl	14	5,058,467	-9,213,662	124,895	($0.611)	100.00
Gas 2.20 MEF Washer	ReplaceAppl	14	23,033,983	-41,954,874	442,334	($0.540)	100.00
Gas ETO Dishwasher	New Appl	12	2,392,903	-4,202,713	36,150	($0.430)	100.00
Gas ETO Dishwasher	ReplaceAppl	12	6,347,577	-11,148,402	74,584	($0.419)	100.00
Gas 2.46 MEF Washer	ReplaceAppl	14	47,189,994	-46,901,117	565,384	$0.006	1.51
Gas 2.46 MEF Washer	New Appl	14	22,561,657	-22,423,544	322,309	$0.007	1.46
Gas Hearth	Replace GasDHW	20	326,341	0	767,861	$0.035	15.36
Windows, replacement (U=.30)	Retro Gas	45	5,497,730	0	1,999,024	$0.159	3.46
Windows, replacement (U=.25)	Retro Gas	45	17,962,182	0	3,646,516	$0.285	1.93
NW Energy Star BOP Ducts Inside	New Gas	35	62,680,876	0	3,569,225	$0.370	1.48
AFUE 92 to condensing combo hydrocoil, Z A	New GasEquip	25	598,370	0	103,717	$0.418	1.29
NW Energy Star BOP Equip Upg	New Gas	25	169,224,943	0	11,134,457	$0.466	1.16
MH Duct Sealing, Z A	Retro Gas	20	372,230	0	39,303	$0.773	0.69
Wx insulation (ceiling, floor), Z A	Retro Gas	45	1,206,535	0	90,324	$0.774	0.71
HRV, Z A	Retro Gas	18	20,331,023	8,163,491	2,942,373	$0.841	0.63
Near Net Zero	New Gas	45	3,745,822	0	247,746	$0.853	0.65
Wx SF Ceiling Insulation, Zone A	Retro Gas	45	17,066,582	0	1,121,162	$0.882	0.62
Energy Star 0.67 EF	New GasDHW	12	1,397,755	0	176,140	$0.905	0.55
Energy Star 0.67 EF	Replace GasDHW	12	6,749,445	0	850,540	$0.905	0.55
NW Energy Star BOP Env Upg	New Gas	35	62,063,463	0	1,455,684	$0.928	0.59
MF Corridor Ventilation	New Gas	15	3,207,656	0	324,494	$0.965	0.54
MF Corridor Ventilation	Retro Gas	15	14,818,265	0	1,499,051	$0.965	0.54
Energy Star 0.67 EF after 2015	Replace GasDHW	12	23,644,542	0	2,591,183	$1.041	0.48
Energy Star 0.67 EF after 2015	New GasDHW	12	8,191,862	0	897,738	$1.041	0.48
Tankless Gas	New GasDHW	15	1,242,922	0	113,292	$1.071	0.47
Tankless Gas after 2015	New GasDHW	15	9,938,843	0	808,440	$1.200	0.42
AFUE 95 Furnace, Z A	Replace GasEquip	25	25,065,695	2,786,682	1,671,046	$1.206	0.45
Wx SF Wall Insulation, Zone A	Retro Gas	45	22,245,284	0	907,608	$1.420	0.39
Condensing Tankless	New GasDHW	15	1,278,435	0	85,831	$1.454	0.35
Wx SF Duct Sealing, Z A	Retro Gas	20	3,992,926	0	215,834	$1.510	0.35
Condensing Tankless Gas after 2015	New GasDHW	15	11,664,411	0	695,254	$1.638	0.31
Wx SF Floor Insulation, Zone A	Retro Gas	45	24,914,718	0	872,015	$1.655	0.33
Wx Air Sealing, Z A	Retro Gas	20	5,381,878	0	233,215	$1.883	0.28
Windows, retrofit (U=.25)	Retro Gas	45	167,565,079	0	4,595,254	$2.112	0.26
Windows, retrofit (U=.30)	Retro Gas	45	116,692,479	0	2,554,516	$2.646	0.21
Solar DHW (50 gal) - gas backup	New GasDHW	20	5,953,567	0	169,944	$2.859	0.17
Solar DHW - gas	Replace GasDHW	20	5,552,175	0	158,485	$2.859	0.17

Measure Description	Program	Average Lifetime	Total Incremental Cost ($)	Total O&M Impact ($)	Gas Savings (Therms)	Level Cost ($/therm)	BCR
Solar DHW - Gas after 2015	New GasDHW	20	55,562,491	0	1,424,353	$3.183	0.16
Solar DHW - gas afer 2015	Replace GasDHW	20	32,484,678	0	832,741	$3.184	0.16
Condensing Tankless	Replace GasDHW	15	13,328,338	0	397,704	$3.273	0.15
Tankless Gas	Replace GasDHW	15	25,737,466	0	756,276	$3.323	0.15
HRV, E*	New Gas	18	17,253,494	0	432,346	$3.467	0.15
Condensing Tankless after 2015	Replace GasDHW	15	69,408,585	0	1,750,303	$3.872	0.13
Tankless Gas after 2015	Replace GasDHW	15	146,622,389	0	3,466,473	$4.130	0.12

Table 2: Detailed Measure Table, Commercial Sector, Gas Savings, 2032 Technical Potential

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost ($)	Total O&M ($)	Gas Impacts (kTherms)	Levelized Cost ($/therm)	BCR
Estar Commercial Clothes Washer	Install high performance commercial clothes washers - coin op	Replace	Water Heat	10	469,179	-4,256,021	19	($7.1456)	9.64
Estar Commercial Clothes Washer	Install high performance commercial clothes washers - coin op	New	Water Heat	10	50,931	-367,793	7	($3.6797)	8.07
EStar Steam Cooker	Replace with EStar in place of conventional	Replace	Cooking	10	130,322	-331,484	17	($1.5488)	3.04
EStar Steam Cooker	Install EStar in place of conventional	New	Cooking	10	79,145	-201,062	10	($1.5335)	3.04
Efficient Estar Dishwasher	Install EStar in place of conventional	New	Water Heat	12	928,338	-4,590,636	429	($0.3306)	10.91
Efficient Estar Dishwasher	Retrofit with EStar in place of conventional	Retrofit	Water Heat	12	655,621	-3,242,052	303	($0.3306)	10.91
DHW Wrap	Insulate the surface of the storage water heater or an unfired storage tank to R-5 to reduce standby losses.	Retrofit	Water Heat	7	24,077		154	$0.0273	18.57
Estar Convection Oven	Replace with EStar in place of conventional	Replace	Cooking	12	128,829		231	$0.0638	7.84
Roof Insulation - Attic R0-30	Roof Insulation - Attic R0-30. Application: Buildings with uninsulated attics	Retrofit	Heating	45	614,465		268	$0.0825	6.68

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost ($)	Total O&M ($)	Gas Impacts (kTherms)	Levelized Cost ($/therm)	BCR
EStar Fryer	Install EStar in place of conventional	New	Cooking	8	390,327		565	$0.1077	4.68
HW Boiler Tune	Tune up in accordance with Minneapolis Energy Office protocol. Can include derating the burner, adjusting the secondary air, adding flue restrictors, cleaning the fire-side of the heat exchanger, cleaning the water side, or installing turbulators. Other modifications may include uprating the burner to reduce oxygen or derating the burner to reduce stack temperature. Note: In gas systems, excess air and stack temperatures are often within reasonable ranges, so the technical potential for this measure is limited. Combining this measure with the vent damper and power burner measures increases both applicability and cost effectiveness, and was assumed for this analysis.	Retrofit	Heating	5	10,117		22	$0.1078	4.84
Roof Insulation - Rigid R0-11	Roof Insulation - Rigid R0-11-not including re-roofing costs but including deck preparation. Application: Old buildings with flat roofs and no attics	Replace	Heating	45	3,035,273		763	$0.1249	4.41
DHW Shower Heads	Install low flow shower heads (2.0 gallons per minute) to replace 3.4 GPM shower heads.	Retrofit	Water Heat	8	93,276		114	$0.1276	3.95

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost ($)	Total O&M ($)	Gas Impacts (kTherms)	Levelized Cost ($/therm)	BCR
Hot Water Temperature Reset	Controller automatically resets the delivery temperature in a hot water radiant system based on outside air temperature. The reset reduces the on-time of the heating equipment and the occurrence of simultaneous heating and cooling through instantaneous adjustments.	Retrofit	Heating	10	1,184,393		1,117	$0.1386	3.76
DHW Condensing Tankless (repl)	Costs and savings are incremental over a Code-rated tank (combustion efficiency of 80%) for a condensing tank with a minimum combustion efficiency of 94% and an R-16 tank wrap.	Replace	Water Heat	15	3,991,752		2,414	$0.1615	3.11
Wall Insulation - Blown R11	Wall Insulation - Blown R11. Application: Old buildings	Retrofit	Heating	45	6,781,587		1,929	$0.1684	3.27
Roof Insulation - Rigid R0-22	Roof Insulation - Rigid R0-22-- not including re-roofing costs but including deck preparation and ~4" rigid.. Application: Old buildings with flat roofs and no attics	Replace	Heating	45	5,242,744		866	$0.1906	2.89

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost ($)	Total O&M ($)	Gas Impacts (kTherms)	Levelized Cost ($/therm)	BCR
Steam Balance	Single-pipe steam systems are notorious for uneven heating, which wastes energy because the thermostat must be set to heat the coldest spaces and overheating other spaces. Steam balances corrects these problems by: 1) Adding air venting on the main line or at the radiators; 2) Adding boiler cycle controls; 3) Adding or subtracting radiators. Energy savings accrue from lowering the overall building temperature.	Retrofit	Heating	15	1,006,682		460	$0.2137	2.45
Wall Insulation - Spray On for Metal Buildings	Wall Insulation - Spray On for Metal Buildings (Cellulose) Unfinished. Application: Old buildings	Retrofit	Heating	45	585,393		154	$0.2274	2.42
Estar Convection Oven	Install EStar in place of conventional	New	Cooking	12	328,133		161	$0.2333	2.14
DHW Condensing Tank (new)	Costs and savings are incremental over a Code-rated tank (combustion efficiency of 80%) for a condensing tank with a minimum combustion efficiency of 94% and an R-16 tank wrap.	New	Water Heat	15	1,989,832		775	$0.2508	2.00
Windows - Add Low E to Vinyl Tint	Windows - Add Low E to Vinyl Tint. Application: Old buildings	Replace	Heating	20	3,527,778		334	$0.2618	2.03
Roof Insulation - Blanket R0-19	Roof Insulation - Blanket R0-19. Application: Buildings with open truss unfinished interior	Retrofit	Heating	45	900,322		192	$0.2671	2.06

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost ($)	Total O&M ($)	Gas Impacts (kTherms)	Levelized Cost ($/therm)	BCR
Roof Insulation - Rigid R11-22	Roof Insulation - Rigid R11-22 2" rigid added to an existing foam roof insulation at re-roof, includes some surface prep. Application: Old buildings with flat roofs, no attics, and some insulation	Replace	Heating	45	9,917,116		1,439	$0.2676	2.06
DCV	Applicable to single zone packaged systems with large make -up air fractions either because of intermittent occupancy or because of code requirements. In most cases the outdoor air is reset to 5% or less with CO2 build-up modulating ventilation.	Retrofit	Heating	10	9,662,491		1,032	$0.2812	1.85
Roof Insulation - Blanket R0-30	Roof Insulation - Blanket R0-30. Application: Buildings with open truss unfinished interior	Retrofit	Heating	45	1,012,863		201	$0.2862	1.92
Ducts	Duct retrofit of both insulation and air sealing	Retrofit	Heating	15	3,179,785		313	$0.3061	1.71
EStar Fryer	Replace with EStar in place of conventional	Replace	Cooking	8	2,236,760		1,082	$0.3225	1.56
DHW Condensing Tankless (new)	Costs and savings are incremental over a Code-rated tank (combustion efficiency of 80%) for a condensing tank with a minimum combustion efficiency of 94% and an R-16 tank wrap.	New	Water Heat	15	2,467,392		685	$0.3519	1.43

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost ($)	Total O&M ($)	Gas Impacts (kTherms)	Levelized Cost ($/therm)	BCR
DHW Condensing Tank (repl)	Costs and savings are incremental over a Code-rated tank (combustion efficiency of 80%) for a condensing tank with a minimum combustion efficiency of 94% and an R-16 tank wrap.	Replace	Water Heat	15	3,227,410		881	$0.3575	1.41
Ozone Laundry Treatment	Ozone treatment allows use of cold water	Retrofit	Water Heat	10	379,980	-83,812	108	$0.3593	1.31
Windows - Add Low E and Argon to Vinyl Tint	Windows - Add Low E and Argon to Vinyl Tint. Application: Old buildings	Replace	Heating	20	5,517,127		461	$0.3647	1.46

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost ($)	Total O&M ($)	Gas Impacts (kTherms)	Levelized Cost ($/therm)	BCR
Roof Insulation - Attic 11-30	Roof Insulation - Attic 11-30. Application: Buildings with partially insulated attics	Retrofit	Heating	45	3,791,959		463	$0.3649	1.51
Hot Food Holding Cabinet	Install EStar in place of conventional	New	Cooking	8	741,621		294	$0.3939	1.28
DestratificationFan	Destrat fan reduces heat load	Retrofit	Heating	12	4,160,485		1,193	$0.3981	1.31
Hot Food Holding Cabinet	Install EStar in place of conventional	Replace	Cooking	8	1,453,032		564	$0.4017	1.26
Vent Damper	Install vent damper downstream of the draft relief to prevent airflow up the stack, while allowing warm air from the boiler to spill into the conditioned space as heat or into the boiler room to reduce jacket losses. This measure is most cost-effective when combined with the boiler tune up and power burner measures.	Retrofit	Heating	12	474,045		125	$0.4321	1.20
Windows - Tinted AL Code to Class 40	Windows - Tinted AL Code to Class 40. Application: New Construction	New	Heating	20	1,663,246		96	$0.4516	1.12
EStar Griddle	Install EStar in place of conventional	New	Cooking	12	426,581		105	$0.4621	1.08

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost ($)	Total O&M ($)	Gas Impacts (kTherms)	Levelized Cost ($/therm)	BCR
Combo Hieff Boiler (new)	Replace existing boiler with unit meeting OR Code requirements of 80% combustion efficiency.	New	Heating	20	769,967		131	$0.4792	1.07
DHW Hieff Boiler (new)	Replace existing boiler with unit meeting OR Code requirements of 80% combustion efficiency.	New	Water Heat	20	1,659,089		278	$0.4875	1.05
Combo Hieff Boiler (repl)	Replace existing boiler with unit meeting OR Code requirements of 80% combustion efficiency.	Replace	Heating	20	2,518,769		417	$0.4930	1.08
EStar Griddle	Replace with EStar in place of conventional	Replace	Cooking	12	608,152		137	$0.5064	0.99
Windows - Tinted AL Code to Class 40	Windows - Tinted AL Code to Class 40. Application: Old buildings	Replace	Heating	20	2,521,565		92	$0.5077	1.05
Roof Insulation - Roofcut 0-22	Roof Insulation - Roofcut 0-22. Application: Buildings with uninsulated flat roofs at reroofing time	Replace	Heating	45	8,710		1	$0.5735	0.96
SPC Hieff Boiler Replace	Install near condensing boiler. Assumed seasonal combustion efficiency of 85% over base of 80%	Replace	Heating	20	1,320,560		168	$0.6426	0.83
DHW Cond Boiler (new)	Replace with boiler using condensing or pulse technology to achieve steady-state combustion efficiencies of 89% to 94% (this analysis used 92% efficiency for savings calculations).	New	Water Heat	20	5,075,857		616	$0.6727	0.76

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost ($)	Total O&M ($)	Gas Impacts (kTherms)	Levelized Cost ($/therm)	BCR
DHW Faucets	Add aerators to existing faucets to reduce flow from 2.2 gallons per minute to 1.5 GPM.	New	Water Heat	8	40,302		9	$0.7321	0.69
DHW Recirc Controls	Install electronic controller to hot water boiler system that turns off the boiler and circulation pump when the hot water demand is reduced (usually in residential type occupancies) or can be reset to meet the hot water load. (Steel boilers also require a mixing valve to prevent water temperatures from dropping below required levels).	Retrofit	Water Heat	10	798,946		142	$0.7347	0.68
DHW Faucets	Add aerators to existing faucets to reduce flow from 2.2 gallons per minute to 1.5 GPM.	Retrofit	Water Heat	8	36,333		8	$0.7458	0.68

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost ($)	Total O&M ($)	Gas Impacts (kTherms)	Levelized Cost ($/therm)	BCR
Cond Furnace (new)	Condensing / pulse package or residential-type furnace with a minimum AFUE of 92%. Base case: AFUE 80	New	Heating	18	3,205,091		365	$0.7631	0.66
DHW Hieff Boiler (repl)	Replace existing boiler with unit meeting OR Code requirements of 80% combustion efficiency.	Replace	Water Heat	20	2,272,460		226	$0.8201	0.65
Combo Cond Boiler (new)	Replace with boiler using condensing or pulse technology to achieve steady-state combustion efficiencies of 89% to 94% (this analysis used 92% efficiency for savings calculations).	New	Heating	20	3,030,655		291	$0.8507	0.60
SPC Cond Boiler Replace	Install condensing boiler. Assumed seasonal combustion efficiency of 92% over base of 80%	Replace	Heating	20	4,894,787		450	$0.8873	0.60
Combo Cond Boiler (repl)	Replace with boiler using condensing or pulse technology to achieve steady-state combustion efficiencies of 89% to 94% (this analysis used 92% efficiency for savings calculations).	Replace	Heating	20	10,057,535		925	$0.8878	0.60
Power burner	Replace standard burner with a power burner to optimize combustion and reduce standby losses in the stack. Note: Costs and savings assume that this measure will be performed in conjunction with a boiler tune up when appropriate.	Retrofit	Heating	12	10,190,449		1,292	$0.9002	0.58
DHW Pipe Ins	Add 1" insulation to pipes used for steam or hydronic	New	Water Heat	15	412,525		44	$0.9191	0.55

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost ($)	Total O&M ($)	Gas Impacts (kTherms)	Levelized Cost ($/therm)	BCR
	distribution; particularly effective when pipes run through unheated spaces.								
Waste Water Heat Exchanger	Install HX on waste water	New	Water Heat	15	1,942,808		206	$0.9191	0.55
Windows - Tinted AL Code to Class 36	Windows - Tinted AL Code to Class 36. Application: New Construction	New	Heating	20	4,158,116		153	$0.9435	0.54
Roof Insulation - Rigid R11-33	Roof Insulation - Rigid R11-33: add 4' of insulation at reroof. Application: Old buildings with flat roofs, no attics, and some insulation	Replace	Heating	45	14,875,673		446	$0.9643	0.57
Windows - Tinted AL Code to Class 36	Windows - Tinted AL Code to Class 36. Application: Old buildings	Replace	Heating	20	6,303,914		159	$1.0610	0.50
SPC Cond Boiler (new)	Install condensing boiler. Assumed seasonal combustion efficiency of 88% over base of 75%	New	Heating	20	17,583,678		1,224	$1.1727	0.43
Windows - Add Argon to Vinyl Lowe	Windows - Add Argon to Vinyl Lowe. Application: Old buildings	Replace	Heating	20	7,845,826		510	$1.3020	0.41

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost ($)	Total O&M ($)	Gas Impacts (kTherms)	Levelized Cost ($/therm)	BCR
Rooftop Condensing Burner	Install condensing burner	New	Heating	10	15,004,953		742	$1.3302	0.39
Waste Water Heat Exchanger	Install HX on waste water	Retrofit	Water Heat	15	317,666		23	$1.3340	0.38
DHW Cond Boiler (repl)	Replace with boiler using condensing or pulse technology to achieve steady-state combustion efficiencies of 89% to 94% (this analysis used 92% efficiency for savings calculations).	Replace	Water Heat	20	8,211,654		501	$1.3365	0.40
DDC HVAC controls	Control set up and algorithm. This assumes the development of an open source control package aimed at describing scheduling and control points throughout the HVAC system, properly training operators so that scheduling can be maintained and adjusted as needed, and providing operator back up so that temperature reset, pressure reset, and minimum damper settings are set at optimum levels for the current occupancy.	New	Heating	5	24,663,193		2,695	$1.3392	0.37
Cond Unit Heater from Nat draft (replace)	Install condensing power draft units (90% seas. Eff) in place of natural draft (80% seas. Eff)	Replace	Heating	18	18,405,270		1,064	$1.5029	0.35
Computerized Water Heater Control	Install intelligent controls on the hot water circulation loops.	New	Water Heat	15	836,567		51	$1.5992	0.31

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost ($)	Total O&M ($)	Gas Impacts (kTherms)	Levelized Cost ($/therm)	BCR
Computerized Water Heater Control	Install intelligent controls on the hot water circulation loops.	Retrofit	Water Heat	15	1,114,954		65	$1.6779	0.30
Steam Trap Maintenance	Set up a in-house steam trap maintenance program with equipment, training, and trap replacement. An alternative procedure is to just pay for an outside contractor to conduct a steam survey.	Retrofit	Heating	10	1,468,427	5,651,625	519	$1.7928	0.29
Windows - Non-Tinted AL Code to Class 40	Windows - Non-Tinted AL Code to Class 40. Application: New Construction	New	Heating	20	5,433,614		255	$1.8022	0.28
Roof Insulation - Blanket R11-41	Roof Insulation - Blanket R11-41. Application: Buildings with open truss unfinished interior	Retrofit	Heating	45	2,532,156		79	$1.8256	0.30
Roof Insulation - Blanket R11-30	Roof Insulation - Blanket R11-30. Application: Buildings with open truss unfinished interior	Retrofit	Heating	45	2,250,806		65	$1.9386	0.28
Windows - Non-Tinted AL Code to Class 40	Windows - Non-Tinted AL Code to Class 40. Application: Old buildings	Replace	Heating	20	8,167,046		327	$2.0662	0.26
Windows - Non-Tinted AL Code to Class 36	Windows - Non-Tinted AL Code to Class 36. Application: New Construction	New	Heating	20	10,937,965		389	$2.3723	0.21

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost ($)	Total O&M ($)	Gas Impacts (kTherms)	Levelized Cost ($/therm)	BCR
Cond Furnace (repl)	Condensing / pulse package or residential-type furnace with a minimum AFUE of 92%.	Replace	Heating	18	22,750,568		709	$2.7899	0.19
Warm Up Control	This measure is designed to implement a shut down of outside air when the building is coming off night setback. Usually the capability for this is available in a commercial t-stat but either the extra control wire is not attached or the unit itself has not been set up to receive the signal. Cost is based on labor cost to enable this ability in existing controllers	Retrofit	Heating	10	9,184,113		398	$3.0185	0.17
Windows - Non-Tinted AL Code to Class 36	Windows - Non-Tinted AL Code to Class 36. Application: Old buildings	Replace	Heating	20	20,417,616		501	$3.3586	0.16
Windows - Non-Tinted AL Code to Class 45	Windows - Non-Tinted AL Code to Class 45. Application: Old buildings	Replace	Heating	20	5,431,086		119	$3.7902	0.14
HVAC System Commissioning	HVAC system commissioning. Includes testing and balancing, damper settings, economizer settings, and proper HVAC heating and compressor control installation. This measure includes the proper set-up of single zone package equipment in simple HVAC systems. The majority of the Commercial area is served by this	New	Heating	7	89,216,398		1,752	$5.1499	0.10

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost ($)	Total O&M ($)	Gas Impacts (kTherms)	Levelized Cost ($/therm)	BCR
	technology. Work done in Eugene (Davis, et al, 2002) suggests higher savings than the other documented commissioning on more complex systems.								
Solar Hot Water	Install solar water heaters on large use facility such as multifamily or lodging	New	Water Heat	15	7,362,902	575,776	106	$7.2914	0.07
Solar Hot Water	Install solar water heaters on large use facility such as multifamily or lodging	Retrofit	Water Heat	15	9,839,581	675,964	137	$7.4802	0.07
Cond Unit Heater from power draft (replace)	Install condensing power draft units (90% seas. Eff) in place of power draft (80% seas. Eff)	Replace	Heating	18	660,459,793		709	$80.8964	0.01
Windows - Tinted AL Code to Class 45	Windows - Tinted AL Code to Class 45. Application: Old buildings	Replace	Heating	20	570,796,700		18	$148.9149	0.00
Heat Reclaim	Large Grocery - Heat recovery to space heating. Assumes floating head control exists and must be changed to allow HR.	New	Refrigeration	18	1,902,154		293	$0.1546	3.26
Heat Reclaim	Large Grocery - Heat recovery to space heating. Assumes floating head control exists and must be changed to allow HR.	Retrofit	Refrigeration	18				na	na
Heat Reclaim	Large Grocery - Heat recovery to space heating. Assumes floating head control exists and must be changed to allow HR.	Replace	Refrigeration	18	4,411,709		638	$0.1714	2.94

Table 3: Detailed Measure Description, Industrial Natural Gas Technical Potential

Conservation Measure	Potential Savings (therm/yr)	Annual O&M Cost ($)	Levelized Cost ($/therm)	Initial Cost (k$)	BCR
Chiller heat recovery (Electronics)	63,526	$0	$1.229	$800	0.41
Combo Cond Boiler (repl)	815,993	$0	$0.637	$6,373	0.80
Combo Cond Boiler (retro)	0	$0	$1.714	$0	na
Combo Hieff Boiler (repl)	417,947	$0	$0.347	$1,775	1.46
Combo Hieff Boiler (retro)	0	$0	$1.804	$0	na
Cond Furnace (repl)	904,616	$0	$2.776	$25,716	0.18
Cond Unit Heater from Nat draft (replace)	0	$0	$1.066	$0	na
Cond Unit Heater from power draft (replace)	320,403	$0	$2.157	$7,953	0.23
Heat Recovery to HW	1,877,447	($252,385)	$0.157	$5,609	1.75
DHW Cond Boiler (repl)	448,631	$0	$0.158	$868	3.22
DHW Cond Boiler (retro)	0	$0	$0.495	$0	na
DHW Condensing Tank (repl)	365,731	$0	$0.026	$97	19.32
DHW Condensing Tank (retro)	0	$0	$0.116	$0	na
DHW Hieff Boiler (repl)	229,786	$0	$0.049	$139	10.28
DHW Hieff Boiler (retro)	0	$0	$0.386	$0	na
DHW Pipe Ins	52,213	$0	$0.020	$11	25.15
DHW Std. Boiler (retro)	7,735	$0	$0.232	$22	2.19
DHW Wrap	23,206	$0	$0.001	$0	100.00
Ducts	1,428,697	$0	$3.092	$45,233	0.16
Hi Eff Unit Heater (replace)	865,954	$0	$0.343	$3,417	1.47
Hi Eff Unit Heater (retro)	0	$0	$2.087	$0	na
HiEff Clothes Washer (retro)	5,515	($67,026)	($11.387)	$43	2.05
HiEff Clothes Washer (repl)	5,515	($67,026)	($11.387)	$43	2.05
Hot Water Temperature Reset	1,828,424	$0	$0.194	$2,709	2.56
HW Boiler Tune	1,005,623	$0	$0.179	$774	2.78
Power burner	1,482,288	$0	$1.153	$14,972	0.43
Process Boiler Controls	157,241	$0	$0.002	$2	326.50
Process Boiler Insulation	1,053,674	$1,289	$0.009	$81	67.27
Process Boiler Load Control	526,837	$0	$0.002	$10	282.97
Process Boiler Maintenance	263,419	$137	$0.001	$0	100.00
Process Boiler Steam Trap Maintenance	856,110	$31,101	$0.036	$0	100.00
Process Boiler Water Treatment	131,709	$0	$0.001	$1	606.36
Roof Insulation - Blanket R0-19	461,314	$0	$0.350	$2,426	1.48
Roof Insulation - Blanket R0-30	484,002	$0	$0.375	$2,730	1.38
Roof Insulation - Blanket R11-30	168,056	$0	$2.562	$6,470	0.20
Roof Insulation - Blanket R11-41	201,668	$0	$2.402	$7,279	0.22
Roof Insulation - Rigid R11-22 repl	454,559	$0	$0.908	$6,200	0.57
Roof Insulation - Rigid R11-33 repl	224,187	$0	$2.761	$9,301	0.19
Solar Hot Water	57,990	$0	$4.697	$3,337	0.11
SPC Cond Boiler Replace	473,441	$0	$1.111	$6,443	0.46
SPC Cond Boiler Retro	0	$0	$2.357	$0	na

Conservation Measure	Potential Savings (therm/yr)	Annual O&M Cost ($)	Levelized Cost ($/therm)	Initial Cost (k$)	BCR
SPC Hieff Boiler Replace	273,743	$0	$0.712	$2,388	0.71
SPC Hieff Boiler Retro	0	$0	$2.490	$0	na
Steam Balance (Wood Prod)	47,373	$0	$0.374	$182	1.33
Steam Trap Maint (Wood Prod)	58,559	$0	$0.648	$290	0.77
Upgrade Process Heat	202,613	($68,804)	$1.007	$2,031	0.54
Vent Damper	897,807	($68,804)	$0.482	$3,768	1.05
Wall Insulation - Blown R11	308,492	$0	$0.254	$1,175	2.05
Wall Insulation - Spray On for Metal Buildings	338,707	$0	$0.282	$1,437	1.84
Waste Water Heat Exchanger	56,597	$0	$0.700	$486	0.72
Ozone Treated Laundry	0	$0	$0.179	$0	na

NORTHWEST NATURAL GAS COMPANY
WN U-6 Eighth Revision of Sheet G.1
Cancels Seventh Revision of Sheet G.1

SCHEDULE G
ENERGY EFFICIENCY SERVICES AND PROGRAMS – RESIDENTIAL AND COMMERCIAL

APPLICABLE:
This program is intended to provide an economical and effective means for conserving Natural Gas through reduced heat loss and improved efficiencies in Residential dwellings and Commercial buildings.

AVAILABLE:
To all Residential Customers served on Rate Schedules 1, 2 and 27; and all Commercial Firm and Interruptible Sales Customers served on Rate Schedules 3, 41 and 42 in all territory served by the Company under the Tariff of which this program is a part.

DESCRIPTION:
The Energy Trust of Oregon (Energy Trust) will deliver and administer a cost-effective energy efficiency program to NW Natural's Residential and Commercial Firm Sales and Interruptible Sales Customers in accordance with the Company's Energy Efficiency Plan, revised on November 29, 2012 (EE Plan). Energy Trust administered programs will offer applicable Customers incentive dollars for installing specific, cost-effective energy efficient measures, including rebates for energy efficient retrofit or replacement appliances. Program offerings may vary from time-to-time. Current offerings are described on the following Company webpage:
https://www.nwnatural.com/Residential/Conserve/EnergyTrustOfOregonServicesAndIncentives

OVERSIGHT
Oversight of these programs will be provided by the Energy Efficiency Advisory Group (EEAG), which is a group comprised of interested parties to the Company's 2008 general rate case. EEAG oversight is required per the stipulated agreement attached to Commission Order No. 04 to the Company's rate case, docketed as UG-080546. The Company will consult with the EEAG prior to making any significant program changes such as changing an incentive amount or adding program measures.

REPORTING
Energy Trust will provide the EEAG and WUTC with Quarterly and an Annual Reports demonstrating total program costs, therms saved and levelized costs of measures offered. Reporting will be consistent with the Company's EE Plan.

COST-EFFECTIVE STANDARD
The portfolio of programs offered through the Energy Trust will be deemed cost-effective if the program meets the following Benefit Cost Ratio (BCR) tests: 1) Total Resource Cost (TRC) test; and 2) the Utility Cost (UC) test. The program is cost-effective when the end value for each of the following test is greater than one (1):

1) Total Resource Cost (TRC) looks at the total benefits attributable to the program divided by the total program costs. A TRC value equal to or greater than one means the benefits are equal to or exceed the costs, and the program is cost-effective.

   TRC is expressed formulaically as follows:
   TRC = Present Value of Benefits / Present Value of Costs

(continue to Sheet G.2)

Issued November 29, 2012
NWN Advice No. WUTC 12-8

Effective with service on and after January 1, 2013

SCHEDULE G
ENERGY EFFICIENCY SERVICES AND PROGRAMS – RESIDENTIAL AND COMMERCIAL

The Present Value of Benefits includes
1. The value of gas energy saved based on the Company's avoided costs as established in its most current Integrated Resource Plan (IRP).
2. Non-energy benefits as quantified by a reasonable and practical method and described in situations where they cannot practically be quantified.
3. The 10% credit for energy efficiency as required under the Northwest Power Act. This credit recognizes the benefits of conservation in addressing risk and uncertainty.
4. A credit for carbon as defined in the most current version of the Northwest Power and Conservation Planning Council's (NWPPC) Conservation Plan.

The Present Value of Costs includes:
1. Incentives paid to the participant
2. Administrative costs
3. Monitoring, evaluation and non-incentive costs of Program Management Contractors (PMCs) and Energy Trust staff
4. The participant's remaining out-of-pocket costs for the installed cost of the measures after incentives and Federal tax credits.

2. Utility Cost (UC) measures the present value of the energy savings divided by the net costs incurred by the program, including incentive costs and excluding any net costs incurred by the participant. The UC is expressed with the same formula as the TRC but Present Value of Benefits and Present Value of Costs are defined as follows:

   The Present Value of Benefits includes
   1. The value of gas energy saved based on the Company's avoided costs as established in its most current IRP.
   2. The 10% credit for energy efficiency as required under the Northwest Power Act. This credit recognizes the benefits of conservation in addressing risk and uncertainty.
   3. A credit for carbon as defined in the most current version of the NWPPC's Conservation Plan.

   The Present Value of Costs includes:
   1. Incentives paid to the participant
   2. Administrative costs
   3. Monitoring, evaluation and non-incentive costs of PMCs and Energy Trust staff

Natural gas capacity benefits as well as lost and unaccounted for gas will not be included in the calculation except to the extent that they are included in NW Natural price forecasts.

(continue to Sheet G-3)

Issued June 30, 2009
NWN Advice No. OPUC 09-7

Effective with service on
and after October 1, 2009

NORTHWEST NATURAL GAS COMPANY

WN U-6 Second Revision of Sheet G.3

Cancels First Revision of Sheet G.3

SCHEDULE G

ENERGY EFFICIENCY SERVICES AND PROGRAMS – RESIDENTIAL AND COMMERCIAL

LEVELIZED COST METRIC

The portfolio of measures promoted through the program will also meet the following Levelized Cost metric, which is determined as follows:

The levelized cost is the present value of the total cost of a measure over its economic life, converted to equal annual payments. The levelized cost calculation starts with the incremental capital cost of a given measure or package of measures. The total cost is amortized over an estimated measure lifetime using the discount rate established in the Company's most current IRP. The annual net measure cost is then divided by the annual net energy savings (therms) from the measure application (again relative to a standard technology) to produce the levelized cost estimate in dollars per therm saved, as illustrated in the following formula.

$$\textit{Levelized Cost} = \frac{\textit{Net Annual Cost (\$)}}{\textit{Net Annual Savings}}$$

The levelized cost of an energy efficiency measure is cost-effective if it is less than the average levelized costs of other supply-side options. A cost-effective threshold is established in the Company's most current Integrated Resource Plan (IRP) and further refined through the BCR test.

CUSTOMER NOTIFICATION

This information may be provided through the use of bill inserts, displays, booklets, handouts, advertisements, and industry and public agency literature.

FUNDING

The costs incurred for the administration and delivery of the services and programs offered under this Schedule will be deferred as allowed by Washington Utility and Transportation Commission (WUTC) Orders to UG-011230 and UG-011231. Each year, the Company will seek recovery of ongoing program costs from Residential and Commercial customers through Schedule 215, coincident with the Company's Annual Purchased Gas Adjustment filing made in accordance with Schedule P. Deferred balances will accrue interest.

(continue to Sheet G. 4)

Issued February 18, 2010
NWN Advice No. WUTC 10-2

Effective with service on
and after March 26, 2010

NORTHWEST NATURAL GAS COMPANY

WN U-6 Second Revision of Sheet G.4

Cancels First Revision of Sheet G.4

SCHEDULE G

ENERGY EFFICIENCY SERVICES AND PROGRAMS – RESIDENTIAL AND COMMERCIAL

--- CANCELLED --- (N)

(D)

Issued December 1, 2011
NWN Advice No. WUTC 11-6

Effective with service on
and after January 1, 2012

Issued by: NORTHWEST NATURAL GAS COMPANY
d.b.a. NW Natural
220 N.W. Second Avenue
Portland, Oregon 97209-3991

NORTHWEST NATURAL GAS COMPANY

WN U-6 Third Revision of Sheet G.5

Cancels Second Revision Sheet G.5

SCHEDULE G

ENERGY EFFICIENCY SERVICES AND PROGRAMS – RESIDENTIAL AND COMMERCIAL

--- CANCELLED --- (N)
(D)

Issued December 1, 2011
NWN Advice No. WUTC 11-6

Effective with service on
and after January 1, 2012

Issued by: NORTHWEST NATURAL GAS COMPANY
d.b.a. NW Natural
220 N.W. Second Avenue
Portland, Oregon 97209-3991

NORTHWEST NATURAL GAS COMPANY

WN U-6 Second Revision of Sheet G.6
Cancels First Revision Sheet G.6

SCHEDULE G
ENERGY EFFICIENCY SERVICES AND PROGRAMS – RESIDENTIAL AND COMMERCIAL

--- CANCELLED --- (N)
(D)

Issued December 1, 2011
NWN Advice No. WUTC 11-6

Effective with service on
and after January 1, 2012

Issued by: ***NORTHWEST NATURAL GAS COMPANY***
d.b.a. NW Natural
220 N.W. Second Avenue
Portland, Oregon 97209-3991

NW Natural's 2013 Energy Efficiency Plan

I. Background

Northwest Natural, dba NW Natural ("NW Natural" or Company"), began offering its current energy efficiency programs to Washington customers on October 1, 2009. The Washington Utilities and Transportation Commission's ("WUTC's") Order No. 04 in the Company's 2008 rate case, docketed as UG-080546, directed NW Natural to create and begin offering a program.

II. Oversight

NW Natural's energy efficiency programs were developed and continue to evolve under the direction and oversight of the Energy Efficiency Advisory Group ("EEAG") which is comprised of interested parties to the Company's 2008 rate case. The EEAG includes representatives from NW Natural, Energy Trust of Oregon ("Energy Trust"), WUTC Staff, Public Counsel, Northwest Industrial Gas Users ("NWIGU"), The Energy Project, and NW Energy Coalition.

III. Program Administration

NW Natural's general energy efficiency programs are administered by the Energy Trust, which is an independent, nonprofit organization dedicated to helping utility customers save electric and gas energy. Energy Trust was formed in 2002 in response to Oregon legislation that restructured electric utilities[1] for multiple reasons including allowing non-residential customers to purchase their electricity from providers other than the utility and reassigning the responsibility for demand side management from utility operations to Energy Trust.

NW Natural began using Energy Trust as the delivery arm for its Oregon energy efficiency program in 2003. Since NW Natural's Washington service territory is contiguous with its Oregon territory, it made sense to have Energy Trust extend the boundaries of the Oregon program offerings into Washington.

As agreed to in UG-080546, Energy Trust administered the Company's program for one pilot year. During this time, the EEAG monitored the program's performance and assessed whether Energy Trust should be the ongoing program administrator. On May

[1] SB 1149, codified as ORS 757.612, mandated the creation of an independent entity capable of providing demand side management services to utility customers.

25, 2011, NW Natural made a compliance filing in UG-080546 wherein it stated the EEAG's opinion to allow Energy Trust to continue administering NW Natural's energy efficiency programs in Washington. On June 8, 2011, Public Counsel separately filed a letter supporting this decision.

NW Natural's Washington Low Income Energy Efficiency Program ("WA-LIEE") is administered by Clark County Community Action Agency, Klickitat County Community Action Agency and Skamania County Community Action Agency.

IV. Programs Offered

NW Natural offers the following general energy efficiency programs:

> Residential – Residential customers with gas heated homes are offered home energy reviews wherein an energy consultant identifies measures that could be installed to improve the customer's home's efficiency. Specific incentive offerings are also available for the installation of certain efficient gas appliances.
>
> New Homes – The New Homes program encourages builders to construct homes to an energy efficiency standard that is better than Washington building code. Qualifying homes must meet the criteria established in ENERGY STAR's Builder Option Package ("BOP") for natural gas heated new construction.
>
> Commercial – Commercial customers are offered incentives for prescriptive efficient gas appliance installations, as well as efficient installations unique to the customer's facilities that are identified in a custom study.

Specific measure offerings are as listed in Appendix A to this Plan."

Under NW Natural's low income energy efficiency program, agencies administering the program leverage other funding sources with WA-LIEE dollars to provide whole-house weatherization services to qualifying customers. Agencies are paid $3,500 per home for cost effective energy efficiency installations as well as an average of $440 per home for health and safety repairs. Program details are available in the Company's Schedule I, "Washington Low Income Energy Efficiency Program (WA-LIEE)."

V. Program Evaluation, Monitoring and Verification ("EM&V")

Impact Evaluations

Deemed gross savings by measure are used to determine total therms reported as saved per program year. The deemed savings used will be consistent with the most current impact studies performed on the programs that the Energy Trust delivers in Oregon until after mid-2012 when such impact evaluations will include results from the

Washington-delivered programs. The Energy Trust performs the impact study wherein they analyze customers' energy usage data before and after a measure is installed. The savings from all measures' are analyzed annually unless sample sizes based on participation rates are not statistically significant. From the impact evaluation, the Energy Trust is able to determine if average savings are consistent with deemed savings. If they are not, the deemed savings are "trued-up" once annually to reflect the findings. A link to the annual true up report as well as a short summary of the results will be provided in the quarterly report following the report's release.

Process Evaluations

Besides impact evaluations, the Energy Trust contracts with a third party to perform a process evaluation on all general energy efficiency programs offered, typically on an annual basis. The third party studies and reports on the processes employed for each program. Study results are available on the Energy Trust's website: www.energytrust.org. A link to the annual process evaluation as well as a short summary of the results will be provided in the quarterly report following the report's release.

VI. Process for Program Changes

NW Natural will file to revise Appendix A of its Energy Efficiency Plan when it plans to add, change, or remove a long- term incentive offering. Every year the Company will consider if program year changes are needed. If they are, the Company will revise its EE Plan to make requested program modifications when it makes its annual advice filing, submitted no later than December 1, to revise the performance metrics and budget that are also included in the Plan. This does not preclude the Company from filing to revise Schedule G or its EE Plan at any time during the year. Advice filings revising or adding measures will include:

1) A benefit cost ratio ("BCR") calculator demonstrating the measure's life, measure cost, the quantifiable non-energy benefits, the utility system benefits and the societal BCR; and

2) For new measures, a blessing memo which refers to an in-house Energy Trust document that summarizes the vetting of a measure before it is introduced as a program offering. The EEAG will be given the opportunity to review all tariff filings before they are filed. The Company will generally give the EEAG ten business days to review a draft filing. The EEAG's review process will not be less than five business days.

3) New programs proposed mid-cycle will include a program-specific plan addressing the possible need for program-specific metrics.

Please note that not all advice filings must include the EE Plan. The EE Plan will only be included when it is being revised.

The Company will work to resolve issues with EEAG members before filing. If the EEAG cannot completely recommend approval of a filing, the Company may still choose to make the filing with the WUTC with the understanding that EEAG members may intervene in that public proceeding.

VII. Annual Schedule for Program Planning

By November 15 of each year, the Company will provide the EEAG with the following proposals for the next program year, which will subsequently be filed with the WUTC in a new docket that will contain all the required reporting for the calendar year, including a link to the Purchased Gas Adjustment (PGA) filing wherein program costs are recovered:

<u>Budget</u>
The Company will provide a total estimated program budget for the next calendar year. The budget will present expected expenditures by program and customer class.

Please note that this budget forecast will be based on the best information available at the time. As the year progresses, budgeted dollars may be reallocated among various programs or new offerings that are approved by the WUTC.

<u>Funding Schedule</u>
A funding schedule is a contractually-agreed-to timeline between NW Natural and Energy Trust wherewith NW Natural will provide Energy Trust the necessary money for program administration and delivery. The amounts dispersed to the Energy Trust in one year are the sum of all funds needed for that program year determined by subtracting any unspent or uncommitted funds previously dispersed to the Energy Trust for the Washington program from the total forecasted budget.

<u>Metrics</u>
The Company will propose performance metrics that will address the following:

- Total program costs
- Projected therm savings consistent with most recent IRP
- Average levelized cost for measures

- A ceiling for average cost per therm
- Projected homes to be weatherized in the WA-LIEE program

The Company expects that Total Resource Cost (TRC) and Utility Cost (UC) at the portfolio level should always be greater than 1.0 and will report compliance to this on an annual basis.

The Company will come to agreement with the EEAG on the next year's budget and performance metrics before making a tariff filing with the WUTC to modify this plan so that it incorporates the next year's projected costs and metrics accordingly. This filing will be made annually not later than December 1 for a January 1 effective date.

Generally, milestones for the program year will be as follows:

Program Year Schedule	
January 1	Start of program year
April 25	Annual report for previous program year is filed.
May 25	Q1 report on January 1 through March 31 of current year
August 25	Q2 report on April 1 through June 30 and YTD
October 1	Tariff filing submitted for program cost recovery.
November 1	Requested effective date of program cost recovery filing.
November 15	Share next year's budget range, funding schedule, and proposed performance metrics with EEAG no later than this date
November 25	Q3 report on July 1 through September 30 and YTD
December 1	Latest date to file EE Plan for next program year
January 1	Start of next program year; new EE Plan effective

VIII. Reporting

The Company will file all required reporting with the WUTC in the docket established for the current program year.

Quarterly

The Company will report on its program on a calendar year basis. Quarterly reports will be provided to the EEAG and filed with the WUTC on the following schedule:

1Q – May 25
2Q – August 25
3Q – November 25

Annual

An annual report will be due annually for the previous year by April 25th.

EEAG Review

The EEAG will meet either in person or by teleconference to review the annual report and on an as requested basis.

Content of Reports

The quarterly reports will include

- Quarterly progress toward annual program metrics
- A breakdown of costs by program and customer sector
- A reporting on percentage of program costs spent on customer incentives
- The funding received to date
- The 2Q report will include a 6 month check in on WA-LIEE
  - program year costs,
  - homes served,
  - estimated total therms saved per home, and
  - total therm savings to-date
- The quarterly report following the annual release of the impact and process report will include a link to that report and a short summary of the findings

The annual report will include the following:

- Budget compared to actual results by program
- Cost-effectiveness calculations on a program by program and total portfolio basis
- Measure level participation (units installed and savings) under each program
- Reporting on achievement of metrics
- Evaluation results (if performed)
- WA-LIEE program results including:
  - total program year costs
  - homes served
  - estimated total therm savings, and
  - average therms saved per home.

IX. Annual Program Budget

Budgets

Forecasted program costs for the next calendar year will be reviewed annually in November when metrics are also proposed for the following program year.

Actual Costs

Each year, the Company will file its annual report by April 25 which will detail costs and acquisitions for the previous program year. This filing will trigger the EEAG's review of general energy efficiency and WA-LIEE program costs.

X. Cost Recovery

Energy Efficiency and WA-LIEE program costs are deferred and later amortized for recovery from applicable customers on an equal cents per margin basis as established annually in the temporary rate adjustments, Schedules 215 and 230, respectively. Beginning in 2012, the Company will annually submit a stand-alone filing concurrently with its PGA filing, for cost recovery of its energy efficiency program expenses for the prior calendar year. That annual filing will include the following information:

- Background on the Company's energy efficiency programs and cost recovery
- A copy of the prior program year's Annual Report which will include detail on the achievement of performance metrics; the forecasted budget for that year and actual expenditures
- The total dollar amount the Company is seeking to recover
- The total incremental dollar impact that the proposed rate change will have on average residential and commercial customer monthly bills.
- Total average monthly bill of proposed rate for applicable customers.
- Work papers demonstrating the analysis behind the collection rate.

Beginning on January 1, 2013, the Company will include a message on applicable Customers' monthly bills stating how much of their current monthly bill represents costs collected to pay for the residential and commercial energy efficiency programs.

XI. 2013 Performance Metrics

Below are the 2013 program metrics. Each metric is followed by a statement explaining how it was determined.

- Total residential and commercial program costs will be between $1,430,092 and $1,613,437

The total costs for this metric correlate to the range of costs estimated to achieve all cost effective therms for the programs being offered as determined in the Company's 2013 Integrated Resource Plan ("IRP").

- Therms saved will be between 220,421 and 259,319

The program's primary goal is to meet system demand with the least cost conservation as required per WAC 480-90-238(1). The therm savings target is aligned with the demand-side management targets for the programs offered as identified in the Company's 2011 Modified IRP.

- Average levelized cost for the portfolio of measures will not to exceed $0.65 per therm

This metric is unchanged from the prior year. The profile of NW Natural Washington service territory makes it harder to reduce the averaged levelized cost per therm than it would be in an area with more industrial customers since therm savings are acquired more cost effectively for bigger customers than for residential customers.

- First year therms will cost less than $6.50 per therm

This metric is reduced from $8.00 per therm the first year and $7.00 the second.

- Total Resource Cost (TRC) and Utility Cost (UC) at the portfolio level are greater than 1.0

The TRC and the UC shall be calculated as prescribed in Schedule G. A value greater than 1.0 demonstrates that the benefits received are greater than the costs. This test is applied at the portfolio level to allow measures that are less cost effective to be bundled with those that are more cost effective.

<u>Schedule I, Washington Low Income Energy Efficiency (WA-LIEE) 2012 Performance Targets</u>

In 2012, the WA-LIEE program will strive to weatherize 15-20 homes for a cost of $66,975 to $89,300. Assumptions are as provided below in Table II.

Table II – WA-LIEE 2013 Performance Targets

Estimated homes served	15-20
Estimated Average Cost of Incentives per home	$3,500
Maximum Cost per home ($3,500 incentives + $440 health, safety and repairs and $525 administration costs)	$4,465
Maximum cost based on estimated homes served	$66,975 to $89,300
Estimated therms saved per home	211
Total estimated therms saved	3165 to 4220

XII. 2013 Budget and Funding Schedule

Below is the 2013 budget for the residential and commercial energy efficiency programs and the WA-LIEE program.

Programs 2013 Budget		
Range	**Low**	**High**
Commercial		
Retrofit	$635,568	$717,052
Residential		
Retrofit	$465,617	$525,312
New Homes	$328,907	$371,074
Total For Schedule G Programs		
WALIEE	$66,975	$89,300
TOTAL	**$1,497,067**	**$1,702,738**

Funding Schedule: As of the November 2012, the Company and Energy Trust have not executed a contract to define the 2013 funding schedule but parties expect the funding schedule will mirror what was done in 2012 which was that 50% of budgeted need was provided to Energy Trust on March 1 and the remaining 50% was provided on October 1.

APPENDIX A to EE Plan
The Company's Residential and Commercial Program offers incentives for measures as listed below.

RESIDENTIAL PROGRAM INCENTIVES

The following are offerings for Residential customers:

DESCRIPTION	INCENTIVE
Weatherization	
Air Sealing	$150 per home
Attic/Ceiling Insulation	$0.25 per square foot
Duct Insulation	50% of cost, up to $100
Floor Insulation	$0.30per square foot
Knee-Wall Insulation	$0.30 per square foot
Boiler Pipe Insulation	$0.50 per linear foot
Wall Insulation	$0.30 per square foot
Windows (0.25 to 0.30)	$2.25 to $3.50 per square foot
Heating	
Gas Furnace	$100.00
Direct Vent Gas Unit Heater	$100.00
Direct Vent Gas Fireplace	$100.00 to $150.00
Intermittent Pilot Ignition	$100.00
Gas Boiler	$200.00
Water Heating	
Gas Water Heater	$35.00 - $150.00
Clothes Washer with gas water heat (MEF 2.2+)	$30.00
Solar Thermal Pool Heating	$3 per square foot of collector
Direct Install Measures	
Faucet Aerator	Free to customer
Home Energy Review	Free to customer
Showerhead	Free to customer
Shower wand	Free to customer
Water Heater Set Back	Free to customer
Distributor or Retail Buy Down	$8.50
Showerhead	

APPENDIX A to EE Plan (Continued)

RESIDENTIAL NEW CONSTRUCTION

Tankless Hot Water Heating	$ 200.00 per unit
Energy Star Builder Option Package*	$ 600.00 per home
Showerhead	Free to customer
Clothes Washer with gas water heat (MEF 2.2+)	$30.00

* Building requirements are as stated on this site: http://www.energystar.gov/index.cfm?c=bop.pt_bop_washington

COMMERCIAL

General	
Custom	$1 per therm
Heating	
Steam Traps, Small Commercial, <12 hrs/day, small-med pressure	$ 100.00 per trap*
Gas-fired Condensing Boiler > 2500 kbtuh 0.9 EC	$ 4.00 per kBtu hr in
Gas-fired Condensing Boiler < 300 kbtuh 0.9 AFUE	$ 4.00 per kBtu hr in
Gas-fired Condensing Boiler >= 300 kbtuh, <= 2500 kbtuh 0.9 ET	$ 4.00 per kBtu hr in
Boiler Vent Damper	$ 1,000.00 per unit
High Efficiency Unit Heater - Non-Condensing with Electronic Ignition	$ 1.50 per kBtu hr in
High Efficiency Condensing Furnace <225,000 kBtuh	$ 3.00 per kBtu hr in
Direct-fired Radiant Heating	
Minimum 80% Efficiency, non-modulating	$ 6.50 per kBtu hr in
Minimum 82% Efficiency, modulating	$10.00 per kBtu hr in
Pipe Insulation	$2.00 to $6.00 per linear foot
Building Envelope insulation	$0.30 per sq ft
Rooftop Unit Tune Ups	$1,250 to $1,050
Greenhouse Thermal Curtain	$0.9 per sq ft

* Pre-verification of steam traps required for dry cleaners

Water Heating	
Domestic Tankless/Instantaneous Water Heater with Electronic Ignition	$ 2.00 per kBtu hr in
Domestic Tankless/Instantaneous Water Heater with Standing Pilot	$ 1.50 per kBtu hr in
Condensing Tank	$ 2.50 per kBtu hr in
Commercial Clothes Washer, Gas Water Heat, Partial Gas	$ 200.00 per unit
Showerhead Gas	$ 6.00 to $10.00 per unit
Commercial Bathroom Faucet Aerators (0.5 gal per minimum; 15 unit minimum)	$3.00 each
Commercial Kitchen Faucet Aerators (1.5 gal per minimum; 15 unit minimum)	$5.00 each
Ozone Laundry System	$40 per pound of washing capacity up to a max of 35% of cost of system
Solar Thermal Pool Heating	$3 per sq ft of collector

APPENDIX A to EE Plan (Continued)

Food Service

Gas Full-Size Convection Oven	$ 300.00 per unit
Gas Fryer	$ 1,000.00 per unit
Gas Griddle	$ 150.00 per unit
Gas Steam Cooker	$ 1,300.00 per unit
Dishwasher - Single Tank Conveyor - Low temp - Gas hot water	$ 500.00 per unit
Dishwasher - Single Tank Door/Upright - Low Temp - Gas water heat	$ 400.00 per unit
Dishwasher - Single Tank Conveyor - High temp - Gas hot water	$ 500.00 per unit
Dishwasher - Single Tank Door/Upright - High Temp - Gas water heat	$ 400.00 per unit
Dishwasher - Undercounter - high temp - Gas water heat	$ 200.00 per unit
Turbo Pot – limit one per applicant	$40 per pot*

* Customers installing one other food service measure may receive one free turbo pot while promotional quantities last.

SPECIAL PROVISIONS

1. One time bonuses or coupons may be periodically offered to supplement standard incentives.
2. Limited time incentive offerings for measures may be offered.

Appendix 5: Linear Programming and The Company's Resource Choices

NW Natural®

1518 - Base Case	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	79,519	80,884	82,603	84,311	85,313	86,368	87,426	88,915	89,804	91,006	92,200	93,901	94,828	96,242	97,735	99,716	101,003	102,808	104,853	105,329	
Forecast DSM	266	640	960	1,267	1,501	1,725	1,949	2,188	2,409	2,634	2,855	3,081	3,275	3,478	3,681	3,890	4,064	4,238	4,406	4,578	
Forecast Demand (net DSM)	79,253	80,244	81,643	83,045	83,811	84,642	85,476	86,727	87,395	88,373	89,345	90,819	91,552	92,764	94,055	95,826	96,940	98,569	100,446	100,751	
Served Demand	79,253	80,244	81,643	83,045	83,811	84,642	85,476	86,727	87,395	88,373	89,345	90,819	91,552	92,764	94,055	95,826	96,940	98,569	100,446	100,751	
Unserved Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	923.2	923.7	929.0	933.5	940.5	949.1	958.2	965.5	976.0	985.6	995.4	1,006.1	1,018.2	1,030.4	1,041.8	1,055.2	1,069.8	1,084.7	1,100.1	1,098.9	
Peak Day Demand Served	923.2	923.7	929.0	933.5	940.5	949.1	958.2	965.5	976.0	985.6	995.4	1,006.1	1,018.2	1,030.4	1,041.8	1,055.2	1,069.7	1,084.6	1,100.1	1,098.8	
Peak Day Demand Unserved	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1	0.1	0.1	
COST ($000 Nominal)																					
Supply Fixed Costs	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	
Supply Variable Costs	247,873	291,293	319,653	342,558	355,671	376,371	386,846	401,965	401,402	427,925	445,292	467,395	483,792	501,431	526,289	549,044	575,556	612,413	640,954	643,107	
Total Supply Costs	247,934	291,354	319,714	342,619	355,732	376,432	386,907	402,025	401,463	427,986	445,353	467,456	483,853	501,492	526,350	549,105	575,617	612,474	641,015	643,168	5,407,546
Transport Fixed Costs	92,499	93,332	93,384	93,384	94,880	95,181	95,181	95,181	95,181	95,181	95,181	95,181	95,181	95,181	95,181	95,477	96,435	99,023	101,445	101,542	1,230,073
Transport Variable Costs	2,946	2,958	3,033	3,110	3,096	3,144	3,233	3,492	3,425	3,499	3,605	3,766	3,818	3,883	3,950	4,011	4,052	4,061	3,818	3,822	
Total Transport Cost	95,445	96,290	96,417	96,493	97,977	98,325	98,414	98,672	98,606	98,680	98,786	98,946	98,999	99,064	99,130	99,488	100,486	103,084	105,263	105,364	1,274,427
Storage Fixed Cost	24,959	24,968	25,073	25,143	25,220	25,476	25,780	26,127	26,504	26,870	27,261	27,697	28,252	28,996	29,837	30,190	30,190	30,190	30,190	30,190	
Storage Variable Cost	1,332	1,151	1,162	1,326	1,349	1,474	1,599	1,401	1,772	1,782	1,839	2,002	2,259	2,386	2,468	2,605	2,613	2,623	2,713	2,758	
Total Storage Cost	26,291	26,119	26,235	26,469	26,569	26,951	27,379	27,528	28,276	28,652	29,100	29,699	30,511	31,382	32,305	32,795	32,802	32,813	32,902	32,947	370,665
DSM Annual Utility Cost	9,945	10,776	10,232	11,529	13,700	15,853	17,218	19,362	19,316	19,250	19,225	18,970	18,970	18,884	18,884	18,600	18,574	18,285	18,239	18,029	
Total Levelized Utility Cost	255	614	921	1,209	1,439	1,653	1,867	2,086	2,306	2,519	2,730	2,934	3,130	3,323	3,516	3,700	3,880	4,046	4,205	4,351	
Total Costs	379,616	424,539	452,597	477,110	493,978	517,560	529,919	547,587	547,660	574,568	592,464	615,072	632,333	650,822	676,669	699,988	727,480	766,656	797,419	799,508	7,858,215
Key Resource Decisions (increm. MDT/day)																					
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Eastside Loop	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Cross-Cascades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	18	19	
GTN Malin to Madras	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	18	19	
GTN Stanfield to Madras	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Increase NWP Mainline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
GTN Malin to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Newport LNG Delivery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	40	40	40	40	
N MAX	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Ruby Pipeline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Gorge Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Expansion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Recall	-	-	0	5	5	8	17	24	35	44	54	64	76	93	114	136	136	136	136	136	
Satellite LNG Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NW Natural Transmission																					
North WVF (POR to SAL)	30.9	28.1	18.1	23.8	19.3	33.7	26.8	22.3	38.0	25.9	26.8	43.1	36.5	32.3	34.9	26.8	4.2	15.3	9.3	3.6	
Harrisburg River Crossing (ALB to EUG)	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	
MWVF	-	13.4	-	-	-	7.8	-	-	0.7	1.2	1.0	15.9	2.6	2.6	3.2	3.8	4.5	5.2	5.9	5.8	
Storage																					
GASCO LNG	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	
JP	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	
MIST	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	273.4	254.1	237.4	243.0	249.7	248.0	
NEWPORT LNG	58.0	58.0	58.0	58.1	58.2	58.3	58.4	58.5	58.7	58.8	59.0	59.1	59.3	59.4	59.6	69.2	99.6	99.8	100.0	100.0	
PLYMOUTH LNG	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	
March Point	-	-	-	-	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	
Peak Day Resources-Recall Agreements																					
Recall 1	25.4	30.0	30.0	30.0	26.3	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	
Recall 2	8.0	3.9	8.0	8.0	6.7	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	
Recall 3	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	

1519 - No New Resources	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	79,519	80,884	82,603	84,311	85,313	86,368	87,426	88,915	89,804	91,006	92,200	93,901	94,828	96,242	97,735	99,716	101,003	102,808	104,853	105,329	
Forecast DSM	266	640	960	1,267	1,501	1,725	1,949	2,188	2,409	2,634	2,855	3,081	3,275	3,478	3,681	3,890	4,064	4,238	4,406	4,578	
Forecast Demand (net DSM)	79,253	80,244	81,643	83,045	83,811	84,642	85,476	86,727	87,395	88,373	89,345	90,819	91,552	92,764	94,055	95,826	96,940	98,569	100,446	100,751	
Served Demand	79,253	80,244	81,642	83,039	83,811	84,633	85,458	86,702	87,359	88,328	89,290	90,754	91,475	92,674	93,425	94,542	95,464	96,844	98,313	98,536	
Unserved Demand	0	0	1	6	1	9	18	25	36	45	55	65	77	89	629	1,284	1,476	1,725	2,133	2,215	
Peak Day Demand (net DSM)	923.2	923.7	929.0	933.5	940.5	949.1	958.2	965.5	976.0	985.6	995.4	1,006.1	1,018.2	1,030.4	1,041.8	1,055.2	1,069.8	1,084.7	1,100.1	1,098.9	
Peak Day Demand Served	923.2	923.7	927.8	927.9	940.0	940.1	940.2	940.4	940.5	940.6	940.8	940.9	941.1	941.2	941.4	941.6	927.6	908.5	891.6	885.3	
Peak Day Demand Unserved	-	-	1.2	5.6	0.6	9.0	18.0	25.2	35.5	45.0	54.6	65.2	77.1	89.2	100.3	113.6	142.2	176.2	208.6	213.6	
COST ($000 Nominal)																					
Supply Fixed Costs	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	
Supply Variable Costs	247,873	291,257	319,319	342,635	355,515	375,549	386,258	401,060	400,906	428,687	444,158	469,573	500,732	521,937	543,919	565,865	591,983	626,787	651,802	654,076	
Total Supply Costs	247,934	291,317	319,380	342,695	355,576	375,609	386,318	401,121	400,967	428,747	444,219	469,634	500,792	521,997	543,980	565,926	592,044	626,848	651,863	654,137	5,464,763
Transport Fixed Costs	92,499	93,332	93,332	93 332	94,829	95,129	95,129	95,129	95,129	95,129	95,129	95,129	95,129	95,129	95,129	95,129	95,129	95,129	95,129	95,129	1,222,197
Transport Variable Costs	2,946	2,958	3,031	3,114	3,095	3,135	3,222	3,469	3,421	3,507	3,591	3,727	3,745	3,788	3,829	3,886	3,918	3,975	3,891	3,906	
Total Transport Cost	95,445	96,290	96,363	96,446	97,924	98,264	98,352	98,598	98,550	98,637	98,720	98,856	98,874	98,917	98,958	99,016	99,047	99,104	99,020	99,035	1,266,249
Storage Fixed Cost	24,959	24,959	24,959	24,959	24,959	24,959	24,959	24,959	24,959	24,959	24,959	24,959	24,959	24,959	24,959	24,959	24,959	24,959	24,959	24,959	
Storage Variable Cost	1,332	1,150	1,157	1,321	1,342	1,450	1,567	1,361	1,724	1,946	1,974	1,951	2,062	2,073	2,054	2,207	2,281	2,212	2,179	2,195	
Total Storage Cost	26,291	26,110	26,116	26,281	26,301	26,409	26,526	26,320	26,683	26,905	26,934	26,910	27,021	27,032	27,013	27,167	27,240	27,171	27,138	27,155	344,303
DSM Annual Utility Cost	9,945	10,776	10,232	11,529	13,700	15,853	17,218	19,362	19,316	19,250	19,225	18,970	18,970	18,884	18,884	18,600	18,574	18,285	18,239	18,029	
Total Levelized Utility Cost	255	614	921	1,209	1,439	1,653	1,867	2,086	2,306	2,519	2,730	2,934	3,130	3,323	3,516	3,700	3,880	4,046	4,205	4,351	
Total Costs	379,616	424,492	452,091	476,951	493,501	516,135	528,415	545,401	545,516	573,540	589,098	614,371	645,658	666,831	688,836	710,708	736,905	771,408	796,260	798,356	7,280,891
Key Resource Decisions (increm. MDT/day)																					
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Eastside Loop	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Cross-Cascades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
GTN Malin to Madras	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
GTN Stanfield to Madras	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Increase NWP Mainline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
GTN Malin to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Newport LNG Delivery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
N-MAX	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Ruby Pipeline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Gorge Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Expansion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Recall	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NW Natural Transmission																					
North WVF (POR to SAL)	10.3	18.2	31.3	18.3	19.3	20.3	21.2	34.0	35.6	37.2	35.5	32.7	41.0	42.3	29.3	-	-	-	-	-	
Harrisburg River Crossing (ALB to EUG)	8.0	8.0	8.0	8.0	8.0	5.8	8.0	8.0	8.0	8.0	8.0	-	8.0	8.0	8.0	8.0	7.7	5.9	7.1	7.2	
MWVF	-	-	-	-	-	-	-	-	13.9	14.4	11.5	7.4	-	-	-	-	-	-	-	-	
Storage																					
GASCO LNG	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	
JP	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	45.8	46.0	46.0	
MIST	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	273.9	256.7	238.6	232.0	
NEWPORT LNG	58.0	58.0	58.0	58.1	58.2	58.3	58.4	58.5	58.7	58.8	59.0	59.1	59.3	59.4	59.6	59.8	60.0	60.2	60.4	60.3	
PLYMOUTH LNG	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	
March Point	-	-	-	-	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	
Peak Day Resources-Recall Agreements																					
Recall 1	25.4	26.9	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	
Recall 2	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	
Recall 3	1.0	-	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	

1520 - DSM at 217%	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	79,519	80,884	82,603	84,311	85,313	86,368	87,426	88,915	89 804	91,006	92,200	93,901	94,828	96,242	97,735	99,716	101,003	102,808	104,853	105,329	
Forecast DSM	570	1,374	2,063	2,722	3 227	3,708	4,189	4,702	5,179	5,662	6,138	6,626	7,044	7,481	7,917	8,368	8,742	9,119	9,481	9,851	
Forecast Demand (net DSM)	78,949	79,510	80,540	81,589	82,086	82,660	83,236	84,213	84,625	85,344	86,061	87,275	87,784	88,761	89,818	91,348	92,261	93,689	95,372	95,478	
Served Demand	78,949	79,510	80,540	81,589	82,086	82,660	83,236	84,213	84,625	85,344	86,061	87,275	87,784	88,761	89,818	91,348	92,261	93,689	95,372	95,478	
Unserved Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	920.4	918.0	920.9	922.8	928.2	934.9	942.1	947.4	955 9	963.5	971.3	980.1	990.3	1,000.7	1,010.2	1,021.9	1,034.8	1,048.1	1,062.0	1,059.2	
Peak Day Demand Served	920.4	918.0	920.9	922.8	928.2	934.9	942.1	947.4	955.9	963.5	971.3	980 1	990.3	1,000.7	1,010.2	1,021.9	1,034.8	1,048.0	1,061.9	1,059.2	
Peak Day Demand Unserved	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1	-	
COST ($000 Nominal)																					
Supply Fixed Costs	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	
Supply Variable Costs	246,774	288,305	314,488	336,128	347,476	366,133	375,618	388,794	387,512	411,931	428,451	448,006	461,838	477,789	503,016	525,042	548,415	581,549	608,250	609,718	
Total Supply Costs	246,835	288,366	314,549	336,189	347,537	366,194	375,679	388,854	387,573	411,991	428,512	448,066	461,899	477,850	503,077	525,103	548,475	581,609	608,311	609,779	5,221,990
Transport Fixed Costs	92,499	93,332	93,384	93,384	94,880	95,181	95,225	95,389	95,654	95,860	96,103	96,103	96,103	96,103	96,103	96,103	96,354	98,019	100,244	100,244	1,232,378
Transport Variable Costs	2,932	2,921	2,976	3,039	3,004	3,020	3 084	3,350	3,288	3,336	3,415	3,568	3,602	3,652	3,732	3,810	3,832	3,846	3,654	3,663	
Total Transport Cost	95,432	96,253	96,360	96,422	97,885	98,201	98,310	98,740	98,942	99,195	99,518	99,671	99,705	99,755	99,835	99,913	100,186	101,865	103,899	103,908	1,275,006
Storage Fixed Cost	24,959	24,959	24,959	24 959	24 959	24,959	24,959	24,959	24,982	24,999	25,195	25,561	25,951	26,325	26,732	27,247	27,482	27,482	27,482	27,482	
Storage Variable Cost	1,333	1,138	1,153	1,321	1 335	1,434	1,524	1,337	1,659	1,685	1,739	1,729	1,865	1,933	2,168	2,398	2,471	2,397	2,393	2,439	
Total Storage Cost	26,293	26,097	26,113	26,280	26,295	26 393	26,484	26,297	26,641	26,684	26,934	27,290	27,816	28,257	28,900	29,645	29,953	29 879	29,875	29,921	351,977
DSM Annual Utility Cost	21,582	23,383	22,203	25,017	29,730	34,401	37,364	42,016	41,915	41,774	41,719	41,166	41,166	40,979	40,979	40,361	40,306	39,679	39,578	39,122	
Total Levelized Utility Cost	255	614	921	1,209	1,439	1,653	1,867	2,086	2,306	2,519	2,730	2,934	3,130	3,323	3,516	3,700	3,880	4,046	4,205	4,351	
Total Costs	390,140	434,099	459,224	483,909	501,446	525,188	537,836	555,906	555,072	579,644	596,683	616,193	630,586	646,841	672,791	695,023	718,920	753,032	781,664	782,730	7,295,875
Key Resource Decisions (increm. MDT/day)																					
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Eastside Loop	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Cross-Cascades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	14	14	
GTN Malin to Madras	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	14	14	
GTN Stanfield to Madras	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Increase NWP Mainline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
GTN Malin to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Newport LNG Delivery	-	-	-	-	-	-	1	7	15	21	29	29	29	29	29	29	37	40	40	40	
N-MAX	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Ruby Pipeline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Gorge Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Expansion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Recall	-	-	-	-	-	-	-	-	-	1	1	10	20	30	39	51	66	66	66	66	
Satellite LNG Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NW Natural Transmission																					
North WVF (POR to SAL)	30.3	30.5	16.6	22.3	17.5	29.8	23.1	13.2	18 9	0.2	-	8.6	1.6	-	-	0.3	0.3	7.5	1.2	-	
Harrisburg River Crossing (ALB to EUG)	8.0	8.0	8.0	8.0	8.0	7.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	
MWVF	-	13.1	-	-	-	5.9	-	-	-	-	6.7	14.2	0.9	0.8	1.2	1.7	2.3	3.0	3.5	3.4	
Storage																					
GASCO LNG	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	
JP	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	
MIST	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	
NEWPORT LNG	57.9	57.9	57.9	57 9	58.0	58.0	59.5	64.8	73.3	79.9	87.7	87.8	87.9	88.0	88.2	88.3	96.4	99.5	99.6	99.6	
PLYMOUTH LNG	60 1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	
March Point	-	-	-	-	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	
Peak Day Resources-Recall Agreements																					
Recall 1	22.7	28.9	23.4	24.3	21 1	24.3	30.0	30.0	30.0	30 0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30 0	30.0	
Recall 2	8.0	0.4	8.0	8.0	4.6	8.0	8.0	8.0	8 0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	
Recall 3	1.0	-	-	1.0	1.0	1.0	1.0	1.0	1 0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	

1521 - Low Customers	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	79,354	80,504	81,974	83,406	84,107	84,852	85,626	86,861	87,568	88,640	89,756	91,389	92,290	93,666	95,121	97,048	98,307	100,071	102,074	103,827	
Forecast DSM	266	640	960	1,267	1,501	1,725	1,949	2,188	2,409	2,634	2,855	3,081	3,275	3,478	3,681	3,890	4,064	4,238	4,406	4 578	
Forecast Demand (net DSM)	79,089	79,864	81,014	82,139	82 605	83,126	83,677	84,674	85,159	86,006	86,901	88,308	89,015	90,188	91,440	93,158	94,244	95,832	97,668	99,248	
Served Demand	79,089	79,864	81,014	82,139	82,605	83,126	83,677	84,674	85,159	86,006	86,901	88,308	89,015	90,188	91,440	93,158	94,244	95,832	97,668	99,248	
Unserved Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	921 1	918.9	920.9	921.6	924 6	928.9	934.1	938.0	945.9	953.6	962.3	972.2	983.7	995 3	1,006 1	1,018.9	1,032.9	1,047 2	1,062.1	1,078.4	
Peak Day Demand Served	921 1	918.9	920.9	921.6	924.6	928.9	934.1	938.0	945.9	953.6	962.3	972.2	983.7	995.3	1,006.1	1,018.9	1,032.8	1,047 2	1,062.0	1,078.4	
Peak Day Demand Unserved	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1	0.1	0.1	
COST ($000 Nominal)																					
Supply Fixed Costs	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	
Supply Variable Costs	247,256	289,670	316,422	338,464	349,672	368,096	377,462	390,853	390,693	415,697	432,745	453,454	468,523	487,319	511,965	533,028	559,461	595,464	623,291	633,895	
Total Supply Costs	247,317	289,731	316,483	338 525	349,733	368,156	377,523	390,914	390,754	415,758	432,806	453,515	468,584	487,380	512,026	533,089	559,521	595,525	623,352	633,956	5,286,932
Transport Fixed Costs	92,499	93,332	93,384	93,384	94,880	95,181	95,181	95,181	95,340	95,340	95,448	95,448	95,448	95,448	95,448	95,448	96,554	99,054	101,405	103,837	1,231,933
Transport Variable Costs	2,938	2,938	2,998	3,065	3,028	3,045	3,112	3,376	3,322	3,376	3,458	3,622	3,667	3,744	3,823	3,876	3,918	3,926	3,715	3,694	
Total Transport Cost	95,437	96,270	96,381	96,448	97 908	98,226	98,293	98,557	98,662	98,716	98,907	99,070	99,115	99,192	99,271	99,324	100,472	102,980	105,120	107,531	1,275,078
Storage Fixed Cost	24,959	24,959	24,959	24,959	24,959	24,959	24,959	24,959	25,131	25,366	25,667	26,078	26,516	26,937	27,536	27,840	27,840	27,840	27,840	27,840	
Storage Variable Cost	1,333	1,144	1,154	1,316	1,332	1,438	1,530	1,335	1,665	1,695	1,758	1,769	1,906	2,177	2,300	2,430	2,449	2,429	2,441	2,505	
Total Storage Cost	26,292	26,103	26,113	26,275	26,291	26,397	26,490	26,295	26,796	27,061	27,426	27,847	28,422	29,114	29,836	30,270	30,289	30,268	30,281	30,345	355,119
DSM Annual Utility Cost	9,945	10,776	10,232	11,529	13,700	15,853	17,218	19,362	19,316	19,250	19,225	18,970	18,970	18,884	18,884	18,600	18,574	18,285	18,239	18,029	
Total Levelized Utility Cost	255	614	921	1,209	1,439	1,653	1,867	2,086	2,306	2,519	2,730	2,934	3,130	3,323	3,516	3,700	3,880	4,046	4,205	4,351	
Total Costs	378,992	422,880	449,209	472,777	487,632	508,632	519,524	535,128	535,528	560,785	578,363	599,403	615,091	634,571	660,017	681,283	708,856	747,058	776,992	789,861	7,122,706
Key Resource Decisions (increm. MDT/day)																					
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Eastside Loop	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Cross-Cascades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	10	18	27	
GTN Malin to Madras	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	10	18	27	
GTN Stanfield to Madras	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Increase NWP Mainline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
GTN Malin to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Newport LNG Delivery	-	-	-	-	-	-	-	-	5	5	8	8	8	8	8	8	40	40	40	40	
N-MAX	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Ruby Pipeline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Gorge Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Expansion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Recall	-	-	-	-	-	-	-	-	-	8	13	23	34	45	56	75	75	75	75	75	
Satellite LNG Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NW Natural Transmission																					
North WVF (POR to SAL)	30.6	30.7	16.1	23.6	17.6	30.4	24.2	18.7	28.0	16.3	13.9	29.0	22.3	18.0	20.5	21.8	-	8.7	2.7	-	
Harrisburg River Crossing (ALB to EUG)	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	
MWVF	-	13.2	-	-	-	6.7	-	-	-	-	-	13 9	0.6	0.6	1.1	1.6	4.5	3.0	3.7	4.6	
Storage																					
GASCO LNG	120.0	120.0	120.0	120.0	120.0	120.0	120 0	120.0	120.0	120.0	120.0	120.0	120 0	120.0	120 0	120.0	120.0	120.0	120.0	120.0	
JP	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	
MIST	275.0	275.0	275.0	275 0	275.0	275.0	275.0	275 0	275.0	275.0	275.0	275.0	275.0	275.0	275 0	275.0	262.8	268.1	274.4	275.0	
NEWPORT LNG	57.9	57.9	57 9	57 9	57 9	58.0	58.1	58 1	63.3	63.4	66.9	67.1	67.2	67.4	67.5	67.7	99.4	99.6	99.8	100.0	
PLYMOUTH LNG	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60 1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	
March Point	-	-	-	-	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	
Peak Day Resources-Recall Agreements																					
Recall 1	23.4	30.0	23.4	30.0	19.7	18.3	25.9	27.3	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	
Recall 2	8.0	0.0	8 0	2.1	2.3	8.0	5.6	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	
Recall 3	1.0	0.1	-	-	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	

1522 - High Customers	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	79,646	81,156	83,107	85,045	86,296	87,627	88,974	90,790	91,994	93,526	95,048	97,090	98,324	100,047	101,853	104,176	105,768	107,904	110,287	112,461	
Forecast DSM	266	640	960	1,267	1,501	1,725	1,949	2,188	2,409	2,634	2,855	3,081	3,275	3,478	3,681	3,890	4,064	4,238	4,406	4,578	
Forecast Demand (net DSM)	79,381	80,516	82,147	83,779	84,794	85,902	87,025	88,603	89,585	90,892	92,193	94,009	95,049	96,569	98,172	100,286	101,704	103,665	105,880	107,883	
Served Demand	79,381	80,516	82,147	83,779	84,794	85,902	87,025	88,603	89,585	90,892	92,193	94,009	95,049	96,569	98,172	100,286	101,704	103,665	105,880	107,882	
Unserved Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	924.6	926.7	934.6	942.0	952.5	964.8	977.8	989.4	1,004.2	1,018.2	1,032.4	1,047.5	1,063.9	1,080.3	1,095.9	1,113.6	1,132.7	1,152.1	1,172.1	1,193.6	
Peak Day Demand Served	924.6	926.7	934.6	942.0	952.5	964.8	977.8	989.4	1,004.2	1,018.2	1,032.4	1,047.5	1,063.9	1,080.3	1,095.9	1,113.6	1,132.5	1,151.9	1,171.9	1,193.4	
Peak Day Demand Unserved	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2	0.2	0.2	
COST ($000 Nominal)																					
Supply Fixed Costs	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	
Supply Variable Costs	248,354	292,907	321,973	345,700	360,847	382,573	394,529	411,426	412,449	442,398	461,746	485,163	502,967	523,701	547,781	574,308	604,251	644,302	675,622	688,642	
Total Supply Costs	248,415	292,968	322,034	345,760	360,908	382,634	394,590	411,487	412,510	442,459	461,807	485,224	503,028	523,762	547,842	574,369	604,312	644,363	675,683	688,703	5,574,979
Transport Fixed Costs	92,499	93,332	93,384	93,384	94,880	95,181	95,181	95,181	95,181	95,181	95,181	95,181	95,181	95,181	95,181	96,401	98,907	102,391	105,724	109,163	1,237,705
Transport Variable Costs	2,952	2,976	3,057	3,141	3,157	3,224	3,335	3,583	3,549	3,659	3,809	3,947	4,001	4,080	4,126	4,216	4,208	4,147	3,904	3,825	
Total Transport Cost	95,452	96,308	96,440	96,525	98,037	98,404	98,516	98,764	98,730	98,839	98,990	99,127	99,182	99,260	99,307	100,617	103,114	106,537	109,628	112,987	1,283,321
Storage Fixed Cost	24,959	25,092	25,349	25,465	25,701	26,155	26,614	27,123	27,666	28,199	29,032	30,090	31,177	32,367	32,963	33,016	33,016	33,016	33,016	33,016	
Storage Variable Cost	1,331	1,166	1,182	1,344	1,375	1,503	1,667	1,480	1,914	2,108	2,157	2,348	2,477	2,640	2,696	2,785	2,854	2,930	3,052	3,072	
Total Storage Cost	26,291	26,258	26,531	26,809	27,076	27,658	28,281	28,603	29,580	30,307	31,189	32,438	33,654	35,007	35,659	35,801	35,870	35,946	36,068	36,088	390,373
DSM Annual Utility Cost	9,945	10,776	10,232	11,529	13,700	15,853	17,218	19,362	19,316	19,250	19,225	18,970	18,970	18,884	18,884	18,600	18,574	18,285	18,239	18,029	
Total Levelized Utility Cost	255	614	921	1,209	1,439	1,653	1,867	2,086	2,306	2,519	2,730	2,934	3,130	3,323	3,516	3,700	3,880	4,046	4,205	4,351	
Total Costs	380,103	426,309	455,237	480,622	499,721	524,549	538,606	558,216	560,136	590,857	611,211	635,759	654,834	676,914	701,692	729,386	761,871	805,131	839,618	855,807	7,454,250
Key Resource Decisions (increm. MDT/day)																					
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Eastside Loop	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Cross Cascades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	20	31	43	
GTN Malin to Madras	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	20	31	43	
GTN Stanfield to Madras	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Increase NWP Mainline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
GTN Malin to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Newport LNG Delivery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39	39	39	39	39	
N-MAX	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Ruby Pipeline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Gorge Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Expansion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Recall	-	-	6	13	13	24	36	48	62	76	90	117	145	174	207	210	210	210	210	210	
Satellite LNG Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NW Natural Transmission																					
North WVF (POR to SAL)	31.1	26.5	20.2	24.7	20.6	36.3	30.0	26.0	42.7	31.4	33.0	50.0	44.2	41.3	44.0	7.5	15.9	27.7	22.5	21.0	
Harrisburg River Crossing (ALB to EUG)	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	
MWVF	-	13.6	-	-	-	8.8	1.1	1.1	2.3	3.1	3.2	18.3	5.4	6.2	6.4	7.3	8.3	9.3	10.2	11.5	
Storage																					
GASCO LNG	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	
JP	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	
MIST	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	263.6	250.5	232.2	206.6	217.0	224.9	234.1	244.8	
NEWPORT LNG	58.0	58.0	58.1	58.2	58.4	58.5	58.7	58.9	59.1	59.3	59.5	59.7	59.9	60.2	60.4	99.2	99.5	99.7	100.0	100.0	
PLYMOUTH LNG	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	
March Point	-	-	-	-	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	
Peak Day Resources-Recall Agreements																					
Recall 1	26.8	30.0	30.0	30.0	28.4	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	
Recall 2	8.0	6.8	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	
Recall 3	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	

1523 - Medium Emerging	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	79,968	81,852	84,379	86,943	88,919	90,858	93,136	95,843	97,920	100,708	104,131	106,596	108,335	110,434	112,712	116,948	118,786	121,215	123,660	124,188	
Forecast DSM	266	640	960	1,267	1,501	1,725	1,949	2,188	2,409	2,634	2,855	3,081	3,275	3,478	3,681	3,890	4,064	4,238	4,406	4,578	
Forecast Demand (net DSM)	79,702	81,212	83,419	85,676	87,417	89,132	91,187	93,655	95,511	98,075	101,276	103,515	105,060	106,955	109,031	113,058	114,723	116,977	119,254	119,610	
Served Demand	79,702	81,212	83,419	85,676	87,417	89,132	91,187	93,655	95,511	98,075	101,276	103,515	105,060	106,955	109,031	113,058	114,722	116,976	119,254	119,610	
Unserved Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	924.4	926.4	933.9	940.7	950.4	961.4	973.9	984.4	998.3	1,012.2	1,028.1	1,040.8	1,055.2	1,069.3	1,082.8	1,102.2	1,118.5	1,135.1	1,151.7	1,150.4	
Peak Day Demand Served	924.4	926.4	933.9	940.7	950.4	961.4	973.9	984.4	998.3	1,012.2	1,028.1	1,040.8	1,055.2	1,069.3	1,082.8	1,102.1	1,118.3	1,134.9	1,151.5	1,150.2	
Peak Day Demand Unserved	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2	0.2	0.2	0.2	
COST ($000 Nominal)																					
Supply Fixed Costs	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	
Supply Variable Costs	249,574	295,281	327,061	353,764	372,097	397,224	414,827	437,009	441,685	478,692	506,831	534,131	556,548	576,801	607,604	649,470	683,657	728,313	761,131	763,579	
Total Supply Costs	249,635	295,342	327,122	353,825	372,157	397,284	414,888	437,070	441,746	478,753	506,892	534,192	556,609	576,862	607,665	649,531	683,718	728,373	761,192	763,640	5,998,038
Transport Fixed Costs	92,499	93,332	93,384	93,384	94,880	95,181	95,181	95,181	95,181	95,181	95,181	95,181	95,181	95,181	96,325	100,104	102,728	105,417	108,151	108,202	1,243,618
Transport Variable Costs	2,968	3,004	3,115	3,231	3,287	3,397	3,613	3,836	3,909	4,102	4,306	4,411	4,487	4,543	4,603	4,591	4,503	4,476	4,391	4,390	
Total Transport Cost	95,467	96,336	96,499	96,615	98,167	98,578	98,794	99,016	99,090	99,283	99,486	99,591	99,668	99,724	100,927	104,695	107,231	109,892	112,541	112,593	1,292,726
Storage Fixed Cost	24,959	25,078	25,312	25,418	25,610	26,023	26,454	27,248	28,424	29,789	30,983	32,054	33,254	33,777	33,777	33,777	33,777	33,777	33,777	33,777	
Storage Variable Cost	1,402	1,174	1,186	1,334	1,348	1,475	1,878	1,805	2,190	2,159	2,292	2,546	2,673	2,778	2,820	2,894	2,944	2,975	3,255	3,322	
Total Storage Cost	26,361	26,252	26,498	26,753	26,958	27,498	28,332	29,053	30,614	31,947	33,275	34,600	35,926	36,554	36,597	36,671	36,721	36,752	37,032	37,098	399,151
DSM Annual Utility Cost	9,945	10,776	10,232	11,529	13,700	15,853	17,218	19,362	19,316	19,250	19,225	18,970	18,970	18,884	18,884	18,600	18,574	18,285	18,239	18,029	
Total Levelized Utility Cost	255	614	921	1,209	1,439	1,653	1,867	2,086	2,306	2,519	2,730	2,934	3,130	3,323	3,516	3,700	3,880	4,046	4,205	4,351	
Total Costs	381,409	428,705	460,350	488,721	510,983	539,213	559,232	584,501	590,766	629,234	658,878	687,354	711,174	732,025	764,074	809,496	846,244	893,303	929,004	931,360	7,895,492
Key Resource Decisions (increm. MDT/day)																					
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Eastside Loop	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Cross-Cascades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	23	33	43	43	
GTN Malin to Madras	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	23	33	43	43	
GTN Stanfield to Madras	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Increase NWP Main'ine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
GTN Malin to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Newport LNG Delivery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	36	40	40	40	40	40	
N-MAX	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Ruby Pipeline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Gorge Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Expansion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Recall	-	-	5	12	12	21	33	43	71	104	142	168	197	230	230	230	230	230	230	230	
Satellite LNG Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NW Natural Transmission																					
North WVF (POR to SAL)	30.9	25.4	18.3	23.9	19.4	33.8	27.0	22.5	38.3	26.2	27.2	43.4	36.9	33.3	-	-	4.8	16.0	10.0	4.3	
Harrisburg River Crossing (ALB to EUG)	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	
MWVF	-	13.4	-	-	-	7.9	-	-	0.7	1.2	1.1	16.0	2.8	3.4	3.4	3.9	4.7	5.4	6.1	6.0	
Storage																					
GASCO LNG	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	
JP	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	
MIST	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	273.7	254.0	230.9	216.3	200.9	180.9	156.9	159.3	166.1	173.0	179.7	178.2	
NEWPORT LNG	58.0	58.0	58.0	58.1	58.2	58.3	58.4	58.5	58.7	58.8	59.0	59.1	59.3	59.4	95.8	99.4	99.6	99.8	100.0	100.0	
PLYMOUTH LNG	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	
March Point	-	-	-	-	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	
Peak Day Resources-Recall Agreements																					
Recall 1	26.6	30.0	30.0	30.0	27.7	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	
Recall 2	8.0	6.6	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	
Recall 3	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	

1524 - High Emerging	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	81,642	85,657	90,160	95,976	101,265	119,020	137,715	158,928	180,988	206,852	211,798	217,817	222,333	227,984	233,695	240,568	246,009	252,711	259,762	260,663	
Forecast DSM	266	640	960	1,267	1,501	1,725	1,949	2,188	2,409	2,634	2,855	3,081	3,275	3,478	3,681	3,890	4,064	4,238	4,406	4,578	
Forecast Demand (net DSM)	81,377	85,017	89,199	94,709	99,764	117,295	135,765	156,741	178,579	204,219	208,943	214,736	219,058	224,505	230,014	236,678	241,945	248,472	255,356	256,085	
Served Demand	81,376	85,017	89,199	94,709	99,764	117,247	135,765	156,741	178,579	204,219	208,943	214,736	219,058	224,505	230,014	236,678	241,945	248,472	255,356	256,085	
Unserved Demand	1	0	0	0	0	47	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	929.0	936.8	949.7	965.3	984.3	1,038.6	1,096.0	1,156.8	1,225.8	1,303.0	1,323.1	1,344.7	1,367.5	1,391.3	1,414.3	1,440.0	1,467.1	1,495.4	1,524.6	1,523.3	
Peak Day Demand Served	927.8	936.8	949.7	965.3	984.3	991.2	1,096.0	1,156.8	1,225.8	1,303.0	1,323.1	1,344.7	1,367.5	1,391.3	1,414.3	1,440.0	1,467.1	1,495.4	1,524.6	1,523.3	
Peak Day Demand Unserved	1.2	-	-	-	-	47.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
COST ($000 Nominal)																					
Supply Fixed Costs	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	
Supply Variable Costs	256,310	311,248	354,397	395,814	433,271	522,645	631,573	725,902	827,168	1,000,110	1,053,751	1,118,769	1,172,287	1,235,683	1,314,525	1,388,952	1,458,271	1,561,458	1,637,985	1,642,883	
Total Supply Costs	256,371	311,309	354,458	395,874	433,332	522,706	631,634	725,963	827,229	1,000,171	1,053,812	1,118,829	1,172,348	1,235,743	1,314,586	1,389,013	1,458,332	1,561,519	1,638,046	1,642,944	10,617,399
Transport Fixed Costs	92,499	93,332	93,384	93,384	94,880	96,371	115,462	122,402	134,103	148,698	151,755	155,085	158,488	162,088	165,655	169,506	173,563	177,938	182,456	182,540	1,664,815
Transport Variable Costs	3,044	3,189	3,415	3,759	4,025	4,698	4,386	4,518	4,651	4,621	4,594	4,584	4,553	4,541	4,551	4,556	4,442	4,391	4,168	4,172	
Total Transport Cost	95,543	96,521	96,799	97,142	98,905	101,069	119,848	126,920	138,753	153,320	156,349	159,668	163,041	166,629	170,206	174,062	178,006	182,329	186,624	186,712	1,718,421
Storage Fixed Cost	25,161	25,576	26,650	28,299	30,860	32,157	32,157	32,157	32,157	32,157	32,157	32,157	32,157	32,157	32,157	32,157	32,157	32,157	32,157	32,157	
Storage Variable Cost	1,449	1,415	1,585	1,661	1,943	2,219	2,200	2,288	2,367	2,391	2,497	2,600	2,695	2,758	2,848	2,940	3,006	2,997	3,170	3,215	
Total Storage Cost	26,610	26,991	28,235	29,960	32,803	34,376	34,357	34,445	34,525	34,549	34,654	34,757	34,853	34,915	35,006	35,097	35,163	35,154	35,327	35,372	422,304
DSM Annual Utility Cost	9,945	10,776	10,232	11,529	13,700	15,853	17,218	19,362	19,316	19,250	19,225	18,970	18,970	18,884	18,884	18,600	18,574	18,285	18,239	18,029	
Total Levelized Utility Cost	255	614	921	1,209	1,439	1,653	1,867	2,086	2,306	2,519	2,730	2,934	3,130	3,323	3,516	3,700	3,880	4,046	4,205	4,351	
Total Costs	388,470	445,597	489,724	534,506	578,740	674,005	803,057	906,690	1,019,823	1,207,289	1,264,040	1,332,225	1,389,212	1,456,172	1,538,682	1,616,771	1,690,076	1,797,286	1,878,236	1,883,057	12,963,701
Key Resource Decisions (increm. MDT/day)																					
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Eastside Loop	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Cross-Cascades	-	-	-	-	-	-	95	129	188	260	275	292	309	327	345	364	384	406	428	429	
GTN Malin to Madras	-	-	-	-	-	-	95	130	188	260	276	292	309	327	345	364	384	406	429	429	
GTN Stanfield to Madras	-	-	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	1	1	
Increase NWP Mainline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
GTN Malin to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Newport LNG Delivery	-	-	-	-	-	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	
N-MAX	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Ruby Pipeline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Gorge Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Expansion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Recall	-	9	21	60	106	188	188	188	188	188	188	188	188	188	188	188	188	188	188	188	
Satellite LNG Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NW Natural Transmission																					
North WVF (POR to SAL)	30.8	24.1	18.4	24.0	19.5	-	-	-	1.1	-	-	6.4	-	1.9	-	5.5	7.8	19.0	13.1	6.9	
Harrisburg River Crossing (ALB to EUG)	8.0	2.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	
MWVF	-	6.9	-	-	-	9.6	0.3	13.8	0.3	11.7	10.5	16.1	3.0	3.0	3.6	4.2	4.9	5.7	6.4	6.4	
Storage																					
GASCO LNG	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	
JP	46.0	46.0	46.0	46.0	46.0	43.1	44.6	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	
MIST	275.0	275.0	275.0	263.8	223.1	108.7	117.3	176.7	154.0	158.6	163.5	168.7	174.7	180.8	186.0	192.7	199.8	206.5	213.3	211.5	
NEWPORT LNG	58.0	58.0	58.0	58.1	58.2	95.9	96.1	96.2	96.3	96.5	96.6	96.8	96.9	97.1	97.3	97.5	97.6	97.8	98.0	98.0	
PLYMOUTH LNG	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	
March Point	-	-	-	-	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	
Peak Day Resources-Recall Agreements																					
Recall 1	30.0	30.0	30.0	30.0	30.0	30.0	30.0	-	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	
Recall 2	8.0	8.0	8.0	8.0	8.0	8.0	8.0	6.5	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	
Recall 3	1.0	1.0	1.0	1.0	1.0	1.0	1.0	-	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	

1525 - High Sumas	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	79,519	80,884	82,603	84,311	85,313	86,368	87,426	88,915	89,804	91,006	92,200	93,901	94,828	96,242	97,735	99,716	101,003	102,808	104,853	105,329	
Forecast DSM	266	640	960	1,267	1,501	1,725	1,949	2,188	2,409	2,634	2,855	3,081	3,275	3,478	3,681	3,890	4,064	4,238	4,406	4,578	
Forecast Demand (net DSM)	79,253	80,244	81,643	83,045	83,811	84,642	85,476	86,727	87,395	88,373	89,345	90,819	91,552	92,764	94,055	95,826	96,940	98,569	100,446	100,751	
Served Demand	79,253	80,244	81,643	83,045	83,811	84,642	85,476	86,727	87,395	88,373	89,345	90,819	91,552	92,764	94,055	95,826	96,940	98,569	100,446	100,751	
Unserved Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	923.2	923.7	929.0	933.5	940.5	949.1	958.2	965.5	976.0	985.6	995.4	1,006.1	1,018.2	1,030.4	1,041.8	1,055.2	1,069.8	1,084.7	1,100.1	1,098.9	
Peak Day Demand Served	923.2	923.7	929.0	933.5	940.5	949.1	958.2	965.5	976.0	985.6	995.4	1,006.1	1,018.2	1,030.4	1,041.8	1,055.1	1,069.7	1,084.6	1,100.1	1,098.8	
Peak Day Demand Unserved	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1	0.1	0.1	0.1	
COST ($000 Nominal)																					
Supply Fixed Costs	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	
Supply Variable Costs	249,528	295,152	328,394	340,667	353,464	374,071	385,719	400,800	400,218	427,377	444,960	465,935	480,992	497,106	520,473	546,113	574,510	610,197	639,186	641,368	
Total Supply Costs	249,589	295,213	328,455	340,728	353,524	374,132	385,780	400,861	400,279	427,438	445,020	465,996	481,052	497,167	520,533	546,174	574,571	610,258	639,246	641,429	**5,400,895**
Transport Fixed Costs	92,499	93,332	93,384	93,384	94,880	95,181	95,181	95,181	95,181	95,181	95,181	95,181	95,181	95,537	96,435	98,504	100,651	102,957	105,350	105,468	**1,238,948**
Transport Variable Costs	2,996	3,071	3,246	3,271	3,238	3,259	3,342	3,565	3,487	3,583	3,708	3,813	3,848	3,890	3,942	3,984	3,979	3,921	3,662	3,678	
Total Transport Cost	95,495	96,403	96,630	96,655	98,118	98,440	98,523	98,745	98,668	98,763	98,889	98,993	99,029	99,426	100,378	102,488	104,630	106,879	109,012	109,146	**1,284,105**
Storage Fixed Cost	24,959	25,524	27,858	29,226	29,226	29,347	29,773	30,442	31,221	31,872	32,531	33,325	34,069	34,353	34,353	34,353	34,353	34,353	34,353	34,353	
Storage Variable Cost	1,551	1,491	1,614	1,681	1,692	1,836	2,039	1,891	2,384	2,235	2,299	2,492	2,589	2,688	2,665	2,765	2,864	2,920	3,052	3,091	
Total Storage Cost	26,510	27,015	29,472	30,906	30,918	31,183	31,813	32,333	33,606	34,107	34,830	35,816	36,658	37,041	37,017	37,118	37,217	37,273	37,405	37,444	**424,081**
DSM Annual Utility Cost	9,945	10,776	10,232	11,529	13,700	15,853	17,218	19,362	19,316	19,250	19,225	18,970	18,970	18,884	18,884	18,600	18,574	18,285	18,239	18,029	
Total Levelized Utility Cost	255	614	921	1,209	1,439	1,653	1,867	2,086	2,306	2,519	2,730	2,934	3,130	3,323	3,516	3,700	3,880	4,046	4,205	4,351	
Total Costs	381,539	429,407	464,788	479,817	496,261	519,608	533,334	551,301	551,869	579,559	597,965	619,776	635,710	652,519	676,813	704,379	734,992	772,695	803,902	806,048	**7,314,658**
Key Resource Decisions (increm. MDT/day)																					
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Eastside Loop	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Cross-Cascades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	15	24	33	33	
GTN Malin to Madras	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	15	24	33	33	
GTN Stanfield to Madras	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Increase NWP Mainline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
GTN Malin to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Newport LNG Delivery	-	-	-	-	-	-	-	-	-	-	-	-	-	11	40	40	40	40	40	40	
N MAX	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Ruby Pipeline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Gorge Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Expansion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Recall	-	-	25	111	111	111	117	132	151	172	186	206	227	245	245	245	245	245	245	245	
Satellite LNG Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NW Natural Transmission																					
North WVF (POR to SAL)	30.9	28.1	18.1	23.8	19.3	34.7	35.0	22.3	38.0	26.9	26.8	43.1	36.5	21.0	-	-	4.2	15.3	9.3	3.6	
Harrisburg River Crossing (ALB to EUG)	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	
MWVF	-	13.4	-	-	-	7.8	-	-	0.7	1.2	1.0	15.9	2.6	2.6	8.0	3.8	4.5	5.2	5.9	5.8	
Storage																					
GASCO LNG	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	
JP	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	
MIST	275.0	275.0	262.8	176.9	177.5	195.5	184.3	175.9	166.8	159.0	149.9	140.6	130.4	114.5	99.1	105.3	112.6	113.9	120.7	119.0	
NEWPORT LNG	58.0	58.0	58.0	58.1	58.2	58.3	58.4	58.5	58.7	58.8	59.0	59.1	59.3	70.7	99.3	99.4	99.6	99.8	100.0	100.0	
PLYMOUTH LNG	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	
March Point	-	-	-	-	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	
Peak Day Resources-Recall Agreements																					
Recall 1	25.4	30.0	30.0	30.0	25.7	16.8	30.0	30.0	30.0	26.7	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	
Recall 2	8.0	3.9	8.0	8.0	6.7	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	
Recall 3	1.0	1.0	1.0	1.0	1.0	-	1.0	1.0	1.0	-	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	

1526 - High NA Prices	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	79,185	80,518	82,177	83,361	83,365	84,095	84,894	86,186	86,754	87,631	88,473	89,856	90,474	91,432	92,409	93,881	94,400	95,166	96,389	96,825	
Forecast DSM	266	640	960	1,267	1,501	1 725	1,949	2,188	2,409	2,634	2,855	3,081	3,275	3,478	3,681	3,890	4,064	4,238	4 406	4,578	
Forecast Demand (net DSM)	78,919	79,878	81,217	82 094	81,863	82,370	82,945	83,999	84,344	84,998	85,618	86,775	87,199	87,954	88,729	89,991	90,337	90,927	91,982	92,247	
Served Demand	78,919	79,878	81,217	82,094	81,863	82,370	82,945	83,999	84,344	84,998	85,618	86,775	87 199	87,954	88,729	89,991	90,337	90,927	91,981	92,247	
Unserved Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	
Peak Day Demand (net DSM)	921.9	923.5	926.1	921.6	918.7	923 1	928.2	935.4	943.5	948.0	953.7	961.3	969.7	975.9	983.9	990.7	997 4	998.1	1,007.6	1,006.3	
Peak Day Demand Served	921.9	923.5	926.1	921.6	918.7	923 1	928.2	935.4	943.5	948.0	953.7	961 3	969 7	975.9	983.9	990 7	997.3	998.1	1,006.3	1,006.3	
Peak Day Demand Unserved	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1	1.3	0.1	
COST ($000 Nominal)																					
Supply Fixed Costs	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	
Supply Variable Costs	266,955	345,041	417,883	494,549	566,466	614,886	642,688	667,450	679,327	721,181	752,094	783,107	804,296	842,387	881,626	932,412	984,511	1,061,219	1,121,303	1,133,732	
Total Supply Costs	267,016	345,102	417,944	494,609	566,527	614,946	642,749	667,511	679,388	721,241	752,155	783,168	804,357	842,448	881,687	932,473	984,572	1,061,280	1,121,364	1,133,793	8,635,174
Transport Fixed Costs	92,499	93,332	93,384	93,384	94,880	95,181	95,181	95,181	95,263	95,263	95,282	95,518	95,780	95,780	96,028	96,242	96,447	96,650	98,869	98,869	1,228,781
Transport Variable Costs	2 936	2,976	3,039	3,157	3,095	3,145	3,249	3,370	3.321	3,374	3,474	3,526	3,562	3,594	3,641	3.710	3,730	3,690	3,495	3,542	
Total Transport Cost	95,435	96,308	96,422	96,540	97,976	98,326	98,429	98,550	98,584	98,636	98,756	99,043	99.342	99,374	99,669	99,952	100,177	100,339	102,364	102,411	1,271,623
Storage Fixed Cost	24,959	24,959	24,959	24,959	24,959	24,959	24,959	24,959	25,058	25,242	25,323	25,323	25,461	25,558	25,558	25,558	25,558	25,558	25,558	25,558	
Storage Variable Cost	1,569	1,514	1,868	2,052	2,038	2,352	2 754	2,204	2,812	2,515	2,709	3,017	3,153	3,282	3,315	3,714	3,893	3,498	3,639	4,039	
Total Storage Cost	26,529	26,474	26,827	27,011	26,997	27,311	27,713	27,163	27,870	27,757	28 031	28,340	28,613	28,841	28,874	29,273	29,451	29.056	29,197	29,598	359,002
DSM Annual Utility Cost	9,945	10,776	10,232	11,529	13,700	15,853	17,218	19,362	19,316	19,250	19,225	18,970	18,970	18,884	18,884	18,600	18,574	18,285	18,239	18,029	
Total Levelized Utility Cost	255	614	921	1,209	1,439	1,653	1,867	2,086	2,306	2,519	2,730	2 934	3,130	3,323	3,516	3,700	3,880	4,046	4,205	4,351	
Total Costs	398,926	478,660	551,425	629,690	705,200	756,436	786,109	812,587	825,157	866,885	898,167	929 522	951,282	989,547	1,029 114	1,080,298	1,132,774	1,208,961	1,271,165	1,283,831	10,471,375
Key Resource Decisions (increm. MDT/day)																					
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Eastside Loop	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Cross-Cascades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	9	9	
GTN Malin to Madras	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	9	9	
GTN Stanfield to Madras	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Increase NWP Mainline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
GTN Malin to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Newport LNG Delivery	-	-	-	-	-	-	-	-	3	3	3	11	19	19	27	34	40	40	40	40	
N-MAX	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Ruby Pipeline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Gorge Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Expansion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Recall	-	-	-	-	-	-	-	-	-	4	9	9	9	16	16	16	16	16	16	16	
Satellite LNG Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NW Natural Transmission																					
North WVF (POR to SAL)	30.6	28 4	18.6	22.6	16.9	27.3	29.1	18.9	29.9	17.9	17.9	24.6	9.4	4.7	-	6.0	-	0.2	1.5	-	
Harrisburg River Crossing (ALB to EUG)	8.0	8.0	8.0	8.0	8.0	5.1	7 1	8 0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	
MWVF	-	13.4	-	-	-	3.4	-	-	-	-	-	13.3	-	0.2	1.8	14.5	0.5	0.4	14.5	0.7	
Storage																					
GASCO LNG	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	
JP	46.0	46.0	46.0	46.0	46.0	46.0	46 0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	
MIST	275.0	275 0	275.0	275.0	275.0	275.0	275 0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	
NEWPORT LNG	58.0	58.0	58.0	58.0	57 9	58.0	58.1	58.2	60.9	61.0	61.7	69.2	77 6	77.7	85.7	92.5	99 1	99.1	99.2	99.2	
PLYMOUTH LNG	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60 1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	
March Point	-	-	-	-	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12 2	12.2	12.2	12.2	12.2	12.2	
Peak Day Resources-Recall Agreements																					
Recall 1	24.1	30.0	28.5	23.0	13.0	13.5	17.5	24.6	30 0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	
Recall 2	8.0	3.7	8.0	8.0	3.2	8 0	8.0	8.0	8.0	8.0	8.0	8.0	8 0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	
Recall 3	1.0	1.0	-	1.0	1.0	-	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	

1529 - Out Peak Open	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	79,519	80,884	82,603	84,311	85,313	86,368	87,426	88,915	89,804	91,006	92,200	93,901	94,828	96,242	97,735	99,716	101,003	102,808	104,853	105,329	
Forecast DSM	266	640	960	1,267	1,501	1,725	1,949	2,188	2,409	2,634	2,855	3,081	3,275	3,478	3,681	3,890	4,064	4,238	4,406	4,578	
Forecast Demand (net DSM)	79,253	80,244	81,643	83,045	83,811	84,642	85,476	86,727	87,395	88,373	89,345	90,819	91,552	92,764	94,055	95,826	96,940	98,569	100,446	100,751	
Served Demand	79,253	80,244	81,643	83,045	83,811	84,642	85,470	86,727	87,395	88,373	89,345	90,819	91,552	92,764	94,055	95,826	96,940	98,569	100,446	100,751	
Unserved Demand	0	0	0	0	0	0	6	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	923.2	923.7	929.0	933.5	940.5	949.1	958.2	965.5	976.0	985.6	995.4	1,006.1	1,018.2	1,030.4	1,041.8	1,055.2	1,069.8	1,084.7	1,100.1	1,098.9	
Peak Day Demand Served	923.2	923.7	929.0	933.5	940.5	949.1	952.2	965.5	976.0	985.6	995.4	1,006.1	1,018.2	1,030.4	1,041.8	1,055.2	1,069.8	1,084.7	1,100.1	1,098.9	
Peak Day Demand Unserved	-	-	-	-	-	-	6.0	-	-	-	-	-	-	-	-	-	-	-	-	-	
COST ($000 Nominal)																					
Supply Fixed Costs	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	
Supply Variable Costs	247,873	291,375	319,736	342,620	355,741	396,550	383,977	392,069	401,086	424,830	441,594	462,211	478,225	496,092	520,929	546,301	574,444	609,548	638,621	642,625	
Total Supply Costs	247,934	291,436	319,797	342,681	355,802	396,611	384,037	392,130	401,147	424,890	441,654	462,272	478,286	496,153	520,990	546,362	574,505	609,608	638,681	642,686	**5,394,420**
Transport Fixed Costs	92,499	93,332	93,332	93,332	94,829	95,129	113,779	112,769	112,769	112,769	112,769	112,769	113,452	112,769	112,769	112,821	113,226	114,594	114,690	114,744	**1,360,252**
Transport Variable Costs	2,946	2,961	3,036	3,113	3,099	3,462	3,061	3,431	3,523	3,539	3,704	3,768	3,657	3,871	3,920	3,973	3,895	3,757	3,610	3,588	
Total Transport Cost	95,445	96,294	96,368	96,445	97,928	98,592	116,840	116,200	116,292	116,308	116,472	116,536	117,109	116,640	116,688	116,793	117,121	118,351	118,300	118,332	**1,404,346**
Storage Fixed Cost	24,959	25,324	25,441	25,510	25,588	31,362	35,216	35,216	35,216	35,216	35,216	35,216	35,216	35,216	35,216	35,216	35,216	35,216	35,216	35,216	
Storage Variable Cost	1,332	1,218	1,231	1,398	1,410	1,651	2,055	1,726	2,131	2,042	2,049	2,174	2,364	2,338	2,364	2,452	2,580	2,540	2,641	2,934	
Total Storage Cost	26,291	26,542	26,672	26,909	26,998	33,014	37,271	36,942	37,347	37,258	37,265	37,390	37,580	37,554	37,581	37,668	37,796	37,756	37,857	38,150	**432,047**
DSM Annual Utility Cost	9,945	10,776	10,232	11,529	13,700	15,853	17,218	19,362	19,316	19,250	19,225	18,970	18,970	18,884	18,884	18,600	18,574	18,285	18,239	18,029	
Total Levelized Utility Cost	255	614	921	1,209	1,439	1,653	1,867	2,086	2,306	2,519	2,730	2,934	3,130	3,323	3,516	3,700	3,880	4,046	4,205	4,351	
Total Costs	379,616	425,047	453,068	477,563	494,428	544,069	555,367	564,634	574,101	597,707	614,617	635,169	651,945	669,231	694,143	719,423	747,996	784,001	813,077	817,197	7,436,389
Key Resource Decisions (increm. MDT/day)																					
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Eastside Loop	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Cross-Cascades	-	-	-	-	-	-	73	73	73	73	73	73	73	73	73	73	73	73	73	73	
GTN Malin to Madras	-	-	-	-	-	-	18	-	-	-	-	-	41	-	-	-	-	27	29	30	
GTN Stanfield to Madras	-	-	-	-	-	-	55	-	-	-	-	-	-	-	-	1	12	12	12	12	
Increase NWP Mainline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
GTN Malin to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Newport LNG Delivery	-	-	-	-	-	-	40	40	40	40	40	40	40	40	40	40	40	40	40	40	
N-MAX	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Ruby Pipeline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Gorge Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Expansion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Recall	-	-	1	6	6	9	201	201	201	201	201	201	201	201	201	201	201	201	201	201	
Satellite LNG Albany	-	-	-	-	-	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	
Satellite LNG Eugene	-	-	-	-	-	-	6	6	6	6	6	6	6	6	6	6	6	6	6	6	
Satellite LNG Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NW Natural Transmission																					
North WVF (POR to SAL)	30.9	30.6	31.3	28.2	32.7	25.8	62.2	-	-	1.4	2.8	0.1	-	-	-	-	21.5	-	26.4	26.1	
Harrisburg River Crossing (ALB to EUG)	8.0	8.0	8.0	4.5	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	
MWVF	-	-	13.4	9.9	11.9	-	41.0	14.8	13.5	0.6	1.4	11.3	4.6	-	-	6.6	26.6	0.5	27.4	27.9	
Storage																					
GASCO LNG	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	
JP	46.0	46.0	46.0	46.0	46.0	46.0	46.0	45.3	45.3	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	
MIST	275.0	275.0	275.0	275.0	275.0	275.0	275.0	98.6	107.7	188.1	135.4	133.7	252.1	158.9	170.6	184.5	199.5	196.5	209.9	199.0	
NEWPORT LNG	58.0	58.0	58.0	58.1	58.2	58.3	98.6	98.5	98.7	98.8	99.2	99.1	99.6	99.4	99.6	99.8	100.0	100.0	100.0	100.0	
PLYMOUTH LNG	60.1	60.1	60.1	60.1	60.1	60.1	0.5	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	
March Point	-	-	-	-	12.2	12.2	-	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	
Peak Day Resources-Recall Agreements																					
Recall 1	25.4	25.9	30.0	30.0	26.0	30.0	16.0	-	-	-	-	-	-	-	-	-	-	-	-	-	
Recall 2	8.0	8.0	8.0	8.0	8.0	8.0	8.0	-	-	-	-	-	-	-	-	-	-	-	-	-	
Recall 3	1.0	1.0	1.0	1.0	-	1.0	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-	

1530 - Out Peak CC 110	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	79,519	80,884	82,603	84,311	85,313	86,368	87,426	88,915	89,804	91,006	92,200	93,901	94,828	96,242	97,735	99,716	101,003	102,808	104,853	105,329	
Forecast DSM	266	640	960	1,267	1,501	1,725	1,949	2,188	2,409	2,634	2,855	3,081	3,275	3,478	3,681	3,890	4,064	4,238	4,406	4,578	
Forecast Demand (net DSM)	79,253	80,244	81,643	83,045	83,811	84,642	85,476	86,727	87,395	88,373	89,345	90,819	91,552	92,764	94,055	95,826	96,940	98,569	100,446	100,751	
Served Demand	79,253	80,244	81,643	83,045	83,811	84,642	85,452	86,727	87,395	88,373	89,345	90,819	91,552	92,764	94,055	95,826	96,940	98,569	100,446	100,751	
Unserved Demand	0	0	0	0	0	0	25	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	923.2	923.7	929.0	933.5	940.5	949.1	958.2	965.5	976.0	985.6	995.4	1,006.1	1,018.2	1,030.4	1,041.8	1,055.2	1,069.8	1,084.7	1,100.1	1,098.9	
Peak Day Demand Served	923.2	923.7	929.0	933.5	940.5	949.1	944.7	965.5	976.0	985.6	995.4	1,006.1	1,018.2	1,030.4	1,041.8	1,055.2	1,069.8	1,084.7	1,100.1	1,098.9	
Peak Day Demand Unserved	-	-	-	-	-	-	13.5	-	-	-	-	-	-	-	-	-	-	-	-	-	
COST ($000 Nominal)																					
Supply Fixed Costs	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	
Supply Variable Costs	247,873	290,588	318,972	342,178	355,455	392,544	387,877	397,311	401,649	427,765	444,693	463,766	482,607	499,345	524,292	550,563	576,558	611,784	640,408	644,679	
Total Supply Costs	247,934	290,649	319,033	342,239	355,516	392,604	387,938	397,372	401,710	427,826	444,754	463,827	482,668	499,406	524,353	550,624	576,619	611,845	640,469	644,740	**5,411,997**
Transport Fixed Costs	92,499	94,306	94,358	94,358	95,855	96,155	102,193	101,722	101,722	101,722	101,722	101,722	102,239	101,722	101,722	101,722	101,767	102,835	102,835	102,835	**1,278,800**
Transport Variable Costs	2,946	2,921	2,996	3,073	3,058	3,322	2,469	2,374	2,762	2,823	2,827	2,808	2,759	2,916	2,954	2,994	2,801	2,690	2,750	2,761	
Total Transport Cost	95,445	97,227	97,354	97,431	98,912	99,476	104,662	104,096	104,484	104,545	104,548	104,530	104,998	104,638	104,676	104,715	104,568	105,525	105,585	105,596	**1,315,880**
Storage Fixed Cost	24,959	25,306	25,411	25,480	25,558	29,198	31,395	31,395	31,395	31,395	31,395	31,395	31,395	31,395	31,395	31,395	31,395	31,395	31,395	31,395	
Storage Variable Cost	1,332	1,208	1,257	1,394	1,406	1,613	1,856	1,740	2,000	1,946	2,036	2,225	2,429	2,467	2,561	2,607	2,641	2,493	2,745	3,049	
Total Storage Cost	26,291	26,514	26,668	26,874	26,964	30,812	33,251	33,135	33,395	33,341	33,431	33,620	33,824	33,862	33,956	34,002	34,036	33,888	34,140	34,444	**401,238**
DSM Annual Utility Cost	9,945	10,776	10,232	11,529	13,700	15,853	17,218	19,362	19,316	19,250	19,225	18,970	18,970	18,884	18,884	18,600	18,574	18,285	18,239	18,029	
Total Levelized Utility Cost	255	614	921	1,209	1,439	1,653	1,867	2,086	2,306	2,519	2,730	2,934	3,130	3,323	3,516	3,700	3,880	4,046	4,205	4,351	
Total Costs	379,616	425,166	453,287	478,073	495,093	538,745	543,068	553,965	558,905	584,962	601,959	620,948	640,461	656,791	681,869	707,942	733,797	769,544	798,433	802,810	7,334,691
Key Resource Decisions (increm. MDT/day)																					
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Eastside Loop	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Cross-Cascades	-	-	-	-	-	-	110	110	110	110	110	110	110	110	110	110	110	110	110	110	
GTN Malin to Madras	-	-	-	-	-	-	98	77	77	77	77	77	109	77	77	77	78	99	99	99	
GTN Stanfield to Madras	-	-	-	-	-	-	12	1	1	1	1	1	1	1	1	1	1	1	1	1	
Increase NWP Mainline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
GTN Malin to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Newport LNG Delivery	-	-	-	-	-	-	40	40	40	40	40	40	40	40	40	40	40	40	40	40	
N-MAX	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Ruby Pipeline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
NWP Gorge Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Expansion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Recall	-	-	0	5	5	8	168	168	168	168	168	168	168	168	168	168	168	168	168	168	
Satellite LNG Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NW Natural Transmission																					
North WVF (POR to SAL)	24.3	24.4	25.3	18.4	32.2	33.7	62.2	-	-	-	67.3	34.6	69.8	-	-	-	0.9	43.0	78.8	45.2	
Harrisburg River Crossing (ALB to EUG)	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	
MWVF	-	-	-	-	-	-	41.0	16.1	1.5	14.2	41.0	41.0	41.0	9.4	7.9	5.2	6.0	41.0	41.0	41.0	
Storage																					
GASCO LNG	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	
JP	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	
MIST	275.0	275.0	275.0	275.0	275.0	275.0	275.0	136.2	147.1	221.2	167.2	178.3	244.2	203.5	215.2	228.3	241.3	233.7	248.6	247.4	
NEWPORT LNG	58.0	58.0	58.0	58.1	58.2	58.3	98.4	98.5	98.7	98.8	99.0	99.1	99.3	99.4	99.6	99.8	100.0	100.0	100.0	100.0	
PLYMOUTH LNG	60.1	60.1	60.1	60.1	60.1	60.1	0.5	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	
March Point	-	-	-	-	12.2	12.2	-	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	
Peak Day Resources-Recall Agreements																					
Recall 1	26.4	26.9	30.0	30.0	25.0	30.0	16.0	-	-	-	-	-	19.4	-	-	-	-	-	-	-	
Recall 2	8.0	8.0	8.0	8.0	8.0	8.0	8.0	-	-	-	-	-	8.0	-	-	0.7	1.9	3.2	4.5	4.4	
Recall 3	-	-	1.0	1.0	1.0	1.0	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-	

1531 - Out Peak CC 165	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	79,519	80,884	82,603	84,311	85,313	86,368	87,426	88,915	89,804	91,006	92,200	93,901	94,828	96,242	97,735	99,716	101,003	102,808	104,853	105,329	
Forecast DSM	266	640	960	1,267	1,501	1,725	1,949	2,188	2,409	2,634	2,855	3,081	3,275	3,478	3,681	3,890	4,064	4,238	4,406	4,578	
Forecast Demand (net DSM)	79,253	80,244	81,643	83,045	83,811	84,642	85,476	86,727	87,395	88,373	89,345	90,819	91,552	92,764	94,055	95,826	96,940	98,569	100,446	100,751	
Served Demand	79,253	80,244	81,643	83,045	83,811	84,642	85,452	86,727	87,395	88,373	89,345	90,819	91,552	92,764	94,055	95,826	96,940	98,569	100,446	100,751	
Unserved Demand	0	0	0	0	0	0	25	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	923.2	923.7	929.0	933.5	940.5	949.1	958.2	965.5	976.0	985.6	995.4	1,006.1	1,018.2	1,030.4	1,041.8	1,055.2	1,069.8	1,084.7	1,100.1	1,098.9	
Peak Day Demand Served	923.2	923.7	929.0	933.5	940.5	949.1	944.7	965.5	976.0	985.6	995.4	1,006.1	1,018.2	1,030.4	1,041.8	1,055.2	1,069.8	1,084.7	1,100.1	1,098.9	
Peak Day Demand Unserved	-	-	-	-	-	-	13.5	-	-	-	-	-	-	-	-	-	-	-	-	-	
COST ($000 Nominal)																					
Supply Fixed Costs	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	
Supply Variable Costs	247,873	290,588	318,972	342,178	355,455	386,402	387,846	399,224	401,146	428,238	445,074	463,622	483,097	499,826	525,041	550,411	576,695	611,924	640,430	644,997	
Total Supply Costs	247,934	290,649	319,033	342,239	355,516	386,462	387,907	399,285	401,206	428,299	445,135	463,683	483,158	499,887	525,102	550,472	576,756	611,984	640,491	645,058	5,409,723
Transport Fixed Costs	92,499	94,306	94,358	94,358	95,855	96,155	103,122	101,923	101,923	101,923	101,923	101,923	103,367	102,115	102,142	102,487	102,897	103,982	103,992	103,992	1,283,421
Transport Variable Costs	2,946	2,921	2,996	3,073	3,058	3,233	2,456	2,444	2,809	2,848	2,876	2,860	2,707	2,906	3,015	2,968	2,808	2,659	2,753	2,761	
Total Transport Cost	95,445	97,227	97,354	97,431	98,912	99,387	105,578	104,366	104,732	104,771	104,799	104,783	106,074	105,021	105,157	105,455	105,705	106,641	106,745	106,753	1,320,556
Storage Fixed Cost	24,959	25,306	25,411	25,480	25,558	27,963	29,286	29,286	29,286	29,286	29,286	29,286	29,286	29,286	29,286	29,286	29,286	29,286	29,286	29,286	
Storage Variable Cost	1,332	1,208	1,257	1,394	1,406	1,577	1,761	1,677	1,907	1,788	1,903	2,027	2,334	2,349	2,383	2,525	2,472	2,347	2,546	2,853	
Total Storage Cost	26,291	26,514	26,668	26,874	26,964	29,539	31,047	30,963	31,193	31,074	31,189	31,313	31,620	31,635	31,669	31,811	31,758	31,633	31,832	32,139	383,176
DSM Annual Utility Cost	9,945	10,776	10,232	11,529	13,700	15,853	17,218	19,362	19,316	19,250	19,225	18,970	18,970	18,884	18,884	18,600	18,574	18,285	18,239	18,029	
Total Levelized Utility Cost	255	614	921	1,209	1,439	1,653	1,867	2,086	2,306	2,519	2,730	2,934	3,130	3,323	3,516	3,700	3,880	4,046	4,205	4,351	
Total Costs	379,616	425,166	453,287	478,073	495,093	531,242	541,750	553,977	556,447	583,394	600,348	618,750	639,823	655,427	680,813	706,338	732,793	768,544	797,307	801,978	7,319,031
Key Resource Decisions (increm. MDT/day)																					
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	1	1	1	1	1	1	1	1	1	1	1	3	3	3	3	3	3	3	
Eastside Loop	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Cross-Cascades	-	-	-	-	-	-	165	165	165	165	165	165	165	165	165	165	165	165	165	165	
GTN Malin to Madras	-	-	-	-	-	-	105	77	77	77	77	77	164	77	78	84	92	114	114	114	
GTN Stanfield to Madras	-	-	-	-	-	-	60	1	1	1	1	1	1	3	3	3	3	3	3	3	
Increase NWP Mainline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
GTN Malin to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Newport LNG Delivery	-	-	-	-	-	-	40	40	40	40	40	40	40	40	40	40	40	40	40	40	
N-MAX	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Ruby Pipeline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
NWP Gorge Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Expansion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Recall	-	-	0	5	5	8	113	113	113	113	113	113	113	113	113	113	113	113	113	113	
Satellite LNG Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NW Natural Transmission																					
North WVF (POR to SAL)	24.3	24.4	25.3	18.4	32.2	33.7	62.2	-	-	-	67.3	34.6	69.8	-	-	-	0.9	43.0	78.8	45.2	
Harrisburg River Crossing (ALB to EUG)	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	
MWVF	-	-	-	-	-	-	41.0	16.1	1.5	14.2	41.0	41.0	41.0	9.4	7.9	5.2	6.0	41.0	41.0	41.0	
Storage																					
GASCO LNG	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	
JP	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	
MIST	275.0	275.0	275.0	275.0	275.0	275.0	275.0	194.0	204.9	258.7	224.9	236.0	245.3	259.2	270.4	275.0	275.0	274.1	275.0	275.0	
NEWPORT LNG	58.0	58.0	58.0	58.1	58.2	58.3	98.4	98.5	98.7	98.8	99.0	99.1	99.3	99.4	99.6	99.8	100.0	100.0	100.0	100.0	
PLYMOUTH LNG	60.1	60.1	60.1	60.1	60.1	60.1	0.5	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	
March Point	-	-	-	-	12.2	12.2	-	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	
Peak Day Resources-Recall Agreements																					
Recall 1	26.4	26.9	30.0	30.0	25.0	30.0	16.0	-	-	-	-	-	-	-	-	-	-	-	-	-	
Recall 2	8.0	8.0	8.0	8.0	8.0	8.0	8.0	-	-	-	-	-	-	-	-	0.7	1.9	3.2	4.5	4.4	
Recall 3	-	-	1.0	1.0	1.0	1.0	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-	

1533 - Out Pre Open	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	79,519	80,884	82,603	84,311	85,313	86,368	87,426	88,915	89,804	91,006	92,200	93,901	94,828	96,242	97,735	99,716	101,003	102,808	104,853	105,329	
Forecast DSM	266	640	960	1,267	1,501	1,725	1,949	2,188	2,409	2,634	2,855	3,081	3,275	3,478	3,681	3,890	4,064	4,238	4,406	4,578	
Forecast Demand (net DSM)	79,253	80,244	81,643	83,045	83,811	84,642	85,476	86,727	87,395	88,373	89,345	90,819	91,552	92,764	94,055	95,826	96,940	98,569	100,446	100,751	
Served Demand	79,253	80,244	81,643	83,045	83,811	84,642	85,470	86,727	87,395	88,373	89,345	90,819	91,549	92,764	94,055	95,826	96,940	98,569	100,446	100,751	
Unserved Demand	0	0	0	0	0	0	6	0	0	0	0	0	4	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	923.2	923.7	929.0	933.5	940.5	949.1	958.2	965.5	976.0	985.6	995.4	1,006.1	1,018.2	1,030.4	1,041.8	1,055.2	1,069.8	1,084.7	1,100.1	1,098.9	
Peak Day Demand Served	923.2	923.7	929.0	933.5	940.5	949.1	958.2	965.5	976.0	985.6	995.4	1,006.1	1,014.6	1,030.4	1,041.8	1,055.2	1,069.8	1,084.7	1,100.1	1,098.9	
Peak Day Demand Unserved	-	-	-	-	-	-	-	-	-	-	-	-	3.6	-	-	-	-	-	-	-	
COST ($000 Nominal)																					
Supply Fixed Costs	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	
Supply Variable Costs	247,873	291,303	319,660	342,561	355,694	391,684	384,826	397,353	396,830	424,869	441,825	462,906	479,585	496,729	521,690	547,223	575,125	610,882	640,010	644,111	
Total Supply Costs	247,934	291,364	319,720	342,622	355,754	391,744	384,887	397,413	396,891	424,929	441,886	462,967	479,645	496,790	521,751	547,284	575,186	610,943	640,071	644,172	5,396,360
Transport Fixed Costs	92,499	93,332	93,384	93,384	94,880	95,181	100,629	101,597	101,597	101,597	101,597	101,597	101,988	101,597	101,597	101,597	102,357	102,783	102,783	102,783	1,272,926
Transport Variable Costs	2,946	2,961	3,036	3,113	3,098	3,345	3,180	3,481	3,442	3,527	3,634	3,742	3,663	3,832	3,899	3,991	3,948	3,921	3,740	3,770	
Total Transport Cost	95,445	96,293	96,420	96,497	97,978	98,525	103,809	105,078	105,039	105,125	105,231	105,339	105,651	105,430	105,496	105,589	106,306	106,704	106,522	106,553	1,317,129
Storage Fixed Cost	24,959	25,306	25,411	25,480	25,558	28,959	30,935	30,987	30,987	30,987	30,987	30,987	30,987	30,987	30,987	30,987	30,987	30,987	30,987	30,987	
Storage Variable Cost	1,332	1,217	1,231	1,397	1,408	1,627	1,918	1,693	2,084	1,971	1,979	2,083	2,205	2,261	2,293	2,387	2,446	2,468	2,539	2,828	
Total Storage Cost	26,291	26,523	26,642	26,878	26,966	30,586	32,853	32,679	33,070	32,958	32,966	33,069	33,191	33,248	33,280	33,373	33,433	33,455	33,525	33,815	397,139
DSM Annual Utility Cost	9,945	10,776	10,232	11,529	13,700	15,853	17,218	19,362	19,316	19,250	19,225	18,970	18,970	18,884	18,884	18,600	18,574	18,285	18,239	18,029	
Total Levelized Utility Cost	255	614	921	1,209	1,439	1,653	1,867	2,086	2,306	2,519	2,730	2,934	3,130	3,323	3,516	3,700	3,880	4,046	4,205	4,351	
Total Costs	379,616	424,956	453,014	477,525	494,399	536,709	538,768	554,533	554,316	582,262	599,308	620,346	637,458	654,351	679,411	704,845	733,499	769,387	798,358	802,569	7,316,204
Key Resource Decisions (increm. MDT/day)																					
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Eastside Loop	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Cross-Cascades	-	-	-	-	-	-	23	23	23	23	23	23	23	23	23	23	23	23	23	23	
GTN Malin to Madras	-	-	-	-	-	-	23	-	-	-	-	-	23	-	-	-	15	23	23	23	
GTN Stanfield to Madras	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	
Increase NWP Mainline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
GTN Malin to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Newport LNG Delivery	-	-	-	-	-	-	40	40	40	40	40	40	40	40	40	40	40	40	40	40	
N-MAX	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Ruby Pipeline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Gorge Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Expansion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Recall	-	-	0	5	5	8	157	157	157	157	157	157	157	157	157	157	157	157	157	157	
Satellite LNG Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NW Natural Transmission																					
North WVF (POR to SAL)	30.9	30.6	30.5	27.5	30.9	25.8	85.0	-	-	0.1	2.1	3.5	-	-	-	-	13.2	2.4	18.6	18.3	
Harrisburg River Crossing (ALB to EUG)	8.0	8.0	8.0	4.5	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	
MWVF	-	-	12.6	9.1	11.1	-	33.3	1.1	13.8	0.6	1.6	15.3	5.6	2.6	3.2	6.6	18.2	5.2	19.6	20.1	
Storage																					
GASCO LNG	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	
JP	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	45.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	
MIST	275.0	275.0	275.0	275.0	275.0	275.0	275.0	151.0	160.1	176.7	179.2	190.3	244.5	215.5	226.1	238.8	237.1	242.7	257.6	256.4	
NEWPORT LNG	58.0	58.0	58.0	58.1	58.2	58.3	95.9	98.5	98.7	98.8	99.0	99.1	99.3	99.4	99.6	99.8	100.0	100.0	100.0	100.0	
PLYMOUTH LNG	60.1	60.1	60.1	60.1	60.1	60.1	14.3	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	
March Point	-	-	-	-	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	
Peak Day Resources-Recall Agreements																					
Recall 1	25.4	25.9	30.0	30.0	25.0	30.0	-	-	-	-	-	-	30.0	-	-	-	-	-	-	-	
Recall 2	8.0	8.0	8.0	8.0	8.0	8.0	-	-	-	-	-	-	8.0	-	1.0	2.2	3.4	4.6	5.9	5.8	
Recall 3	1.0	1.0	1.0	1.0	1.0	1.0	-	-	-	-	-	-	1.0	-	-	-	-	-	-	-	

1534 - Out Post Open	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	79,519	80,884	82,603	84,311	85,313	86,368	87,426	88,915	89,804	91,006	92,200	93,901	94,828	96,242	97,735	99,716	101,003	102,808	104,853	105,329	
Forecast DSM	266	640	960	1,267	1,501	1,725	1,949	2,188	2,409	2,634	2,855	3,081	3,275	3,478	3,681	3,890	4,064	4,238	4,406	4,578	
Forecast Demand (net DSM)	79,253	80,244	81,643	83,045	83,811	84,642	85,476	86,727	87,395	88,373	89,345	90,819	91,552	92,764	94,055	95,826	96,940	98,569	100,446	100,751	
Served Demand	79,253	80,244	81,643	83,045	83,811	84,642	85,470	86,727	87,395	88,373	89,345	90,819	91,551	92,764	94,055	95,826	96,940	98,569	100,446	100,751	
Unserved Demand	0	0	0	0	0	0	6	0	0	0	0	0	2	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	923.2	923.7	929.0	933.5	940.5	949.1	958.2	965.5	976.0	985.6	995.4	1,006.1	1,018.2	1,030.4	1,041.8	1,055.2	1,069.8	1,084.7	1,100.1	1,098.9	
Peak Day Demand Served	923.2	923.7	929.0	933.5	940.5	949.1	958.2	965.5	976.0	985.6	995.4	1,006.1	1,016.3	1,030.4	1,041.8	1,055.2	1,069.8	1,084.7	1,100.1	1,098.9	
Peak Day Demand Unserved	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	-	
COST ($000 Nominal)																					
Supply Fixed Costs	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	
Supply Variable Costs	247,873	291,303	319,660	342,561	355,694	389,372	384,300	397,680	397,188	425,040	442,038	463,180	479,598	496,975	521,982	547,451	575,190	611,006	640,256	644,295	
Total Supply Costs	247,934	291,364	319,720	342,622	355,754	389,433	384,361	397,741	397,249	425,101	442,099	463,241	479,659	497,036	522,042	547,512	575,251	611,067	640,316	644,356	5,395,677
Transport Fixed Costs	92,499	93,332	93,384	93,384	94,880	95,181	103,120	102,650	102,650	102,650	102,650	102,650	103,120	102,692	102,692	102,770	103,666	104,064	104,064	104,064	1,282,546
Transport Variable Costs	2,946	2,961	3,036	3,113	3,098	3,332	3,145	3,495	3,443	3,540	3,641	3,758	3,663	3,839	3,911	3,993	3,936	3,906	3,756	3,741	
Total Transport Cost	95,445	96,293	96,420	96,497	97,978	98,513	106,266	106,145	106,093	106,190	106,291	106,408	106,783	106,531	106,604	106,763	107,602	107,971	107,820	107,805	1,326,740
Storage Fixed Cost	24,959	25,306	25,411	25,480	25,558	29,857	32,668	32,668	32,668	32,668	32,668	32,668	32,668	32,668	32,668	32,668	32,668	32,668	32,668	32,668	
Storage Variable Cost	1,332	1,217	1,231	1,397	1,408	1,611	1,889	1,626	2,007	1,939	1,937	2,047	2,144	2,197	2,234	2,333	2,400	2,408	2,440	2,734	
Total Storage Cost	26,291	26,523	26,642	26,878	26,966	31,468	34,557	34,294	34,676	34,607	34,606	34,716	34,812	34,866	34,902	35,002	35,069	35,077	35,109	35,402	410,246
DSM Annual Utility Cost	9,945	10,776	10,232	11,529	13,700	15,853	17,218	19,362	19,316	19,250	19,225	18,970	18,970	18,884	18,884	18,600	18,574	18,285	18,239	18,029	
Total Levelized Utility Cost	255	614	921	1,209	1,439	1,653	1,867	2,086	2,306	2,519	2,730	2,934	3,130	3,323	3,516	3,700	3,880	4,046	4,205	4,351	
Total Costs	379,616	424,956	453,014	477,525	494,399	535,266	542,402	557,542	557,334	585,149	602,221	623,335	640,225	657,317	682,432	707,877	736,496	772,400	801,484	805,592	7,338,240
Key Resource Decisions (increm. MDT/day)																					
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Eastside Loop	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Cross-Cascades	-	-	-	-	-	-	28	28	28	28	28	28	28	28	28	28	28	28	28	28	
GTN Malin to Madras	-	-	-	-	-	-	28	-	-	-	-	-	28	-	-	2	19	27	27	27	
GTN Stanfield to Madras	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	1	1	1	1	1	
Increase NWP Mainline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
GTN Malin to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Newport LNG Delivery	-	-	-	-	-	-	40	40	40	40	40	40	40	40	40	40	40	40	40	40	
N-MAX	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Ruby Pipeline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Gorge Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Expansion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Recall	-	-	0	5	5	8	136	136	136	136	136	136	136	136	136	136	136	136	136	136	
Satellite LNG Albany	-	-	-	-	-	-	8	8	8	8	8	8	8	8	8	8	8	8	8	8	
Satellite LNG Eugene	-	-	-	-	-	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	
Satellite LNG Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NW Natural Transmission																					
North WVF (POR to SAL)	30.9	30.6	30.5	27.5	30.9	25.8	-	-	-	-	-	-	-	-	2.7	-	6.3	-	11.8	-	
Harrisburg River Crossing (ALB to EUG)	8.0	8.0	8.0	4.5	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	
MWVF	-	-	12.6	9.1	11.1	-	-	9.4	13.5	-	-	9.9	3.3	-	-	6.6	11.3	-	12.8	1.8	
Storage																					
GASCO LNG	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	
JP	46.0	46.0	46.0	46.0	46.0	46.0	46.0	44.7	44.9	46.0	45.3	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	
MIST	275.0	275.0	275.0	275.0	275.0	275.0	275.0	170.2	179.3	187.6	196.1	205.2	244.7	226.3	238.0	250.3	246.6	252.7	267.6	266.4	
NEWPORT LNG	58.0	58.0	58.0	58.1	58.2	58.3	97.4	98.5	98.8	98.8	99.0	99.1	99.3	99.4	99.6	99.8	100.0	100.0	100.0	100.0	
PLYMOUTH LNG	60.1	60.1	60.1	60.1	60.1	60.1	14.3	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	
March Point	-	-	-	-	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	
Peak Day Resources-Recall Agreements																					
Recall 1	25.4	25.9	30.0	30.0	25.0	30.0	-	-	-	-	-	-	30.0	-	-	-	-	-	-	-	
Recall 2	8.0	8.0	8.0	8.0	8.0	8.0	-	-	-	-	-	-	8.0	-	-	-	0.5	1.8	3.1	3.0	
Recall 3	1.0	1.0	1.0	1.0	1.0	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	

1535 - Out Pre CC 110	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	79,519	80,884	82,603	84,311	85,313	86,368	87,426	88,915	89,804	91,006	92,200	93,901	94,828	96,242	97,735	99,716	101,003	102,808	104,853	105,329	
Forecast DSM	266	640	960	1,267	1,501	1,725	1,949	2,188	2,409	2,634	2,855	3,081	3,275	3,478	3,681	3,890	4,064	4,238	4,406	4,578	
Forecast Demand (net DSM)	79,253	80,244	81,643	83,045	83,811	84,642	85,476	86,727	87,395	88,373	89,345	90,819	91,552	92,764	94,055	95,826	96,940	98,569	100,446	100,751	
Served Demand	79,253	80,244	81,643	83,045	83,811	84,642	85,470	86,727	87,395	88,373	89,345	90,819	91,542	92,764	94,055	95,826	96,940	98,569	100,446	100,751	
Unserved Demand	0	0	0	0	0	0	6	0	0	0	0	0	10	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	923.2	923.7	929.0	933.5	940.5	949.1	958.2	965.5	976.0	985.6	995.4	1,006.1	1,018.2	1,030.4	1,041.8	1,055.2	1,069.8	1,084.7	1,100.1	1,098.9	
Peak Day Demand Served	923.2	923.7	929.0	933.5	940.5	949.1	958.2	965.5	976.0	985.6	995.4	1,006.1	1,008.1	1,030.4	1,041.8	1,055.2	1,069.8	1,084.7	1,100.1	1,098.9	
Peak Day Demand Unserved	-	-	-	-	-	-	-	-	-	-	-	-	10.0	-	-	-	-	-	-	-	
COST ($000 Nominal)																					
Supply Fixed Costs	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	
Supply Variable Costs	247,873	290,588	318,972	342,178	355,455	381,792	388,098	399,902	401,908	428,581	445,448	472,810	482,576	499,784	525,124	550,494	576,724	612,140	640,696	645,140	
Total Supply Costs	247,934	290,649	319,033	342,239	355,516	381,852	388,159	399,963	401,969	428,642	445,509	472,871	482,637	499,845	525,184	550,555	576,784	612,201	640,757	645,200	5,413,079
Transport Fixed Costs	92,499	94,306	94,358	94,358	95,855	96,155	101,139	101,086	101,086	101,086	101,086	101,086	101,604	101,086	101,086	101,361	101,768	102,681	102,681	102,698	1,274,652
Transport Variable Costs	2,946	2,921	2,996	3,073	3,058	3,166	2,504	2,469	2,853	2,828	2,915	2,905	2,791	2,914	2,999	2,989	2,796	2,674	2,756	2,763	
Total Transport Cost	95,445	97,227	97,354	97,431	98,912	99,321	103,643	103,555	103,938	103,914	104,001	103,991	104,395	104,000	104,085	104,351	104,564	105,355	105,437	105,460	1,311,908
Storage Fixed Cost	24,959	25,306	25,411	25,480	25,558	27,007	27,603	27,655	27,655	27,655	27,655	28,874	29,735	29,735	29,735	29,735	29,735	29,735	29,735	29,735	
Storage Variable Cost	1,332	1,208	1,257	1,394	1,406	1,564	1,682	1,641	1,825	1,674	1,843	2,065	2,337	2,377	2,445	2,555	2,527	2,389	2,605	2,900	
Total Storage Cost	26,291	26,515	26,668	26,874	26,964	28,572	29,286	29,296	29,480	29,329	29,498	30,939	32,072	32,112	32,180	32,290	32,262	32,124	32,340	32,635	378,259
DSM Annual Utility Cost	9,945	10,776	10,232	11,529	13,700	15,853	17,218	19,362	19,316	19,250	19,225	18,970	18,970	18,884	18,884	18,600	18,574	18,285	18,239	18,029	
Total Levelized Utility Cost	255	614	921	1,209	1,439	1,653	1,867	2,086	2,306	2,519	2,730	2,934	3,130	3,323	3,516	3,700	3,880	4,046	4,205	4,351	
Total Costs	379,616	425,166	453,287	478,073	495,092	525,598	538,306	552,176	554,703	581,135	598,234	626,771	638,074	654,841	680,334	705,796	732,184	767,965	796,773	801,325	7,308,823
Key Resource Decisions (increm. MDT/day)																					
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Eastside Loop	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Cross-Cascades	-	-	-	-	-	-	110	110	110	110	110	110	110	110	110	110	110	110	110	110	
GTN Malin to Madras	-	-	-	-	-	-	109	77	77	77	77	77	109	77	77	82	90	108	108	109	
GTN Stanfield to Madras	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Increase NWP Mainline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
GTN Malin to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Newport LNG Delivery	-	-	-	-	-	-	40	40	40	40	40	40	40	40	40	40	40	40	40	40	
N-MAX	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Ruby Pipeline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Gorge Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Expansion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Recall	-	-	0	5	5	8	70	70	70	70	70	70	125	125	125	125	125	125	125	125	
Satellite LNG Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NW Natural Transmission																					
North WVF (POR to SAL)	30.9	30.6	30.5	31.0	32.2	25.8	82.6	-	-	66.8	67.3	35.2	-	-	-	-	41.4	2.4	45.4	79.2	
Harrisburg River Crossing (ALB to EUG)	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	
MWVF	-	-	12.6	12.6	12.3	-	41.0	16.7	15.3	41.0	41.0	41.0	6.4	9.4	3.2	6.6	41.0	5.2	41.0	41.0	
Storage																					
GASCO LNG	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	
JP	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	
MIST	275.0	275.0	275.0	275.0	275.0	275.0	275.0	238.7	249.5	259.5	269.6	275.0	244.9	248.9	259.6	266.6	272.2	267.8	275.0	275.0	
NEWPORT LNG	58.0	58.0	58.0	58.1	58.2	58.3	95.9	98.5	98.7	98.8	99.0	99.1	99.3	99.4	99.6	99.8	100.0	100.0	100.0	100.0	
PLYMOUTH LNG	60.1	60.1	60.1	60.1	60.1	60.1	14.3	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	
March Point	-	-	-	-	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	
Peak Day Resources-Recall Agreements																					
Recall 1	25.4	25.9	30.0	30.0	25.0	30.0	-	-	-	-	-	-	30.0	-	-	-	-	-	-	-	
Recall 2	8.0	8.0	8.0	8.0	8.0	8.0	-	-	-	-	-	-	8.0	-	1.0	2.2	3.4	4.6	5.9	5.8	
Recall 3	1.0	1.0	1.0	1.0	1.0	1.0	-	-	-	-	-	-	1.0	-	-	-	-	-	-	-	

1536 - Out Pre CC 165	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	79,519	80,884	82,603	84,311	85,313	86,368	87,426	88,915	89,804	91,006	92,200	93,901	94,828	96,242	97,735	99,716	101,003	102,808	104,853	105,329	
Forecast DSM	266	640	960	1,267	1,501	1,725	1,949	2,188	2,409	2,634	2,855	3,081	3,275	3,478	3,681	3,890	4,064	4,238	4,406	4,578	
Forecast Demand (net DSM)	79,253	80,244	81,643	83,045	83,811	84,642	85,476	86,727	87,395	88,373	89,345	90,819	91,552	92,764	94,055	95,826	96,940	98,569	100,446	100,751	
Served Demand	79,253	80,244	81,643	83,045	83,811	84,642	85,476	86,727	87,395	88,373	89,345	90,819	91,546	92,764	94,055	95,826	96,940	98,569	100,445	100,751	
Unserved Demand	0	0	0	0	0	0	0	0	0	0	0	0	7	0	0	0	0	0	1	0	
Peak Day Demand (net DSM)	923.2	923.7	929.0	933.5	940.5	949.1	958.2	965.5	976.0	985.6	995.4	1,006.1	1,018.2	1,030.4	1,041.8	1,055.2	1,069.8	1,084.7	1,100.1	1,098.9	
Peak Day Demand Served	923.2	923.7	929.0	933.5	940.5	949.1	958.2	965.5	976.0	985.6	995.4	1,006.1	1,011.5	1,030.4	1,041.8	1,055.2	1,069.8	1,084.7	1,098.8	1,098.8	
Peak Day Demand Unserved	-	-	-	-	-	-	-	-	-	-	-	-	6.7	-	-	-	-	-	1.3	0.1	
COST ($000 Nominal)																					
Supply Fixed Costs	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	
Supply Variable Costs	247,873	290,588	318,972	342,178	355,455	376,382	387,869	400,511	402,596	429,029	446,166	465,480	483,137	500,949	525,985	551,435	577,579	612,708	639,069	646,547	
Total Supply Costs	247,934	290,649	319,033	342,239	355,516	376,443	387,930	400,572	402,657	429,090	446,227	465,541	483,198	501,010	526,046	551,496	577,640	612,769	639,130	646,608	5,408,383
Transport Fixed Costs	92,499	94,306	94,358	94,358	95,855	96,155	102,064	101,568	101,761	101,761	101,761	101,761	102,846	102,736	103,308	103,986	104,727	105,856	105,856	105,856	1,286,392
Transport Variable Costs	2,946	2,921	2,996	3,073	3,058	3,110	2,452	2,502	2,873	2,845	2,906	2,922	2,750	2,825	2,959	2,811	2,686	2,481	2,599	2,619	
Total Transport Cost	95,445	97,227	97,354	97,431	98,912	99,265	104,516	104,070	104,633	104,606	104,667	104,683	105,596	105,560	106,267	106,797	107,413	108,337	108,455	108,475	1,323,195
Storage Fixed Cost	24,959	25,306	25,411	25,480	25,558	25,905	25,722	25,774	25,774	25,774	25,774	25,774	25,774	25,774	25,774	25,774	25,774	25,931	26,042	26,042	
Storage Variable Cost	1,332	1,208	1,257	1,394	1,406	1,523	1,590	1,564	1,682	1,596	1,706	1,858	2,014	2,070	2,016	2,203	2,119	2,131	2,258	2,572	
Total Storage Cost	26,291	26,515	26,668	26,874	26,964	27,428	27,312	27,338	27,456	27,370	27,480	27,632	27,788	27,844	27,790	27,977	27,892	28,061	28,300	28,613	353,193
DSM Annual Utility Cost	9,945	10,776	10,232	11,529	13,700	15,853	17,218	19,362	19,316	19,250	19,225	18,970	18,970	18,884	18,884	18,600	18,574	18,285	18,239	18,029	
Total Levelized Utility Cost	255	614	921	1,209	1,439	1,653	1,867	2,086	2,306	2,519	2,730	2,934	3,130	3,323	3,516	3,700	3,880	4,046	4,205	4,351	
Total Costs	379,616	425,166	453,287	478,073	495,092	518,989	536,977	551,341	554,062	580,316	597,598	616,826	635,553	653,299	678,987	704,869	731,520	767,453	794,124	801,725	7,290,347
Key Resource Decisions (increm. MDT/day)																					
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	1	1	1	1	1	1	3	3	3	3	3	3	3	3	3	3	3	3	
Eastside Loop	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Cross-Cascades	-	-	-	-	-	-	165	165	165	165	165	165	165	165	165	165	165	165	165	165	
GTN Malin to Madras	-	-	-	-	-	-	115	83	83	83	83	83	163	102	113	126	141	163	163	163	
GTN Stanfield to Madras	-	-	-	-	-	-	50	1	3	3	3	3	3	3	3	3	3	3	3	3	
Increase NWP Mainline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
GTN Malin to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Newport LNG Delivery	-	-	-	-	-	-	40	40	40	40	40	40	40	40	40	40	40	40	40	40	
N-MAX	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Ruby Pipeline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Gorge Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Expansion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Recall	-	-	0	5	5	8	21	21	21	21	21	21	21	21	21	21	21	21	28	28	
Satellite LNG Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NW Natural Transmission																					
North WVF (POR to SAL)	30.9	30.6	30.5	31.0	32.2	25.8	64.7	-	-	65.8	66.3	35.2	-	30.6	-	-	40.4	1.4	44.4	78.2	
Harrisburg River Crossing (ALB to EUG)	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	
MWVF	-	-	12.6	12.6	12.3	-	41.0	16.7	15.3	41.0	41.0	41.0	6.4	41.0	3.2	7.6	41.0	5.2	41.0	41.0	
Storage																					
GASCO LNG	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	
JP	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	
MIST	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	235.5	275.0	275.0	275.0	275.0	275.0	275.0	275.0	
NEWPORT LNG	58.0	58.0	58.0	58.1	58.2	58.3	98.4	98.5	98.7	98.8	99.0	99.1	99.3	99.4	99.6	99.8	100.0	100.0	100.0	100.0	
PLYMOUTH LNG	60.1	60.1	60.1	60.1	60.1	60.1	32.7	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	
March Point	-	-	-	-	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	
Peak Day Resources-Recall Agreements																					
Recall 1	25.4	25.9	30.0	30.0	25.0	30.0	-	-	-	4.8	14.4	26.1	30.0	30.0	30.0	30.0	30.0	22.9	30.0	30.0	
Recall 2	8.0	8.0	8.0	8.0	8.0	8.0	-	-	4.4	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	
Recall 3	1.0	1.0	1.0	1.0	1.0	1.0	-	-	-	1.0	1.0	-	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	

1537 - Out Post CC 110	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	79,519	80,884	82,603	84,311	85,313	86,368	87,426	88,915	89,804	91,006	92,200	93,901	94,828	96,242	97,735	99,716	101,003	102,808	104,853	105,329	
Forecast DSM	266	640	960	1,267	1,501	1,725	1,949	2,188	2,409	2,634	2,855	3,081	3,275	3,478	3,681	3,890	4,064	4,238	4,406	4,578	
Forecast Demand (net DSM)	79,253	80,244	81,643	83,045	83,811	84,642	85,476	86,727	87,395	88,373	89,345	90,819	91,552	92,764	94,055	95,826	96,940	98,569	100,446	100,751	
Served Demand	79,253	80,244	81,643	83,045	83,811	84,642	85,465	86,727	87,395	88,373	89,345	90,819	91,542	92,764	94,055	95,826	96,940	98,569	100,446	100,751	
Unserved Demand	0	0	0	0	0	0	11	0	0	0	0	0	10	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	923.2	923.7	929.0	933.5	940.5	949.1	958.2	965.5	976.0	985.6	995.4	1,006.1	1,018.2	1,030.4	1,041.8	1,055.2	1,069.8	1,084.7	1,100.1	1,098.9	
Peak Day Demand Served	923.2	923.7	929.0	933.5	940.5	949.1	958.2	965.5	976.0	985.6	995.4	1,006.1	1,008.1	1,030.4	1,041.8	1,055.2	1,069.8	1,084.7	1,100.1	1,098.9	
Peak Day Demand Unserved	-	-	-	-	-	-	-	-	-	-	-	-	10.0	-	-	-	-	-	-	-	
COST ($000 Nominal)																					
Supply Fixed Costs	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	
Supply Variable Costs	247,873	290,588	318,972	342,178	355,455	380,599	387,817	400,079	402,101	428,695	445,601	474,362	482,576	499,784	525,124	550,494	576,724	612,140	640,696	645,140	
Total Supply Costs	247,934	290,649	319,033	342,239	355,516	380,660	387,878	400,140	402,161	428,756	445,662	474,423	482,637	499,845	525,184	550,555	576,784	612,201	640,757	645,200	5,413,254
Transport Fixed Costs	92,499	94,306	94,358	94,358	95,855	96,155	101,604	101,086	101,086	101,086	101,086	101,086	101,604	101,086	101,086	101,361	101,768	102,681	102,681	102,698	1,274,995
Transport Variable Costs	2,946	2,921	2,996	3,073	3,058	3,156	2,528	2,480	2,863	2,837	2,921	2,914	2,791	2,914	2,999	2,989	2,796	2,674	2,756	2,763	
Total Transport Cost	95,445	97,227	97,354	97,431	98,912	99,311	104,132	103,566	103,949	103,923	104,007	104,000	104,395	104,000	104,085	104,351	104,564	105,355	105,437	105,460	1,312,291
Storage Fixed Cost	24,959	25,306	25,411	25,480	25,558	26,768	27,247	27,247	27,247	27,247	27,247	28,705	29,735	29,735	29,735	29,735	29,735	29,735	29,735	29,735	
Storage Variable Cost	1,332	1,208	1,257	1,394	1,406	1,548	1,688	1,626	1,805	1,658	1,817	2,065	2,337	2,377	2,445	2,555	2,527	2,389	2,605	2,900	
Total Storage Cost	26,291	26,514	26,668	26,874	26,964	28,316	28,935	28,872	29,052	28,905	29,064	30,770	32,073	32,112	32,180	32,290	32,262	32,124	32,340	32,635	376,588
DSM Annual Utility Cost	9,945	10,776	10,232	11,529	13,700	15,853	17,218	19,362	19,316	19,250	19,225	18,970	18,970	18,884	18,884	18,600	18,574	18,285	18,239	18,029	
Total Levelized Utility Cost	255	614	921	1,209	1,439	1,653	1,867	2,086	2,306	2,519	2,730	2,934	3,130	3,323	3,516	3,700	3,880	4,046	4,205	4,351	
Total Costs	379,616	425,166	453,287	478,073	495,093	524,140	538,163	551,941	554,478	580,834	597,958	628,164	638,075	654,841	680,334	705,796	732,185	767,964	796,773	801,325	7,307,709
Key Resource Decisions (increm. MDT/day)																					
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Eastside Loop	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Cross-Cascades	-	-	-	-	-	-	110	110	110	110	110	110	110	110	110	110	110	110	110	110	
GTN Malin to Madras	-	-	-	-	-	-	109	77	77	77	77	77	109	77	77	82	90	108	108	109	
GTN Stanfield to Madras	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Increase NWP Mainline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
GTN Malin to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Newport LNG Delivery	-	-	-	-	-	-	40	40	40	40	40	40	40	40	40	40	40	40	40	40	
N-MAX	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Ruby Pipeline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Gorge Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Expansion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Recall	-	-	0	5	5	8	60	60	60	60	60	60	125	125	125	125	125	125	125	125	
Satellite LNG Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NW Natural Transmission																					
North WVF (POR to SAL)	24.3	24.4	25.3	18.4	32.2	33.7	28.8	-	-	-	67.3	34.6	68.6	-	-	-	-	43.0	78.8	45.2	
Harrisburg River Crossing (ALB to EUG)	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	
MWVF	-	-	-	-	-	-	41.0	16.1	0.1	14.2	41.0	41.0	41.0	9.4	7.9	6.0	4.5	41.0	41.0	41.0	
Storage																					
GASCO LNG	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	
JP	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	
MIST	275.0	275.0	275.0	275.0	275.0	275.0	275.0	249.8	260.7	270.6	275.0	275.0	244.9	248.9	259.6	266.6	272.2	267.8	275.0	275.0	
NEWPORT LNG	58.0	58.0	58.0	58.1	58.2	58.3	98.4	98.5	98.7	98.8	99.0	99.1	99.3	99.4	99.6	99.8	100.0	100.0	100.0	100.0	
PLYMOUTH LNG	60.1	60.1	60.1	60.1	60.1	60.1	14.3	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	
March Point	-	-	-	-	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	
Peak Day Resources-Recall Agreements																					
Recall 1	26.4	26.9	30.0	30.0	25.0	30.0	-	-	-	-	-	-	30.0	-	-	-	-	-	-	-	
Recall 2	8.0	8.0	8.0	8.0	8.0	8.0	-	-	-	-	-	3.0	8.0	-	1.0	2.2	3.4	4.6	5.9	5.8	
Recall 3	-	-	1.0	1.0	1.0	1.0	-	-	-	-	-	-	1.0	-	-	-	-	-	-	-	

1538 - Out Post CC 165	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	79,519	80,884	82,603	84,311	85,313	86,368	87,426	88,915	89,804	91,006	92,200	93,901	94,828	96,242	97,735	99,716	101,003	102,808	104,853	105,329	
Forecast DSM	266	640	960	1,267	1,501	1,725	1,949	2,188	2,409	2,634	2,855	3,081	3,275	3,478	3,681	3,890	4,064	4,238	4,406	4,578	
Forecast Demand (net DSM)	79,253	80,244	81,643	83,045	83,811	84,642	85,476	86,727	87,395	88,373	89,345	90,819	91,552	92,764	94,055	95,826	96,940	98,569	100,446	100,751	
Served Demand	79,253	80,244	81,643	83,045	83,811	84,642	85,465	86,727	87,395	88,373	89,345	90,819	91,546	92,764	94,055	95,826	96,940	98,569	100,445	100,751	
Unserved Demand	0	0	0	0	0	0	11	0	0	0	0	0	7	0	0	0	0	0	1	0	
Peak Day Demand (net DSM)	923.2	923.7	929.0	933.5	940.5	949.1	958.2	965.5	976.0	985.6	995.4	1,006.1	1,018.2	1,030.4	1,041.8	1,055.2	1,069.8	1,084.7	1,100.1	1,098.9	
Peak Day Demand Served	923.2	923.7	929.0	933.5	940.5	949.1	958.2	965.5	976.0	985.6	995.4	1,006.1	1,011.4	1,030.4	1,041.8	1,055.2	1,069.8	1,084.7	1,098.8	1,098.8	
Peak Day Demand Unserved	-	-	-	0.0	-	-	-	-	-	-	-	-	6.8	-	-	-	-	-	1.3	0.1	
COST ($000 Nominal)																					
Supply Fixed Costs	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	
Supply Variable Costs	247,873	290,588	318,970	342,178	355,089	374,923	387,640	400,676	402,867	429,264	446,425	467,592	483,162	500,947	525,982	551,400	577,609	612,750	639,069	646,547	
Total Supply Costs	247,934	290,649	319,031	342,239	355,149	374,984	387,701	400,737	402,928	429,325	446,486	467,652	483,223	501,008	526,043	551,461	577,670	612,811	639,130	646,608	5,408,622
Transport Fixed Costs	92,499	94,306	94,358	94,358	95,855	96,265	102,559	101,830	102,022	102,022	102,022	102,354	102,846	102,747	103,320	103,998	104,738	105,856	105,856	105,856	1,287,890
Transport Variable Costs	2,946	2,921	2,996	3,073	3,054	3,092	2,448	2,495	2,865	2,837	2,889	2,896	2,750	2,824	2,958	2,811	2,686	2,481	2,599	2,619	
Total Transport Cost	95,445	97,227	97,354	97,431	98,908	99,356	105,008	104,325	104,887	104,859	104,911	105,250	105,596	105,571	106,278	106,808	107,424	108,337	108,455	108,475	1,324,632
Storage Fixed Cost	24,959	25,306	25,410	25,480	25,480	25,480	25,142	25,142	25,142	25,142	25,142	25,507	25,765	25,765	25,765	25,765	25,765	25,927	26,042	26,042	
Storage Variable Cost	1,332	1,208	1,257	1,394	1,403	1,485	1,570	1,527	1,623	1,555	1,659	1,814	2,009	2,065	2,011	2,197	2,113	2,125	2,253	2,566	
Total Storage Cost	26,291	26,514	26,668	26,873	26,883	26,965	26,711	26,669	26,765	26,697	26,801	27,321	27,774	27,830	27,776	27,963	27,878	28,052	28,295	28,608	350,329
DSM Annual Utility Cost	9,945	10,776	10,232	11,529	13,700	15,853	17,218	19,362	19,316	19,250	19,225	18,970	18,970	18,884	18,884	18,600	18,574	18,285	18,239	18,029	
Total Levelized Utility Cost	255	614	921	1,209	1,439	1,653	1,867	2,086	2,306	2,519	2,730	2,934	3,130	3,323	3,516	3,700	3,880	4,046	4,205	4,351	
Total Costs	379,616	425,166	453,284	478,072	494,641	517,158	536,639	551,093	553,896	580,132	597,424	619,194	635,564	653,294	678,982	704,832	731,547	767,486	794,119	801,720	7,289,159
Key Resource Decisions (increm. MDT/day)																					
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	1	1	1	1	1	1	3	3	3	3	3	3	3	3	3	3	3	3	
Eastside Loop	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Cross-Cascades	-	-	-	-	-	-	165	165	165	165	165	165	165	165	165	165	165	165	165	165	
GTN Malin to Madras	-	-	-	-	-	-	124	88	88	88	88	94	163	102	113	126	141	163	163	163	
GTN Stanfield to Madras	-	-	-	-	-	-	42	1	3	3	3	3	3	3	3	3	3	3	3	3	
Increase NWP Mainline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
GTN Malin to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Newport LNG Delivery	-	-	-	-	-	3	40	40	40	40	40	40	40	40	40	40	40	40	40	40	
N-MAX	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Ruby Pipeline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Gorge Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Expansion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Recall	-	-	0	5	5	5	5	5	5	5	5	5	21	21	21	21	21	21	28	28	
Satellite LNG Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NW Natural Transmission																					
North WVF (POR to SAL)	24.3	24.4	25.3	18.4	32.2	30.2	28.9	-	-	-	66.4	33.7	68.6	-	-	-	-	42.0	77.8	38.2	
Harrisburg River Crossing (ALB to EUG)	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	
MWVF	-	-	-	-	-	-	41.0	16.0	0.1	15.1	41.0	41.0	41.0	10.4	8.9	7.0	4.5	41.0	41.0	41.0	
Storage																					
GASCO LNG	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	
JP	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	
MIST	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	235.6	275.0	275.0	275.0	275.0	275.0	275.0	275.0	
NEWPORT LNG	58.0	58.0	58.0	58.1	58.2	61.8	98.3	98.4	98.6	98.7	98.9	99.0	99.3	99.4	99.6	99.8	100.0	100.0	100.0	100.0	
PLYMOUTH LNG	60.1	60.1	60.1	60.1	60.1	60.1	23.7	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	
March Point	-	-	-	-	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	
Peak Day Resources-Recall Agreements																					
Recall 1	26.4	26.9	30.0	30.0	25.0	30.0	-	-	6.8	16.3	25.9	30.0	30.0	30.0	30.0	30.0	30.0	23.1	30.0	30.0	
Recall 2	8.0	8.0	8.0	8.0	8.0	8.0	-	7.3	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	
Recall 3	-	-	1.0	1.0	1.0	1.0	-	-	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	

1540 - Base with CC 165	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	79,519	80,884	82,603	84,311	85,313	86,368	87,426	88,915	89.804	91,006	92,200	93,901	94,828	96,242	97,735	99,716	101,003	102,808	104,853	105,329	
Forecast DSM	266	640	960	1,267	1,501	1,725	1,949	2,188	2.409	2,634	2,855	3,081	3,275	3,478	3,681	3.890	4,064	4,238	4,406	4,578	
Forecast Demand (net DSM)	79,253	80,244	81,643	83,045	83,811	84,642	85,476	86,727	87,395	88,373	89,345	90.819	91,552	92,764	94,055	95,826	96,940	98,569	100,446	100,751	
Served Demand	79,253	80,244	81,643	83,045	83,811	84,642	85,476	86,727	87,395	88.373	89,345	90,819	91,552	92,764	94,055	95,826	96,940	98,569	100,445	100,751	
Unserved Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	
Peak Day Demand (net DSM)	923.2	923.7	929.0	933.5	940.5	949.1	958.2	965.5	976.0	985.6	995.4	1,006.1	1,018.2	1,030.4	1,041.8	1,055.2	1,069.8	1,084.7	1,100.1	1,098.9	
Peak Day Demand Served	923.2	923.7	929.0	933.5	940.5	949.1	958.2	965.5	976.0	985.6	995.4	1,006.1	1,018.2	1,030.4	1,041.8	1,055.2	1,069.8	1,084.7	1,098.8	1,098.8	
Peak Day Demand Unserved	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.3	0.1	
COST ($000 Nominal)																					
Supply Fixed Costs	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	
Supply Variable Costs	247,873	290,588	318,995	342,172	355,425	376,578	387,739	400,512	402,600	429,033	446,170	467,190	482,415	500,944	525,982	551,400	577,609	612,756	639,069	646,547	
Total Supply Costs	247,934	290,649	319,055	342,232	355,485	376,639	387,800	400,573	402,661	429,094	446,231	467,251	482,475	501,004	526,043	551,460	577,669	612,817	639,130	646,608	5,409,038
Transport Fixed Costs	92,499	94,306	94,358	94,358	95,855	96,155	101,453	101,572	101.765	101,765	101,765	101,765	102,130	102,749	103,322	103,999	104,740	105,856	105,856	105,856	1,285,587
Transport Variable Costs	2,946	2,921	2,996	3,073	3,057	3,113	2,693	2,502	2,873	2,845	2,906	2,923	2,870	2 824	2,958	2.811	2,686	2,481	2,599	2.619	
Eastside Loop							4,217	4,217	4,217	4,217	4,217	4 217	4,217	4,217	4,217	4,217	4,217	4,217	4,217	4,217	
Total Transport Cost	95,445	97,227	97,354	97,431	98,912	99,268	108,364	108,291	108,854	108,827	108,888	108.905	109,217	109,790	110,497	111,027	111,643	112,555	112,672	112,692	1,354,766
Storage Fixed Cost	24.959	25,306	25,416	25,489	25,561	25,899	25,764	25,764	25,764	25,764	25,764	25,764	25,764	25 764	25.764	25,764	25,764	25,927	26,042	26,042	
Storage Variable Cost	1,332	1,208	1,257	1,394	1,406	1,547	1,622	1,563	1,681	1,595	1,705	1,873	2,002	2,068	2,015	2,201	2,118	2,130	2,259	2,571	
Total Storage Cost	26,291	26,514	26,673	26,883	26,967	27,446	27,386	27,327	27,445	27,359	27,469	27.637	27,766	27,832	27,779	27,965	27,882	28,057	28,300	28,613	353,214
DSM Annual Utility Cost	9,945	10,776	10,232	11,529	13,700	15,853	17,218	19,362	19,316	19,250	19,225	18,970	18,970	18,884	18,884	18,600	18,574	18,285	18,239	18,029	
Total Costs	379,616	425,166	453,314	478,075	495,065	519,206	540,767	555,553	558,276	584,530	601,813	622,764	638,429	657,511	683,203	709,053	735,768	771,714	798,341	805,942	7,322,594
Key Resource Decisions (increm. MDT/day)																					
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Alberta path (1)	-	-	1	1	1	1	1	1	3	3	3	3	3	3	3	3	3	3	3	3	
Eastside Loop	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Cross-Cascades	-	-	-	-	-	-	165	165	165	165	165	165	165	165	165	165	165	165	165	165	
GTN Malin to Madras	-	-	-	-	-	-	80	83	83	83	83	83	90	102	113	126	141	163	163	163	
GTN Stanfield to Madras	-	-	-	-	-	-	1	1	3	3	3	3	3	3	3	3	3	3	3	3	
Increase NWP Mainline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
GTN Malin to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Newport LNG Delivery	-	-	-	-	-	-	40	40	40	40	40	40	40	40	40	40	40	40	40	40	
N-MAX	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Ruby Pipeline	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Gorge Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Expansion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mist Storage Recall	-	-	0	5	5	8	21	21	21	21	21	21	21	21	21	21	21	21	28	28	
Satellite LNG Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite LNG Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NW Natural Transmission																					
North WVF (POR to SAL)	24.3	30.6	30.5	27.7	19.0	33.7	4.5	63.8	-	-	-	28.2	69.4	15.1	0.3	-	-	6.2	3.9	3.0	
Harrisburg River Crossing (ALB to EUG)	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	
MWVF	-	-	12.6	12.0	-	13.3	-	41.0	0.1	0.6	1.0	41.0	41.0	25.4	3.8	7.0	4.5	5.2	6.5	5.8	
Storage																					
GASCO LNG	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	
JP	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	
MIST	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	
NEWPORT LNG	58.0	58.0	58.0	58.1	58.2	58.3	98.4	98.5	98.7	98.8	99.0	99.1	99.3	99.4	99.6	99 8	100.0	100.0	100.0	100.0	
PLYMOUTH LNG	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	
March Point	-	-	-	-	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	
Peak Day Resources-Recall Agreements																					
Recall 1	26.4	25.9	30.0	30.0	25.8	30.0	-	-	-	6.0	14.6	25.2	30.0	30.0	30 0	30.0	30.0	23.1	30.0	30.0	
Recall 2	8.0	8.0	8.0	8.0	8.0	8.0	-	-	4.5	8.0	8.0	8.0	8.0	8.0	8.0	8 0	8.0	8.0	8.0	8.0	
Recall 3	-	1.0	1.0	0.8	-	1.0	-	-	-	-	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	

Appendix 6: Avoided Cost Determination

NW Natural®

Appendix 6.1 Avoided Costs – Base Case

Gas Year	Month	Albany	Astoria	Dalles, OR	Eugene / Coos Bay	Newport / Lincoln City	Portland	Salem	Vancouver / Dalles, WA	OR	WA	System
2012-2013	NOV	3.51	3.60	3.58	3.51	3.62	3.60	3.60	3.60	3.59	3.60	3.59
2012-2013	DEC	3.84	3.84	3.84	3.84	3.85	3.84	3.84	3.86	3.84	3.86	3.84
2012-2013	JAN	3.75	3.85	3.83	3.75	3.89	3.87	3.87	3.85	3.86	3.85	3.86
2012-2013	FEB	4.15	4.16	4.17	4.16	3.55	4.16	4.16	4.19	4.15	4.19	4.15
2012-2013	MAR	3.37	3.37	3.37	3.37	3.46	3.37	3.37	3.37	3.37	3.37	3.37
2012-2013	APR	3.24	3.24	3.24	3.24	3.33	3.24	3.24	3.24	3.25	3.24	3.25
2012-2013	MAY	3.26	3.28	3.26	3.26	3.35	3.26	3.26	3.26	3.26	3.26	3.26
2012-2013	JUN	3.29	3.31	3.29	3.29	3.38	3.29	3.29	3.29	3.29	3.29	3.29
2012-2013	JUL	3.32	3.34	3.32	3.32	3.42	3.32	3.32	3.32	3.33	3.32	3.33
2012-2013	AUG	3.36	3.38	3.36	3.36	3.45	3.36	3.36	3.36	3.36	3.36	3.36
2012-2013	SEP	3.39	3.41	3.39	3.39	3.48	3.39	3.39	3.39	3.39	3.39	3.39
2012-2013	OCT	3.47	3.49	3.47	3.47	3.56	3.47	3.47	3.47	3.47	3.47	3.47
	Annual Average	3.50	3.52	3.51	3.50	3.53	3.51	3.51	3.52	3.51	3.52	3.51
	Winter Average	3.72	3.76	3.76	3.72	3.67	3.77	3.77	3.77	3.76	3.77	3.76

Gas Year	Month	Albany	Astoria	Dalles, OR	Eugene / Coos Bay	Newport / Lincoln City	Portland	Salem	Vancouver / Dalles, WA	OR	WA	System
2013-2014	NOV	3.99	4.08	4.07	3.99	4.09	4.07	4.07	4.08	4.06	4.08	4.07
2013-2014	DEC	4.24	4.31	4.31	4.24	4.31	4.31	4.30	4.33	4.30	4.33	4.30
2013-2014	JAN	4.31	4.35	4.34	4.31	4.35	4.35	4.34	4.35	4.34	4.35	4.34
2013-2014	FEB	4.74	4.74	4.74	4.74	4.13	4.74	4.74	4.76	4.73	4.76	4.73
2013-2014	MAR	3.90	3.90	3.90	3.90	4.01	3.90	3.90	3.90	3.90	3.90	3.90
2013-2014	APR	3.71	3.71	3.71	3.71	3.81	3.71	3.71	3.71	3.71	3.71	3.71
2013-2014	MAY	3.65	3.65	3.65	3.65	3.75	3.65	3.65	3.65	3.65	3.65	3.65
2013-2014	JUN	3.69	3.69	3.69	3.69	3.79	3.69	3.69	3.69	3.69	3.69	3.69
2013-2014	JUL	3.72	3.72	3.72	3.72	3.82	3.72	3.72	3.72	3.72	3.72	3.72
2013-2014	AUG	3.75	3.76	3.75	3.75	3.86	3.75	3.75	3.75	3.76	3.75	3.76
2013-2014	SEP	3.79	3.79	3.79	3.79	3.89	3.79	3.79	3.79	3.79	3.79	3.79

2013-2014	OCT	3.82	3.83	3.82	3.82	3.93	3.82	3.82	3.82	3.83	3.82	3.83
	Annual Average	3.94	3.96	3.96	3.94	3.98	3.96	3.96	3.96	3.96	3.96	3.96
	Winter Average	4.24	4.28	4.27	4.24	4.18	4.27	4.27	4.29	4.27	4.29	4.27

Gas Year	Month	Albany	Astoria	Dalles, OR	Eugene / Coos Bay	Newport / Lincoln City	Portland	Salem	Vancouver / Dalles, WA	OR	WA	System
2014-2015	NOV	4.29	4.38	4.37	4.29	4.40	4.38	4.38	4.39	4.37	4.39	4.37
2014-2015	DEC	4.52	4.62	4.61	4.52	4.62	4.62	4.61	4.63	4.61	4.63	4.61
2014-2015	JAN	4.56	4.66	4.64	4.56	4.67	4.66	4.66	4.66	4.65	4.66	4.65
2014-2015	FEB	5.33	5.34	5.35	5.35	4.44	5.34	5.34	5.37	5.33	5.37	5.33
2014-2015	MAR	4.18	4.18	4.18	4.18	4.29	4.18	4.18	4.18	4.18	4.18	4.18
2014-2015	APR	3.92	3.92	3.92	3.92	4.03	3.92	3.92	3.92	3.92	3.92	3.92
2014-2015	MAY	3.85	3.86	3.85	3.85	3.93	3.85	3.85	3.85	3.86	3.85	3.86
2014-2015	JUN	3.85	3.85	3.85	3.85	3.95	3.85	3.85	3.85	3.85	3.85	3.85
2014-2015	JUL	3.88	3.89	3.88	3.88	3.99	3.88	3.88	3.88	3.89	3.88	3.89
2014-2015	AUG	3.92	3.92	3.92	3.92	4.03	3.92	3.92	3.92	3.92	3.92	3.92
2014-2015	SEP	3.96	3.96	3.96	3.96	4.06	3.96	3.96	3.96	3.96	3.96	3.96
2014-2015	OCT	3.99	3.99	3.99	3.99	4.10	3.99	3.99	3.99	3.99	3.99	3.99
	Annual Average	4.19	4.21	4.21	4.19	4.21	4.21	4.21	4.22	4.21	4.22	4.21
	Winter Average	4.58	4.64	4.63	4.58	4.49	4.64	4.63	4.65	4.63	4.65	4.63

Gas Year	Month	Albany	Astoria	Dalles, OR	Eugene / Coos Bay	Newport / Lincoln City	Portland	Salem	Vancouver / Dalles, WA	OR	WA	System
2015-2016	NOV	4.49	4.59	4.58	4.49	4.60	4.58	4.58	4.59	4.57	4.59	4.57
2015-2016	DEC	4.71	4.82	4.82	4.71	4.82	4.82	4.82	4.84	4.81	4.84	4.81
2015-2016	JAN	4.74	4.86	4.84	4.74	4.87	4.86	4.86	4.86	4.85	4.86	4.85
2015-2016	FEB	5.18	5.19	5.19	5.19	4.62	5.19	5.19	5.21	5.18	5.21	5.18
2015-2016	MAR	4.36	4.36	4.36	4.36	4.47	4.36	4.36	4.36	4.36	4.36	4.36
2015-2016	APR	4.10	4.11	4.10	4.10	4.21	4.10	4.10	4.10	4.10	4.10	4.10
2015-2016	MAY	4.06	4.06	4.06	4.06	4.15	4.06	4.06	4.06	4.06	4.06	4.06
2015-2016	JUN	4.06	4.07	4.06	4.06	4.17	4.06	4.06	4.06	4.07	4.06	4.07
2015-2016	JUL	4.10	4.10	4.10	4.10	4.21	4.10	4.10	4.10	4.10	4.10	4.10
2015-2016	AUG	4.13	4.14	4.13	4.13	4.24	4.13	4.13	4.13	4.13	4.13	4.13

2015-2016	SEP	4.17	4.17	4.17	4.17	4.29	4.17	4.17	4.17	4.18	4.17	4.17
2015-2016	OCT	4.23	4.23	4.23	4.23	4.34	4.23	4.23	4.23	4.23	4.23	4.23
	Annual Average	4.36	4.39	4.39	4.36	4.42	4.39	4.39	4.39	4.39	4.39	4.39
	Winter Average	4.70	4.76	4.76	4.70	4.68	4.76	4.76	4.77	4.75	4.77	4.75

Gas Year	Month	Albany	Astoria	Dalles, OR	Eugene / Coos Bay	Newport / Lincoln City	Portland	Salem	Vancouver / Dalles, WA	OR	WA	System
2016-2017	NOV	4.63	4.72	4.71	4.63	4.74	4.72	4.72	4.73	4.71	4.73	4.71
2016-2017	DEC	4.90	4.96	4.95	4.90	4.96	4.96	4.95	4.97	4.95	4.97	4.95
2016-2017	JAN	4.87	4.99	4.98	4.87	5.00	5.00	5.00	5.00	4.98	5.00	4.98
2016-2017	FEB	5.25	5.25	5.26	5.27	4.66	5.26	5.26	5.28	5.25	5.28	5.25
2016-2017	MAR	4.40	4.41	4.40	4.40	4.52	4.40	4.40	4.40	4.41	4.40	4.41
2016-2017	APR	4.19	4.20	4.19	4.19	4.30	4.19	4.19	4.19	4.19	4.19	4.19
2016-2017	MAY	4.19	4.19	4.19	4.19	4.28	4.19	4.19	4.19	4.19	4.19	4.19
2016-2017	JUN	4.19	4.19	4.19	4.19	4.30	4.19	4.19	4.19	4.19	4.19	4.19
2016-2017	JUL	4.23	4.23	4.23	4.23	4.34	4.23	4.23	4.23	4.23	4.23	4.23
2016-2017	AUG	4.25	4.26	4.25	4.25	4.36	4.25	4.25	4.25	4.25	4.25	4.25
2016-2017	SEP	4.30	4.30	4.30	4.30	4.41	4.30	4.30	4.30	4.30	4.30	4.30
2016-2017	OCT	4.36	4.36	4.36	4.36	4.47	4.36	4.36	4.36	4.36	4.36	4.36
	Annual Average	4.48	4.51	4.50	4.48	4.53	4.50	4.50	4.51	4.50	4.51	4.50
	Winter Average	4.81	4.87	4.86	4.81	4.78	4.87	4.86	4.88	4.86	4.88	4.86

Gas Year	Month	Albany	Astoria	Dalles, OR	Eugene / Coos Bay	Newport / Lincoln City	Portland	Salem	Vancouver / Dalles, WA	OR	WA	System
2017-2018	NOV	4.83	4.88	4.88	4.83	4.89	4.87	4.87	4.89	4.87	4.89	4.87
2017-2018	DEC	5.01	5.10	5.11	5.01	5.10	5.10	5.10	5.13	5.09	5.13	5.09
2017-2018	JAN	5.02	5.14	5.13	5.02	5.15	5.14	5.14	5.15	5.13	5.15	5.13
2017-2018	FEB	5.82	5.83	5.83	5.84	4.88	5.83	5.83	5.85	5.81	5.85	5.81
2017-2018	MAR	4.63	4.63	4.63	4.63	4.75	4.63	4.63	4.63	4.63	4.63	4.63
2017-2018	APR	4.38	4.40	4.38	4.38	4.50	4.38	4.38	4.38	4.39	4.38	4.39
2017-2018	MAY	4.38	4.38	4.38	4.38	4.47	4.38	4.38	4.38	4.38	4.38	4.38
2017-2018	JUN	4.37	4.38	4.37	4.37	4.49	4.37	4.37	4.37	4.38	4.37	4.38
2017-2018	JUL	4.41	4.41	4.41	4.41	4.53	4.41	4.41	4.41	4.41	4.41	4.41

2017-2018	AUG	4.44	4.45	4.44	4.44	4.56	4.44	4.44	4.44	4.44	4.44	4.44
2017-2018	SEP	4.49	4.49	4.49	4.49	4.61	4.49	4.49	4.49	4.49	4.49	4.49
2017-2018	OCT	4.55	4.55	4.55	4.55	4.67	4.55	4.55	4.55	4.55	4.55	4.55
	Annual Average	4.69	4.72	4.72	4.70	4.72	4.72	4.72	4.72	4.71	4.72	4.71
	Winter Average	5.06	5.12	5.12	5.07	4.95	5.11	5.11	5.13	5.10	5.13	5.11

Gas Year	Month	Albany	Astoria	Dalles, OR	Eugene / Coos Bay	Newport / Lincoln City	Portland	Salem	Vancouver / Dalles, WA	OR	WA	System
2018-2019	NOV	4.94	4.94	4.95	4.94	4.96	4.94	4.94	4.96	4.94	4.96	4.94
2018-2019	DEC	5.16	5.16	5.17	5.16	5.17	5.16	5.16	5.19	5.16	5.19	5.16
2018-2019	JAN	5.20	5.20	5.21	5.20	5.21	5.20	5.20	5.23	5.20	5.23	5.21
2018-2019	FEB	5.21	5.21	5.22	5.24	4.95	5.21	5.21	5.24	5.21	5.24	5.21
2018-2019	MAR	4.62	4.62	4.62	4.62	4.74	4.62	4.62	4.62	4.62	4.62	4.62
2018-2019	APR	4.49	4.50	4.49	4.49	4.61	4.49	4.49	4.49	4.50	4.49	4.50
2018-2019	MAY	4.44	4.44	4.44	4.44	4.56	4.44	4.44	4.44	4.45	4.44	4.45
2018-2019	JUN	4.48	4.48	4.48	4.48	4.60	4.48	4.48	4.48	4.48	4.48	4.48
2018-2019	JUL	4.52	4.52	4.52	4.52	4.64	4.52	4.52	4.52	4.52	4.52	4.52
2018-2019	AUG	4.56	4.56	4.56	4.56	4.68	4.56	4.56	4.56	4.56	4.56	4.56
2018-2019	SEP	4.59	4.60	4.59	4.59	4.72	4.59	4.59	4.59	4.60	4.59	4.60
2018-2019	OCT	4.65	4.65	4.65	4.65	4.78	4.65	4.65	4.65	4.65	4.65	4.65
	Annual Average	4.74	4.74	4.74	4.74	4.80	4.74	4.74	4.75	4.74	4.75	4.74
	Winter Average	5.03	5.03	5.03	5.03	5.01	5.03	5.03	5.05	5.03	5.05	5.03

Gas Year	Month	Albany	Astoria	Dalles, OR	Eugene / Coos Bay	Newport / Lincoln City	Portland	Salem	Vancouver / Dalles, WA	OR	WA	System
2019-2020	NOV	5.07	5.07	5.08	5.07	5.10	5.07	5.07	5.09	5.07	5.09	5.07
2019-2020	DEC	5.30	5.30	5.32	5.30	5.31	5.30	5.30	5.33	5.30	5.33	5.31
2019-2020	JAN	5.35	5.35	5.35	5.35	5.36	5.35	5.35	5.37	5.35	5.37	5.35
2019-2020	FEB	5.32	5.32	5.33	5.35	5.02	5.32	5.32	5.35	5.32	5.35	5.32
2019-2020	MAR	4.68	4.68	4.68	4.68	4.80	4.68	4.68	4.68	4.68	4.68	4.68
2019-2020	APR	4.60	4.60	4.60	4.60	4.72	4.60	4.60	4.60	4.60	4.60	4.60
2019-2020	MAY	4.50	4.50	4.50	4.50	4.61	4.50	4.50	4.50	4.50	4.50	4.50
2019-2020	JUN	4.52	4.52	4.52	4.52	4.64	4.52	4.52	4.52	4.52	4.52	4.52

2019-2020	JUL	4.56	4.56	4.56	4.56	4.68	4.56	4.56	4.56	4.56	4.56	4.56
2019-2020	AUG	4.60	4.60	4.60	4.60	4.72	4.60	4.60	4.60	4.60	4.60	4.60
2019-2020	SEP	4.61	4.63	4.61	4.61	4.74	4.61	4.61	4.61	4.62	4.61	4.62
2019-2020	OCT	4.68	4.68	4.68	4.68	4.81	4.68	4.68	4.68	4.68	4.68	4.68
	Annual Average	4.82	4.82	4.82	4.82	4.88	4.82	4.82	4.83	4.82	4.83	4.82
	Winter Average	5.14	5.15	5.15	5.15	5.12	5.14	5.14	5.17	5.14	5.17	5.15

Gas Year	Month	Albany	Astoria	Dalles, OR	Eugene / Coos Bay	Newport / Lincoln City	Portland	Salem	Vancouver / Dalles, WA	OR	WA	System
2020-2021	NOV	5.11	5.11	5.12	5.11	5.14	5.11	5.11	5.14	5.11	5.14	5.11
2020-2021	DEC	5.33	5.33	5.35	5.33	5.34	5.33	5.33	5.37	5.33	5.37	5.34
2020-2021	JAN	5.37	5.37	5.37	5.37	5.39	5.37	5.37	5.39	5.37	5.39	5.37
2020-2021	FEB	5.63	5.63	5.64	5.65	5.05	5.63	5.63	5.66	5.62	5.66	5.63
2020-2021	MAR	4.68	4.68	4.68	4.68	4.80	4.68	4.68	4.68	4.68	4.68	4.68
2020-2021	APR	4.61	4.61	4.61	4.61	4.73	4.61	4.61	4.61	4.61	4.61	4.61
2020-2021	MAY	4.48	4.48	4.48	4.48	4.60	4.48	4.48	4.48	4.49	4.48	4.49
2020-2021	JUN	4.52	4.52	4.52	4.52	4.64	4.52	4.52	4.52	4.52	4.52	4.52
2020-2021	JUL	4.55	4.56	4.55	4.55	4.68	4.55	4.55	4.55	4.56	4.55	4.56
2020-2021	AUG	4.59	4.59	4.59	4.59	4.71	4.59	4.59	4.59	4.59	4.59	4.59
2020-2021	SEP	4.63	4.63	4.63	4.63	4.75	4.63	4.63	4.63	4.63	4.63	4.63
2020-2021	OCT	4.84	4.84	4.84	4.84	4.97	4.84	4.84	4.84	4.84	4.84	4.84
	Annual Average	4.86	4.86	4.87	4.86	4.90	4.86	4.86	4.87	4.86	4.87	4.86
	Winter Average	5.22	5.23	5.23	5.23	5.14	5.22	5.22	5.25	5.22	5.25	5.22

Gas Year	Month	Albany	Astoria	Dalles, OR	Eugene / Coos Bay	Newport / Lincoln City	Portland	Salem	Vancouver / Dalles, WA	OR	WA	System
2021-2022	NOV	5.15	5.15	5.17	5.15	5.17	5.15	5.15	5.18	5.15	5.18	5.15
2021-2022	DEC	5.33	5.33	5.35	5.33	5.34	5.33	5.33	5.37	5.33	5.37	5.34
2021-2022	JAN	5.37	5.37	5.38	5.37	5.39	5.37	5.37	5.40	5.37	5.40	5.37
2021-2022	FEB	5.91	5.91	5.92	5.93	5.32	5.91	5.91	5.94	5.90	5.94	5.91
2021-2022	MAR	4.99	4.99	4.99	4.99	5.12	4.99	4.99	4.99	4.99	4.99	4.99
2021-2022	APR	4.91	4.91	4.91	4.91	5.04	4.91	4.91	4.91	4.91	4.91	4.91
2021-2022	MAY	4.80	4.80	4.80	4.80	4.91	4.80	4.80	4.80	4.80	4.80	4.80

2021-2022	JUN	4.81	4.81	4.81	4.81	4.94	4.81	4.81	4.81	4.81	4.81	4.81
2021-2022	JUL	4.85	4.85	4.85	4.85	4.98	4.85	4.85	4.85	4.85	4.85	4.85
2021-2022	AUG	4.89	4.89	4.89	4.89	5.02	4.89	4.89	4.89	4.89	4.89	4.89
2021-2022	SEP	4.92	4.93	4.92	4.92	5.05	4.92	4.92	4.92	4.93	4.92	4.93
2021-2022	OCT	5.03	5.03	5.03	5.03	5.16	5.03	5.03	5.03	5.03	5.03	5.03
	Annual Average	5.08	5.08	5.08	5.08	5.12	5.08	5.08	5.09	5.08	5.09	5.08
	Winter Average	5.35	5.35	5.36	5.35	5.27	5.35	5.35	5.38	5.35	5.38	5.35

Gas Year	Month	Albany	Astoria	Dalles, OR	Eugene / Coos Bay	Newport / Lincoln City	Portland	Salem	Vancouver / Dalles, WA	OR	WA	System
2022-2023	NOV	5.29	5.29	5.30	5.29	5.32	5.29	5.29	5.32	5.29	5.32	5.29
2022-2023	DEC	5.49	5.49	5.51	5.49	5.50	5.49	5.49	5.53	5.49	5.53	5.50
2022-2023	JAN	5.54	5.54	5.55	5.54	5.55	5.54	5.54	5.57	5.54	5.57	5.54
2022-2023	FEB	6.04	6.04	6.05	6.07	5.45	6.04	6.04	6.07	6.03	6.07	6.04
2022-2023	MAR	5.14	5.15	5.14	5.14	5.28	5.14	5.14	5.14	5.14	5.14	5.14
2022-2023	APR	5.07	5.08	5.07	5.07	5.21	5.07	5.07	5.07	5.08	5.07	5.08
2022-2023	MAY	4.96	4.96	4.96	4.96	5.07	4.96	4.96	4.96	4.96	4.96	4.96
2022-2023	JUN	4.97	4.97	4.97	4.97	5.10	4.97	4.97	4.97	4.97	4.97	4.97
2022-2023	JUL	5.01	5.01	5.01	5.01	5.14	5.01	5.01	5.01	5.01	5.01	5.01
2022-2023	AUG	5.05	5.05	5.05	5.05	5.18	5.05	5.05	5.05	5.05	5.05	5.05
2022-2023	SEP	5.08	5.09	5.08	5.08	5.22	5.08	5.08	5.08	5.09	5.08	5.09
2022-2023	OCT	5.20	5.20	5.20	5.20	5.33	5.20	5.20	5.20	5.20	5.20	5.20
	Annual Average	5.24	5.24	5.24	5.24	5.28	5.24	5.24	5.25	5.24	5.25	5.24
	Winter Average	5.50	5.50	5.51	5.51	5.42	5.50	5.50	5.53	5.50	5.53	5.50

Gas Year	Month	Albany	Astoria	Dalles, OR	Eugene / Coos Bay	Newport / Lincoln City	Portland	Salem	Vancouver / Dalles, WA	OR	WA	System
2023-2024	NOV	5.46	5.46	5.47	5.46	5.48	5.46	5.46	5.49	5.46	5.49	5.46
2023-2024	DEC	5.64	5.64	5.66	5.64	5.65	5.64	5.64	5.68	5.64	5.68	5.65
2023-2024	JAN	5.68	5.68	5.70	5.68	5.70	5.68	5.68	5.72	5.68	5.72	5.69
2023-2024	FEB	6.17	6.17	6.18	6.20	5.60	6.17	6.17	6.20	6.16	6.20	6.16
2023-2024	MAR	5.23	5.23	5.23	5.23	5.36	5.23	5.23	5.23	5.23	5.23	5.23
2023-2024	APR	5.21	5.21	5.21	5.21	5.34	5.21	5.21	5.21	5.21	5.21	5.21

2023-2024	MAY	5.11	5.11	5.11	5.11	5.25	5.11	5.11	5.11	5.11	5.11	5.11
2023-2024	JUN	5.14	5.15	5.14	5.14	5.28	5.14	5.14	5.14	5.15	5.14	5.15
2023-2024	JUL	5.19	5.19	5.19	5.19	5.33	5.19	5.19	5.19	5.20	5.19	5.20
2023-2024	AUG	5.23	5.24	5.23	5.23	5.37	5.23	5.23	5.23	5.24	5.23	5.24
2023-2024	SEP	5.28	5.28	5.28	5.28	5.41	5.28	5.28	5.28	5.28	5.28	5.28
2023-2024	OCT	5.49	5.49	5.49	5.49	5.63	5.49	5.49	5.49	5.49	5.49	5.49
	Annual Average	5.40	5.41	5.41	5.41	5.45	5.40	5.40	5.41	5.40	5.41	5.40
	Winter Average	5.63	5.64	5.65	5.64	5.56	5.63	5.63	5.66	5.63	5.66	5.64

Gas Year	Month	Albany	Astoria	Dalles, OR	Eugene / Coos Bay	Newport / Lincoln City	Portland	Salem	Vancouver / Dalles, WA	OR	WA	System
2024-2025	NOV	5.60	5.60	5.62	5.60	5.62	5.60	5.60	5.63	5.60	5.63	5.61
2024-2025	DEC	5.79	5.79	5.81	5.79	5.80	5.79	5.79	5.83	5.79	5.83	5.80
2024-2025	JAN	5.83	5.83	5.84	5.83	5.85	5.83	5.83	5.86	5.83	5.86	5.83
2024-2025	FEB	6.49	6.49	6.51	6.53	5.76	6.49	6.49	6.53	6.48	6.53	6.49
2024-2025	MAR	5.40	5.41	5.40	5.40	5.54	5.40	5.40	5.41	5.41	5.41	5.41
2024-2025	APR	5.40	5.40	5.40	5.40	5.54	5.40	5.40	5.40	5.40	5.40	5.40
2024-2025	MAY	5.26	5.28	5.26	5.26	5.40	5.26	5.26	5.26	5.26	5.26	5.26
2024-2025	JUN	5.30	5.32	5.30	5.30	5.44	5.30	5.30	5.30	5.30	5.30	5.30
2024-2025	JUL	5.34	5.36	5.34	5.34	5.48	5.34	5.34	5.34	5.34	5.34	5.34
2024-2025	AUG	5.38	5.40	5.38	5.38	5.52	5.38	5.38	5.38	5.39	5.38	5.39
2024-2025	SEP	5.42	5.44	5.42	5.42	5.57	5.42	5.42	5.42	5.43	5.42	5.43
2024-2025	OCT	5.67	5.69	5.67	5.67	5.80	5.67	5.67	5.67	5.67	5.67	5.67
	Annual Average	5.57	5.59	5.58	5.58	5.61	5.57	5.57	5.59	5.58	5.59	5.58
	Winter Average	5.82	5.83	5.84	5.83	5.72	5.82	5.82	5.85	5.82	5.85	5.83

Gas Year	Month	Albany	Astoria	Dalles, OR	Eugene / Coos Bay	Newport / Lincoln City	Portland	Salem	Vancouver / Dalles, WA	OR	WA	System
2025-2026	NOV	5.75	5.75	5.77	5.75	5.77	5.75	5.75	5.78	5.75	5.78	5.76
2025-2026	DEC	5.94	5.94	5.96	5.94	5.95	5.94	5.94	5.98	5.94	5.98	5.94
2025-2026	JAN	5.98	5.98	5.99	5.98	6.00	5.98	5.98	6.01	5.98	6.01	5.98
2025-2026	FEB	6.74	6.74	6.75	6.78	5.92	6.74	6.74	6.77	6.73	6.77	6.73
2025-2026	MAR	5.54	5.55	5.54	5.54	5.69	5.54	5.54	5.55	5.55	5.55	5.55

2025-2026	APR	5.56	5.56	5.56	5.56	5.70	5.56	5.56	5.56	5.56	5.56	5.56
2025-2026	MAY	5.41	5.43	5.41	5.41	5.55	5.41	5.41	5.41	5.41	5.41	5.41
2025-2026	JUN	5.45	5.47	5.45	5.45	5.60	5.45	5.45	5.45	5.46	5.45	5.46
2025-2026	JUL	5.49	5.51	5.49	5.49	5.64	5.49	5.49	5.49	5.50	5.49	5.50
2025-2026	AUG	5.54	5.56	5.54	5.54	5.68	5.54	5.54	5.54	5.54	5.54	5.54
2025-2026	SEP	5.58	5.60	5.58	5.58	5.73	5.58	5.58	5.58	5.58	5.58	5.58
2025-2026	OCT	5.93	5.95	5.93	5.93	6.04	5.93	5.93	5.93	5.93	5.93	5.93
	Annual Average	5.74	5.75	5.75	5.75	5.77	5.74	5.74	5.75	5.74	5.75	5.74
	Winter Average	5.99	5.99	6.00	6.00	5.87	5.99	5.99	6.02	5.99	6.02	5.99

Gas Year	Month	Albany	Astoria	Dalles, OR	Eugene / Coos Bay	Newport / Lincoln City	Portland	Salem	Vancouver / Dalles, WA	OR	WA	System
2026-2027	NOV	5.99	5.99	6.01	5.99	6.02	5.99	5.99	6.02	5.99	6.02	5.99
2026-2027	DEC	6.19	6.19	6.21	6.19	6.20	6.19	6.19	6.23	6.19	6.23	6.19
2026-2027	JAN	6.24	6.24	6.25	6.24	6.25	6.24	6.24	6.27	6.24	6.27	6.24
2026-2027	FEB	7.08	7.08	7.10	7.11	6.19	7.08	7.08	7.12	7.07	7.12	7.08
2026-2027	MAR	5.74	5.75	5.74	5.74	5.89	5.74	5.74	5.75	5.74	5.75	5.74
2026-2027	APR	5.79	5.79	5.79	5.79	5.94	5.79	5.79	5.79	5.79	5.79	5.79
2026-2027	MAY	5.63	5.65	5.63	5.63	5.78	5.63	5.63	5.63	5.63	5.63	5.63
2026-2027	JUN	5.66	5.68	5.66	5.66	5.81	5.66	5.66	5.66	5.67	5.66	5.67
2026-2027	JUL	5.71	5.73	5.71	5.71	5.86	5.71	5.71	5.71	5.71	5.71	5.71
2026-2027	AUG	5.75	5.77	5.75	5.75	5.90	5.75	5.75	5.75	5.75	5.75	5.75
2026-2027	SEP	5.79	5.81	5.79	5.79	5.95	5.79	5.79	5.79	5.80	5.79	5.80
2026-2027	OCT	6.12	6.14	6.12	6.12	6.21	6.12	6.12	6.12	6.13	6.12	6.13
	Annual Average	5.97	5.99	5.98	5.98	6.00	5.97	5.97	5.99	5.98	5.99	5.98
	Winter Average	6.25	6.25	6.26	6.25	6.11	6.25	6.25	6.28	6.25	6.28	6.25

Gas Year	Month	Albany	Astoria	Dalles, OR	Eugene / Coos Bay	Newport / Lincoln City	Portland	Salem	Vancouver / Dalles, WA	OR	WA	System
2027-2028	NOV	6.16	6.16	6.17	6.16	6.19	6.16	6.16	6.19	6.16	6.19	6.16
2027-2028	DEC	6.35	6.35	6.37	6.35	6.37	6.35	6.35	6.39	6.35	6.39	6.36
2027-2028	JAN	6.41	6.41	6.42	6.41	6.42	6.41	6.41	6.44	6.41	6.44	6.41
2027-2028	FEB	7.20	7.20	7.22	7.24	6.28	7.20	7.20	7.24	7.19	7.24	7.19

2027-2028	MAR	5.86	5.87	5.86	5.86	6.02	5.86	5.86	5.87	5.87	5.87	5.87
2027-2028	APR	5.91	5.91	5.91	5.91	6.06	5.91	5.91	5.91	5.91	5.91	5.91
2027-2028	MAY	5.75	5.77	5.75	5.75	5.90	5.75	5.75	5.75	5.75	5.75	5.75
2027-2028	JUN	5.79	5.81	5.79	5.79	5.94	5.79	5.79	5.79	5.79	5.79	5.79
2027-2028	JUL	5.83	5.85	5.83	5.83	5.99	5.83	5.83	5.83	5.84	5.83	5.84
2027-2028	AUG	5.88	5.90	5.88	5.88	6.03	5.88	5.88	5.88	5.88	5.88	5.88
2027-2028	SEP	5.92	5.94	5.92	5.92	6.08	5.92	5.92	5.92	5.93	5.92	5.93
2027-2028	OCT	6.27	6.29	6.27	6.27	6.33	6.27	6.27	6.27	6.27	6.27	6.27
	Annual Average	6.11	6.12	6.12	6.11	6.13	6.11	6.11	6.12	6.11	6.12	6.11
	Winter Average	6.40	6.40	6.41	6.40	6.26	6.40	6.40	6.43	6.39	6.43	6.40

Gas Year	Month	Albany	Astoria	Dalles, OR	Eugene / Coos Bay	Newport / Lincoln City	Portland	Salem	Vancouver / Dalles, WA	OR	WA	System
2028-2029	NOV	6.29	6.30	6.31	6.31	6.33	6.29	6.29	6.32	6.29	6.32	6.30
2028-2029	DEC	6.43	6.44	6.45	6.43	6.46	6.43	6.43	6.47	6.44	6.47	6.44
2028-2029	JAN	6.52	6.52	6.54	6.52	6.54	6.52	6.52	6.56	6.52	6.56	6.53
2028-2029	FEB	7.32	7.32	7.33	7.35	6.44	7.32	7.32	7.35	7.30	7.35	7.31
2028-2029	MAR	6.01	6.02	6.01	6.01	6.17	6.01	6.01	6.02	6.02	6.02	6.02
2028-2029	APR	6.02	6.02	6.02	6.02	6.17	6.02	6.02	6.02	6.02	6.02	6.02
2028-2029	MAY	5.90	5.91	5.90	5.90	6.05	5.90	5.90	5.90	5.90	5.90	5.90
2028-2029	JUN	5.93	5.95	5.93	5.93	6.09	5.93	5.93	5.93	5.94	5.93	5.94
2028-2029	JUL	5.99	6.01	5.99	5.99	6.14	5.99	5.99	5.99	5.99	5.99	5.99
2028-2029	AUG	6.03	6.05	6.03	6.03	6.19	6.03	6.03	6.03	6.03	6.03	6.03
2028-2029	SEP	6.07	6.09	6.07	6.07	6.23	6.07	6.07	6.07	6.08	6.07	6.08
2028-2029	OCT	6.25	6.27	6.25	6.25	6.41	6.25	6.25	6.25	6.25	6.25	6.25
	Annual Average	6.23	6.24	6.24	6.23	6.27	6.23	6.23	6.24	6.23	6.24	6.23
	Winter Average	6.52	6.52	6.53	6.53	6.39	6.52	6.52	6.55	6.51	6.55	6.52

Gas Year	Month	Albany	Astoria	Dalles, OR	Eugene / Coos Bay	Newport / Lincoln City	Portland	Salem	Vancouver / Dalles, WA	OR	WA	System
2029-2030	NOV	6.56	6.56	6.57	6.57	6.60	6.56	6.56	6.59	6.56	6.59	6.56
2029-2030	DEC	6.78	6.78	6.80	6.78	6.79	6.78	6.78	6.82	6.78	6.82	6.78
2029-2030	JAN	6.82	6.82	6.84	6.82	6.84	6.82	6.82	6.86	6.82	6.86	6.83

2029-2030	FEB	7.37	7.37	7.38	8.08	7.48	7.37	7.37	7.40	7.42	7.40	7.42
2029-2030	MAR	6.29	6.29	6.29	6.29	6.45	6.29	6.29	6.30	6.29	6.30	6.29
2029-2030	APR	6.27	6.27	6.27	6.27	6.43	6.27	6.27	6.27	6.27	6.27	6.27
2029-2030	MAY	6.20	6.22	6.20	6.20	6.35	6.20	6.20	6.20	6.20	6.20	6.20
2029-2030	JUN	6.19	6.21	6.19	6.19	6.35	6.19	6.19	6.19	6.19	6.19	6.19
2029-2030	JUL	6.24	6.26	6.24	6.24	6.40	6.24	6.24	6.24	6.24	6.24	6.24
2029-2030	AUG	6.28	6.30	6.28	6.28	6.45	6.28	6.28	6.28	6.29	6.28	6.29
2029-2030	SEP	6.31	6.33	6.31	6.31	6.47	6.31	6.31	6.31	6.31	6.31	6.31
2029-2030	OCT	6.50	6.52	6.50	6.50	6.66	6.50	6.50	6.50	6.50	6.50	6.50
	Annual Average	6.48	6.50	6.49	6.54	6.61	6.48	6.48	6.50	6.49	6.50	6.49
	Winter Average	6.76	6.77	6.78	6.91	6.83	6.76	6.76	6.79	6.78	6.79	6.78

Gas Year	Month	Albany	Astoria	Dalles, OR	Eugene / Coos Bay	Newport / Lincoln City	Portland	Salem	Vancouver / Dalles, WA	OR	WA	System
2030-2031	NOV	6.61	6.62	6.63	6.64	6.66	6.61	6.61	6.65	6.62	6.65	6.62
2030-2031	DEC	6.78	6.78	6.80	6.78	6.80	6.78	6.78	6.82	6.78	6.82	6.78
2030-2031	JAN	6.88	6.88	6.90	6.88	6.89	6.88	6.88	6.92	6.88	6.92	6.88
2030-2031	FEB	11.64	11.64	####	12.36	11.75	11.64	11.64	11.68	11.70	11.68	11.69
2030-2031	MAR	6.38	6.39	6.38	6.38	6.55	6.38	6.38	6.39	6.38	6.39	6.39
2030-2031	APR	6.37	6.37	6.37	6.37	6.53	6.37	6.37	6.37	6.37	6.37	6.37
2030-2031	MAY	6.30	6.32	6.30	6.30	6.45	6.30	6.30	6.30	6.31	6.30	6.31
2030-2031	JUN	6.29	6.31	6.29	6.29	6.45	6.29	6.29	6.29	6.29	6.29	6.29
2030-2031	JUL	6.36	6.38	6.36	6.36	6.53	6.36	6.36	6.36	6.37	6.36	6.37
2030-2031	AUG	6.41	6.43	6.41	6.41	6.58	6.41	6.41	6.41	6.41	6.41	6.41
2030-2031	SEP	6.46	6.48	6.46	6.46	6.62	6.46	6.46	6.46	6.46	6.46	6.46
2030-2031	OCT	6.63	6.65	6.63	6.63	6.74	6.63	6.63	6.63	6.63	6.63	6.63
	Annual Average	6.93	6.94	6.93	6.99	7.05	6.93	6.93	6.94	6.93	6.94	6.93
	Winter Average	7.66	7.66	7.67	7.81	7.73	7.66	7.66	7.69	7.67	7.69	7.67

Gas Year	Month	Albany	Astoria	Dalles, OR	Eugene / Coos Bay	Newport / Lincoln City	Portland	Salem	Vancouver / Dalles, WA	OR	WA	System
2031-2032	NOV	6.62	6.62	6.63	6.64	6.66	6.62	6.62	6.65	6.62	6.65	6.62
2031-2032	DEC	6.78	6.78	6.80	6.78	6.80	6.78	6.78	6.82	6.78	6.82	6.78

2031-2032	JAN	6.88	6.88	6.89	6.88	6.89	6.88	6.88	6.91	6.88	6.91	6.88
2031-2032	FEB	10.54	10.54	####	11.24	10.65	10.54	10.54	10.58	10.60	10.58	10.59
2031-2032	MAR	6.38	6.39	6.38	6.38	6.55	6.38	6.38	6.40	6.38	6.40	6.39
2031-2032	APR	6.37	6.37	6.37	6.37	6.53	6.37	6.37	6.37	6.37	6.37	6.37
2031-2032	MAY	6.30	6.32	6.30	6.30	6.47	6.30	6.30	6.30	6.31	6.30	6.31
2031-2032	JUN	6.29	6.31	6.29	6.29	6.45	6.29	6.29	6.29	6.29	6.29	6.29
2031-2032	JUL	6.36	6.38	6.36	6.36	6.53	6.36	6.36	6.36	6.37	6.36	6.37
2031-2032	AUG	6.41	6.43	6.41	6.41	6.58	6.41	6.41	6.41	6.41	6.41	6.41
2031-2032	SEP	6.46	6.48	6.46	6.46	6.62	6.46	6.46	6.46	6.46	6.46	6.46
2031-2032	OCT	6.63	6.65	6.63	6.63	6.80	6.63	6.63	6.63	6.63	6.63	6.63
	Annual Average	6.83	6.85	6.84	6.89	6.96	6.83	6.83	6.85	6.84	6.85	6.84
	Winter Average	7.44	7.44	7.45	7.58	7.51	7.44	7.44	7.47	7.45	7.47	7.45

Chapter 7: Distribution System Planning

NW Natural

Appendix 7 - Washington Distribution System Projects

Washington Distribution Project List					
Name	**Location**	**Description**	**Purpose**	**Cost**	**Aniticpated Construction Date**
119th Street	Vancouver - NE 119th St from 111th Avenue to 72nd Avenue	Approximately 1.5 miles of 6 inch wrapped steel class D high Pressure Main	Reinforcement to the NW area of Vancouver	$2 million	2014

Chapter 8: Public Communication and Participation

NW Natural®

NW Natural – 2013 Integrated Resource Plan (IRP) Technical Working Group Meeting
June 28, 2012

NAME - please print	Company	Email
Teresa Hagins	Northwest Pipeline GP	Teresa.L.Hagins@williams.com
MASSOUD E. JOURABCHI	NWPCC	MJOURABCHI@NWCOUNCIL.ORG
Wendy Gerlitz	NWEC	wendy@nwenergy.org
Ben Hemson	NWGA	BHemson@NWGA.org
Chris McGuire	WUTC	cmcguire@utc.wa.gov
CHRIS GALATI	NWN	cfg@nwnatural.com
Dan Kirschner	NWGA	dkirschner@nwga.org
Randy Friedman	NWN	randy.friedman@nwnatural.com
STEVE NELSON	NWN	sen@nwnatural.com
Glenn Carlson	NWN	gec@nwnatural.com
Paula Pyron	NWIGU	ppyron@nwigu.org
Kevin McVay	NWN	ksm@nwnatural.com
Mike Mott	NWN	Mike.Mott@nwnatural.com
Phone:		
Adam Bartini	ETO	
Mark Sellers Vaughn	CNG	

NW Natural – 2013 Integrated Resource Plan (IRP) Technical Working Group Meeting
August 22, 2012

NAME - please print	Company	Email
MASSOUD JOURABCHI	NWPCC	MJOURABCHI@NWCOUNCIL.ORG
Teresa Hagins	Northwest Pipeline GP	Teresa.L.Hagins@williams.com
Ed Finklea	NWIGU	efinklea@nwigu.org
Chris McGuire	WUTC	cmcguire@utc.wa.gov
Wendy Gerlitz	NWEC	wendy@nwenergy.org
Holly Meyer	NWN	
Jon Huddleston	NWN	jon.huddleston@nwnatural.com
Glenn Carlson	NWN	gec@nwnatural.com
STEVE NELSON	NWN	sen@nwnatural.com
Elaine Prause	ETO	elaine.prause@energytrust.org
Adam Bartini	ETO	adam.bartini@energytrust.org
Lakin Garth	Energy Trust	lakin.garth@energytrust.org
Sarah Dammen	NWN	s2d@nwnatural.com
Jennifer Gross	NWN	jgg@nwnatural.com
Kevin McVay	NWN	
Randy Friedman	NWN	
Katie Gough	NWN	
On the phone:		
Lynn	NWEC	