Avista 2009 Natural Gas Integrated Resource Plan
Oregon Addendum
March 2010

Avista provides this addendum to its 2009 Integrated Resource Plan which was filed with the Oregon Public Utility Commission on December 30, 2009. The addendum more concisely summarizes the integration of the demand forecast methodology applied, the resource alternatives reviewed and risk analysis conducted in performing our portfolio analysis. It incorporates information included in various parts of our filed plan including Appendix 3.6, 3.7, 5.2, 6.3, 7.1 and 7.5 to provide a summarized presentation of our analysis and portfolio selection.

This addendum also amends our plan to include four additional action items to our filed plan.

Part 1: Demand Forecast Methodology

A. Definitions

Dynamic Demand Methodology – Avista's demand forecasting approach wherein we 1) identify key demand drivers (factors) behind natural gas consumption, 2) perform sensitivity analysis on each demand driver, and 3) combine demand drivers under various scenarios to develop alternative potential outcomes for forecasted demand.

Demand Influencing Factors – Factors that directly influence the volume of natural gas consumed by our core customers.

Price Influencing Factors – Factors that, through price elasticity response, indirectly influence the volume of natural gas consumed by our core customers.

Reference Case – A baseline point of reference that captures the basic inputs for determining a demand forecast in SENDOUT which includes number of customers, use per customer, daily weather temperatures and natural gas prices.

Sensitivities – Focused analysis of a specific natural gas demand driver and its impact on forecasted demand relative to the Reference Case when underlying input assumptions are modified.

Scenarios – Combination of natural gas demand drivers that make up a demand forecast.

B. Reference Case Input Assumptions

Customer growth rates reflect roll up of underlying county level growth rate analysis utilizing Global Insights forecast data. Initial use per customer is based on historical analysis of last three years data. Peak Day weather reflects coldest average daily temperature experienced over available weather data. Natural gas price curve derived from independent consultant forecast with first five years modified to include blend of recent market prices (Nymex forward prices).

C. Sensitivities

The following Sensitivities were performed on identified demand drivers against the reference case for consideration in Scenario development. Note that Sensitivity assumptions reflect incremental adjustments we estimate are not captured in the underlying reference case forecast.

Low & High Customer Growth – In our low customer growth Sensitivity, annual customer growth rates under perform the reference rate of growth by 50% over our 20 year planning horizon while annual customer growth rates exceed the reference rate by 50% in our high growth Sensitivity.

Coldest Day 20yrs Weather Standard – Peak Day weather temperature reduced to coldest average daily temperature (HDDs) experienced in the most recent 20 years in each region. Note this sensitivity only affects our WA/ID, Medford and Roseburg service regions as Klamath Falls and La Grande have experienced a coldest day on record within the last 20 years.

Low & High Prices – To capture a wide band of alternative prices forecasts, we use the Northwest Power and Conservation Council's "very low" and "very high" natural gas price forecast scenarios with first five years modified to include blend of recent market prices (Nymex forward prices) consistent with our Expected price forecast.

Low, Medium and High Elasticity – For our medium elasticity Sensitivity, we incorporate reduced consumption in response to higher natural gas prices utilizing a price elasticity study prepared by the American Gas Association. We then consider a lower response rate to the study as well as a higher response. We also consider a wider band of response in especially volatile prices defined as annual price increases exceeding 30%.

Carbon Mitigation 1 – Utilizes carbon cost adders quantified by independent analysis from Wood Mackenzie. They identify both an adder reflecting carbon allowances as well as an adder to capture the effect of increased natural gas demand as more gas turbines come online to replace coal plants and back up wind generation. The allowance adder escalates from $5/ton in 2012 to $67/ton by 2030 while the increased demand adder climbs from $.50/mmbtu to $1.00 over our planning horizon.

Carbon Mitigation 2 – Recognizing significant uncertainty exists regarding the amount, scope, and timing of carbon regulation, we utilize a second alternate range of cost adders to develop a high carbon cost case. We escalate an allowance adder from $37/ton in 2012 to $140/ton by 2030 as forecasted in a Pacific Northwest electric utility's integrated resource plan. The increased demand adder is consistent with our **Carbon Mitigation 1** case.

Canadian Imports Decline – Beginning in 2015, we apply an estimate of $.20/mmbtu *incremental* adder each year to regional natural gas prices to capture upward price pressure because of decreased Canadian imports more severe than generally anticipated. The cumulative cost adder by the end of our planning horizon is $3.00/mmbtu. After discussion with the TAC, we dropped further analysis of our initial most severe imports decline case of $.50/mmbtu incremental each year as we concluded this type of price increase would support several supply responses (including frontier gas pipelines) which would curtail such a long term price increase.

Drilling Constraints –This price adder estimates the impact from increased costs to comply with potential increased environmental regulations. Significant uncertainty exists regarding potential costs, impacts on production and timing of more stringent regulation. Also, it is very difficult to ascertain to what degree these types of costs are already captured in forward market prices and various price forecasts. In light of this challenge, we have assumed a $.30/mmbtu adder in each year from 2012 to 2030 for this Sensitivity recognizing the wide range of actual outcomes.

D. Scenarios

After identifying the above demand drivers and analyzing the various Sensitivities, we have developed the following demand forecast Scenarios:

Expected Case – This Scenario we believe represents the most likely demand forecast modeled. We assume service territory customer growth rates consistent with the reference case, a weather standard of coldest day on record in each service territory, our middle range natural gas price forecast (Consultant #1), low price elasticity[1], and the CO2 cost adders from our **Carbon Mitigation 1 (CM1)** Sensitivity. The Scenario does not include incremental cost adders for declining Canadian imports or drilling restrictions beyond what is incorporated in the selected price forecast. The moderate customer forecast, mid range price forecast, moderate carbon mitigation case and low price elastic response due to challenging economic times represents in our judgment the most likely trends for the assumptions analyzed. We believe it to be consistent with the current economic environment and our expectation of a slow economic recovery.

High Growth, Low Price – This Scenario models a rapid return to robust growth in part spurred on by low energy prices. We assume customer growth rates 50% higher than the reference case, coldest day on record weather standard, our low natural gas price forecast, low price elasticity, and CO2 adders from **CM1**. The Scenario does not include incremental cost adders for declining Canadian imports or drilling restrictions beyond what is incorporated in the selected price forecast.

Low Growth, High Price – This Scenario models an extended period of slow economic growth in part resulting from high energy prices. We assume customer growth rates 50% lower than the reference case, coldest day on record weather standard, our high natural gas price forecast, high price elasticity, and CO2 adders from our **Carbon Mitigation 1 Sensitivity (CM1)**. The Scenario also includes an incremental cost adder for drilling restrictions.

Green Future – This Scenario models a moderate return to economic growth consistent with our Expected Case while striving for environmentally friendly objectives. We assume service territory customer growth rates consistent with the reference case, a weather standard of coldest day on record in each service territory, and our middle range natural gas price forecast but with price adjustments including the CO2 cost adders from **CM2**, and drilling restrictions. We also assume our high elasticity response to rising prices.

Alternate Weather Standard – This Scenario models all the same assumptions as the **Expected Case** Scenario except for the change in the weather planning standard from coldest day on record to coldest day in 20 years for each service territory. As noted in the Sensitivity analysis, this change does not affect the Klamath Falls and La Grande service territories which have each experienced their coldest day on record within the last 20 years.

Supply Constraints – This Scenario models an extended period of slow economic growth in part resulting from high energy prices. We assume customer growth rates 50% lower than the reference case, coldest day on record weather standard, our high natural gas price forecast, medium price elasticity, and CO2 adders from our **Carbon Mitigation 1 Sensitivity (CM1)**. The Scenario also includes incremental cost adders for declining Canadian imports and drilling restrictions.

[1] Our price forecast captured very low pricing early in the forecast but included a very steep increase in the second and third years. The medium and high price elasticity assumptions, when run through the SENDOUT® model, resulted in significant curtailment of demand which was much greater than historical experience. This curtailment had a cumulative effect and our forecasted demand in some cases took several years to return to our current demand. This raised apprehension that the forecasted curtailment might not occur and our modeled demand could be understated. This, in turn, could distort the timing of actual future resource deficiencies. Further, we had concerns that economic challenges could deter or defer implementation of otherwise cost effective conservation measures. On the other hand, the customer response could materialize as modeled, resulting in an actual significant demand curtailment. With TAC consensus, we decided to use the low price elasticity assumption for our Expected Case and monitor closely future actual use per customer data and DSM program results for indications of price elasticity response trends that may be influenced by evolving economic conditions.

E. Sensitivities - Summary of Assumptions

Demand Influencing (Direct)

Model Sensitivities			**DEMAND INFLUENCING - DIRECT**							
		Reference Case	Low Cust Growth	High Cust Growth	Cold Day 20yr Weather Std	CNG Vehicles	1HDD Lower Weather Std	Northern Migration	Stagnant Growth	Global Warning
INPUT ASSUMPTIONS										
Customer Growth Rate										
Residential	WA/ID	2.2%								
Residential	Medford	2.6%								
Residential	Roseburg	3.6%								
Residential	Klamath	1.9%	50% Decrease in Cust Growth Rates	50% Increase in Cust Growth Rates						
Residential	La Grande	1.4%								
Commercial	WA/ID	2.3%						**???**	**???**	
Commercial	Medford	1.2%								
Commercial	Roseburg	2.1%								
Commercial	Klamath	1.9%								
Commercial	La Grande	0.6%								
Use per Customer		Flat				15% Growth Cumulative				
Weather										
Planning Standard		Coldest Day			Coldest 20yrs		Coldest-1HDD			**???**
Prices										
Price curve		Expected								
Elasticity		None								
Carbon Adder ($/Ton)		None								
Coal to Gas Adder ($/Dth)		None								
Cdn Imports Decline Adder										
Drilling Constraints ($/Dth)										
First Year Unserved										
WA/ID		2027	N/A	2019	N/A	2026	2028			
Medford		2017	2025	2015	2018	2016	2017	**???**	**???**	**???**
Klamath		2018	N/A	2015	2018	2017	2019			
La Grande		N/A	N/A	2019	2024	2022	2025			
							= Did Not full cycle model			

F. Sensitivities - Summary of Assumptions

Price Influencing (Indirect)

Model Sensitivities			**PRICE INFLUENCING - INDIRECT**								
		Reference Case	Medium Elasticity	Low Elasticity	High Elasticity	Low Prices	High Prices	Carbon Mitigate 1	Carbon Mitigate 2	Cdn Imports Decline	Drilling Constraints
INPUT ASSUMPTIONS											
Customer Growth Rate											
Residential	WA/ID	2.2%									
Residential	Medford	2.6%									
Residential	Roseburg	3.6%									
Residential	Klamath	1.9%									
Residential	La Grande	1.4%									
Commercial	WA/ID	2.3%									
Commercial	Medford	1.2%									
Commercial	Roseburg	2.1%									
Commercial	Klamath	1.9%									
Commercial	La Grande	0.6%									
Use per Customer		Flat									
Weather											
Planning Standard		Coldest Day									
Prices											
Price curve		Expected	Expected	Expected	Expected	Low	High	Expected	Expected	Expected	Expected
Elasticity		None	Medium	Low	High	Medium	Medium	Medium	Medium	Medium	Medium
Carbon Adder ($/Ton)		None						$5-$67	$37-$140		
Coal to Gas Adder ($/Dth)		None						$.50-$1.00	$.50-$1.00		
Cdn Imports Decline Adder										$.20 incremental	
Drilling Constraints ($/Dth)											$0.30
First Year Unserved											
WA/ID		2027	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Medford		2017	2022	2017	N/A	2019	2024	2019	2020	2021	2021
Klamath		2018	2027	2020	N/A	2022	N/A	2022	2022	2025	2025
La Grande		N/A	N/A	2026	N/A	N/A	N/A	N/A	N/A	N/A	N/A

G. Scenarios - Summary of Assumptions

Scenarios		Expected Case	Low Growth & High Prices	High Growth & Low Prices	Green Future	Alternate Weather Std	Supply Constraints
INPUT ASSUMPTIONS							
Customer Growth Rate		Reference Case Cust Growth Rates	50% Decrease in Cust Growth Rates	50% Increase in Cust Growth Rates	Reference Case Cust Growth Rates	Reference Case Cust Growth Rates	Reference Case Cust Growth Rates
Use per Customer		Flat +	Flat +	Flat +	Flat +	Flat +	Flat +
		Price Elast.	Price Elast.	Price Elast.	Price Elast.	Price Elast.	Price Elast.
Weather							
Planning Standard		Coldest Day	Coldest Day	Coldest Day	Coldest Day	CD 20 yrs	Coldest Day
Prices							
Price curve		Expected	High	Low	Expected	Expected	High
Elasticity		Low	High	Low	High	Low	Medium
Carbon Adder ($/Ton)		$5-$67	$5-$67	$5-$67	$37-$140	$5-$67	$5-$67
Coal to gas adder ($/Dth)		$.50-$1.00	$.50-$1.00	$.50-$1.00	$.50-$1.00	$.50-$1.00	$.50-$1.00
Drilling Constraints ($/Dth)		None	$0.30	None	$0.30	None	$0.30
Declining Canada Gas ($/Dth)		None	None	None	None	None	$.20-$3.00
RESULTS							
First Year Unserved							
WA/ID		2023	N/A	2016	N/A	N/A	2029
Medford		2018	N/A	2015	2027	2020	2027
Klamath		2021	N/A	2016	N/A	2021	N/A
La Grande		N/A	N/A	2022	N/A	N/A	N/A

Part 2: Existing Resources and Alternate Supply Scenarios

Avista's existing resources portfolio consists of commodity, transportation, and storage resources.

A. COMMODITY RESOURCES

Avista is located in relatively close proximity to the two largest natural gas producing regions in North America—the Western Canadian Sedimentary Basin (WCSB) and the Rocky Mountain gas basins. Extending out from the two primary basins are numerous regional market hubs where natural gas is traded. Avista transacts at most of the Pacific Northwest regional market hubs which include:

- AECO
- Rockies
- Sumas/Huntingdon
- Malin
- Station 2
- Stanfield
- Kingsgate

B. TRANSPORTATION RESOURCES

Avista has contracted firm pipeline capacity from the major pipelines servicing our region as follows:

- Williams - Northwest Pipeline (NWP)
- TransCanada Gas Transmission Northwest (GTN)
- TransCanada Alberta System
- TransCanada BC System
- TransCanada Tuscarora Gas Transmission
- Spectra Energy - BC Pipeline

Contracts are of different vintages, thus different expiration dates; however, all have the right to be renewed by Avista.

C. STORAGE RESOURCES

Avista's existing storage resources consist of ownership and leasehold rights in two in-ground regional storage facilities.

- Jackson Prairie
- Mist

D. SUPPLY SCENARIOS

For this IRP we modeled four supply scenarios.

- Existing Resources – Represents all resources currently owned or contracted by Avista.
- Existing + Expected Available – Existing resources plus supply resource options expected to be available when resource needs are identified. This includes: currently available GTN, capacity release recalls, NWP expansions, satellite LNG, backhauls combined with increased lateral compression, liquefaction LNG and Klamath Falls Lateral Purchase.
- GTN Rate Escalation – Same resource options as Existing + Expected Available except GTN subscription rate is doubled.
- GTN Fully Subscribed – Same resource options as Existing + Expected Available except GTN is fully subscribed so there is no incremental GTN capacity available.

Alternate Supply Scenarios

Scenarios	Existing Resources	Existing + Expected Available	GTN Rate Escallation	GTN Fully Subscribed
INPUT ASSUMPTIONS				
Resources:				
	Currently contracted capacity net of long term releases	Currently contracted capacity net of long term releases	Currently contracted capacity net of long term releases	Currently contracted capacity net of long term releases
		Currently available GTN	Currently available GTN	
		Capacity Release Recalls	Capacity Release Recalls	Capacity Release Recalls
		NWP Expansions	NWP Expansions	NWP Expansions
		Satellite LNG	Satellite LNG	Satellite LNG
		Backhaul plus add'l compression	Backhaul plus add'l compression	
		Liquifiaction LNG	Liquifiaction LNG	Liquifiaction LNG
		Klamath Falls Lateral Purchase	Klamath Falls Lateral Purchase	Klamath Falls Lateral Purchase
Rates:	Current Rates	Current Rates	GTN rate doubles	Current Rates

Part 3: Portfolio Analysis Summary

SENDOUT® #	Portfolio NPVRR[1] (billions)	Demand Scenario[2]	Demand Major Assumptions	Supply Scenario[3]	Resource Major Assumptions	First Year Unserved[4]	Notes
1022	N/A	Reference Case	**Expected** customer growth rates, **flat** use per customer, coldest day on record, **no** price elasticity, **expected** (Consult1) price curve	Existing Resources	Existing transporation, storage, and DSM resources	M-2017 K-2018 L-N/A	A
1111	$6,515	Expected Case	Reference case except **low** elasticity and carbon adder phase in to **expected** (Consult1) price curve (updated) @ $5-$67/ton beginning 2016	Existing Resources	Existing transporation, storage, and DSM resources	M-2018 K-2021 L-N/A	B
1113	$6,548	Expected Case	Reference case except **low** elasticity and carbon adder phase in to **expected** (Consult1) price curve (updated) @ $5-$67/ton beginning 2016	Existing + Expected Available	Existing resources plus expected available resources including unsubscribed transport on existing pipelines, capacity expansions, backhauls and satellite LNG.	M-2018 K-2021 L-N/A	C
1120	$6,594	Expected Case	Reference case except **low** elasticity and carbon adder phase in to **expected** (Consult1) price curve (updated) @ $5-$67/ton beginning 2016	GTN Rate Escalation	Existing resources and expected available resources. However, the GTN rates are doubled to incorporate a major turnback of capacity on their system.	M-2018 K-2021 L-N/A	D
1121	$7,440	Expected Case	Reference case except **low** elasticity and carbon adder phase in to **expected** (Consult1) price curve (updated) @ $5-$67/ton beginning 2016	GTN Fully Subscribed	Existing resources and expected available resources. However, there is no more available capacity on GTN's system due to the decomissioing of one of their lines in response to capacity turnback.	M-2018 K-2021 L-N/A	E
1118	$5,587	Expected Case with High Elasticity	Expected Case demand assumptions except **high** price elasticity response assumption	Existing Resources	Existing transporation, storage, and DSM resources	M-N/A K-N/A L-N/A	F
1117	$6,249	Expected Case with Medium Elasticity	Expected Case demand assumptions except **medium** price elasticity response assumption	Existing + Expected Available	Existing resources plus expected available resources including unsubscribed transport on existing pipelines, capacity expansions, backhauls and satellite LNG.	M-2022 K-2026 L-N/A	G
1110	$7,997	Alternate Weather Standard	Expected Case demand assumptions except **coldest day in the last 20 years** weather planning standard and **low** elasticity on **expected** (Consult1) price curve (not updated)	Existing Resources	Existing transporation, storage, and DSM resources	M-2020 K-2021 L-N/A	H
1108	$7,691	High Growth & Low Prices	Expected Case demand assumptions except **high** customer growth and **low** elasticity on **low** (NPCC) price curve	Existing Resources	Existing transporation, storage, and DSM resources	M-2015 K-2016 L-2022	I
1115	$10,705	High Growth & Low Prices	Expected Case demand assumptions except **high** customer growth and **low** elasticity on **low** (NPCC) price curve	Existing + Expected Available	Existing resources plus expected available resources including unsubscribed transport on existing pipelines, capacity expansions, backhauls and satellite LNG.	M-2015 K-2016 L-2022	J
1109	$9,277	Green Future	Expected Case demand assumptions except **medium** elasticity and adders to **expected** (Consult1) price curve (not updated) of $.30 for drilling constraints and phase in of **high** carbon $37-$140/ton	Existing Resources	Existing transporation, storage, and DSM resources	M-2027 K-N/A L-N/A	K
1107	$10,815	Low Growth & High Prices	Expected Case demand assumptions except **low** customer growth and **high** elasticity on **high** (NPCC) price curve	Existing Resources	Existing transporation, storage, and DSM resources	M-N/A K-N/A L-N/A	L
1114	$11,783	Supply Constrained	Expected case demand assumptions except **medium** elasticity plus adders to **high** (NPCC) price curve of $.30 for drilling constraints and phase in of $.20 to $3.00 for Canadian imports declines	Existing Resources	Existing transporation, storage, and DSM resources	M-2027 K-N/A L-N/A	M

Footnotes:

1 - Detailed Net Present Value of Revenue Requirement for resource costs by gas year for each portfolio are detailed at Appendix 7.5

2 - Chapter 3 details our demand forecast methodology that derive inputs into the SENDOUT model including customer forecasts, base and weather sensitive usage, HDDs, and prices. Appendix 3.6 & 3.7 describes the development of a reference case, focused analysis of specific demand drivers (sensitivities) relative to the reference case and alternate demand scenario development from combination of one or more sensitivities to simulate various demand environments.

3 - Chapter 4 details DSM methodology while Chapter 5 describes supply side resources, existing and potential future regional infrastructure, supply scenarios considered and supply issues and uncertainties. Appendix 5.1 describes Alternate Supply Scenario assumptions while Appendix 6.3 details specific supply side resources and assumptions available to SENDOUT to meet identified resource deficiencies.

4 - Medford is "M", Klamath Falls is "K" and LaGrande is "L"

Portfolio Analysis Summary - NOTES

Note:

A The Reference Case is a baseline point of reference that captures basic starting point inputs for determining a demand forecast in SENDOUT including number of customers, use per customer (base and weather sensitive), weather temperatures and natural gas prices. Customer growth rates reflect roll-up of underlying county level growth rate analysis utilizing Global Insights forecast data. Initial use per customer is based on historical analysis of last three years data. Peak Day weather reflects coldest average daily temperature experienced over available weather data. Natural gas price curve derived from independent consultant forecast with first five years modified to include blend of recent market prices (see Figure 3.7). These demand assumptions produced our Reference Case demand forecast which was run against our existing resource portfolio to determine the timing of future resource needs. From this baseline, multiple **sensitivities** were run (focused analysis of a specific natural gas demand driver and its impact on forecasted demand relative to the Reference Case). One or more of these sensitivities were then combined to develop alternate demand **scenarios** (see Appendix 3.6 & 3.7).

B This portfolio starts with the Reference Case demand assumptions and adds a **low** price elasticity response assumption (see Table 3.5) and adjusts the natural gas price forecast for CO2 cost adders from our Carbon Mitigation 1 (CM1) sensitivity (Appendix 3.7). It also uses an **updated** expected price curve as requested by our TAC given the significant market price revisions that occurred from the original price forecast (see Figures 7.4 and 7.5 [Updated Prices, Low Elasticity]).These demand assumptions produced our Expected Case demand forecast which represents what we believe is the most likely demand forecast. This forecast was run against our existing resource portfolio to determine the amount and timing of future resource needs (see Table 6.3 and Figures 6.11-13).

C This portfolio continues with the Expected Case demand scenario run against existing AND expected available resources for each of the service territories modeled (see Appendix 6.3). In Medford, the preferred resource selected is GTN Medford lateral expansion coupled with Malin backhaul of supply (see Figure 6.17). In Klamath Falls, the preferred resource selected is purchase of the lateral (see Figure 6.18). LaGrande does not go resource short during the planning horizon for this demand scenario. **The demand and resource scenario in this portfolio represents what we believe is the most likely demand forecast and the preferred resources to be selected to meet future resource needs. The moderate customer forecast, mid range price forecast, moderate carbon mitigation case and low price elastic response due to challenging economic times represents in our judgment the most likely trends for the assumptions analyzed. We believe it to be consistent with the current economic environment and our expectation of a slow economic recovery.** The demand forecast represents mid range customer and price forecast assumptions while resource selections reflect the lowest cost resources analyzed in the portfolio and reflect lower overall risk with respect to availability, cost estimation, and implementation.

D This portfolio continues with the Expected Case demand scenario run against existing AND expected available resources but further assumes GTN mainline **rates double** due to significant decontracting of GTN capacity in favor of assumed new Ruby pipeline capacity. Malin backhaul is assumed to not be available. In Medford, the preferred resource selected is GTN Medford lateral expansion coupled with GTN mainline (and upstream) capacity to AECO (see Appendix 7.2 p.295 [Medford GTN Rate Double demand and resources graph]). In Klamath Falls, the preferred resource selected is purchase of the lateral coupled with GTN mainline capacity (see Appendix 7.2 p.296 [Klamath GTN Rate Double graph]). LaGrande does not go resource short during the planning horizon for this demand scenario.

E This portfolio continues with the Expected Case demand scenario run against existing AND expected available resources but further assumes additional GTN mainline capacity is not available due to decommissioning of one of their lines in response to significant decontracting of GTN capacity (due to Ruby pipeline). In Medford, the preferred resource selected is NWP Grants Pass lateral expansion (see Appendix 7.2 p.297 [Medford GTN Unavailable demand and resources graph]). In Klamath Falls, the preferred resource selected is purchase of the lateral coupled with existing GTN mainline capacity (see Appendix 7.2 p.298 [Klamath GTN Unavailable graph]). LaGrande does not go resource short during the planning horizon for this demand scenario.

F This portfolio continues with the Expected Case demand scenario but assumes a **high** elasticity assumption. It uses the **updated** expected price curve as requested by our TAC given the significant market price revisions that occurred from the original price forecast (see Figures 7.4 and 7.5 [Updated Prices, High Elasticity]). The effect of the high elasticity price response for this demand scenario resulted in essentially flat demand and subsequently no region goes resource deficient over the planning horizon.

G	This portfolio continues with the Expected Case demand scenario but assumes a **medium** elasticity assumption. It uses the **updated** expected price curve as requested by our TAC given the significant market price revisions that occurred from the original price forecast (see Figures 7.4 and 7.5 [Updated Prices, Medium Elasticity]). The effect of the medium elasticity price response for this demand scenario resulted in resource deficiencies deferred into the latter years of our planning horizon in Medford (2022) and Klamath Falls (2026). This demand scenario was run against existing and expected available resources. In Medford, the preferred resource selected is GTN Medford lateral expansion coupled with Malin backhaul of supply (see Figure 7.7). In Klamath Falls, the preferred resource selected is purchase of the lateral (see Figure 7.8). LaGrande does not go resource short during the planning horizon for this demand scenario.	
H	This portfolio starts with the initial Expected Case demand assumptions but changes the weather planning standard from coldest day on record to **coldest day in the past 20 years** (see Appendix 3.7). All other demand assumptions were unchanged from our initial Expected Case demand assumptions (without price curve update). This forecast was run against our existing resource portfolio to determine the amount and timing of future resource needs (see Appendix 7.3 p.304). In Medford, the first resource deficiency occurred in 2020. The timing of Klamath Falls and LaGrande resource deficiencies were unaffected.	
I	This portfolio starts with the initial Expected Case demand assumptions but changes the customer growth assumptions to reflect **50% greater** growth rates in each service territory (see Appendix 3.7). It also assumes a lower price environment using the **NPCC Low** price curve (Figure 6.4) and a **low** price elasticity response assumption to simulate a robust demand growth scenario (Figures 7.1 & 7.2 [High Growth Low Price]). All other demand assumptions were unchanged from our initial Expected Case demand assumptions (without price curve update). This forecast was run against our existing resource portfolio to determine the amount and timing of future resource needs (see Appendix 7.3 p.301). In Medford, the first resource deficiency occurred in 2015, in Klamath 2016 and LaGrande 2021.	
J	This portfolio continues with the High Growth Low Price demand scenario run against existing AND expected available resources for each of the service territories modeled (see Appendix 6.3). In Medford, the preferred resource selected is GTN Medford lateral expansion coupled with Malin backhaul of supply (see Appendix 7.2 p.293). In Klamath Falls, the preferred resource selected is purchase of the lateral (Appendix 7.2 p.294). In LaGrande, the preferred resource selected is contracting additional NWP available lateral capacity (Appendix 7.2 p.294).	
K	This portfolio starts with the initial Expected Case demand assumptions but changes the price elasticity response assumption to **medium** and adjusts the expected (Consult1) natural gas price curve (Figure 6.4) to incorporate high range CO2 cost adders from our Carbon Mitigation 2 (CM2) sensitivity and also adjusts for a cost adder for drilling constraints (Appendix 3.7). These demand adjustment assumptions strive to simulate strong environmental policies that encourage conservation and alternative engery development resulting in a reduced natural gas demand scenario (Figures 7.1 & 7.2 [Green Future]). All other demand assumptions were unchanged from our initial Expected Case demand assumptions (without price curve update). This forecast was run against our existing resource portfolio to determine the amount and timing of future resource needs (see Appendix 7.3 p.303). The effect of the relatively high commodity costs from environmental adders and the medium elasticity price response for this demand scenario resulted in declining demand initially with very slow long term growth. Only Medford has a resource deficiency very late into the planning horizon (2027).	
L	This portfolio starts with the initial Expected Case demand assumptions but changes the customer growth assumptions to reflect **50% lower** growth rates in each service territory (see Appendix 3.7). It also assumes a higher price environment using the **NPCC high** price curve (Figure 6.4) and a **high** price elasticity response assumption to simulate a sluggish demand growth scenario. All other demand assumptions were unchanged from our initial Expected Case demand assumptions (without price curve update). This forecast was run against our existing resource portfolio to determine the amount and timing of future resource needs (see Appendix 7.3 p.302). The effect of the high elasticity price response for this demand scenario resulted in declining demand and, subsequently, no region goes resource deficient over the planning horizon.	

M	This portfolio starts with the initial Expected Case demand assumptions but changes the price elasticity response assumption to **medium** and adjusts the expected (Consult1) natural gas price curve (Figure 6.4) to incorporate a $.30 cost adder for drilling constraints (Appendix 3.7) and a phase in of $.20 to $3.00 for Canadian imports declines. These demand adjustment assumptions strive to simulate factors that could constrain supply and drive up commodity prices over time resulting in a reduced natural gas demand scenario (Figures 7.1 & 7.2 [Supply Constrained]). All other demand assumptions were unchanged from our initial Expected Case demand assumptions (without price curve update). This forecast was run against our existing resource portfolio to determine the amount and timing of future resource needs (see Appendix 7.3 p.305). The effect of the relatively high commodity costs from these adders and the medium elasticity price response for this demand scenario resulted in declining demand initially with very slow long term growth. Only Medford has a resource deficiency very late into the planning horizon (2027).	

Part 4: 2010-2011 Action Plan

Pipeline Capacity

During its review, Staff noted the Company's identification of several long term risks in identifying, quantifying, estimating and securing pipeline capacity resources. Staff indicated a pipeline capacity needs study as one method to assess such long term risks.

This IRP indicates no near term resource needs for any of the range of demand forecasts modeled. Avista believes its pipeline capacity needs are identified and risks assessed as part of our IRP process. However, we are open to considering recommended analysis of issues that enhance pipeline capacity needs assessment and risk analysis and incorporate the following action item as part of our IRP:

> *"We will work with our TAC members to enhance pipeline capacity needs assessment and related long term risks."*

The Company will report its progress on enhancing pipeline capacity needs assessments and related long term risks at its Annual Update meeting.

Demand Modeling

During its review, Staff noted additional factors could potentially influence demand beyond what we identified and considered in our demand forecasting (Appendix 3.6 & 3.7). We are open to considering and incorporating additional demand drivers into our modeling and forecasting of demand and incorporate the following action item as part of our IRP:

> *"Avista will work with its TAC members to identify and develop consensus assumptions for additional demand drivers into our modeling and forecasting of demand."*

Portfolio Creation and Selection

In its draft recommendation and order, Staff recommended including a scoring system to improve the comparison between the portfolios with respect to costs, risks, and uncertainties. We are open to the recommendation and incorporate the following recommended action item as part of our IRP:

> *"The next IRP will include a scoring system that assigns values (mathematical or otherwise) to the factors used in the portfolio evaluation with respect to costs, risks and uncertainties. Avista will solicit input from TAC members to develop this system."*

DSM Savings Measurement

In its draft recommendation and order, Staff recommended the IRP should include how the DSM savings will be measured and verified after installation to assess the Company's performance in meeting its conservation goals. We are open to the recommendation and incorporate the following recommended action item as part of our IRP:

> *"The next IRP will explain how the DSM savings are measured and verified after installation, and compare the actual savings vs. the estimated savings (goal). Avista will solicit input from TAC members on adopting a protocol for evaluating, measuring and verifying DSM savings."*