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AVISTA Corp.

September 29, 2010

Public Utility Commission of Oregon
Attn: Filing Center
PO Box 2148
Salem, OR 97308-2148

Advice No. 10-06-G

RE: Request for General Rate Revision of Avista Corporation

In accordance with Oregon Administrative Rules, Avista Corp., dba Avista Utilities, respectfully submits an original and 26 copies of the Company's trial brief, testimony and associated exhibits in support of its request for a general rate revision. Please note that the exhibit 402 of Kevin J. Christie is being provided in electronic format only due to the voluminous nature of these file.

Avista's CONFIDENTIAL exhibit No.601/schedule 9 is provided under a sealed separate envelop, marked CONFIDENTIAL. Due to the voluminous nature of the exhibit (813 pages) it is being provided on a CD. We appreciate your willingness to keep such materials confidential, pending the issuance of a Protective Order. A Motion for a Protective Order is filed herewith. Please limit your distribution accordingly.

Additionally, Three (3) copies of supporting work papers have also been included with this filing. Please note that the Company has only included hardcopies of Mr. Avera's workpapers for the Commission. Due to the voluminous nature of these workpapers (729 pages), they are being provided in electronic format only on the enclosed CD for others on the service list.

Please direct any questions regarding this filing to Liz Andrews at (509) 495-8601.

Sincerely,

Kelly Norwood

Kelly O. Norwood
Vice President, State and Federal Regulation

Enclosure

cc: See attached service list

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served Direct Testimony and Exhibits in the Oregon Natural Gas General Rate Case Filing of Avista Utilities, a division of Avista Corporation, (Advice No. 10-06-G) upon the parties listed below by mailing a copy thereof, postage prepaid and/or by electronic mail.

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I declare under penalty of perjury that the foregoing is true and correct.

Dated at Spokane, Washington this 29th day of September 2010.

Patty Olsness

Patty Olsness
Rates Coordinator

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UG-___

In the matter of the Application of AVISTA CORPORATION, DBA AVISTA UTILITIES for a General Rate Revision	))))	TRIAL BRIEF OF AVISTA CORPORATION

Avista Corporation, doing business as Avista Utilities ("Avista" or "Company"), is filing tariff schedules, pursuant to ORS 757.205 and ORS 757.220, to effect a general revision for its natural gas customers in Oregon. This brief is submitted to meet the requirements of OAR 860-013-0075.

1.

Avista provides natural gas service in the State of Oregon and is a public utility subject to the Public Utility Commission of Oregon's jurisdiction under ORS 757.005(1)(a)(A). Avista provides natural gas distribution service in southwestern and northeastern Oregon. The Company also provides electric and natural gas service within a 26,000 square mile area of eastern Washington and northern Idaho. As of December 31, 2009, Avista supplied retail electric service to an average of approximately 356,620 customers and retail natural gas service to approximately 316,350 customers, including approximately 95,602 customers in Oregon who will be affected by the proposed rate revision. Avista's principal place of business is located in Spokane, Washington.

2.

Avista requests that all notices, pleadings, and correspondence regarding this filing be sent to the following:

David J. Meyer, Esq.
Chief Counsel for Regulatory and Governmental Affairs
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3.

The test period being used by the Company is the twelve months ended December 31, 2011, presented on a forecasted basis. The Company's pro forma results of operations for the test period indicate that, at the current rate levels, Avista would earn a return on equity ("ROE") of 6.47 percent. This ROE is clearly not sufficient to provide Avista with a fair and reasonable return or allow the Company to attract capital at reasonable rates.

Avista's revised tariff schedules effect an increase in rates for Oregon retail customers of $5,446,000, or 5.6 percent, which would produce an overall rate of return of 8.61 percent and a return on equity of 10.9 percent. Pursuant to ORS 757.220, the revised schedules contain an effective date of November 1, 2010.

4.

The Company acquired its Oregon natural gas operations from CP National in 1991. In the past 19 years that Avista has operated these properties, its base rates have previously increased only five times. A combination of capital additions, declining margins and increases in general business expense now require the Company to request an increase in overall base retail rates of $5,446,000.

The Company used the cost of service results prepared by Company witness Miller as a guide in the proposed spread of the requested increase to the various service schedules. As described in Company witness Mr. Ehrbar's testimony, the spread of the proposed increase generally results in the margin-to-cost ratios for the various service schedules moving approximately 30% closer to 1.00 (unity). As a result, the proposed rate spread would result in an increase of 6.2% to residential customers, and increases ranging between 0.5% and 5.7% to other rate schedules.

5.

Avista's direct case consists of the testimony and exhibits of the following witnesses:

(a) Policy and Operations – Exhibit 100. **Scott L. Morris**, Chairman of the Board, President and Chief Executive Officer of Avista Corporation, presents an overview of the filing and identifies the cost increases that make this filing necessary. Mr. Morris describes efforts to reduce operating costs and explains the Company's customer support programs that are in place to assist customers.

(b) Financial Overview, Capital Structure, and Overall Rate of Return – Exhibit 200. **Mark T. Thies**, Senior Vice President and Chief Financial Officer, will address the Company's capital structure, the proposed cost of embedded debt and the overall rate of return. He will explain the actions the Company has taken to acquire needed capital and improve Avista's financial condition in recent years.

(c) Return on Equity – Exhibit 300. **William E. Avera**, as President of Financial Concepts and Applications (FINCAP), Inc., has been retained to present testimony with respect to the reasonableness of the Company's proposed overall capital structure and will testify in support of an 10.9% return on equity.

(d) Gas Supply and Storage - Exhibit 400. **Kevin J. Christie**, Director, Gas Supply, will describe the additional Jackson Prairie (JP) natural gas storage that the utility will receive to serve customers beginning May 1, 2011. He will also describe the allocation of this additional storage, and the associated costs, to the three jurisdictions that the Company serves.

(e) Capital Projects – Exhibit 500. **Dave B. Defelice**, Senior Business Analyst, will describe the adjustments for capital expenditures, which are necessary to maintain safe and reliable service.

(f) Working Capital - Exhibit 600. **Donald J. Clayton**, Vice President of Management Consulting at Tangibl, LLC., will discuss the lead/lag study he performed for Avista Utilities in order to determine the revenue and expense lags by category for revenue and operating expenses, then to apply the leads and lags to the jurisdictional operating expenses in order to calculate appropriate daily and annual cash working capital requirements necessary to operate the Company.

(g) Revenue Requirement and Allocations – Exhibit 700. **Elizabeth M. Andrews,** Manager, Revenue Requirements, will discuss the Company's overall revenue requirement proposals. In addition, her testimony and exhibits will cover accounting and financial data in support of the Company's need for the proposed increase in rates and the allocation methodologies. She will also explain forecasted operating results, including expense and rate base adjustments made to actual operating results and rate base.

(h) Long-Run Incremental Cost of Service – Exhibit 800. **Joseph D. Miller**, Regulatory Analyst, sponsors the long-run incremental cost study for Oregon natural gas service. Mr. Miller discusses his study results and how each schedule's present and proposed rates compare to the indicated cost.

(i) Rate Design and Rate Spread – Exhibit 900. **Patrick D. Ehrbar**, Manager, Rates and Tariffs, discusses the spread of the annual revenue changes among the Company's general service schedules and related rate design. Mr. Ehrbar also discusses the forecasted revenue adjustment.

6.

The following exhibits are attached pursuant to OAR 860-13-0075:

(a) Exhibit A. The information required by OAR 860-013-0075(1)(b)(A)-(F).

(b) Exhibit B. From Ms. Andrew's Exhibit 501, page 1, which shows the results of operations for Avista's Oregon jurisdiction before and after the proposed rate change, as required by OAR 860-013-0075(1)(b)(G).

(c) Exhibit C. This exhibit shows the effect of the proposed rate change on each class of customers as required by OAR 860-013-0075(1)(b)(H). Exhibit C also contains information required by OAR 860-022-0030(1). Specifically, the exhibit shows, for each tariff schedule, the total number of customers affected, the total annual revenue derived under the existing schedule, and the amount of estimated revenue derived from applying the proposed rate revisions. For each tariff schedule, the exhibit also shows the average monthly use and resulting bills under both existing rates and proposed rates for characteristic customers.

7.

Avista Corporation respectfully requests that the Commission issue an order granting the rate relief requested in this filing and approving the proposed tariff schedules.

DATED: September 29, 2010.

David J. Meyer
Chief Counsel for Regulatory and Governmental Affairs
Avista Corporation

EXHIBIT A

INFORMATION REQUIRED BY OAR 860-013-0075(1)(b)(A)-(F)

A. The dollar amount of total revenues that would be collected under the proposed rates is $102,898,000.

B. The dollar amount of revenue change requested is $5,446,000.

C. The percentage change in revenues requested is 5.6 percent.

D. The forecasted test period proposed is January 1, 2011 to December 31, 2011.

E. The requested overall rate of return is 8.61 percent and the requested return on equity is 10.9 percent.

F. The rate base proposed in this filing is $148,421,000.

AVISTA UTILITIES
NATURAL GAS RESULTS OF OPERATION
OREGON JURISDICTION FORECASTED RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 2011
(000'S OF DOLLARS)

		WITH PRESENT RATES			WITH PROPOSED RATES	
Line No.	**DESCRIPTION**	**Actual Per Results Report (EOP)**	**Total Adjustments**	**Forecasted Total**	**Proposed Revenues & Related Exp**	**Forecasted Proposed Total (AMA)**
	a	*b*	*c*	*d*	*e*	*f*
	OPERATING REVENUES					
1	Total General Business	$113,472	$ (18,332)	$95,140	$5,446	$100,586
2	Total Transportation	2,198	325	2,523		2,523
3	Other Revenues	40,811	(40,659)	152		152
4	Total Operating Revenues	156,481	(58,666)	97,815	5,446	103,261
	OPERATING EXPENSES					
5	Gas Purchased	118,258	(61,231)	57,027		57,027
6	Operation and Maintenance	12,721	(322)	12,399	30	12,429
7	Administration & General	7,193	(27)	7,166	18	7,184
8	Taxes Other than Income	6,017	(1,633)	4,384	114	4,498
9	Depreciation & Amortization	4,078	1,381	5,459		5,459
10	Total Operating Expenses	148,267	(61,832)	86,435	162	86,597
11	OPERATING INCOME BEFORE FIT	8,214	3,166	11,380	5,284	16,664
	INCOME TAXES					
12	Current Federal Income Taxes	(2,680)	1,611	(1,069)	1,709	640
13	Deferred Federal Income Taxes	2,877	(185)	2,692		2,692
14	State Income Taxes	423	(271)	152	402	554
15	Total Income Taxes	620	1,155	1,775	2,111	3,886
16	NET OPERATING INCOME	$7,594	$2,011	$9,605	$3,173	$12,778
	RATE BASE					
17	Utility Plant in Service	242,885	20,906	263,791		263,791
18	Less: Accum Depr and Amort	(89,352)	(7,523)	(96,875)	0	(96,875)
19	Net Utility Plant	153,533	13,383	166,916	0	166,916
20	Accumulated Deferred FIT	(25,385)	(3,820)	(29,205)		(29,205)
21	Inventory and Other	1,997	1,227	3,224	0	3,224
22	Working Capital	0	7,486	7,486	0	7,486
23	TOTAL RATE BASE	$130,145	$18,276	$148,421	$0	$148,421
24	RATE OF RETURN	5.84%		6.47%		8.61%

Avista Utilities
Docket No. UG-___
Rate Spread Summary
Oregon - Gas
Pro Forma 12 Months Ended December 31, 2011

	Type of Service	Schedule Number	Avg. No. of Customers	Annual Therms	Avg. Use per Customer per Month	Revenue at Pres. Rates ($000's)	Avg. Bill Under Pres. Rates	Revenue Percentage Increase	Revenue Increase ($000's)	Avg. Increase per Customer per Month	Revenue at Prop. Rates ($000's)	Avg. Bill Under Prop. Rates
1	Residential	410	84,714	46,808,685	46	$61,071	$60.02	6.2%	$3,771	$3.71	$64,842	$63.73
2	General Service	420	11,132	24,945,857	187	27,973	$209.68	5.7%	1,599	$11.99	29,572	$221.67
3	Large General Service	424	80	3,429,042	3,572	3,162	$3,294	0.2%	8	$8	3,170	$3,302
4	Interruptible Service	440	36	4,393,867	10,171	2,596	$6,008	0.5%	13	$31	2,609	$6,039
5	Seasonal Service	444	3	140,144	3,893	127	$3,538	3.5%	5	$125	132	$3,663
6	Transportation Service	456	36	24,997,889	57,865	2,266	$5,245	2.2%	50	$116	2,316	$5,360
7	Special Contract	447	4	2,839,561	59,158	257	$5,353	0.0%	0	$0	257	$5,353
8	Total		96,005	107,555,045		$97,452		5.6%	$5,446		$102,898	

EXHIBIT C

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UG-____

In the matter of the Application of) AVISTA CORPORATION, DBA) AVISTA UTILITIES for a) General Rate Increase in the) Company's Oregon Annual Revenues)	MOTION FOR PROTECTIVE ORDER **Expedited Consideration Requested**

Pursuant to ORCP 36(C)(7) and OAR 860-012-0035(1)(k), Avista Corporation d/b/a Avista Utilities ("Company") moves for entry of the Commission's standard protective order in this proceeding. The Company requests expedited consideration of this Motion in order to allow parties that execute the protective order to obtain prompt access to the confidential information filed in support of the request and to expedite any discovery in this proceeding. Good cause exists to issue a Protective Order to protect commercially sensitive and confidential business information related to the Company's request for a general rate increase. In support of this Motion, the Company states:

1.

The Commission's rules authorize Avista to seek reasonable restrictions on discovery of sensitive commercial information and other confidential business information. See OAR 860-11-000(3) (adopting Oregon Rules of Civil Procedure ("ORCP")); ORCP 36(C)(7) (providing protection against unrestricted discovery of "trade secrets or other confidential research, development, or commercial information"). See also *In re Investigation into the Cost of Providing Telecommunication Service* (UM 351), Order No. 91-500 (1991) (recognizing that protective orders are a reasonable means to protect "the rights of a party to trade secrets and other confidential commercial information" and "to facilitate the communication of information between litigants").

2.

Avista anticipates that parties to this docket may request proprietary cost data and models, commercially sensitive load and resource projections, confidential market analyses and business projections, confidential employee data, and confidential information regarding contracts for the purchase or sale of natural gas. This confidential business information is of significant commercial value, which would expose the Company to competitive injury if disclosure is unrestricted.

3.

It is substantially likely that Staff and other parties in this proceeding will seek to discover information held by Avista, including confidential business information. "The Commission's standard blanket protective order is designed to facilitate discovery in cases involving discovery of large numbers of documents." *See In re Portland Extended Area Service Region*, Docket UM 261, Order No. 91-958 (1991). Issuance of a protective order will facilitate the production of relevant information and expedite the discovery process.

4.

The Company requests expedited consideration of this Motion to allow parties who execute the protective order to obtain prompt access to the confidential exhibits and workpapers in support of the Company's request for a general rate increase and to expedite any discovery in this proceeding.

For the foregoing reasons, Avista requests expedited entry of the Commission's standard protective order in this docket.

DATED: September 29, 2010.

David J. Meyer
Chief Counsel for Regulatory and Governmental Affairs
Avista Corporation

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF SCOTT L. MORRIS
REPRESENTING AVISTA CORPORATION

Policy and Operations

I. INTRODUCTION

Q. Please state your name, employer and business address.

A. My name is Scott L. Morris and I am employed as the Chairman of the Board, President, and Chief Executive Officer of Avista Corporation (Company or Avista), at 1411 East Mission Avenue, Spokane, Washington.

Q. Would you briefly describe your educational background and professional experience?

A. Yes. I am a graduate of Gonzaga University with a Bachelors degree and a Masters degree in organizational leadership. I have also attended the Kidder Peabody School of Financial Management.

I joined the Company in 1981 and have served in a number of roles including customer service manager. In 1991, I was appointed general manager for Avista Utilities' Oregon and California natural gas utility business. I was appointed President and General Manager of Avista Utilities, an operating division of Avista Corporation, in August 2000. In February 2003, I was appointed Senior Vice-President of Avista Corporation, and in May 2006, I was appointed as President and Chief Operating Officer. Effective January 1, 2008, I assumed the position of Chairman of the Board, President, and Chief Executive Officer.

I am a member of the Western Energy Institute board of directors, a member of the Gonzaga University board of trustees, a member of Edison Electric Institute board of directors, a member of the American Gas Association board of directors, a member of ReliOn board of directors, and board director of the Washington Roundtable. I also serve on the board of trustees of Greater Spokane Incorporated.

During my time as general manager in Oregon, I was appointed by then-Governor

John Kitzhaber as a board member of the Oregon Economic and Community Development Commission. I served as a member of the board of directors and as board president of Southern Oregon Regional Economic Development Inc. I served as a director and board president of the Medford/Jackson County Chamber of Commerce. I was a board member and served as board president of the Providence Community Health Foundation. I have also served as a member of the board of directors and a board president for the Medford YMCA, as a member of the board for the Oregon Shakespeare Festival, and the Rogue Valley College Regional Advisory Board.

Q. While general manager in Oregon, what were your responsibilities?

A. As general manager in Oregon, my responsibilities included accountability for all aspects of business operations for our Oregon properties.

Q. What is the scope of your testimony?

A. I will provide an overview of Avista Corporation. I will also summarize the Company's rate request in this filing, the primary factors driving the Company's need for general rate relief, and provide some background on why utility costs are continuing to increase. The Company continues to experience increasing costs from additional compliance requirements, and the need to replace aging infrastructure.

My testimony will provide an overview of some of the measures we have taken to cut costs, as well as initiatives to increase operating efficiencies in an effort to mitigate a portion of the cost increases. I will briefly explain the Company's customer support programs in place to assist our customers, as well as our communications initiatives to help customers better understand the changes in costs that are causing our rates to go up.

Finally, I will introduce each of the other witnesses providing testimony on the Company's behalf.

Q. Are you sponsoring exhibits in this proceeding?

A. Yes. I am sponsoring Exhibit No. 101, page 1 of which includes a diagram of Avista's current corporate structure, page 2 includes a map of the Company's service territories, and page 3 includes a map of its natural gas service areas, gas fields, trading hubs and major pipelines. This exhibit was prepared under my direction.

Q. Would you please provide an overview of Avista Utilities' request in this filing?

A. Yes. A combination of declining loads, increasing rate base and increases in general business expenses requires the Company to request an overall increase in base retail rates of $5.446 million or 5.6%. This request is based on a proposed rate of return of 8.61%, with a capital structure common equity component of 50.76% and a 10.9% return on equity. The Company is utilizing a forecasted test period for the twelve months ended December 31, 2011. The forecasted test period was selected to best reflect the conditions during the time new rates would be in effect, as discussed further by Company witness Ms. Andrews. The Company used the results of a long-run incremental cost study as a starting point in the proposed spread of the requested increase to the various customer rate schedules. Company witnesses Mr. Miller and Mr. Ehrbar testify to these rates spread issues.

Based on an average usage level of 46 therms per month, the average residential bill would increase $3.71 per month, or 6.2%, from $59.77 to $63.48.

Q. Please explain the Company's need for additional rate relief?

A. The Company's need for additional rate relief is due in part to an increase in overall net rate base, including an adjustment for working capital and additional plant in service, such as the Company's Roseburg reinforcement project and other 2011 required projects as described by Company witness Mr. DeFelice. In addition, as described by Company witness Mr. Ehrbar, the Company expects a drop in revenues due to a reduction in customers and declining therm usage by our customers on a weather-adjusted basis, versus what was approved in the Company's last general rate case (UG-186).

In addition, the Company is requesting the inclusion of the increased plant investment and inventory associated with the transfer of the Jackson Prairie Storage facility from Avista Energy to Avista Utilities effective May 1, 2011. Company witness Mr. Christie discusses the details of this project while Ms. Andrews discusses the revenue requirement impact.

Company witness Mr. Thies and Company witness Mr. Avera discuss in detail the Company's weighted cost of capital of 8.61%, including a requested return on equity of 10.9%. The Company's forecasted rate of return under present rates is 6.47%, which is well below what would be considered to be a reasonable rate of return.

Q. Is the Company proposing any changes to the cost of natural gas for its retail natural gas customers in this case?

A. No. Avista is not proposing changes in this filing related to the cost of natural gas included in current rates for natural gas customers. Changes in natural gas costs are addressed in the annual purchased gas adjustment (PGA) filings.

Q. Please briefly describe Avista's subsidiary businesses.

A. Avista Corp.'s primary subsidiary is the information and technology business, Advantage IQ, described below, which is headquartered in Spokane, Washington. In 2007, Avista completed the sale of the operations of Avista Energy to Coral Energy Holding, L.P. Avista currently holds a 5.8% share in Avista Labs' successor company, ReliOn, which is held under Avista Capital. A diagram of Avista's corporate structure is provided on page 1 of Exhibit No. 101.

Q. Please provide an overview of Advantage IQ.

A. Advantage IQ, formerly known as Avista Advantage, commenced operations in 1998 and is a provider of utility bill processing, payment and information services to multi-site customers. Advantage IQ analyzes and presents consolidated bills on-line, and pays utility and other facility-related expenses for multi-site customers throughout North America. Customers include CSK Auto, Jack in the Box, Staples, and Big Lots, to name a few. Information gathered from invoices, providers and other customer-specific data allows Advantage IQ to provide its customers with in-depth analytical support, real-time reporting and consulting services with regard to facility-related energy, waste, repair and maintenance, and telecom expenses. In 2007, 2008 and 2009, Advantage IQ was awarded the ENERGY STAR® Sustained Excellence Award and in 2010, received the Energy Management Award in recognition of its continued leadership in protecting our environment through energy efficiency.

II. OVERVIEW OF AVISTA UTILITIES

Q. Please briefly describe Avista Utilities.

A. Avista Utilities provides natural gas distribution service in southwestern and northeastern Oregon. The Company, headquartered in Spokane, Washington, also provides electric and natural gas service within a 26,000 square mile area of eastern Washington and northern Idaho. Of the Company's 356,620 electric and 316,350 natural gas customers (as of December 31, 2009), 95,602 were Oregon customers. A map showing Avista's total electric and natural gas service areas is provided on page 2 of Exhibit No. 101. Also, a map of the natural gas service areas, gas fields, trading hubs and major pipelines are shown on Page 3 of Exhibit No. 101.

As of December 31, 2009, Avista Utilities had total assets (electric and natural gas) of approximately $3.6 billion (on a system basis), with electric retail revenues of $705 million (system) and natural gas retail revenues of $397 million (system). As of December 2009, the Utility had 1,538 full-time employees.

Avista has a long history of innovation and environmental stewardship. At the turn of the 20th century, the Company built its first renewable hydro generation plant on the banks of the Spokane River. In the 1980's, Avista developed an award-winning biomass plant (Kettle Falls) that generates energy from wood-waste.

Avista was one of the three original developers of the natural gas storage facility at Jackson Prairie. Although there have been corporate changes because of mergers, acquisitions and name changes, Avista, Puget Sound Energy and Northwest Pipeline each hold a one-third share of this underground gas storage facility. Development began in the 1960's and the project first went into service in 1972. As Mr. Christie explains in his testimony, beginning

May 1, 2011 Oregon customers will begin receiving a greater share of the benefits and costs associated with this facility.

To the future, Avista as well as other utilities are facing new state and federal mandates for renewable energy and carbon control standards. For example, Washington's Senate Bill 6001 and Initiative 937 require certain public and private utilities to produce 15 percent of their power from new renewable resources by 2020, not including legacy hydro production, and eliminate the option of coal-fired generation because of carbon emission limitations. Today, Avista has one of the smallest carbon footprints in the U.S.

Q. Please describe Avista Utilities' natural gas utility operations in Oregon.

A. Of the Company's 316,350 natural gas customers, approximately 95,602 are served in Oregon. The Company serves the Oregon areas of Medford, Klamath Falls, Roseburg, and LaGrande. Lumber and wood products manufacturing is the dominant industry in our Oregon service area. During 2009 Avista delivered approximately 488 million therms to its retail natural gas customers. Of this total, 111 million were delivered to Oregon customers. The forecasted 2011 mix of customers by rate schedule and their proportionate share of usage and revenues at present rates are summarized in the table below by rate schedule:

Rate Schedule	% Revenues	No. of Customers	% Therms Delivered
410 — Residential	62.7%	84,714	43.5%
420 — General Service	28.7%	11,132	23.2%
424 — Large General Service	3.2%	80	3.2%
440 — Interruptible	2.7%	36	4.1%
444 — Seasonal	0.1%	3	0.1%
456 — Transportation	2.3%	36	23.2%
447 — Special Contract	0.3%	4	2.6%

Q. Please describe Avista's current business focus for its utility operations.

A. Our strategy continues to focus on our energy and utility-related businesses, with our primary emphasis on the electric and natural gas utility business. There are four distinct components to our business focus for the utility, which we have referred to as the four legs of a stool, with each leg representing customers, employees, the communities we serve, and our financial investors. For the stool to be level, each of these legs must be in balance by having the proper emphasis. This means we must maintain a strong utility business by delivering efficient, reliable and high quality service, at a reasonable price, to our customers and the communities we serve, and provide the opportunity for sustained employment for our employees, while providing an attractive return to our investors.

III. COST MANAGEMENT AND EFFICIENCIES

Q. What is Avista doing to manage its costs and mitigate the impact of increased costs on its customers?

A. Although the current economic conditions are at the forefront of everyone's minds, Avista has focused on managing its costs to mitigate rate pressure over a much longer period of time. Following the energy crisis of 2000/2001, Avista cut its operating expenses and reduced capital spending. Since that time we have continued to pay particular attention to limiting the growth in these costs, and Avista continues to run its operations with attention to minimizing expenses, while meeting its reliability and environmental compliance requirements, and preserving a high level of customer satisfaction.

We occasionally receive comments from some of our customers to the effect that Avista should cut its costs, and "tighten its belt," like other businesses are having to do in these difficult economic circumstances, and keep retail rates the same. We hear those comments and take them to heart, but we are not like other businesses. Under the regulatory compact we have an obligation to serve all customers with safe, reliable service. When a new customer wants service, we must hook them up, even if the cost to serve that customer results in increased costs to all other customers. Likewise, if the facilities serving an existing customer are deteriorating and need repair, we must repair or replace them so that the customer continues to receive safe, reliable service. Without the obligation to serve, we could consider refusing to hook up some new customers, because it could avoid a further increase in costs to our existing customers. Without an obligation to serve, we could consider no longer serving some of the more remote, more costly areas to provide service, which would allow us to avoid further investment, and reduce labor and other costs. Unregulated businesses have the opportunity to shut down under-producing retail outlets, eliminate product lines, and cut back on investment, maintenance, and other costs.

Please don't misunderstand my point -- we do have opportunities to cut back on investment and operating costs, and we have. But those opportunities are limited by our obligation to safely and reliably serve all customers, and our obligation to comply with numerous mandatory state and federal requirements.

In recent years there has been a significant increase in costly, mandatory requirements on utilities related to, among others things, reliability, environmental compliance, safety, and security.

We simply don't have the choice to say no to new customers, no to maintaining a safe, reliable system, and no to mandatory requirements. Although we have taken extensive measures to ensure that the costs that we incur represent the most cost-effective and reliable way to continue to serve our customers, we continue to experience increases in costs.

We worked very hard for many years to gain upgrades to our corporate credit ratings to investment grade by Moodys Investors Service in December 2007 and Standard & Poors in February 2008. Part of what made that possible was tight controls on operating expenses and capital investment in recent years. Accordingly, although we are continuing to make progress in improving the Company's financial condition, we are still not as strong financially as we need to be. Timely rate relief through this filing is an important element in continuing to gain financial strength and improving our credit rating.

With higher levels of capital spending required over the next several years (i.e., approximately $460 million during 2010-2011), it is more important than ever that the Company remain financially healthy in order to attract capital investment and financing at the lowest cost possible. Company witness Mr. Thies will discuss further actions taken by the Company to improve cash flow, reduce debt, and our continuing efforts to improve our financial condition.

Q. What measures has the Company taken to mitigate increased costs?

A. Avista is constantly looking for improvements in the way it provides services to its customers, as well as ways to reduce the costs of those services. Ideas are generated through periodic evaluation of our operating practices, and communications with other utilities and other industry participants across the country on best practices.

Some of the measures we have taken to control costs and improve efficiency are as follows:

Hiring Restriction

The Company continues to operate under a hiring restriction which requires approval by the Avista Corporation Chairman/President/CEO, the President of Avista Utilities, the CFO, and the Sr. VP for Human Resources for all replacement or new hire positions.

Limitations on Capital Spending

For both 2009 and 2010 Avista approved a lower capital budget than was requested by the Company's Engineering and Operations personnel. The Capital Prioritization Committee reduced the list of projects to be completed by approximately $60 million in 2009, and we have limited our near-term capital budget to approximately $210 million annually (excluding Stimulus Projects[1]).

Long Term Debt Issuance

As explained further by Mr. Thies, in 2008 the Company opted to defer its plan to issue $250 million of long-term secured debt until 2009. Avista instead established a second bank line of credit to ensure continued adequate liquidity. The Company's decision to delay the debt issuance, and rely on short-term debt for a longer period of time, resulted in a reduction of interest costs to customers by approximately $80 million over a ten year period (approximately $8 million annually). This benefit to customers is reflected in our filing.

Cancelled Office Building Addition

Avista's main office building was constructed in 1958, and expanded in 1978. Even though Avista's ratio of the number of customers served per employee continues to increase, we have needed additional office space for some time. In 2008, in order to reduce costs, we cancelled plans to build additional office space adjacent to the main office, and instead chose to remodel existing space formerly used by Horizon Credit Union nine miles from the main office.

Outsourced Billing and Disaster Recovery

Avista's bill printing and mail services were outsourced to Regulus, the second largest first class mailer in the United States. The project objectives were to move bill printing, inserting and mailing offsite and to leverage core competencies of the provider. It also served to meet disaster recovery requirements, ensure daily print volume flexibility and scalability, reduce costs for bill print, inserting and mailing, and serve to maximize technology.

[1] Avista was awarded matching grants from the U.S. Department of Energy for two "Smart Grid" projects. One project will upgrade portions of the utility's electric distribution system to smart grid standards in Spokane, Washington and the other project is a demonstration project in Pullman, Washington that involves automation of many parts of the electric distribution system using advanced metering, enhanced utility communication and other elements of smart grid technologies.

We recognize that our proposed rate increase will result in energy bills that will be more difficult for some of our customers to pay. I can assure you that we are not just sitting on the sidelines as our costs go up.

IV. COMMUNICATIONS WITH CUSTOMERS

Q. Is Avista communicating with its customers to explain what is driving increased costs for the Company?

A. Yes. The Company proactively communicates with its customers in a number of ways: electronic customer communications, one-on-one customer interactions through field personnel and account representatives, media contacts, and through our employees' involvement in community, business and civic organizations, to name a few. We believe our communications are helping our customers, and the communities that we serve, better understand the issues faced by the Company, such as increased environmental mitigation, volatile natural gas prices, and infrastructure investment, all of which have led to changes in costs for our customers.

The economic recession, rising prices for necessities, including energy, extreme cold and record snow, coupled with a variety of public policy issues, created an increased response from our customers in early 2009 related to energy prices. We learned that customers don't always understand the complexities of the energy business and want information and conversations with Avista employees to better understand the choices they have to manage how they use energy. We began intensifying our communication efforts last year and are continuing to engage every employee in the Company in our efforts to more directly communicate with customers.

Q. What are some of the most recent changes the Company has made in its communications with its customers?

A. One of the important principles in our intensified outreach is to meet customers where they gather. The "new conversation" uses traditional and non-traditional communication channels including print, radio, website, face-to-face listening posts, newsletters, videos, social media, emails, and one-on-one and group presentations.

One important customer segment that we have recently targeted is those customers who gather online. Last year we implemented our social media program with the Avista blog as our foundation. We also communicate on Twitter and in online discussion forums. For those customers who want a more private online conversation, we offer customers a conversation email account to make sure they were comfortable having this new conversation with us.

Our employees provide excellent customer service, and this focus on communicating with our customers includes providing them simplified messaging and new tools to make is easier to have conversations about Avista with friends, family and customers. We are finding that once a customer talks with one of our employees and has the opportunity to voice their concerns and receive answers to their questions, their satisfaction level increases significantly. We're listening to our customers' point-of-view and sharing ours about energy issues that directly affect us all.

We'll continue focusing on informing our customers of the many programs we offer to provide assistance in managing their energy bills, and ensuring that our employees are equipped to engage in these conversations. We will also work to build understanding on how decisions today, specifically in areas such as energy efficiency, sustainability, reliability and renewable energy will affect our energy future.

V. CUSTOMER SUPPORT PROGRAMS

Q. Please explain the customer support programs that Avista provides for its customers in Oregon.

A. Avista Utilities offers a number of programs for its Oregon customers, such as energy efficiency programs, the Low Income Rate Assistance Program (LIRAP), Project Share for emergency assistance to customers, the Customer Assistance Referral and Evaluation Service (CARES) program, level pay plans, and payment arrangements. Some of these programs will serve to mitigate the impact on customers of the proposed rate increase.

Q. Please describe Avista Utilities' demand-side management (DSM) or energy efficiency programs.

A. Avista Utilities' energy efficiency programs in Oregon have provided for the consistent delivery of comprehensive conservation services. Avista Utilities offers energy efficiency services to residential, commercial, and industrial customers. Programs include both audits and direct incentives for residential weatherization, high-efficiency furnace and water heaters, and commercial qualifying gas-efficiency projects.

Q. What is the Company's Low Income Rate Assistance Program or LIRAP?

A. The low-income rate assistance program (LIRAP), collects approximately $212,000 (or .438 cents per therm annually) from a 0.50% distribution charge on natural gas service. These funds are distributed by community action agencies in a manner similar to the Federal and State-sponsored Low Income Home Energy Assistance Program (LIHEAP). Avista Utilities' LIRAP program supplements the reach of available LIHEAP funds. The

Company, with the assistance of community action agencies and the Commission, directed this program toward those members of the community least able to pay for natural gas service.

Q. Please describe the recent results of the Company's Project Share efforts?

A. Project Share is a community-funded program Avista sponsors to provide one-time emergency support to families in the Company's service area. Avista customers and shareholders help support the fund with voluntary contributions that are distributed through local community action agencies to customers in need. Grants are available to those in need without regard to their heating source. Avista Utilities has consistently had relatively high per-customer contributions when compared to other utilities with Project Share programs.

Q. Does the Company offer a bill-averaging program?

A. Yes. Comfort Level Billing helps smooth out the seasonal highs and lows of customers' energy usage and provides the customer with the option to pay the same bill amount each month of the year. This allows customers to more easily budget for energy bills and it also avoids higher winter bills. This program has been well-received by participating customers. Over 8,320 (or 9%) of Oregon natural gas customers are on Comfort Level Billing.

In addition, the Company's Contact Center Representatives work with customers to set up payment arrangements to pay energy bills. In 2010, 23,353 Oregon customers were provided with over 67,157 such payment arrangements.

Q. Please summarize Avista's CARES program.

A. In Oregon, Avista is currently working with over 474 special needs customers in the CARES program. Specially-trained representatives provide referrals to area agencies and churches for customers with special needs for help with housing, utilities, medical assistance, etc.

In the 2009/2010 heating season, 7,308 Oregon customers received $1,966,649 in various forms of energy assistance (Avista LIRAP, Federal LIHEAP program, Project Share, and local community funds). This program and the partnerships we have formed have been invaluable to customers who often have nowhere else to go for help.

Q. Are there other noteworthy items that you would like to address?

A. Yes. There are several items of which I am particularly proud. The Company's contact center has been recognized nationally for its quality and efficiency. The Medford call center is networked with call centers in Lewiston, Idaho, Coeur d'Alene, Idaho, and Spokane, Washington. In 2009, this allowed a total of 62 full-time equivalent call center employees to effectively respond to over 930,585 calls from natural gas and electric customers in our three state service territory.

I am pleased with the dedication of Avista Utilities' employees and their commitment to provide quality service to our customers. While we continue to maintain tight controls on capital and O&M budgets, our customer service surveys indicate that customer satisfaction remains high. Our recent August 2010 customer survey, results show an overall customer satisfaction rating of 95% in our Washington, Idaho, and Oregon operating divisions. This rating reflects a positive experience for the majority of customers who have contacted Avista related to the customer service they received.

According to the recent 2010 J.D. Power and Associates Gas Utility Residential Customer Satisfaction Study, Avista earned the highest ranking in customer satisfaction among residential natural gas customers in the midsize natural gas utilities segment of the

West region. Avista's score of 654 placed the utility highest in the segment, tied with Boise-based Intermountain Gas Company. The segment average score on this study was 629. In its ninth year, the study surveys customer satisfaction across a number of factors, including billing and payment, price, corporate citizenship, communications, customer service and field service. These results can be achieved only with very committed and competent employees.

I am also very pleased with the previously discussed LIRAP and energy efficiency programs. I appreciate the community action agencies' collaboration and the Commission's approval to effectuate and support the LIRAP program.

VI. OTHER COMPANY WITNESSES

Q. Would you please provide a brief summary of the testimony of the other witnesses representing Avista in this proceeding?

A. Yes. The following additional witnesses are presenting direct testimony on behalf of Avista.

Mr. Mark Thies, Senior Vice President and Chief Financial Officer, will address the Company's capital structure, the proposed cost of embedded debt and the overall rate of return. He will explain the actions the Company has taken to acquire needed capital and improve Avista's financial condition in recent years.

Mr. William E. Avera, as President of Financial Concepts and Applications (FINCAP), Inc., has been retained to present testimony with respect to the reasonableness of the Company's proposed overall capital structure and will testify in support of the proposed 10.9% return on equity.

Mr. Kevin Christie, Director, Gas Supply, will describe the additional Jackson Prairie (JP) natural gas storage that the utility will receive to serve customers beginning May 1, 2011.

He will also describe the allocation of this additional storage, and the associated costs, to the three jurisdictions that the Company serves.

Mr. Dave DeFelice, Senior Business Analyst, will describe the Company's proposed regulatory treatment of capital investments in utility plant through 2011.

Mr. Donald Clayton, Vice President of Management Consulting at Tangibl, LLC., will discuss the lead/lag study he performed for Avista Utilities in order to determine the revenue and expense lags by category for revenue and operating expenses, then to apply the leads and lags to the jurisdictional operating expenses in order to calculate appropriate daily and annual cash working capital requirements necessary to operate the Company.

Ms. Elizabeth Andrews, Manager, Revenue Requirements, will discuss the Company's overall revenue requirement proposal. In addition, her testimony and exhibits will cover accounting and financial data in support of the Company's need for the proposed increase in rates and the allocation methodologies. She will also explain forecasted operating results, including expense and rate base adjustments made to actual operating results and rate base.

Mr. Joseph Miller, Regulatory Analyst, sponsors the long-run incremental cost study for Oregon natural gas service. Mr. Miller discusses his study results and how each schedule's present and proposed rates compare to the indicated cost.

Mr. Patrick Ehrbar, Manager, Rates and Tariffs, discusses the spread of the annual revenue changes among the Company's general service schedules and related rate design. Mr. Ehrbar also discusses the proforma revenue adjustment.

Q. Does that conclude your pre-filed direct testimony?

A. Yes.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

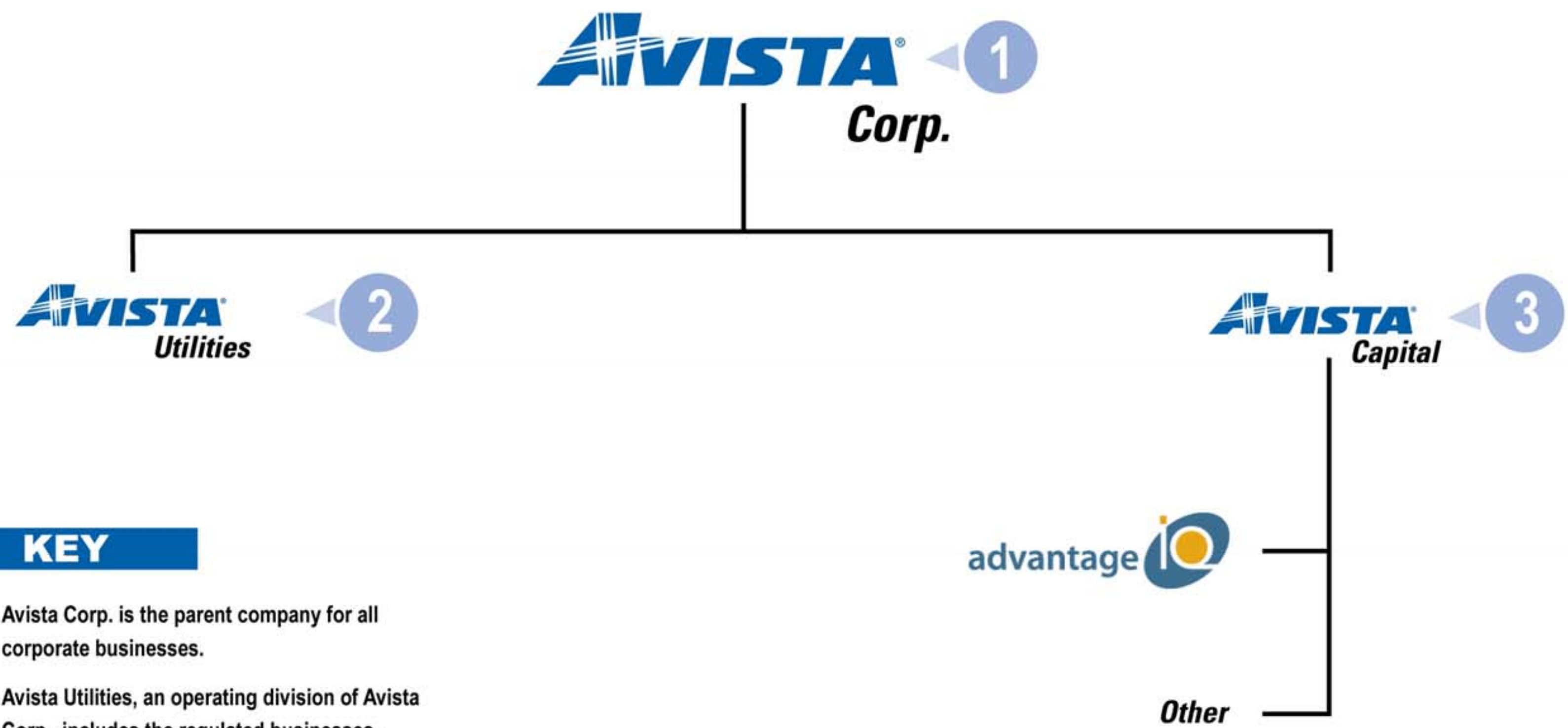
AVISTA CORP

SCOTT L. MORRIS
Exhibit No. 101

Policy and Operations

Avista Corporation Overview

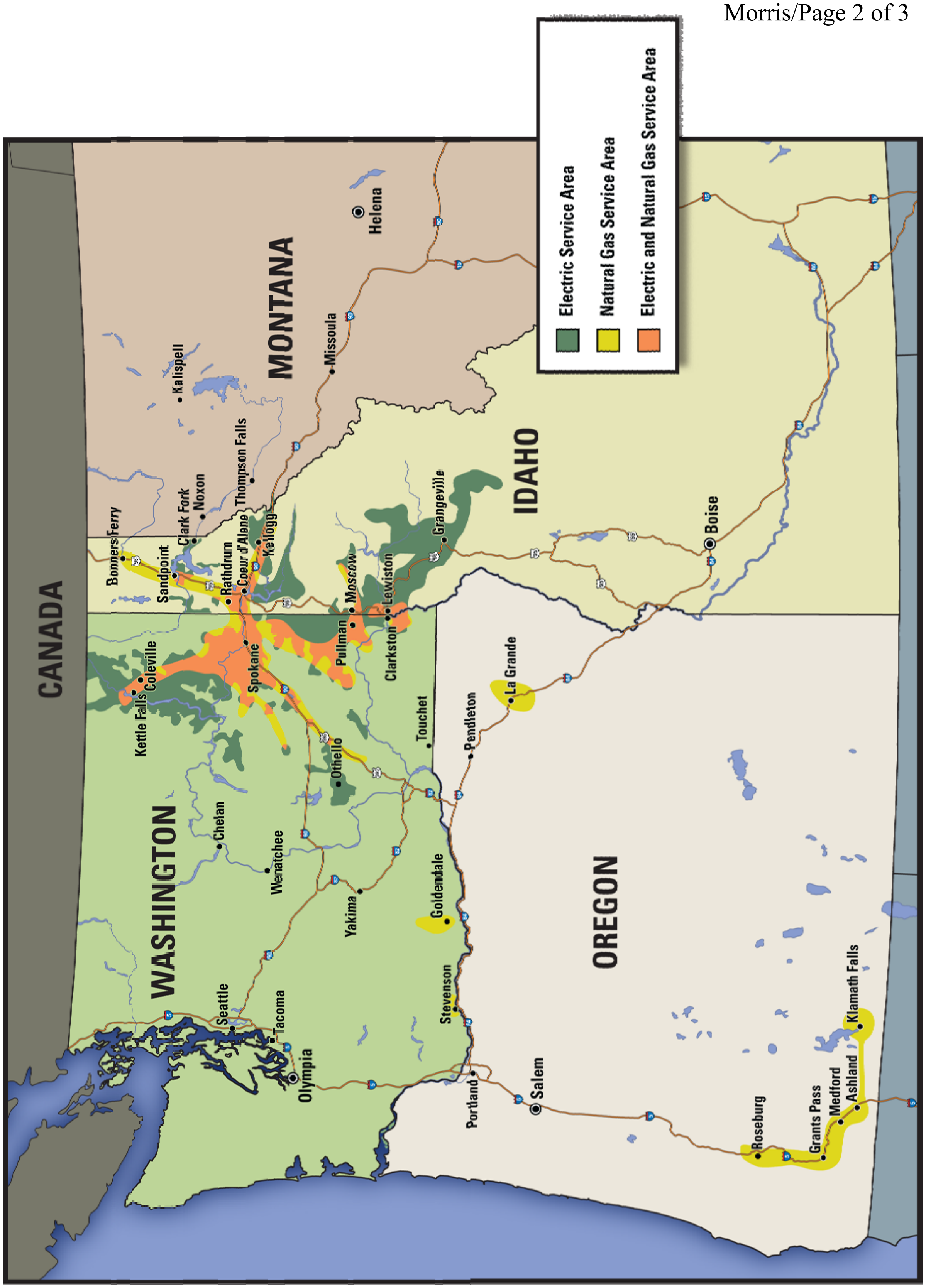
Avista Corporate Business Organizational Structure

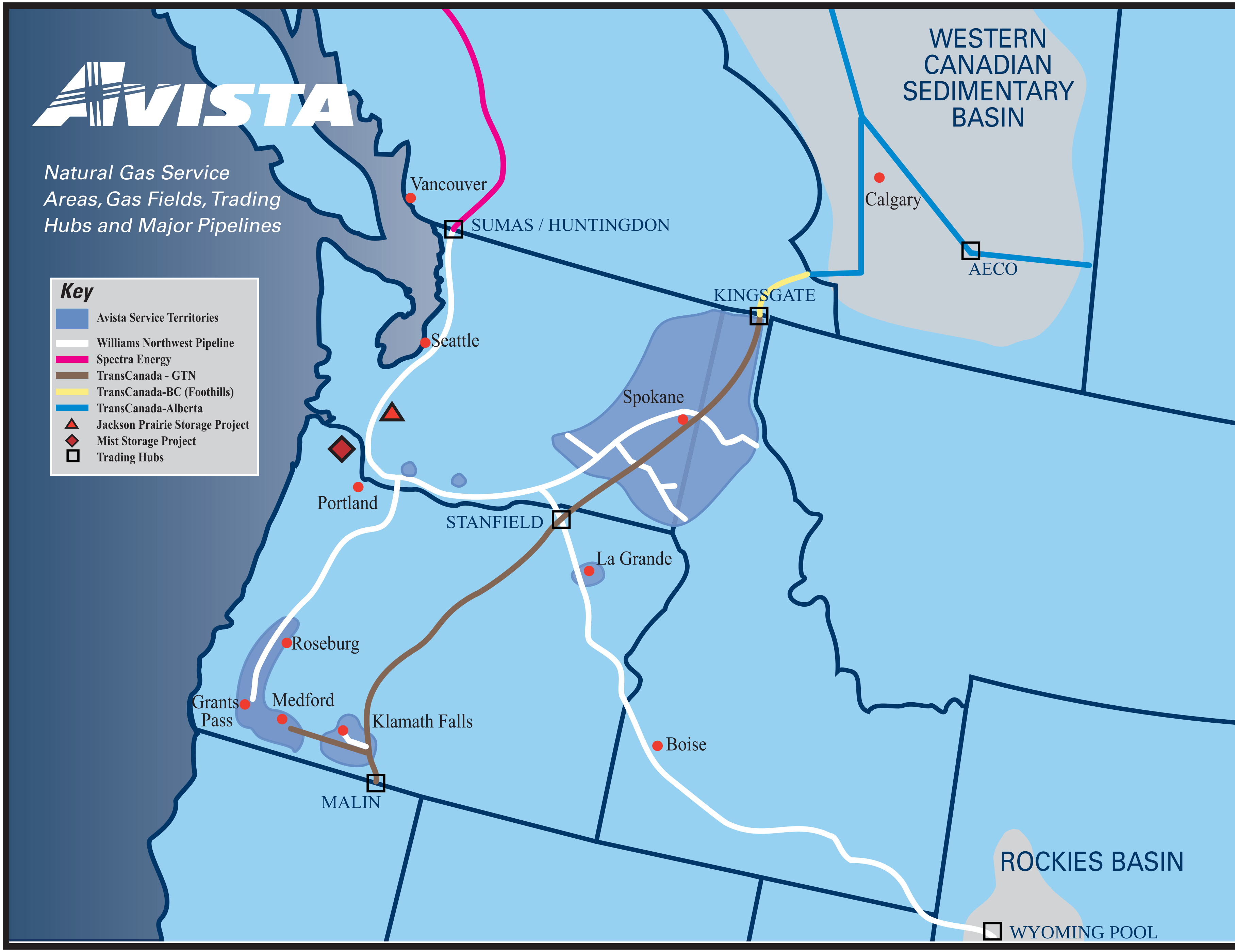


KEY

1. Avista Corp. is the parent company for all corporate businesses.
2. Avista Utilities, an operating division of Avista Corp., includes the regulated businesses, serving customers in Washington, Idaho, and Oregon.
3. Avista Capital is the parent company of all non-regulated subsidiaries. Avista Capital is a wholly owned subsidiary of Avista Corp.

Avista's Electric and Natural Gas Service Areas




Natural Gas Service
Areas, Gas Fields, Trading
Hubs and Major Pipelines
Key
Avista Service Territories
Williams Northwest Pipeline
Spectra Energy
TransCanada - GTN
TransCanada-BC (Foothills)
TransCanada-Alberta
Jackson Prairie Storage Project
Mist Storage Project
Trading Hubs
WESTERN CANADIAN SEDIMENTARY BASIN
Calgary
AECO
KINGSGATE
Vancouver
SUMAS / HUNTINGDON
Seattle
Spokane
Portland
STANFIELD
La Grande
Roseburg
Grants Pass
Medford
Klamath Falls
MALIN
Boise
ROCKIES BASIN
WYOMING POOL

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF MARK T. THIES
REPRESENTING AVISTA CORPORATION

Financial Overview, Capital Structure and Overall Rate of Return

Table of contents for the testimony of Mark Thies:

I. INTRODUCTION

Q. Please state your name, business address, and present position with Avista Corp.

A. My name is Mark Thies. My business address is 1411 East Mission Avenue, Spokane, Washington. I am employed by Avista Corporation as Senior Vice President and Chief Financial Officer.

Q. Would you please describe your education and business experience?

A. I received a Bachelor of Arts degree with majors in Accounting and Business Administration from Saint Ambrose College in Davenport, Iowa, and became a Certified Public Accountant in 1987. I have extensive experience in finance, risk management, accounting and administration within the utility sector, primarily in the Midwest.

I joined Avista in September of 2008 as Senior Vice President and Chief Financial Officer (CFO). Prior to joining Avista, I was Executive Vice President and CFO for Black Hills Corporation, a diversified energy company, providing regulated electric and natural gas service to areas of South Dakota, Wyoming and Montana. I joined Black Hills Corporation in 1997 upon leaving InterCoast Energy Company in Des Moines, Iowa, where I was the manager of accounting. Previous to that I was a senior auditor for Arthur Anderson & Co. in Chicago, Illinois.

Q. What is the scope of your testimony in this proceeding?

A. I will provide a financial overview of the Company and will explain the overall rate of return proposed by the Company in this filing for its natural gas operations. The proposed rate of return is derived from Avista's long-term cost of debt, and common equity, weighted in proportion to the proposed capital structure.

I will address the proposed capital structure, as well as the proposed cost of debt and equity in this filing. Dr. Avera, on behalf of the Company, will provide additional testimony related to the appropriate return on equity for Avista, based on the specific circumstances of the Company, together with the current state of the financial markets.

In brief, I will provide information that shows:

- Avista's plans call for significant capital expenditure requirements for the utility over the next two years to assure reliability in serving our customers and meeting customer growth. Capital expenditures of approximately $460 million are planned for 2010-2011 for customer growth, necessary maintenance and replacements of our natural gas utility systems, and investment in generation, transmission and distribution facilities for the electric utility business. Capital expenditures of approximately $1.2 billion are planned for the five year period ending December 31, 2014. Avista needs adequate cash flow from operations to fund these requirements, together with access to capital from external sources under reasonable terms.

- Avista's corporate credit rating from Standard & Poor's (S&P) is currently BBB- and Baa3 from Moody's Investors Service (Moody's). Avista Utilities must operate at a level that will support a strong investment grade corporate credit rating, meaning "BBB" or "BBB+", in order to access capital markets at reasonable rates, which will decrease long-term borrowing costs to customers. Avista has been placed on "positive" outlook by both S&P and Moody's, which may result in an upgrade in the near-term. A supportive regulatory environment will be taken into consideration by the rating agencies when reviewing Avista for a possible upgrade. Maintaining solid credit metrics and credit ratings will also help support a stock price necessary to issue equity to fund a portion of our capital requirements.

- The Company has proposed an overall rate of return of 8.61%, including a 50.76% equity ratio and a 10.9% return on equity. Our cost of debt is 6.26%. We believe the 8.61% provides a reasonable balance of the competing objectives of continuing to improve our financial health, and the impacts that increased rates have on our customers.

The Company's initiatives to carefully manage its operating costs and capital expenditures are an important part of improving performance, but are not sufficient without revenues from the general rate request for our natural gas businesses in this case. Certainty of cash flows from operations can only be achieved with the support of regulators in allowing the timely recovery of costs and the ability to earn a fair return on investment.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring Exhibit No. 201, which was prepared under my direction. Avista's credit ratings by the two principal rating agencies are summarized on page 1. Page 2 includes Avista's actual capital structure at December 31, 2009 and the forecasted capital structure at December 31, 2011 utilized for this case. Pages 3 through 4 are supporting documentation for page 2.

II. FINANCIAL OVERVIEW

Q. Please provide an overview of Avista's financial situation.

A. The Company has made good progress in improving its financial health in recent years, as demonstrated by improved financial ratios. Avista has reduced investments in unregulated subsidiaries and redeployed the majority of the proceeds from the sales of the unregulated subsidiaries to the Utility. The Company has been able to improve and balance its debt and equity ratios by paying down debt, issuing additional common stock, and through additional retained earnings. Although we have made progress in improving the Company's financial condition, we are still not as strong as we need to be.

Avista's goal is to operate at a level that will support a strong corporate credit rating of BBB / BBB+, and move away from the bottom notch of the investment grade rating scale. Operating at a higher rating will help reduce long-term costs to customers. It will also reduce collateral requirements and allow us to maintain access to more counterparties for acquisition of natural gas. We expect that a continued focus on the regulated utility, conservative financing strategies (including the issuance of common equity) and a supportive regulatory environment will contribute to an overall improved financial situation, that will allow us to move up from the current BBB- rating.

Avista was placed on "positive" outlook by both S&P and Moody's in August 2009, which indicates that continued financial improvement and prudent financial management could lead to an upgrade. This may not be achieved, however, if the company does not obtain adequate and timely support for recovery of costs from state regulators, or the company's financial metrics otherwise deteriorate.

Q. What additional steps is the Company taking to improve its financial health?

A. We are working to assure we have adequate funds for operations, capital expenditures and debt maturities. We are maintaining a $320 million line of credit and a $75 million line of credit, which will both expire in April 2011, as well as an Accounts Receivable Sales program which will expire in March 2011. The Company does not plan to renew the accounts receivable program after expiration in March 2011. We are in the process of renewing the line(s) of credit with banks, and we expect to be able to obtain sufficient commitments from banks to provide adequate liquidity. The new lines of credit are expected to be in place during the first quarter of 2011. We plan to obtain a portion of our capital requirements through equity issuance. We also maintain an ongoing dialogue with the rating agencies regarding the measures taken by the Company to improve our credit rating.

We have reduced our overall cost of debt from approximately 6.9% in 2008 to 6.4% at December 31, 2009 primarily by issuing $250 million of secured debt at a coupon of 5.125%. Additionally, our December 31, 2011 forecasted cost of debt is projected to further decrease to 6.26% due to the maturity of higher cost debt and issuance of new debt at lower rates.

We are operating the business efficiently to keep costs as low as practicable for our customers, while at the same time ensuring that our energy service is reliable, and customers are satisfied. An efficient, well-run business is not only important to our customers, but also to investors. Additionally, the Company is working through regulatory processes to recover our costs in a timely manner so that earned returns are closer to those allowed by regulators in each of the states we serve. This is one of the key determinants from the rating agencies' standpoint when they are reviewing our overall credit ratings.

Q. In addition to having credit ratings that will allow Avista to attract debt capital under reasonable terms, is it also necessary to attract capital from equity investors?

A. It is absolutely essential. Avista has two primary sources of external capital – debt and equity investors. Avista currently has approximately $2.2 billion of debt and equity in place to serve its customers. Approximately half of that investment is funded by debt holders, and half is funded by equity investors. There tends to be a lot of emphasis on maintaining credit metrics and credit ratings that will provide access to debt capital under reasonable terms, however, access to equity capital is equally important. In fact, equity investors also focus on cash flows, capital structure and liquidity, consistent with debt investors.

Additional equity capital generally comes in two forms – retained earnings and new equity issuances. Retained earnings represent the annual earnings (return on equity) of the Company that is not paid out to investors in dividends. The retained earnings are reinvested by the Company in utility plant, and other capital requirements, to serve customers, which avoids the need to issue new debt. Occasionally it is necessary to issue new common stock to maintain a balanced debt and equity capital structure, which allows Avista access to both debt and equity markets under reasonable terms, on a sustainable basis. Because of the large capital requirements at Avista, it is imperative that Avista have ready-access to both the debt and equity markets at reasonable costs.

Q. Are the debt and equity capital markets a competitive market?

A. Yes. Our ability to attract new capital, especially equity capital, under reasonable terms is dependent on our ability to offer a risk/reward opportunity that is better than the equity investors' other alternatives. As explained in more detail by Dr. Avera, we are competing with not only other utilities, but businesses in other sectors of the economy. Demand for the stock supports the stock price, which provides the opportunity to issue additional stock under reasonable terms to fund capital investment requirements.

To the extent that the equity investor holds a diversified portfolio of companies that includes utilities and other energy companies, we would be competing with those companies to attract those equity dollars.

In the debt markets, utilities are the third largest issuers, right behind governments and financial services. Therefore, it is a very competitive market and the Company must be able to attract debt investors as well as equity investors.

Q. What is Avista doing to attract equity investment?

A. Avista is carrying a capital structure that provides the opportunity to have financial metrics that offer a risk/reward proposition that is competitive and/or attractive for equity holders.

We have increased our dividend for common shareholders, and have worked toward a dividend payout ratio that is comparable to other utilities in the industry. This is an essential element in providing a competitive risk/reward opportunity for equity investors.

We are operating the business efficiently to keep costs as low as practicable for our customers, while at the same time ensuring that our energy service is reliable, and customers are satisfied.

We are employing tracking mechanisms such as Purchased Gas Adjustment (PGA), approved by the regulatory commissions, to balance the risk of owning and operating the business in a manner that places us in a position to offer a risk/reward opportunity that is competitive with not only other utilities, but with businesses in other sectors of the economy.

We are seeking rate relief to provide timely recovery of costs and earned returns closer to those allowed by regulators. If we are not able to achieve a reasonable actual earned return on our equity investment, we will not be able to attract equity dollars that are absolutely necessary to support this business going forward.

Dr. Avera provides additional testimony related to the appropriate return on equity for Avista, that would allow the Company access to equity capital under reasonable terms, and on a sustainable basis.

Q. Has regulatory lag reduced the actual return earned by the Company?

A. Yes. Although we have received recent additional rate increases in all three states where we do business, we are continuing to experience increases in costs, and increased capital investment requirements.

Furthermore, if we do not reflect in retail rates the full cost of capital investment that will be serving customers during the period that retail rates are in place from this case, we will continue to earn a lower return than what we are authorized to earn.

As we process this rate filing, it is imperative that we work toward a more timely recovery of the costs to provide service to customers, and a meaningful opportunity to earn a return closer to the allowed return, so that we can have access to debt and equity capital under reasonable terms.

III. CREDIT RATINGS

Q. How important are credit ratings for Avista?

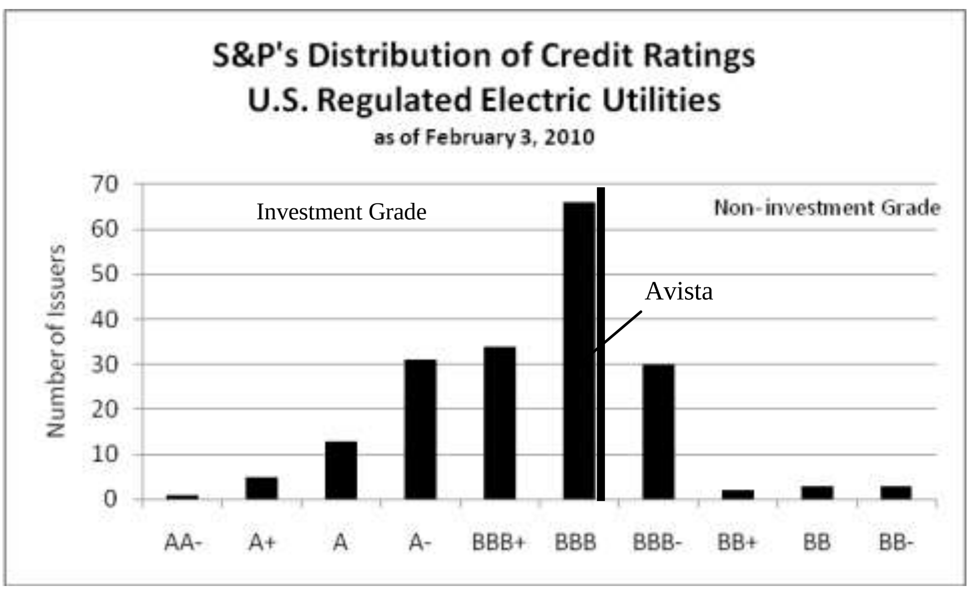
A. Utilities need ready access to capital markets in all types of economic environments. The nature of our business with long-term capital projects, our obligation to serve, and the potential for high volatility in natural gas and fuel and purchased power markets, necessitates the ability to go to the financial markets under reasonable terms on a regular basis.

Q. Please explain the credit ratings for Avista's debt securities.

A. Rating agencies are independent agencies that assess risks for investors. Two of the most widely recognized rating agencies are Standard & Poor's (S&P) and Moody's. These rating agencies assign a credit rating to companies and their securities so investors can more easily understand the risks associated with investing in their debt. Avista's credit ratings are summarized on page 1 of Exhibit 201.

As shown in Illustration No. 1 below, Avista is on the lowest rung of the investment grade credit rating scale. As I noted earlier, I believe it is important that we move up the scale to at least a BBB or BBB+, so that we are not on the edge of the investment grade cliff.

<u>Illustration No. 1:</u>



Additionally, as shown in Illustration No. 2 below, Avista has the lowest corporate credit rating among its peers (that S&P compares us to).

Illustration No. 2:

Avista Corporation Peer Comparison - S&P Corporate Issuer Rating

	Avista	IDACORP	Portland General Electric	Northwestern	Puget Sound Energy
Corporate Issuer Rating	BBB-	BBB	BBB	BBB	BBB

Q. Please explain the implications of the credit ratings in terms of the Company's ability to access financial markets.

A. Credit ratings impact investor demand and expected return. More specifically, when the Company issues debt, the credit rating helps determine the interest rate at which the debt will be issued. The credit rating also determines the type of investor who will be interested in purchasing the debt. For each type of investment a potential investor could make, the investor looks at the quality of that investment in terms of the risk they are taking and the priority they would have in the event that the organization experiences severe financial stress. Investment risks include the likelihood that a company will not meet all of its debt obligations in terms of timeliness and amounts owed for principal and interest. Secured debt receives the highest ratings and priority for repayment and, hence, has the lowest relative risk. In challenging credit markets, where investors are less likely to buy corporate bonds (as opposed to U.S. Government bonds), a higher credit rating will attract more investors, and a lower credit rating could reduce or eliminate the number of potential investors. Thus, lower credit ratings may result in a company having more difficulty accessing financial markets and/or incur higher financing costs.

Q. What credit rating does Avista Corporation believe is appropriate?

A. The move to investment grade for Avista Corp was a significant step in improving the Company's ability to access capital at a reasonable cost. However, a credit rating at the bottom of investment grade is not appropriate for Avista. In adverse conditions – whether unique to Avista or to all market participants – a downgrade from BBB- (investment grade) to BB+ (non-investment grade) is significantly harder to overcome than a downgrade from BBB to BBB-. As Avista experienced, it took approximately six years for the Company to regain its investment grade rating from S&P after it was downgraded during the energy crisis. The difference between investment grade and non-investment grade is not only a matter of debt pricing, it can be a matter of not having the ability to access markets. To avoid adverse circumstances, Avista Utilities should operate at a level that will support a strong corporate investment grade credit rating, meaning a "BBB" or "BBB+," using S&P's rating scale. As shown in illustration 1 above, BBB+/BBB is the average rating of U.S. regulated electric utilities. The Company's goal is to have a credit rating of at least average (our current credit rating is below average).

As noted in Dr. Avera's testimony, the Chairman of the New York State Public Service Commission noted in his role as spokesman for the National Association of Regulatory Utility Commissioners the following:

> While there is a large difference between A and BBB, there is an even brighter line between Investment Grade (BBB-/Baa3 bond ratings by S&P/Moody's, and higher) and non-Investment Grade (Junk) (BB+/Ba1 and lower). The cost of issuing non-investment grade debt, assuming the market is receptive to it, has in some cases been hundreds of basis points over the yield on investment grade securities. To me this suggests that you do not want to be rated at the lower end

> of the BBB range because an unexpected shock could move you outside the investment grade range.[1] (P. 16, L's 8-15).

A solid investment grade corporate credit rating (meaning BBB or BBB+) would also allow the Company to post less collateral with counterparties than would otherwise be required with a lower credit rating. This results in lower costs. It also increases financial flexibility since the credit line capacity would not be reduced for outstanding letters of credit.

Financially healthy utilities have lower financing costs which, in turn, benefit customers. In addition, financially healthy utilities are better able to invest in the needed infrastructure over time to serve their customers, and to withstand the challenges and risks facing the industry.

Q. What financial metrics are used by the rating agencies to establish credit ratings?

A. S&P's financial ratio benchmarks used to rate companies such as Avista are set forth in Illustration No. 3 below.

[1] Brown, George, "Credit and Capital Issues Affecting the Electric Power Industry," *Federal Energy Regulatory Commission Technical Conference* (Jan. 13, 2009).

<u>Illustration No. 3:</u>

Standard & Poor's Financial Risk Indicative Ratios

	FFO/Debt (%)	FFO/Interest (x)	Debt/Capital (%)
Minimal	Greater than 60	(a)	Less than 25
Modest	45 - 60	(a)	25 - 35
Intermediate	30 - 45	(a)	35 - 45
Significant	20 - 30	(a)	45 - 60
Aggressive	12 - 20	(a)	50 - 60
Highly leveraged	Less than 12	(a)	Greater than 60
12 Months Ended 12/31/09 Ratios:			
Avista Adjusted [b]	19.8%	4.33x	55.3%

[a] Not available, however, S&P has indicated that it is a benchmark ratio used for the Utility industry.
[b] Calculated as of 12/31/09 based on last known S&P methodology

The ratios above are utilized to determine the financial risk profile. Currently, Avista is in the "Aggressive" category. The financial risk category along with the business risk profile (Avista is in the Excellent category) is then utilized in Illustration No. 4 below to determine a company's rating. S&P currently has Avista's corporate credit rating as a BBB-. Based upon an aggressive financial risk profile and excellent business risk profile, Avista should have a corporate credit rating of BBB (as indicated in the following table). S&P has placed Avista on "positive" outlook, which indicates that continued financial improvement and prudent financial management could lead to an upgrade. This may not be achieved, however, if the Company does not obtain adequate and timely support for recovery of costs from state regulators, there are significant drought conditions or negative impacts to the Company's hydro generating facilities, there are significant changes in wholesale energy prices, the Company's financial metrics otherwise deteriorate, or adequate liquidity is not achieved or maintained.

<u>Illustration No. 4:</u>

Standard & Poor's Business and Financial Risk Profile Matrix

Business Risk Profile	Financial Risk Profile: Minimal	Modest	Intermediate	Significant	Aggressive	Highly Leveraged
Excellent	AAA	AA	A	A-	BBB	-
Strong	AAA	A	A-	BBB	BB	BB-
Satisfactory	A-	BBB+	BBB	BB+	BB-	B+
Fair	-	BBB-	BB+	BB	BB-	B
Weak	-	-	BB	BB-	B+	B-
Vulnerable	-	-	-	B+	B	CCC+

Moody's uses a similar methodology to analyze and determine utility credit ratings and has also placed Avista Corporation on "positive" outlook.

Q. Please describe how S&P's Financial Risk ratios are calculated and what they mean?

A. The first ratio, "Funds from operations/total debt (%)", calculates the amount of cash flow from operations as a percent of total debt. The ratio indicates the company's ability to fund debt obligations. The second ratio, "Funds from operations/interest coverage (x)", calculates the amount of cash from operations that is available to cover interest requirements. This ratio indicates how well a company's earnings can cover interest payments on its debt. The third ratio, "Total debt/total capital (%)", is the amount of debt in our total capital structure. The ratio is an indication of the extent to which the company is using debt to finance its operations. S&P looks at many other financial ratios; however, these are three critical ratios they use when analyzing our financial profile.

Q. Do rating agencies make adjustments to the financial ratios that are calculated directly from the financial statements of the Company?

A. Yes. Rating agencies make adjustments to debt to factor in off-balance sheet commitments (for example, purchased power agreements and the unfunded status of pension and other post-retirement benefits) that negatively impact the ratios. In 2009, S&P made adjustments to Avista's debt totaling approximately $116 million related to the purchased power and post-retirement benefits. The adjusted financial ratios for Avista are included in Illustration No. 2 above.

Q. Where does Avista fall within those coverage ratios?

A. Progress in increasing the cash flow ratios in recent years has been slower than anticipated due to higher capital expenditures that require cash up front before we can recover the costs from customers and below normal stream flows affecting hydro generation. Each has an impact on the Company by reducing the amount of available cash flow from operations, requiring external financing and ultimately resulting in higher debt and lower cash flow ratios. In fact, Moody's stated the following in an August 2010 credit review of Avista Corporation:

> What could change the rating down: Given the recent and expected financial performance of the Company and positive rating outlook, it is not likely that Avista's ratings will be downgraded over the near term. However, if the Company were to receive surprisingly disappointing rate case outcomes (primarily in Washington, its largest jurisdiction), where adequate cost recovery might be compromised, the outlook could be stabilized. The rating could be downgraded if there were sustained periods of time where significantly poor hydro conditions were prevalent or where CFO pre-WC to interest and CFO pre-WC to debt were to decline to levels of 2.7x and 13%, respectively.[2]

[2] Moody's Investor Services, *Credit Opinion: Avista Corp. Global Credit Research,* August 2010

In order to improve the cash flow ratios, Avista must reduce its debt to total capitalization ratio and increase its available cash funds from operations.

Q. Do the rating agencies look at any other factors when evaluating a company's credit quality?

A. Yes. In addition to financial ratios and metrics, rating agencies also look at a number of qualitative factors which directly or indirectly may affect a company's cash flow. These factors include:

- Regulation
- Markets
- Operations
- Competitiveness, and
- Management

In evaluating these factors, the rating agencies look for regulatory actions that are supportive of cost recovery and that eliminate or minimize volatility of cash flows. They also consider the strength and growth of the economy in our service territory, operations' ability to control costs, whether our service is competitive, and the effectiveness of management.

Therefore, while the ratios are utilized in their quantitative evaluation of a company, they are not the only factors that are taken into account.

Q. What risks are Avista and the utility sector facing that may impact credit ratings?

A. Avista's credit ratings are impacted by risks that could negatively affect the Company's cash flows. These risks include, but are not limited to, recoverability of natural gas and power costs, the level and volatility of wholesale electric market prices and natural gas prices for fuel costs, liquidity in the wholesale market (fewer counterparties and tighter credit restrictions), streamflow and weather conditions, changes in legislative and governmental regulations, rising construction and raw material costs, customers' ability to timely pay their bills, and access to capital markets at a reasonable cost.

Credit ratings for the utility sector are also adversely impacted by large capital expenditures for environmental compliance, and the need for new generation and transmission and distribution facilities. The utility sector is in a cycle of significant capital spending, which will likely be funded by significant issuances of debt and equity. This increases the competition for financial capital at a time when the average utility credit rating is just above investment grade (i.e. BBB / BBB+) and Avista is lower at BBB-.

Given the downturn in the economy and the tightened credit markets, the rating agencies are keeping closer tabs on all companies in order to make sure there is sufficient liquidity in case the credit markets are inaccessible. Not having sufficient sources of cash for potential cash requirements could prompt a credit rating downgrade. The rating agencies are concerned about the significant amount of bank credit facilities that will need to be refinanced or addressed in 2010 through 2012. They expect that over $110 billion of bank credit facilities will need to be refinanced during this time. This is expected to create significant competition for bank credit and may result in increased fees as well as, in some cases, a reduction in the size of facilities.

The increased capital spending needs and resulting increased debt and equity issuances make regulation supporting the full and timely recovery of prudently incurred costs even more critical to the utility sector than in previous years.

Q. How important is the regulatory environment in which a Company operates?

A. The regulatory environment in which a company operates is a major qualitative factor in determining a company's creditworthiness. Moody's stated the following regarding Avista's regulatory environment in an August 2010 credit ratings report:

> Timely and adequate rate relief is a key ratings and outlook determinant for Avista going forward. Should the complications that face each of Avista's respective regulatory commissions persist to a level where Avista's recovery is compromised or should economic conditions create customer backlash over increasing utility prices (resulting in political unrest or possible intervention), there could be negative rating implications.[3]

S&P stated the following:

> Regulation is the most critical aspect that underlies regulated integrated utilities' creditworthiness. Regulatory decisions can profoundly affect financial performance. Our assessment of the regulatory environments in which a utility operates is guided by certain principles, most prominently consistency and predictability, as well as efficiency and timeliness. For a regulatory process to be considered supportive of credit quality, it must limit uncertainty in the recovery of a utility's investment. They must also eliminate, or at least greatly reduce, the issue of rate-case lag, especially when a utility engages in a sizable capital expenditure program.[4]

Due to the major capital expenditures planned by Avista, a supportive regulatory environment is critical to Avista's financial health. Additionally, although Avista has natural gas and electric tracking mechanisms (PGA and PCA) to provide recovery of the majority of the variability in commodity costs, these changes in costs must be financed until the costs are recovered from customers. Investors and rating agencies are concerned about regulatory lag and cost-recovery related to these items.

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[3] Moody's Investor Service, *Credit Opinion: Avista Corp. Global Credit Research,* August 2010

[4] Standard and Poors, *Key Credit Factors: Business and Financial Risks in the Investor-owned Utilities Industry,* March 2010

IV. CASH FLOW

Q. What are the Company's sources to fund capital requirements?

A. The Company utilizes cash flow from operations, long-term debt and common stock issuances to fund its capital expenditures. Additionally, on an interim basis, the Company utilizes its credit facilities to fund short-term cash requirement needs and capital expenditures until longer-term financing can be obtained.

Q. What are the Company's near-term capital requirements?

A. As a combination natural gas and electric utility, over the next few years, capital will be required for, customer growth as well as necessary maintenance and replacements of our natural gas systems, investment in generation upgrades, and transmission and distribution facilities for the electric utility business.

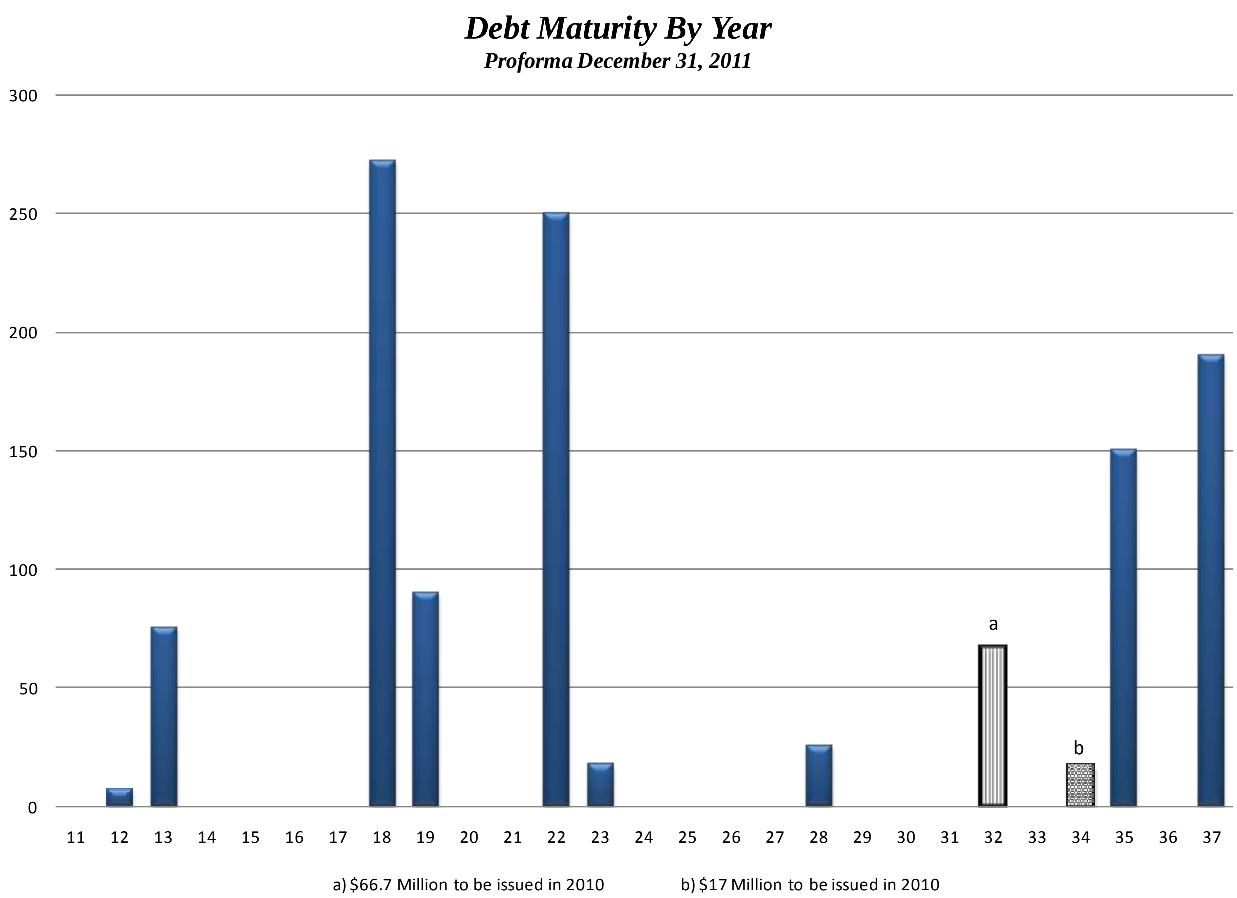
The amount of capital expenditures planned for 2010-2011 is approximately $460 million and approximately $1.2 billion for the five year period ending December 31, 2014. For 2010 alone, these costs equate to a total of $235 million. Total company ratebase at December 31, 2009 was approximately $2.1 billion; therefore, these planned capital additions represent substantial new investments given the relative size of the Company.

Q. What are the Company's near-term plans related to its debt?

A. The Company issued $280 million of secured debt in 2008, and $250 million of secured debt in 2009. The $250 million secured debt was issued at a coupon of 5.125% in September 2009. The Company's original plan was to issue long-term secured debt in September 2008. Due to the disruption in the financial markets, the Company elected to defer the issuance until September 2009. The Company instead sought out and was able to establish a second bank line of credit to ensure continued adequate liquidity. The Company was able to reduce interest costs by approximately $80 million over a ten year period (approximately $8 million annually) by deferring the issuance of long-term debt from 2008 to 2009.

The Company currently plans to issue up to $83.7 million of secured debt in 2010. The proceeds from the issuance of the securities will be utilized to fund capital expenditures, repay maturing long-term debt and repay funds borrowed under our credit facilities. The Company has $35 million of long-term debt scheduled to mature in 2010 ($10 million matured in July 2010 and $25 million matures in October 2010). Illustration No. 5 below shows the amount of proforma debt maturities for Avista as of December 31, 2011:

Illustration No. 5:



Q. What is the status of the Company's lines of credit secured by first mortgage bonds and its accounts receivable program?

A. The Company has a $320 million line of credit, and a $75 million line of credit that both expire in April 2011. Additionally, the Company has a $50 million accounts receivable funding program that expires in March 2011. The Company does not currently plan to renew the accounts receivable program after expiration in March 2011. We are in the process of renewing the line(s) of credit with banks, and we expect to be able to obtain sufficient commitments from banks to provide adequate liquidity. The new lines of credit are expected to be in place during the first quarter of 2011.

The costs related to our $320 million line are expected to increase (when it is refinanced) due to the tightened credit markets and competition for bank credit. The increased costs are evident in our $75 million credit agreement that was completed in November 2009.

The facilities have been sized to allow the Company to maintain adequate liquidity to cover short-term cash requirements, manage counterparty collateral requirements, and avoid issuing securities in unfavorable markets. We believe our current agreements provide us adequate liquidity and flexibility to face volatile financial markets and volatile energy commodity prices.

Q. Is there new legislation that may impact the Company's collateral requirements?

A. Yes. The Dodd-Frank Wall Street Reform and Consumer Protection Act (Act) was signed into law by President Obama on July 21, 2010. The Act establishes regulatory jurisdiction by the Commodity Futures Trading Commission (CFTC) and the Securities and Exchange Commission (SEC) for certain swaps (which include a variety of derivative instruments) and the users of such swaps, that otherwise would have been exempted under the Commodity Exchange Act, federal securities laws, and federal banking laws.

A variety of rules must be adopted by federal agencies (including the CFTC, SEC and the FERC) to implement the Act. These rules, which will be implemented over timeframes as defined in the Act, could have a significant impact on Avista Corporation that was not clearly defined in the Act itself.

Under the Act, "Swap Dealers" and "Major Swap Participants" will be required to post collateral to meet minimum capital requirements as well as minimum initial and variation margin requirements; the purpose of which is to ensure the safety and soundness of the capital markets by addressing concerns brought about by the global financial crisis of 2007 and 2008. Swap Dealers and/or Major Swap Participants are persons who serve as dealers in swaps or who maintain a substantial position in swaps, for reasons other than mitigating commercial risk.

The Act also requires a broad category of swaps to be cleared and traded on registered exchanges or special derivatives exchanges. Such clearing requirements would result in a significant change from our current practice of bilateral transactions and negotiated credit terms. An exemption to such clearing requirements is outlined in the Act for end users that are not Major Swap Participants or Swap Dealers and enter into hedges to mitigate commercial risk. We expect to qualify under the end user exemption. Despite the end user exemption, concern remains that counterparties that are Swap Dealers or Major Swap Participants will pass along the increased cost and margin requirements through higher prices and reductions in unsecured credit limits.

Q. What are Avista's plans regarding common equity and why is this important?

A. Avista will continue to monitor the common equity ratio of its capital structure, and assess the need to issue additional common equity. Avista entered into an amendment to the amended and restated sales agency agreement in August 2010 to issue up to 3.1 million shares of our common stock from time to time. Avista originally entered into an amended and restated sales agency agreement to issue up to 1.25 million shares of its common stock in December 2009. During the six months ended June 30, 2010, we issued 435,000 shares of common stock for $8.8 million under this sales agency agreement. We are planning to issue up to $45 million of common stock in 2010 in order to finance a portion of our capital expenditures and maturing long-term debt and to support our common equity ratio. To the extent that we are not able to access the equity market, there will be increased pressure on our lines of credit, and an increased need to issue long term debt, which is likely to unfavorably impact our cost of debt and debt to equity ratio. It is important to the rating agencies for Avista to maintain a balanced debt/equity ratio in order to minimize the risk of default on required debt interest payments.

As Dr. Avera explains in his testimony, the 50.76 percent common equity ratio requested by Avista in this case is consistent with the range of equity ratios maintained by the firms in the Utility Proxy Groups.

Dr. Avera notes that electric utilities are facing, among other things, rising cost structures, the need to finance significant capital investment plans, and uncertainties over accommodating future environmental mandates. A more conservative financial profile, in the form of a higher common equity ratio, is consistent with the increasing uncertainties and the need to maintain the continuous access to capital that is required to fund operations and necessary system investment.

This is especially the case for Avista, as we face the dual challenge of financing significant capital expansion plans while at the same time endeavoring to improve our credit standing. Avista is committed to maintaining an appropriate level of equity to support a strong corporate credit rating (meaning BBB or BBB+).

Q. What are Avista's plans regarding preferred equity and other financing structures (for example, hybrid instruments)?

A. Avista does not currently have any preferred equity or other financing structures outstanding. Currently, Avista does not plan to issue preferred equity or other financing structures, but will continue to evaluate the appropriateness of these financing vehicles.

V. CAPITAL STRUCTURE

Q. Please explain the capital structure proposed by Avista in this case.

A. Avista's current capital structure consists of a blend of long-term debt and common equity necessary to support the assets and operating capital of the Company. The proportionate shares of Avista Corp.'s actual capital structure on December 31, 2009, are shown on page 2 of Exhibit No. 201. A pro forma capital structure is also shown on page 2, which reflects expected changes for the period ending December 31, 2011. Supporting workpapers provide additional details related to these adjustments on pages 3 through 4.

The rate of return to be applied to rate base in this proceeding is equal to the weighted average cost of capital, taking into account the pro forma adjusting items. As shown on page 1 of Exhibit No. 201, Avista Utilities is proposing an overall rate of return of 8.61%.

VI. COST OF DEBT

Q. How have you determined the cost of debt?

A. Cost of debt in the Company's proposed capital structure includes long-term debt. As shown on page 2 of Exhibit No. 201, the actual weighted average cost of total debt outstanding on December 31, 2009 was 6.35%. The size and mix of debt changes over time based upon the actual financing completed. We have made certain pro forma adjustments to update the debt cost through December 31, 2011 to 6.26%, which is a slight reduction from the 6.28% currently allowed in rates. Pro forma adjustments to total debt reflect expected maturities of outstanding long-term debt and issuance of new debt to fund those maturities.

VII. COST OF COMMON EQUITY

Q. What rate of return on common equity is the Company proposing in this proceeding?

A. The Company is proposing a 10.9% return on common equity (ROE), which falls in the lower end of Dr. Avera's recommended range of required return on equity. Dr. Avera testifies to analyses related to the cost of common equity with an ROE range of 10.5% to 12.0% and 10.65% to 12.15% (after accounting for the impact of common equity flotation costs).

Q. Dr. Avera suggests an ROE range of 10.65% to 12.15%. Why is Avista requesting an ROE in the lower end of the range?

A. As I have testified, Avista has made solid progress towards improving its financial health. If Avista can earn a 10.9% ROE, I believe our financial condition would continue to improve and would further strengthen our financial ratios.

Furthermore, as the Company has worked toward improving its financial condition over the last several years, it has done so with the customer in mind. Avista is attempting to balance the ability to continue to improve our financial health and access capital markets under reasonable terms with the impacts that increased retail rates have on its customers. In this case, although we believe an ROE greater than 10.9% is supported and is warranted, we also believe the 10.9% provides a reasonable balance of the competing objectives.

Q. Please summarize the proposed capital structure and the cost components for debt and common equity.

A. As also shown on page 2 of Exhibit No. 201, the following illustration shows the capital structure and cost components proposed by the Company.

Illustration No. 6:

AVISTA CORPORATION
Proposed Cost of Capital
December 31, 2011

	Amount	Percent of Total Capital	Cost	Component
Total Debt	$1,160,800,000	49.24%	6.26%	3.08%
Common Equity	1,196,660,000	50.76%	10.90%	5.53%
Total	$2,357,460,000	100.00%		8.61%

Q. Does that conclude your pre-filed direct testimony?

A. Yes.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

MARK T. THIES
Exhibit No. 201

Financial Overview, Capital Structure and Overall Rate of Return

AVISTA CORPORATION
Long-term Securities Credit Ratings

	Standard & Poor's		Moody's	
Last Upgraded	February 2008		December 2007 and the First Mortgage Bonds and Secured Medium-term Notes were further upgraded to Baa1 from Baa2 in August 2009	
Credit Outlook	Positive		Positive	
	A+		**A1**	
	A		**A2**	
	A-		**A3**	
	BBB+	First Mortgage Bonds Secured Medium-Term Notes	**Baa1**	First Mortgage Bonds Secured Medium-Term Notes
	BBB		**Baa2**	
	BBB-	Avista Corp./Corporate rating	**Baa3**	Avista Corp./Issuer rating
	INVESTMENT GRADE			
	BB+		**Ba1**	Trust-Originated Preferred Securities
	BB	Trust-Originated Preferred Securities	**Ba2**	
	BB-		**Ba3**	

AVISTA CORPORATION
Proposed Cost of Capital
December 31, 2011

	Amount	Percent of Total Capital	Cost	Component
Total Debt	$1,160,800,000	49.24%	6.26%	3.08%
Common Equity	1,196,660,000	50.76%	10.90% (1)	5.53%
Total	$2,357,460,000	100.00%		**8.61%**

AVISTA CORPORATION
Cost of Capital as of
December 31, 2009

	Amount	Percent of Total Capital	Cost	Component
Total Debt	$1,112,100,000	51.04%	6.35%	3.24%
Common Equity	1,066,938,893	48.96%	10.10%	4.95%
Total	$2,179,038,893	100.00%		**8.19%**

[1] Proposed Return on Common Equity - See Avera testimony

AVISTA CORPORATION
Forecasted Cost of Long-Term Debt Detail
December 31, 2011

Line No.	Description	Coupon Rate	Maturity Date	Settlement Date	Principal Amount	Issuance Costs	SWAP Loss/(Gain)	Discount (Premium)	Loss/Reacq Expenses	Net Proceeds	Yield to Maturity	Principal Outstanding 12/31/2011	Effective Cost	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(g)	(h)	(i)	(j)	(k)	(l)	
1	SMTN Series A	7.18%	8/11/2023	8/12/1993	7,000,000	54,364				6,945,636	7.244%	7,000,000	507,064	1
2	SMTN Series A	7.37%	5/10/2012	5/10/1993	7,000,000	49,114			1,227,883	5,723,003	9.455%	7,000,000	661,877	2
3	SMTN Series A	7.39%	5/11/2018	5/11/1993	7,000,000	54,364			1,227,883	5,717,753	9.287%	7,000,000	650,114	3
4	SMTN Series A	7.45%	6/11/2018	6/9/1993	15,500,000	120,377		50,220	2,140,440	13,188,963	8.953%	15,500,000	1,387,715	4
5	SMTN Series A	7.53%	5/5/2023	5/6/1993	5,500,000	42,712			963,011	4,494,277	9.359%	5,500,000	514,744	5
6	SMTN Series A	7.54%	5/5/2023	5/7/1993	1,000,000	7,766			175,412	816,822	9.375%	1,000,000	93,747	6
7	5.70% FMB's	5.70%	7/1/2037	12/15/2006	150,000,000	4,702,304	3,738,000	222,000		141,337,696	6.120%	150,000,000	9,179,674	7
8	6.125% FMB's	6.13%	9/1/2013	9/8/2003	45,000,000	825,301		229,839	815,824	43,129,036	6.703%	45,000,000	3,016,248	8
9	5.45% FMB's	5.45%	12/1/2019	11/18/2004	90,000,000	1,192,681		239,400		88,567,919	5.608%	90,000,000	5,047,001	9
10	6.25% FMB's	6.25%	12/1/2035	11/17/2005	150,000,000	1,812,935	(4,445,000)	367,500		152,264,565	6.139%	150,000,000	9,208,605	10
11	5.125% FMB's	5.125%	4/1/2022	9/22/2009	250,000,000	2,284,788	(10,776,222)	575,000	2,904,114	255,012,320	4.909%	250,000,000	12,271,628	11
12	5.95% FMB's	5.95%	6/1/2018	4/2/2008	250,000,000	2,246,419	16,395,000	835,000		230,523,581	7.034%	250,000,000	17,585,352	12
13	7.25% FMB's	7.25%	12/16/2013	12/16/2008	30,000,000	523,272				29,476,728	7.677%	30,000,000	2,302,993	13
14	PCB's Kettle Falls	6.00%	12/1/2023	7/29/1993	4,100,000	115,355		20,500	146,393	3,817,752	6.523%	4,100,000	267,441	14
15	MTN's Series C	Series Costs	6/15/2013	6/15/1998		650,179				-650,179		-	43,345	15
16	MTN's Series C	6.37%	6/19/2028	6/19/1998	25,000,000	158,304			188,649	24,653,047	6.475%	25,000,000	1,618,863	16
17	PCB $66.7 million	5.50%	6/1/2032	12/15/2010	66,700,000	1,414,486 [5]			3,392,425 [4]	61,893,089	6.107%	66,700,000	4,073,229	17
18	PCB $17 million	5.50%	3/1/2034	12/15/2010	17,000,000	360,514 [5]			1,900,481 [4]	14,739,006	6.630%	17,000,000	1,127,030	18
19												1,120,800,000	69,556,673	19
20														20
21	Repurchase	[1] 7.74%	12/31/2017	6/30/2006	6,875,000				483,582	6,391,418	8.721%		[2] 70,127	21
22	Repurchase	[1] 8.17%	6/30/2015	6/30/2005	26,000,000				1,700,371	24,299,629	9.184%		[2] 267,096	22
23	Repurchase	[1] 8.41%	6/30/2014	6/30/2004	36,590,000				7,244,895	29,345,106	11.840%		[2] 1,273,854	23
24	Repurchase	[1] 8.68%	9/30/2012	6/30/2003	52,485,000				3,085,624	49,399,376	9.651%		[2] 528,378	24
25												1,120,800,000	71,696,129	25
26														26
27		[3] Var. Rate Long-Term Debt			40,000,000	1,296,086			(1,769,125)	40,473,039	2.314%	40,000,000	925,415	27
28	**OREGON TOTAL DEBT OUTSTANDING AND COST OF DEBT AT December 31, 2011**											**1,160,800,000**	**72,621,544**	28
29														29
30									**Forecasted Weighted Average Cost of Debt**		**6.256%**			30
31														31
32	[1] The coupon rate used is the cost of debt at the time of the repurchases													32
33	[2] The amounts are calculated using the IRR function													33
34	[3] Interest rate information comes from Exhibit No. 201 Page 4.													34
35	[4] These are the estimated unamortized expenses on reacquired debt at the forecasted time of issuance in December 2010													35
36	[5] Projected Issuance Cost													36

AVISTA CORPORATION
Forecasted Cost of Long-Term Variable Rate Debt Detail
December 31, 2011

1		Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Avg of
2	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
3	Number of Days in Month		31	28	31	30	31	30	31	31	30	31	30	31	365
4	Trust Preferred	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	**40,000,000**
5	Forecasted Rates Trust Preferred*		2.08%	2.08%	2.08%	2.20%	2.20%	2.20%	2.33%	2.33%	2.33%	2.70%	2.70%	2.70%	
6	Trust Preferred Interest Expense		71,472	64,556	71,472	73,333	75,778	73,333	80,083	80,083	77,500	93,000	90,000	93,000	**943,611**
7															
8											Average borrowing rate used in the calculation of the effective costs below				2.36%
9															

10		Coupon	Maturity	Settlement	Principal	Issuance	Loss/Reacq	Net	Yield to	Outstanding	Effective
11	Description	Rate	Date	Date	Amount	Costs	Expenses	Proceeds	Maturity	12/31/2010	Cost
12	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
13	Trust Preferred	2.36%	6/1/2037	6/3/1997	40,000,000	1,296,086	(1,769,125)	40,473,039	2.314%	40,000,000	925,415
14											

15 *The forecasted interest rates come from forecast Jun7 model.

AVISTA CORPORATION
Long-term Securities Credit Ratings

	Standard & Poor's		Moody's	
Last Upgraded	February 2008		December 2007 and the First Mortgage Bonds and Secured Medium-term Notes were further upgraded to Baa1 from Baa2 in August 2009	
Credit Outlook	Positive		Positive	
	A+		**A1**	
	A		**A2**	
	A-		**A3**	
	BBB+	First Mortgage Bonds Secured Medium-Term Notes	**Baa1**	First Mortgage Bonds Secured Medium-Term Notes
	BBB		**Baa2**	
	BBB-	Avista Corp./Corporate rating	**Baa3**	Avista Corp./Issuer rating
	INVESTMENT GRADE			
	BB+		**Ba1**	Trust-Originated Preferred Securities
	BB	Trust-Originated Preferred Securities	**Ba2**	
	BB-		**Ba3**	

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF WILLIAM E. AVERA
REPRESENTING AVISTA CORPORATION

Return on Equity

DIRECT TESTIMONY OF WILLIAM E. AVERA

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. William E. Avera, 3907 Red River, Austin, Texas, 78751.

Q. In what capacity are you employed?

A. I am the President of FINCAP, Inc., a firm providing financial, economic, and policy consulting services to business and government.

Q. Please describe your educational background and professional experience.

A. A description of my background and qualifications, including a resume containing the details of my experience, is attached as Exhibit 302.

A. Overview

Q. What is the purpose of your testimony in this case?

A. The purpose of my testimony is to present to the Public Utility Commission of Oregon ("OPUC") my independent evaluation of the fair rate of return on equity ("ROE") for the jurisdictional gas utility operations of Avista Corp. ("Avista" or "the Company"). In addition, I also examined the reasonableness of the Company's requested capital structure, considering both the specific risks faced by Avista and other industry guidelines.

Q. Please summarize the basis of your knowledge and conclusions concerning the issues to which you are testifying in this case.

A. As is common and generally accepted in my field of expertise, I have accessed and used information from a variety of sources. I am familiar with the organization, finances, and operations of Avista from my participation in prior proceedings before the OPUC, Washington Utilities and Transportation Commission ("WUTC"), and the Idaho Public

Utilities Commission ("IPUC"). In connection with the present filing, I considered and relied upon corporate disclosures and management discussions, publicly available financial reports and filings, and other published information relating to Avista. I also reviewed information relating generally to current capital market conditions and specifically to current investor perceptions, requirements, and expectations for Avista's gas utility operations. These sources, coupled with my experience in the fields of finance and utility regulation, have given me a working knowledge of the issues relevant to investors' required return for Avista, and they form the basis of my analyses and conclusions.

Q. What is the practical test of the reasonableness of the ROE used in setting a utility's rates?

A. The ROE compensates common equity investors for the use of their capital to finance the plant and equipment necessary to provide utility service. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. To be consistent with sound regulatory economics and the standards set forth by the Supreme Court in the *Bluefield*[1] and *Hope*[2] cases, a utility's allowed ROE should be sufficient to: (1) fairly compensate investors for capital invested in the utility, (2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and (3) maintain the utility's financial integrity.

[1] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).
[2] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

Q. How did you develop your conclusions regarding a fair rate of return for Avista?

A. I first reviewed the operations and finances of Avista, and the general conditions in the utility industry and the capital markets. With this as a background, I conducted various well-accepted quantitative analyses to estimate the current cost of equity, including alternative applications of the discounted cash flow ("DCF") model and the Capital Asset Pricing Model ("CAPM"), as well as reference to expected earned rates of return for utilities. Based on the cost of equity estimates indicated by my analyses, Avista's ROE was evaluated taking into account the specific risks and potential challenges for its jurisdictional gas utility operations.

B. Summary of Conclusions

Q. What are your findings regarding the fair rate of return on equity for Avista?

A. Based on the results of my analyses and the economic requirements necessary to support continuous access to capital, I recommend that Avista be authorized an ROE in the range of 10.65 percent to 12.15 percent. The bases for my conclusion are summarized below:

- In order to reflect the risks and prospects associated with Avista's jurisdictional utility operations, my analyses focused on proxy groups of 1) other natural gas utilities, and 2) combination utilities with both gas and electric utility operations. Consistent with the fact that utilities must compete for capital with firms outside their own industry, I also referenced a proxy group of lower-risk companies in the non-utility sector of the economy;
- Because investors' required return on equity is unobservable and no single method should be viewed in isolation, I applied both the DCF and CAPM methods, as well as the expected earnings approach, to estimate a fair ROE for Avista;
- Based on my evaluation of the strength of the various methods, I concluded that the cost of equity for the proxy groups of utilities and non-utility companies is in the 10.5 percent

to 12.0 percent range, or 10.65 percent to 12.15 percent after incorporating a minimum adjustment to account for the impact of common equity flotation costs.

Q. What other evidence did you consider in evaluating your ROE recommendation in this case?

A. My recommendation was reinforced by the following findings:

- Sensitivity to financial market and regulatory uncertainties has increased dramatically and investors recognize that constructive regulation is a key ingredient in supporting utility credit standing and financial integrity;
- Given Avista's present credit standing, an inadequate rate of return authorized in this proceeding would further pressure its financial flexibility and credit ratings; and,
- Providing Avista with the opportunity to earn a return that reflects these realities is an essential ingredient to support the Company's financial position, which ultimately benefits customers by ensuring reliable service at lower long-run costs.

Q. What is your conclusion as to the reasonableness of Avista's capital structure?

A. Based on my evaluation, I concluded that a common equity ratio of 50.76 percent represents a reasonable capitalization for Avista. This conclusion was based on the following findings:

- The common equity ratio implied by Avista's capital structure falls within the range of capitalizations maintained by the proxy groups of utilities based on data at year-end and near-term expectations;
- Avista's 50.76 percent common equity ratio falls below the 53.79 percent average for the proxy group of gas utilities at year-end 2009. Similarly, Avista's requested equity ratio falls short of the 58.5 percent equity ratio based on Value Line's expectations for these utilities over the near-term. Because a capitalization that contains relatively more debt leverage implies greater financial risk, it also implies a higher required rate of return to compensate investors for bearing additional uncertainty.

Q. What did you conclude with respect to the reasonableness of Avista's requested ROE?

A. Considering investors' expectations for capital markets and the need to support financial integrity and fund crucial capital investment even under adverse circumstances, I concluded that Avista's requested ROE of 10.9 percent is reasonable and, if anything, understated. Based on my evaluation, I determined that:

- Because Avista's requested ROE of 10.9 percent falls in the bottom end of my recommended range, it represents a conservative estimate of investors' required rate of return;
- The reasonableness of a 10.9 percent minimum ROE for Avista is also supported by the need to consider the Company's credit standing, which remains relatively weak;
- The reasonableness of a 10.9 percent ROE for Avista is also supported by the greater risks associated with the Company's lower credit ratings as compared with the proxy groups;
- My conclusion that a 10.9 percent ROE for Avista is a conservative estimate of investors' required return is also reinforced by the lack of a weather normalization adjustment mechanism ("WNA") in Oregon for Avista, and the fact that, unlike some utilities in Oregon, Avista does not benefit from a decoupling mechanism that provides recovery of fixed costs as customer usage changes.

II. FUNDAMENTAL ANALYSES

Q. What is the purpose of this section?

A. As a predicate to subsequent quantitative analyses, this section briefly reviews the operations and finances of Avista. In addition, it examines the risks and prospects for the utility industry and conditions in the capital markets and the general economy. An understanding of the fundamental factors driving the risks and prospects of utilities is essential in developing an informed opinion of investors' expectations and requirements that are the basis of a fair ROE.

A. Avista Corp.

Q. Briefly describe the operations and finances of Avista.

A. Avista is engaged primarily in the procurement, transmission, and distribution of natural gas and electric energy, as well as other energy-related businesses. The Avista Utilities operating division is comprised of state-regulated utility activities, including retail natural gas and electric distribution and transmission services and energy generation. In addition to providing gas distribution service in 4,000 square miles of northeast and southwest Oregon, Avista's utility segment also provides natural gas and electric utility service within a 26,000 square mile area of eastern Washington and northern Idaho.

Q. Please describe Avista's gas utility operations.

A. At December 31, 2009, Avista supplied natural gas to approximately 314,000 customers in parts of Oregon, Idaho, and Washington. Natural gas sales to residential customers accounted for approximately 60 percent of total retail gas deliveries, while commercial customers made up 37 percent. Avista transports gas for large industrial customers, which purchase their own natural gas requirements through other parties. Several of Avista's largest natural gas customers are served under individual transportation contracts, which are subject to regulatory review and approval. During 2009, transportation sales accounted for approximately 16 percent of total natural gas deliveries. Avista obtains its gas supply from a variety of domestic and Canadian sources, through both long-term and spot market purchases. As well as owning a one-third interest in the Jackson Prairie natural gas storage facilities, Avista contracts with Northwest Natural Gas Company to obtain storage service from its Mist facility and has contracted for capacity delivery rights on six pipeline networks. Avista's retail gas distribution operations are subject to the jurisdiction of the OPUC, WUTC, and the IPUC. While Avista has natural gas trackers in place that allow it to pass-through a portion of changes in natural gas costs to customers, it currently does not have any regulatory mechanisms in Oregon to adjust for the impact of abnormal weather on earnings, or for changes in retail loads related to energy efficiency or price elasticity.

B. Natural Gas Utility Industry

Q. How have investors' risk perceptions for the utility industry evolved?

A. Beginning in approximately 1980, the natural gas industry was buffeted by decreasing demand and prices, a natural gas glut, an ever-changing federal regulatory environment, and increased competition among participants and with other fuels. These developments spawned striking structural changes, not only within the pipeline segment of the industry, but for natural gas local distribution companies ("LDCs") as well, with both experiencing "bypass" as large commercial, industrial, and wholesale customers sought to acquire gas supplies at the lowest possible cost. Structural changes within the utility industry have forced LDCs and electric utilities to confront new complexities and risks entailed in actively contracting for economical and secure energy supplies. Coupled with an increasingly competitive market environment, these structural changes have resulted in LDCs having greater business and operating risk.

Implementation of structural change and related events caused investors to rethink their assessment of the relative risks associated with the utility industry. The past decade witnessed steady erosion in credit quality throughout the utility industry, both as a result of revised perceptions of the risks in the industry and the weakened finances of the utilities themselves. S&P recently reported that the majority of the companies in the utility sector now fall in the triple-B rating category.[3]

Q. Is the potential for energy market volatility an ongoing concern for investors?

A. Yes. In recent years LDCs and their customers have had to contend with dramatic fluctuations in gas costs due to ongoing price volatility in the spot markets. S&P concluded that "natural gas prices have proven to be very volatile" and warned of a "turbulent journey" due to the uncertainty associated with future fluctuations in energy costs,[4] with Moody's warning investors of ongoing exposure to "extremely volatile" energy commodity costs.[5] Fitch has also highlighted the challenges that fluctuations in natural gas prices can have for utilities:

> From their September 2007 low of $5.29, spot natural gas prices as reported at Henry Hub rose 150% to $13.31 in early July 2008 and declined 57% to $5.68 per million British thermal unit (mmBtu) on Dec. 10, 2008. The sharp run-up and subsequent collapse of natural gas prices in 2008 is emblematic of the extreme price volatility that characterizes the commodity and is likely to persist in the future.[6]

While lower consumption brought about by the economic slowdown and higher production levels have contributed to a significant decline in gas costs, investors recognize the potential that such trends could quickly reverse. S&P observed that "short-term price

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[3] Standard & Poor's Corporation, "Issuer Ranking: U.S. Regulated Electric Utilities, Strongest To Weakest," *RatingsDirect* (Sep. 9, 2010).
[4] Standard & Poor's Corporation, "Top Ten Credit Issues Facing U.S. Utilities," *RatingsDirect* (Jan. 29, 2007).
[5] Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* (Aug. 2007).
[6] Fitch Ratings, Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," *Global Power North American Special Report* (Dec. 22, 2008).

volatility from numerous possibilities … is always possible,"[7] while Fitch noted, "uncertainty regarding energy prices, in particular natural gas costs, has made planning for the future even more problematic."[8] Moody's concluded that natural gas "remains highly volatile," and observed that utilities remain exposed to "volatile commodity prices … which can wreak havoc on even the strongest utility liquidity profiles."[9]

Besides discouraging potential customers from choosing natural gas, causing certain existing users to substitute alternative fuels, and leading to decreased customer usage, volatile natural gas prices have increased the risks of investing in natural gas distribution utilities and placed additional pressure on their bond ratings. Moody's echoed this sentiment, concluding that rising natural gas prices represent a challenge for LDCs because of reduced demand and margins.[10] As a result, a senior Fitch analyst concluded that investors "should exercise greater caution" when evaluating companies in the gas utility sector.[11]

Q. What other risks are faced by natural gas distribution utilities?

A. Investors are aware of the financial and regulatory pressures faced by utilities associated with the need to support significant capital investments. S&P noted that cost increases and capital projects, along with uncertain load growth, were a significant challenge

[7] Standard & Poor's Corporation, "Top 10 Investor Questions: U.S. Regulated Electric Utilities," *RatingsDirect* (Jan. 22, 2010).
[8] Fitch Ratings, Ltd., "Electric Utility Capital Spending: The Show Will Go On," *Global Power U.S. and Canada Special Report* (Oct. 14, 2009).
[9] Moody's Investors Service, "U.S. Electric Utilities Face Challenges Beyond Near-Term," *Industry Outlook* (Jan. 2010).
[10] Moody's Investors Service, "North American Natural Gas Transmission & Distribution," *Industry Outlook* (Sep. 2007).
[11] Lapson, Ellen, "Rising Unit Costs & Credit Quality: Warning Signals," *Public Utilities Fortnightly* (Feb. 1, 2006).

to the utility industry.[12] Fitch echoed this assessment, concluding that a combination of high capital expenditures and relatively weak demand "will continue to pressure credit quality and require base rate increases in 2010 and beyond."[13] As discussed in the testimony of Mr. Mark T. Theis, Avista will require capital investment to meet customer growth, provide for necessary maintenance and replacements of utility infrastructure, as well as fund new investment in gas distribution facilities. Maintaining financial integrity and flexibility will be instrumental in attracting the capital necessary to fund these projects in an effective manner.

In addition, LDCs such as Avista continue to face the same ongoing challenges and risks that have confronted them in the past, including those related to inflation, weather, rate regulation, customer usage and growth, non-rate regulatory changes, tax law changes, environmental laws and regulations, operating hazards, general economic conditions, and capital market changes, as well as extraordinary risks such as legal liabilities and natural disasters.

C. Impact of Capital Market Conditions

Q. What are the implications of recent capital market conditions?

A. The deep financial and real estate crisis that the country experienced in late 2008, and continuing into 2009 led to unprecedented price fluctuations in the capital markets as investors dramatically revised their risk perceptions and required returns. As a result of investors' trepidation to commit capital, stock prices declined sharply while the yields on corporate bonds experienced a dramatic increase. While conditions improved significantly

[12] Standard & Poor's Corporation, "Industry Economic And Ratings Outlook," *RatingsDirect* (Feb. 2, 2010).
[13] Fitch Ratings Ltd., "U.S. Utilities, Power, and Gas 2010 Outlook," *Global Power North America Special Report* (Dec. 4, 2009).

since the depths of the crisis, investors have had to confront ongoing fluctuation in share prices and stress in the credit markets. As the Wall Street Journal noted in February 2010:

> Stocks pulled out of a 167-point hole with a late rally Friday, capping a wild week reminiscent of the most volatile days of the credit crisis. … It was a return to the unusual relationships, or correlations, seen at major flash points over the past two years when investors fled risky assets and jumped into safe havens. This market behavior, which has reasserted itself repeatedly since the financial crisis began, suggests that investment decisions are still being driven more by government support and liquidity concerns than market fundamentals.[14]

In response to renewed capital market uncertainties initiated in the summer of 2010 by concerns over the European sovereign debt crisis and the sustainability of economic growth, investors once again fled to the safety of U.S. Treasury bonds, and stock prices have experienced renewed volatility. In addition, investors' risk premiums have widened, as evidenced by rising spreads between the yields on U.S. Treasuries compared to corporate bonds.

With respect to utilities specifically, as of August 2010, the Dow Jones Utility Average stock index remained more than 25 percent below the previous high reached in May 2008. This sell-off in common stocks and sharp fluctuations in utility bond yields reflect the fact that the utility industry was not immune to the impact of financial market turmoil and the ongoing economic downturn. As the Edison Electric Institute ("EEI") noted in a letter to congressional representatives as the financial crisis intensified, capital market uncertainties have serious implications for utilities and their customers:

[14] Gongloff, Mark, "Stock Rebound Is a Crisis Flashback – Late Surge Recalls Market's Volatility at Peak of Credit Difficulties; Unusual Correlations," *Wall Street Journal* at B1 (Feb. 6, 2010).

> In the wake of the continuing upheaval on Wall Street, capital markets are all but immobilized, and short-term borrowing costs to utilities have already increased substantially. If the financial crisis is not resolved quickly, financial pressures on utilities will intensify sharply, resulting in higher costs to our customers and, ultimately, could compromise service reliability.[15]

An October 1, 2008 *Wall Street Journal* report confirmed that utilities had been forced to delay borrowing or pursue more costly alternatives to raise funds.[16] In December 2008, Fitch confirmed "sharp repricing of and aversion to risk in the investment community," and noted that the disruptions in financial markets and the fundamental shift in investors' risk perceptions had increased the cost of capital for utilities.[17]

More recently, in assessing the impact of the downturn on the utility sector, Fitch concluded, "While utilities maintained relatively good market access during the credit crisis, the cost of capital is higher than prior to the credit crisis, and bank credit remains relatively tight."[18] Similarly, S&P noted that while utilities were expected to maintain access to credit in 2010, such access will be "on more demanding terms than in previous years,"[19] with Moody's noting that "costs associated with credit facilities have increased significantly."[20]

[15] *Letter to House of Representatives*, Thomas R. Kuhn, President, Edison Electric Institute (Sep. 24, 2008).
[16] Smith, Rebecca, "Corporate News: Utilities' Plans Hit by Credit Markets," *Wall Street Journal* at B4 (Oct. 1, 2008).
[17] Fitch Ratings Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," *Global Power North America Special Report* (Dec. 22. 2008).
[18] Fitch Ratings Ltd., "Electric Utility Capital Spending: The Show Will Go On," *Global Power U.S. and Canada Special Report* (Oct. 14, 2009).
[19] Standard & Poor's Corporation, "Ratings Roundup: Ratings Trend In Electric Utility Sector Turns More Negative In First Quarter Of 2010," *RatingsDirect* (Apr. 16, 2010).
[20] Moody's Investors Service, "U.S. Electric Utilities Face Challenges Beyond Near-Term," *Industry Outlook* (Jan. 2010).

Q. How do interest rates on long-term bonds compare with those projected for the next few years?

A. Table WEA-1 below compares current interest rates on 30-year Treasury bonds, triple-A rated corporate bonds, and double-A rated utility bonds with near-term projections from the Value Line Investment Survey ("Value Line"), IHS Global Insight, and the EIA:

TABLE WEA-1
INTEREST RATE TRENDS

	2011	2012	2013	2014	2015	Current (a)
30-Yr. Treasury						
Value Line (b)	4.4%	5.0%	5.3%	6.0%	--	3.8%
IHS Global Insight (c)	4.8%	5.0%	5.1%	5.9%	5.9%	3.8%
AAA Corporate						
Value Line (b)	5.3%	6.0%	6.4%	6.8%	--	4.5%
IHS Global Insight (c)	5.6%	6.0%	6.1%	6.7%	6.8%	4.5%
S&P (d)	4.8%	5.7%	6.2%	--	--	4.5%
AA Utility						
IHS Global Insight (c)	5.8%	6.2%	6.3%	7.2%	7.2%	4.8%
EIA (e)	6.4%	6.5%	6.8%	7.2%	7.2%	4.8%

(a) Based on monthly average bond yields for August 2010 reported at www.credittrends.moodys.com and http://www.federalreserve.gov/releases/h15/data.htm.
(b) The Value Line Investment Survey, Forecast for the U.S. Economy (Aug. 27, 2010).
(c) IHS Global Insight, The U.S. Economy: The 30-Year Focus" (First-Quarter 2010) at Table 34.
(d) Standard & Poor's Corporation, "U.S. Economic Forecast: Cool Summer Breeze Or Severe Headwind?," RatingsDirect (Aug. 17, 2010).
(e) Energy Information Administration, Annual Energy Outlook 2010 (May 11, 2010) at Table 20.

As evidenced above, there is a clear consensus that the cost of permanent capital will be higher in the 2011-2015 timeframe than it is currently. As a result, current cost of capital estimates are likely to understate investors' requirements at the time the outcome of this proceeding becomes effective and beyond.

Return on Equity

Q. What do these events imply with respect to the ROE for Avista?

A. No one knows the future of our complex global economy. We know that the financial crisis had been building for a long time, and few predicted that the economy would fall as rapidly as it did, or that corporate bond yields and stock prices would fluctuate as dramatically as they have. While conditions in the economy and capital markets appear to have stabilized significantly since 2009, investors continue to react swiftly and negatively to any future signs of trouble in the financial system or economy. Given the importance of reliable gas utility service for customers, it would be unwise to ignore investors' increased sensitivity to risk in evaluating Avista's ROE. Similarly, the Company's capital structure must also preserve the financial flexibility necessary to maintain access to capital even during times of unfavorable market conditions.

D. Support For Avista's Credit Standing

Q. What credit ratings have been assigned to Avista?

A. Avista has been assigned a corporate credit rating of "BBB-" by S&P and an issuer default rating of "BBB-" by Fitch. Moody's has assigned the Company an issuer rating of "Baa3". S&P and Moody's have revised their credit outlook on Avista to "positive", indicating the potential for higher ratings going forward.[21] The current ratings assigned by S&P, Moody's, and Fitch represent the lowest rung on the ladder of the investment grade scale.

[21] Standard & Poor's Corporation, "Research Update: Outlook On Avista Corp. Credit Rating Revised To Positive; Ratings Affirmed," *RatingsDirect* (Aug. 10, 2009); Moody's Investors Service, "Ratings Action: Avista Corp.," *Global Credit Research Ratings Action* (Aug. 12, 2009).

Q. How does Avista's relative credit standing compare with others in the utility industry?

A. Avista's credit ratings remain at the very bottom of the investment grade scale, and in a recent report by S&P ranking U.S. regulated utilities from strongest to weakest, Avista was ranked 145 out of the total 181 companies with investment grade credit ratings.[22] Meanwhile, in a ranking of electric and gas utility parent companies, Fitch placed Avista at 34th position out of 49 companies.[23]

Q. What are the implications of Avista's relative credit standing, given the potential for further dislocations in the capital markets?

A. As documented earlier and in the testimony of Mr. Thies, investors' concerns are magnified by the fact that its credit standing remains relatively weak. The Company's efforts to regain investment grade credit ratings have been successful, but Avista's finances remain pressured.

Fitch observed that when credit market conditions are unsettled, "'flight to quality' is selective within the [utility] sector, favoring companies at higher rating levels."[24] Because Avista's ratings are at the very bottom of the investment grade barrel, there is no backstop in the event of a recurring capital market crisis and reduced flexibility to respond to other challenges. Further strengthening Avista's financial integrity and continued progress in raising

[22] Standard & Poor's Corporation, "Issuer Ranking: U.S. Regulated Electric Utilities, Strongest To Weakest," *RatingsDirect* (Sep. 9, 2010).
[23] Fitch Ratings Ltd., "U.S. Utilities, Power, and Gas 2010 Outlook," *Global Power North America Special Report* (Dec. 4, 2009).
[24] *Id.*

the Company's credit standing is imperative to ensure the capability to maintain an investment grade rating while confronting potential challenges.

Moreover, the negative impact of declining credit quality on a utility's capital costs and financial flexibility becomes more pronounced as debt ratings move down the scale from investment to non-investment grade. As the Chairman of the New York State Public Service Commission noted in his role as spokesman for the National Association of Regulatory Utility Commissioners:

> While there is a large difference between A and BBB, there is an even brighter line between Investment Grade (BBB-/Baa3 bond ratings by S&P/Moody's, and higher) and non-Investment Grade (Junk) (BB+/Ba1 and lower). The cost of issuing non-investment grade debt, assuming the market is receptive to it, has in some cases been hundreds of basis points over the yield on investment grade securities. To me this suggests that you do not want to be rated at the lower end of the BBB range because an unexpected shock could move you outside the investment grade range.[25]

Considering the uncertain state of economy and financial markets, competition with other investment alternatives, and investors' sensitivity to the potential for market volatility, greater credit strength is a key ingredient in maintaining access to capital at reasonable cost. With Avista's credit ratings poised on the precipice between investment grade and junk bond status, the stakes associated with an inadequate rate of return are increased dramatically.

[25] Brown, George, "Credit and Capital Issues Affecting the Electric Power Industry," *Federal Energy Regulatory Commission Technical Conference* (Jan. 13, 2009).

III. CAPITAL MARKET ESTIMATES

Q. What is the purpose of this section?

A. In this section, I develop capital market estimates of the cost of common equity. First, I address the concept of the cost of common equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, I describe DCF and CAPM analyses conducted to estimate the cost of common equity for benchmark groups of comparable risk firms and evaluate expected earned rates of return for utilities. Finally, I examine flotation costs, which are properly considered in evaluating a fair rate of return on equity.

A. Economic Standards

Q. What role does the ROE play in a utility's rates?

A. The return on common equity is the cost of inducing and retaining equity investment in the utility's physical plant and assets. This investment is necessary to finance the asset base needed to provide utility service. Competition for investor funds is intense and investors are free to invest their funds wherever they choose. They will commit money to a particular investment only if they expect it to produce a return commensurate with those from other investments with comparable risks. Moreover, the return on common equity is integral in achieving the sound regulatory objectives of rates that are sufficient to: 1) fairly compensate capital investment in the utility, 2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and 3) maintain the utility's financial integrity. Meeting these objectives allows the utility to fulfill its obligation to provide reliable service while meeting the needs of customers through necessary system expansion.

Q. What fundamental economic principle underlies this cost of equity concept?

A. Underlying the concept of the cost of equity is the fundamental notion that investors are risk averse, and will willingly bear additional risk only if they expect compensation for doing so. The required rate of return for a particular asset at any point in time is a function of: 1) the yield on risk-free assets, and 2) its relative risk, with investors demanding correspondingly larger risk premiums for assets bearing greater risk. Given this risk-return tradeoff, the required rate of return (k) from an asset (i) can be generally expressed as:

$$k_i = R_f + RP_i$$

where: R_f = Risk-free rate of return; and
RP_i = Risk premium required to hold risky asset i.

Q. Is this risk-return tradeoff limited to differences between firms?

A. No. The risk-return tradeoff principle applies not only to investments in different firms, but also to different securities issued by the same firm. The securities issued by a utility vary considerably in risk because they have different characteristics and priorities. Secured long-term debt is senior among all capital in its claim on a utility's net revenues and is, therefore, the least risky. The last investors in line are common shareholders. They receive only the net revenues, if any, remaining after all other claimants have been paid. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by the utility's senior, long-term debt.

Q. Is the cost of equity observable in the capital markets?

A. No. Unlike debt capital, there is no contractually guaranteed return on common equity capital since shareholders are the residual owners of the utility. Because it is unobservable, the cost of equity for a particular utility must be estimated by analyzing information about capital market conditions generally, assessing the relative risks of the company specifically, and employing various quantitative methods that focus on investors' current required rates of return. These various quantitative methods typically attempt to infer investors' required rates of return from stock prices, interest rates, or other capital market data.

Q. Did you rely on a single method to estimate the cost of equity for Avista?

A. No. In my opinion, no single method or model should be relied on by itself to determine a utility's cost of common equity because no single approach can be regarded as definitive. For example, a publication of the Society of Utility and Financial Analysts (formerly the National Society of Rate of Return Analysts), concluded that:

> Each model requires the exercise of judgment as to the reasonableness of the underlying assumptions of the methodology and on the reasonableness of the proxies used to validate the theory. Each model has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Each method proceeds from different fundamental premises, most of which cannot be validated empirically. Investors clearly do not subscribe to any singular method, nor does the stock price reflect the application of any one single method by investors.[26]

Similarly, the OPUC has also considered the results of alternative methods in establishing allowed ROEs for utilities under its jurisdiction. Therefore, I used both the DCF and CAPM

[26] Parcell, David C., "The Cost of Capital – A Practitioner's Guide," *Society of Utility and Regulatory Financial Analysts* at Part 2, p. 4 (1997).

methods to estimate the cost of common equity. In addition, I also evaluated a fair ROE using an earnings approach based on investors' current expectations in the capital markets. In my opinion, comparing estimates produced by one method with those produced by other approaches ensures that the estimates of the cost of common equity pass fundamental tests of reasonableness and economic logic.

B. Proxy Groups

Q. How did you implement these quantitative methods to estimate the cost of common equity for Avista's jurisdictional gas utility operations?

A. Application of the DCF model and other quantitative methods to estimate the cost of common equity requires observable capital market data, such as stock prices. Moreover, even for a firm with publicly traded stock, the cost of common equity can only be estimated. As a result, applying quantitative models using observable market data only produces an estimate that inherently includes some degree of observation error. Thus, the accepted approach to increase confidence in the results is to apply the DCF model and other quantitative methods to a proxy group of publicly traded companies that investors regard as risk comparable.

Q. What specific proxy group of utilities did you rely on for your analysis?

A. In order to reflect the risks and prospects associated with Avista's jurisdictional gas utility operations, my analyses focused on a reference group of twelve publicly traded firms included by Value Line in their Natural Gas Utility industry group. I refer to this group as the "Gas Utility Proxy Group". Given that these utilities are all engaged in gas utility operations and classified by Value Line as gas utilities, investors are likely to regard this group as facing similar market conditions and having comparable risks and prospects.

In addition, I also considered quantitative estimates of investors' required rate of return for those utilities followed by Value Line with: (1) both gas and electric utility operations, (2) S&P corporate credit ratings of "BBB-", "BBB", or "BBB+", (2) a Value Line Safety Rank of "1" to "3", and (3) a Value Line Financial Strength Rating of "B+" or higher. These criteria resulted in a proxy group composed of seventeen companies, which I will refer to as the "Combination Utility Proxy Group."

Q. What other proxy group did you consider in evaluating a fair ROE for Avista?

A. Under the regulatory standards established by *Hope* and *Bluefield*, the salient criterion in establishing a meaningful benchmark to evaluate a fair rate of return is relative risk, not the particular business activity or degree of regulation. Utilities must compete for capital, not just against firms in their own industry, but with other investment opportunities of comparable risk. With regulation taking the place of competitive market forces, required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition. Consistent with this accepted regulatory standard, I also applied the DCF model to a reference group of comparable risk companies in the non-utility sectors of the economy. I refer to this group as the "Non-Utility Proxy Group".

Q. Do utilities have to compete with non-regulated firms for capital?

A. Yes. The cost of capital is an opportunity cost based on the returns that investors could realize by putting their money in other alternatives. Clearly, the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment, and there are a plethora of other enterprises available to investors beyond those in the utility industry. Utilities must compete for capital, not just against firms in their own industry, but with other investment opportunities of comparable risk. With regulation taking the place of competitive market forces, required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition.

Q. Is it consistent with the *Bluefield* and *Hope* cases to consider required returns for non-utility companies?

A. Yes. Returns in the competitive sector of the economy form the very underpinning for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets. The Supreme Court has recognized that it is the degree of risk, not the nature of the business, which is relevant in evaluating an allowed ROE for a utility. The *Bluefield* case refers to "business undertakings attended with comparable risks and uncertainties." It does not restrict consideration to other utilities. Similarly, the *Hope* case states:

> By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.

As in the *Bluefield* decision, there is nothing to restrict "other enterprises" solely to the utility industry.

Q. What criteria did you apply to develop the Non-Utility Proxy Group?

A. My comparable risk proxy group was composed of those U.S. companies followed by Value Line that: 1) pay common dividends; 2) have a Safety Rank of "1"; 3) have a Financial Strength Rating of "B++" or greater; 4) have a beta of 0.75 or less; and, 5) have investment grade credit ratings from S&P.

Q. Do these criteria provide objective evidence to evaluate investors' risk perceptions?

A. Yes. Credit ratings are assigned by independent rating agencies for the purpose of providing investors with a broad assessment of the creditworthiness of a firm. Ratings generally extend from triple-A (the highest) to D (in default). Other symbols (*e.g.*, "A+") are used to show relative standing within a category. Because the rating agencies' evaluation includes virtually all of the factors normally considered important in assessing a firm's relative credit standing, corporate credit ratings provide a broad, objective measure of overall investment risk that is readily available to investors. Widely cited in the investment community and referenced by investors, credit ratings are also frequently used as a primary risk indicator in establishing proxy groups to estimate the cost of common equity.

Apart from the broad assessment of investment risk provided by credit ratings, other quality rankings published by investment advisory services also provide relative assessments of risk that are considered by investors in forming their expectations. Given that Value Line is perhaps the most widely available source of investment advisory information, its rankings provide useful guidance regarding the risk perceptions of investors. The Safety Rank is Value Line's primary risk indicator and ranges from "1" (Safest) to "5" (Most Risky). This overall risk measure is intended to capture the total risk of a stock, and incorporates elements of stock price stability and financial strength. The Financial Strength Rating is designed as a guide to overall financial strength and creditworthiness, with the key inputs including financial leverage, business volatility measures, and company size. Value Line's Financial Strength Ratings range from "A++" (strongest) down to "C" (weakest) in nine steps. Finally, Value Line's beta measures the volatility of a security's price relative to the market as a whole. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00.

Q. How do the overall risks of your proxy groups compare with Avista?

A. As shown below, Table WEA-2 compares the Utility Proxy Group, Combination Proxy Group, and Non-Utility Proxy Group with Avista across four key indicators of investment risk:

TABLE WEA-2
COMPARISON OF RISK INDICATORS

	S&P	Value Line		
	Credit Rating	Safety Rank	Financial Strength	Beta
Gas Utility Group	A-	2	B++	0.69
Combination Utility Group	BBB	2	B++	0.75
Non-Utility Proxy Group	A	1	A+	0.65
Avista	BBB-	2	B++	0.70

Considered together, a comparison of these objective measures indicates that the risks investors associate with Avista are comparable to, or exceed those of the proxy groups. As a result, the cost of equity estimates indicated by my analyses provide a conservative estimate of investors' required rate of return for Avista.

C. Discounted Cash Flow Analyses

Q. How are DCF models used to estimate the cost of equity?

A. DCF models attempt to replicate the market valuation process that sets the price investors are willing to pay for a share of a company's stock. The model rests on the assumption that investors evaluate the risks and expected rates of return from all securities in the capital markets. Given these expectations, the price of each stock is adjusted by the market until investors are adequately compensated for the risks they bear. Therefore, we can look to the market to determine what investors believe a share of common stock is worth. By estimating the cash flows investors expect to receive from the stock in the way of future dividends and capital gains, we can calculate their required rate of return. In other words, the cash flows that investors expect from a stock are estimated, and given its current market price, we can "back-into" the discount rate, or cost of equity, that investors implicitly used in bidding the stock to that price.

Q. What market valuation process underlies DCF models?

A. DCF models are based on the assumption that the price of a share of common stock is equal to the present value of the expected cash flows (i.e., future dividends and stock price) that will be received while holding the stock, discounted at investors' required rate of return. Rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form. This constant growth form of the DCF model is customarily used to estimate the cost of equity in rate cases: [27]

$$P_0 = \frac{D_1}{k_e - g}$$

where: P_0 = Current price per share;
D_1 = Expected dividend per share in the coming year;
K_e = Cost of equity; and,
g = Investors' long-term growth expectations.

The cost of equity (K_e) can be isolated by rearranging terms:

$$k_e = \frac{D_1}{P_0} + g$$

The constant growth DCF model recognizes that the rate of return to stockholders consists of two parts: 1) dividend yield (D_1/P_0), and 2) growth (g). In other words, investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation.

Q. How is the constant growth form of the DCF model typically used to estimate the cost of equity?

A. The first step in implementing the constant growth DCF model is to determine the expected dividend yield (D_1/P_0) for the firm in question. This is usually calculated based on an estimate of dividends to be paid in the coming year divided by the current price of the stock. The second, and more controversial, step is to estimate investors' long-term growth

[27] The constant growth DCF model is dependent on a number of strict assumptions, which in practice are never strictly met. These include a constant growth rate for both dividends and earnings; a stable dividend payout ratio; the discount rate exceeds the growth rate; a constant growth rate for book value and price; a constant earned rate of return on book value; no sales of stock at a price above or below book value; a constant price-earnings ratio; a constant discount rate (*i.e.*, no changes in risk or interest rate levels and a flat yield curve); and all of the above extend to infinity.

expectations (*g*) for the firm. The final step is to sum the firm's dividend yield and estimated growth rate to arrive at an estimate of its cost of equity.

Q. How was the dividend yield for the Gas Utility Proxy Group determined?

A. Estimates of dividends to be paid by each of these utilities over the next twelve months, obtained from Value Line, served as D_1. This annual dividend was then divided by the corresponding stock price for each utility to arrive at the expected dividend yield. The expected dividends, stock prices, and resulting dividend yields for the firms in the Gas Utility Proxy Group are presented on Schedule WEA-1. As shown there, dividend yields for the firms in the Gas Utility Proxy Group ranged from 2.9 percent to 5.3 percent.

Q. What is the next step in applying the constant growth DCF model?

A. The next step is to evaluate long-term growth expectations, or "*g*", for the firm in question. In constant growth DCF theory, earnings, dividends, book value, and market price are all assumed to grow in lockstep, and the growth horizon of the DCF model is infinite. But implementation of the DCF model is more than just a theoretical exercise; it is an attempt to replicate the mechanism investors used to arrive at observable stock prices. A wide variety of techniques can be used to derive growth rates, but the only "*g*" that matters in applying the DCF model is the value that investors expect.

Q. Are historical growth rates likely to be representative of investors' expectations for utilities?

A. No. If past trends in earnings, dividends, and book value are to be representative of investors' expectations for the future, then the historical conditions giving rise to these growth rates should be expected to continue. That is clearly not the case for utilities, where structural and industry changes have led to declining dividends, earnings pressure, and, in many cases, significant write-offs. While these conditions serve to depress historical growth measures, they are not representative of long-term growth for the utility industry or the expectations that investors have incorporated into current market prices. As a result, historical growth measures for utilities do not currently meet the requirements of the DCF model.

Q. What are investors most likely to consider in developing their long-term growth expectations?

A. While the DCF model is technically concerned with growth in dividend cash flows, implementation of this DCF model is solely concerned with replicating the forward-looking evaluation of real-world investors. In the case of utilities, dividend growth rates are not likely to provide a meaningful guide to investors' current growth expectations. This is because utilities have significantly altered their dividend policies in response to more accentuated business risks in the industry, with the payout ratio for gas utilities falling from approximately 75 percent historically to on the order of 60 percent.[28] As a result of this trend towards a more conservative payout ratio, dividend growth in the utility industry has remained largely stagnant as utilities conserve financial resources to provide a hedge against heightened uncertainties.

As payout ratios for firms in the utility industry trended downward, investors' focus has increasingly shifted from dividends to earnings as a measure of long-term growth. Future

[28] The Value Line Investment Survey (Mar. 29, 1996 at 472, Sep. 10, 2010 at 547).

trends in earnings, which provide the source for future dividends and ultimately support share prices, play a pivotal role in determining investors' long-term growth expectations. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community. As noted in *Finding Reality in Reported Earnings* published by the Association for Investment Management and Research:

> [E]arnings, presumably, are the basis for the investment benefits that we all seek. "Healthy earnings equal healthy investment benefits" seems a logical equation, but earnings are also a scorecard by which we compare companies, a filter through which we assess management, and a crystal ball in which we try to foretell future performance.[29]

Value Line's near-term projections and its Timeliness Rank, which is the principal investment rating assigned to each individual stock, are also based primarily on various quantitative analyses of earnings. As Value Line explained:

> The future earnings rank accounts for 65% in the determination of relative price change in the future; the other two variables (current earnings rank and current price rank) explain 35%.[30]

The fact that investment advisory services focus primarily on growth in earnings indicates that the investment community regards this as a superior indicator of future long-term growth. Indeed, "A Study of Financial Analysts: Practice and Theory," published in the *Financial Analysts Journal*, reported the results of a survey conducted to determine what analytical techniques investment analysts actually use.[31] Respondents were asked to rank the relative importance of earnings, dividends, cash flow, and book value in analyzing securities.

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[29] Association for Investment Management and Research, "Finding Reality in Reported Earnings: An Overview" at 1 (Dec. 4, 1996).
[30] The Value Line Investment Survey, *Subscriber's Guide* at 53.
[31] Block, Stanley B., "A Study of Financial Analysts: Practice and Theory", *Financial Analysts Journal* (July/August 1999).

Of the 297 analysts that responded, only 3 ranked dividends first while 276 ranked it last. The article concluded:

> Earnings and cash flow are considered far more important than book value and dividends.[32]

More recently, the *Financial Analysts Journal* reported the results of a study of the relationship between valuations based on alternative multiples and actual market prices, which concluded, "In all cases studied, earnings dominated operating cash flows and dividends."[33]

Q. Do the growth rate projections of security analysts consider historical trends?

A. Yes. Professional security analysts study historical trends extensively in developing their projections of future earnings. Hence, to the extent there is any useful information in historical patterns, that information is incorporated into analysts' growth forecasts.

Q. What are security analysts currently projecting in the way of growth for the firms in the Gas Utility Proxy Group?

A. The earnings growth projections for each of the firms in the Gas Utility Proxy Group reported by Value Line, Thomson Reuters ("IBES"), and Zacks Investment Research ("Zacks") are displayed on Schedule WEA-1.[34]

[32] *Id.* at 88.
[33] Liu, Jing, Nissim, Doron, & Thomas, Jacob, "Is Cash Flow King in Valuations?," *Financial Analysts Journal*, Vol. 63, No. 2 at 56 (March/April 2007).
[34] Formerly I/B/E/S International, Inc., IBES growth rates are now compiled and published by Thomson Reuters.

Q. Some argue that analysts' assessments of growth rates are biased. Is there any reason to believe these projections are inappropriate for estimating investors' required return using the DCF model?

A. No. In applying the DCF model to estimate the cost of common equity, the only relevant growth rate is the forward-looking expectations of investors that are captured in current stock prices. Investors, just like securities analysts and others in the investment community, do not know how the future will actually turn out. They can only make investment decisions based on their best estimate of what the future holds in the way of long-term growth for a particular stock, and securities prices are constantly adjusting to reflect their assessment of available information.

Any claims that analysts' estimates are not relied upon by investors are illogical given the reality of a competitive market for investment advice. If financial analysts' forecasts do not add value to investors' decision making, it would be irrational for investors to pay for these estimates. Similarly, those financial analysts who fail to provide reliable forecasts will lose out in competitive markets relative to those analysts whose forecasts investors find more credible. The reality that analyst estimates are routinely referenced in the financial media and in investment advisory publications (e.g., Value Line) implies that investors use them as a basis for their expectations.

The continued success of investment services such as Thompson Reuters and Value Line, and the fact that projected growth rates from such sources are widely referenced, provides strong evidence that investors give considerable weight to analysts' earnings projections in forming their expectations for future growth. While the projections of securities analysts may be proven optimistic or pessimistic in hindsight, this is irrelevant in assessing the expected growth that investors have incorporated into current stock prices, and any bias in analysts' forecasts – whether pessimistic or optimistic – is irrelevant if investors share analysts' views. Earnings growth projections of security analysts provide the most frequently referenced guide to investors' views and are widely accepted in applying the DCF model. As explained in *New Regulatory Finance*:

> Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of *g* [growth]. The accuracy of these forecasts in the sense of whether they turn out to be correct is not an issue here, as long as they reflect widely held expectations.[35]

Q. How else are investors' expectations of future long-term growth prospects often estimated when applying the constant growth DCF model?

A. In constant growth theory, growth in book equity will be equal to the product of the earnings retention ratio (one minus the dividend payout ratio) and the earned rate of return on book equity. Furthermore, if the earned rate of return and the payout ratio are constant over time, growth in earnings and dividends will be equal to growth in book value. Despite the fact that these conditions are seldom, if ever, met in practice, this "sustainable growth" approach may provide a rough guide for evaluating a firm's growth prospects and is frequently proposed in regulatory proceedings.

Accordingly, while I believe that analysts' forecasts provide a superior and more direct

[35] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 298 (2006).

guide to investors' growth expectations, I have included the "sustainable growth" approach for completeness. The sustainable growth rate is calculated by the formula, g = br+sv, where "b" is the expected retention ratio, "r" is the expected earned return on equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate.

Q. What is the purpose of the "sv" term?

A. Under DCF theory, the "sv" factor is a component of the growth rate designed to capture the impact of issuing new common stock at a price above, or below, book value. When a company's stock price is greater than its book value per share, the per-share contribution in excess of book value associated with new stock issues will accrue to the current shareholders. This increase to the book value of existing shareholders leads to higher expected earnings and dividends, with the "sv" factor incorporating this additional growth component.

Q. What growth rate does the earnings retention method suggest for the Gas Utility Proxy Group?

A. The sustainable, "br+sv" growth rates for each firm in the Gas Utility Proxy Group are summarized on Schedule WEA-1, with the underlying details being presented on Schedule WEA-2. For each firm, the expected retention ratio (b) was calculated based on Value Line's projected dividends and earnings per share. Likewise, each firm's expected earned rate of return (r) was computed by dividing projected earnings per share by projected net book value. Because Value Line reports end-of-year book values, an adjustment was incorporated to compute an average rate of return over the year, consistent with the theory underlying this approach to estimating investors' growth expectations. Meanwhile, the percent of common equity expected to be issued annually as new common stock (s) was equal to the product of the projected market-to-book ratio and growth in common shares outstanding, while the equity accretion rate (v) was computed as 1 minus the inverse of the projected market-to-book ratio.

Q. What other growth rate did you consider?

A. As noted earlier, the DCF model assumes that investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation over their holding period. Thus, growth in stock price is directly related to investors' expected returns, and projected stock prices from investment advisory services such as Value Line are widely reported and available to investors. In other words, projected growth in stock price is directly relevant to an analysis of the future cash flows that investors expect to receive when they purchase common stocks and is entirely consistent with the underlying basis of the DCF model.

Under the assumptions required to derive the constant growth form of the DCF model, stock price, earnings, dividends, and book value are all expected to grow at the same rate. Dr. Myron Gordon noted in his seminal article, *The Cost of Capital to a Public Utility* (1974), that growth in stock price could serve as another guide to investors' growth expectations in the constant growth DCF model, observing that, "[T]he rate of growth in the price of a stock … will respond to all of the factors mentioned above and, in addition, to the yield investors require on the share."[36] Similarly, *The Cost of Capital – A Practitioner's Guide*, published by the Society of Utility and Regulatory Financial Analysts, observed that under the assumptions of the DCF model, "The stock price grows proportionally to the growth rate."[37] Consistent with this paradigm, I also examined expected growth in each utility's stock price based on Value Line's 2013-2015 projections.

Q. What cost of common equity estimates were implied for the Gas Utility Proxy Group using the DCF model?

A. After combining the dividend yields and respective growth projections for each utility, the resulting cost of common equity estimates are shown on Schedule WEA-1.

Q. In evaluating the results of the constant growth DCF model, is it appropriate to eliminate estimates that are extreme low or high outliers?

A. Yes. In applying quantitative methods to estimate the cost of equity, it is essential that the resulting values pass fundamental tests of reasonableness and economic logic. Accordingly, DCF estimates that are implausibly low or high should be eliminated when evaluating the results of this method.

Q. How did you evaluate DCF estimates at the low end of the range?

A. It is a basic economic principle that investors can be induced to hold more risky assets only if they expect to earn a return to compensate them for their risk bearing. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by senior,

[36] Gordon, Myron J., "The Cost of Equity to a Public Utility," *MSU Public Utilities Studies* at 58 (1974).
[37] Parcell, David C., "The Cost of Capital – A Practitioner's Guide," *Society of Utility and Regulatory Financial Analysts* at 8-6 (1997).

long-term debt. As noted earlier, S&P has assigned Avista a corporate credit rating of "BBB-". Companies rated "BBB-", "BBB", and "BBB+" are all considered part of the triple-B rating category, with Moody's monthly yields on triple-B bonds averaging approximately 5.6 percent in August 2010.[38] It is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock. Consistent with this principle, the DCF results for the Utility Proxy Group must be adjusted to eliminate estimates that are determined to be extreme low outliers when compared against the yields available to investors from less risky utility bonds.

Q. Have similar tests been applied by regulators?

A. Yes. FERC has noted that adjustments are justified where applications of the DCF approach produce illogical results. FERC evaluates DCF results against observable yields on long-term public utility debt and has recognized that it is appropriate to eliminate estimates that do not sufficiently exceed this threshold. In a 2000 opinion establishing its current precedent for determining ROEs for electric utilities, for example, FERC noted:

> An adjustment to this data is appropriate in the case of PG&E's low-end return of 8.42 percent, which is comparable to the average Moody's "A" grade public utility bond yield of 8.06 percent, for October 1999. Because investors cannot be expected to purchase stock if debt, which has less risk than stock, yields essentially the same return, this low-end return cannot be considered reliable in this case.[39]

For gas utilities, FERC noted in *Kern River Gas Transmission Company* that:

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[38] Moody's Investors Service, www.credittrends.com.
[39] *Southern California Edison Company*, 92 FERC ¶ 61,070 at p. 22 (2000).

> [T]he 7.31 and 7.32 percent costs of equity for El Paso and Williams found by the ALJ are only 110 and 122 basis points above that average yield for public utility debt.[40]

The Commission upheld the opinion of Staff and the Administrative Law Judge that cost of equity estimates for these two proxy group companies "were too low to be credible."[41] More recently, FERC affirmed that, "it is reasonable to exclude any company whose low-end ROE fails to exceed the average bond yield by about 100 basis points or more."[42]

Q. What else should be considered in evaluating DCF estimates at the low end of the range?

A. As indicated earlier, while corporate bond yields have declined substantially as the worst of the financial crisis has abated, it is generally expected that long-term interest rates will rise as the economy returns to a more normal pattern of growth. As shown in Table WEA-3 below, the most recent forecasts of IHS Global Insight and the EIA imply an average triple-B bond yield of 6.88 percent for 2011, or 7.45 percent over the 5-year period 2011-2015:

[40] *Kern River Gas Transmission Company*, Opinion No. 486, 117 FERC ¶ 61,077 at P 140 & n. 227 (2006).
[41] *Id.*
[42] *Southern California Edison Co.*, 131 FERC ¶ 61,020 at P 55 (2010) ("*SoCal Edison*").

TABLE WEA-3
IMPLIED BBB BOND YIELD

	2011	**2011-15**
Projected AA Utility Yield		
IHS Global Insight (a)	5.77%	6.52%
EIA (b)	6.43%	6.82%
Average	6.10%	6.67%
BBB - AA Yield Spread (c)	0.78%	0.78%
Implied Triple-B Utility Yield	**6.88%**	**7.45%**

(a) IHS Global Insight, *The U.S. Economy: The 30-Year Focus* (First-Quarter 2010) at Table 34.
(b) Energy Information Administration, *Annual Energy Outlook 2010* at Table 20 (May 11, 2010).
(c) Based on monthly average bond yields for the six-month March - August 2010.

The increase in debt yields anticipated by IHS Global Insight and EIA is also supported by the widely-referenced Blue Chip Financial Forecasts, which projects that yields on corporate bonds will climb on the order of 70 basis points through the second quarter of 2011.[43] Consistent with these forecasts, Fitch concluded, "Interest rates are expected to rise over the course of the year from very low levels."[44]

Q. What does this test of logic imply with respect to the DCF results for the Gas Utility Proxy Group?

A. As shown on Schedule WEA-1, low-end DCF estimates ranged from 3.2 percent to 7.9 percent. Four of these estimates were below current utility bond yields, with a cost of equity estimate of 7.9 percent being barely 100 basis points above the yield on triple-B

[43] *Blue Chip Financial Forecasts*, Vol. 29, No. 2 (Jul. 1, 2010).
[44] Fitch Ratings Ltd., "U.S. Utilities, Power, and Gas 2010 Outlook," *Global Power North America Special Report* (Dec. 4, 2009).

utility bonds expected during 2011. In light of the risk-return tradeoff principle and the test applied in *SoCal Edison*, it is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock, which is the riskiest of a utility's securities. As a result, consistent with the test of economic logic applied by FERC and the upward trend expected for utility bond yields, these values provide little guidance as to the returns investors require from utility common stocks and should be excluded.

Q. Do you also recommend excluding estimates at the high end of the range of DCF results?

A. Yes. I excluded three of the DCF values for Otter Tail Corp., which all exceeded 20 percent. This is also consistent with the precedent adopted by FERC, which has established that estimates found to be "extreme outliers" should be disregarded in interpreting the results of the DCF model.[45]

Q. What cost of common equity estimates are implied by your constant growth DCF results for the Gas Utility Proxy Group?

A. As shown on Schedule WEA-1 and summarized in Table WEA-4, below, after eliminating illogical values, application of the constant growth DCF model resulted in average cost of common equity estimates ranging from 8.8 percent to 10.7 percent:

[45] *See, e.g., Bangor Hydro-Electric Co.*, 109 FERC ¶ 61,147 at P 205 (2004).

TABLE WEA-4
DCF RESULTS –UTILITY PROXY GROUP

Growth Rate	Average Cost of Equity
Earnings	
Value Line	9.8%
IBES	10.3%
Zacks	8.8%
br+sv	10.1%
Value Line Stock Price	10.7%

Q. What were the results of your constant growth DCF analysis for the Combination Utility Proxy Group?

A. I applied the constant growth DCF model to the Combination Utility Proxy Group in exactly the same manner described earlier for the Gas Utility Proxy Group. The results of my DCF analysis for the Combination Utility Proxy Group are presented in Schedule WEA-3, with the sustainable, “br+sv” growth rates being developed on Schedule WEA-4. As shown there and summarized in Table WEA-5, below, after eliminating illogical values, application of the constant growth DCF model resulted in cost of common equity estimates in the 9.6 percent to 11.5 percent range:

TABLE WEA-5
DCF RESULTS – COMBINATION UTILITY PROXY GROUP

Growth Rate	Average Cost of Equity
Earnings	
Value Line	11.5%
IBES	11.4%
Zacks	10.9%
br+sv	9.6%
Value Line Stock Price	10.3%

Q. What were the results of your constant growth DCF analysis for the Non-Utility Proxy Group?

A. The results of my constant growth DCF analysis for the Non-Utility Proxy Group, which mirror those for the two groups of utilities, are presented in Schedule WEA-5. I noted earlier that values that are implausibly low or high should be eliminated when evaluating the results of any quantitative method used to estimate the cost of equity. As highlighted on Schedule WEA-5, in addition to illogical low-end values, various DCF estimates for the firms in the Combination Utility Proxy Group exceeded 17.0 percent. I determined that, when compared with the balance of the remaining estimates, these values could be considered implausible and should be excluded.

As shown on Schedule WEA-5 and summarized in Table WEA-6, below, after eliminating illogical low and high-end values, application of the constant growth DCF model resulted in cost of common equity estimates generally in the 12 percent to 13 percent range:

TABLE WEA-6
DCF RESULTS – NON-UTILITY PROXY GROUP

Growth Rate	Average Cost of Equity
Earnings	
Value Line	11.8%
IBES	12.3%
Zacks	12.6%
br+sv	12.8%
Value Line Stock Price	13.4%

As discussed earlier, reference to the Non-Utility Proxy Group is consistent with established regulatory principles. Required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition.

Q. Are there any alternatives to the constant growth DCF model?

A. Yes, there are. The constant growth form is a simplified version of the general DCF model:

$$P_0 = \frac{D_1}{(1+k_e)^1} + \frac{D_2}{(1+k_e)^2} + \cdots + \frac{D_t}{(1+k_e)^t} + \frac{P_t}{(1+k_e)^t}$$

where: P_0 = Current price per share;
P_t = Expected future price per share in period t;
D_t = Expected dividend per share in period t;
k_e = Cost of equity.

The general, or multi-state form of the DCF model can be used to estimate the cost of equity by substituting projections for a firm's future dividends (D_t) and price (P_t) for the variables in the equation, and imputing the cost of equity (K_e) by equating the future cash flows to the current price (P_0). The OPUC has previously supported reliance on the multi-stage DCF approach.[46]

Q. Did you apply the multi-stage DCF model to estimate the cost of equity for the Gas and Combination Utility Proxy Groups?

A. Yes. As noted above, the multi-stage DCF model entails estimating the dividends investors expect to receive from holding a share of stock and the price that they expect to sell it for at some point in the future. My application of the multi-stage DCF model to the gas utility proxy group was based on a five-year holding period (2010-2014) corresponding to Value Line's forecast horizon.

[46] See Order No. 01-777 at 27.

As shown on Schedule WEA-7, expected dividends (D_t) during this holding period were based on Value Line's forecasts of 2010, 2011 and 2013-2015 dividends, with values for intervening years being interpolated. The future stock price was based on Value Line's forecast for 2013-2015. The cost of equity was then estimated by imputing the discount rate necessary to equate the projected dividends and stock price to the recent price (P_0) reported by Value Line for each of the companies in the Gas Utility Proxy Group. This approach considers both investors' near-term expectations for dividend cash flows and expectations for future capital gains.

Q. What cost of equity estimates were produced using this multi-stage DCF model?

A. As shown on Schedule WEA-7, after eliminating illogical values, the cost of equity estimates produced by this application of the multi-stage DCF model averaged 10.7 percent for the Gas Utility Proxy Group. For the Combination Utility Proxy Group, the average of the multi-stage DCF estimates (Schedule WEA-8) was 10.4 percent after excluding illogical values.

D. Capital Asset Pricing Model

Q. Please describe the CAPM.

A. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. Because investors are assumed to be fully diversified, the relevant risk of an individual asset (*e.g.*, common stock) is its volatility relative to the market as a whole, with beta reflecting the tendency of a stock's price to follow changes in the market. The CAPM is mathematically expressed as:

$$R_j = R_f + \beta_j(R_m - R_f)$$

where:
R_j = required rate of return for stock j;
R_f = risk-free rate;
R_m = expected return on the market portfolio; and,
β_j = beta, or systematic risk, for stock j.

Like the DCF model, the CAPM is an *ex-ante*, or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using estimates that reflect the expectations of actual investors in the market, not with backward-looking, historical data.

Q. How did you apply the CAPM to estimate the cost of common equity?

A. Application of the CAPM to the Gas Utility Proxy Group based on a forward-looking estimate for investors' required rate of return from common stocks is presented on Schedule WEA-9. In order to capture the expectations of today's investors in current capital markets, the expected market rate of return was estimated by conducting a DCF analysis on the dividend paying firms in the S&P 500.

The expected dividend yield over the coming year was obtained from Value Line, with the growth rate being equal to the consensus earnings growth projections for each firm published by IBES. Consistent with the methodology used to construct the S&P 500 Index, each firm's dividend yield and growth rate was weighted by its proportionate share of total market value. Based on the weighted average of the projections for the 348 individual firms, current estimates imply an average growth rate over the next five years of 10.4 percent. Combining this average growth rate with a year-ahead dividend yield of 2.6 percent results in a current cost of common equity estimate for the market as a whole (R_m) of approximately

13.0 percent. Subtracting a 3.5 percent risk-free rate based on the average yield on 20-year Treasury bonds produced a market equity risk premium of 9.5 percent.

Q. What was the source of the beta values you used to apply the CAPM?

A. I relied on the beta values reported by Value Line, which in my experience is the most widely referenced source for beta in regulatory proceedings. As noted in *New Regulatory Finance*:

> Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors. … Value Line betas are computed on a theoretically sound basis using a broadly based market index, and they are adjusted for the regression tendency of betas to converge to 1.00.[47]

As shown on page 1 of Schedule WEA-9, multiplying the 9.5 percent market risk premium by the average Value Line beta for the Gas Utility Proxy Group, and then adding the resulting risk premium to the average long-term Treasury bond yield, results in an indicated cost of equity of 10.0 percent. Applying this same CAPM approach to the firms in the Combination Utility Proxy Group implied an average cost of equity of 10.6 percent (Schedule WEA-9, page 2).

Q. What cost of common equity was indicated for the Non-Utility Proxy Group based on this forward-looking application of the CAPM?

A. As shown on page 3 of Schedule WEA-9, applying the forward-looking CAPM approach to the firms in the Non-Utility Proxy Group results in an average implied cost of common equity of 9.7 percent.

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[47] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports* at 71 (2006).

Q. Do you have any observations regarding these CAPM results?

A. Yes. Applying the CAPM is complicated by the impact of the recent capital market turmoil and recession on investors' risk perceptions and required returns. The CAPM cost of common equity estimate is calibrated from investors' required risk premium between Treasury bonds and common stocks. In response to heightened uncertainties, investors have sought a safe haven in U.S. government bonds and this "flight to safety" has pushed Treasury yields significantly lower while yield spreads for corporate debt widened. This distortion not only impacts the absolute level of the CAPM cost of equity estimate, but it affects estimated risk premiums. Economic logic would suggest that investors' required risk premium for common stocks over Treasury bonds has also increased. Thus, recent capital market conditions may cause CAPM cost of common equity estimates to understate investors' required returns for common stocks, particularly when historical data are used to calculate the market risk premium. As the Staff of the Florida Public Service Commission concluded:

> [R]ecognizing the impact the Federal Government's unprecedented intervention in the capital markets has had on the yields on long-term Treasury bonds, staff believes models that relate the investor-required return on equity to the yield on government securities, such as the CAPM approach, produce less reliable estimates of the ROE at this time.[48]

While my application of the CAPM makes every effort to incorporate investors' forward-looking expectations, the full effect of the "flight to safety" may not be captured in my market risk premium estimate.

[48] *Staff Recommendation for Docket No. 080677-E1 - Petition for increase in rates by Florida Power & Light Company*, at p. 280 (Dec. 23, 2009).

Second, the beta in CAPM theory is a measure of the investors' expected relationship of a firm's stock price to the market as a whole. Because investors' expected beta for a firm is not known, reported betas are estimated based on historical relationships. The precipitous drop and subsequent partial recovery in stock prices over the last year or so have caused many firms' historical betas to become unstable, so that reported betas may or may not reflect investors' expected beta. Because of this inherent mismatch between the historical circumstances underlying reported beta values and the current perceptions of investors, the CAPM may not accurately reflect investor's forward-looking rate of return requirements.

Forward-looking estimates of the market required rate of return may also be distorted by volatility in the capital markets and ongoing economic uncertainty. It is not clear whether reported security analysts' dividend and growth projections have kept pace with the expectations for economic recovery that have presumably driven stock prices higher; if not, there is a mismatch that under-estimates of the market required rate of return. For example, the *Wall Street Journal* reporting the results of a study confirming that analysts' growth estimates are overly pessimistic, especially following an economic downturn.[49] This incongruity between current measures of the market risk premium and historical beta values is particularly relevant during periods of heightened uncertainty and rapidly changing capital market conditions, such as those experienced recently. As a result, there is every indication that CAPM approaches fail to fully reflect the risk perceptions of real-world investors in today's capital markets, which would violate the standards underlying a fair rate of return by

[49] Denning, Liam, "Wall Streets Missed Expectations," *The Wall Street Journal* at C8 (Apr. 26, 2010).

failing to provide an opportunity to earn a return commensurate with other investments of comparable risk.

Q. Has the OPUC also recognized that the CAPM method may produce unreliable cost of equity estimates?

A. Yes. While the OPUC has relied on the CAPM approach in past determinations of the allowed ROE for utilities under its jurisdiction, it has also recognized the need to adapt its ratemaking practices to ensure that regulatory standards are met. On this basis, the OPUC has chosen to ignore the results of the CAPM method on multiple occasions, concluding:

> [I]n PacifiCorp's general rate proceeding, docket UE 116, as well as a concurrent rate proceeding for Portland General Electric, docket UE 115, we deviated from this traditional practice and declined to rely on the CAPM analysis because we did not believe the methodology produced reliable results. *See* Order No. 01-777 at 32 and 01-787 at 31. Based on growing concerns with this reliability of the CAPM methodology, and on the availability of better forecasting information, we departed from our traditional practice in the course of these ratemaking proceedings without prior rulemaking. The Commission must maintain the flexibility to effectively set fair, just and reasonable rates for the utility and its customers.[50]

E. Expected Earnings Approach

Q. What other analyses did you conduct to estimate the cost of equity?

A. As I noted earlier, I also evaluated the cost of common equity using the expected earnings method. Reference to rates of return available from alternative investments of comparable risk can provide an important benchmark in assessing the return necessary to assure confidence in the financial integrity of a firm and its ability to attract capital. This

[50] Order No. 06-379 at 10.

expected earnings approach is consistent with the economic underpinnings for a fair rate of return established by the U.S. Supreme Court. Moreover, it avoids the complexities and limitations of capital market methods and instead focuses on the returns earned on book equity, which are readily available to investors.

Q. What rates of return on equity are indicated for utilities based on the expected earnings approach?

A. Value Line reports that its analysts anticipate an average rate of return on common equity for the natural gas utility industry of 10.5 percent over its 2013-2015 forecast horizon.[51] Meanwhile, Value Line expects that electric utilities will earn an average rate of return on common equity of 11.0 percent over this same period.[52]

For the firms in the Gas Utility Proxy Group specifically, the returns on common equity projected by Value Line over its three-to-five year forecast horizon are shown on page 1 of Schedule WEA-10, with values for the Combination Utility Proxy Group being presented on page 2. Consistent with the rationale underlying the development of the br+sv growth rates, these year-end values were converted to average returns using the same adjustment factor discussed earlier and developed on Schedules WEA-2 and WEA-4, respectively. As shown on page 1 of Schedule WEA-10, Value Line's projections for the Gas Utility Proxy Group suggested an average ROE of 11.7 percent. The average indicated ROE for the Combination Utility Proxy Group (page 2 of Schedule WEA-10) was 11.0 percent.

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[51] The Value Line Investment Survey at 547 (Sep. 10, 2010).
[52] The Value Line Investment Survey at 146 (Aug. 27, 2010).

F. Flotation Costs

Q. What other considerations are relevant in setting the return on equity for Avista?

A. The common equity used to finance the investment in utility assets is provided from either the sale of stock in the capital markets or from retained earnings not paid out as dividends. When equity is raised through the sale of common stock, there are costs associated with "floating" the new equity securities. These flotation costs include services such as legal, accounting, and printing, as well as the fees and discounts paid to compensate brokers for selling the stock to the public. Also, some argue that the "market pressure" from the additional supply of common stock and other market factors may further reduce the amount of funds a utility nets when it issues common equity.

Q. Is there an established mechanism for a utility to recognize equity issuance costs?

A. No. While debt flotation costs are recorded on the books of the utility, amortized over the life of the issue, and thus increase the effective cost of debt capital, there is no similar accounting treatment to ensure that equity flotation costs are recorded and ultimately recognized. Alternatively, no rate of return is authorized on flotation costs necessarily incurred to obtain a portion of the equity capital used to finance plant. In other words, equity flotation costs are not included in a utility's rate base because neither that portion of the gross proceeds from the sale of common stock used to pay flotation costs is available to invest in plant and equipment, nor are flotation costs capitalized as an intangible asset. Unless some provision is made to recognize these issuance costs, a utility's revenue requirements will not fully reflect all of the costs incurred for the use of investors' funds. Because there is no accounting convention to accumulate the flotation costs associated with equity issues, they must be accounted for indirectly, with an upward adjustment to the cost of common equity being the most logical mechanism.

Q. What is the magnitude of the adjustment to the "bare bones" cost of common equity to account for issuance costs?

A. While there are a number of ways in which a flotation cost adjustment can be calculated, one of the most common methods used to account for flotation costs in regulatory proceedings is to apply an average flotation-cost percentage to a utility's dividend yield. Based on a review of the finance literature, *New Regulatory Finance* concluded:

> The flotation cost allowance requires an estimated adjustment to the return on equity of approximately 5% to 10%, depending on the size and risk of the issue.[53]

Alternatively, a study of data from Morgan Stanley regarding issuance costs associated with utility common stock issuances suggests an average flotation cost percentage of 3.6 percent.[54]

Issuance costs are a legitimate consideration in setting the return on equity for a utility, and applying these expense percentages to a representative dividend yield for a utility of 4.5 percent implies a flotation cost adjustment on the order of 16 to 45 basis points.

[53] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* at 323 (1994).
[54] Application of Yankee Gas Services Company for a Rate Increase, DPUC Docket No. 04-06-01, Direct Testimony of George J. Eckenroth (Jul. 2, 2004) at Exhibit GJE-11.1. Updating the results presented by Mr. Eckenroth through April 2005 also resulted in an average flotation cost percentage of 3.6%.

IV. RECOMMENDED RETURN ON EQUITY

Q. What is the purpose of this section?

A. In addition to summarizing the results of my analyses, this section examines other factors that should be considered in evaluating a fair rate of return for the Company and presents my recommended ROE range for Avista.

A. Summary of Quantitative Results

Q. Please summarize the results of your quantitative analyses.

A. The cost of equity estimates implied by my quantitative analyses are summarized in Table 3 below:

TABLE WEA-7
SUMMARY OF QUANTITATIVE RESULTS

Constant Growth DCF	Gas Utility	Combination Utility	Non-Utility
Value Line	9.8%	11.5%	11.8%
IBES	10.3%	11.4%	12.3%
Zacks	8.8%	10.9%	12.6%
br + sv	10.1%	9.6%	12.8%
Stock Price	10.7%	10.3%	13.4%
Multi-Stage DCF	10.7%	10.4%	--
CAPM	10.0%	10.6%	9.7%
Expected Earnings			
Value Line 2013-15	10.5%	11.0%	--
Utility Proxy Group	11.7%	11.0%	--

As noted earlier, the capital market crisis and ensuing recovery have created a number of problems in applying the CAPM. Based on my assessment of the relative strengths and weaknesses inherent in each method, and conservatively giving less emphasis to the upper- and lower-most boundaries of the range of results, I concluded that the cost of common equity indicated by my analyses is in the 10.5 percent to 12.0 percent range. After incorporating a minimum adjustment for flotation costs of 15 basis points to my "bare bones" cost of equity range, I concluded that my analyses indicate a fair ROE in the 10.65 percent to 12.15 percent range.

B. Other Factors

Q. How do Avista's investment risks compare to the reference groups used to estimate the cost of equity?

A. As noted earlier, the "BBB-" corporate credit rating assigned to Avista occupies the lowest rung on the investment grade ladder. Avista's credit ratings are indicative of significantly higher investment risks than the proxy groups of gas utilities and non-utility firms, which have average corporate credit ratings of "A-" and "A", respectively. Because investors require a higher rate of return to compensate them for bearing more risk, the greater investment risks implied for Avista suggests that the cost of equity is correspondingly higher.

Q. How does the lack of a weather normalization adjustment impact Avista's rate of return on equity relative to the Gas Utility Proxy Group?

A. As indicated earlier, Avista does not have a weather normalization adjustment mechanism in place to account for the impacts of abnormal weather on its Oregon-jurisdictional gas utility operations. A WNA moderates the impact of extreme weather on customers and, at the same time, dampens the volatility of a gas utility's revenues. Indeed, all but one of the eleven LDCs in the proxy group used to estimate the cost of equity have some form of weather mitigant, including decoupling mechanisms, adjustment clauses, insurance, or rate design features that make the LDC less susceptible to variations in gas consumption due to weather. As Value Line noted:

> Unseasonable warmer or colder weather can lead to volatility in results. By using these rate mechanisms, natural gas utilities are less subject to swings in profitability due to unforeseen weather conditions.[55]

As a result, while Avista remains exposed to the risks associated with abnormal weather, the reduced uncertainties associated with a WNA are at least partially accounted-for by investors and reflected in my cost of equity estimates.

Q. What other considerations are relevant in determining a reasonable rate of return on equity for Avista's jurisdictional gas utility operations?

A. In evaluating a reasonable rate of return on equity, it is also important to note that, unlike some utilities in Oregon, Avista does not benefit from elasticity or decoupling mechanisms that insulate utility margins from declining usage. As the OPUC noted in its September 2002 Order adopting a proposed stipulation for Northwest Natural Gas Company ("NW Natural"):

> The stipulation provides that an elasticity adjustment will be applied to the rates of all of NW Natural's residential and commercial customers beginning on October 1, 2002. …This adjustment will help account for the affect that rate changes have on customers usage. Under this elasticity adjustment, NW Natural will recover, on a prospective basis only, the margin shortfalls in each customer category by developing rate increments and applying them in permanent rates for each class as of October 1, 2002.
>
> …Also on October 1, 2002, NW Natural will implement a partial decoupling mechanism, under which it will defer and subsequently amortize 90

[55] The Value Line Investment Survey at 547 (Sep. 10, 2010).

> percent of the margin differentials in the residential and commercial customer groups.[56]

Avista's jurisdictional gas utility operations have experienced declines in customer usage that have translated into reduced margins. As a result, Avista's continued exposure to the uncertainties associated with the impact of price elasticity and other fluctuations in customer usage implies a greater level of risk than is faced by other utilities, including NW Natural and many of the firms in my proxy groups.

Q. What does this evidence suggest with respect to Avista's cost of equity relative to the proxy group results?

A. The higher investment risks associated with Avista's lower credit ratings and the lack of WNA or decoupling mechanism suggest that investors' required return for Avista exceeds that of the proxy groups used to estimate the cost of equity. Competition for capital resources is intense and investors are free to invest their funds wherever they choose. Denying investors the opportunity to earn a return that is commensurate with Avista's investment risks would stymie the Company's efforts to improve its credit standing and hamper its future ability to attract capital under reasonable terms, especially during periods of adverse capital market conditions.

Q. What role does regulation play in ensuring that Avista has access to capital under reasonable terms and on a sustainable basis?

A. Investors recognize that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity, particularly during times of adverse

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[56] In the Matter of Northwest Natural Gas Company Application for Public Purpose Funding and Distribution Margin Normalization, Public Utility Commission of Oregon, Order No. 02-634 (Sep. 12, 2002) at 3.

conditions. S&P concluded "the quality of regulation is at the forefront of our analysis of utility creditworthiness,"[57] and recently observed that its risk analysis focuses on the utility's ability to consistently <u>earn</u> a reasonable return:

> Notably, the analysis does not revolve around "authorized" returns, but rather on actual earned returns. We note the many examples of utilities with healthy authorized returns that, we believe, have no meaningful expectation of actually earning that return because of rate case lag, expense disallowances, etc.[58]

With respect to Avista specifically, the major bond rating agencies have explicitly cited the potential that adverse regulatory rulings could compromise the Company's credit standing. Of particular concern to investors is the impact of regulatory lag and cost-recovery on Avista's ability to earn its authorized ROE. S&P observed that rate relief will remain critical to Avista's credit outlook,[59] and concluded that:

> Regulatory lag has been a consistent issue for Avista Utilities, with the utility operations (consisting of electric and gas service in parts of Washington, Idaho, and Oregon) collectively unable on a consolidated basis to earn its authorized return on equity (ROE). On a consolidated basis, average earned ROE since 2003 has been just under 6%, based on Standard & Poor's calculations.[60]

For Avista, these concerns are magnified by the fact that its credit standing is poised on the precipice between investment and speculative grade ratings. While the Company's efforts to regain an investment grade credit rating have been successful, regulatory support will be a key driver in securing additional improvement in the Company's financial health. Further

[57] Standard & Poor's Corporation, "Assessing U.S. Utility Regulatory Environments," *RatingsDirect* (Nov. 7, 2008).
[58] *Id.*
[59] Standard & Poor's Corporation, "U.S. Electric Utility Credit Quality Remains Strong Amid Continuing Economic Downturn," *RatingsDirect* (Dec. 19, 2008).
[60] Standard & Poor's Corporation, "Summary: Avista Corp.," *RatingsDirect* (Feb. 27, 2009).

strengthening Avista's financial integrity is imperative to ensure that the Company has the capability to maintain an investment grade rating while confronting potential challenges.

Q. Do customers benefit by enhancing the utility's financial flexibility?

A. Yes. While providing an ROE that is sufficient to maintain Avista's ability to attract capital, even in times of financial and market stress, is consistent with the economic requirements embodied in the U.S. Supreme Court's *Hope* and *Bluefield* decisions, it is also in customers' best interests. Ultimately, it is customers and the service area economy that enjoy the benefits that come from ensuring that the utility has the financial wherewithal to take whatever actions are required to ensure reliable service. By the same token, customers also bear a significant burden when the ability of the utility to attract necessary capital is impaired and service quality is compromised.

C. Capital Structure

Q. Is an evaluation of the capital structure maintained by a utility relevant in assessing its return on equity?

A. Yes. Other things equal, a higher debt ratio, or lower common equity ratio, translates into increased financial risk for all investors. A greater amount of debt means more investors have a senior claim on available cash flow, thereby reducing the certainty that each will receive his contractual payments. This increases the risks to which lenders are exposed, and they require correspondingly higher rates of interest. From common shareholders' standpoint, a higher debt ratio means that there are proportionately more creditors ahead of them, thereby increasing the uncertainty as to the amount of cash flow, if any, that will remain.

Q. What common equity ratio will be used to establish the company's overall rate of return?

A. Avista's capital structure is presented in the testimony of Mr. Thies. As summarized in his testimony, the pro-forma common equity ratio used to compute Avista's overall rate of return was 50.76 percent in this filing.

Q. How can Avista's capital structure be evaluated?

A. It is generally accepted that the norms established by comparable firms provide one valid benchmark against which to evaluate the reasonableness of a utility's capital structure. The capital structure maintained by other utilities should reflect their collective efforts to finance themselves so as to minimize capital costs while preserving their financial integrity and ability to attract capital. Moreover, these industry capital structures should also incorporate the requirements of investors (both debt and equity), as well as the influence of regulators.

Q. What is the average capitalization for the Gas Utility Proxy Group?

A. As shown on Schedule WEA-11, for the firms in the Gas Utility Proxy Group, common equity ratios at fiscal year-end 2009 ranged between 42.1 percent and 67.6 percent and averaged 53.7 percent of long-term capital. Meanwhile, Value Line expects an average common equity ratio for the Gas Utility Proxy Group of 58.5 percent for its three-to-five year forecast horizon.

Q. What average capitalization is maintained by the Combination Utility Proxy Group?

A. Capitalization ratios for the firms in the Combination Utility Proxy Group are shown on Schedule WEA-12. Common equity ratios at year-end 2009 ranged between 42.3 percent and 63.4 percent and averaged 50.1 percent of long-term capital for these combination utilities, with Value Line projecting an average common equity ratio for the Combination Utility Proxy Group of 51.8 percent for 2013-2015.

Q. What implication does the increasing risk of the utility industry have for the capital structure maintained by Avista?

A. As discussed earlier, utilities are facing energy market volatility, rising cost structures, the need to finance significant capital investment plans, uncertainties over accommodating economic and financial market uncertainties, and ongoing regulatory risks. Taken together, these considerations warrant a stronger balance sheet to deal with an increasingly uncertain environment. A more conservative financial profile, in the form of a higher common equity ratio, is consistent with increasing uncertainties and the need to maintain the continuous access to capital that is required to fund operations and necessary system investment, including times of adverse capital market conditions.

Moody's has repeatedly warned investors of the risks associated with debt leverage and fixed obligations and advised utilities not to squander the opportunity to strengthen the balance sheet as a buffer against future uncertainties.[61] More recently, Moody's concluded:

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[61] Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* (Aug. 2007); "U.S. Electric Utility Sector," *Industry Outlook* (Jan. 2008).

> From a credit perspective, we believe a strong balance sheet coupled with abundant sources of liquidity represents one of the best defenses against business and operating risk and potential negative ratings actions.[62]

Similarly, S&P recently noted that, "we generally consider a debt to capital level of 50% or greater to be aggressive or highly leveraged for utilities."[63] Fitch affirmed that it expects regulated utilities "to extend their conservative balance sheet stance in 2010," and employ "a judicious mix of debt and equity to finance high levels of planned investments."[64]

Q. What other factors do investors consider in their assessment of capital structure?

A. Depending on their specific attributes, contractual agreements or other obligations that require the utility to make specified payments may be treated as debt in evaluating Avista's financial risk. These commitments have been repeatedly cited by major bond rating agencies in connection with assessments of utility financial risks.[65] Because bond ratings agencies and investors adjust for these various commitments in assessing a utility's financial position, they imply greater risk and reduced financial flexibility.

Q. What does this evidence suggest with respect to Avista's capital structure?

A. Avista's 50.76 percent common equity ratio is consistent with the average

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[62] Moody's Investors Service, "U.S. Electric Utilities Face Challenges Beyond Near-Term," *Industry Outlook* (Jan. 2010).

[63] Standard & Poor's Corporation, "Ratings Roundup: U.S. Electric Utility Sector Maintained Strong Credit Quality In A Gloomy 2009," *RatingsDirect* (Jan. 26, 2010).

[64] Fitch Ratings Ltd., "U.S. Utilities, Power, and Gas 2010 Outlook," *Global Power North America Special Report* (Dec. 4, 2009).

[65] *See, e.g.*, Standard & Poor's Corporation, "Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements," *RatingsDirect* (May 7, 2007); Standard & Poor's Corporation, "Implications Of Operating Leases On Analysis Of U.S. Electric Utilities," *RatingsDirect* (Jan. 15, 2008); Standard & Poor's Corporation, "Top 10 Investor Questions: U.S. Regulated Electric Utilities," *RatingsDirect* (Jan. 22, 2010).

capitalization maintained by the Combination Utility Proxy Group, and it falls below the 53.7 percent average for the Gas Utility Proxy Group at the most recent fiscal year-end. Similarly, the Company's requested equity ratio is well short of the 58.5 percent equity ratio based on Value Line's expectations for these gas utilities over the near-term. Avista's capital structure reflects the Company's ongoing efforts to maintain its credit standing and support access to capital on reasonable terms, including times of adverse industry or market conditions.

Q. Will Avista require access to capital in support of its utility operations?

A. Yes. As discussed in the testimony of Mr. Theis, Avista's plans call for capital expenditure requirements of approximately $1.2 billion over the five-year period 2010-2014, including necessary maintenance and replacements of the Company's natural gas utility systems.

D. Return on Equity Range Recommendation

Q. What then is your conclusion as to a fair rate of return on equity range for Avista?

A. As explained above, based on the capital market oriented analyses for the utility and non-utility proxy groups described in my testimony, I concluded that the fair rate of return on equity range was 10.65 percent to 12.15 percent. Considering capital market expectations, the potential exposures faced by Avista, and the economic requirements necessary to maintain financial integrity and support additional capital investment, including under times of adverse circumstances, it is my opinion that this represents a fair and reasonable ROE range for Avista.

Q. Based on the results of your evaluation, what is your opinion regarding the reasonableness of the ROE requested by Avista in this case?

A. Given the fact that the Company's requested ROE falls in the lower end of my recommended range, my evaluation indicates that Avista's requested ROE of 10.9 percent represents a conservative estimate of investors' required rate of return. This conclusion is reinforced by the need to buttress the Company's credit standing, which remains relatively weak, as well as the fact that Avista's investment risks generally exceed those of the proxy groups used to estimate the cost of equity.

Q. Does this conclude your direct testimony in this case?

A. Yes, it does.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

WILLIAM E. AVERA
Exhibit No. 301

Return on Equity

DCF MODEL

GAS UTILITY PROXY GROUP

		(a)	(a)		(b)	(c)	(d)	(e)	(b)	(f)	(f)	(f)	(f)	(f)
		Dividend Yield			**Growth Rates**					**Cost of Equity Estimates**				
	Company	**Price**	**Dividends**	**Yield**	**V Line**	**IBES**	**Zacks**	**br+sv**	**Price**	**V Line**	**IBES**	**Zacks**	**br+sv**	**Price**
1	AGL Resources, Inc.	$ 36.70	$ 1.76	4.8%	5.0%	5.8%	4.0%	6.0%	8.8%	9.8%	10.6%	8.8%	10.8%	13.6%
2	Atmos Energy Corp.	$ 28.30	$ 1.36	4.8%	5.5%	3.4%	4.7%	4.9%	5.1%	10.3%	8.2%	9.5%	9.8%	9.9%
3	Laclede Group	$ 33.30	$ 1.61	4.8%	2.5%	NA	3.0%	7.0%	8.7%	7.3%	NA	7.8%	11.8%	13.6%
4	New Jersey Resources	$ 37.31	$ 1.36	3.6%	5.0%	3.3%	4.0%	6.1%	3.1%	8.6%	6.9%	7.6%	9.7%	6.8%
5	Nicor, Inc.	$ 42.29	$ 1.86	4.4%	1.0%	0.7%	3.5%	4.2%	4.0%	5.4%	5.1%	7.9%	8.6%	8.4%
6	NiSource Inc.	$ 17.36	$ 0.92	5.3%	6.0%	8.7%	3.0%	3.4%	5.2%	11.3%	14.0%	8.3%	8.7%	10.5%
7	Northwest Natural Gas	$ 45.44	$ 1.66	3.7%	4.5%	4.1%	4.9%	6.5%	6.8%	8.2%	7.8%	8.6%	10.1%	10.4%
8	Piedmont Natural Gas	$ 27.28	$ 1.12	4.1%	3.5%	3.5%	4.5%	2.7%	6.0%	7.6%	7.6%	8.6%	6.8%	10.1%
9	South Jersey Industries	$ 46.99	$ 1.37	2.9%	7.0%	6.3%	6.5%	10.4%	0.3%	9.9%	9.2%	9.4%	13.4%	3.2%
10	Southwest Gas	$ 31.45	$ 1.02	3.2%	7.5%	6.0%	6.0%	5.7%	7.3%	10.7%	9.2%	9.2%	9.0%	10.6%
11	UGI Corp.	$ 27.60	$ 1.00	3.6%	4.0%	3.2%	1.6%	7.5%	5.7%	7.6%	6.8%	5.2%	11.1%	9.4%
12	WGL Holdings, Inc.	$ 35.27	$ 1.51	4.3%	2.5%	3.2%	3.7%	3.9%	3.0%	6.8%	7.5%	8.0%	8.2%	7.3%
	Average (g)									**9.8%**	**10.3%**	**8.8%**	**10.1%**	**10.7%**

(a) Recent price and estimated dividend for next 12 mos. from The Value Line Investment Survey, *Summary and Index* (Sep. 10, 2010).
(b) The Value Line Investment Survey (Sep. 10, 2010).
(c) *Thomson ReutersCompany in Context Report* (Sep. 14, 2010).
(d) www.zacks.com (retrieved Sep. 15, 2010).
(e) See Schedule WEA-2.
(f) Sum of dividend yield and respective growth rate.
(g) Excludes highlighted figures.

GAS UTILITY PROXY GROUP

		(a)	(a)	(b)	(a)	(a)	(a)	(c)	(d)
		2013-15 Market Price			**2013-15 Projections**				
	Company	**High**	**Low**	**Avg.**	**EPS**	**DPS**	**BVPS**	**b**	**r**
1	AGL Resources, Inc.	60.00	45.00	$52.50	$3.50	$1.92	$29.60	45.1%	11.8%
2	Atmos Energy Corp.	40.00	30.00	$35.00	$2.70	$1.45	$29.15	46.3%	9.3%
3	Laclede Group	55.00	40.00	$47.50	$3.00	$1.75	$27.70	41.7%	10.8%
4	New Jersey Resources	45.00	40.00	$42.50	$3.00	$1.56	$21.60	48.0%	13.9%
5	Nicor, Inc.	60.00	40.00	$50.00	$3.00	$1.86	$27.95	38.0%	10.7%
6	NiSource Inc.	25.00	18.00	$21.50	$1.60	$0.94	$19.70	41.3%	8.1%
7	Northwest Natural Gas	65.00	55.00	$60.00	$3.55	$1.90	$30.15	46.5%	11.8%
8	Piedmont Natural Gas	40.00	30.00	$35.00	$1.90	$1.27	$14.45	33.2%	13.1%
9	South Jersey Industries	55.00	40.00	$47.50	$3.35	$1.60	$23.55	52.2%	14.2%
10	Southwest Gas	50.00	35.00	$42.50	$2.75	$1.20	$32.00	56.4%	8.6%
11	UGI Corp.	40.00	30.00	$35.00	$2.60	$1.16	$21.80	55.4%	11.9%
12	WGL Holdings, Inc.	45.00	35.00	$40.00	$2.70	$1.67	$26.50	38.1%	10.2%

GAS UTILITY PROXY GROUP

		(a)	(a)	(e)	(a)	(a)	(e)	(f)	(g)	(h)
		2009			2013-15			Adjusted "r"		
	Company	BVPS	No. Shares	Common Equity	BVPS	No. Shares	Common Equity	Chg in Equity	Adj. Factor	Adj. r
1	AGL Resources, Inc.	$22.95	77.54	$1,780	$29.60	80.00	$2,368	5.9%	1.0286	12.2%
2	Atmos Energy Corp.	$23.52	92.55	$2,177	$29.15	105.00	$3,061	7.1%	1.0341	9.6%
3	Laclede Group	$23.32	22.17	$517	$27.70	26.00	$720	6.9%	1.0331	11.2%
4	New Jersey Resources	$16.59	41.59	$690	$21.60	40.00	$864	4.6%	1.0225	14.2%
5	Nicor, Inc.	$22.93	45.25	$1,038	$27.95	45.50	$1,272	4.2%	1.0203	11.0%
6	NiSource Inc.	$17.54	276.79	$4,855	$19.70	279.50	$5,506	2.5%	1.0126	8.2%
7	Northwest Natural Gas	$24.88	26.53	$660	$30.15	27.70	$835	4.8%	1.0235	12.1%
8	Piedmont Natural Gas	$12.67	73.27	$928	$14.45	69.00	$997	1.4%	1.0071	13.2%
9	South Jersey Industries	$18.27	29.80	$544	$23.55	34.00	$801	8.0%	1.0386	14.8%
10	Southwest Gas	$24.46	45.09	$1,103	$32.00	50.00	$1,600	7.7%	1.0372	8.9%
11	UGI Corp.	$14.66	108.52	$1,591	$21.80	114.00	$2,485	9.3%	1.0446	12.5%
12	WGL Holdings, Inc.	$21.89	50.14	$1,098	$26.50	50.00	$1,325	3.8%	1.0188	10.4%

GAS UTILITY PROXY GROUP

		(a)	(a)	(f)	(i)	(j)	(k)	(l)	(m)
		Common Shares Outstanding			M/B	"sv" Factor			
	Company	2009	2013-15	Change	Ratio	s	v	sv	br + sv
1	AGL Resources, Inc.	77.5	80.0	0.63%	1.77	0.0111	0.4362	0.48%	6.0%
2	Atmos Energy Corp.	92.6	105.0	2.56%	1.20	0.0307	0.1671	0.51%	4.9%
3	Laclede Group	22.2	26.0	3.24%	1.71	0.0555	0.4168	2.31%	7.0%
4	New Jersey Resources	41.6	40.0	-0.78%	1.97	(0.0153)	0.4918	-0.75%	6.1%
5	Nicor, Inc.	45.3	45.5	0.11%	1.79	0.0020	0.4410	0.09%	4.2%
6	NiSource Inc.	276.8	279.5	0.20%	1.09	0.0021	0.0837	0.02%	3.4%
7	Northwest Natural Gas	26.5	27.7	0.87%	1.99	0.0173	0.4975	0.86%	6.5%
8	Piedmont Natural Gas	73.3	69.0	-1.19%	2.42	(0.0289)	0.5871	-1.70%	2.7%
9	South Jersey Industries	29.8	34.0	2.67%	2.02	0.0539	0.5042	2.72%	10.4%
10	Southwest Gas	45.1	50.0	2.09%	1.33	0.0277	0.2471	0.69%	5.7%
11	UGI Corp.	108.5	114.0	0.99%	1.61	0.0159	0.3771	0.60%	7.5%
12	WGL Holdings, Inc.	50.1	50.0	-0.06%	1.51	(0.0008)	0.3375	-0.03%	3.9%

(a) The Value Line Investment Survey (Sep. 10, 2010).
(b) Average of High and Low expected market prices.
(c) Computed at (EPS - DPS) / EPS.
(d) Computed as EPS / BVPS.
(e) Product of BVPS and No. Shares Outstanding.
(f) Five-year rate of change.
(g) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(h) Product of year-end "r" for 2013-15 and Adjustment Factor.
(i) Average of High and Low expected market prices divided by 2013-15 BVPS.
(j) Product of change in common shares outstanding and M/B Ratio.
(k) Computed as 1 - B/M Ratio.
(l) Product of "s" and "v".
(m) Product of average "b" and adjusted "r", plus "sv".

COMBINATION UTILITY PROXY GROUP

		(a)	(a)		(b)	(c)	(d)	(e)	(b)	(f)	(f)	(f)	(f)	(f)
		Dividend Yield			**Growth Rates**					**Cost of Equity Estimates**				
	Company	**Price**	**Dividends**	**Yield**	**V Line**	**IBES**	**Zacks**	**br+sv**	**Price**	**V Line**	**IBES**	**Zacks**	**br+sv**	**Price**
1	ALLETE	$ 35.57	$ 1.76	4.9%	-0.5%	6.5%	4.0%	2.8%	-0.4%	4.4%	11.4%	8.9%	7.7%	4.6%
2	Alliant Energy	$ 35.02	$ 1.58	4.5%	7.0%	9.9%	5.0%	6.1%	7.4%	11.5%	14.4%	9.5%	10.6%	11.9%
3	Ameren Corp.	$ 28.07	$ 1.54	5.5%	-2.5%	-6.0%	-2.0%	2.4%	1.6%	3.0%	-0.5%	3.5%	7.9%	7.1%
4	Avista Corp.	$ 20.87	$ 1.04	5.0%	8.5%	4.0%	4.7%	3.5%	6.7%	13.5%	9.0%	9.7%	8.5%	11.7%
5	Black Hills Corp.	$ 30.43	$ 1.46	4.8%	6.5%	6.0%	6.0%	3.0%	3.3%	11.3%	10.8%	10.8%	7.8%	8.1%
6	Constellation Energy	$ 29.33	$ 0.96	3.3%	7.0%	9.9%	9.9%	4.2%	7.6%	10.3%	13.2%	13.2%	7.5%	10.8%
7	DTE Energy Co.	$ 46.85	$ 2.24	4.8%	6.5%	5.0%	5.0%	3.9%	3.8%	11.3%	9.8%	9.8%	8.7%	8.6%
8	Empire District Elec	$ 19.62	$ 1.28	6.5%	7.0%	NA	NA	3.2%	5.9%	13.5%	NA	NA	9.7%	12.4%
9	Entergy Corp.	$ 78.84	$ 3.39	4.3%	4.5%	5.1%	3.0%	4.4%	8.2%	8.8%	9.4%	7.3%	8.7%	12.5%
10	Exelon Corp.	$ 40.72	$ 2.10	5.2%	-3.0%	1.0%	-3.7%	5.1%	6.2%	2.2%	6.2%	1.5%	10.2%	11.3%
11	Integrys Energy Group	$ 48.45	$ 2.72	5.6%	11.0%	9.4%	10.0%	3.2%	-0.5%	16.6%	15.0%	15.6%	8.8%	5.1%
12	Northeast Utilities	$ 28.97	$ 1.08	3.7%	6.0%	7.3%	7.8%	5.4%	6.3%	9.7%	11.0%	11.5%	9.1%	10.0%
13	PG&E Corp.	$ 46.76	$ 1.89	4.0%	7.0%	6.9%	7.0%	6.3%	2.8%	11.0%	10.9%	11.0%	10.3%	6.8%
14	Pub Sv Enterprise Grp	$ 31.96	$ 1.40	4.4%	2.0%	1.9%	-0.3%	6.7%	6.9%	6.4%	6.3%	4.1%	11.0%	11.3%
15	SCANA Corp.	$ 39.03	$ 1.92	4.9%	3.5%	4.9%	4.3%	5.4%	3.4%	8.4%	9.8%	9.2%	10.4%	8.3%
16	Sempra Energy	$ 50.92	$ 1.62	3.2%	2.0%	3.5%	7.0%	5.8%	4.9%	5.2%	6.7%	10.2%	9.0%	8.1%
17	Wisconsin Energy	$ 55.74	$ 1.60	2.9%	9.0%	9.5%	8.7%	6.6%	5.5%	11.9%	12.4%	11.6%	9.4%	8.4%
	Average (g)									**11.5%**	**11.4%**	**10.9%**	**9.6%**	**10.3%**

(a) Recent price and estimated dividend for next 12 mos. from The Value Line Investment Survey, *Summary and Index* (Sep. 10, 2010).
(b) The Value Line Investment Survey (Jun. 25, Aug. 6, & Aug. 27, 2010).
(c) *Thomson Reuters Company in Context Report* (Sep. 14, 2010).
(d) www.zacks.com (retrieved Sep. 15, 2010).
(e) See Schedule WEA-4.
(f) Sum of dividend yield and respective growth rate.
(g) Excludes highlighted figures.

COMBINATION UTILITY PROXY GROUP

		(a)	(a)	(b)	(a)	(a)	(a)	(c)	(d)
		2013-15 Market Price			**2013-15 Projections**				
	Company	**High**	**Low**	**Avg.**	**EPS**	**DPS**	**BVPS**	**b**	**r**
1	ALLETE	40.00	30.00	$35.00	$2.50	$1.80	$29.25	28.0%	8.5%
2	Alliant Energy	55.00	40.00	$47.50	$3.60	$1.92	$31.05	46.7%	11.6%
3	Ameren Corp.	35.00	25.00	$30.00	$2.50	$1.54	$37.00	38.4%	6.8%
4	Avista Corp.	30.00	25.00	$27.50	$2.00	$1.30	$22.50	35.0%	8.9%
5	Black Hills Corp.	40.00	30.00	$35.00	$2.50	$1.60	$31.50	36.0%	7.9%
6	Constellation Energy	50.00	30.00	$40.00	$3.25	$1.00	$51.50	69.2%	6.3%
7	DTE Energy Co.	65.00	45.00	$55.00	$4.25	$2.60	$46.50	38.8%	9.1%
8	Empire District Elec	30.00	20.00	$25.00	$1.75	$1.35	$17.50	22.9%	10.0%
9	Entergy Corp.	125.00	95.00	$110.00	$7.75	$4.15	$59.50	46.5%	13.0%
10	Exelon Corp.	60.00	45.00	$52.50	$3.50	$2.10	$25.00	40.0%	14.0%
11	Integrys Energy Group	55.00	40.00	$47.50	$4.00	$2.72	$41.25	32.0%	9.7%
12	Northeast Utilities	45.00	30.00	$37.50	$2.50	$1.30	$26.00	48.0%	9.6%
13	PG&E Corp.	60.00	45.00	$52.50	$4.50	$2.40	$38.25	46.7%	11.8%
14	Pub Sv Enterprise Grp	50.00	35.00	$42.50	$3.25	$1.60	$25.75	50.8%	12.6%
15	SCANA Corp.	50.00	40.00	$45.00	$3.50	$2.00	$35.25	42.9%	9.9%
16	Sempra Energy	70.00	55.00	$62.50	$5.00	$2.05	$49.75	59.0%	10.1%
17	Wisconsin Energy	80.00	60.00	$70.00	$5.00	$2.40	$40.75	52.0%	12.3%

SUSTAINABLE GROWTH RATE

COMBINATION UTILITY PROXY GROUP

		(a)	(a)	(e)	(a)	(a)	(e)	(f)	(g)	(h)
		2009			**2013-15**			**Adjusted "r"**		
			No.	**Common**		**No.**	**Common**	**Chg in**	**Adj.**	**Adj.**
	Company	**BVPS**	**Shares**	**Equity**	**BVPS**	**Shares**	**Equity**	**Equity**	**Factor**	**r**
1	ALLETE	$26.41	35.20	$930	$29.25	38.50	$1,126	3.9%	1.0192	8.7%
2	Alliant Energy	$25.07	110.66	$2,774	$31.05	116.00	$3,602	5.4%	1.0261	11.9%
3	Ameren Corp.	$33.08	237.40	$7,853	$37.00	255.00	$9,435	3.7%	1.0183	6.9%
4	Avista Corp.	$19.17	54.84	$1,051	$22.50	59.00	$1,328	4.8%	1.0233	9.1%
5	Black Hills Corp.	$27.84	38.97	$1,085	$31.50	40.25	$1,268	3.2%	1.0156	8.1%
6	Constellation Energy	$43.27	200.99	$8,697	$51.50	211.00	$10,867	4.6%	1.0223	6.5%
7	DTE Energy Co.	$37.96	165.40	$6,279	$46.50	178.00	$8,277	5.7%	1.0276	9.4%
8	Empire District Elec	$15.75	38.11	$600	$17.50	42.00	$735	4.1%	1.0203	10.2%
9	Entergy Corp.	$45.54	189.12	$8,613	$59.50	170.00	$10,115	3.3%	1.0161	13.2%
10	Exelon Corp.	$19.15	660.00	$12,639	$25.00	640.00	$16,000	4.8%	1.0236	14.3%
11	Integrys Energy Group	$37.62	75.98	$2,858	$41.25	78.00	$3,218	2.4%	1.0118	9.8%
12	Northeast Utilities	$20.37	175.62	$3,577	$26.00	188.00	$4,888	6.4%	1.0312	9.9%
13	PG&E Corp.	$27.88	370.60	$10,332	$38.25	400.00	$15,300	8.2%	1.0392	12.2%
14	Pub Sv Enterprise Grp	$17.37	505.99	$8,789	$25.75	506.00	$13,030	8.2%	1.0394	13.1%
15	SCANA Corp.	$27.71	123.00	$3,408	$35.25	147.00	$5,182	8.7%	1.0419	10.3%
16	Sempra Energy	$36.54	246.50	$9,007	$49.75	234.00	$11,642	5.3%	1.0257	10.3%
17	Wisconsin Energy	$30.51	116.91	$3,567	$40.75	116.90	$4,764	6.0%	1.0289	12.6%

COMBINATION UTILITY PROXY GROUP

		(a)	(a)	(f)	(i)	(j)	(k)	(l)	(m)
		Common Shares Outstanding			M/B	"sv" Factor			
	Company	2009	2013-15	Change	Ratio	s	v	sv	br + sv
1	ALLETE	35.2	38.5	1.81%	1.20	0.0216	0.1643	0.36%	2.8%
2	Alliant Energy	110.7	116.0	0.95%	1.53	0.0145	0.3463	0.50%	6.1%
3	Ameren Corp.	237.4	255.0	1.44%	0.81	0.0117	(0.2333)	-0.27%	2.4%
4	Avista Corp.	54.8	59.0	1.47%	1.22	0.0180	0.1818	0.33%	3.5%
5	Black Hills Corp.	39.0	40.3	0.65%	1.11	0.0072	0.1000	0.07%	3.0%
6	Constellation Energy	201.0	211.0	0.98%	0.78	0.0076	(0.2875)	-0.22%	4.2%
7	DTE Energy Co.	165.4	178.0	1.48%	1.18	0.0175	0.1545	0.27%	3.9%
8	Empire District Elec	38.1	42.0	1.96%	1.43	0.0280	0.3000	0.84%	3.2%
9	Entergy Corp.	189.1	170.0	-2.11%	1.85	(0.0390)	0.4591	-1.79%	4.4%
10	Exelon Corp.	660.0	640.0	-0.61%	2.10	(0.0129)	0.5238	-0.67%	5.1%
11	Integrys Energy Group	76.0	78.0	0.53%	1.15	0.0061	0.1316	0.08%	3.2%
12	Northeast Utilities	175.6	188.0	1.37%	1.44	0.0198	0.3067	0.61%	5.4%
13	PG&E Corp.	370.6	400.0	1.54%	1.37	0.0211	0.2714	0.57%	6.3%
14	Pub Sv Enterprise Grp	506.0	506.0	0.00%	1.65	0.0000	0.3941	0.00%	6.7%
15	SCANA Corp.	123.0	147.0	3.63%	1.28	0.0463	0.2167	1.00%	5.4%
16	Sempra Energy	246.5	234.0	-1.04%	1.26	(0.0130)	0.2040	-0.27%	5.8%
17	Wisconsin Energy	116.9	116.9	0.00%	1.72	(0.0000)	0.4179	0.00%	6.6%

(a) The Value Line Investment Survey (Jun. 25, Aug. 6, & Aug. 27, 2010).
(b) Average of High and Low expected market prices.
(c) Computed at (EPS - DPS) / EPS.
(d) Computed as EPS / BVPS.
(e) Product of BVPS and No. Shares Outstanding.
(f) Five-year rate of change.
(g) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(h) Product of year-end "r" for 2013-15 and Adjustment Factor.
(i) Average of High and Low expected market prices divided by 2013-15 BVPS.
(j) Product of change in common shares outstanding and M/B Ratio.
(k) Computed as 1 - B/M Ratio.
(l) Product of "s" and "v".
(m) Product of average "b" and adjusted "r", plus "sv".

NON-UTILITY PROXY GROUP

		(a)	(a)	(b)	(c)	(d)	(a)	(e)	(e)	(e)	(e)	(e)
		Dividend	Growth Rates					Cost of Equity Estimates				
	Company	Yield	V Line	IBES	Zacks	br+sv	Price	V Line	IBES	Zacks	br+sv	Price
1	Abbott Labs.	3.62%	10.5%	9.7%	10.6%	15.0%	18.6%	14.1%	13.3%	14.2%	18.7%	22.2%
2	Alberto-Culver	1.29%	15.0%	13.0%	12.5%	8.4%	11.1%	16.3%	14.3%	13.8%	9.7%	12.4%
3	AT&T Inc.	6.65%	5.5%	6.4%	6.6%	5.7%	13.4%	12.2%	13.1%	13.3%	12.4%	20.0%
4	Automatic Data Proc.	3.21%	8.5%	11.3%	10.8%	9.5%	14.3%	11.7%	14.5%	14.0%	12.7%	17.5%
5	Bard (C.R.)	0.89%	10.0%	11.9%	12.0%	15.3%	12.8%	10.9%	12.8%	12.9%	16.2%	13.7%
6	Baxter Int'l Inc.	2.91%	10.5%	9.7%	9.1%	14.5%	15.8%	13.4%	12.6%	12.0%	17.4%	18.7%
7	Becton, Dickinson	2.06%	9.5%	11.3%	10.6%	12.1%	12.5%	11.6%	13.4%	12.7%	14.1%	14.6%
8	Bristol-Myers Squibb	4.95%	6.0%	2.8%	2.9%	4.3%	6.9%	11.0%	7.8%	7.9%	9.3%	11.9%
9	Brown-Forman 'B'	2.03%	8.5%	10.8%	13.0%	13.7%	7.3%	10.5%	12.8%	15.0%	15.7%	9.3%
10	Church & Dwight	0.83%	13.0%	12.0%	12.0%	11.2%	9.1%	13.8%	12.8%	12.8%	12.0%	9.9%
11	Coca-Cola	3.42%	7.5%	8.5%	9.0%	11.2%	12.8%	10.9%	11.9%	12.4%	14.6%	16.2%
12	Colgate-Palmolive	2.62%	12.0%	9.1%	9.2%	15.7%	14.7%	14.6%	11.7%	11.8%	18.4%	17.3%
13	ConAgra Foods	3.17%	11.0%	10.6%	8.0%	8.8%	10.8%	14.2%	13.8%	11.2%	12.0%	13.9%
14	Costco Wholesale	1.40%	7.5%	13.0%	13.2%	8.8%	7.9%	8.9%	14.4%	14.6%	10.2%	9.3%
15	Everest Re Group Ltd.	2.55%	5.0%	7.5%	12.5%	8.2%	16.6%	7.6%	10.1%	15.1%	10.7%	19.1%
16	Exxon Mobil Corp.	2.84%	6.0%	15.9%	8.3%	14.2%	13.9%	8.8%	18.7%	11.1%	17.0%	16.7%
17	Gen'l Mills	2.59%	10.0%	8.7%	8.0%	8.8%	24.6%	12.6%	11.3%	10.6%	11.4%	27.2%
18	Heinz (H.J.)	3.86%	7.0%	7.0%	8.0%	15.3%	10.3%	10.9%	10.9%	11.9%	19.2%	14.2%
19	Hormel Foods	2.02%	10.0%	10.0%	9.3%	11.2%	12.5%	12.0%	12.0%	11.3%	13.2%	14.5%
20	Johnson & Johnson	3.65%	8.0%	6.4%	6.3%	8.5%	15.3%	11.7%	10.1%	10.0%	12.2%	19.0%

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		(a)	(a)	(b)	(c)	(d)	(a)	(e)	(e)	(e)	(e)	(e)
		Dividend	**Growth Rates**					**Cost of Equity Estimates**				
	Company	**Yield**	**V Line**	**IBES**	**Zacks**	**br+sv**	**Price**	**V Line**	**IBES**	**Zacks**	**br+sv**	**Price**
21	Kellogg	2.96%	10.0%	9.4%	9.0%	12.4%	10.9%	13.0%	12.4%	12.0%	15.3%	13.9%
22	Kimberly-Clark	4.18%	6.0%	8.2%	8.3%	17.2%	8.2%	10.2%	12.4%	12.5%	21.4%	12.4%
23	Kraft Foods	3.87%	7.0%	7.5%	8.0%	10.7%	12.0%	10.9%	11.4%	11.9%	14.6%	15.9%
24	McCormick & Co.	2.55%	8.5%	7.3%	9.5%	13.2%	11.8%	11.1%	9.9%	12.1%	15.8%	14.4%
25	McDonald's Corp.	3.28%	9.0%	10.2%	9.2%	9.6%	7.0%	12.3%	13.5%	12.5%	12.9%	10.3%
26	Medtronic, Inc.	2.26%	7.5%	10.0%	10.3%	11.9%	11.1%	9.8%	12.3%	12.6%	14.2%	13.3%
27	PepsiCo, Inc.	2.98%	12.0%	8.2%	9.5%	14.7%	17.3%	15.0%	11.2%	12.5%	17.7%	20.3%
28	Pfizer, Inc.	4.91%	5.0%	2.6%	1.8%	5.9%	13.6%	9.9%	7.5%	6.7%	10.8%	18.5%
29	Procter & Gamble	3.13%	7.5%	8.6%	9.4%	12.6%	10.0%	10.6%	11.7%	12.5%	15.8%	13.2%
30	Raytheon Co.	2.83%	9.5%	8.0%	8.4%	8.0%	16.3%	12.3%	10.8%	11.2%	10.9%	19.2%
31	Sysco Corp.	3.22%	6.5%	10.5%	11.5%	15.0%	8.6%	9.7%	13.7%	14.7%	18.2%	11.8%
32	Verizon Communic.	6.53%	4.0%	2.0%	4.0%	5.7%	15.2%	10.5%	8.5%	10.5%	12.2%	21.7%
33	Wal-Mart Stores	2.35%	10.0%	10.7%	11.3%	8.9%	13.2%	12.4%	13.1%	13.7%	11.3%	15.6%
34	Walgreen Co.	1.88%	9.0%	13.6%	13.1%	10.1%	15.0%	10.9%	15.5%	15.0%	11.9%	16.9%
	Average (f)							**11.8%**	**12.3%**	**12.6%**	**12.8%**	**13.4%**

(a) www.valueline.com (retrieved June 22, 2010).

(b) Thomson Reuters, *Company in Context Report* (July 1, 2010).

(c) www.zacks.com (retrieved Aug. 4, 2010).

(d) See Schedule WEA-6.

(e) Sum of dividend yield and respective growth rate.

(f) Excludes highlighted figures.

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		(a)	(a)	(b)	(a)	(a)	(a)	(c)	(d)
		2013-15 Market Price			2013-15 Projections				
	Company	High	Low	Avg.	EPS	DPS	BVPS	b	r
1	Abbott Labs.	$115.00	$95.00	$105.00	$5.70	$2.18	$22.05	61.8%	25.9%
2	Alberto-Culver	$50.00	$40.00	$45.00	$2.35	$0.55	$17.85	76.6%	13.2%
3	AT&T Inc.	$50.00	$40.00	$45.00	$3.25	$2.00	$22.35	38.5%	14.5%
4	Automatic Data Proc.	$85.00	$70.00	$77.50	$3.45	$1.60	$22.95	53.6%	15.0%
5	Bard (C.R.)	$155.00	$125.00	$140.00	$7.80	$0.85	$39.25	89.1%	19.9%
6	Baxter Int'l Inc.	$90.00	$75.00	$82.50	$6.00	$1.75	$24.10	70.8%	24.9%
7	Becton, Dickinson	$135.00	$110.00	$122.50	$7.65	$2.20	$39.15	71.2%	19.5%
8	Bristol-Myers Squibb	$40.00	$30.00	$35.00	$2.05	$1.40	$11.65	31.7%	17.6%
9	Brown-Forman 'B'	$90.00	$75.00	$82.50	$4.80	$1.44	$22.85	70.0%	21.0%
10	Church & Dwight	$110.00	$90.00	$100.00	$5.80	$0.64	$39.60	89.0%	14.6%
11	Coca-Cola	$100.00	$80.00	$90.00	$4.35	$2.12	$20.15	51.3%	21.6%
12	Colgate-Palmolive	$165.00	$135.00	$150.00	$7.50	$3.20	$18.25	57.3%	41.1%
13	ConAgra Foods	$45.00	$35.00	$40.00	$2.45	$0.96	$16.80	60.8%	14.6%
14	Costco Wholesale	$90.00	$75.00	$82.50	$4.20	$0.95	$32.45	77.4%	12.9%
15	Everest Re Group Ltd.	$165.00	$135.00	$150.00	$15.00	$2.35	$163.55	84.3%	9.2%
16	Exxon Mobil Corp.	$125.00	$100.00	$112.50	$9.35	$2.05	$45.45	78.1%	20.6%
17	Gen'l Mills	$115.00	$95.00	$105.00	$6.25	$2.65	$27.10	57.6%	23.1%
18	Heinz (H.J.)	$80.00	$65.00	$72.50	$4.30	$2.32	$12.85	46.0%	33.5%
19	Hormel Foods	$80.00	$65.00	$72.50	$4.00	$1.20	$26.50	70.0%	15.1%
20	Johnson & Johnson	$125.00	$100.00	$112.50	$7.05	$2.80	$35.20	60.3%	20.0%
21	Kellogg	$95.00	$80.00	$87.50	$5.25	$2.00	$15.15	61.9%	34.7%
22	Kimberly-Clark	$100.00	$80.00	$90.00	$6.00	$2.75	$15.55	54.2%	38.6%
23	Kraft Foods	$55.00	$45.00	$50.00	$3.00	$1.40	$24.00	53.3%	12.5%
24	McCormick & Co.	$75.00	$60.00	$67.50	$3.45	$1.32	$18.95	61.7%	18.2%
25	McDonald's Corp.	$105.00	$85.00	$95.00	$5.85	$3.00	$19.00	48.7%	30.8%
26	Medtronic, Inc.	$70.00	$55.00	$62.50	$4.40	$1.07	$25.10	75.7%	17.5%
27	PepsiCo, Inc.	$145.00	$120.00	$132.50	$6.70	$2.18	$25.60	67.5%	26.2%
28	Pfizer, Inc.	$30.00	$25.00	$27.50	$2.05	$1.16	$15.50	43.4%	13.2%
29	Procter & Gamble	$105.00	$85.00	$95.00	$5.25	$1.95	$26.00	62.9%	20.2%
30	Raytheon Co.	$115.00	$95.00	$105.00	$7.00	$2.00	$40.45	71.4%	17.3%
31	Sysco Corp.	$50.00	$40.00	$45.00	$2.55	$1.00	$8.60	60.8%	29.7%
32	Verizon Communic.	$60.00	$50.00	$55.00	$3.05	$1.96	$18.95	35.7%	16.1%
33	Wal-Mart Stores	$100.00	$80.00	$90.00	$6.00	$1.70	$30.60	71.7%	19.6%
34	Walgreen Co.	$60.00	$50.00	$55.00	$3.50	$0.84	$23.85	76.0%	14.7%

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		(a)	(a)	(e)	(a)	(a)	(e)	(f)	(g)	(h)
		2009			2013-15			Adjusted "r"		
			No.	Common		No.	Common	Chg in	Adj.	Adj.
	Company	BVPS	Shares	Equity	BVPS	Shares	Equity	Equity	Factor	r
1	Abbott Labs.	$14.73	1551.20	$22,849	$22.05	1520.00	$33,516	8.0%	1.0383	26.8%
2	Alberto-Culver	$12.18	98.26	$1,197	$17.85	92.00	$1,642	6.5%	1.0316	13.6%
3	AT&T Inc.	$17.34	5901.90	$102,339	$22.35	5900.00	$131,865	5.2%	1.0253	14.9%
4	Automatic Data Proc.	$10.61	501.70	$5,323	$22.95	510.00	$11,705	17.1%	1.0786	16.2%
5	Bard (C.R.)	$22.87	95.92	$2,194	$39.25	90.00	$3,533	10.0%	1.0476	20.8%
6	Baxter Int'l Inc.	$11.97	600.97	$7,194	$24.10	550.00	$13,255	13.0%	1.0610	26.4%
7	Becton, Dickinson	$21.69	237.08	$5,142	$39.15	223.00	$8,730	11.2%	1.0529	20.6%
8	Bristol-Myers Squibb	$8.65	1709.50	$14,787	$11.65	1650.00	$19,223	5.4%	1.0262	18.1%
9	Brown-Forman 'B'	$12.75	145.00	$1,849	$22.85	140.00	$3,199	11.6%	1.0548	22.2%
10	Church & Dwight	$22.70	70.55	$1,601	$39.60	65.00	$2,574	10.0%	1.0474	15.3%
11	Coca-Cola	$10.77	2303.00	$24,803	$20.15	2285.00	$46,043	13.2%	1.0618	22.9%
12	Colgate-Palmolive	$5.96	494.17	$2,945	$18.25	460.00	$8,395	23.3%	1.1044	45.4%
13	ConAgra Foods	$10.69	441.66	$4,721	$16.80	435.00	$7,308	9.1%	1.0437	15.2%
14	Costco Wholesale	$22.98	435.97	$10,019	$32.45	415.00	$13,467	6.1%	1.0296	13.3%
15	Everest Re Group Ltd.	$102.90	59.30	$6,102	$163.55	55.00	$8,995	8.1%	1.0388	9.5%
16	Exxon Mobil Corp.	$23.39	4727.00	$110,565	$45.45	4300.00	$195,435	12.1%	1.0569	21.7%
17	Gen'l Mills	$15.78	328.00	$5,176	$27.10	300.00	$8,130	9.5%	1.0451	24.1%
18	Heinz (H.J.)	$5.05	315.00	$1,591	$12.85	310.00	$3,984	20.2%	1.0915	36.5%
19	Hormel Foods	$15.89	133.59	$2,123	$26.50	134.00	$3,551	10.8%	1.0514	15.9%
20	Johnson & Johnson	$18.37	2754.30	$50,596	$35.20	2500.00	$88,000	11.7%	1.0553	21.1%
21	Kellogg	$5.96	381.38	$2,273	$15.15	340.00	$5,151	17.8%	1.0816	37.5%
22	Kimberly-Clark	$12.96	417.00	$5,404	$15.55	400.00	$6,220	2.9%	1.0141	39.1%
23	Kraft Foods	$17.57	1477.90	$25,967	$24.00	1750.00	$42,000	10.1%	1.0480	13.1%
24	McCormick & Co.	$10.13	131.80	$1,335	$18.95	135.00	$2,558	13.9%	1.0649	19.4%
25	McDonald's Corp.	$13.03	1076.70	$14,029	$19.00	1000.00	$19,000	6.3%	1.0303	31.7%
26	Medtronic, Inc.	$13.10	1100.00	$14,410	$25.10	1025.00	$25,728	12.3%	1.0579	18.5%
27	PepsiCo, Inc.	$11.12	1565.00	$17,403	$25.60	1485.00	$38,016	16.9%	1.0780	28.2%
28	Pfizer, Inc.	$11.15	8070.00	$89,981	$15.50	8070.00	$125,085	6.8%	1.0329	13.7%
29	Procter & Gamble	$21.18	2917.00	$61,782	$26.00	2900.00	$75,400	4.1%	1.0199	20.6%
30	Raytheon Co.	$25.64	383.20	$9,825	$40.45	330.00	$13,349	6.3%	1.0306	17.8%
31	Sysco Corp.	$5.85	590.03	$3,452	$8.60	565.00	$4,859	7.1%	1.0342	30.7%
32	Verizon Communic.	$14.67	2835.70	$41,600	$18.95	2820.00	$53,439	5.1%	1.0250	16.5%
33	Wal-Mart Stores	$18.69	3786.00	$70,760	$30.60	3270.00	$100,062	7.2%	1.0346	20.3%
34	Walgreen Co.	$14.54	988.56	$14,374	$23.85	930.00	$22,181	9.1%	1.0434	15.3%

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		(a)	(a)	(f)	(i)	(j)	(k)	(l)	(m)
		Common Shares Outstanding			M/B	"sv" Factor			
	Company	2009	2013-15	Change	Ratio	s	v	sv	br + sv
1	Abbott Labs.	1551.20	1520.00	-0.41%	4.76	(0.0193)	0.7900	-1.53%	15.0%
2	Alberto-Culver	98.26	92.00	-1.31%	2.52	(0.0330)	0.6033	-1.99%	8.4%
3	AT&T Inc.	5901.90	5900.00	-0.01%	2.01	(0.0001)	0.5033	-0.01%	5.7%
4	Automatic Data Proc.	501.70	510.00	0.33%	3.38	0.0111	0.7039	0.78%	9.5%
5	Bard (C.R.)	95.92	90.00	-1.27%	3.57	(0.0452)	0.7196	-3.25%	15.3%
6	Baxter Int'l Inc.	600.97	550.00	-1.76%	3.42	(0.0601)	0.7079	-4.26%	14.5%
7	Becton, Dickinson	237.08	223.00	-1.22%	3.13	(0.0381)	0.6804	-2.59%	12.1%
8	Bristol-Myers Squibb	1709.50	1650.00	-0.71%	3.00	(0.0212)	0.6671	-1.42%	4.3%
9	Brown-Forman 'B'	145.00	140.00	-0.70%	3.61	(0.0253)	0.7230	-1.83%	13.7%
10	Church & Dwight	70.55	65.00	-1.63%	2.53	(0.0410)	0.6040	-2.48%	11.2%
11	Coca-Cola	2303.00	2285.00	-0.16%	4.47	(0.0070)	0.7761	-0.54%	11.2%
12	Colgate-Palmolive	494.17	460.00	-1.42%	8.22	(0.1169)	0.8783	-10.27%	15.7%
13	ConAgra Foods	441.66	435.00	-0.30%	2.38	(0.0072)	0.5800	-0.42%	8.8%
14	Costco Wholesale	435.97	415.00	-0.98%	2.54	(0.0249)	0.6067	-1.51%	8.8%
15	Everest Re Group Ltd.	59.30	55.00	-1.49%	0.92	(0.0137)	(0.0903)	0.12%	8.2%
16	Exxon Mobil Corp.	4727.00	4300.00	-1.88%	2.48	(0.0464)	0.5960	-2.77%	14.2%
17	Gen'l Mills	328.00	300.00	-1.77%	3.87	(0.0685)	0.7419	-5.08%	8.8%
18	Heinz (H.J.)	315.00	310.00	-0.32%	5.64	(0.0180)	0.8228	-1.48%	15.3%
19	Hormel Foods	133.59	134.00	0.06%	2.74	0.0017	0.6345	0.11%	11.2%
20	Johnson & Johnson	2754.30	2500.00	-1.92%	3.20	(0.0613)	0.6871	-4.21%	8.5%
21	Kellogg	381.38	340.00	-2.27%	5.78	(0.1312)	0.8269	-10.84%	12.4%
22	Kimberly-Clark	417.00	400.00	-0.83%	5.79	(0.0480)	0.8272	-3.97%	17.2%
23	Kraft Foods	1477.90	1750.00	3.44%	2.08	0.0716	0.5200	3.72%	10.7%
24	McCormick & Co.	131.80	135.00	0.48%	3.56	0.0171	0.7193	1.23%	13.2%
25	McDonald's Corp.	1076.70	1000.00	-1.47%	5.00	(0.0734)	0.8000	-5.87%	9.6%
26	Medtronic, Inc.	1100.00	1025.00	-1.40%	2.49	(0.0349)	0.5984	-2.09%	11.9%
27	PepsiCo, Inc.	1565.00	1485.00	-1.04%	5.18	(0.0540)	0.8068	-4.36%	14.7%
28	Pfizer, Inc.	8070.00	8070.00	0.00%	1.77	-	0.4364	0.00%	5.9%
29	Procter & Gamble	2917.00	2900.00	-0.12%	3.65	(0.0043)	0.7263	-0.31%	12.6%
30	Raytheon Co.	383.20	330.00	-2.95%	2.60	(0.0764)	0.6148	-4.70%	8.0%
31	Sysco Corp.	590.03	565.00	-0.86%	5.23	(0.0452)	0.8089	-3.65%	15.0%
32	Verizon Communic.	2835.70	2820.00	-0.11%	2.90	(0.0032)	0.6555	-0.21%	5.7%
33	Wal-Mart Stores	3786.00	3270.00	-2.89%	2.94	(0.0849)	0.6600	-5.61%	8.9%
34	Walgreen Co.	988.56	930.00	-1.21%	2.31	(0.0280)	0.5664	-1.59%	10.1%

(a) www.valueline.com (retrieved June 22, 2010).
(b) Average of High and Low expected market prices.
(c) Computed at (EPS - DPS) / EPS.
(d) Computed as EPS / BVPS.
(e) Product of BVPS and No. Shares Outstanding.
(f) Five-year rate of change.
(g) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(h) Product of year-end "r" for 2013-15 and Adjustment Factor.
(i) Average of High and Low expected market prices divided by 2013-15 BVPS.
(j) Product of change in common shares outstanding and M/B Ratio.
(k) Computed as 1 - B/M Ratio.
(l) Product of "s" and "v".
(m) Product of average "b" and adjusted "r", plus "sv".

MULTI-STAGE DCF MODEL

GAS UTILITY PROXY GROUP

	Recent	Projected Price 2013-15			2010	2011	2013-15	Annual	Annual Cash Flows						Implied Cost of
Company	**Price**	**High**	**Low**	**Avg.**	**Div.**	**Div.**	**Div.**	**Change**	**Yr 1**	**Yr 2**	**Yr 3**	**Yr 4**	**Yr 5**	**End Yr 5**	**Equity**
AGL Resources, Inc.	$ 36.70	$ 60.00	$ 45.00	$ 52.50	$ 1.76	$ 1.80	$ 1.92	$ 0.04	$ 0.44	$ 1.80	$ 1.84	$ 1.88	$ 1.92	$ 52.50	13.5%
Atmos Energy Corp.	$ 28.30	$ 40.00	$ 30.00	$ 35.00	$ 1.34	$ 1.36	$ 1.45	$ 0.03	$ 0.34	$ 1.36	$ 1.39	$ 1.42	$ 1.45	$ 35.00	9.9%
Laclede Group	$ 33.30	$ 55.00	$ 40.00	$ 47.50	$ 1.57	$ 1.61	$ 1.75	$ 0.05	$ 0.39	$ 1.61	$ 1.66	$ 1.70	$ 1.75	$ 47.50	13.4%
New Jersey Resources	$ 37.31	$ 45.00	$ 40.00	$ 42.50	$ 1.36	$ 1.44	$ 1.56	$ 0.04	$ 0.34	$ 1.44	$ 1.48	$ 1.52	$ 1.56	$ 42.50	7.0%
Nicor, Inc.	$ 42.29	$ 60.00	$ 40.00	$ 50.00	$ 1.86	$ 1.86	$ 1.86	$ -	$ 0.47	$ 1.86	$ 1.86	$ 1.86	$ 1.86	$ 50.00	8.3%
NiSource Inc.	$ 17.36	$ 25.00	$ 18.00	$ 21.50	$ 0.92	$ 0.92	$ 0.94	$ 0.01	$ 0.23	$ 0.92	$ 0.93	$ 0.93	$ 0.94	$ 21.50	10.4%
Northwest Natural Gas	$ 45.44	$ 65.00	$ 55.00	$ 60.00	$ 1.66	$ 1.72	$ 1.90	$ 0.06	$ 0.42	$ 1.72	$ 1.78	$ 1.84	$ 1.90	$ 60.00	10.5%
Piedmont Natural Gas	$ 27.28	$ 40.00	$ 30.00	$ 35.00	$ 1.11	$ 1.15	$ 1.27	$ 0.04	$ 0.28	$ 1.15	$ 1.19	$ 1.23	$ 1.27	$ 35.00	10.3%
South Jersey Industries	$ 46.99	$ 55.00	$ 40.00	$ 47.50	$ 1.34	$ 1.40	$ 1.60	$ 0.07	$ 0.34	$ 1.40	$ 1.47	$ 1.53	$ 1.60	$ 47.50	3.5%
Southwest Gas	$ 31.45	$ 50.00	$ 35.00	$ 42.50	$ 1.00	$ 1.05	$ 1.20	$ 0.05	$ 0.25	$ 1.05	$ 1.10	$ 1.15	$ 1.20	$ 42.50	10.7%
UGI Corp.	$ 27.60	$ 40.00	$ 30.00	$ 35.00	$ 0.90	$ 1.00	$ 1.16	$ 0.05	$ 0.23	$ 1.00	$ 1.05	$ 1.11	$ 1.16	$ 35.00	9.4%
WGL Holdings, Inc.	$ 35.27	$ 45.00	$ 35.00	$ 40.00	$ 1.66	$ 1.51	$ 1.55	$ 0.01	$ 0.42	$ 1.51	$ 1.52	$ 1.54	$ 1.55	$ 40.00	7.3%
Average															**10.7%**

Source: The Value Line Investment Survey (Sep. 10, 2010). Average excludes highlighted figures.

MULTI-STAGE DCF MODEL

COMBINATION UTILITY PROXY GROUP

Company	Recent Price	Projected Price 2013-15 High	Projected Price 2013-15 Low	Projected Price 2013-15 Avg.	2010 Div.	2011 Div.	2013-15 Div.	Annual Change	Annual Cash Flows Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	End Yr 5	Implied Cost of Equity
ALLETE	$ 35.57	$ 40.00	$ 30.00	$ 35.00	$ 1.76	$ 1.76	$ 1.80	$ 0.01	$ 0.44	$ 1.76	$ 1.77	$ 1.79	$ 1.80	$ 35.00	4.8%
Alliant Energy	$ 35.02	$ 55.00	$ 40.00	$ 47.50	$ 1.58	$ 1.65	$ 1.92	$ 0.09	$ 0.40	$ 1.65	$ 1.74	$ 1.83	$ 1.92	$ 47.50	12.2%
Ameren Corp.	$ 28.07	$ 35.00	$ 25.00	$ 30.00	$ 1.54	$ 1.54	$ 1.54	$ -	$ 0.39	$ 1.54	$ 1.54	$ 1.54	$ 1.54	$ 30.00	7.1%
Avista Corp.	$ 20.87	$ 30.00	$ 25.00	$ 27.50	$ 1.00	$ 1.08	$ 1.30	$ 0.07	$ 0.25	$ 1.08	$ 1.15	$ 1.23	$ 1.30	$ 27.50	12.1%
Black Hills Corp.	$ 30.43	$ 40.00	$ 30.00	$ 35.00	$ 1.44	$ 1.48	$ 1.60	$ 0.04	$ 0.36	$ 1.48	$ 1.52	$ 1.56	$ 1.60	$ 35.00	8.3%
Constellation Energy	$ 29.33	$ 50.00	$ 30.00	$ 40.00	$ 0.96	$ 0.96	$ 1.00	$ 0.01	$ 0.24	$ 0.96	$ 0.97	$ 0.99	$ 1.00	$ 40.00	10.7%
DTE Energy Co.	$ 46.85	$ 65.00	$ 45.00	$ 55.00	$ 2.12	$ 2.24	$ 2.60	$ 0.12	$ 0.53	$ 2.24	$ 2.36	$ 2.48	$ 2.60	$ 55.00	8.9%
Empire District Elec	$ 19.62	$ 30.00	$ 20.00	$ 25.00	$ 1.28	$ 1.28	$ 1.35	$ 0.02	$ 0.32	$ 1.28	$ 1.30	$ 1.33	$ 1.35	$ 25.00	12.4%
Entergy Corp.	$ 78.84	$ 125.00	$ 95.00	$ 110.00	$ 3.24	$ 3.53	$ 4.15	$ 0.21	$ 0.81	$ 3.53	$ 3.74	$ 3.94	$ 4.15	$ 110.00	12.7%
Exelon Corp.	$ 40.72	$ 60.00	$ 45.00	$ 52.50	$ 2.10	$ 2.10	$ 2.10	$ -	$ 0.53	$ 2.10	$ 2.10	$ 2.10	$ 2.10	$ 52.50	11.1%
Integrys Energy Group	$ 48.45	$ 55.00	$ 40.00	$ 47.50	$ 2.72	$ 2.72	$ 2.72	$ -	$ 0.68	$ 2.72	$ 2.72	$ 2.72	$ 2.72	$ 47.50	5.3%
Northeast Utilities	$ 28.97	$ 45.00	$ 30.00	$ 37.50	$ 1.03	$ 1.10	$ 1.30	$ 0.07	$ 0.26	$ 1.10	$ 1.17	$ 1.23	$ 1.30	$ 37.50	10.2%
PG&E Corp.	$ 46.76	$ 60.00	$ 45.00	$ 52.50	$ 1.82	$ 1.96	$ 2.40	$ 0.15	$ 0.46	$ 1.96	$ 2.11	$ 2.25	$ 2.40	$ 52.50	7.3%
Pub Sv Enterprise Grp	$ 31.96	$ 50.00	$ 35.00	$ 42.50	$ 1.37	$ 1.41	$ 1.60	$ 0.06	$ 0.34	$ 1.41	$ 1.47	$ 1.54	$ 1.60	$ 42.50	11.4%
SCANA Corp.	$ 39.03	$ 50.00	$ 40.00	$ 45.00	$ 1.90	$ 1.92	$ 2.00	$ 0.03	$ 0.48	$ 1.92	$ 1.95	$ 1.97	$ 2.00	$ 45.00	8.4%
Sempra Energy	$ 50.92	$ 70.00	$ 55.00	$ 62.50	$ 1.56	$ 1.68	$ 2.05	$ 0.12	$ 0.39	$ 1.68	$ 1.80	$ 1.93	$ 2.05	$ 62.50	8.4%
Wisconsin Energy	$ 55.74	$ 80.00	$ 60.00	$ 70.00	$ 1.60	$ 1.80	$ 2.40	$ 0.20	$ 0.40	$ 1.80	$ 2.00	$ 2.20	$ 2.40	$ 70.00	9.0%
Average															**10.4%**

Source: The Value Line Investment Survey (Sep. 10, 2010). Average excludes highlighted figures.

CAPITAL ASSET PRICING MODEL

GAS UTILITY PROXY GROUP

Market Rate of Return		
Dividend Yield (a)	2.6%	
Growth Rate (b)	10.4%	
Market Return (c)		13.0%
Less: Risk-Free Rate (d)		
Long-term Treasury Bond Yield		3.5%
Market Risk Premium (e)		9.5%
Gas Utility Proxy Group Beta (f)		0.69
Utility Proxy Group Risk Premium (g)		6.5%
Plus: Risk-free Rate (d)		
Long-term Treasury Bond Yield		3.5%
Implied Cost of Equity (h)		**10.0%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (retrieved July 30, 2010).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 (retrieved August 11, 2010).
(c) (a) + (b)
(d) Average yield on 20-year Treasury bonds for August 2010 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/Monthly/H15_TCMNOM_Y20.txt.
(e) (c) - (d).
(f) The Value Line Investment Survey (Sep. 10, 2010).
(g) (e) x (f).
(h) (d) + (g).

CAPITAL ASSET PRICING MODEL

COMBINATION UTILITY PROXY GROUP

Market Rate of Return		
Dividend Yield (a)	2.6%	
Growth Rate (b)	10.4%	
Market Return (c)		13.0%
Less: Risk-Free Rate (d)		
Long-term Treasury Bond Yield		3.5%
Market Risk Premium (e)		9.5%
Combination Utility Proxy Group Beta (f)		0.75
Utility Proxy Group Risk Premium (g)		7.1%
Plus: Risk-free Rate (d)		
Long-term Treasury Bond Yield		3.5%
Implied Cost of Equity (h)		**10.6%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (retrieved July 30, 2010).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 (retrieved August 11, 2010).
(c) (a) + (b)
(d) Average yield on 20-year Treasury bonds for August 2010 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/Monthly/H15_TCMNOM_Y20.txt.
(e) (c) - (d).
(f) The Value Line Investment Survey (Jun. 25, Aug. 6, & Aug. 27, 2010).
(g) (e) x (f).
(h) (d) + (g).

CAPITAL ASSET PRICING MODEL

NON-UTILITY PROXY GROUP

Market Rate of Return		
Dividend Yield (a)	2.6%	
Growth Rate (b)	10.4%	
Market Return (c)		13.0%
Less: Risk-Free Rate (d)		
Long-term Treasury Bond Yield		3.5%
Market Risk Premium (e)		9.5%
Non-Utility Proxy Group Beta (f)		0.65
Utility Proxy Group Risk Premium (g)		6.2%
Plus: Risk-free Rate (d)		
Long-term Treasury Bond Yield		3.5%
Implied Cost of Equity (h)		**9.7%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (retrieved July 30, 2010).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 (retrieved August 11, 2010).
(c) (a) + (b)
(d) Average yield on 20-year Treasury bonds for August 2010 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/Monthly/H15_TCMNOM_Y20.txt.
(e) (c) - (d).
(f) www.valueline.com (retrieved June 22, 2010).
(g) (e) x (f).
(h) (d) + (g).

EXPECTED EARNINGS APPROACH

GAS UTILITY PROXY GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	AGL Resources, Inc.	12.0%	1.0286	12.3%
2	Atmos Energy Corp.	9.5%	1.0341	9.8%
3	Laclede Group	11.0%	1.0331	11.4%
4	New Jersey Resources	14.0%	1.0225	14.3%
5	Nicor, Inc.	11.0%	1.0203	11.2%
6	NiSource, Inc.	8.0%	1.0126	8.1%
7	Northwest Natural Gas	12.0%	1.0235	12.3%
8	Piedmont Natural Gas	13.0%	1.0071	13.1%
9	South Jersey Industries	14.5%	1.0386	15.1%
10	Southwest Gas	9.0%	1.0372	9.3%
11	UGI Corp.	12.0%	1.0446	12.5%
12	WGL Holdings, Inc.	11.0%	1.0188	11.2%
	Average			**11.7%**

(a) 3-5 year projections from The Value Line Investment Survey (Sep. 10, 2010).

(b) Adjustment to convert year-end "r" to an average rate of return from Schedule WEA-2.

(c) (a) x (b).

EXPECTED EARNINGS APPROACH

COMBINATION UTILITY PROXY GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	ALLETE	8.0%	1.0192	8.2%
2	Alliant Energy	11.5%	1.0261	11.8%
3	Ameren Corp.	6.5%	1.0183	6.6%
4	Avista Corp.	9.0%	1.0233	9.2%
5	Black Hills Corp.	8.0%	1.0156	8.1%
6	Constellation Energy	6.5%	1.0223	6.6%
7	DTE Energy Co.	9.0%	1.0276	9.2%
8	Empire District Elec	10.5%	1.0203	10.7%
9	Entergy Corp.	13.5%	1.0161	13.7%
10	Exelon Corp.	14.5%	1.0236	14.8%
11	Integrys Energy Group	9.5%	1.0118	9.6%
12	Northeast Utilities	9.5%	1.0312	9.8%
13	PG&E Corp.	12.0%	1.0392	12.5%
14	Pub Sv Enterprise Grp	13.0%	1.0394	13.5%
15	SCANA Corp.	10.0%	1.0419	10.4%
16	Sempra Energy	10.5%	1.0257	10.8%
17	Wisconsin Energy	12.5%	1.0289	12.9%
	Average			**11.0%**

(a) 3-5 year projections from The Value Line Investment Survey (Jun. 25, Aug. 6, & Aug. 27, 2010).
(b) Adjustment to convert year-end "r" to an average rate of return from Schedule WEA-4.
(c) (a) x (b).

CAPITAL STRUCTURE

GAS UTILITY PROXY GROUP

		At Fiscal Year-End 2008 (a)			Value Line Projected (b)		
	Company	Long-term Debt	Preferred	Common Equity	Long-term Debt	Other	Common Equity
1	AGL Resources, Inc.	52.0%	0.0%	48.0%	39.0%	0.0%	61.0%
2	Atmos Energy Corp.	49.9%	0.0%	50.1%	49.0%	0.0%	51.0%
3	Laclede Group	42.9%	0.0%	57.1%	47.0%	0.0%	53.0%
4	New Jersey Resources	40.1%	0.0%	59.9%	40.0%	0.0%	60.0%
5	Nicor, Inc.	32.4%	0.0%	67.6%	25.0%	0.0%	75.0%
6	NiSource Inc.	57.9%	0.0%	42.1%	52.0%	0.0%	48.0%
7	Northwest Natural Gas	49.1%	0.0%	50.9%	40.0%	0.0%	60.0%
8	Piedmont Natural Gas	46.1%	0.0%	53.9%	47.5%	0.0%	52.5%
9	South Jersey Industries	39.0%	0.0%	61.0%	38.5%	0.0%	61.5%
10	Southwest Gas	53.6%	0.0%	46.4%	46.5%	0.0%	53.5%
11	UGI Corp.	54.0%	0.0%	46.0%	38.0%	0.0%	62.0%
12	WGL Holdings, Inc.	36.4%	1.6%	62.0%	34.0%	1.5%	64.5%
	Average	**46.1%**	**0.1%**	**53.7%**	**41.4%**	**0.1%**	**58.5%**

(a) Company Form 10-K and Annual Reports.
(b) The Value Line Investment Survey (Sep. 10, 2010).

COMBINATION UTILITY PROXY GROUP

		At Fiscal Year-End 2008 (a)			Value Line Projected (b)		
	Company	Long-term Debt	Preferred	Common Equity	Long-term Debt	Other	Common Equity
1	ALLETE	42.7%	0.0%	57.3%	45.5%	0.0%	54.5%
2	Alliant Energy	45.4%	4.4%	50.2%	40.5%	3.5%	56.0%
3	Ameren Corp.	47.6%	0.0%	52.4%	47.0%	1.0%	52.0%
4	Avista Corp.	49.3%	2.4%	48.3%	50.0%	0.0%	50.0%
5	Black Hills Corp.	49.2%	0.0%	50.8%	51.0%	0.0%	49.0%
6	Constellation Energy	35.2%	1.4%	63.4%	28.5%	1.5%	70.0%
7	DTE Energy Co.	51.1%	2.1%	46.7%	52.5%	0.0%	47.5%
8	Empire District Elec	49.7%	3.9%	46.5%	48.0%	0.0%	52.0%
9	Entergy Corp.	56.1%	1.5%	42.3%	58.0%	1.5%	40.5%
10	Exelon Corp.	47.8%	0.4%	51.9%	45.0%	0.0%	55.0%
11	Integrys Energy Group	46.3%	0.9%	52.7%	48.5%	1.0%	50.5%
12	Northeast Utilities	55.2%	1.4%	43.4%	56.5%	1.0%	42.5%
13	PG&E Corp.	50.3%	1.2%	48.5%	45.5%	1.0%	53.5%
14	Pub Sv Enterprise Grp	44.1%	0.5%	55.4%	40.0%	0.0%	60.0%
15	SCANA Corp.	57.0%	0.0%	43.0%	52.5%	0.0%	47.5%
16	Sempra Energy	46.5%	0.6%	52.9%	47.0%	1.0%	52.0%
17	Wisconsin Energy	53.7%	0.4%	45.9%	51.5%	0.0%	48.5%
	Average	**48.7%**	**1.2%**	**50.1%**	**47.5%**	**0.7%**	**51.8%**

(a) Company Form 10-K and Annual Reports.
(b) The Value Line Investment Survey (Jun. 25, Aug. 6, & Aug. 27, 2010).

DCF MODEL

GAS UTILITY PROXY GROUP

		(a)	(a)		(b)	(c)	(d)	(e)	(b)	(f)	(f)	(f)	(f)	(f)
		Dividend Yield			**Growth Rates**					**Cost of Equity Estimates**				
	Company	**Price**	**Dividends**	**Yield**	**V Line**	**IBES**	**Zacks**	**br+sv**	**Price**	**V Line**	**IBES**	**Zacks**	**br+sv**	**Price**
1	AGL Resources, Inc.	$ 36.70	$ 1.76	4.8%	5.0%	5.8%	4.0%	6.0%	8.8%	9.8%	10.6%	8.8%	10.8%	13.6%
2	Atmos Energy Corp.	$ 28.30	$ 1.36	4.8%	5.5%	3.4%	4.7%	4.9%	5.1%	10.3%	8.2%	9.5%	9.8%	9.9%
3	Laclede Group	$ 33.30	$ 1.61	4.8%	2.5%	NA	3.0%	7.0%	8.7%	7.3%	NA	7.8%	11.8%	13.6%
4	New Jersey Resources	$ 37.31	$ 1.36	3.6%	5.0%	3.3%	4.0%	6.1%	3.1%	8.6%	6.9%	7.6%	9.7%	6.8%
5	Nicor, Inc.	$ 42.29	$ 1.86	4.4%	1.0%	0.7%	3.5%	4.2%	4.0%	5.4%	5.1%	7.9%	8.6%	8.4%
6	NiSource Inc.	$ 17.36	$ 0.92	5.3%	6.0%	8.7%	3.0%	3.4%	5.2%	11.3%	14.0%	8.3%	8.7%	10.5%
7	Northwest Natural Gas	$ 45.44	$ 1.66	3.7%	4.5%	4.1%	4.9%	6.5%	6.8%	8.2%	7.8%	8.6%	10.1%	10.4%
8	Piedmont Natural Gas	$ 27.28	$ 1.12	4.1%	3.5%	3.5%	4.5%	2.7%	6.0%	7.6%	7.6%	8.6%	6.8%	10.1%
9	South Jersey Industries	$ 46.99	$ 1.37	2.9%	7.0%	6.3%	6.5%	10.4%	0.3%	9.9%	9.2%	9.4%	13.4%	3.2%
10	Southwest Gas	$ 31.45	$ 1.02	3.2%	7.5%	6.0%	6.0%	5.7%	7.3%	10.7%	9.2%	9.2%	9.0%	10.6%
11	UGI Corp.	$ 27.60	$ 1.00	3.6%	4.0%	3.2%	1.6%	7.5%	5.7%	7.6%	6.8%	5.2%	11.1%	9.4%
12	WGL Holdings, Inc.	$ 35.27	$ 1.51	4.3%	2.5%	3.2%	3.7%	3.9%	3.0%	6.8%	7.5%	8.0%	8.2%	7.3%
	Average (g)									**9.8%**	**10.3%**	**8.8%**	**10.1%**	**10.7%**

(a) Recent price and estimated dividend for next 12 mos. from The Value Line Investment Survey, *Summary and Index* (Sep. 10, 2010).
(b) The Value Line Investment Survey (Sep. 10, 2010).
(c) *Thomson ReutersCompany in Context Report* (Sep. 14, 2010).
(d) www.zacks.com (retrieved Sep. 15, 2010).
(e) See Schedule WEA-2.
(f) Sum of dividend yield and respective growth rate.
(g) Excludes highlighted figures.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

WILLIAM E. AVERA
Exhibit No. 302

Return on Equity

WILLIAM E. AVERA

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Summary of Qualifications

Ph.D. in economics and finance; Chartered Financial Analyst (CFA ®) designation; extensive expert witness testimony before courts, alternative dispute resolution panels, regulatory agencies and legislative committees; lectured in executive education programs around the world on ethics, investment analysis, and regulation; undergraduate and graduate teaching in business and economics; appointed to leadership positions in government, industry, academia, and the military.

Employment

Principal, FINCAP, Inc. (Sep. 1979 to present)	Financial, economic and policy consulting to business and government. Perform business and public policy research, cost/benefit analyses and financial modeling, valuation of businesses (almost 200 entities valued), estimation of damages, statistical and industry studies. Provide strategy advice and educational services in public and private sectors, and serve as expert witness before regulatory agencies, legislative committees, arbitration panels, and courts.
Director, Economic Research Division, Public Utility Commission of Texas (Dec. 1977 to Aug. 1979)	Responsible for research and testimony preparation on rate of return, rate structure, and econometric analysis dealing with energy, telecommunications, water and sewer utilities. Testified in major rate cases and appeared before legislative committees and served as Chief Economist for agency. Administered state and federal grant funds. Communicated frequently with political leaders and representatives from consumer groups, media, and investment community.
Manager, Financial Education, International Paper Company New York City (Feb. 1977 to Nov. 1977)	Directed corporate education programs in accounting, finance, and economics. Developed course materials, recruited and trained instructors, liaison within the company and with academic institutions. Prepared operating budget and designed financial controls for corporate professional development program.

Lecturer in Finance, The University of Texas at Austin (Sep. 1979 to May 1981) Assistant Professor of Finance, (Sep. 1975 to May 1977)	Taught graduate and undergraduate courses in financial management and investment theory. Conducted research in business and public policy. Named Outstanding Graduate Business Professor and received various administrative appointments.
Assistant Professor of Business, University of North Carolina at Chapel Hill (Sep. 1972 to Jul. 1975)	Taught in BBA, MBA, and Ph.D. programs. Created project course in finance, Financial Management for Women, and participated in developing Small Business Management sequence. Organized the North Carolina Institute for Investment Research, a group of financial institutions that supported academic research. Faculty advisor to the Media Board, which funds student publications and broadcast stations.

Education

Ph.D., Economics and Finance, University of North Carolina at Chapel Hill (Jan. 1969 to Aug. 1972)	Elective courses included financial management, public finance, monetary theory, and econometrics. Awarded the Stonier Fellowship by the American Bankers' Association and University Teaching Fellowship. Taught statistics, macroeconomics, and microeconomics. Dissertation: *The Geometric Mean Strategy as a Theory of Multiperiod Portfolio Choice*
B.A., Economics, Emory University, Atlanta, Georgia (Sep. 1961 to Jun. 1965)	Active in extracurricular activities, president of the Barkley Forum (debate team), Emory Religious Association, and Delta Tau Delta chapter. Individual awards and team championships at national collegiate debate tournaments.

Professional Associations

Received Chartered Financial Analyst (CFA) designation in 1977; Vice President for Membership, Financial Management Association; President, Austin Chapter of Planning Executives Institute; Board of Directors, North Carolina Society of Financial Analysts; Candidate Curriculum Committee, Association for Investment Management and Research; Executive Committee of Southern Finance Association; Vice Chair, Staff Subcommittee on Economics and National Association of Regulatory Utility Commissioners (NARUC); Appointed to NARUC Technical Subcommittee on the National Energy Act.

Teaching in Executive Education Programs

University-Sponsored Programs: Central Michigan University, Duke University, Louisiana State University, National Defense University, National University of Singapore, Texas A&M University, University of Kansas, University of North Carolina, University of Texas.

Business and Government-Sponsored Programs: Advanced Seminar on Earnings Regulation, American Public Welfare Association, Association for Investment Management and Research, Congressional Fellows Program, Cost of Capital Workshop, Electricity Consumers Resource Council, Financial Analysts Association of Indonesia, Financial Analysts Review, Financial Analysts Seminar at Northwestern University, Governor's Executive Development Program of Texas, Louisiana Association of Business and Industry, National Association of Purchasing Management, National Association of Tire Dealers, Planning Executives Institute, School of Banking of the South, State of Wisconsin Investment Board, Stock Exchange of Thailand, Texas Association of State Sponsored Computer Centers, Texas Bankers' Association, Texas Bar Association, Texas Savings and Loan League, Texas Society of CPAs, Tokyo Association of Foreign Banks, Union Bank of Switzerland, U.S. Department of State, U.S. Navy, U.S. Veterans Administration, in addition to Texas state agencies and major corporations.

Presented papers for Mills B. Lane Lecture Series at the University of Georgia and Heubner Lectures at the University of Pennsylvania. Taught graduate courses in finance and economics for evening program at St. Edward's University in Austin from January 1979 through 1998.

Expert Witness Testimony

Testified in over 300 cases before regulatory agencies addressing cost of capital, regulatory policy, rate design, and other economic and financial issues.

Federal Agencies: Federal Communications Commission, Federal Energy Regulatory Commission, Surface Transportation Board, Interstate Commerce Commission, and the Canadian Radio-Television and Telecommunications Commission.

State Regulatory Agencies: Alaska, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Idaho, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Missouri, Nevada, New Mexico, Montana, Nebraska, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Virginia, Washington, West Virginia, Wisconsin, and Wyoming.

Testified in 42 cases before federal and state courts, arbitration panels, and alternative dispute tribunals (89 depositions given) regarding damages, valuation, antitrust liability, fiduciary duties, and other economic and financial issues.

Board Positions and Other Professional Activities

Audit Committee and Outside Director, Georgia System Operations Corporation (electric system operator for member-owned electric cooperatives in Georgia); Chairman, Board of Print Depot, Inc. and FINCAP, Inc.; Co-chair, Synchronous Interconnection Committee, appointed by Public Utility Commission of Texas and approved by governor; Appointed by Hays County Commission to Citizens Advisory Committee of Habitat Conservation Plan, Operator of AAA Ranch, a certified organic producer of agricultural products; Appointed to Organic Livestock Advisory Committee by

Texas Agricultural Commissioner Susan Combs; Appointed by Texas Railroad Commissioners to study group for *The UP/SP Merger: An Assessment of the Impacts on the State of Texas; A*ppointed by Hawaii Public Utilities Commission to team reviewing affiliate relationships of Hawaiian Electric Industries; Chairman, Energy Task Force, Greater Austin-San Antonio Corridor Council; Consultant to Public Utility Commission of Texas on cogeneration policy and other matters; Consultant to Public Service Commission of New Mexico on cogeneration policy; Evaluator of Energy Research Grant Proposals for Texas Higher Education Coordinating Board.

Community Activities

Board of Directors, Sustainable Food Center; Chair, Board of Deacons, Finance Committee, and Elder, Central Presbyterian Church of Austin; Founding Member, Orange-Chatham County (N.C.) Legal Aid Screening Committee.

Military

Captain, U.S. Naval Reserve (retired after 28 years service); Commanding Officer, Naval Special Warfare Engineering (SEAL) Support Unit; Officer-in-Charge of SWIFT patrol boat in Vietnam; Enlisted service as weather analyst (advanced to second class petty officer).

Bibliography

Monographs

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"Definition of Industry Ethics and Development of a Code" and "Applying Ethics in the Real World," in *Good Ethics: The Essential Element of a Firm's Success*, Association for Investment Management and Research (1994)

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An Examination of the Concept of Using Relative Customer Class Risk to Set Target Rates of Return in Electric Cost-of-Service Studies, with Bruce H. Fairchild, Electricity Consumers Resource Council (ELCON) (1981); portions reprinted in *Public Utilities Fortnightly* (Nov. 11, 1982)

"Usefulness of Current Values to Investors and Creditors," *Research Study on Current-Value Accounting Measurements and Utility*, George M. Scott, ed., Touche Ross Foundation (1978)

"The Geometric Mean Strategy and Common Stock Investment Management," with Henry A. Latané in *Life Insurance Investment Policies*, David Cummins, ed. (1977)

Investment Companies: Analysis of Current Operations and Future Prospects, with J. Finley Lee and Glenn L. Wood, American College of Life Underwriters (1975)

Articles

"Should Analysts Own the Stocks they Cover?" *The Financial Journalist*, (March 2002)

"Liquidity, Exchange Listing, and Common Stock Performance," with John C. Groth and Kerry Cooper, *Journal of Economics and Business* (Spring 1985); reprinted by National Association of Security Dealers

"The Energy Crisis and the Homeowner: The Grief Process," *Texas Business Review* (Jan.–Feb. 1980); reprinted in *The Energy Picture: Problems and Prospects*, J. E. Pluta, ed., Bureau of Business Research (1980)

"Use of IFPS at the Public Utility Commission of Texas," *Proceedings of the IFPS Users Group Annual Meeting* (1979)

"Production Capacity Allocation: Conversion, CWIP, and One-Armed Economics," *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"Some Thoughts on the Rate of Return to Public Utility Companies," with Bruce H. Fairchild in *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"A New Capital Budgeting Measure: The Integration of Time, Liquidity, and Uncertainty," with David Cordell in *Proceedings of the Southwestern Finance Association* (1977)

"Usefulness of Current Values to Investors and Creditors," in *Inflation Accounting/Indexing and Stock Behavior* (1977)

"Consumer Expectations and the Economy," *Texas Business Review* (Nov. 1976)

"Portfolio Performance Evaluation and Long-run Capital Growth," with Henry A. Latané in *Proceedings of the Eastern Finance Association* (1973)

Book reviews in *Journal of Finance* and *Financial Review*. Abstracts for *CFA Digest*. Articles in *Carolina Financial Times*.

Selected Papers and Presentations

"Economic Perspective on Water Marketing in Texas," 2009 Water Law Institute, The University of Texas School of Law, Austin, TX (Dec. 2009).

"Estimating Utility Cost of Equity in Financial Turmoil," SNL EXNET 15th Annual FERC Briefing, Washington, D.C. (Mar. 2009)

"The Who, What, When, How, and Why of Ethics," San Antonio Financial Analysts Society (Jan. 16, 2002). Similar presentation given to the Austin Society of Financial Analysts (Jan. 17, 2002)

"Ethics for Financial Analysts," Sponsored by Canadian Council of Financial Analysts: delivered in Calgary, Edmonton, Regina, and Winnipeg, June 1997. Similar presentations given to Austin Society of Financial Analysts (Mar. 1994), San Antonio Society of Financial Analysts (Nov. 1985), and St. Louis Society of Financial Analysts (Feb. 1986)

"Cost of Capital for Multi-Divisional Corporations," Financial Management Association, New Orleans, Louisiana (Oct. 1996)

"Ethics and the Treasury Function," Government Treasurers Organization of Texas, Corpus Christi, Texas (Jun. 1996)

"A Cooperative Future," Iowa Association of Electric Cooperatives, Des Moines (December 1995). Similar presentations given to National G & T Conference, Irving, Texas (June 1995), Kentucky Association of Electric Cooperatives Annual Meeting, Louisville (Nov. 1994), Virginia, Maryland, and Delaware Association of Electric Cooperatives Annual Meeting, Richmond (July 1994), and Carolina Electric Cooperatives Annual Meeting, Raleigh (Mar. 1994)

"Information Superhighway Warnings: Speed Bumps on Wall Street and Detours from the Economy," Texas Society of Certified Public Accountants Natural Gas, Telecommunications and Electric Industries Conference, Austin (Apr. 1995)

"Economic/Wall Street Outlook," Carolinas Council of the Institute of Management Accountants, Myrtle Beach, South Carolina (May 1994). Similar presentation given to Bell Operating Company Accounting Witness Conference, Santa Fe, New Mexico (Apr. 1993)

"Regulatory Developments in Telecommunications," Regional Holding Company Financial and Accounting Conference, San Antonio (Sep. 1993)

"Estimating the Cost of Capital During the 1990s: Issues and Directions," The National Society of Rate of Return Analysts, Washington, D.C. (May 1992)

"Making Utility Regulation Work at the Public Utility Commission of Texas," Center for Legal and Regulatory Studies, University of Texas, Austin (June 1991)

"Can Regulation Compete for the Hearts and Minds of Industrial Customers," Emerging Issues of Competition in the Electric Utility Industry Conference, Austin (May 1988)

"The Role of Utilities in Fostering New Energy Technologies," Emerging Energy Technologies in Texas Conference, Austin (Mar. 1988)

"The Regulators' Perspective," Bellcore Economic Analysis Conference, San Antonio (Nov. 1987)

"Public Utility Commissions and the Nuclear Plant Contractor," Construction Litigation Superconference, Laguna Beach, California (Dec. 1986)

"Development of Cogeneration Policies in Texas," University of Georgia Fifth Annual Public Utilities Conference, Atlanta (Sep. 1985)

"Wheeling for Power Sales," Energy Bureau Cogeneration Conference, Houston (Nov. 1985).

"Asymmetric Discounting of Information and Relative Liquidity: Some Empirical Evidence for Common Stocks" (with John Groth and Kerry Cooper), Southern Finance Association, New Orleans (Nov. 1982)

"Used and Useful Planning Models," Planning Executive Institute, 27th Corporate Planning Conference, Los Angeles (Nov. 1979)

"Staff Input to Commission Rate of Return Decisions," The National Society of Rate of Return Analysts, New York (Oct. 1979)

""Discounted Cash Life: A New Measure of the Time Dimension in Capital Budgeting," with David Cordell, Southern Finance Association, New Orleans (Nov. 1978)

"The Relative Value of Statistics of Ex Post Common Stock Distributions to Explain Variance," with Charles G. Martin, Southern Finance Association, Atlanta (Nov. 1977)

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BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF KEVIN J. CHRISTIE
REPRESENTING AVISTA CORPORATION

Natural Gas Supply and Storage

I. INTRODUCTION

Q. Please state your name, business address, and present position with Avista Corp.

A. My name is Kevin Christie and I am employed as Director of Gas Supply of Avista Utilities (Avista or Company), at 1411 East Mission Avenue, Spokane, Washington.

Q. Would you please describe your education and business experience?

A. Yes. I graduated from Washington State University with a Bachelors Degree in Business Administration with an accounting emphasis. I have also attended the University of Idaho Utility Executive Course.

I joined the Company in 2005 as the Manager of Natural Gas Planning. In 2007, I was appointed the Director of Gas Supply. Prior to joining Avista, I was employed by Gas Transmission Northwest (GTN). I was employed by GTN from 2001 to 2005 and was the Director of Pipeline Marketing and Development from 2003 to 2005 and the Director of Pricing and Business Analysis from 2001 to 2003. From 2000 to 2001, I was employed by PG&E Corporation (PG&E) as the Manager of Finance and Assistant to the SVP, Treasurer and CFO. Before joining PG&E, I was employed by Pacific Gas Transmission Company (PGT) from 1994 to 2000. While at PGT, I held several positions including Manager, Pricing and Business Analysis, Senior Business Analyst, Senior Pricing Planner, Director of Regulatory Affairs, Project Manager – Rates and Regulatory Affairs, Senior Regulatory Analyst, Regulatory Analyst, and Revenue Accountant. From 1990 to 1994, I was employed by Chevron USA as a Lease Revenue Accountant.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to describe additional Jackson Prairie (JP) natural gas storage that the utility will receive to serve customers beginning May 1, 2011. I will also describe the allocation of this additional storage, and the associated costs, to the three jurisdictions that the Company serves.

This additional JP storage is the result of an expansion at the facility initiated in 1999, which was temporarily assigned to the Company's subsidiary, Avista Energy. This expansion and subsequent expansions at the facility are described later in my testimony. I will also describe the proposed allocation of this additional storage, and the associated costs, to the three jurisdictions that the Company serves. The allocation of the additional storage and total cost associated with all of the expansions since 1999 are proposed to be allocated proportionately to the three jurisdictions based on forecasted sales volumes. The revenue requirement impact associated with the additional storage and associated costs are described by Ms. Andrews.

Q. Are you sponsoring exhibits in this proceeding?

A. Yes. I am sponsoring Exhibit No. 401, which contains cost and pricing information relative to Jackson Prairie Storage. I am also sponsoring Exhibit No. 402, which is a copy of the Company's 2009 Natural Gas Integrated Resource Plan, which was acknowledged by this Commission on June 8, 2010.

II. HISTORY OF JACKSON PRAIRIE STORAGE FACILITY

Q. Could you please describe Avista's involvement with the Jackson Prairie gas storage facility?

A. Yes. Avista is one of the three original developers of the underground storage facility at Jackson Prairie, which is located near Chehalis, Washington. Although there have been corporate changes due to mergers, acquisitions and name changes, Avista, Puget Sound

Energy (PSE) and Northwest Pipeline each hold a one-third share (equal, undivided interest) of this underground gas storage facility through a joint ownership agreement. Development of the facility began in the 1960's and the project first went into service in the early 1970's. Puget Sound Energy is the operator of the facility.

Q. What type of storage facility is Jackson Prairie?

A. Jackson Prairie is an underground aquifer storage facility. Storage and the associated withdrawal and injection capability has been created by a combination of wells, gathering pipelines, compression and dehydration equipment, and the removal and disposal of aquifer water.

Q. Please describe the present level of storage that Avista owns at Jackson Prairie.

A. At the present time, Avista Utilities owns a total of 5,497,112 dekatherms (Dth) of capacity. This capacity comes with a withdrawal capability of 294,667 Dth per day (deliverability). Oregon's current share of that capacity is 262,446 Dth and 26,000 Dth of deliverability.

Q. Could you please describe what is meant by "capacity" and "deliverability"?

A. Yes. Capacity is the amount of gas that the facility holds and represents the volume of gas that can be made available for injection and withdrawal by the owner. This capacity is typically referred to as "working" gas. Working gas is different from "cushion" gas which is also stored in the facility. Cushion gas provides the field pressure necessary to allow the withdrawal of working gas. Cushion gas must physically remain in the facility at all times to ensure the deliverability of the working gas and, therefore, cannot be withdrawn on a seasonal basis. Capacity, as used herein, refers to the working gas portion of Jackson Prairie. Deliverability, as used herein, is the maximum amount of gas that can be withdrawn from the facility on a daily basis.

Q. How is cushion gas at Jackson Prairie accounted for?

A. As stated above, cushion gas must remain in the facility in order to withdraw working gas. When the field is abandoned there will be residual cushion gas in the field that will not be recoverable due to economics and physical constraints. Therefore, a portion of cushion gas is estimated to be non-recoverable from the facility and that portion is depreciated over the estimated life of the facility (account 352.3-Nonrecoverable natural gas). The recoverable portion of cushion gas remains in rate base at its original cost over the life of the facility (account 117.1-Gas stored-base gas). Both accounts are included in the Company's rate base (Company witness Ms. Andrews provides additional details related to the accounting treatment).

Q. Could you please describe Avista's share of the expansions that have occurred at the facility since 1999?

A. Yes. In 1999, the owners agreed to both a capacity and deliverability expansion of the facility (FERC Certificate in CP98-250-000). Avista's allocated share of the expansion was 1,066,667 Dth of capacity and 104,000 Dth per day of deliverability. Based on the Company's Integrated Resource Plan (IRP) at the time, Avista's share of the expansion capacity would have provided storage capacity in excess of what was needed to serve Avista's near-term customer requirements. In order to better align the incremental cost to the utility and the future need for this resource, the increased capacity and deliverability were temporarily assigned to Avista Energy.

Beginning in 2002, another capacity expansion was initiated at the facility (FERC Certificate in CP02-384-000). This expansion was for capacity only and did not include additional daily deliverability. This capacity expansion was a multi-year expansion that was completed in phases with the last phase placed into service during 2008. Again, to better align the incremental costs with IRP requirements, this expansion was also temporarily assigned to Avista Energy; Avista Energy paid the capital required for this expansion in exchange for the rights to utilize that portion of the facility for an agreed upon period of time. The temporary assignment of this expansion to Avista Energy was for 1,964,220 Dth of capacity. Under this arrangement, Avista Utilities would receive the expansion capability back at a later date, as cost, to serve its retail customers, and it also enabled Avista to preserve its full one-third interest in the project.

On July 1, 2007, Avista Energy's business and contracts were sold to Shell Energy North America (Shell). The sale included the aforementioned expansion assignments and increased capacity that had been completed up to that point in time. As the 2002 expansion was not yet complete, Avista Utilities (funded the remaining capital requirements necessary to complete the remaining phases (after July 1, 2007 through October 31, 2008). Upon completion of this expansion, all costs associated with these remaining phases were assigned to the Company's Oregon customers. As a result, Oregon customers received 262,446 Dth of working gas storage capacity The Commission approved recovery of those costs in Order No. 08-185 in Docket UG 181.

In 2007, under FERC Docket CP06-412-000, a deliverability expansion (no additional capacity) was initiated at the facility and, by late 2008, that expansion was completed. In order to provide firm deliverability of the capacity assigned to Oregon customers described above, Oregon was allocated 25% of the volumes and costs associated with this deliverability expansion. This proportion was based on forecasted jurisdictional sales volumes for the Nov. 2008 – Oct. 2009 period. This Commission approved recovery of those costs in Order No. 08-185 in Docket UG 181.

Q. Please describe the future capacity and deliverability available to Avista Utilities at Jackson Prairie.

A. On May 1, 2011, the temporary assignment of the capacity and deliverability expansions expire and the utility will take possession of 3,030,887 Dth of working gas capacity and an additional 104,000 Dth of daily deliverability from Shell Energy North America (Shell). The capacity and deliverability will revert to Avista Utilities at net book value. The net book value of this storage is $11.6 million (system)[1], as shown on Page 2, line 3 in Exhibit No. 401. Company witness Ms. Andrews further discusses the proforma adjustment associated with this incremental storage.

III. COST ALLOCATION AND RECOVERY OF JACKSON PRAIRIE

Q. How is the Company proposing to allocate the costs by jurisdiction associated with the additional (JP) capacity and deliverability that it will have available on May 1, 2011?

A. The allocation of this capacity and deliverability is proposed to be such that, when all JP expansion volumes and costs (added since 1999 and included and approved in Docket UG 181) described above are totaled, Washington/Idaho customers will receive 75% of the total and Oregon will receive 25% of the total, based on forecasted jurisdictional sales volumes for the Nov. 2008 – Oct. 2009 period. As a result, the allocation of JP Storage will

[1] The net book value of the storage transferred from Avista Energy to Avista Utilities is comprised of cushion gas of approximately $5.9 million and fixed assets/plant of approximately $5.7 million.

be approximately in proportion to the retail load for each of the jurisdictions. As shown in Exhibit No. 401, the incremental rate base addition for Oregon associated with the storage expansions requested in this filing is $2,012,236, excluding the amount approved by this Commission in Docket UG-181.

Q. Has the Company previously discussed this JP expansion allocation plan with representatives of the three Commission staffs?

A. Yes. This allocation plan was first discussed in person with Oregon, Washington and Idaho Commission staffs in early 2007, as well as in subsequent meetings. All three staffs indicated support of the allocation plan.

Q. Has the Company proposed this jurisdictional allocation to the other two Commissions?

A. Yes. The Company has proposed this allocation methodology as part of its general rate requests in Docket UG-100468 (Washington) and Case AVU-G-10-01 (Idaho). This allocation plan was adopted in the settlement agreements in both states. The Idaho settlement has been approved by the Idaho Public Utilities Commission, and the Washington settlement is pending Washington Utilities and Transportation Commission approval.

Q. What are the benefits of storage to Avista's customers?

A. Access to regionally located storage provides several benefits to Avista customers. It enables the Company to capture seasonal price spreads (differentials), improves reliability of supply, increases operational flexibility, mitigates peak demand price spikes and provides numerous other economic benefits. The transfer of the storage back to the utility is reflected in Avista's 2009 Natural Gas Integrated Resource Plan (IRP) attached as Exhibit No. 402, and acknowledged by this Commission on June 8, 2010.

Q. Has the value of these benefits increased over time?

A. Yes. As further described below, with the increased volatility of natural gas prices and a more complex gas market in recent years, the market value of storage has increased.

Q. What is a seasonal price spread and what is its estimated value?

A. The seasonal price spread, in its simplest terms, is the difference in the price per Dth between what one could purchase gas for in the non-winter months versus what those same volumes would cost if purchased in the winter season. Storage allows for the capture of typically lower priced non-winter gas and the ability to use it during the typically higher priced winter months. Sumas, due to its proximity and available pipeline transportation, is the market hub that is the likely pricing point for natural gas injections and withdrawals into Northwest area storage. Page 1 of Exhibit No. 401 shows the present monthly forward prices at Sumas over the next three years. These forward prices reflect the purchase price today for gas delivered during that future month. As shown, the average seasonal price spread over the next three years is $1.69 per Dth.

Q. Have you compared this estimated market value of $1.69 to an estimated annual revenue requirement (cost) associated with this incremental storage capacity?

A. Yes. The estimated revenue requirement cost is $0.50 per Dth, as shown on Page 2, Line 7 of Exhibit No. 401. Without even considering the other benefits associated with this incremental storage, this annual cost is well below the forward market value of $1.69 per Dth.

Q. You also mentioned improved reliability of supply. Please explain.

A. The Company relies on monthly and longer-term seasonal, annual and multi-year contracts for supply to satisfy its projected average daily demand. For daily swings in demand, above and below average, the Company relies on a combination of storage and daily purchases and sales. In today's market, virtually all physical short-term purchases are done at market hubs like Sumas. While these purchases are generally reliable, there is a risk of delivery failure either in counterparty risk or supply availability. There are a number of reasons why delivery risk can be problematic. First, using the Sumas Hub as an example, ownership of gas may change hands (trade) numerous times before delivery. The failure of one party in the ownership chain relying on interruptible transportation or a less than secure supply source can result in supply loss on any given day. A second reason is that it takes just one scheduling error in the supply chain to result in a supply loss. With multiple parties involved, the potential for error is increased. Third, actual physical problems such as well freeze-offs or pipeline force majeure situations along the transportation path can also result in supply loss. While all of the above can be financially resolved through underlying contractual commitments, they can still result in a loss of physical supply on any given day. As an owner of the facility, Avista controls the Company's nominations both at the facility and on the pipeline. This ensures supply reliability by eliminating third parties in scheduling transactions, thereby reducing the potential for error. Further, this results in a more reliable and timely process during pipeline entitlements.

Q. What operational benefits does storage provide?

A. Storage provides the operating flexibility to adjust supply either up or down during the actual day. Normally, gas is scheduled for delivery one day in advance. Jackson Prairie storage allows Avista the flexibility to increase or decrease the supply several times during the actual gas day. This flexibility is critical to maintaining mandated tolerances on pipelines and allows for active supply management during pipeline entitlements and Operational Flow Orders (OFOs). This level of management reduces the likelihood of incurring pipeline penalties.

Q. Please explain what you mean by mitigation of peak demand price spikes.

A. As with most local distribution companies in the Northwest, Avista's customer demand is very temperature-sensitive, i.e., "winter-peaking". During severe cold weather events in its service territory, or cold weather events in large market centers outside of the Northwest, natural gas prices may increase dramatically. To the extent that the Company can rely on storage withdrawals, the purchase of potentially higher-priced spot gas may be avoided during these events. As previously mentioned, storage also provides the ability to adjust volumes, even after the original nomination schedule. This eliminates the need to purchase peaking contracts from suppliers. Peaking supply is one of the most expensive resources to acquire - the greater the operational flexibility in a supply contract, the more expensive the product. The avoided cost of procuring a peaking resource with the flexibility characteristics of storage is a significant cost savings/avoidance; acquiring supply contracts that allow for day-ahead and intraday flexibility to manage supply requirements similar to the flexibility of storage would be cost prohibitive and may not even be obtainable.

Q. Are there other economic benefits related to JP?

A. As previously mentioned, Sumas is the most likely pricing point to Jackson Prairie. Sumas pricing can be very volatile during winter weather events. Storage allows the Company to minimize contracting for winter supply at Sumas, which is typically the most expensive supply point available to Northwest utilities. JP storage also provides opportunities to benefit from Sumas price spikes during cold events west of the Cascades by selling natural gas into that market when Avista customers may not otherwise be experiencing similar weather or high supply requirements.

Q. Does Avista have pipeline transportation capacity available to provide delivery of these incremental storage volumes?

A. Yes. Jackson Prairie is situated in the firm path of Avista's existing transportation contracts from Sumas to our service territories. This pipeline transportation can receive gas at Jackson Prairie instead of Sumas and can be used to deliver storage volumes throughout our service territories. The Company will avoid a portion of winter purchases at Sumas and utilize storage as a substitute for this supply. Therefore, the same transportation contracts that would otherwise be utilized to deliver physical supply purchases can be used for the delivery of storage gas.

Q. How much of Avista's annual average demand and average winter demand for its Oregon customers can be served by Jackson Prairie storage after May 1, 2011?

A. Approximately 10% of Avista's average annual demand and 16% of average winter demand can be served by JP storage after May 1, 2011.

Q. Company witness Andrews mentions an adjustment in her testimony associated with JP working gas inventory. Can you describe how that adjustment was determined?

A. Yes. The adjustment reflects the estimated cost of the average JP working gas inventory during the calendar year ending December 2011, less the actual end of period inventory cost during the test year (2009). This working gas inventory is considered rate base as there will be an average level of working gas that will exist in the facility for the life of the project, and the revenue requirement reflects the authorized rate of return on that rate base. The average level (working gas volumes) of JP inventory will increase with the additional capacity returning to the Company on May 1, 2011. Therefore, the inventory level will reflect an adjustment related to the capacity as well as year-over-year changes in the cost of gas injected into storage.

The Company uses a "synthetic" or forecasted injection/withdrawal schedule to determine the average inventory level during the year. This synthetic schedule is based on monthly forecasted injection and withdrawal volumes during the year, resulting in an estimated monthly inventory level. The forecasted storage injections are priced at the "forward" gas price for that month, i.e., the price at which gas could be purchased today for delivery in a future month. In estimating the cost of injections during 2011, the Company used a 60-day average of forward prices from July 3, 2010 to August 31, 2010. The forward price for each month's injections is applied and as the inventory account is filled, a total WACOG is calculated. When volumes are withdrawn they are priced at the total inventory WACOG. Based on the estimated average inventory balance during 2011 compared to the actual end of period balance during 2009, the increase to rate base is $176,000.

Q. Is this methodology consistent with the JP inventory adjustment used in the Company's last general rate case?

A. Yes.

Q. Does this complete your pre-filed direct testimony?

A. Yes it does.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

AVISTA CORP

KEVIN J. CHRISTIE
Exhibit No. 401

Natural Gas Supply and Storage

Forward Sumas Summer - Winter Differentials

Prices are an average of the forward prices for the month from January 2009 through August 2010 at Sumas

	a	b	c	d	e	f	g	h	i	j	k
			Summer Price 2010	**Winter Price 2010-2011**	**Difference 2010-2011**	**Summer Price 2011**	**Winter Price 2011-2012**	**Difference 2011-2012**	**Summer Price 2012**	**Winter Price 2012-2013**	**Difference 2012-2013**
1	January-09		$ 5.99	$ 7.95	$ (1.96)	$ 6.35	$ 8.21	$ (1.87)	$ 6.40	$ 8.23	$ (1.84)
2	February-09		$ 5.36	$ 7.30	$ (1.94)	$ 6.04	$ 7.92	$ (1.88)	$ 6.19	$ 7.94	$ (1.75)
3	March-09		$ 4.90	$ 6.77	$ (1.87)	$ 5.48	$ 7.36	$ (1.87)	$ 5.67	$ 7.42	$ (1.76)
4	April-09		$ 4.95	$ 6.92	$ (1.97)	$ 5.80	$ 7.54	$ (1.74)	$ 6.06	$ 7.83	$ (1.77)
5	May-09		$ 5.25	$ 7.23	$ (1.98)	$ 6.07	$ 7.81	$ (1.73)	$ 6.27	$ 8.03	$ (1.76)
6	June-09		$ 5.31	$ 7.32	$ (2.01)	$ 6.19	$ 7.92	$ (1.73)	$ 6.42	$ 8.18	$ (1.76)
7	July-09		$ 4.85	$ 6.85	$ (2.00)	$ 5.76	$ 7.47	$ (1.71)	$ 5.97	$ 7.70	$ (1.73)
8	August-09		$ 4.95	$ 7.02	$ (2.07)	$ 5.82	$ 7.51	$ (1.70)	$ 5.96	$ 7.69	$ (1.73)
9	September-09		$ 4.98	$ 7.10	$ (2.12)	$ 5.71	$ 7.43	$ (1.72)	$ 5.91	$ 7.61	$ (1.70)
10	October-09		$ 5.53	$ 7.49	$ (1.96)	$ 6.06	$ 7.75	$ (1.69)	$ 6.25	$ 7.96	$ (1.71)
11	November-09		$ 4.87	$ 7.11	$ (2.25)	$ 5.69	$ 7.34	$ (1.64)	$ 5.89	$ 7.55	$ (1.66)
12	December-09		$ 5.26	$ 7.35	$ (2.09)	$ 5.82	$ 7.46	$ (1.64)	$ 6.00	$ 7.60	$ (1.61)
13	January-10		$ 5.32	$ 7.05	$ (1.73)	$ 5.67	$ 7.21	$ (1.54)	$ 5.85	$ 7.36	$ (1.52)
14	February-10		$ 5.06	$ 6.71	$ (1.65)	$ 5.52	$ 6.99	$ (1.45)	$ 5.68	$ 7.15	$ (1.46)
15	March-10		$ 4.26	$ 5.94	$ (1.68)	$ 5.02	$ 6.47	$ (1.45)	$ 5.31	$ 6.74	$ (1.43)
16	April-10		$ 3.98	$ 5.77	$ (1.78)	$ 4.96	$ 6.48	$ (1.52)	$ 5.24	$ 6.63	$ (1.39)
17	May-10		$ 3.88	$ 5.68	$ (1.80)	$ 4.90	$ 6.49	$ (1.59)	$ 5.25	$ 6.67	$ (1.42)
18	June-10		$ 3.99	$ 5.69	$ (1.70)	$ 4.84	$ 6.33	$ (1.49)	$ 5.14	$ 6.49	$ (1.35)
19	July-10		$ 4.18	$ 5.39	$ (1.20)	$ 4.54	$ 5.96	$ (1.42)	$ 4.84	$ 6.18	$ (1.34)
20	August-10		$ 4.20	$ 4.96	$ (0.76)	$ 4.11	$ 5.59	$ (1.47)	$ 4.54	$ 5.88	$ (1.34)
21											
22	Average				**$ (1.83)**			**$ (1.64)**			**$ (1.60)**
23	Three Year Average	**$ (1.69)**									

1/ Summer prices are the average of May, June, and July.

2/ Winter prices are the average of December, January, and February.

Avista Corporation
Company Owned - Jackson Prairie Storage Summary

	a	b	c	d		e	f	g	h		i	j	k	l	m	n
		Total Capacity	**Total Deliverability**	**Total Cost as Filed**		**WA/ID Capacity Allocation**	**Oregon Capacity Allocation**	**WA/ID Deliverability Allocation**	**Oregon Deliverability Allocation**		**WA/ID Capacity** (b*e)	**WA/ID Deliverability** (c*g)	**Cost Assigned** (d*e)	**Oregon Capacity** (b*f)	**Oregon Deliverability** (c*h)	**Cost Assigned** (d*f)
1	'02 Capacity Expansion - July '07 - Oct '08 1/	262,446	-	$ 976,027	6/	0%	100%	0%	0%	9/	-	-	$ -	262,446	-	$ 976,027
2	'08 Deliverability Expansion - 11/08 2/	-	104,000	$ 14,673,253	7/	75%	25%	75%	25%	9/	-	78,000	$ 10,861,221	-	26,000	$ 3,812,032
3	'99 Capacity & Deliverability & '02 Capacity Expansion from Shell/AE - 4/11 3/	3,030,901	104,000	$ 11,551,885	8/			75%	25%	9/	2,470,010	78,000	$ 9,539,649	560,891	26,000	$ 2,012,236
4	Total Capacity/Deliverability/Costs	3,293,347	208,000	$ 27,201,165							2,470,010	156,000	$ 20,400,870	823,337	52,000	$ 6,800,295
5																
6	Revenue Requirement 4/															**$ 281,713**
7	Capacity Cost per Dth 5/															**0.50**
8																
9																
10	Ending Capacity and Deliverability Percent 9/										**75.00%**	**75.00%**	**75.00%**	**25.00%**	**25.00%**	**25.00%**

1/ Capacity expansion began in 2002 and was paid for by Avista Energy. After the sale of Avista Energy to Shell in July 2007 Avista Utilities took over the remaining costs and associated capacity.
2/ Avista Utilities participated in the deliverability expansion which was completed in October 2008.
3/ Capacity and deliverability expansion owned by Avista Energy and subsequently released to Shell at the time of the Avista Energy sale.
4/ The estimated annual revenue requirement is based on 14% of the allocated incremental capital costs of $2,012,236.
5/ The capacity cost per Dth is based on the annual revenue requirement divided by the incremental capacity of 560,891.
6/ The cost of wells and cushion gas (174,964 Dth) injected at an average actual price of $5.58. This is the balance as of 12/31/2009.
7/ Actual cost of the expansion as of 12/31/2009. The project was completed and placed in service 10/31/2008.
8/ The estimated book value on Avista Energy's books @ 4/30/2011 as of 06/30/2010.
Capacity $ 5,854,448 Deliverability $ 5,697,437 Total $ 11,551,885
9/ The capacity and deliverability were to be allocated so that 75% to Washington and Idaho and 25% to Oregon after all capacity and deliverability expansions were completed. (Line 6 divided by total capacity in line 4).
This split was based on estimated demand derived within SENDOUT®.

Forward Sumas Summer - Winter Differentials

Prices are an average of the forward prices for the month from January 2009 through August 2010 at Sumas

	a	b	c	d	e	f	g	h	i	j	k
			Summer Price 2010	**Winter Price 2010-2011**	**Difference 2010-2011**	**Summer Price 2011**	**Winter Price 2011-2012**	**Difference 2011-2012**	**Summer Price 2012**	**Winter Price 2012-2013**	**Difference 2012-2013**
1	January-09		$ 5.99	$ 7.95	$ (1.96)	$ 6.35	$ 8.21	$ (1.87)	$ 6.40	$ 8.23	$ (1.84)
2	February-09		$ 5.36	$ 7.30	$ (1.94)	$ 6.04	$ 7.92	$ (1.88)	$ 6.19	$ 7.94	$ (1.75)
3	March-09		$ 4.90	$ 6.77	$ (1.87)	$ 5.48	$ 7.36	$ (1.87)	$ 5.67	$ 7.42	$ (1.76)
4	April-09		$ 4.95	$ 6.92	$ (1.97)	$ 5.80	$ 7.54	$ (1.74)	$ 6.06	$ 7.83	$ (1.77)
5	May-09		$ 5.25	$ 7.23	$ (1.98)	$ 6.07	$ 7.81	$ (1.73)	$ 6.27	$ 8.03	$ (1.76)
6	June-09		$ 5.31	$ 7.32	$ (2.01)	$ 6.19	$ 7.92	$ (1.73)	$ 6.42	$ 8.18	$ (1.76)
7	July-09		$ 4.85	$ 6.85	$ (2.00)	$ 5.76	$ 7.47	$ (1.71)	$ 5.97	$ 7.70	$ (1.73)
8	August-09		$ 4.95	$ 7.02	$ (2.07)	$ 5.82	$ 7.51	$ (1.70)	$ 5.96	$ 7.69	$ (1.73)
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10	October-09		$ 5.53	$ 7.49	$ (1.96)	$ 6.06	$ 7.75	$ (1.69)	$ 6.25	$ 7.96	$ (1.71)
11	November-09		$ 4.87	$ 7.11	$ (2.25)	$ 5.69	$ 7.34	$ (1.64)	$ 5.89	$ 7.55	$ (1.66)
12	December-09		$ 5.26	$ 7.35	$ (2.09)	$ 5.82	$ 7.46	$ (1.64)	$ 6.00	$ 7.60	$ (1.61)
13	January-10		$ 5.32	$ 7.05	$ (1.73)	$ 5.67	$ 7.21	$ (1.54)	$ 5.85	$ 7.36	$ (1.52)
14	February-10		$ 5.06	$ 6.71	$ (1.65)	$ 5.52	$ 6.99	$ (1.45)	$ 5.68	$ 7.15	$ (1.46)
15	March-10		$ 4.26	$ 5.94	$ (1.68)	$ 5.02	$ 6.47	$ (1.45)	$ 5.31	$ 6.74	$ (1.43)
16	April-10		$ 3.98	$ 5.77	$ (1.78)	$ 4.96	$ 6.48	$ (1.52)	$ 5.24	$ 6.63	$ (1.39)
17	May-10		$ 3.88	$ 5.68	$ (1.80)	$ 4.90	$ 6.49	$ (1.59)	$ 5.25	$ 6.67	$ (1.42)
18	June-10		$ 3.99	$ 5.69	$ (1.70)	$ 4.84	$ 6.33	$ (1.49)	$ 5.14	$ 6.49	$ (1.35)
19	July-10		$ 4.18	$ 5.39	$ (1.20)	$ 4.54	$ 5.96	$ (1.42)	$ 4.84	$ 6.18	$ (1.34)
20	August-10		$ 4.20	$ 4.96	$ (0.76)	$ 4.11	$ 5.59	$ (1.47)	$ 4.54	$ 5.88	$ (1.34)
21											
22	Average				**$ (1.83)**			**$ (1.64)**			**$ (1.60)**
23	Three Year Average	**$ (1.69)**									

1/ Summer prices are the average of May, June, and July.

2/ Winter prices are the average of December, January, and February.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

AVISTA CORP

KEVIN J. CHRISTIE
Exhibit No. 402

Natural Gas Integrated Resource Plan

Natural Gas Integrated Resource Plan (IRP)

Compact Disc Exhibit

Also Available At:

http://www.avistautilities.com/inside/resources/irp/pages/default.aspx

2009

Natural Gas Integrated Resource Plan

December 31, 2009

www.avistautilities.com

AVISTA

TABLE OF CONTENTS

Note: Appendices provided under separate cover.

SAFE HARBOR STATEMENT

This document contains forward-looking statements. Such statements are subject to a variety of risks, uncertainties and other factors, most of which are beyond the Company's control, and many of which could have a significant impact on the Company's operations, results of operations and financial condition, and could cause actual results to differ materially from those anticipated.

For a further discussion of these factors and other important factors, please refer to the Company's reports filed with the Securities and Exchange Commission which are available on our website at www.avistacorp.com. The Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events.

2009 IRP KEY MESSAGES

- Avista has a diversified portfolio of existing natural gas supply resources including owned and contracted storage, firm capacity rights on six pipelines and purchase contracts from several different supply basins. Our philosophy is to reliably provide natural gas to customers with an appropriate balance of price stability and prudent cost.
- Avista's 2009 Integrated Resource Plan (IRP) forecasts lower demand for all service territories than our 2007 plan. These reductions are driven mainly by lower growth rates in our service territories than originally anticipated as a result of the severe economic downturn during this IRP cycle.
- Additional resource needs do not occur until well into the future. In Oregon, resource deficits occur in 2018-2019 and in Washington and Idaho in 2022-2023. The deficits are driven primarily by demand growth averaging 1.4 percent and 1.0 percent per year in the respective jurisdictions. Customer accounts are expected to grow at an annual average rate of 2.5 percent and 2.2 percent, respectively. Our plan indicates incremental pipeline transportation capacity is the preferred resource to meet the identified needs.
- An important risk with the identified future resource deficits is the relatively flat slope of forecasted demand growth. Implied in this outlook is existing resources will be sufficient for quite some time to meet demand. However, should demand growth accelerate, the steepening of the demand curve could quickly accelerate resource shortages by several years. This "flat demand risk" requires that we closely monitor signs of accelerating demand and carefully evaluate lead times to acquire preferred incremental resources.
- Other risks we evaluated include price elasticity variability, climate change policy uncertainty, long-term availability of supply, weather planning standard alternatives and cost escalation risks/lead times when acquiring resources.
- Conservation programs are an integral component of our IRP process, as these programs result in multiple benefits including reduced customers' bills, reduced supply-side resource needs and reduced greenhouse gas (GHG) emissions. Avista's long-time commitment to energy conservation and efficiency is founded in the belief that these benefits make acquiring cost effective conservation resources the single best strategy for minimizing energy service costs to our customers while promoting a cleaner environment.
- We have identified first-year conservation goals of 2,193,300 therms for our North Division (Washington and Idaho) and 303,300 therms for our South Division (Oregon).
- The IRP identifies and establishes an Action Plan that continues to guide us toward the risk-adjusted, least-cost method of providing service to our natural gas customers. Included in this Action Plan are efforts to improve price elasticity modeling, monitor trends for Canadian natural gas imports, and goals for demand-side management.

INDEX OF TABLES

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LIST OF ACRONYMS

AGA	American Gas Association
DSM	Demand-Side Management*
Dth	Dekatherm*
EIA	Energy Information Administration
FERC	Federal Energy Regulatory Commission*
GTN	Gas Transmission Northwest*
GHG	Greenhouse Gas
HDD	Heating Degree Day*
HP	High Pressure
IRP	Integrated Resource Plan*
LNG	Liquified Natural Gas*
Mmbtu	Million British Thermal Units*
NOAA	National Oceanic and Atmospheric Administration*
NPCC	Northwest Power and Conservation Council*
NWP	Williams - Northwest Pipeline*
NYMEX	New York Mercantile Exchange*
Psig	Pounds per Square Inch Gauge*
PVRR	Present Value Revenue Requirement
TAC	Technical Advisory Committee*
TRC	Total Resource Cost
Triple E	External Energy Efficiency Board
WCSB	Western Canadian Sedimentary Basin

* Glossary contains additional information.

CHAPTER 1 – EXECUTIVE SUMMARY

Avista's 2009 Natural Gas Integrated Resource Plan (IRP) identifies a strategic natural gas resource portfolio that meets future customer demand requirements. The formal exercise of bringing together customer demand forecasts with comprehensive analyses of resource options, including supply-side resources and demand-side measures, is valuable to Avista, its customers, Regulatory Commissions and other stakeholders for long-range planning.

The IRP identifies and establishes an Action Plan to steer Avista toward the least-cost method of providing service to our natural gas customers. There are other factors that must be considered besides cost within the context of least-cost planning, including an assessment of risks associated with each alternative as well as environmental and regulatory issues. Actions resulting from the IRP process represent risk-adjusted, least-cost results, which we refer to as best cost/risk resources.

IRP PROCESS AND STAKEHOLDER INVOLVEMENT

The IRP is a coordinated effort by several Avista departments along with input from our Technical Advisory Committee (TAC) which includes Commission Staff, peer utilities, customers and other stakeholders. This group is a vital component of our IRP process, as it provides a forum for idea exchange that communicates multiple perspectives, identifies issues and risks and improves analytical methods. Topics discussed include natural gas demand forecasts, demand-side management (DSM), supply-side resources, computer modeling tools and distribution planning. The end result is an integrated resource portfolio designed to serve our customers' natural gas needs well into the future while balancing cost and risk.

PLANNING ENVIRONMENT

This IRP was developed during a two-year period in which an international credit crisis severely disrupted the United States and global economy. Long-term effects on the natural gas industry are uncertain, prompting us to consider a wider range of scenarios to evaluate and prepare for a broad spectrum of potential outcomes. We examined key assumptions and historical trends, questioning how they might be impacted by the economic environment which is ambiguous, fluid and evolving. We have sought to perform analysis and modeling that not only looks at "what happened?" but also asks "what if?" to understand possible outcomes. Over time, as more becomes known about this uncertain period, some of our scenarios may differ substantially from subsequent actual results. Nonetheless, the trade-off of examining a broad range of possibilities with stretched assumptions is preferable to a narrower analysis of more-likely outcomes that could completely miss a less probable future.

DEMAND FORECASTS

For this IRP, we define eight demand areas, which are structured around the transportation resources that serve them. These demand areas are aggregated into four service territories (Washington/Idaho, Medford/Roseburg, Oregon, Klamath Falls, Oregon and La Grande, Oregon) and further summarized into two divisions (North and South) for presentation throughout this IRP.

Avista's approach to demand forecasting focuses on customer growth and use per customer as the base components of demand. We recognize and have accounted for weather as a fundamental demand-influencing factor as well. We also studied other factors that influence demand including population, employment trends, age and income demographics, construction trends, conservation technology, new uses development (e.g. natural gas vehicles) and use per customer trends.

Recognizing customers adjust consumption in response to price, we also analyzed factors that influence natural gas prices and demand through price elasticity. These included unconventional natural gas production trends, climate change policies and legislation, Canadian import trends, potential drilling restrictions and alternate price forecasts.

We developed a historical based reference case and conducted sensitivity analysis on key demand drivers by varying assumptions to understand how demand changes. Using this information and incorporating input from the TAC, we formed several alternate demand scenarios for detailed analysis. Table 1.1 summarizes these scenarios, which do not represent the maximum bounds of possible cases, but frame a broad range of potential outcomes. Within this range, we define an Expected Case which we view as the most likely scenario.

Table 1.1 Alternate Demand Scenarios
Expected Case
High Growth, Low Price
Low Growth, High Price
Green Future
Alternate Weather Standard
Supply Constraints

Avista uses the IRP process to develop two primary types of demand forecasts ─ annual average daily and peak day. Annual average daily demand forecasts are useful for preparing revenue budgets, developing natural gas procurement plans and preparing purchased gas adjustment filings. Peak day demand forecasts are critical for determining the adequacy of existing resources or the timing for new resource acquisitions to meet our customers' natural gas needs in extreme weather conditions. The demand forecasts from the Expected Case revealed:

Annual Average Daily Demand ─ Average day, system-wide core demand is projected to increase from an average of 96,160 dekatherms per day (Dth/day) in 2009-2010 to 117,660 Dth/day in 2028-2029. This is an annual average growth rate of 1.1 percent and is net of projected conservation savings from DSM programs[1].

Peak Day Demand ─ Coincidental peak day, system-wide core demand is projected to increase from a peak of 365,720 Dth/day in 2009-2010 to 474,670 Dth/day in 2028-2029. Forecasted non coincidental peak day demand peaks at 341,850 Dth/day in 2009-2010 and increases to 440,630 Dth/day in 2028-2029, a 1.3 percent compounded growth rate in peak day requirements. This is also net of projected conservation savings from DSM programs.

Figure 1.1 shows forecasted system-wide **annual average daily demand** for the six main scenarios modeled over the planning horizon.

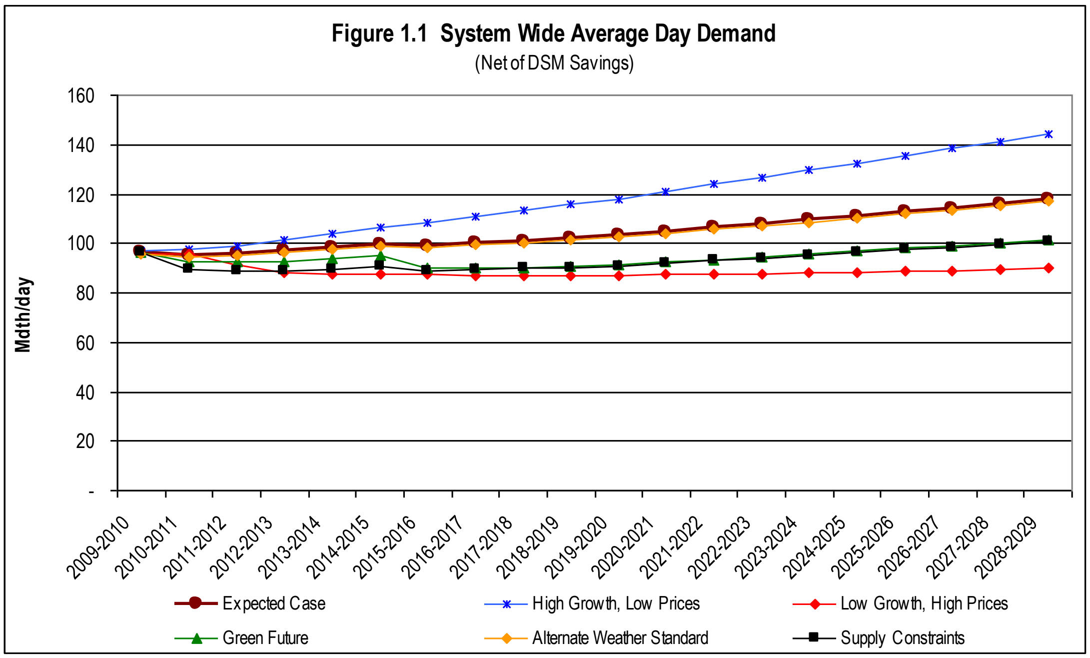
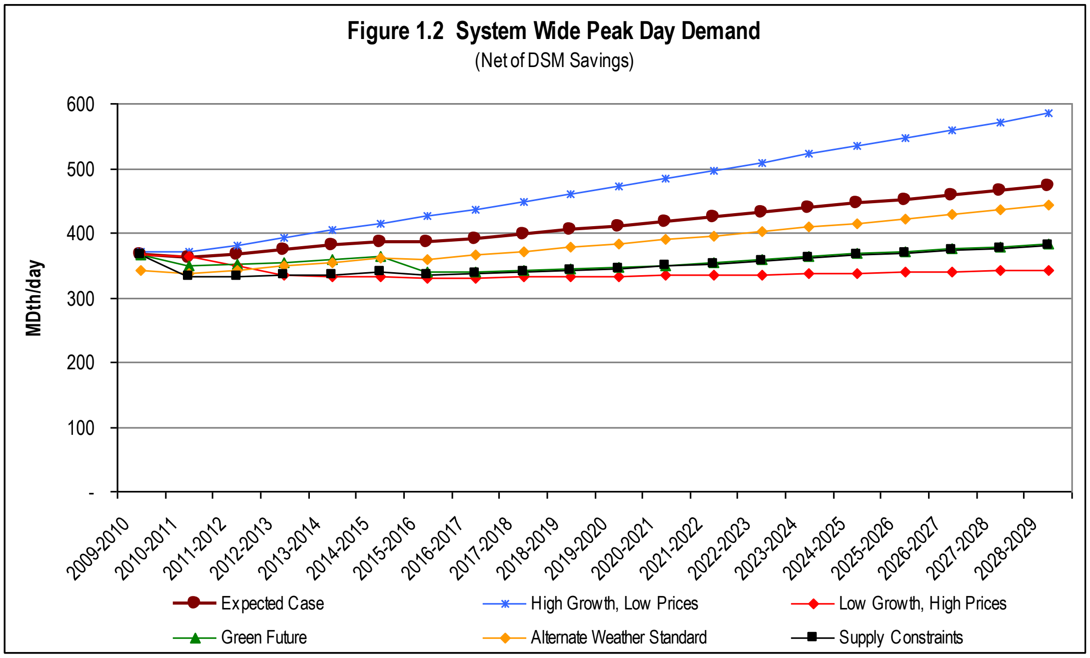


Figure 1.2 shows forecasted system-wide **peak day demand** for the six main scenarios modeled over the planning horizon.

[1] Appendix 3.9 shows gross demand, DSM savings, and net demand.

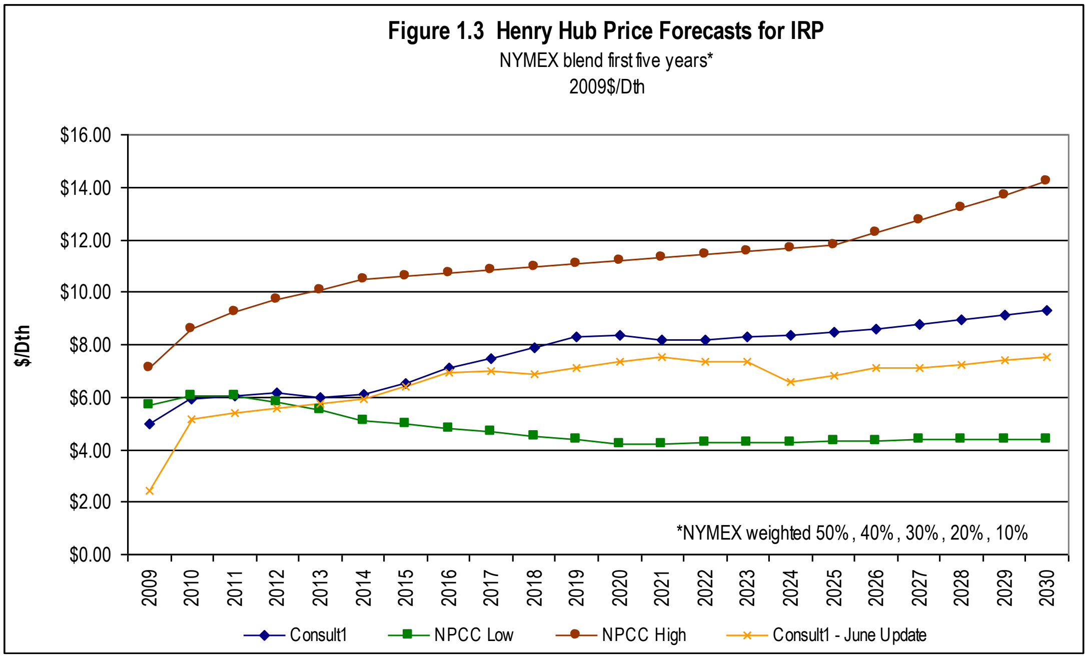


NATURAL GAS PRICE FORECASTS

Natural gas prices are a fundamental component of integrated resource planning. The commodity price is a significant component of the total resource cost of a resource option. This affects the avoided cost threshold for determining cost effectiveness of conservation measures. The price of natural gas influences the consumption of natural gas by customers, so we included price elasticity analysis in our evaluation of demand.

The outlook for natural gas prices has changed dramatically over the recent planning cycle because of several influential events and trends affecting the natural gas industry. Most notable is the severe economic recession triggered by the global credit crisis. Other significant influences include expectations of prolific shale gas production and increased natural gas-fired power generation as anticipated climate change legislation encourages replacement of coal burning power plants. The outlook for these and other factors has evolved rapidly in the midst of significant uncertainty precipitating wide swings and frequent updates to the natural gas price forecasts we monitor.

Although we do not believe we can accurately predict future prices for the 20-year horizon of this IRP, we have reviewed several price forecasts from credible sources and have selected high, medium and low price forecasts to represent aggressive but reasonable pricing possibilities for our analysis. Figure 1.3 depicts the price forecasts used in our IRP. Continuing our theme of stretching modeling assumptions to better prepare for an uncertain environment, the price curves have considerable variation.



In modeling a consumption response to these price curves, we developed high, medium and low price elasticity response factors to be applied under various scenarios. We have assumed a low response to prices in our Expected Case, partly based on a conservative assumption that tight economic conditions and declining real estate values may deter many customers from investing in long-term capital intensive conservation measures in the near term. We will monitor this assumption over the next IRP cycle and make any necessary adjustments.

EXISTING AND POTENTIAL RESOURCES

Avista has a diversified portfolio of natural gas supply resources, including contracts to purchase natural gas from several different supply basins, owned and contracted storage enabling flexibility and diversity of supply sources, and firm capacity rights on six pipelines enabling delivery of supply to our service territory city gates. For potential resource additions, we also evaluate incremental pipeline transportation, storage options, distribution enhancements and various forms of liquefied natural gas storage or service.

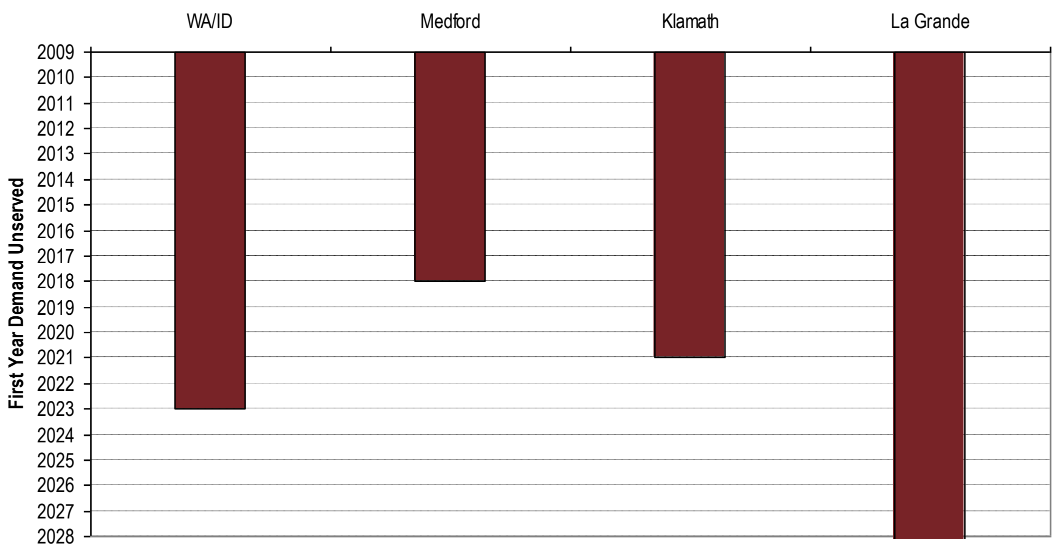
In our IRP process, we model a number of conservation measures that reduce demand if they prove to be cost effective over the planning horizon. Based on the projected natural gas prices and the estimated cost of alternative supply resources, our computer planning model (SENDOUT®) selects measures for further review and implementation. We actively promote these measures to our customers as one component of a comprehensive strategy to arrive at best cost/risk adjusted resources.

RESOURCE NEEDS

Using our Expected Case demand scenario matched with our Existing Resources supply scenario, we ran the case through the SENDOUT® computer model to determine when the first year peak day demand is not fully served. The results of this portfolio are summarized in Figure 1.4.

Figure 1.4 First Year Peak Demand Not Met With Existing Resources

Expected Case



In the Expected Case for Washington and Idaho, this system first becomes unserved in 2023. In Oregon, the first unserved year is in Medford/Roseburg in 2018 followed by Klamath Falls in 2021. The La Grande system does not go unserved at any time during the 20-year planning horizon.

Figures 1.5 through 1.8 provide detailed illustrations of when our peak day demand first goes unserved by service territory for both this IRP and our prior IRP. These charts compare existing peak day resources to expected peak day demand by year and show timing and extent of resource deficiencies for the Expected Case. Given this information, it appears we have ample time to carefully monitor, plan and take action on potential resource additions.

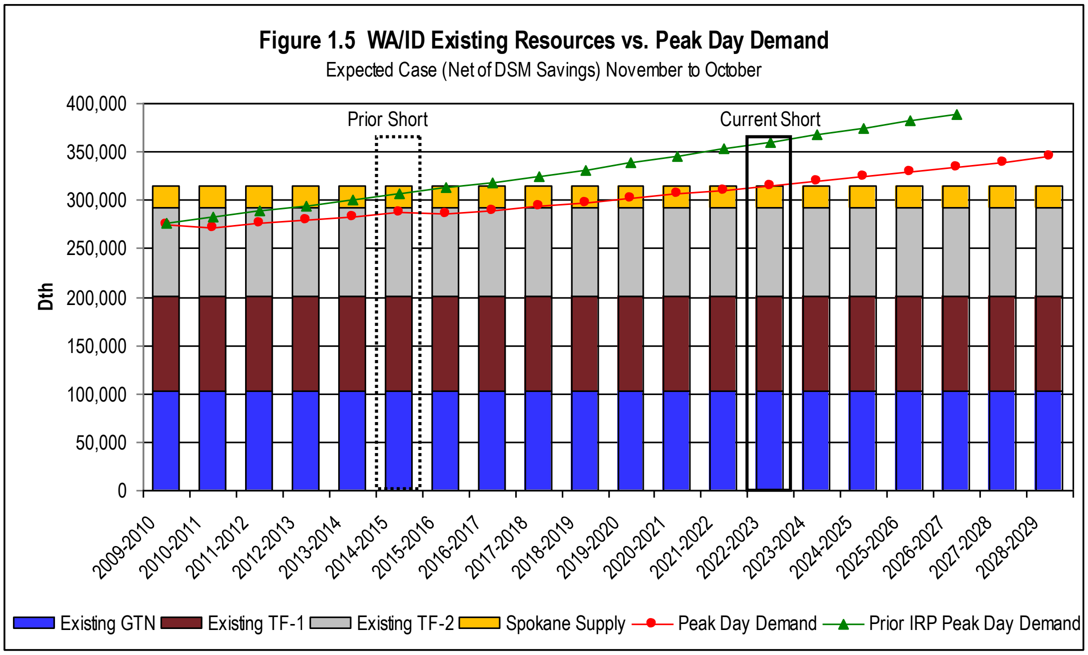


Figure 1.5 WA/ID Existing Resources vs. Peak Day Demand
Expected Case (Net of DSM Savings) November to October
Dth
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
Prior Short
Current Short
2009-2010
2010-2011
2011-2012
2012-2013
2013-2014
2014-2015
2015-2016
2016-2017
2017-2018
2018-2019
2019-2020
2020-2021
2021-2022
2022-2023
2023-2024
2024-2025
2025-2026
2026-2027
2027-2028
2028-2029
Existing GTN
Existing TF-1
Existing TF-2
Spokane Supply
Peak Day Demand
Prior IRP Peak Day Demand

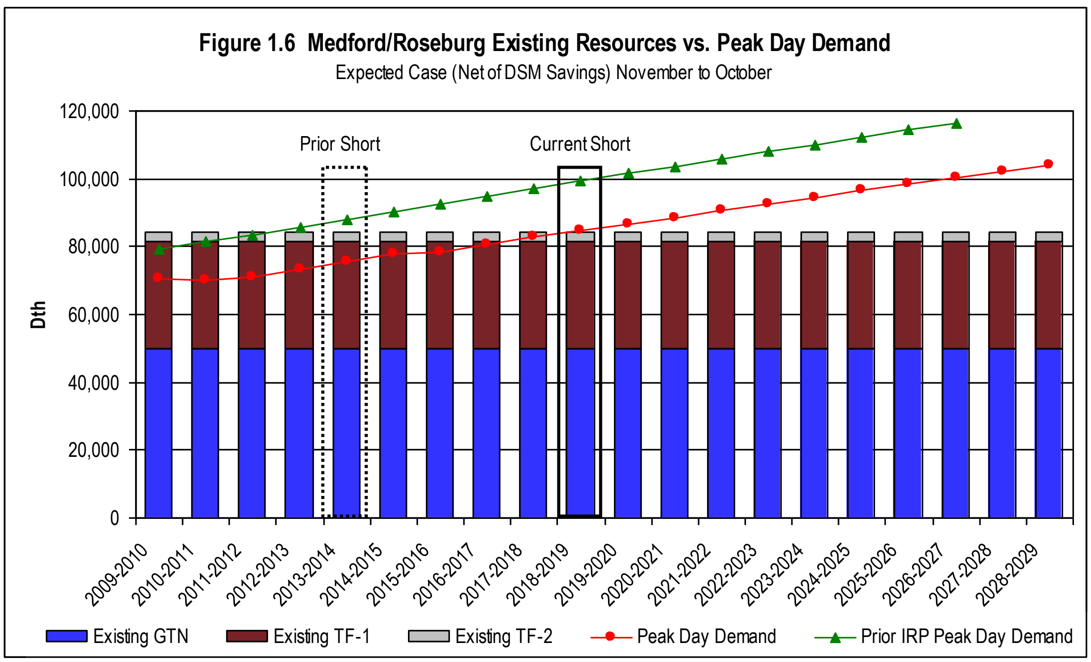
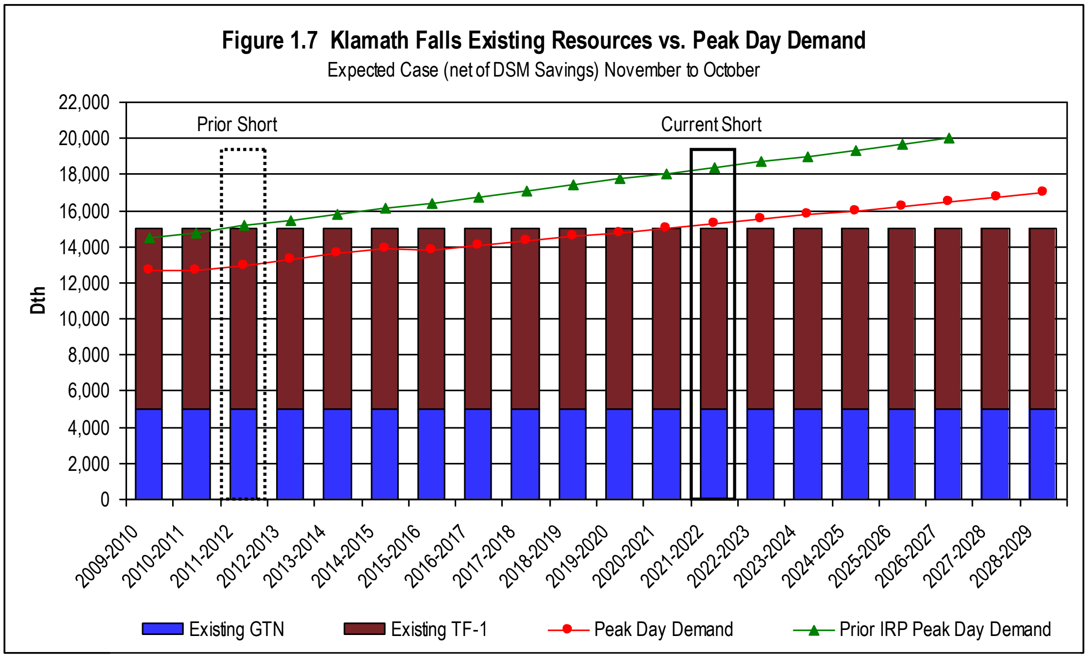
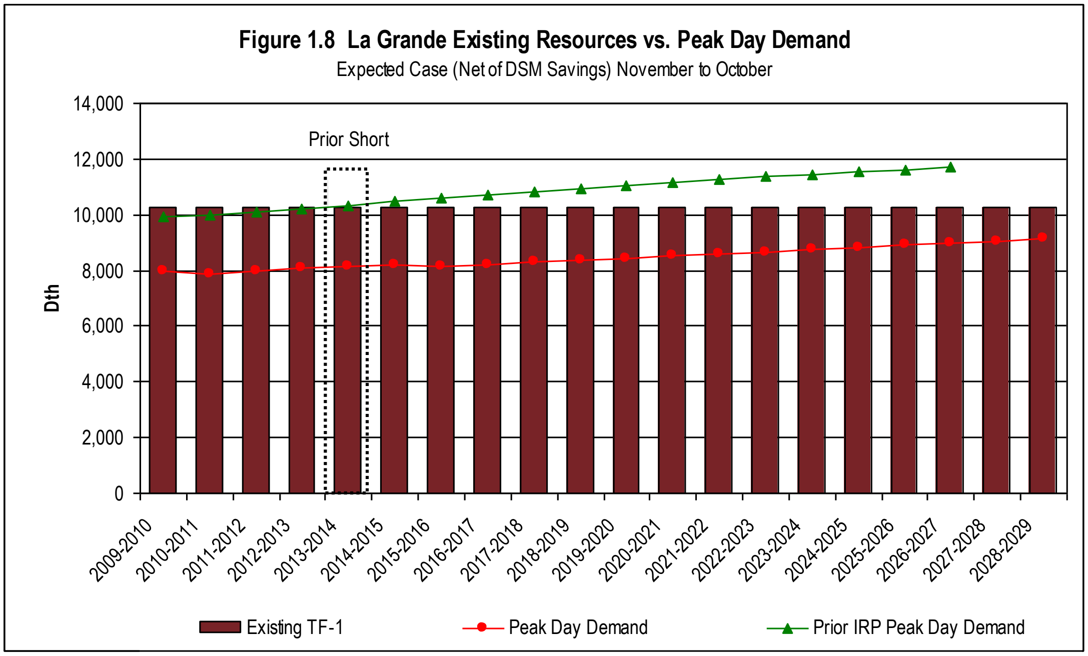


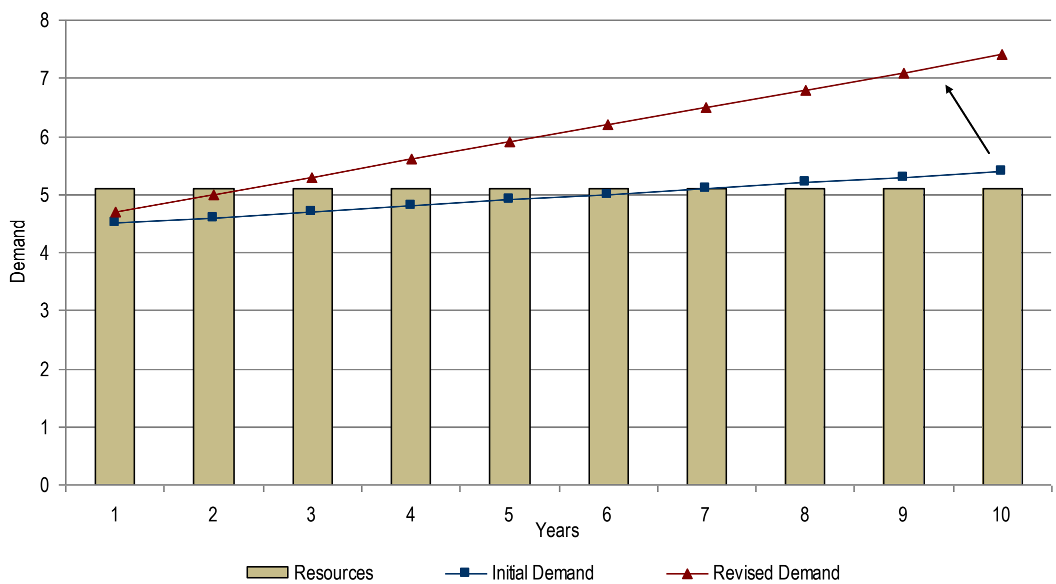
Figure 1.6 Medford/Roseburg Existing Resources vs. Peak Day Demand
Expected Case (Net of DSM Savings) November to October
Dth
120,000
100,000
80,000
60,000
40,000
20,000
0
Prior Short
Current Short
2009-2010
2010-2011
2011-2012
2012-2013
2013-2014
2014-2015
2015-2016
2016-2017
2017-2018
2018-2019
2019-2020
2020-2021
2021-2022
2022-2023
2023-2024
2024-2025
2025-2026
2026-2027
2027-2028
2028-2029
Existing GTN
Existing TF-1
Existing TF-2
Peak Day Demand
Prior IRP Peak Day Demand





A critical risk with respect to our identified resource shortages is the slope of forecasted demand growth which is almost flat. This outlook implies that existing resources will be sufficient for quite some time to meet demand. However, if demand growth accelerates, the steeper demand curve could quickly accelerate resource shortages by several years. Figure 1.9 is a conceptual diagram that illustrates this risk. In this hypothetical example, a resource shortage does not occur until year eight in the initial demand case. However, the shortage dramatically accelerates by five years under the revised demand case to year three. This "flat demand risk" necessitates close monitoring of accelerating demand as well as careful evaluation of lead times to acquire the preferred incremental resource.

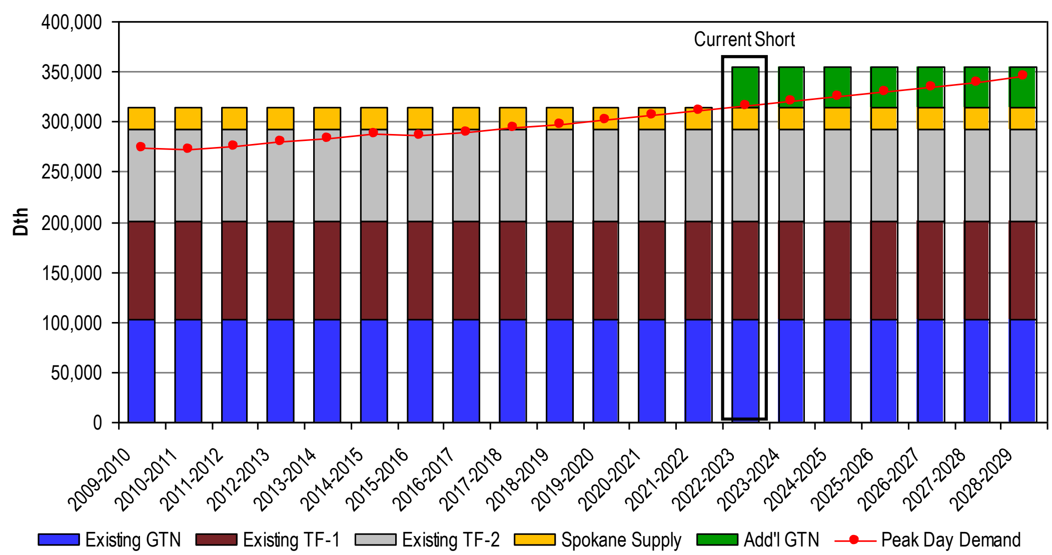
Figure 1.9 Flat Demand Risk Example

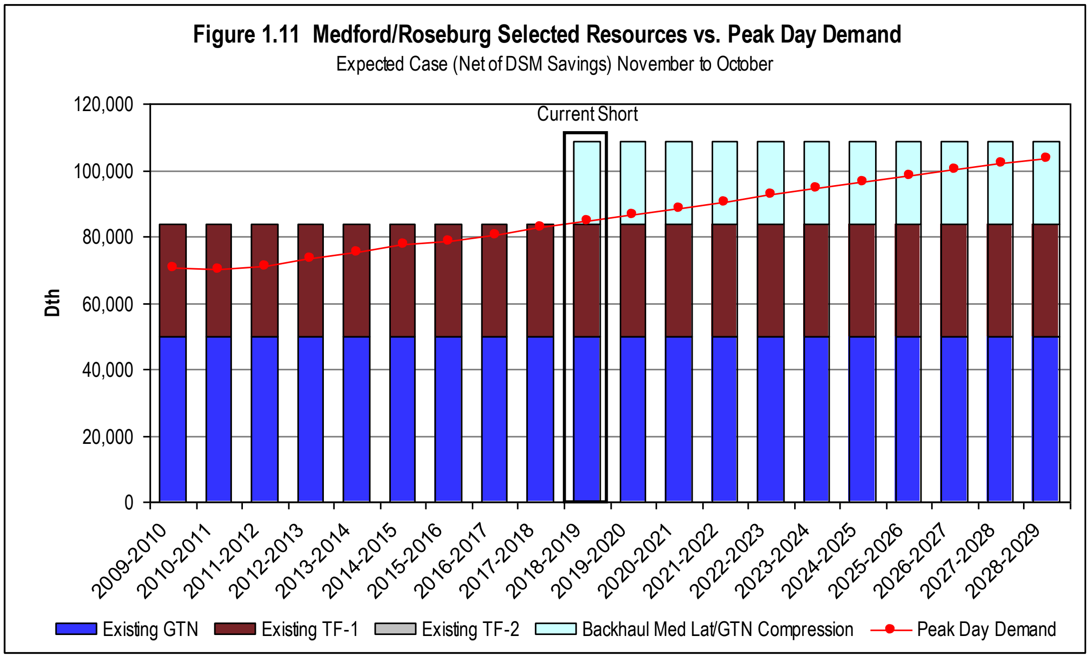


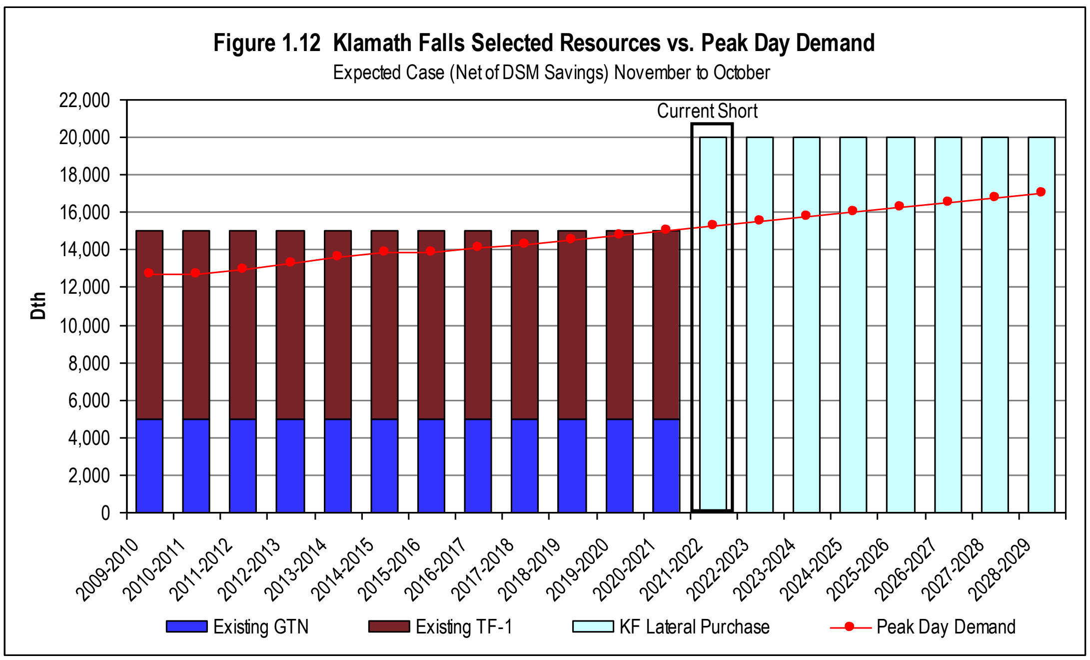
RESOURCE SELECTIONS

The next step is to determine how to resolve resource deficiencies. For this step, we identified possible resource options and placed them into the SENDOUT® model to allow it to select the best cost/risk incremental resources over the 20-year planning horizon. Figures 1.10, 1.11 and 1.12 depict the best cost/risk portfolio selected by SENDOUT® to meet the identified resource shortages. As previously mentioned, the La Grande service territory does not have resource shortages over our planning horizon in the Expected Case.

Figure 1.10 WA/ID Selected Resources vs. Peak Day Demand
Expected Case (Net of DSM Savings) November to October



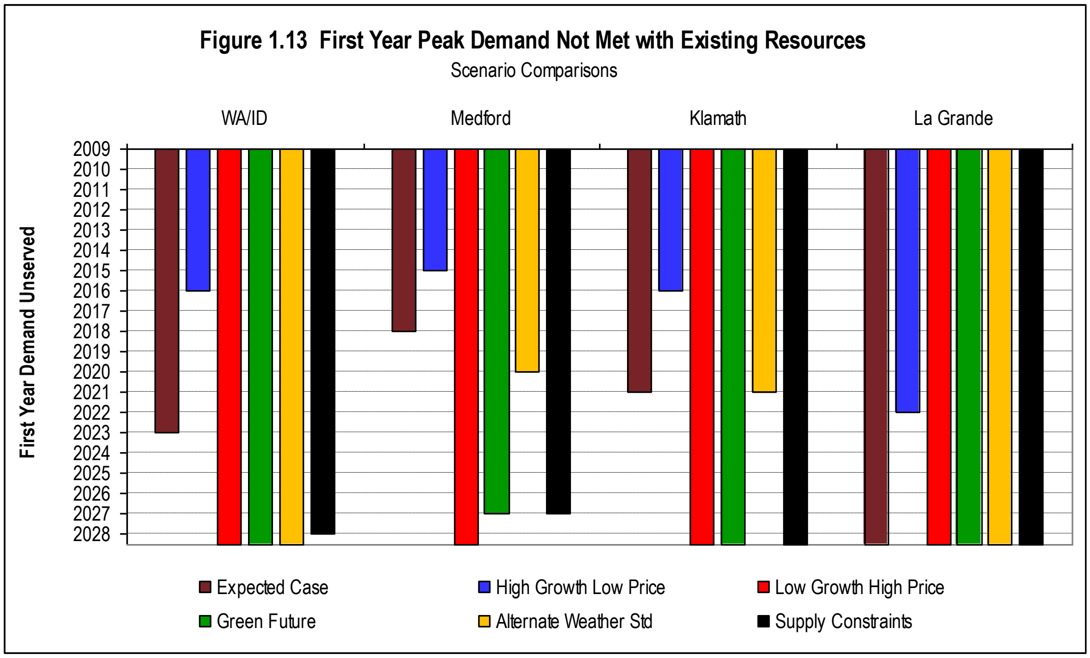




As indicated in the figures, after DSM savings, the model shows a general preference for incremental transportation resources from existing pipelines and supply basins to resolve resource shortages.

ALTERNATE DEMAND SCENARIOS

We performed the same SENDOUT® process for five other demand scenarios, which identified first year unserved dates for each scenario by service territory (Figure 1.13). As expected, the High Growth, Low Price scenario has the most rapid growth and the earliest first year unserved dates. This "steeper" demand somewhat lessens the "flat demand risk" discussed above, but the earlier unserved dates warrant close monitoring of demand trends and resource lead times.



Several scenarios indicate no resource deficiencies over the planning horizon due to very slow or even negative demand growth. A key reason for this is our price elasticity assumptions combined with price forecasts with steep price increases early in the planning horizon. This perfect storm combination produces a significant curtailment in total demand early in the forecast. A key question for these scenarios is whether this early price shock materializes as forecasted and, if so, is demand permanently curtailed as predicted in the price elastic response assumption. This condition also warrants close monitoring and comparison to actual results.

ACTION PLAN

Our 2010-2011 Action Plan outlines activities identified by our IRP team, with advice from management and TAC members, for development and inclusion in the 2011 IRP. The purpose of these action items is to position Avista to provide the best cost/risk resource portfolio and to support and improve IRP planning. Key components of the Action Plan include:

- Monitor actual demand for indications of growth exceeding our forecast to respond aggressively to address potential accelerated resource deficiencies arising from exposure to "flat demand" risk. This includes researching and refining evaluation of resource alternatives, including implementation risk factors and timelines, updated cost estimates, feasibility assessments and targeting options for the service territories with nearer term unserved demand exposure.
- Analyze use per customer data and DSM program results for indications of price elasticity response trends that may have been influenced by evolving economic conditions. Investigate

contemporary analytical sources for information on natural gas price elasticity. Determine if the American Gas Association (AGA) will update its analytical work and/or consider hiring a third-party price elasticity study and assess interest of other utilities in pursuing a regional study.

- Continue cost effective demand-side solutions. In Washington and Idaho, conservation measures are targeted to reduce demand by 2,193,338 therms in the first year (2010). In Oregon, conservation measures are targeted to reduce demand by 303,300 therms in the first year. These goals represent an increase of 25 percent in Washington and Idaho and a nominal decrease of less than 1 percent in Oregon from the 2010 projected goals in the 2007 IRP.
- Research and engage a conservation consultant to perform an updated assessment of technical and achievable potential for conservation in our service territories prior to the 2011 IRP.
- Continue to monitor the discussion around diminishing Canadian natural gas imports and look for signals that indicate increased risk of disrupted supply given much of our supply comes from Canadian sources.
- Explore and evaluate alternative and additional forecasting methodologies for potential inclusion in our next IRP.
- Regularly meet with Commission Staff members to provide information on market activities and significant changes in assumptions and/or status of Avista activities related to the IRP or natural gas procurement practices.

ISSUES AND CHALLENGES

Although we are satisfied with the planning, analysis and conclusions reached in this IRP, we recognize widespread uncertainty results in a heightened risk environment requiring diligent monitoring of the following issues and challenges:

ECONOMIC UNCERTAINTY

The current economic downturn has been dramatic and has impacted near-term trends in economic activity. The potential influence on natural gas demand, DSM, infrastructure developments, commodity prices, credit terms and procurement practices in such an unsettled environment presents many forecasting challenges. Historical relationships may be altered or fundamentally changed. For example, customer changes in natural gas consumption may be driven as much by personal income changes as by natural gas prices. DSM initiatives could be enthusiastically pursued by more customers seeking savings on their energy costs while other customers may forego participation due to personal economic constraints. Tight credit markets, lower regional demand and community opposition could delay pipeline and other infrastructure projects. Alternatively, lower labor, materials and interest costs may prompt accelerated infrastructure investment.

In such an uncertain environment, there is more risk of unanticipated outcomes. Although we sought to capture many of these issues through a wide range of scenarios in our modeling and analysis, monitoring will be required to see how events unfold and if there are outcomes we did not consider, requiring adjustment of our analysis and action.

CLIMATE CHANGE LEGISLATION

Global economic growth earlier in the decade was partly driven by low cost debt and inexpensive energy. The two are not uncorrelated ─ robust growth usually depends on both. In hindsight, we now see this growth was vulnerable. Debt was improperly priced for risk while energy was underpriced for carbon emissions and other environmental concerns. As prices of debt and energy readjust to reflect these costs, economic growth will face strong headwinds. The emerging political dilemma will be how to facilitate this readjustment in a fragile economic climate.

When we initiated our IRP planning and analysis, federal climate change legislation appeared almost certain to pass with far reaching and long-term implications. We still believe some form of federal climate change legislation is likely to be enacted though the form, extent and timing continue to be uncertain. A cap and trade structure remains the most likely framework for greenhouse gas legislation. Economic issues aside, this complex structure has numerous design issues that must be addressed, including emissions target levels, phase in timeframes, allocation of allowances, availability of offsets, cost mitigation to customers and a host of implementation challenges.

By design, this legislation is meant to substantially alter the energy production and consumption landscape. Inherent in this new landscape is significant uncertainty in market behavior and acceptance, which can profoundly impact resource needs. Additional carbon mitigation costs may slow or reverse end user adoption of natural gas appliances and applications. Direct use initiatives may stall given significant regional hydro and other renewable electric resources will not be burdened with carbon costs. The integration of federal legislation with the regional Western Climate Initiative also remains uncertain. These example issues pose significant modeling and forecasting challenges.

To address these challenges, we worked closely with one of our energy industry consultants, leveraging their monitoring of climate change policy issues and in-depth research to develop our long-term price forecasts. This includes specific alternative price forecast scenarios that separately captured influences of potential carbon emissions legislation. We also conferred with and solicited ideas and feedback from Avista's electric resource planning team and the TAC to develop two carbon emission reduction sensitivities that were ultimately incorporated in each of our modeled scenarios. This provided useful findings and a solid base to continue analysis and monitoring developments in this important sphere going forward.

SEISMIC SUPPLY SHIFTS

The main driver of North American natural gas production growth is now forecast to be unconventional gas, especially shale gas. Several new shale gas fields have been identified with many of the wells delivering impressive results. However, the reality is huge future volumes are being forecast for this resource, yet the long-term estimates for these resources remain relatively untested and unknown. Although we are encouraged by this progress, we will need to be prudently wary as well.

Burgeoning supply from international liquefied natural gas projects, which have been at least a half decade in the making, is just now coming on line. Significant capacity is being added as near-term global demand is diminished from the prospects of a lingering global recession. This, combined with the unconventional gas production supply surge, resulted in an unprecedented rapid collapse in prices. Although beneficial to end users in the near term, this dramatic volatility and uncertainty could cause long-term disruption in production, pipeline and storage capital investment exacerbating boom/bust cycles in the long term.

CONCLUSION

Lower demand since our last IRP as well as slower forecasted demand in our Expected Case indicates no near-term need for additional supply-side resources. This will not diminish our efforts to encourage customer adoption of cost effective conservation measures consistent with our longstanding commitment to acquire demand-side resources. The IRP process has many objectives but foremost is to ensure that proper planning will enable us to continue delivering safe, reliable and economic natural gas service to our customers well into the future. We are confident this plan delivers on that objective.

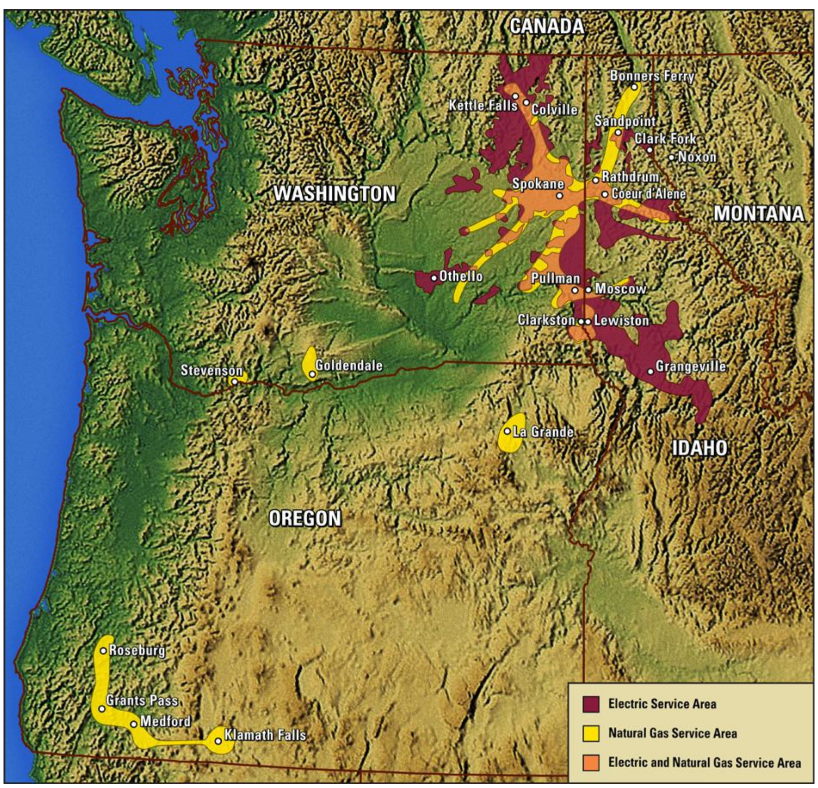
CHAPTER 2 – INTRODUCTION

OUR COMPANY

Avista is involved in the production, transmission and distribution of energy as well as other energy-related businesses. Avista was founded in 1889 as Washington Water Power and has been providing reliable, efficient and competitively priced energy to customers for nearly 120 years.

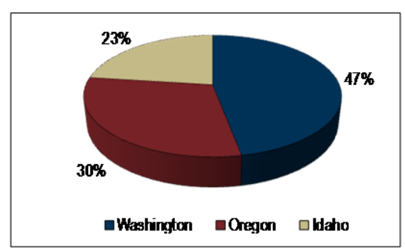
Avista entered the natural gas business with the purchase of Spokane Natural Gas Company in 1958. In 1970, we expanded into natural gas storage with Washington Natural Gas (now Puget Sound Energy) and El Paso Natural Gas (their interest subsequently purchased by Williams - Northwest Pipeline (NWP)) to develop the Jackson Prairie natural gas underground storage facility in Chehalis, Washington. In 1991, we added 63,000 customers with the acquisition of CP National Corporation's Oregon and California properties. Avista subsequently sold the California properties and its 18,000 South Lake Tahoe customers to Southwest Gas in 2005. Avista currently provides natural gas service to over 314,000 customers in eastern Washington, northern Idaho and several communities in northeast and southwest Oregon.

SERVICE TERRITORIES AND NUMBER OF CUSTOMERS



Natural Gas Customers as of Dec. 31, 2008

Washington	145,600
Idaho	73,250
Oregon	95,300
Total	314,150



Avista manages its natural gas operations through two operating divisions – North and South:

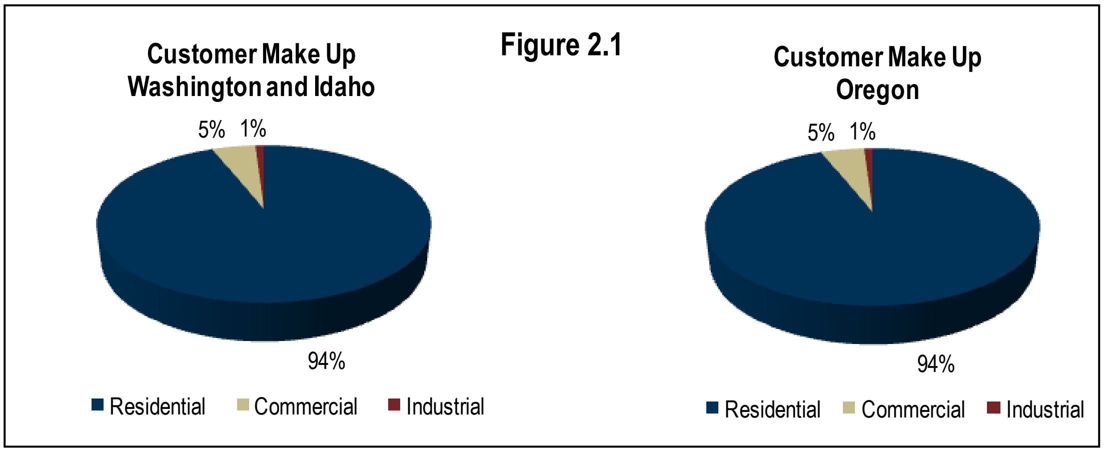
- The North Division covers about 26,000 square miles, primarily in eastern Washington and northern Idaho. Over 840,000 people live in Avista's Washington/Idaho service area. It includes urban areas, farms, timberlands and the Coeur d'Alene mining district. Spokane is the largest metropolitan area with a regional population of approximately 450,000 followed by the Lewiston, Idaho/Clarkston, Washington area and Coeur d'Alene, Idaho. The North Division has about 74 miles of natural gas distribution mains and 5,000 miles of distribution lines. Natural gas is received at more than 40 points along interstate pipelines and distributed to over 219,000 residential, commercial and industrial customers.
- The South Division serves four counties in southwest Oregon and one county in northeast Oregon. The combined population of these two areas is over 480,000 residents. The South Division includes urban areas, farms and timberlands. The Medford, Ashland and Grants Pass area, located in Jackson and Josephine Counties, is the largest single area served by Avista in this division, with a regional population of approximately 280,000 residents. The South Division consists of about 67 miles of natural gas distribution mains and 2,000 miles of distribution lines. Natural gas is received at more than 20 points along interstate pipelines and distributed to over 95,000 residential, commercial and industrial customers.

OUR CUSTOMERS

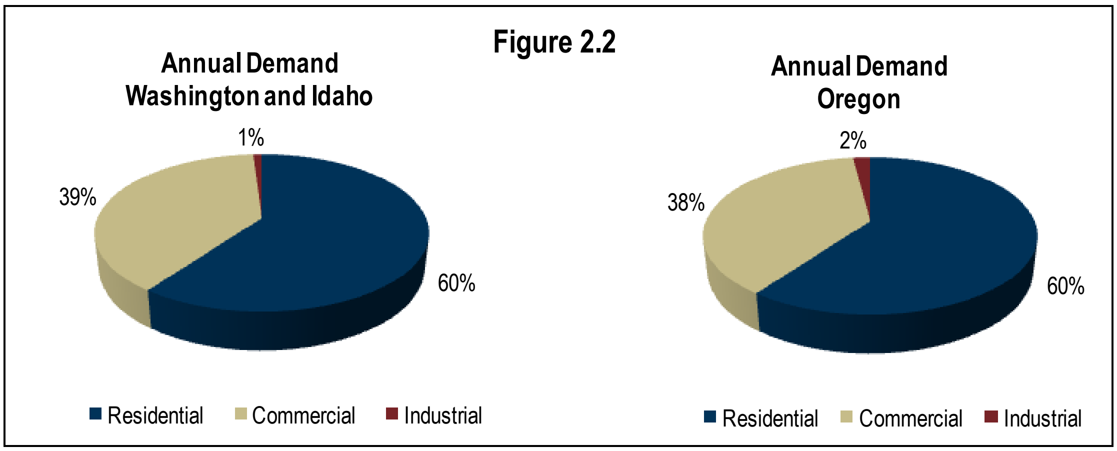
We provide natural gas services to two customer classifications ─ core and transportation only customers. Core customers purchase natural gas directly from us with delivery to their home or business under a bundled rate. This service implicitly obligates Avista to deliver whatever volume is needed by the customer under firm delivery requirements.

Transportation only customers purchase natural gas from third-parties who deliver their gas to our distribution system. We then deliver this gas to their business charging a distribution rate only. This delivery service can be interrupted by us during periods of high demand by our core customers. Because our transportation only customers purchase their own gas and delivery on our distribution system is non-firm, we exclude these customers from our long-term resource planning analysis.

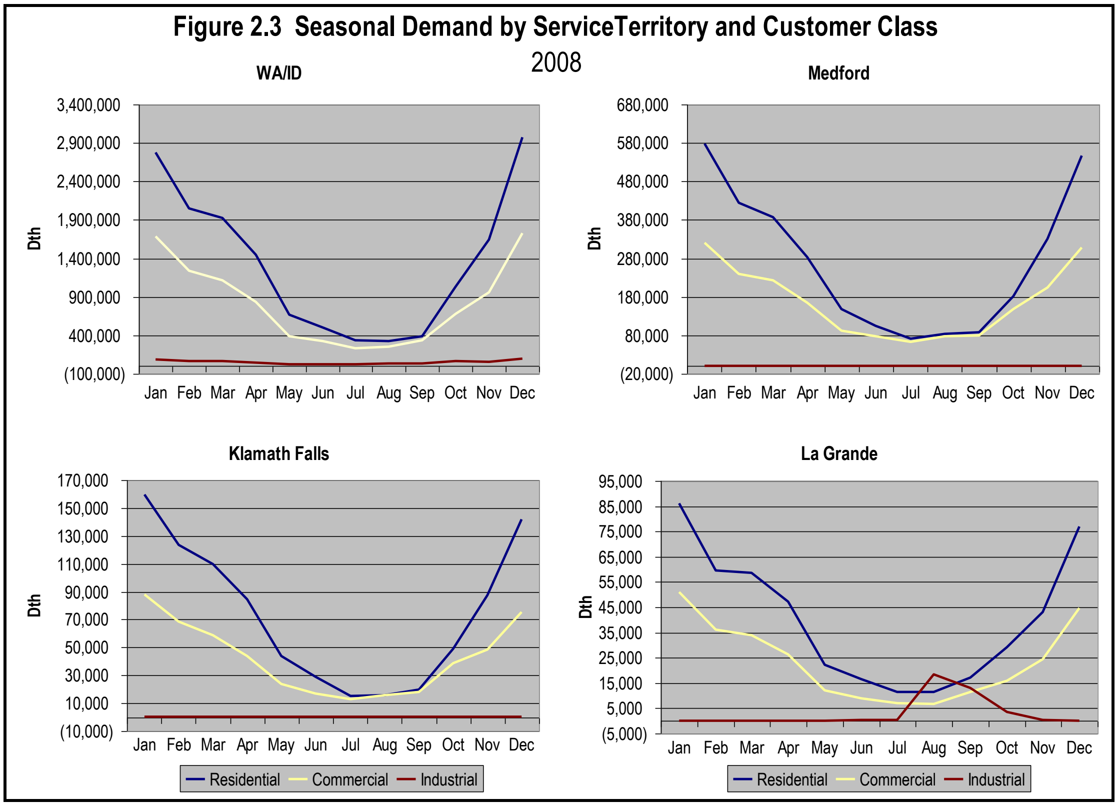
Our core or retail customers are further divided into three categories ─ residential, commercial and industrial. Most of our customers are residential followed by commercial and relatively few are industrial accounts (Figure 2.1).



The mix is more balanced between residential and commercial accounts on an annual volume basis (Figure 2.2). Volume consumed by core industrial customers is not significant to the total partly because most industrial companies in our service territories are transportation only customers.



Core customer demand is seasonal, especially by our residential accounts in our service territories with colder winters (Figure 2.3). Industrial demand, which is typically not weather sensitive, has very little seasonality. However, our La Grade service territory has several agricultural processing facilities that produce a late summer seasonal demand spike.



INTEGRATED RESOURCE PLANNING

In order to ensure that our core customers are provided with long-term reliable natural gas service at an economic price, we undertake a comprehensive analytical process through the integrated resource plan. We evaluate, identify and plan for the acquisition of the best-risk, least-cost portfolio of existing and future resources, to meet daily and peak day demand and delivery requirements over a 20-year planning horizon.

PURPOSE OF THE IRP

This document has several objectives:

- Provides a comprehensive long-range planning tool;
- Fully integrates forecasted requirements with potential resources;
- Determines the most cost effective, risk-adjusted means for meeting demand requirements; and
- Responds to Washington, Idaho and Oregon rules and orders.

AVISTA'S IRP PROCESS

The IRP process considers:

- Customer growth and usage;
- Weather planning standard;

- DSM opportunities;
- Existing and potential supply-side resource options; and
- Risk.

PUBLIC PARTICIPATION

Members of Avista's TAC play a key role and have a significant impact in development of the IRP. TAC members include Commission Staff, peer utilities, public interest groups, customers, academics, government agencies and other interested parties. A list of TAC members is in Appendix 1.1. The TAC provides important input on modeling, planning assumptions and the general direction of the process.

Avista sponsored four TAC meetings to facilitate stakeholder involvement in the 2009 IRP. The first meeting convened on April 26, 2009 and the last meeting was held on July 16, 2009. A broad spectrum of stakeholders was represented at each meeting. The meetings focused on specific planning topics, reviewed the status and progress of planning activities and solicited input on the IRP development. A draft of this IRP was provided to TAC members on September 4, 2009. We gained valuable input from the interaction and communication with TAC members and express our thanks and appreciation for their contributions and participation.

Preparation of the IRP is a coordinated endeavor by several departments within Avista with involvement and guidance from management. We are grateful for these efforts and contributions.

REGULATORY REQUIREMENTS

Avista submits an IRP to the Public Utility Commissions in Washington, Idaho and Oregon every two years as required by state regulation[1]. We intend to file our plan with all three Commissions on or before December 31, 2009. We have a statutory obligation to provide reliable natural gas service to customers at rates, terms and conditions that are fair, just, reasonable and sufficient. We regard the IRP as a means for identifying and evaluating resource options and as a process to establish an Action Plan for resource decisions. Ongoing investigation, analysis and research may cause us to determine that alternative resources are more cost effective than resources selected in this IRP. We will continue to review and refine our understanding of resource options and will act to secure these risk-adjusted, least-cost options when appropriate.

PLANNING MODEL

Consistent with several prior IRPs is SENDOUT®, the computer planning model we use to perform comprehensive and effective natural gas supply planning and analysis. This linear programming-based model is widely used in the industry to solve natural gas supply, storage and transportation

[1] In Washington, IRP requirements are outlined in WAC 480-90-238 entitled "Integrated Resource Planning." In Idaho, the IRP requirements are outlined in Case No. GNR-G-93-2, Order No. 25342. In Oregon, the IRP requirements are outlined in Order Nos. 07-002, 07-047 and 08-339. Appendix 2.1 provides details of these requirements and how they were met.

optimization problems. This model uses present value revenue requirement (PVRR) methodology to perform least cost optimization based on daily, monthly, seasonal and annual assumptions related to:

- Customer growth and customer natural gas usage to form demand forecasts;
- Existing and potential transportation and storage options;
- Existing and potential natural gas supply availability and pricing;
- Revenue requirements on all new asset additions;
- Weather assumptions; and
- Demand-side management.

We have also incorporated the Monte Carlo simulation module within SENDOUT® (formerly called VectorGas™) to simulate weather and price uncertainty. The module uses Monte Carlo functionality to generate simulations of weather and price to provide a probability distribution of results from which decisions can be made. Some examples of the types of analysis Monte Carlo simulation provides include:

- Price and weather probability distributions;
- Probability distributions of costs (i.e. system cost, storage costs, commodity costs); and
- Resource mix (optimally sizing a contract or asset level of various and competing resources).

These computer-based planning tools were used to develop our 20-year best cost/risk resource portfolio plan to serve customers.

PLANNING ENVIRONMENT

Although we prepare and publish an IRP biannually, the IRP process is ongoing to take into account new information and developments. In "normal" circumstances, the process can become complex as underlying assumptions evolve and impact previously completed analyses. The most recent cycle has been even more challenging because the planning environment has undergone extraordinary changes to the economic and natural gas industry landscape.

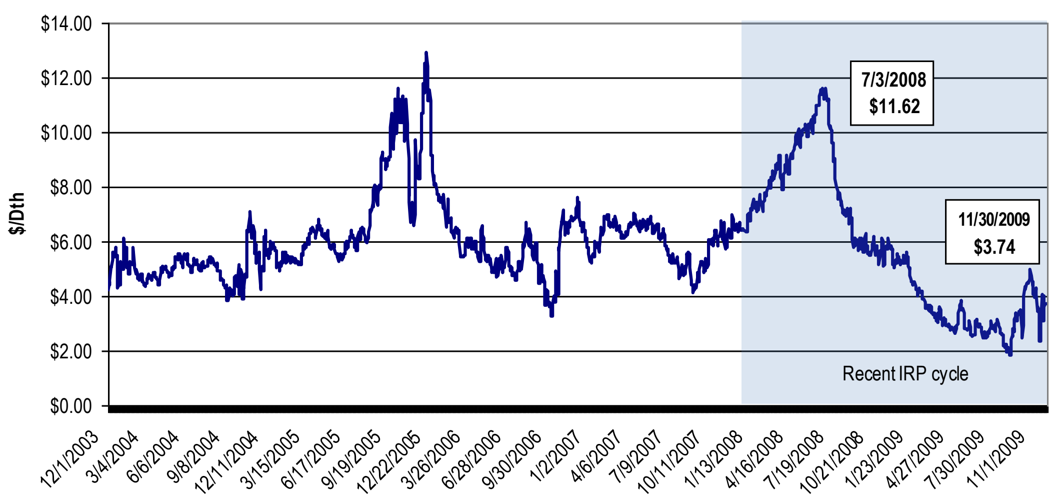
HISTORICAL RECAP

As we completed our 2007 IRP, continued robust global economic activity was pressuring energy commodity prices upward. Natural gas prices were strained by extremely tight production versus production capacity conditions and declining production in the Gulf of Mexico and western Canada. Increased oil sands production consumed an increasing share of western Canada's declining production exacerbating a declining import trend into the United States. At that time there was much discussion that imported liquefied natural gas (LNG) was essential to bridging the supply/demand gap. Higher forecasted prices were predicted to be necessary to lure LNG away from the higher priced European and Asian markets. Further, firming climate change policy generally predicted solid demand growth from increased gas-fired power generation to replace coal burning generation.

Higher prices brought increased investment in natural gas exploration, production and infrastructure. Emerging successes in existing unconventional gas production, especially shale gas, was a primary recipient of this increased investment, particularly in the areas of securing land leases and drilling test wells in new and existing plays throughout North America. With the expectation of strong demand growth came numerous new proposed pipeline projects announced including several to serve the Pacific Northwest.

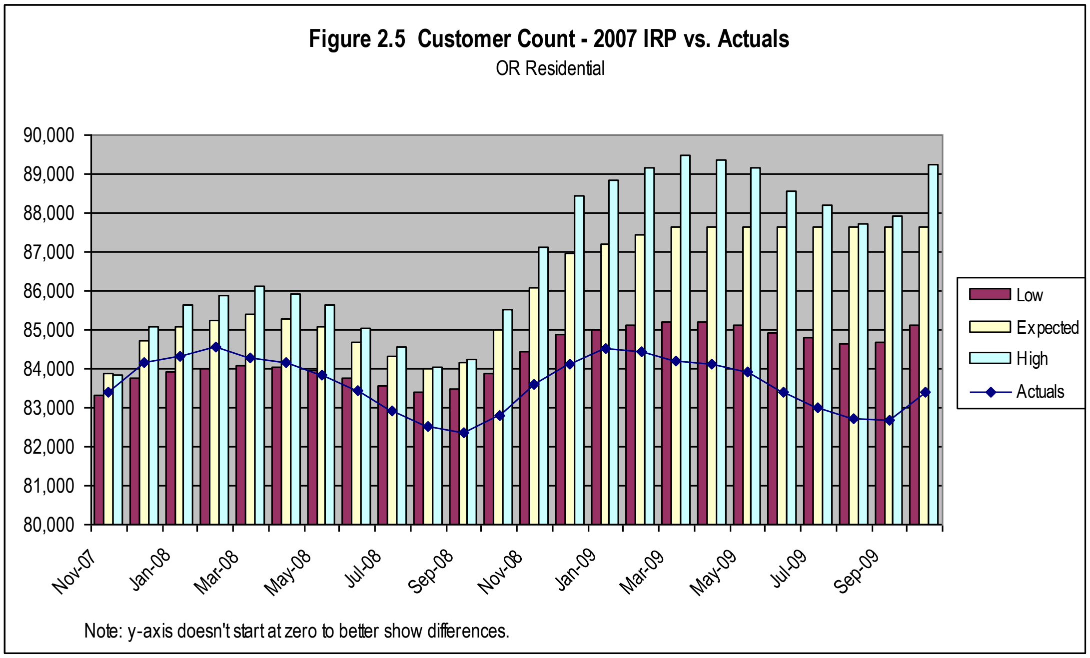
Strong energy price increases and tight fundamentals also caught the attention of the investment community prompting significant interest in energy commodities and investment inflows into the sector. Prices were bid strongly and by summer 2008, natural gas prices reached all-time highs on a seasonal basis (Figure 2.4).

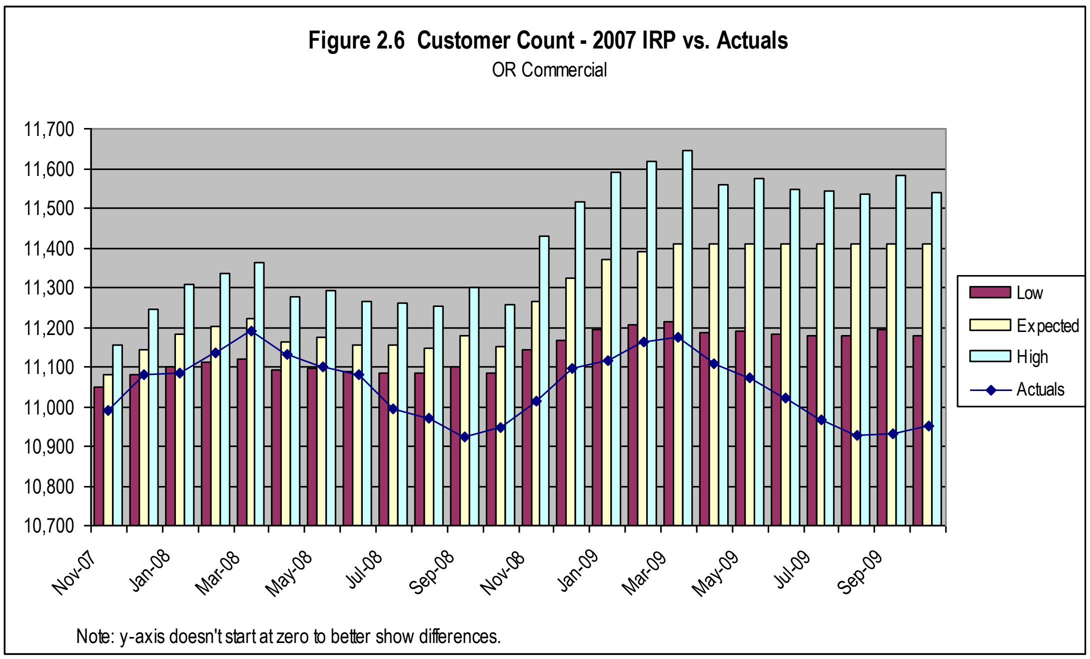
Figure 2.4 Historical Daily Prices
AECO



However, shifting fundamental factors and a slowing economy increasingly contradicted with this price strength. In the second half of 2008 and into 2009, the global credit crisis led to widespread economic disruption and energy demand destruction which dramatically reversed energy market expectations. Energy prices plummeted and uncertainty reigned. Meanwhile, earlier investments in shale exploration and production began delivering prolific results, leading to several upward revisions for predicted future supply sources prompting significant downward revisions to forward price forecasts.

In our own data, we saw a dramatic drop in a key demand metric, customer counts, which began lagging our 2007 IRP forecast. In Oregon, the counts even fell below our low-case projection, raising concern about the severity of the downturn and questions about our underlying modeling assumptions (See Figures 2.5 and 2.6).





IRP PLANNING STRATEGY

Amid this rapidly changing and uncertain environment, we contemplated our IRP planning strategy. We determined our approach needed to:

- Recognize historical trends may be fundamentally altered;
- Critically review all assumptions;
- Stress test assumptions via sensitivity analysis;
- Pursue a wide spectrum of possible scenarios;

- Develop a flexible analytical framework to accommodate changes; and
- Maintain a long-term perspective.

With these objectives in mind, we believe we have developed a sound strategy encompassing all required planning criteria that allowed us to produce a complete IRP that effectively analyzes risks and resource options, which sufficiently ensures our customers will receive safe and reliable energy delivery services well into the future with the best-risk, least-cost long-term solutions.

CHAPTER 3 – DEMAND FORECASTS

OVERVIEW

The integrated resource planning process begins with the development of forecasted demand. This was a challenging time to predict future events including preparing demand forecasts. Although historical trends normally provide a reliable baseline, they were used with heightened caution given the dramatic economic disruption we confronted as we prepared and presented this analysis.

The current economic situation is ambiguous, fluid and evolving. Although the economy appears to be stabilizing, long-term effects on the natural gas industry are uncertain, prompting us to consider a wide range of scenarios to evaluate and prepare for a broad spectrum of potential outcomes.

DEMAND AREAS

Eight demand areas, structured around the pipeline transportation resources that serve them, were defined within the SENDOUT® computer model (Table 3.1). These demand areas are aggregated into four service territories and further summarized into two divisions for presentation throughout this IRP.

Table 3.1 Geographic Demand Classifications

Demand Area	Service Territory	Division
Spokane NWP	Washington/Idaho	North
Spokane GTN	Washington/Idaho	North
Spokane Both	Washington/Idaho	North
Medford NWP	Medford/Roseburg	South
Medford GTN	Medford/Roseburg	South
Roseburg	Medford/Roseburg	South
Klamath Falls	Klamath Falls	South
La Grande	La Grande	South

DEMAND FORECAST METHODOLOGY

Avista uses the IRP process to develop two types of demand forecasts ─ annual and peak day. Annual demand forecasts are useful for several purposes including preparing revenue budgets, developing natural gas procurement plans and preparing purchased gas adjustment filings. Peak day demand forecasts are critical for determining the adequacy of existing resources or the timing for acquiring new resources to meet our customers' natural gas needs in extreme weather conditions throughout the planning period.

DEMAND MODELING EQUATION

Because natural gas demand can vary widely from day to day, especially in winter months when heating demand is at its highest, developing daily demand forecasts is essential. In its most basic form, demand is a function of customer base usage plus customer weather sensitive usage. This can be expressed by the following general formula:

Table 3.2 Basic Demand Formula

# of customers **x** Daily **base usage** / customer

Plus

# of customers **x** Daily **weather sensitive** usage / customer

More specifically, SENDOUT® requires inputs as expressed in the below format to compute daily demand in dekatherms (Dth):

Table 3.3 SENDOUT® Demand Formula

# of customers **x** Daily Dth of base usage / customer

Plus

# of customers **x** Daily Dth of degree day usage / customer **x** # of daily degree days

This calculation is performed by SENDOUT® for each day for each customer class and each demand area. The base and weather sensitive usage (degree day usage) factors are customer demand coefficients developed outside the SENDOUT® model and capture a variety of demand usage assumptions. This is discussed in more detail in the Use per Customer Forecast section below. The number of daily degree days is simply heating degree days (HDDs), which are further discussed in the Weather Forecast section later in this chapter.

Customer Forecasts

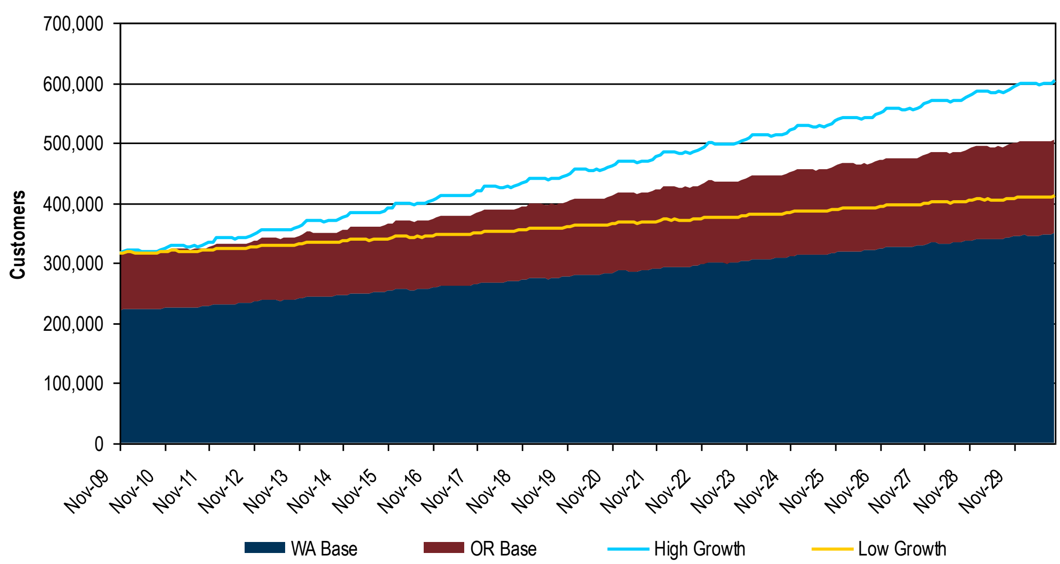
Avista's customer base is segregated into three categories: residential, commercial and industrial. For each of the customer categories, we develop our customer forecasts by starting with national economic forecasts and then drilling down into regional economies. Population growth expectations and employment are key drivers in regional economic forecasts and are useful in estimating natural gas customers. We contract with Global Insight, Inc. for long-term regional economic forecasts. A description of the Global Insight forecasts is found in our customer forecasts detail in Appendix 3.1. We combine this data with local knowledge about sub-regional construction activity, age and other demographic trends and historical data to develop our 20-year customer forecasts.

In response to a previous IRP action item, this IRP incorporates sub-area core customer forecasting for each municipality and unincorporated county area throughout the three-state service area. This includes 56 governmental subdivisions or "town codes" in Washington, 26 in Idaho and 37 in Oregon.

The annual growth for each state is allocated so that the total equals the sum of the parts. These 119 town code forecasts are used by the distribution engineering group for optimizing decisions within these geographic sub-areas and facilitating integrated forecasting and planning within Avista (see further discussion in Chapter 8 – Distribution Planning).

Forecasting customer growth is an inexact science so it is important to consider alternative forecasts. Two alternative forecasts were developed for consideration in this IRP. During the last 25 years, customer growth during five-year periods has ranged between one-half and one-and-a-half times the 25-year average customer growth rate. Since both patterns have been observed, Avista has created low and high customer growth alternatives with these parameters. The three customer growth forecasts are shown in Figure 3.1. Detailed customer count data, by region and by class, for all three scenarios, is in Appendix 3.2.

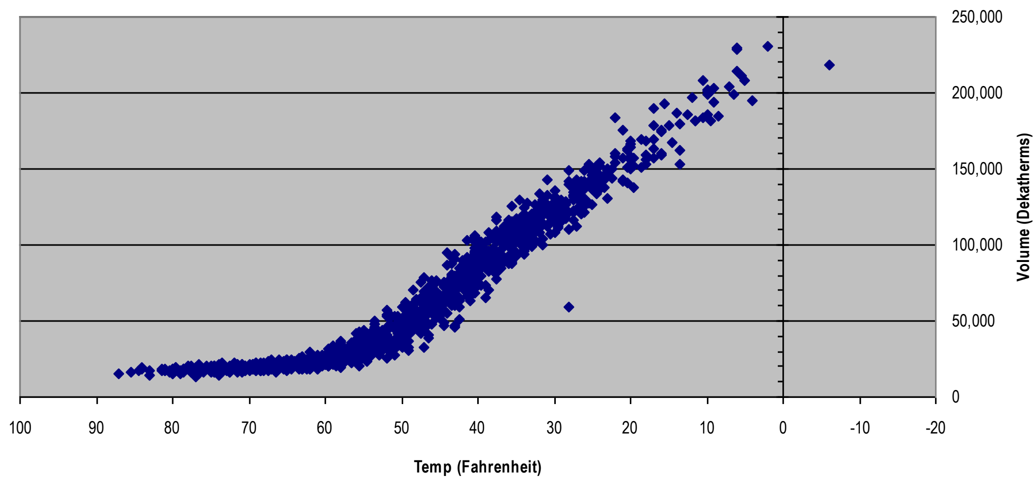
Figure 3.1 Customer Growth Scenarios



Use per Customer Forecast

The goal for a use per customer forecast is to develop base and weather sensitive demand coefficients that can be combined and applied to HDD weather parameters to reflect average use per customer. This produces a very reliable forecast because of the high correlation between usage and temperature as depicted in the example scatter plot in Figure 3.2.

Figure 3.2 - Example Daily Demand vs. Temperature Profile
Washington Idaho



The first step in developing demand coefficients was gathering daily historical gas flow data for all of our city gates. Three years of data were gathered, segregated by service territory/temperature zone and then by month. Weather normalized July and August data was used to calculate base demand coefficients by dividing total usage by total number of customers. Customer class factors were then calculated using allocations based on customer billing data demand ratios.

To derive weather sensitive demand coefficients, for each monthly data subset, we removed base demand from the total and plotted usage by HDD in a scatter plot chart. We then applied linear regression to the data to capture the linear relationship of usage to HDD. The slopes of the resulting lines were our monthly weather sensitive demand coefficients. Again, to derive factors by customer class, we used allocations based on customer billing data demand ratios.

In extreme weather conditions, demand can sometimes begin to flatten out relative to the linear relationships at less extreme temperatures. This occurs, for example, when appliances such as furnaces reach maximum output and do not consume any more natural gas regardless of how much colder temperatures get. We sought to capture this phenomenon through development of super peak coefficients.

The methodology for deriving super peak coefficients was exactly the same as deriving weather sensitive demand coefficients except, instead of forming data subsets by month, a dataset was created using temperature (specifically only very cold temperatures). The line slope from the regression on this data was typically flatter relative to the other monthly weather sensitive demand coefficients. One inherent drawback to this methodology is the lack of sufficient data points to develop a strong linear relationship. More years of data can help, but the older data becomes less and less relevant to current demand relationships.

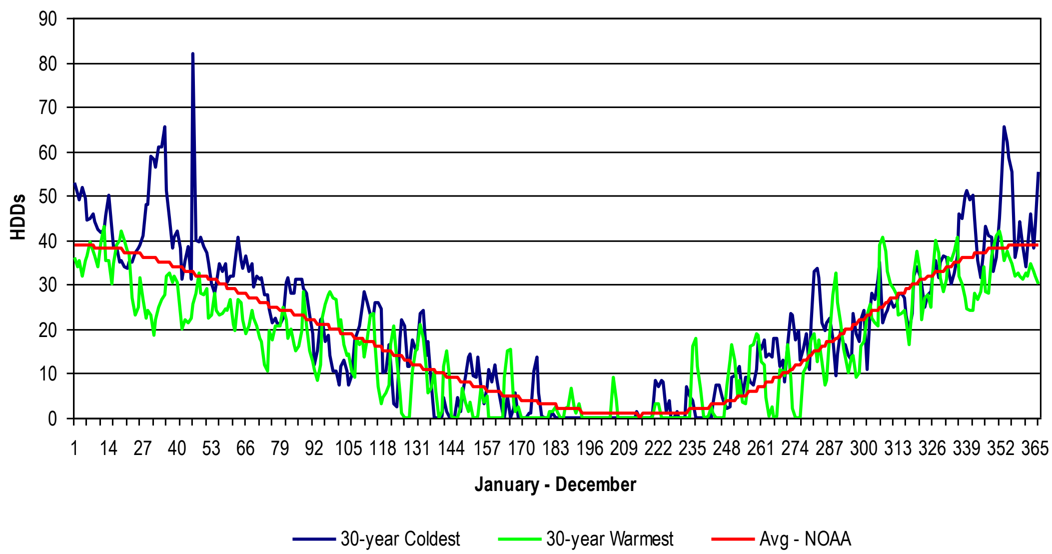
As a final step, to check coefficient reasonableness, we applied the coefficients to actual customer count and weather data to backcast demand. This was compared to actual demand with satisfactory results. The regression calculations and coefficients can be found in Appendix 3.3.

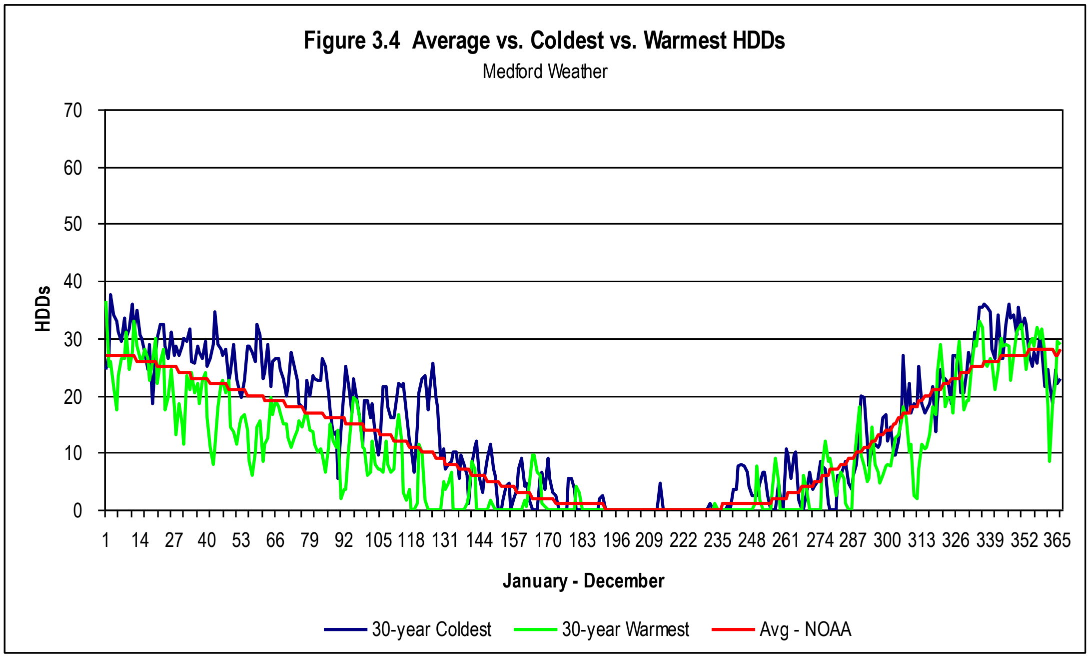
Weather Forecast

The last input in the demand modeling equation is weather (specifically HDDs). We obtain the most current 30 years of daily weather data from the National Oceanic Atmospheric Administration (NOAA), convert it to HDDs and compute an average for each day to develop our weather forecast. For Oregon, we use four weather stations, corresponding to the areas where natural gas services are provided. HDD weather patterns between these areas are uncorrelated. For the eastern Washington and northern Idaho portions of our service area, weather data for the Spokane Airport is used, as HDD weather patterns within that region are correlated.

Figures 3.3 and 3.4 show NOAA's most recent 30-year average weather data in comparison to the coldest and warmest planning year in history for the Spokane and Medford areas. Measurements of historical average weather do not necessarily represent the range of potential future weather patterns, including some days that may differ substantially from that average pattern.

Figure 3.3 Average vs. Coldest vs. Warmest HDDs
Spokane Weather





Figures 3.5 and 3.6 compare the NOAA 30-year average weather with a company-selected composite of weather months that form a weather year based on average HDDs with the variability of actual weather.

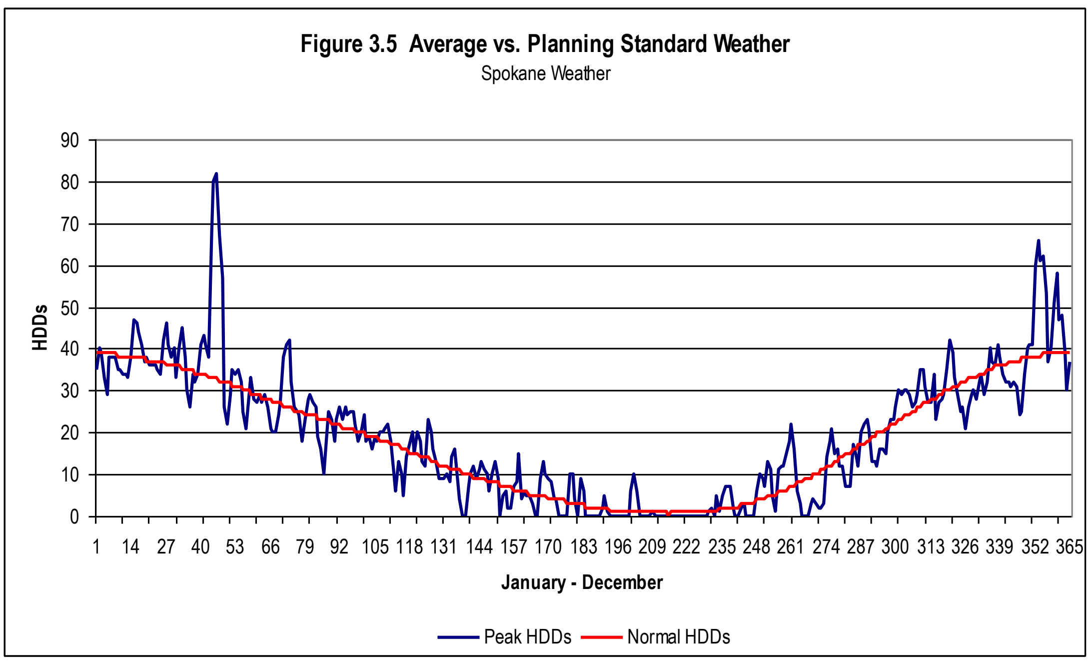
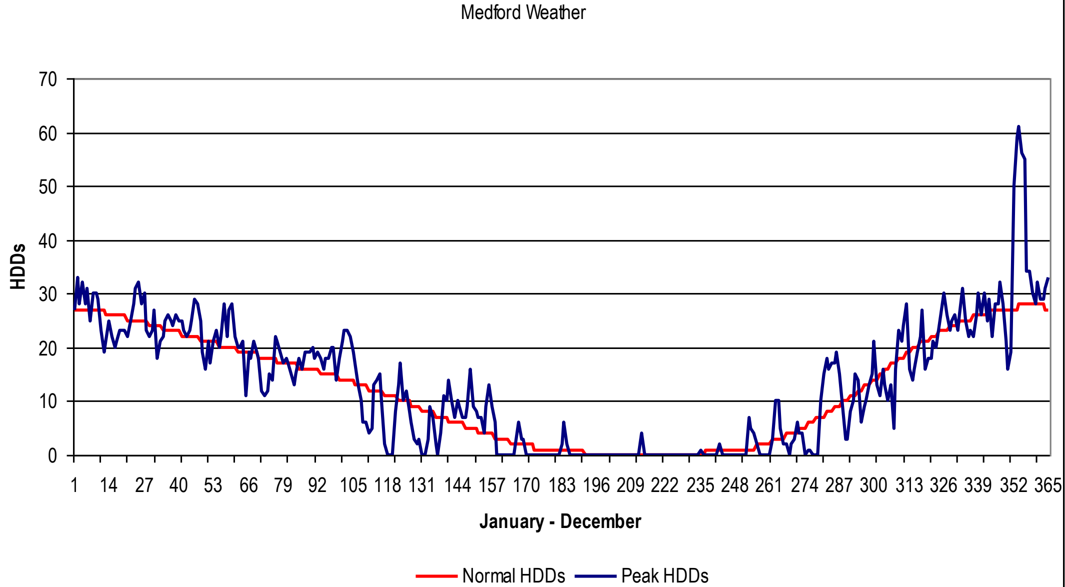


Figure 3.6 Average vs. Planning Standard Weather



The NOAA 30-year average weather (adjusted for global warming-see below) serves as the base weather forecast that is used to prepare the annual average demand forecast. In preparing the peak day demand forecast we adjust average weather to reflect a five-day cold weather event. This consists of adjusting the middle day of the five day cold weather event to the coldest temperature on record for a service territory, as well as adjusting the two days either side of the coldest day to temperatures slightly warmer than the coldest day. For our Washington/Idaho and La Grande service territories, we model this event on and around February 15 each year. For our southwestern Oregon service territories (Medford, Roseburg, Klamath Falls) we model this event on and around December 20 each year.

The following describes specific details on the coldest days on record for each service territory:

- On Dec. 30, 1968, the Washington/Idaho service area experienced the coldest day on record, an 82 HDD for Spokane. This is equal to an average daily temperature of -17 degrees Fahrenheit. Only one 82 HDD has been experienced in the last 40 years for this area; however, within that same time period, 80 and 79 HDD events occurred on Dec. 29, 1968, and Dec. 31,1978, respectively.
- On Dec. 9, 1972, Medford experienced the coldest day on record, a 61 HDD. This is equal to an average daily temperature of 4 degrees Fahrenheit. Medford has experienced only one 61 HDD in the last 40 years; however, it has also experienced 59 and 58 HDD events on Dec. 8, 1972, and Dec. 21, 1990, respectively.
- The other three areas in Oregon have similar weather data. For Klamath Falls, a 72 HDD occurred on Dec. 21, 1990, in La Grande a 74 HDD occurred on Dec. 23, 1983, and a 55 HDD occurred in Roseburg on Dec. 22, 1990. As with Washington/Idaho and Medford, these days are used as the peak day weather standard for modeling purposes.

The actual HDDs by area and by day entered into SENDOUT® can be found in Appendix 3.4.

For this IRP, we adjusted the NOAA weather data to incorporate estimates for global warming in developing our HDD forecast. This was based on extensive analysis of historical weather data in each of the areas we serve. Adjustments were applied to daily data and include a phase-in over the first ten years of our planning horizon. The effect of the adjustments, all else equal, results in declining annual demand over time. Appendix 3.5 summarizes our historical analysis and adjustment factors.

Although our analysis identified a gradual warming trend in the historical data, we were unable to discern any definitive evidence to support a peak day warming trend. We unsuccessfully searched for potential supporting studies or analysis on the topic and, after discussion with our TAC, determined we would not make warming trend adjustments to our peak day weather events in our HDD forecast. Therefore, our modeling and analysis with respect to peak day planning is unaffected by global warming. Additional information on this topic is in Appendix 3.5.

DEVELOPING A REFERENCE CASE

Significant uncertainty in the planning environment led us to develop a demand forecasting process that could flexibly adapt to a host of alternative demand forecast assumptions. To understand how various alternative assumptions influence forecasted demand, we needed a reference point for comparative analysis. For this we define a reference case demand forecast (Figure 3.7). We stress that this case is not intended to reflect anything other than a simple assumption start point.

Figure 3.7 Reference Case Assumptions

1. Customer annual growth rates:

	Residential	Commercial	Industrial
Washington	1.8%	2.1%	1.2%
Idaho	3.0%	2.5%	0.6%
Oregon	2.7%	1.4%	0%

2. Use per customer coefficients – Flat all classes
3. Weather planning standard – coldest day on record
   - WA/ID 82; Medford 61; Klamath 72; La Grande 74

DYNAMIC DEMAND METHODOLOGY

To address the uncertain planning environment, we identified a demand planning strategy to critically examine a wide range of potential outcomes. The approach developed consisted of:

- Identifying key demand drivers behind natural gas consumption;

- Performing sensitivity analysis on each demand driver; and
- Combining demand drivers under various scenarios to develop alternative potential outcomes for forecasted demand.

In analyzing demand drivers, we grouped them into two categories based on:

- 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.

Once factors were identified, we developed sensitivities which we define as focused analysis of a specific natural gas demand driver and its impact on forecasted demand relative to our Reference Case when the underlying input assumptions are modified.

Appendix 3.6 schedules the specific sensitivities we identified and the base assumptions we varied to determine the resultant effect on demand relative to our reference case. Sensitivity assumptions reflect incremental adjustments we estimate are not captured in the underlying Reference Case forecast.

Following our testing of the various sensitivities we grouped them into meaningful combinations of demand drivers to develop demand forecasts representing scenarios. Table 3.4 identifies the scenarios we developed. Included is an Expected Case reflecting the demand forecast we believe is most likely. Appendix 3.6 schedules the specific assumptions within the scenarios while Appendix 3.7 contains a detailed description of each scenario.

Table 3.4 Alternate Demand Scenarios
Expected Case
High Growth, Low Price
Low Growth, High Price
Green Future
Alternate Weather Standard
Supply Constraints

PRICE ELASTICITY

With increased natural gas price volatility, it has become difficult to project future natural gas prices. We acknowledge changing price levels influence usage so we incorporate a price elasticity of demand factor into our model to allow use per customer to vary into the future as our natural gas price forecast changes.

Price elasticity is usually expressed as a numerical factor that defines the relationship of a consumer’s consumption change in response to price change. Typically, the factor is a negative number as consumers normally reduce their consumption in response to higher prices or will increase their consumption in response to lower prices. For example, a price elasticity factor of negative 0.13 means a 10% price increase will prompt a 1.3% consumption decrease and a 10% price decrease will prompt a 1.3% consumption increase.

We noted complex relationships influence price elasticity and given the challenging economic environment, we questioned whether current behavior might differ from historical trends. Working with the TAC we sought to develop a range of elasticity factors to examine sensitivity of demand to various price elasticity assumptions.

AGA PRICE ELASTICITY STUDY

From our participation in the AGA price elasticity study, we received regional elasticity factors which compared favorably to our past estimates. Based on this corroboration, we used a factor of negative .13 as our medium case factor to adjust use per customer coefficients. From this base line assumption, we varied the factors to come up with a range of price elasticity responses which was then used in various price influencing demand scenarios (Table 3.5).

Table 3.5 Price Elasticity Assumptions

	Real Price annual increase within 30%	Real Price annual increase exceeds 30%
High	Negative .20	Negative .30
Medium	Negative .13	Negative .13
Low	No response	Negative .06

RESULTS

During 2009-10, our Expected Case demand forecast indicates we will serve an average of 317,700 core natural gas customers with 35,099,000 dekatherms of natural gas. By 2028-29, we project 493,600 core natural gas customers with an annual demand of over 42,944,000 dekatherms. In Washington/Idaho, the number of customers is projected to increase at an average annual rate of 2.2 percent with demand growing at a compounded average annual rate of 1.0 percent. In Oregon, the number of customers is projected to increase at an average annual rate of 2.5 percent, with demand growing 1.4 percent per year.

Figure 3.8 shows system forecasted demand for the Expected, High and Low demand cases on an **average daily basis** for each year[1].

[1] Appendix 3.9 shows gross demand, DSM savings, and net demand.

Figure 3.8 System Wide Average Daily Demand
(Net of DSM Savings)

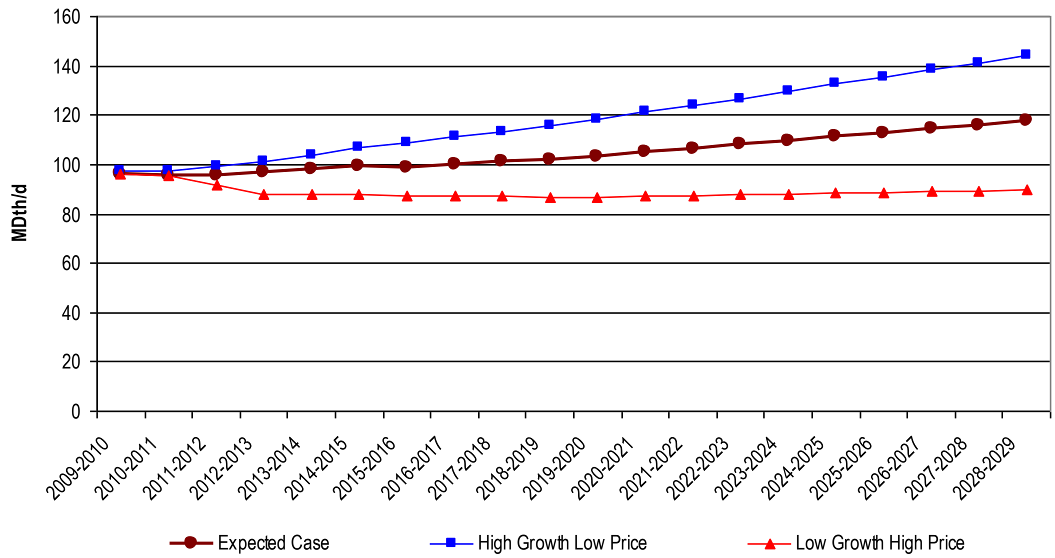
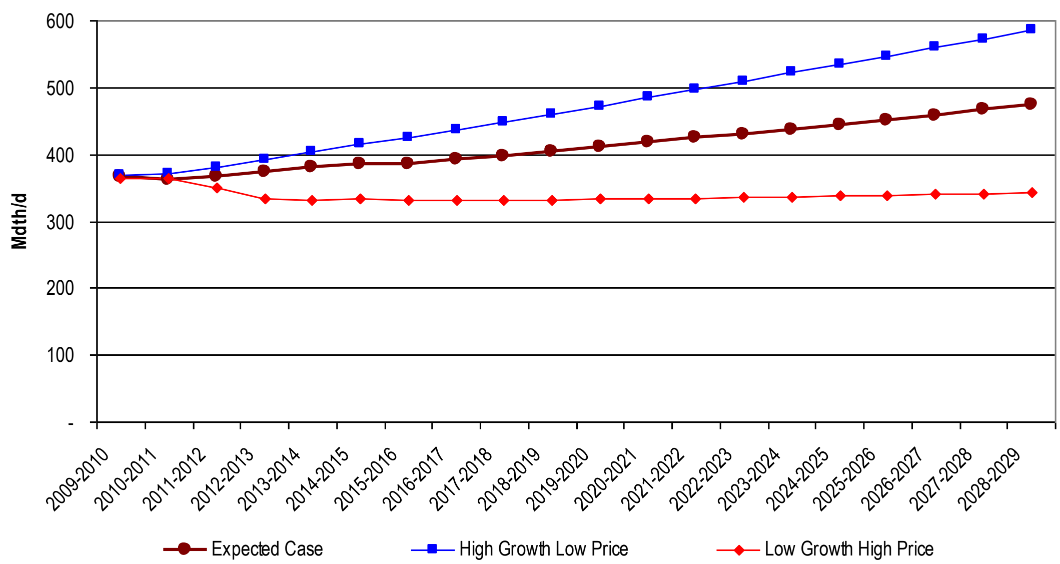


Figure 3.9 shows system forecasted demand for the Expected, High and Low Demand cases on a **peak day basis** for each year.

Figure 3.9 System Feb 15 Peak Day Demand
(Net of DSM Savings)



Detailed data depicting annual and peak day demand data is in Appendix 3.8.

The purpose of the IRP is to balance forecasted demand with existing and new supply alternatives. Since new supply sources include conservation resources, which act as a demand reduction, the demand forecasts prepared and described in this section include existing efficiency standards and normal market acceptance levels. The incremental conservation measures modeled are described in the Demand-Side Resources Chapter.

ACTION ITEM

Our price elasticity analysis raised several issues. First, we noted the AGA factors were derived from annual demand data. This was satisfactory for our annual demand forecasting, but this raised a question whether the factors were applicable to peak demand analysis. We also use the same factors for residential and commercial customer classes even though the AGA factors were derived from residential customer data only.

We also noted that price signals to core customers are lagged and they are often insulated from volatile prices due to their exposure to tariff rates versus wholesale prices. Finally, we noted that the period we were analyzing presented a challenging scenario because of the timing of our price forecasts.

During our planning cycle, prices had reached all-time seasonal highs in summer 2008 but by the beginning of 2009, prices had tumbled to multi-year lows. This dramatic volatility in the wholesale market was not necessarily a price signal to core customers who were on more stable tariff rates.

Our medium 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 case 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. On the other hand, the customer response could materialize as modeled, resulting in an actual significant demand curtailment.

We discussed this dilemma with the TAC. We decided to use the low price elasticity assumption for our Expected Case and monitor closely actual use per customer data and DSM program results for indications of price elasticity response trends that may have been influenced by evolving economic conditions.

For the coming IRP cycle, we plan to investigate contemporary analytical sources for information on natural gas price elasticity and inquire if the AGA will update its analytical work. We may also consider hiring a third-party price elasticity study and assess interest of other utilities in pursuing a regional study.

CONCLUSION

Through the scenario planning process, we have considered the potential demand impacts of both changing natural gas prices and a changing economy. The result of those considerations is a reasonable range of outcomes with respect to core consumption of natural gas. While we recognize that the actual level of demand is dependent on a variety of factors, reviewing a range of potential outcomes allows us to plan more effectively as economic or pricing conditions change.

CHAPTER 4 – DEMAND-SIDE RESOURCES

OVERVIEW

Demand-side management (DSM) is the activity pursued by an energy utility to influence its customers to reduce their energy consumption or change their patterns of energy use away from peak consumption periods. This usually includes information campaigns and financial incentives to persuade customers to adopt conservation measures. Conservation measures are installations of appliances, products or facility upgrades that result in energy savings. Demand-side resources represent the aggregate energy savings attained from the installation of conservation measures.

Avista has been offering natural gas DSM programs to its customers periodically since 1995. These programs result in multiple benefits including reducing customers' bills, reducing supply-side resource needs and reducing GHG emissions. These benefits make acquiring cost effective demand-side resources a very attractive resource alternative which we believe is the best strategy for minimizing energy service costs to our customers while promoting a cleaner environment.

Since our last IRP, energy policy and legislation activity are placing a high level of awareness and importance on environmental and energy use issues. Spiking energy prices in early 2008 and subsequent economic challenges in latter 2008 and into 2009 have also led to increased public awareness and interest in energy saving measures. In response, Avista is committed to provide the resources to help consumers reduce energy consumption through cost effective conservation programs.

Avista's DSM organization is split into a North Division (Washington and Idaho), and a South Division (Oregon). The North Division is one delivery area while the South Division is further segmented into four delivery areas consistent with our SENDOUT® modeling.

COST EFFECTIVENESS

Cost effectiveness is a fundamental concept to DSM. In simple terms, it is the determination of whether the present value of the energy savings (net of non-energy benefits) for any given conservation measure is greater than the cost to achieve the savings. When making this assessment, it is important to capture all benefits and costs in the evaluation. For example, Avista identifies and quantifies the non-energy benefits of water conservation in high efficiency front loading washing machines as an offset against the avoided cost of that measure. For the South Division, the presence of environmental externalities in supply resources relative to conservation measures is quantified and factored into any comparative cost analysis[1]. Incremental administrative costs are also evaluated for possible inclusion in analyzing conservation measure economics.

[1] Oregon IRP regulations require that a 10% cost advantage accrues to DSM resources relative to supply resources for environmental externalities costs. Appendix 4.4 describes our analysis.

Exceptions to the cost effectiveness rule include conservation measures that are pursued as part of a broader market transformation effort or measures that are mandated or approved by regulators. In some cases, bundling measures may justify inclusion of a non-cost effective measure when the overall bundle of measures is cost effective, otherwise enhancing the non-cost effective measure with cost effective measures while enticing the customer to install more measures.

TYPES OF CONSERVATION MEASURES

Conservation measures that achieve generally uniform year round energy savings independent of weather temperature changes are considered base load measures. Examples include high efficiency water heaters, cooking equipment and front load clothes washers. Measures that are influenced by weather temperature changes are weather sensitive measures which include higher efficiency furnaces, ceiling/wall/floor insulation, weather stripping, insulated windows, duct work improvements (tighter sealing to reduce leaks) and ventilation heat recovery systems (capturing "chimney" heat). Weather sensitive measures are desirable in resource planning, as they save the most energy during the coldest periods thus displacing the more expensive peaking or seasonal supply resources. Weather sensitive measures are often referred to as winter measures and are valued using a higher avoided cost while base load measures are often called annual measures and are valued at a lower avoided cost.

Conservation measures are offered to residential, non-residential and low income customers. Conservation measures offered to residential customers are classified as prescriptive, meaning they have a standardized therm savings which can be generalized across the customer class and all customers receive the same financial incentive for the same measures. Low income customers receive a more holistic, customized approach through six Community Action Agency partnerships. Non-residential customers have access to prescriptive and site-specific conservation measures. Site-specific measures are customized to the facility and have cost and therm savings that are unique to the individual facility.

Finally, some conservation measures in our South Division are offered based on legislation and are therefore designated "mandatory" or "must take" measures in our SENDOUT® modeling tool, which means they are offered to customers without regard to their current cost effectiveness relative to the utility's supply resources. An example of something mandated would be a walk-through energy audit which would not be accompanied with energy savings unless a customer chooses to participate in a program. In addition, a customer may choose to delay participating in a program for many years if they choose to participate at all. In these cases, the audit would be non-cost effective since there is no savings benefit to offset the cost of the audit.

METHODOLOGY

Avista's methodology for evaluating DSM within our IRP is based on four key concepts:

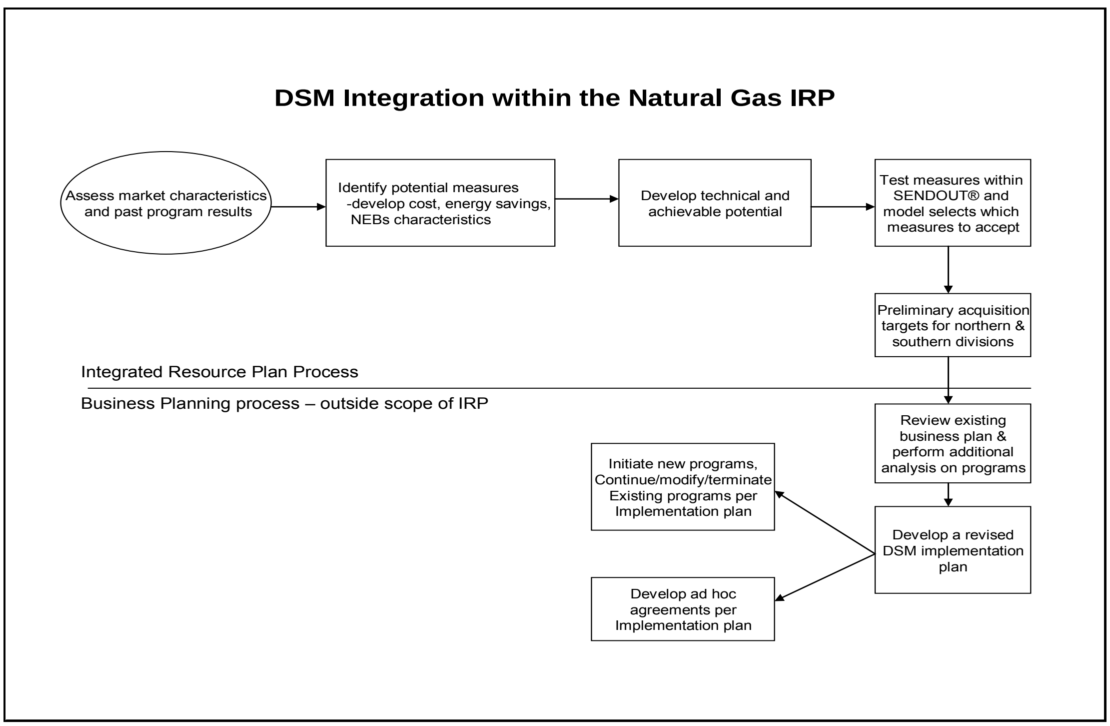
- Provides a comprehensive evaluation of all significant conservation measures that are currently commercially available and emerging measures that are likely to be available in the future;
- Evaluates conservation measures in a process that is interactive with supply-side options;
- Maximizes portfolio net total resource value (we strive to get the most for each dollar spent); and
- Delivers analytical results that are actionable for the DSM implementation planning process[2].

The methodology we adopted to fulfill these concepts has four phases:

- Identifying Technical Potential
- Assessing Achievable Potential
- SENDOUT® Testing
- Conservation Goal Development

The above DSM methodology is summarized in the flowchart in Figure 4.1. Details of each phase follows.

Figure 4.1 DSM Methodology Flowchart



[2] The completion of IRP analysis is not the end point but rather the midpoint of a larger reassessment of the DSM resource portfolio. Appendix 4.1 describes the development of our DSM implementation plan and overall DSM operations.

PHASE ONE: IDENTIFYING TECHNICAL POTENTIAL

Technical potential is an estimate of all energy savings that can theoretically be accomplished if every customer that could potentially install a conservation measure did so without consideration of market barriers such as cost and customer awareness. For example, the “replace on burnout” technical potential for high efficiency water heaters would quantify total savings assuming every existing water heater (gas or electric) within a natural gas service territory would be replaced with a high efficiency model upon an assumed burnout schedule in all cases.

In 2005, Avista contracted with RLW Analytics, a conservation analysis consultant, to independently identify and analyze the potential energy savings for our Oregon service territories. Methodology from their study was extrapolated to Washington and Idaho and served as the initial basis for determining conservation technical potential for all of Avista’s natural gas service territories. The energy savings data for weather-sensitive measures were adjusted to incorporate local heating degree day data appropriate to each geographic area. Avista DSM engineers, program implementers and analysts also reviewed the consultant’s estimates of incremental measure costs, measure lives, energy savings and other inputs and assumptions, making adjustments when knowledge of local factors differed from the more generalized assumptions used in the study.

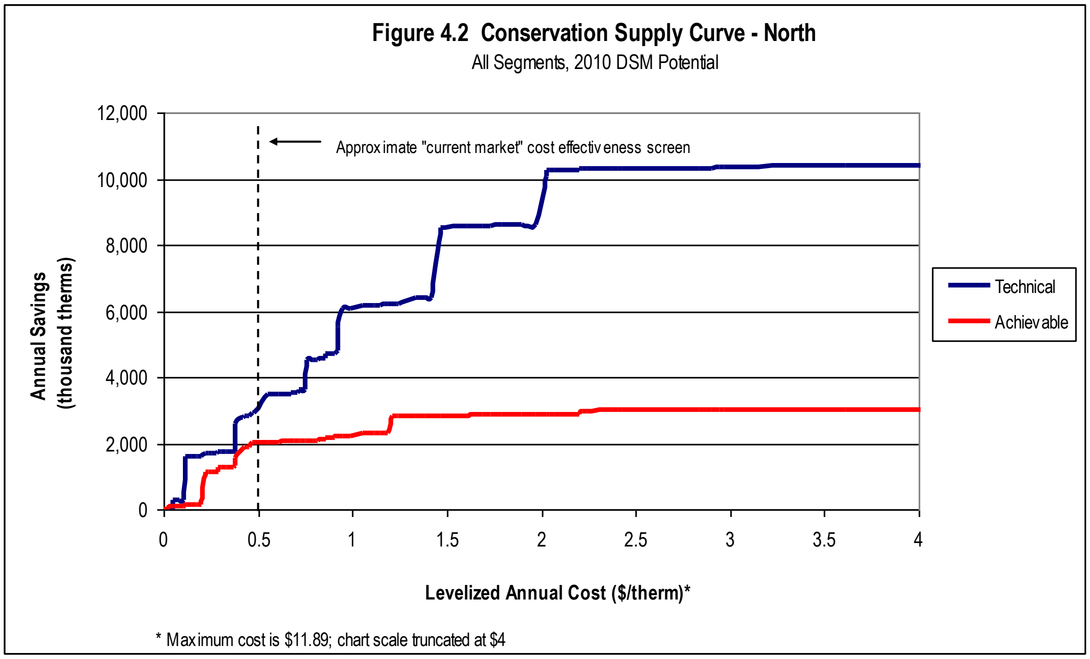
Since 2005, we have made adjustments and updates to incorporate new information regarding measure cost and energy savings, augmenting the study with additional measures not previously evaluated. A total of 155 residential and 147 non-residential measures were considered for this IRP. A summary of these measures for both divisions are contained in Appendix 4.2.

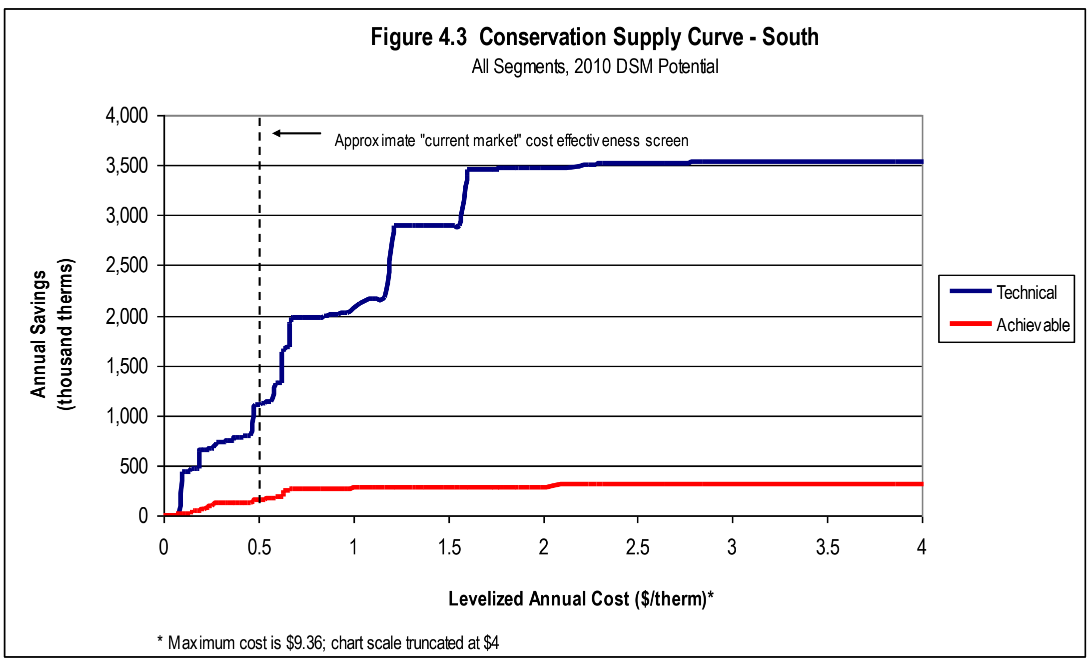
PHASE TWO: ASSESSING ACHIEVABLE POTENTIAL

Achievable potential represents a more realistic assessment of expected energy savings since it recognizes and accounts for economic and other constraints that preclude full installation of every identified conservation measure. Even the most robust information campaigns will not reach every eligible customer nor sufficiently motivate all affected customers to immediately install every conservation measure applicable to them.

Unlike other regional utilities that have selected an overall percentage to estimate achievable potential, Avista analyzes each measure’s likely installation rate to establish measure by measure achievable potential. Engineers and program implementers begin their evaluation with the number of natural gas customers in that division broken down by the percentage that is single family, multifamily or manufactured homes. The applications are evaluated based on how many have that application in their home or facility and/or have access to have it in their home or facility and, finally, how many of those that would be replaced with a higher efficiency option over the standard option over the 20-year horizon. A summary list of technical and achievable potential is included in Appendix 4.2.

Figures 4.2 and 4.3 show the comparison of technical potential and achievable potential for our North and South Divisions, respectively. For perspective, we indicate a cost effectiveness screen of $0.50 per therm based on an approximate commodity cost of $5 per Dth. Around this level, Avista’s achievable potential tracks much closer with the technical potential and is similar to other regional utilities. We further discuss the gap in technical versus achievable potential in Appendix 4.1 including our plans to obtain a new external study of technical potential prior to completion of the 2011 IRP.





These estimates are preliminary assessments of the best implementation approach for particular technologies and market segments and the expected growth or decline of those markets. These assessments may require revision based on further development of program plans during the implementation planning process.

PHASE THREE: SENDOUT® TESTING

In past IRPs, conservation measures were grouped into bundles to facilitate easier data input and faster system processing within SENDOUT®. However, this method required a complex process of manually calculating levelized total resource cost (TRC) outside the model based on estimated avoided costs that had to be checked and adjusted against SENDOUT® results in an iterative process.

For this IRP, we elected to invest the time to enter each individual conservation measure into SENDOUT® to enable more granular and accurate measure selection for DSM resource acquisition. This effort was no small task considering the exponential proliferation of inputs, as each assumption for every conservation measure had to be entered by customer class across the eight sub areas we model in SENDOUT®. This resulted in significantly more data entry that required managing around potential system processing constraints but eliminated prepackaging issues and potentially less accurate "group" measure selection.

Inputs included conservation measure cost, measure life, annual energy savings, non-energy benefits and discount rate. The model then calculated a levelized TRC for each measure to compare against the model's avoided cost calculation.

Mandated measures were entered into SENDOUT® as must takes which bypassed system cost effectiveness testing and were automatically selected as a preferred resource by the model. All other measures were evaluated by SENDOUT® against other supply-side resource options.

The demand-side resources selected by SENDOUT® are summarized in Table 4.1. Note that these results do not include site-specific measures. These measures are incorporated in the next phase of the IRP process.

Table 4.1 SENDOUT® DSM Results
(calendar year 2010)

	North	South
Residential measures	2,926,761	215,580
Non-residential meaures	75,601	110,734
Total adopted measures (therms)	3,002,362	326,314

PHASE FOUR: CONSERVATION GOAL DEVELOPMENT

In this phase, we augment the results of the SENDOUT® testing with estimates of resource acquisition from commercial and industrial site-specific programs to develop a therm acquisition goal. These programs can include multiple conservation measures, are inherently individualized and have unique characteristics that preclude input into SENDOUT®.

Site-specific programs are designed to be all inclusive so any natural gas efficiency options with measureable therm savings qualify for the program in some fashion. Direct financial incentives are contingent upon minimum project simple-payback criteria in the North Division and a TRC cost effectiveness test in the South Division based on differing regulation. Generally speaking, all projects have the potential for receiving technical assistance and many qualify for direct financial assistance. Site-specific therm acquisition is estimated by establishing a baseline of historical site-specific program results modified to reflect past and estimated future growth.

A final adjustment must be made to eliminate the duplication of resource opportunities between the all-inclusive site-specific programs and the measures accepted within the SENDOUT® modeling. Some of the measures incorporated into the SENDOUT® model are duplicative of resource acquisition incorporated into the estimates of site-specific resource acquisition. Based on a review of the SENDOUT® accepted measures and the expectations of site-specific program targets, we estimated that all of the South Division and 84 percent of the North Division future site-specific therm acquisition were included in the SENDOUT® analysis.

It is possible that there will be measures selected in this process that will subsequently be determined to be unsuitable for inclusion in Avista's DSM portfolio based on post-IRP analysis, implementation planning and program planning efforts. It is also possible that programs could be developed for measures that were rejected by this IRP as a result of this same process. Though the IRP is our best opportunity to comprehensively re-evaluate the DSM portfolio and its integration into the overall resource mix at one point in time, it is necessary to incorporate an ongoing implementation planning process to ensure that the best resource decisions are made.

PRELIMINARY CONSERVATION GOAL

The following therm goals reflect of the results of the integrated resource optimization as further described in Chapter 6 – Integrated Resource Portfolio. See that chapter for the complete results of the integrated resource optimization including the regional cumulative benefits over the 20-year planning horizon.

The SENDOUT® results[3] and modifications for site-specific programs for the first two years are summarized in Table 4.2.

Table 4.2 Results of Achievable Resource Potential
Current Year 2010 and 2011

	2010	2011
SENDOUT®-accepted residential programs	2,926,761	2,862,948
SENDOUT®-accepted non-residential programs	75,601	77,852
Estimated site-specific acquisition	811,920	844,397
Less: non-res prescriptive programs duplication	(685,440)	(712,858)
Total North Division	3,128,842	3,072,339

	2010	2011
SENDOUT®-accepted residential programs	215,580	206,333
SENDOUT®-accepted non-residential programs	110,734	118,650
Total South Division	326,314	324,983

[3] The results of the SENDOUT® model required a minor revision to translate into the calendar year implementation planning and budgeting cycle used for DSM operations.

Based on the analytical process described in the above Methodology section, first-year energy savings goals resulting from the IRP process were approximately 3,128,842 therms in the North Division and 326,314 therms in the South Division. This commitment represents an increase of 98 percent from the 2007 IRP annual resource acquisition for 2010 in the North Division and an increase of 9 percent in the South Division.

Site-specific acquisition included in the above is estimated to be 126,480 therms for the North Division and is no longer applicable for the South Division as all measures were tested within SENDOUT®. These estimates incorporate consideration of the significantly different non-residential customer bases within our North and South Divisions. Specifically, non-residential customers within our South Division tend to be smaller-sized retail customers and generally non-industrial. However, in spite of their limited opportunity to acquire resources through their site-specific program, existing utility staff has been redeployed to establish and foster relationships with contract auditors and trade allies in effort to increase participation.

The North Division site-specific program has been a highly successful component of the overall portfolio. However, active and real-time management is necessary to continue to focus on and move toward new opportunities within this market. As more participation occurs in specific applications and technologies, program implementers and engineers use results to establish more prescriptive approaches in order to increase participation without having to add additional infrastructure. This has proved to be a successful approach to address developing markets and influencing customers toward them.

The North potential is in excess of the 2010 acquisition goal of 1,755,829 therms developed in the 2007 IRP. The potential increase in the target is the result of a steep carbon mitigation cost adder[4] in our natural gas price forecast that we model to take effect in 2015. This large increase in natural gas prices, correspondingly, significantly increases avoided costs over the planning horizon. A concern is how to influence customers to implement natural gas efficiency upgrades now based on a price increase modeled to take effect in 2015 which they may not see or are skeptical of it materializing that far into the future.

We are resolved to meet all cumulative potential identified in this IRP over the planning cycle, but will do so with a gradual ramping up of program activity. We determined it was possible to establish an approximate 6.5 percent constraint on the annual increase over the first 10 years while simultaneously achieving this objective in the long run by the end of the 20-year period. This increase is in excess of customer growth but ensures that the infrastructure growth can be managed more carefully and without undue inflation of acquisition costs associated with rapid growth.

For the South Division, the potential is slightly below the 2010 acquisition goal of 304,548 therms from the 2007 IRP. This comes at a time when customers in this service territory are facing state unemployment rates exceeding 14 percent in some counties. We are resolved to meet all cumulative

[4] Adder reflects price impacts to comply with anticipated climate change legislation. Appendices 3.6 and 3.7 has detailed discussion on our modeling of climate change policy.

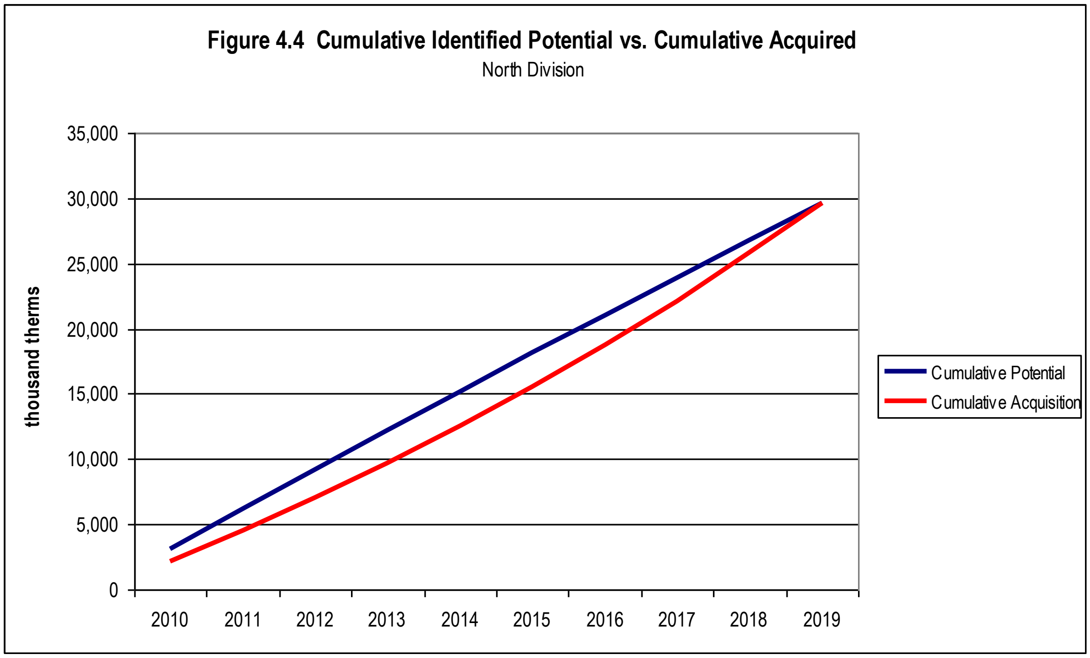
potential identified in this IRP over the long-term (20-year) planning cycle, but will do so with a gradual ramping up of program activity. We determined this to be possible by establishing an approximate 2.2 percent constraint on the annual increase over the first five years while simultaneously achieving this objective in the long run by the end of the 20-year planning horizon. This increase is greater than the projected customer growth but ensures that the infrastructure growth can be managed more carefully during this economic time.

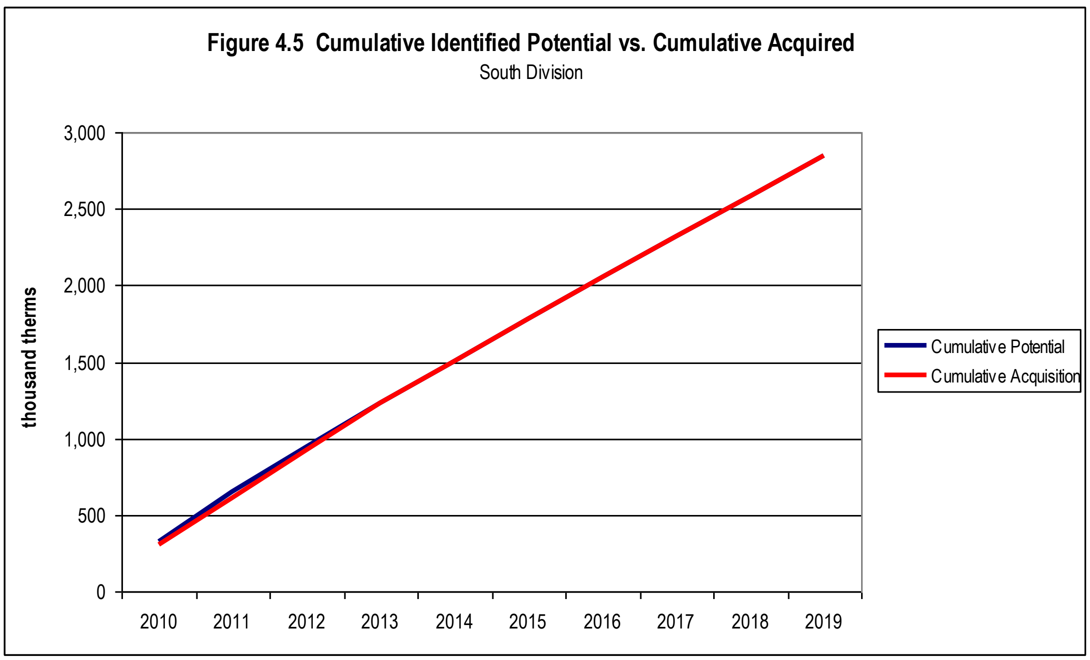
Application of this 6.5 percent annual growth constraint for the North Division and 2.2 percent annual growth constraint for the South Division results in a summary of annual and cumulative acquisition and identified DSM potential as listed in Table 4.3

Table 4.3 Annual and Cumulative SENDOUT® Achievable Potential and Revised Goal

	North Divison				South Divison			
	Achievable Potential	Cumulative Potential	DSM Goal	Cumulative Goal	Achievable Potential	Cumulative Potential	DSM Goal	Cumulative Goal
CY2010	3,128,842	3,128,842	2,193,338	2,193,338	326,314	326,314	303,300	303,300
CY2011	3,072,339	6,201,181	2,336,541	4,529,879	324,983	651,297	309,973	613,273
CY2012	3,010,146	9,211,327	2,489,094	7,018,973	298,759	950,056	316,792	930,065
CY2013	3,000,080	12,211,407	2,651,607	9,670,579	280,458	1,230,514	299,879	1,229,944
CY2014	3,005,777	15,217,184	2,824,730	12,495,310	278,214	1,508,728	278,214	1,508,158
CY2015	2,943,985	18,161,169	3,009,157	15,504,466	275,973	1,784,701	275,973	1,784,130
CY2016	2,864,302	21,025,471	3,205,625	18,710,091	271,604	2,056,305	271,604	2,055,735
CY2017	2,849,376	23,874,847	3,414,920	22,125,011	266,358	2,322,663	266,358	2,322,093
CY2018	2,862,118	26,736,965	3,637,633	25,762,643	262,851	2,585,514	263,041	2,585,134
CY2019	2,900,317	29,637,283	3,874,639	29,637,283	266,715	2,852,229	267,095	2,852,229
CY2020	2,796,582	32,433,864	2,796,582	32,433,865	269,559	3,121,789	269,559	3,121,788
CY2021	2,675,821	35,109,685	2,675,821	35,109,686	257,134	3,378,923	257,134	3,378,922
CY2022	2,690,538	37,800,223	2,690,538	37,800,224	227,802	3,606,725	227,802	3,606,724
CY2023	2,707,941	40,508,164	2,707,941	40,508,165	188,897	3,795,622	188,897	3,795,621
CY2024	2,651,295	43,159,459	2,651,295	43,159,460	154,709	3,950,331	154,709	3,950,330
CY2025	2,621,258	45,780,716	2,621,258	45,780,718	136,043	4,086,374	136,043	4,086,373
CY2026	2,585,548	48,366,264	2,585,548	48,366,266	132,376	4,218,750	132,376	4,218,749
CY2027	2,278,881	50,645,145	2,278,881	50,645,147	135,054	4,353,804	135,054	4,353,803
CY2028	2,034,955	52,680,100	2,034,955	52,680,102	129,141	4,482,945	129,141	4,482,944
CY2029	2,029,521	54,709,621	2,029,521	54,709,623	120,643	4,603,588	120,643	4,603,587

The North Division potential and acquisition identified in Figures 4.4 and 4.5 indicates that we will fully acquire identified DSM potential over the 20-year planning cycle within the 6.5 and 2.2 percent annual ramp-up constraint for North and South, respectively.





The IRP resource analysis is, as previously mentioned, the starting point for the implementation planning process. Appendix 4.1 discusses Avista's DSM programs and how the IRP results will be incorporated into DSM operations.

DSM SENSITIVITIES

Avista continues to acknowledge its obligation to acquire all cost effective natural gas-efficiency resources available through utility intervention. Given the rapid changes within the natural gas market, new efficiency opportunities may arise in the market within the 20-year horizon being analyzed within this process. As we continue to consider and evaluate any developing applications and/or technologies for inclusion in our portfolio between IRPs, considerable uncertainty remains regarding customers' response to these programs. Since this is a time of economic uncertainty when retail gas prices are declining, we face the challenge of how to get customers to respond now to prices they might not actually see for years to come. Historically, we have seen levels of less participation as retail prices decline. However, stimulus-related government incentives could accelerate participation.

To better understand how demand-side resources may be affected by uncertain economic conditions, we evaluated two DSM sensitivities based on the following:

- **DSM Accelerated** - Tax credits, particularly on the residential side, induce a combination of increasing participation in our programs to some degree, but the greatest impact is in inducing participating residential customers to stretch to higher levels of efficiency in order to qualify for tax credits as a complement to our existing rebates. Non-residential customers have far fewer such tax credits available to them, but to a much lesser degree the same impact occurs in that market. Stimulus funded residential audit programs result in the acquisition of low-cost/no-cost measures beyond what was assumed in the IRP base case.
- **DSM Delayed** - Budget constraints restrict customer incentives to less than current levels. Our program outreach is cut by 50% and staffing is curtailed. The economic recession continues and due to reduced disposable income, we see a reduction in non-lost-opportunity (deferrable) efficiency measures such as weatherization and a lesser reduction in the installation of lost-opportunity (furnace, hot water heater, etc.) measures. We also see a reduction in non-residential energy-efficiency measures due to the lack of discretionary capital budget within our customers businesses.

The resulting incremental (decremental) savings of these sensitivities are summarized in Table 4.4:

Table 4.4 DSM Sensitivities Summary

	DSM Accelerated		DSM Delayed	
	2010 Therms	Cumulative Therms over 20 Years	2010 Therms	Cumulative Therms over 20 Years
Annual Measures				
Medford	3,666	65,985	(444)	(7,986)
Roseburg	843	15,173	(102)	(1,837)
Klamath	1,539	27,697	(186)	(3,353)
LaGrande	642	11,560	(78)	(1,400)
WA/ID	56,311	1,013,598	(32,584)	(586,512)
Winter Measures				
Medford	16,330	293,944	-	-
Roseburg	3,755	67,586	-	-
Klamath	6,854	123,372	-	-
LaGrande	2,861	51,494	-	-
WA/ID	233,720	4,206,960	(125,057)	(2,251,026)

The impact of either sensitivity could be meaningful. We will continue to watch for signs of either sensitivity developing. However, this uncertainty does not preclude us from pursuing the planned aggressive ramp-up of natural gas-efficiency programs. Additionally, we have, and will continue to actively seek, opportunities for new or enhanced resource acquisition through the development of cooperative regional programs.

ENVIRONMENTAL EXTERNALITIES

The impact of utilizing energy on the environment continues to be a subject of societal concern and debate. If there are impacts that cannot be repaired naturally within a reasonable period of time, damage cost to the environment occurs for which society will have to pay in some future undetermined form. The question of who pays, how much and when payment should be made, are complicated issues. This debate is beginning to be addressed through a variety of public policy initiatives and legislation. Regulatory guidelines in Oregon advocate specific analysis in the IRP process to better understand these issues. Avista included an evaluation of the impacts of environmental externalities in the context of this evolving legislative environment. Appendix 4.4 discusses our analysis.

DEMAND RESPONSE

Demand response is a peak demand management concept where customers adjust the timing of their energy consumption away from consumption peaks in exchange for lower rates. Implementation strategies encompass a number of activities including real time pricing, time of use rates, critical peak pricing, demand buyback, interruptible rates and direct load controls. When effectively implemented, acquisition of costly supply resources can be deferred.

Demand response works best when it is a quick solution to an immediate problem. When demand peaks, system operators need the ability to either quickly notify customers to curtail consumption or do it themselves via control systems to physically manage/restrict gas flow to increase distribution system pressures.

This mechanism exists with respect to our interruptible transportation-only customers, which make up approximately one third of Avista's total annual throughput. However, because we do not purchase supply for these customers, they do not represent an incremental supply resource alternative. Only core customers with high winter consumption profiles would provide an incremental supply resource using demand response curtailment strategies. Unfortunately, we currently have very few core customers with a complying consumption profile. As a result, we believe that all customers who can manage their operations on interruptible service are currently served on an interruptible basis, leaving little opportunity to reduce peak loads through expanded interruptible service.

While little demand response opportunity exists on our natural gas system, we continue to monitor the progress of other natural gas utilities and their efforts of peak load shifting to offset hourly and/or daily flow constraints. Whereas electric demand response technologies have been in place for over two decades, major differences exist between electric and natural gas supply/delivery systems. The economics of the timing of natural gas usage are much more forgiving than electric due to underground storage and line packing. Furthermore, natural gas curtailment is not an option since a natural gas company cannot restart service without a technician on-site to ensure all pilots are properly lit for safety reasons.

At times natural gas providers may find implementing a demand response program helpful in offsetting or postponing a pipeline upgrade or in price balancing. However, mandatory participation in the affected areas would be vital to fund the necessary investment in enabling technologies.

One possible demand response program for the residential sector is remotely controllable thermostats. Avista is currently conducting a pilot project using this technology with Idaho electric customers. At present this pilot is limited to controlling the thermostat for space heating and cooling during times of electric peak demand. This pilot will conclude December 31, 2009 at which time a draft report will be compiled for results and what was learned from the program. Preliminary findings at this time show this technology is not cost effective for Avista for either summer or winter peak. Future technologies may offer cheaper, more reliable and flexible options for customers and their fuel providers. However, there are no near-term plans to pursue demand response programs.

CONCLUSION

By prompting customers to change their demand for natural gas, Avista can displace the need to purchase additional natural gas supplies, displace or delay contracting for incremental pipeline capacity and possibly displace or delay the need for reinforcements on our distribution system. This IRP process provides Avista with the necessary resource analysis to evaluate demand-side resource options alongside supply-side resources, periodically review and update DSM operations and finally, develop and implement improved natural gas efficiency programs.

The completion of IRP analysis is not the end point but rather the midpoint of a larger reassessment of the DSM resource portfolio. The IRP analysis presented has generally indicated a set of cost effective measures and achievable resource potential for a future DSM resource portfolio. Yet further evaluation is needed to facilitate the development of program plans and to incorporate them into an updated DSM implementation plan in the overall DSM operations.

CHAPTER 5 – SUPPLY-SIDE RESOURCES

OVERVIEW

We have analyzed a range of anticipated future demand scenarios and a variety of possible conservation measures to reduce demand. This chapter discusses possible supply options to meet net demand. Our objective is to reliably provide natural gas to customers with an appropriate balance of price stability and prudent cost while navigating continuously changing market conditions. To achieve this, we evaluate a variety of supply-side resources and attempt to build a supply portfolio that is appropriately diversified. The resource acquisition and commodity procurement programs resulting from our evaluation consider physical and financial risks, market-related risks and procurement execution risks and identify the methods we deploy to mitigate these risks.

We manage our natural gas procurement and related activities on a system-wide basis. We have a number of regional supply options available to serve our core customers. These include firm and non-firm supplies, firm and interruptible transportation on six interstate pipelines and two storage projects. Because Avista's core customers span three states, the diversity of delivery points and demand requirements adds to the options available to meet customers' needs. The utilization of these components varies depending on demand and operating conditions. In this chapter, we discuss the available regional commodity resources and our procurement plan strategies, the regional pipeline resource options available to deliver the commodity to our customers, and the storage resource options available which provide additional supply diversity, enhanced reliability, favorable price opportunities, and flexibility to meet a varied demand profile. Beyond these traditional supply-side resources, we discuss non-traditional resources which are also considered.

COMMODITY RESOURCES

SUPPLY BASINS

Avista is fortunate to be located in relatively close proximity to the two largest natural gas producing regions in North America—the Western Canadian Sedimentary Basin (WCSB), which is located primarily in the Canadian provinces of Alberta and British Columbia, and the Rocky Mountain gas basins, located primarily in Wyoming, Utah and Colorado. Avista sources virtually all of its natural gas supplies from these two basins.

The WCSB and Rockies gas basins used to have limited pipeline export potential, which has historically resulted in lower regional natural gas prices that were discounted to other parts of the country. Over the last decade, however, several large pipelines have been completed (or capacities of existing pipelines increased) connecting the WCSB and Rockies gas basins to the Southwest, Midwest and Northeast sections of the continent. This has, at times, diminished the discounted price advantage the region has enjoyed. Future projects that relieve bottlenecks and pipeline congestion out of the basins enabling gas to flow to higher priced markets could further erode this historically favorable price advantage. Future shale production in eastern markets could also reduce or eliminate this advantage.

REGIONAL MARKET HUBS

Extending out from the two primary basins are numerous regional market hubs where natural gas is traded. These typically are located at pipeline interconnects. Avista is located near and transacts at most of the Pacific Northwest regional market hubs, enabling flexible access to a diversity of supply points. These supply points include:

AECO – The AECO-C/Nova Inventory Transfer market center is a major connection region to long-distance transportation systems, which take gas to points throughout Canada and the United States. Alberta has historically produced 90% of Canada's natural gas and is the source of most Canadian natural gas exports to the United States representing volume that accounts for approximately 13% of U.S. natural gas requirements.

Rockies – This pricing "point" actually represents several locations on the southern end of the NWP system in the Rocky Mountain region. The system draws on Rocky Mountain gas-producing areas clustered in areas of Colorado, Utah, and Wyoming.

Sumas/Huntingdon – This pricing point at Sumas, Washington, is on the U.S.-Canadian border where the northern end of the NWP system connects with Spectra Energy's BC Pipeline, and is predominantly Canadian gas coming south from Northern British Columbia.

Malin – this pricing point is at Malin, Oregon on the California-Oregon border where the pipelines of TransCanada Gas Transmission Northwest (GTN) and Pacific Gas & Electric Co. connect.

Station 2 – Located at the center of the Spectra Energy - BC Pipeline system connecting to northern British Columbia production.

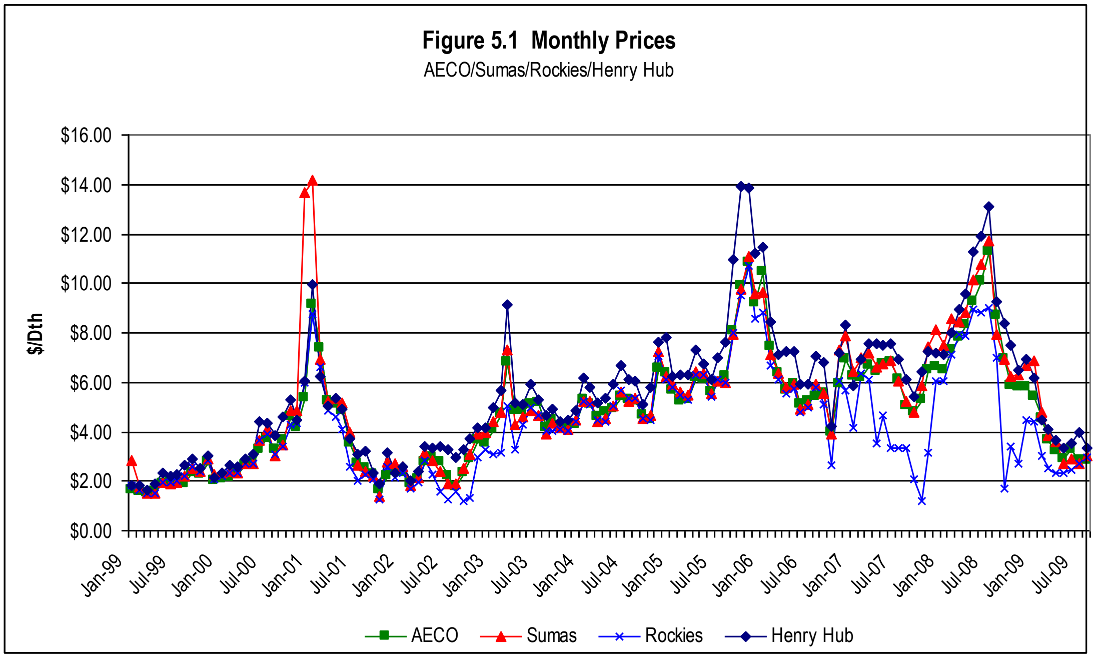
Stanfield – Located near the Washington/Oregon border at the intersection of the NWP and GTN pipelines

Kingsgate – Located at the US-Canadian (Idaho) border where the GTN pipeline connects with the TransCanada Foothills pipeline.

Given the ability to transport natural gas to other portions of North America, natural gas pricing is often compared to the Henry Hub price for natural gas. Henry Hub is a natural gas trading point located in Louisiana and is widely recognized as the primary natural gas pricing point in the United States. Henry Hub is also the trading point used in NYMEX futures contracts.

Figure 5.1 shows historic natural gas prices for first-of-month index physical purchases at AECO, Sumas, Rockies and Henry Hub. The figure illustrates there is usually a tight relationship among the various locations; however, there have been periods where one or more price points have disconnected. In winter 2000-2001, Sumas rallied on a combination of the western energy crisis and unusually cold local weather conditions. In fall of 2005, hurricanes Katrina and Rita disrupted significant Gulf of Mexico regional production causing the Henry Hub to spike disproportionately to Northwest hubs. Since 2007, increased production in the Rocky Mountain basin has exceeded the takeaway pipeline capacity forcing concessions on Rockies prices pending completion of major phases of the Rockies Express pipeline project. This significant project, completed in late summer

2009, enables substantial volumes to reach Midwestern and Northeast demand centers. Consequently, Rockies prices have resumed tighter tracking with Henry Hub prices.



Natural gas prices among the Northwest regional supply points typically move together as well; however, the basis differential can change depending on market or operational factors. This includes differences in weather patterns, pipeline constraints at different locations and the ability to shift supplies to higher-priced delivery points in the United States or Canada. By monitoring these price shifts, we are often able to purchase at the lowest-priced trading hubs on a given day, subject to operational and contractual constraints.

As mentioned above, Rockies natural gas has tended to trade at a discount to Henry Hub when production out-paced local demand and takeaway pipeline capacity. Pipeline expansion activity moving incremental production southwest to California (Kern River pipeline) and east to the Midwest and Eastern seaboard markets (via the Rockies Express pipeline) has eased the basis differential between AECO and Sumas prices as well.

Liquidity is generally sufficient in the day-markets at most northwest supply points. AECO continues to be the most liquid supply point, especially for longer-term transactions. Sumas has historically been the least liquid of the four major supply points (AECO, Rockies, Sumas, Malin). This illiquidity contributes to generally higher relative prices in the high demand winter months.

Procurement of natural gas is done via contracts. There are a number of contract specifics that vary from transaction-to-transaction, and many of those terms or conditions impact commodity pricing. Some of the agreed-upon terms and conditions include:

Firm vs. Non-Firm – Most term contracts specify that supplies are firm except for force majeure conditions. In the case of non-firm supplies, the standard provision is that they may be cut for reasons other than force majeure conditions.

Fixed vs. Floating Pricing – The agreed-upon price for the delivered gas may be fixed or based upon a daily or monthly index.

Physical vs. Financial – Certain counterparties, such as banking institutions, may not trade physical natural gas but are still active in the natural gas markets. Rather than managing physical supplies, those counterparties choose to transact financially rather than physically. Financial transactions provide another way for Avista to financially hedge price.

Load Factor/Variable Take – Some contracts have fixed reservation charges assessed during each of the winter months, while others have minimum daily or monthly take requirements. Depending on the specific provisions, the resulting commodity price will contain a discount or premium compared to standard terms.

Liquidated Damages – Most contracts contain provisions for symmetrical penalties for failure to take or supply natural gas.

For this IRP, the SENDOUT® model assumes the natural gas is purchased as a firm, physical, fixed-price contract regardless of when the contract is executed and what type of contract it is. However, in reality, we pursue a variety of contractual terms and conditions in order to capture the most value from each transaction.

AVISTA'S PROCUREMENT PLAN

We cannot accurately predict future natural gas prices but market conditions and experience help shape our overall approach. Avista has designed a natural gas procurement plan process that seeks to competitively acquire natural gas supplies while reducing exposure to short-term price volatility. Our procurement strategy includes hedging, storage utilization and index purchases. Although the specific provisions of the procurement plan will change as a result of ongoing analysis and experience, the following principles guide Avista's development of its procurement plan:

Avista employs a time, location and counterparty diversified hedging strategy – It is appropriate to hedge over a period of time, and we establish hedge periods within which portions of future demand are financially hedged. The hedges may not be completed at the lowest possible price, but they will protect our customers from price volatility. Additionally, we pursue diversified purchases at multiple basin/market hubs and transact with a range of counterparties.

Avista establishes a disciplined but flexible hedging approach – In addition to establishing hedge periods within which hedges are to be completed, we also set upper and lower pricing points. In a rising market, this reduces Avista's exposure to extreme price spikes. In a declining market, this encourages capturing the benefit associated with lower prices.

Avista regularly reviews its procurement plan in light of changing market conditions and opportunities – Avista's plan is open to change in response to ongoing review of the assumptions that led to the procurement plan. Although we establish various targets in the initial plan design, policies provide flexibility to exercise judgment to revise/adjust targets in response to changing conditions.

A number of tools are utilized to help mitigate financial risks. Avista purchases gas in the spot market as well as the forward market. Spot purchases are made on a day for the next day or weekend. Forward purchases are made on a day for a designated future delivery period. Many of these tools are financial instruments or derivatives that can be utilized to provide fixed prices or dampen price volatility. We continue to evaluate how to manage daily demand volatility, whether through option tools available from counterparties or through access to additional storage capacity and/or transportation.

TRANSPORTATION RESOURCES

Although proximity to the liquid hubs is important from a cost perspective, those supplies are only as reliable or firm as the pipeline transportation from the hubs to Avista's service territories. Capturing favorable price differentials and mitigating price and operational risk can also be realized by holding multiple pipeline transport options. Consequently, we have contracted for a sufficient amount of diversified firm pipeline capacity from various receipt and delivery points (including out of storage facilities) so that firm deliveries will meet peak day demand. We believe the combination of firm transportation rights to our service territory, storage facilities and access to liquid supply basins will ensure peak supplies are available to our core customers.

The major pipelines servicing our region are as follows:

Williams - Northwest Pipeline (NWP) - A natural gas transmission pipeline serving the Pacific Northwest moving natural gas from the US/Canadian border in Washington and from the Rocky Mtn. region of the US.

TransCanada Gas Transmission Northwest (GTN) - A natural gas transmission pipeline originating at Kingsgate, ID (Canadian/US border) and terminating at the California/Oregon border close to Malin, OR.

TransCanada Alberta System - A natural gas gathering and transmission pipeline in Alberta Canada that delivers natural gas into the TransCanada Foothills pipeline at the Alberta/British Columbia border.

TransCanada BC System - A natural gas transmission pipeline that delivers natural gas between the Alberta, BC border and the Canadian/US border at Kingsgate, ID.

TransCanada Tuscarora Gas Transmission - A natural gas transmission pipeline originating at Malin, OR and terminating at Wadsworth, NV.

Spectra Energy - BC Pipeline - A natural gas transmission pipeline originating at Fort Nelson, BC and terminating at the Canadian/US border at Huntington, BC/Sumas, WA.

Avista has contracts with each of the above pipelines for firm transportation to serve our core customers. Table 5.1 details the firm transportation/resource services contracted by Avista. These contracts are of different vintages, thus different expiration dates; however, all have the right to be renewed by Avista. This gives Avista and its customers the knowledge that Avista will have available capacity to meet existing core demand now and in the future.

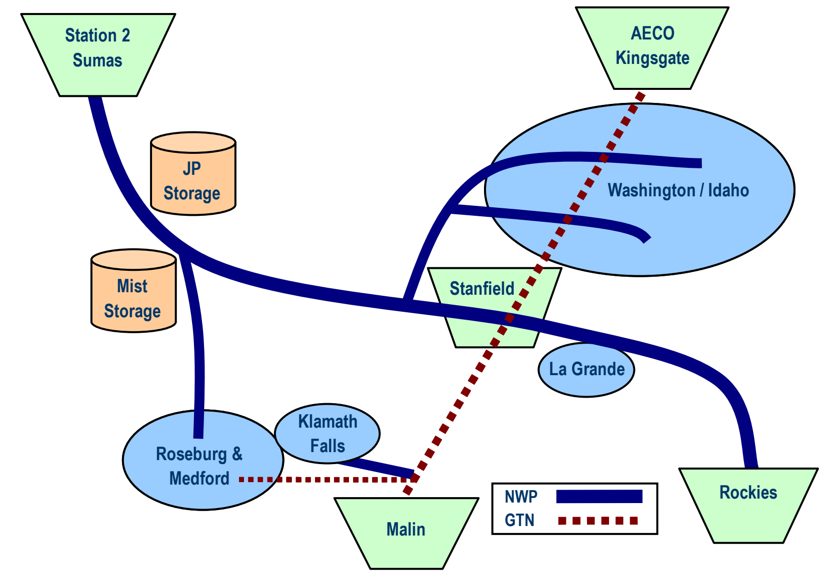
Table 5.1 - Existing Firm Transportation & Storage Resources
Dth/Day

	Avista North		Avista South	
Firm Transportation	**Winter**	**Summer**	**Winter**	**Summer**
NWP TF-1	119,526	119,526	22,562	22,562
GTN T-1	100,605	75,782	42,260	20,640
NWP TF-2	91,200		2,623	
Total	**311,331**	**195,308**	**67,445**	**43,202**
Firm Storage Resources - Deliverability				
Jackson Prairie	266,667		2,623	
MIST			15,000	
Total	**266,667**		**17,623**	

Avista defines two categories of interstate pipeline capacity. “Direct-connect” pipelines deliver supplies directly to our local distribution system from production areas, storage facilities or interconnections with other pipelines. “Upstream” pipelines deliver natural gas to the direct-connect pipelines from remote production areas, market centers and out of area storage facilities. Figure 5.2 illustrates the direct-connect pipeline network relative to our supply sources and service territories[1].

1 Avista has a small amount of pipeline capacity with TransCanada Tuscarora Gas Transmission, a natural gas transmission pipeline originating at Malin, Oregon, to service a small number of Oregon customers near the southern border of the state.

Figure 5.2 Direct-Connect Pipelines



Supply-side resource decisions focus on where to purchase natural gas and how to deliver it to customers. Each LDC has distinctive service territories and geography relative to supply sources and pipeline infrastructure. Solutions that deliver supply to service territories among regional LDCs are similar but are rarely generic—instead they are almost always unique.

The NWP system for the most part is a fully contracted system. With the exception of La Grande, our service territories lie at the end of various NWP pipeline laterals. Washington/Idaho is served via the Spokane and Lewiston laterals while Roseburg and Medford are served by the Grants Pass lateral. Capacity expansions on each of these laterals are lengthy and costly endeavors which Avista would likely bear most of the incremental costs.

The GTN system, on the other hand, currently has ample unsubscribed capacity. This pipeline runs directly through or lies in close proximity to most of our service territories. Mileage based rates and backhaul potential provide attractive options for securing incremental resource needs.

Peak day planning aside, both pipelines provide an array of options to flexibly manage daily operations. Our two largest service territories are directly served by both pipelines providing diversification and risk management with respect to supply source, price and reliability. The NWP system (a bi-directional, fixed reservation fee-based pipeline) provides direct access to historically cheaper Rockies supply and facilitates excellent storage facility management. The Stanfield interconnect of the two lines is also geographically well situated to our service territories.

The rates we use in our planning model start with filed rates that are currently in effect (See Appendix 5.1). Forecasting future pipeline rates is challenging. Our assumptions for future rate changes are the result of market information on comparable pipeline projects, prior rate case experience and informal discussions. It is generally assumed that the pipelines will file to recover costs at rates equal to the GDP with adjustments made for specific project conditions. Refinement of theses assumptions will be done as better information becomes available.

NWP and GTN also offer interruptible transportation service to Avista. The level of service of interruptible transportation is subject to curtailment when pipeline capacity constraints limit the amount of natural gas that may be moved. Although the commodity cost per dekatherm transported is the same as firm transportation, there are no demand or reservation charges in these transportation contracts. As the marketplace for release of transportation capacity by the pipeline companies and other third parties has become more prevalent, the use of interruptible transportation services has diminished. We do not rely on interruptible capacity to meet peak day core demand requirements.

Avista's transportation acquisition strategy is to contract for firm transportation to serve core customers should a peak day occur in the near-term planning horizon. Too much firm transportation could keep us from achieving our goal of being a low-cost energy provider. But too little firm transportation impairs our reliability goal. Determining the appropriate level of firm transportation is a complex evaluation of many factors, including the projected number of firm customers and their expected annual and peak day demand, opportunities for future pipeline or storage expansions and relative costs between pipelines and their upstream supplies. It is important to maintain an appropriate time cushion to allow for required lead times for securing new capacity. Also, the ability to release capacity can offset some or all of the cost of holding underutilized capacity.

STORAGE RESOURCES

Storage is a valuable strategic resource that enables improved management of a highly seasonal and varied demand profile. Storage benefits include:

- Flexibility to serve peak period needs;
- Access to typically lower cost off-peak supplies;
- Reduced need for higher cost annual firm transportation;
- Improved utilization of existing firm transportation via off-season storage injections; and
- Additional supply point diversity.

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

JACKSON PRAIRIE STORAGE

Avista is one-third owner, with NWP and Puget Sound Energy (PSE), in the Jackson Prairie storage project for the benefit of its core customers in all three states. Jackson Prairie Storage is an underground reservoir facility located near Chehalis, Washington approximately 30 miles south of Olympia, Washington. The total working gas capacity of the facility is approximately 25 Bcf. Avista’s current share of this capacity for core customers is approximately 5.2 Bcf and includes 266,667 Dth of daily deliverability rights.

In 1999, and again in 2002, Avista participated in capacity expansions of the project with NWP and PSE. It was determined that the additional capacity for core utility customers was not needed at that time, and the expansion went under the management of Avista Energy, Avista's former non-regulated energy marketing and trading affiliate. In June 2007, Avista Energy sold substantially all of its energy contracts and ongoing operations to Shell Energy North America (U.S.), L.P. (Shell Energy). Concurrent with the sales transaction, Avista reacquired the rights to the 2002 expansion while the 1999 expansion rights were temporarily included in the sale. Shell Energy retains these rights through April 30, 2011. These rights represent approximately 3 Bcf of storage capacity and 100,000 Dth of daily deliverability.

After this date, we anticipate recalling these storage rights for availability in our utility operations, and have included it in our SENDOUT® model as an incremental available storage resource at that time.

We continue to evaluate our Jackson Prairie capacity and deliverability requirements to determine if we should opportunistically optimize storage capacity beyond what is able to be delivered to customers.

Outside of Avista's ownership rights, we have leased an additional 95,565 Dth of Jackson Prairie capacity with 2,623 Dth of deliverability from NWP to serve Oregon customers.

MIST STORAGE

The Mist storage project is an underground depleted reserve storage project owned by Northwest Natural Gas and is located near the small community of Mist, Oregon about 60 miles northwest of Portland, Oregon. The total working gas capacity of the facility is approximately 16 Bcf. For our Oregon customers, Avista has contracted for service in this storage project which includes rights to 500,000 Dth of capacity with 15,000 Dth of deliverability. This contract expires in April 2011.

INCREMENTAL SUPPLY-SIDE RESOURCE OPTIONS

Our existing portfolio of supply-side resources provides a good mix of assets to manage demand requirements for peak day events and throughout each year in the near term. But in anticipation of growing and changing demand requirements, we monitor the following potential resource options to meet future requirements.

SYSTEM ENHANCEMENTS

In certain instances, Avista can facilitate additional peak and base load-serving capabilities through a modification or upgrade of our distribution facilities. These opportunities are geographically specific and require case-by-case study. We have reviewed several enhancements and preliminary findings indicate that the following opportunities may be viable:

NWP Klamath Falls Lateral – Avista has the opportunity to purchase and operate the NWP Klamath Falls lateral as a high-pressure distribution system. Although we would incur the capital costs associated with the purchase price, we would be able to terminate current NWP reservation and fuel charges at Klamath Falls and relocate the transportation contract deliverability on NWP to areas where additional deliverability is needed. This solution would facilitate additional deliveries into the Klamath Falls area off of GTN. If certain terms are met, this enhancement can likely be completed with less than one year's notice.

Medford System Enhancement – Avista is constructing a high-pressure distribution system reinforcement off of the GTN Medford lateral. This will facilitate delivery of incremental volumes off of the GTN system into Medford when needed. This solution also will allow existing NWP supply and capacity on the Grants Pass Lateral to be diverted from Medford back to the Roseburg area. Through this enhancement, potential resource shortages in the Medford and Roseburg areas can be addressed.

La Grande Distribution System Enhancement – Avista has the option to enhance the distribution system in the La Grande area with high-pressure distribution looping from an adjacent city-gate station such that the distribution system would be reinforced. This solution would allow additional deliveries off of the NWP system to La Grande.

CAPACITY RELEASE RECALL

As discussed earlier, pipeline transportation that is not utilized to serve core customer demand can be released to other parties or optimized through daily or term transactions. Released capacity is generally marketed through a competitive bidding process and can be done on a short-term (month-to-month) or long-term basis. We actively participate in the capacity release market and have both short-term and long-term capacity releases.

We assess the need to recall capacity or extend a release of capacity on an on-going basis. The IRP process also helps evaluate if or when we need to recall some or all of our long-term releases.

GTN BACKHAULS

On the GTN system, due to the north-to-south flow dynamics and the large amount of natural gas flowing that direction, backhauling supply purchases to Avista's service territory can be done on a relatively reliable basis. For example, Avista can purchase cost effective supplies at Malin, Oregon and transport those supplies via displacement to our service territory at either Klamath Falls or Medford. Malin-based natural gas supplies typically price at a premium to AECO supplies but are generally less expensive than the cost of forward-haul transporting those traditional supplies and paying the associated demand charges. The GTN system is a mileage-based system so we pay only a fraction of the forward rate if it is transporting supplies from Malin to Medford and Klamath Falls. The GTN system is approximately 612 miles long and the distance from Malin to the Medford lateral is only about 12 miles. Avista can decrease costs by avoiding fuel charges and full reservation charges on an annual or seasonal basis and/or by avoiding potentially expensive peaking resources.

Although we are confident in this resource option especially in the near to intermediate term, it is only available as long as sufficient forward-haul natural gas flow exists. Pipeline capacity at Malin is over two Bcf with several high volume subscribers currently flowing substantial daily volumes into

California. However, in the future this condition could change if declines in forward-haul volume occur or requests for backhauls increase, causing net forward-haul volume to be insufficient to honor all backhaul requests. Specifically, the proposed Ruby pipeline project (see new pipeline projects section below) which would interconnect with the GTN system at Malin could decrease forward-haul volumes if GTN subscribers source significant volumes from the new Ruby pipeline. We continue to monitor this possibility in conjunction with the Ruby project development.

NEW PIPELINE TRANSPORTATION

Additional firm pipeline transportation resources are viable and attractive resource options. However, determining the appropriate level, supply source and associated pipeline path, costs and timing and determining whether or not existing resources will be available at the appropriate time, make this resource difficult to analyze. Firm pipeline capacity provides several advantages; it provides the ability to receive firm supplies at the production basin, it provides for base-load demand and it can be a low-cost option given optimization and capacity release opportunities. Pipeline capacity also has several drawbacks, including typically long-dated contract requirements, limited need in the summer months (many pipelines require annual contracts) and limited availability and/or inconvenient sizing/timing relative to resource need.

Some pipelines currently have available pipeline capacity on the mainline portion of their systems. Unfortunately, NWP does not have any available capacity on its mainline or on any of the relevant laterals that serve Avista's requirements. GTN has mainline capacity currently available and may be able to provide additional service to some Washington/Idaho and Oregon customers without an expansion. Further, longer-term permanent capacity release options may be available on both pipelines.

Pipeline expansions are typically more expensive than existing pipeline capacity and often require long-term annual contracts. Even though expansions may be more expensive than existing capacity, this approach may still provide the best option to us given that some of the other options discussed in this section require matching pipeline transportation anyway.

Several specific projects have been proposed for the region. The following summaries describe these projects while Figure 5.3 illustrates their location:

Figure 5.3 Proposed New Pipelines

Ruby – Project sponsor El Paso Corporation. The project is expected to include approximately 675 miles of 42-inch natural gas transmission pipeline beginning at the Opal Hub in Wyoming and terminating at interconnects near Malin, Oregon. The project will have an initial capacity of up to 1.5 billion cubic feet per day (Bcf/d) and would traverse portions of four states: Wyoming, Utah, Nevada, and Oregon.

Blue Bridge Pipeline – Northwest Pipeline GP and Puget Sound Energy are jointly proposing this project, which would include the installation of additional compression horsepower at existing Northwest Pipeline stations and the construction of up to 120 miles of pipe. The project is bi-directional and is designed to deliver between 250 and 500 MMcf/d from Stanfield, Oregon to the I-5 Corridor. The project would generally follow Northwest Pipeline's existing pipeline corridor for the majority of the route.

Inland Pacific Connector – Terasen Gas is proposing to build this 153-mile, 24-inch diameter pipeline as an extension of its Southern Crossing Pipeline from southern Alberta near Kingsgate, Idaho, to Huntingdon, BC, near Sumas, Washington. The initial design capacity is projected to be about 350 MMcf/d.

Palomar Cascade – Palomar Gas Transmission is a partnership between NW Natural and TransCanada. The proposed 110-mile, 36-inch-diameter pipeline would extend from TransCanada's GTN system near Madras, Oregon, to NW Natural's system near Molalla, Oregon. It would be a bi-directional pipeline with an initial capacity of up to 1,000 MMcf/d.

Sunstone – Project partners include Williams Gas Pipeline Company, LLC, TransCanada PipeLine USA Ltd. and Sempra Gas Pipelines and Storage Corp. The proposed 598-mile pipeline would transport gas from the Rockies to markets in the West and Pacific Northwest. The pipeline would generally follow existing pipeline and utility corridors from the Opal Hub in Wyoming through southern Idaho, connecting with TransCanada's GTN system and

Williams' Northwest Pipeline near Stanfield, Oregon. The developers have suspended activity on this project due to unfavorable current market conditions.

None of the above projects provide end delivery to any of our service territories. Therefore, to be a viable peak day incremental resource requires combining with additional pipeline resources. In our modeling, we utilized available cost and other information to develop more generic pipeline resource alternatives rather than specifically modeling the various segments.

To accurately assess costs and location feasibility of potential expansion scenarios requires detailed engineering studies by the pipelines. These studies can be expensive and of limited shelf life for projects that might be developed well into the future. Consequently, we employ estimates derived from our knowledge of historical costs, reasonable price escalations, and site specific issues that may impact a specific scenario. We combine this knowledge with past information from the pipelines to develop a reasonable basis for our transportation analysis. If and when we determine that additional transportation capacity is necessary, we will request thorough estimates from the appropriate pipeline companies, search the release market for capacity that may include winter-only service, and seek capacity on constrained segments. These pipeline estimates are costly and will be prudently acquired.

IN-GROUND STORAGE

In-ground storage provides many advantages when storage deliveries can be delivered to Avista's service territory city-gates. It can enable deliveries of natural gas to customers during cold weather events when they need it most. It also facilitates potentially lower cost supply for our customers by capturing peak/non-peak pricing differentials and potential arbitrage opportunities within individual months. Although additional storage can be a valuable resource, without deliverability to Avista's service territory, this storage cannot be considered an incremental firm peak serving resource.

Jackson Prairie

Jackson Prairie is a potential resource for expansion opportunities. The Shell Energy recall discussed earlier and any future storage expansion capacity does not include transportation and therefore cannot be considered an incremental peak day resource. However, we will continue to look for swap and transportation release opportunities that could fully utilize these additional resource options. Even without deliverability, we believe it can make financial sense to fully develop/recall Jackson Prairie capacity to optimize time spreads within the natural gas market and provide net revenue offsets to customer gas costs.

Other In-Ground Storage

Other regional storage facilities exist and may be cost effective. Additional capacity at Northwest Natural's Mist facility, capacity at one of the Alberta area storage facilities, Questar's Clay Basin facility in northeast Utah, and northern California storage are all possibilities. Again, transportation to and from these facilities to Avista's service territories continues to be the largest impediment to contracting for these options. Northern California storage opportunities may be able to overcome this hurdle by using backhaul transportation for deliveries to some of the Washington/Idaho and Oregon customers but firm, reliable delivery on peak days or cold weather events remains an issue. Another issue is whether sellers of storage capacity will offer multi-year contracts or contracts with beginning dates during the timeframes that we may need these incremental resources.

SATELLITE LNG

Satellite LNG is another storage option that could be constructed within Avista's service territories and is ideal for meeting peak day or cold weather events. Satellite LNG uses natural gas that is trucked to the facilities in liquid form rather than liquefying on site. Locating the facility in the service area would avoid interstate pipeline transportation and related charges. Permitting issues notwithstanding, facilities could be located in optimal locations within the distribution system.

Estimates for this type of resource are somewhat challenging because of sizing and location issues. For our modeling, we have used estimates from other facilities constructed in the area and believe these to be reasonable estimates for planning purposes. We will continue to monitor and refine the costs of developing satellite LNG while remaining mindful of lead time requirements and environmental issues.

PLYMOUTH LNG

NWP owns and operates an LNG storage facility located at Plymouth, Washington, which provides a gas liquefaction, storage, and vaporization service under its LS-1 and LS-2F tariffs. An example ratio of injection and withdrawal rates are such that it can take more than 200 days to fill to capacity, but only 3-5 days to empty. As such, the resource is best suited for needle-peak demands. Incremental transportation capacity to our service territories would have to be obtained in order for it to be a truly effective peaking resource.

This peaking resource is fully contracted and not available for contracting at this time. Given this situation, this option is not being modeled in SENDOUT® for this IRP. However, due to the fact that many of the current capacity holders are on one-year rolling evergreen contracts, it is possible that this option will again become viable in the future.

COMPANY OWNED LIQUEFACTION LNG

Instead of leasing LNG capacity from Plymouth, Avista could construct a liquefaction LNG facility within our service area. Doing so could use excess transportation during off-peak periods to fill the facility but avoid tying up transportation during peak weather events. Additional annual pipeline charges could probably be avoided.

Construction would be dependent on regulatory and environmental approval as well as cost effectiveness requirements. Preliminary estimates of the construction, environmental, right of way, legal, operating and maintenance, required lead times, and inventory costs indicate company-owned LNG facilities have significant development risks. We include this resource in our modeling, recognizing this type of project is highly complex and there are many risk considerations that require evaluation and monitoring should this resource be selected.

IMPORTED LNG

Although burgeoning supply from unconventional gas production in the U.S. is now forecasted to ease the need for LNG imports to meet domestic demand, there continues to be interest and discussion nationally regarding LNG regasification terminals (import LNG). Several terminals have been proposed in the U.S., Mexico and Canada with several projects proposed for the Pacific Northwest[2]. Not all of these terminals will advance, and it may be possible that none of the Pacific Northwest projects will proceed. The siting of import LNG terminals is a difficult endeavor. In order for a terminal to advance, it will require economies of scale, the ability to move regasified supplies to markets, a favorable environmental review and public reception, secure LNG supply, long-term output/sales agreements and financing. We have participated in several forums on the various regional projects.

Although the Pacific Northwest may not provide project sponsors with these requirements, the announcement to construct a pipeline from the proposed Coos Bay LNG facility to Malin, Oregon remains of interest to Avista. This pipeline may provide gasified LNG to be directly delivered to Avista's service territory around Roseburg, Medford and Klamath Falls while potentially helping supply other regions via further backhaul or displacement opportunities. We continue to monitor the progress of this project having participated in their open season and contingently reserving capacity. We are also monitoring progress of other regional projects noting, however, that they currently do not provide supply directly to any of our service territories. In particular, we continue to monitor our regional prices relative to global prices, as these differentials directly affect the securing of dependable supply which we believe poses a significant challenge for LNG project sponsors.

Some industry experts believe that if additional LNG terminals are built and receive incremental supply, natural gas prices may trend downward or at least become less volatile given the flexibility and responsiveness of incremental volumes to enter our domestic market. These experts also believe that it generally does not matter where the LNG terminals are located because the national natural gas markets are so tightly connected. Even if the Pacific Northwest facilities do not proceed, Avista will likely benefit from increasing amounts of imported LNG nationally.

For this IRP, we are not making import LNG a resource option available to the model. This is because LNG in the Pacific Northwest is highly speculative, the region is not considered to be a premium market when compared to other locations in North America, and because it will take at least five years before this option would move forward in the Pacific Northwest. Each of the price forecasts we have reviewed make assumptions regarding LNG imports to North America, so LNG commodity impacts are imbedded in those forecasts. If a terminal were to be built regionally, we believe the approximate supply price would be the nearest market hub price adjusted for delivery charges to our service territories. So to some extent, LNG resources are indirectly captured in our modeling.

[2] The Kitimat LNG project in Kitimat, British Columbia has changed its project scope to become a liquefaction terminal to export LNG to Asian and other markets.

We will continue to monitor this option and will take more formal action if a Pacific Northwest terminal begins to look promising.

BIOGAS

Biogas typically refers to a gas produced by the biological breakdown of organic matter in the absence of oxygen. One type of biogas is produced by anaerobic digestion or fermentation of biodegradable materials such as biomass, manure or sewage, municipal waste, green waste and energy crops. This type of biogas comprises primarily methane and carbon dioxide.

Biogas is a renewable fuel so it sometimes attracts renewable energy subsidies in some parts of the world. We are not aware of any current subsidies but future stimulus or energy policies could lead to some form of financial incentives at a later time.

Biogas projects are inherently individualized, making reasonable and reliable cost estimates difficult to obtain. Project sponsorship has many complex issues and the more likely participation in such a project is as a long-term contracted purchaser. We did not consider biogas as a resource in this planning cycle but remain receptive to such projects as they are proposed.

SUPPLY SCENARIOS

For this IRP we modeled four supply scenarios. Table 5.2 lists the supply scenarios and Appendix 5.2 provides the details on what is included in each of these scenarios. Additional detail about the results of these supply scenarios modeled is included in Chapters 6 and 7.

Table 5.2 Alternate Supply Scenarios
Existing Resources
Existing + Expected Available
GTN Rate Escalation
GTN Fully Subscribed

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.

SUPPLY ISSUES

The market for natural gas has undergone dramatic changes over the last several years. Previously, the commodity market was transitioning from a regionally-based market to a nationally-based, and perhaps, globally-based market. The economic recession and emerging abundant supply now looks to interrupt and potentially shift away from that paradigm. Issues likely to play a prominent role in defining the future for natural gas are as follows:

Unconventional Supply – Shale gas and other unconventional sources are changing the industry in ways not yet fully understood. Although there are several instances of mature and seasoned wells, most have limited long-term track records. The high natural gas prices pre-2008 spurred technological breakthroughs that have advanced and improved production methods. Yet as we enter a potentially long-term cycle of lower prices, innovation may be stifled. Some of the more promising plays are in areas with little or no infrastructure. Investment in required infrastructure may be stifled as well. Alternatively, lower natural gas prices may serve as an important catalyst for economic recovery and future investment.

Climate Change Policies – By design, climate change policy is intended to disrupt the consumption of fossil fuels. The role of natural gas in this arena is one of inherent contradiction. In the near term, consumption is predicted to increase significantly via gas-fired power generation replacing coal plants. It is unclear however, whether natural gas has a long-term role in power generation or will be marginalized by nuclear, renewables or other emerging technologies. Economic conditions add further uncertainty regarding legislative enactment and/or delayed implementation.

Supply from Canada – There is an abundance of evidence supporting the assumption that gas will continue to be imported from Canada into the United States. However, since much of our supply comes from the WCSB, the possibility that supply could become significantly constrained is monitored closely. Oil sands production and royalty structures are two key factors that will likely influence this issue. We will continue to monitor this situation looking for signals that indicate increased risk of disrupted supply from Canadian exports.

Pipeline rate increases – A sustained economic slow-down could result in excess or underutilized pipeline capacity in many parts of the country including our region. This excess capacity may cause capacity holders with expiring contracts to consider relinquishing their capacity back to the pipelines. Many capacity holders have shown a preference to turn back transportation contracts where transportation expenses exceed the value of this transportation. The result of this action from a pipeline perspective is to cause affected pipelines to file rate cases to recover some or all of the lost revenues. Distribution companies that rely on firm supplies and transportation will likely continue to hold or may be locked into their long-term transportation contracts and may end up paying higher transportation rates depending on the FERC's approach to this issue.

National pipeline infrastructure – Pipeline capacity out of the supply regions has increased in volume and delivery points. As a result, natural gas prices in the Pacific Northwest have become more dependent on demand and prices in regions as far away as the east coast. The

Rockies Express pipeline expansion to the Midwest and Eastern markets is expected to further solidify price correlation with these markets.

The role of LNG in the United States – Projections indicate that, over the long term, there will still be a growing gap between North American natural gas production and North American demand for natural gas. The consensus is that LNG will supply the gap. Should this occur, there will be global price competition for LNG. We have been, and will continue to be, involved in discussions about LNG as a potential supply resource.

MARKET-RELATED RISKS AND RISK MANAGEMENT

While risk management can be defined in a variety of ways, the integrated resource plan focuses on two areas of risk: the financial risk under which the cost to supply customers will be unreasonably high or unreasonably volatile, and the physical risk that there may not be enough natural gas resources (either the transportation capacity or the commodity) to serve core customers.

Avista has a Risk Management Policy that describes the policies and procedures associated with financial and physical risk management. The Risk Management Policy addresses, among other things, issues related to management oversight and responsibilities, internal reporting requirements, documentation and transaction tracking, and credit risk.

There are two internal organizations that assist in the establishment, reporting and review of Avista's business activities as they relate to management of natural gas business risks:

- The Risk Management Committee consists of several corporate officers and senior-level management. The committee establishes the Risk Management Policy and monitors compliance. They receive regular reports on natural gas activity and meet regularly to discuss market conditions, hedging activity and other natural gas-related matters.
- The Strategic Oversight Group exists to coordinate natural gas matters among internal natural gas-related stakeholders and to serve as a reference/sounding board for strategic decisions, including hedges, made by the Natural Gas Supply department. Members include representatives from the Accounting, Regulatory, Credit, Power Resources and Risk Management departments. While the Natural Gas Supply department is responsible for implementing hedge transactions, the Group provides input and advice.

ACTION ITEMS

We will continue to monitor the supply issues identified in this chapter including shale production trends, climate change policies, slowing Canadian exports, pipeline constraints in our region, pipeline expansions moving volumes away from our region, pipeline cost escalations and import LNG activity.

We will also monitor new resource lead time requirements relative to when resources are needed to preserve resource option flexibility.

CONCLUSION

Avista is committed to providing reliable supplies of natural gas to its customers. We procure these supplies with a diversified plan that seeks to competitively acquire natural gas supplies while reducing exposure to short-term price volatility through a strategy that includes hedging, storage utilization and index purchases. We have long-term contracts for firm pipeline transportation capacity from many supply points and also own and lease firm natural gas storage capacity sufficient to serve customer demand during peak weather events and throughout the year.

CHAPTER 6 – INTEGRATED RESOURCE PORTFOLIO

OVERVIEW

This chapter combines all previously discussed IRP components and the model used to determine resource deficiencies during the 20-year planning horizon. This chapter also provides an analysis of potential resource options and displays the model-selected best cost/risk resource options to meet resource deficiencies.

The foundation for integrated resource planning is the demand planning criteria used for developing demand forecasts. Avista currently uses the "coldest day on record" as its weather planning standard for determining peak day demand. This is consistent with our past IRPs and is more fully described in Chapter 3 • Demand Forecasts. We utilize historic peak and average weather data for each demand region for this IRP. We plan to serve our expected peak day in each demand region with firm resources. Firm resources include natural gas supplies, pipeline transportation and storage resources. In addition to planning for peak requirements, we also plan for non-peak periods such as winter, shoulder and summer demand. Our modeling process includes running an optimization for every day of the 20-year planning period.

It is assumed that on a peak day all interruptible customers have left the system in order to provide service to firm customers. Avista does not make firm commitments to serve interruptible customers. Therefore, our IRP analysis of demand-serving capabilities only focuses on the residential, commercial and firm industrial classes.

Our supply forecasts are increased between 1.0 percent and 3.0 percent on both an annual and peak day basis to account for additional supplies that are purchased primarily for pipeline compressor station fuel. The percentage of additional supply that must be purchased is governed through FERC and National Energy Board approved tariffs.

SENDOUT® PLANNING MODEL

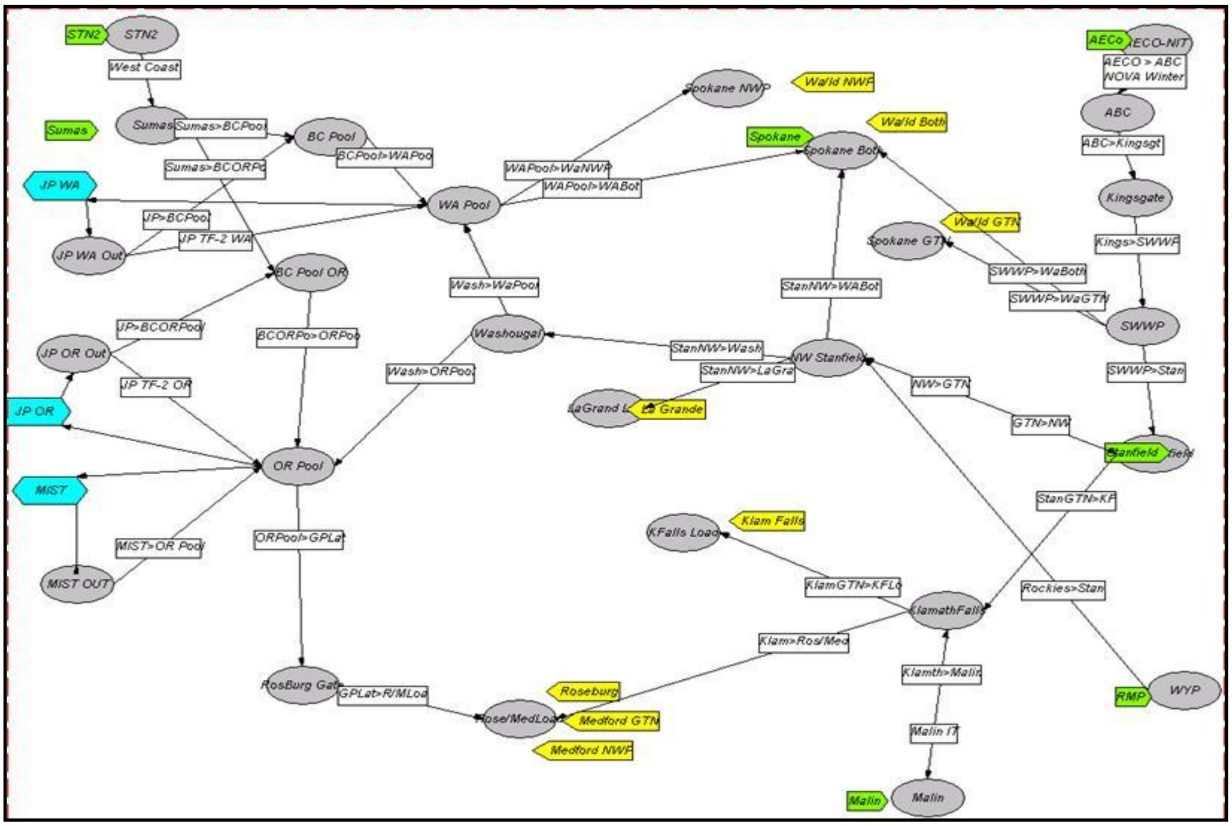
The SENDOUT® Gas Planning System from Ventyx is used to perform integrated resource optimization. The SENDOUT® model was purchased in April 1992 and has been used in preparing all IRPs since then. Avista has a long-term maintenance agreement with Ventyx that allows us to receive software updates and enhancements. These enhancements include software corrections and improvements brought on by industry change.

SENDOUT® is a linear programming model widely used to solve natural gas supply and transportation optimization questions. Linear programming is a proven technique used to solve minimization/maximization problems. SENDOUT® looks at the complete problem at one time within the study horizon, while taking into account physical limitations and contractual constraints. The software analyzes thousands of variables and valuates possible solutions to generate a least cost solution. The model uses the following variables:

- Demand data, such as customer count forecasts and demand coefficients by customer type (e.g. residential, commercial and industrial);
- HDD information;
- Existing and potential transportation data which describes to the model the network for the physical movement of the natural gas and associated pipeline costs;
- Existing and potential supply options including supply basins, revenue requirements as the key cost metric for all asset additions, and prices;
- Natural gas storage options with injection/withdrawal rates, capacities and costs; and
- DSM programs.

Figure 6.1 is a SENDOUT® network diagram of our demand centers and resources (see also Appendix 6.5). This diagram illustrates Avista's current transportation and storage assets, flow paths and constraint points.

Figure 6.1 SENDOUT® Model Diagram



The SENDOUT® model also provides a flexible tool to analyze potential scenarios such as:

- Pipeline capacity needs and capacity releases;
- Effects of different weather patterns upon demand;
- Effects of natural gas price increases upon total natural gas costs;
- Storage optimization studies;

- Resource mix analysis for DSM programs;
- Weather pattern testing and analysis;
- Transportation cost analysis;
- Avoided cost calculations; and
- Short-term planning comparisons.

The latest SENDOUT® version includes Monte Carlo capabilities, which facilitates price and demand uncertainty modeling and detailed portfolio optimization techniques to produce probability distributions. Similar to SENDOUT®, there are numerous variables entered for Monte Carlo simulation. The variables required for the Monte Carlo analysis are:

- Expected monthly HDDs by month;
- Standard deviation of monthly HDDs;
- Monthly minimum and maximum HDDs;
- Daily HDD pattern derived from historical data;
- Expected monthly gas price by month;
- Standard deviation of the monthly gas price;
- Monthly minimum and maximum gas price;
- Temperature-to-temperature correlations;
- Price-to-price correlations; and
- Price-to-temperature correlations.

This additional software module enhances Avista's analytical capabilities. More information and analytical results are located in Chapter 7 – Alternate Scenarios, Portfolios and Stochastic Analysis.

RESOURCE INTEGRATION

We have defined the planning methodologies, described the modeling tools and identified the existing and potential resources. The following summarizes the comprehensive analysis of bringing demand forecasting and existing and potential supply and demand-side resources together to form our 20-year, risk adjusted least-cost plan.

DEMAND FORECASTING

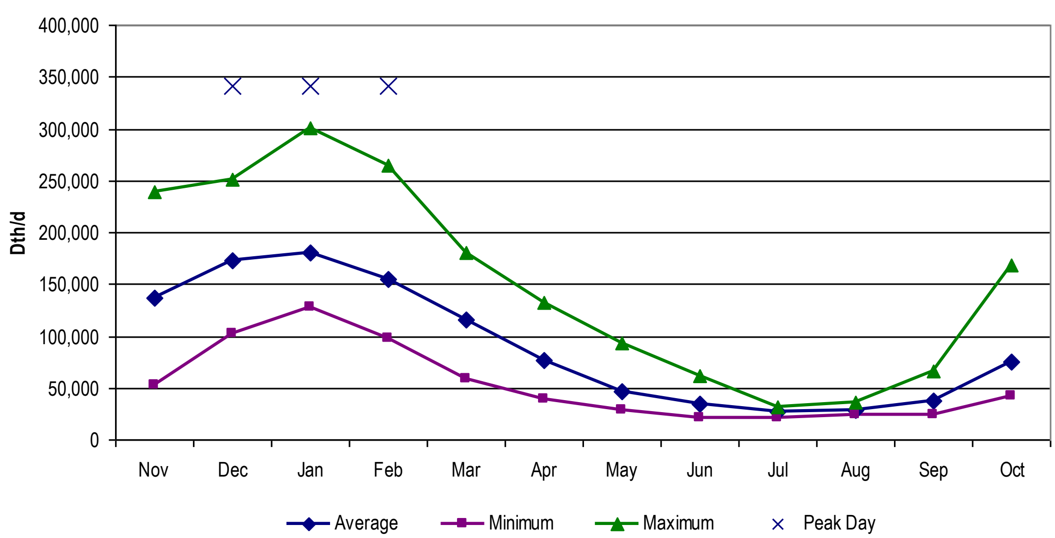
Avista's demand forecasting approach is described in detail in the Demand Forecasts chapter.

We forecast demand in the SENDOUT® model in eight service areas given the existence of distinct weather and demand patterns for each area and pipeline infrastructure dynamics. The SENDOUT® areas are Washington/Idaho (disaggregated into three sub-areas because of pipeline flow limitations), Medford (disaggregated into two sub-areas because of pipeline flow limitations) and

Roseburg, Klamath Falls and La Grande. In addition to area distinction, we also model demand by customer class within each area. The relevant customer classes in Avista's service territories are residential, commercial and firm industrial customers.

Customer demand reflects a highly weather-sensitive component. Avista's customer demand is not only highly seasonable but also highly variable. Figure 6.2 captures this variability showing our monthly system-wide average demand, minimum demand day observed in each month, and maximum demand day observed in each month, and our winter projected peak day demand for the first year of our Expected Case forecast as determined in SENDOUT®.

Figure 6.2 Total System Average Daily Demand
(Average, Minimum, Maximum, and Peak Day)



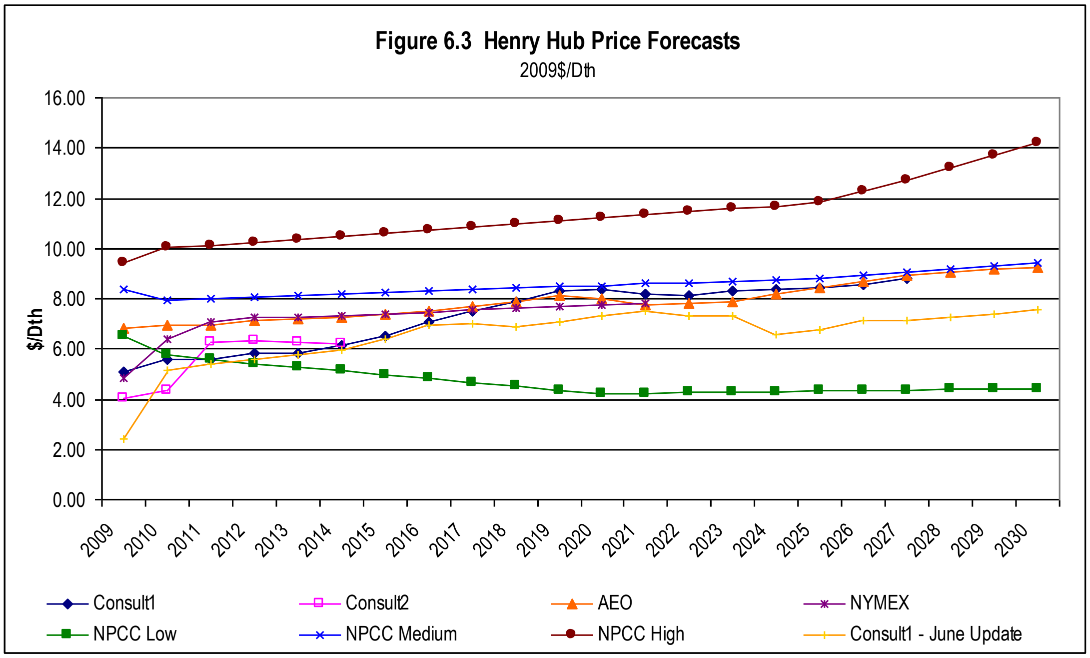
NATURAL GAS PRICE FORECASTS

Natural gas prices are a fundamental component of the IRP. The commodity price is a significant component of the total cost of a resource option. This in turn affects the avoided cost threshold for determining cost-effectiveness of conservation measures. We also recognize the price of natural gas influences consumption, so we include price elasticity analysis in our demand evaluation (see Chapter 3 – Demand Forecasts).

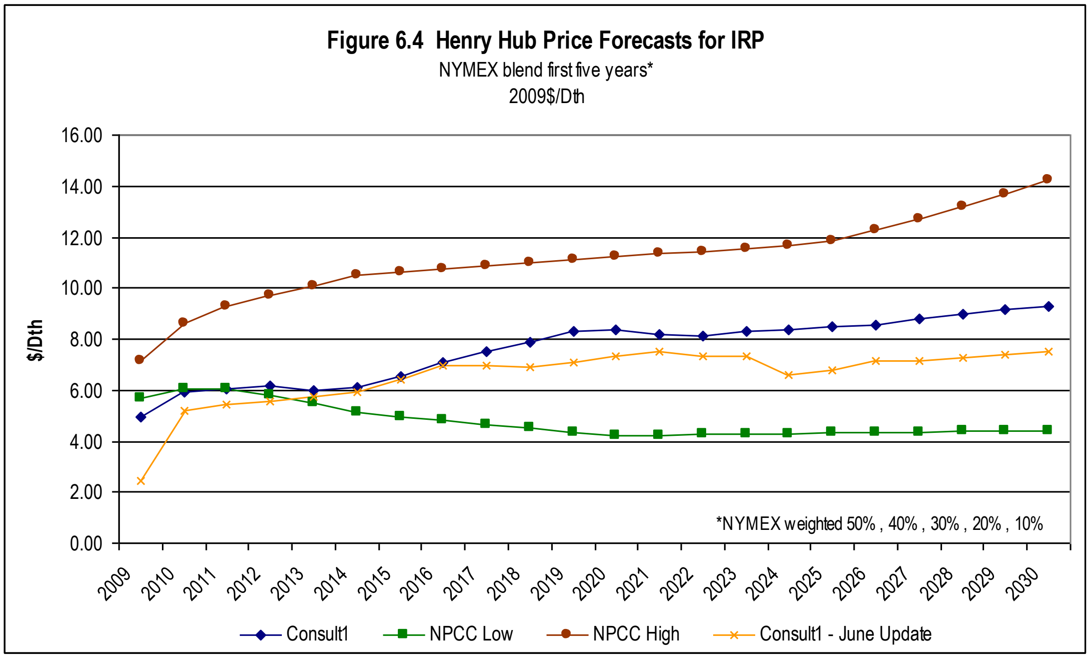
The natural gas price outlook has changed dramatically over the recent planning cycle in response to several influential events and trends affecting the industry. Most notably is the severe economic recession trigged by the global credit crisis, but two other significant influencers are the surge in shale gas production expectations and potential climate change legislation encouraging natural gas-fired power generation to replace coal burning power plants. The outlook for these factors has evolved rapidly in the midst of an environment of significant uncertainty precipitating wide swings and frequent updates to the price forecasts we monitor.

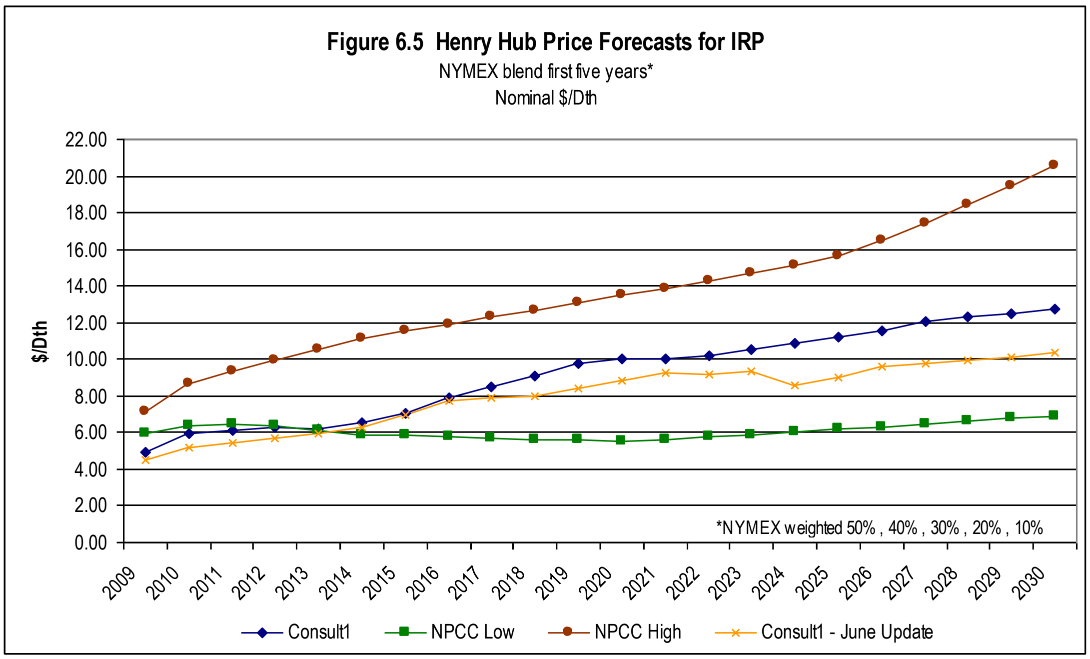
Many additional factors influence natural gas pricing and volatility, such as regional supply/demand issues, weather conditions, hurricanes/storms, storage levels, gas-fired generation, infrastructure disruptions and infrastructure additions (e.g. new pipelines, LNG terminals).

Even though we continually monitor these factors, we cannot accurately predict future prices for the 20-year horizon of this IRP. We have reviewed several price forecasts from credible sources. Figure 6.3 depicts the price forecasts we considered in our analyses.



Some of these forecasts are more plausible than others, but most of them are possible. With assistance and concurrence of the TAC Committee, we selected high, medium and low price curves to consider possible outcomes and the impact that this volatile and high pricing environment might have on planning. The price curves we have selected have considerable variation, which is consistent with our theme of stretching modeling assumptions in an uncertain environment. These curves are shown in real dollars in Figure 6.4 and nominal dollars in Figure 6.5.





Each of the price forecasts above are for Henry Hub, which is located in Louisiana just onshore from the Gulf of Mexico. Henry Hub is widely recognized as the most important pricing point in the U.S. because of its proximity to a large portion of U.S. natural gas production and the sheer volume traded in the daily or spot market, as well as the forward markets via the New York Mercantile Exchange's (NYMEX) futures contracts. Consequently, all other trading points tend to be priced off of the Henry Hub.

The primary physical supply points at Sumas, Washington, AECO Alberta, Canada, and Opal, Wyoming in the United States Rockies (and other secondary regional market hubs) ultimately determines Avista's costs. Prices at these points typically trade at a discount or negative basis differential to Henry Hub primarily because of their relative close proximity to the two largest natural gas basins in North America (the WCSB and the Rockies).

Table 6.1 shows the Pacific Northwest regional prices from our consultant as a percent of Henry Hub price along with historical comparisons.

Table 6.1 Regional Price as a percent of Henry Hub Price

	AECO	Rockies	Sumas	Malin	Stanfield
Consultant1 Forecast Average	**92.7%**	**85.6%**	**95.2%**	**94.1%**	**93.7%**
Forward Markets Five Yr Average	88.8%	84.5%	97.1%	N/A	N/A
Prior IRP	86.0%	80.5%	87.6%	N/A	N/A

This IRP used monthly prices for modeling purposes because of our heavily winter-weighted demand profile. Table 6.2 depicts the monthly price shape we used in this IRP and comparisons to the 2007 IRP.

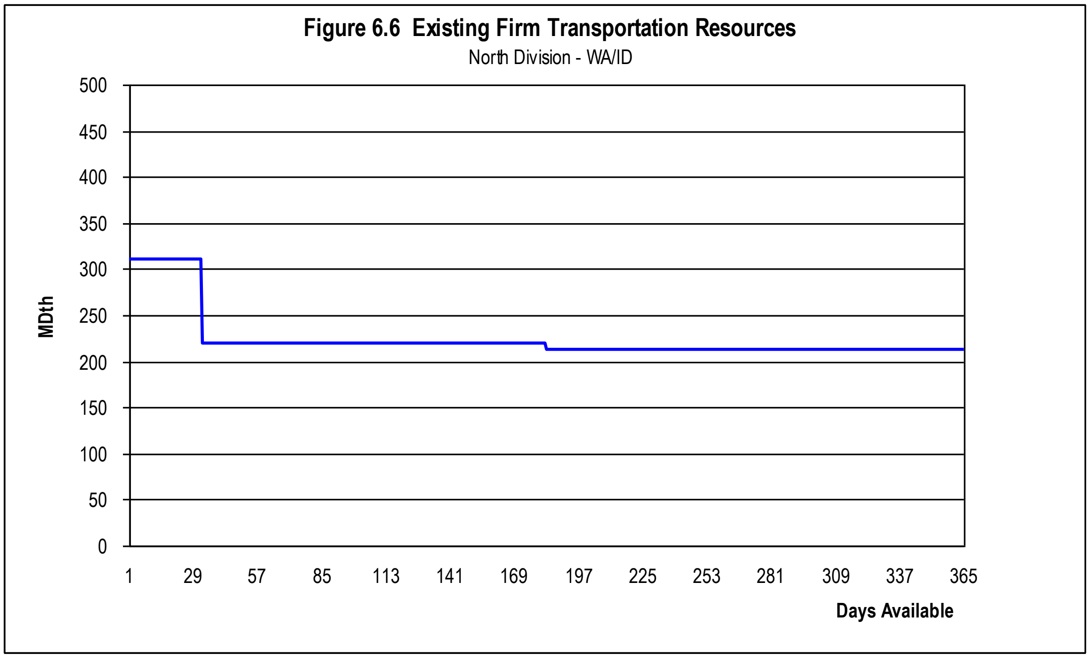
Table 6.2 Monthly Price as a percent of Average Price

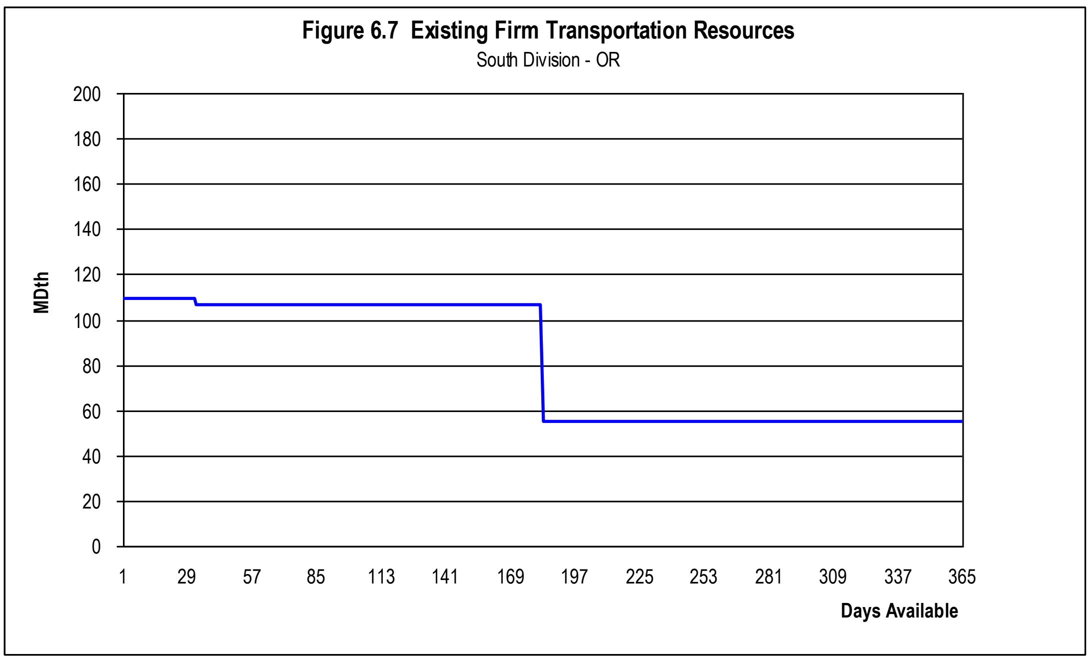
	Jan	Feb	Mar	Apr	May	Jun
Consult1	**107%**	**108%**	**103%**	**93%**	**93%**	**94%**
Prior IRP	113%	113%	110%	93%	92%	93%
	Jul	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Consult1	**95%**	**96%**	**96%**	**97%**	**109%**	**110%**
Prior IRP	94%	94%	95%	96%	101%	106%

Appendix 6.1 contains detailed monthly price data behind the summary table information discussed above.

TRANSPORTATION AND STORAGE

Valuing natural gas supplies is a critical first step in resource integration. Equally important is capturing all costs to deliver the gas to the customer. Daily capacity of our existing transportation resources (described in Chapter 5 – Supply-Side Resources) is represented by the firm resource duration curves depicted in Figures 6.6 and 6.7.





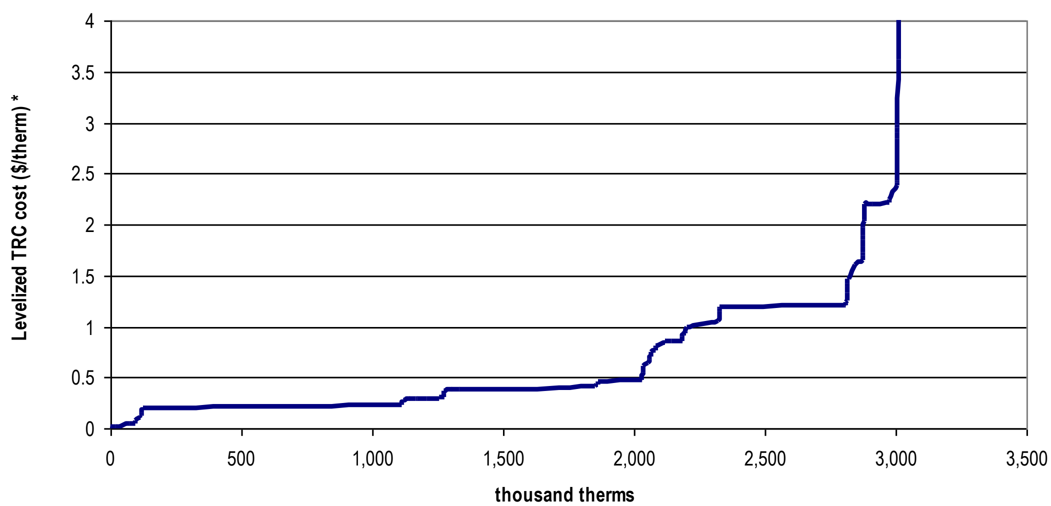
Current rates for capacity are in Appendix 5.1. Forecasting future pipeline rates can be a challenge, as we need to estimate the amount and timing of rate changes. Our estimates and timing of future rate increases are based on knowledge obtained from industry discussions and participation in various pipeline rate cases. This IRP assumes that pipelines will file to recover costs at rates equal to increases in GDP (see Appendix 6.2 – General Assumptions).

DEMAND-SIDE MANAGEMENT

Chapter 4 – Demand-side Resources describes the methodology used to identify all possible conservation measures (technical potential), ascertain what level of measures can be reasonably attained (achievable potential) and the interactive process deployed in SENDOUT® that computes avoided cost thresholds for determining cost effectiveness of conservation measures on an equivalent basis with supply-side resources.

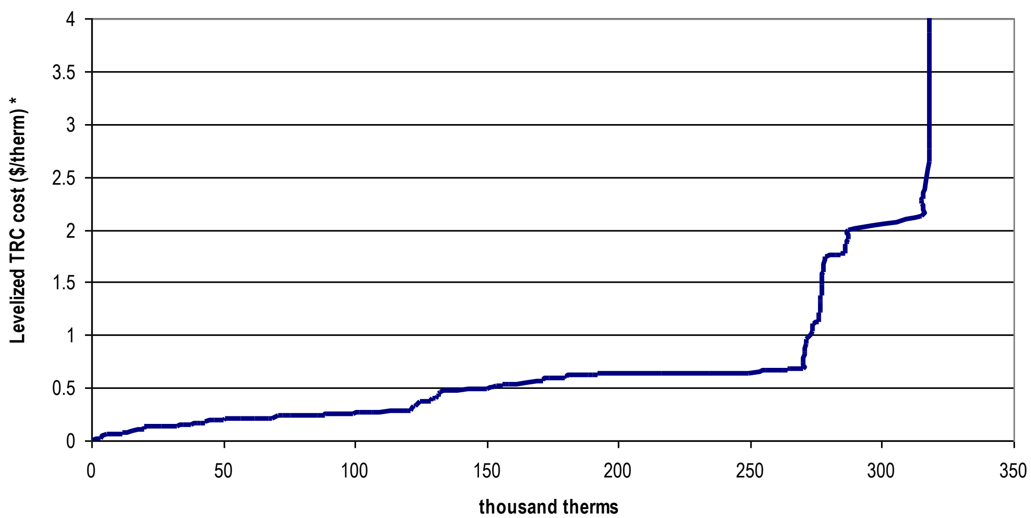
This process results in conservation measures data that facilitates construction of natural gas DSM supply curves. These curves represent the cumulative therms of the evaluated measures stacked in ascending order of levelized TRC. Supply curves for our Expected Case are presented for the two divisions (Figures 6.8 and 6.9).

Figure 6.8 North Division DSM Supply Curve, 1st Year (2010)
SENDOUT® selected mesures only



* Maximum cost is $11.89; chart scale truncated at $4

Figure 6.9 South Division DSM Supply Curve, 1st Year (2010)
SENDOUT® selected mesures only



* Maximum cost is $9.36; chart scale truncated at $4

PRELIMINARY RESULTS

After incorporating the above data into the SENDOUT® model, we then generate an assessment of demand compared to existing resources for several scenarios. The demand results from these cases are discussed in Chapter 3 – Demand Forecasts, with additional details supported in the Appendices 3.1 through 3.9.

Figures 6.10 through 6.13 graphically represent summaries of Expected Case peak day demand compared to existing resources, as well as demand comparisons to our prior IRP. This demand is net of DSM savings. This comparison shows by service territory the amount and timing of deficits over the planning horizon.

Figure 6.10 WA/ID Existing Resources vs. Peak Day Demand
Expected Case (Net of DSM Savings) November to October

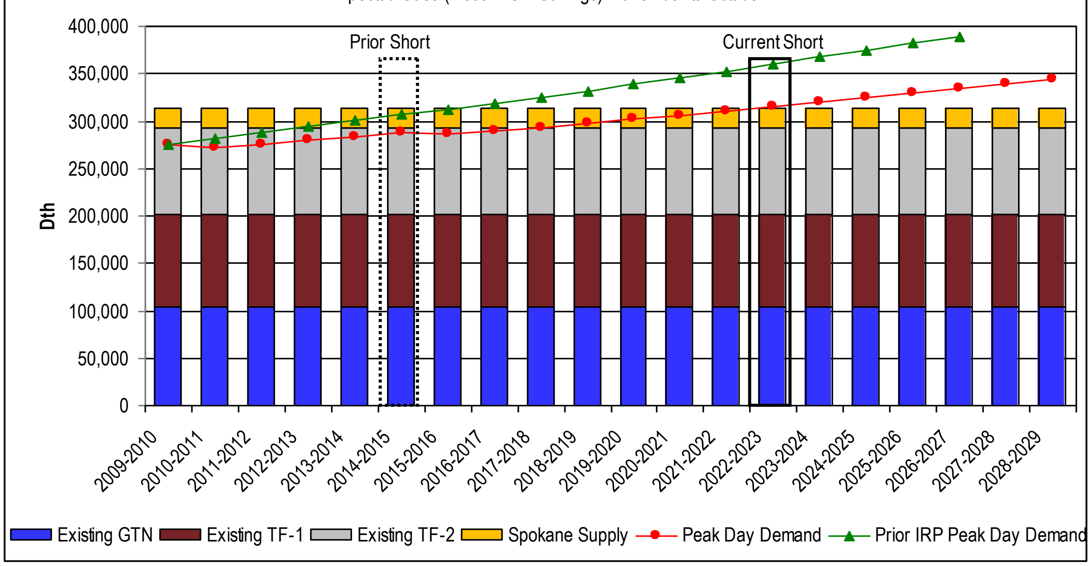
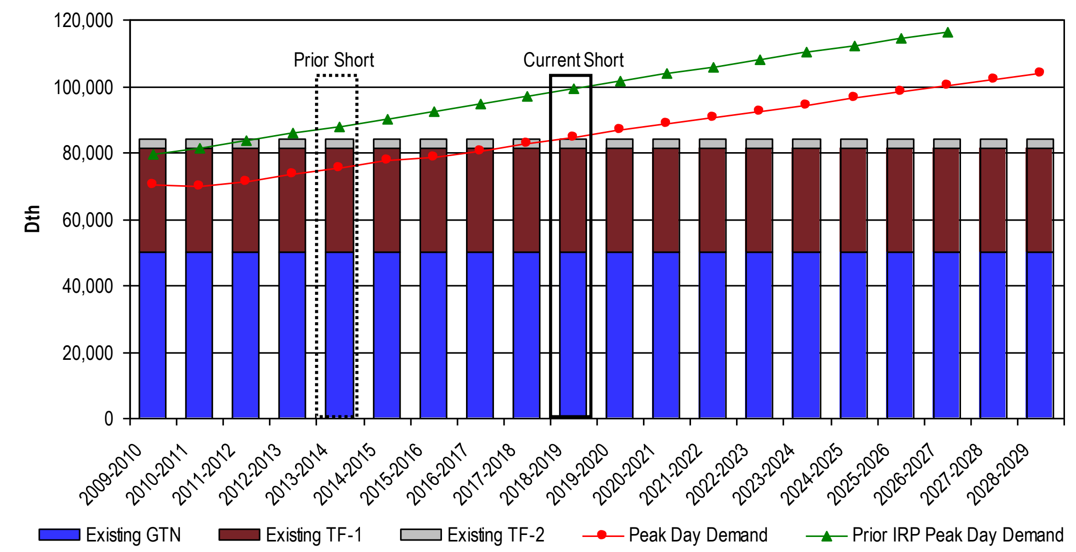
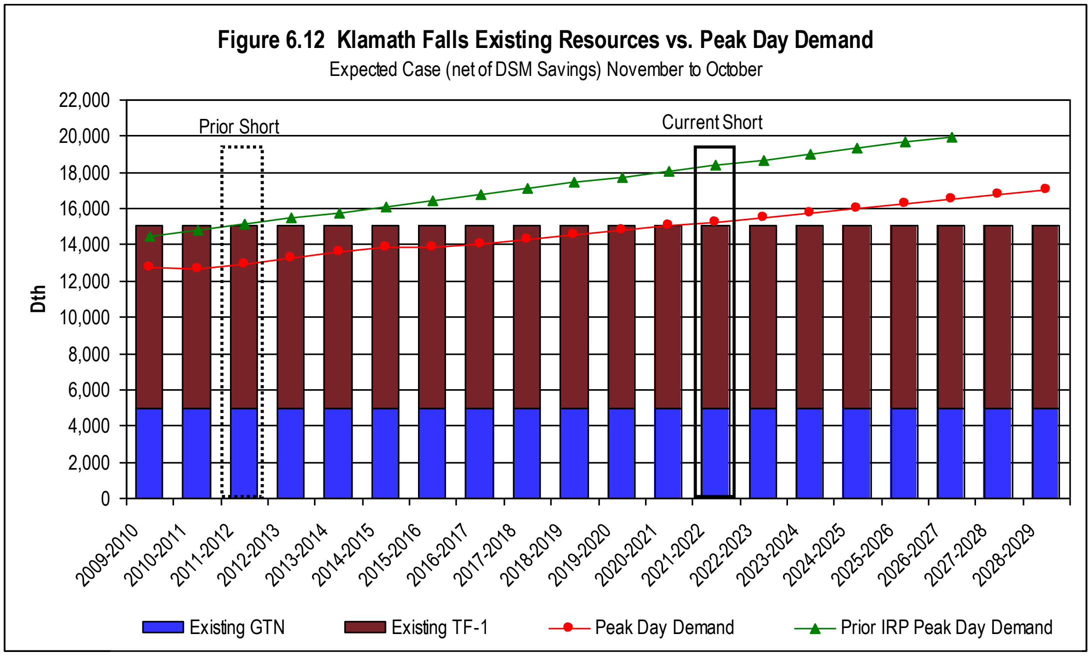
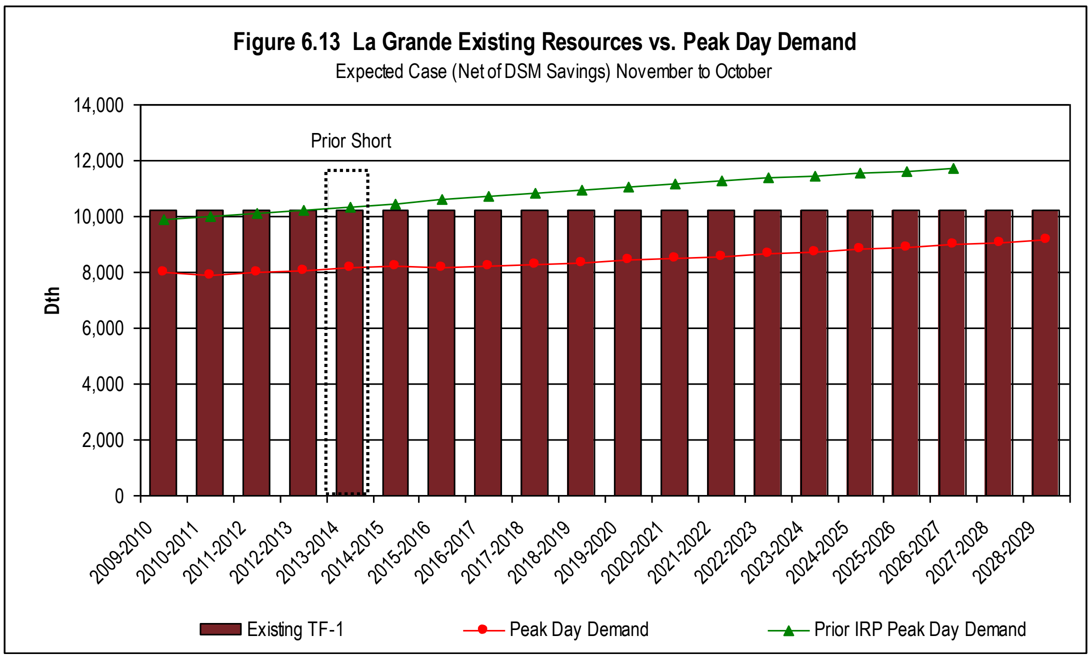


Figure 6.11 Medford/Roseburg Existing Resources vs. Peak Day Demand
Expected Case (Net of DSM Savings) November to October







These charts show that resource shortages occur well into the future. In the Expected Case for Washington and Idaho, the system first becomes unserved in 2023. In Oregon, the first unserved year is in Medford/Roseburg in 2018 followed by Klamath Falls in 2021. The La Grande service territory does not go unserved at any time during the 20-year planning horizon. This surplus resource situation provides ample time to carefully monitor, plan and act on potential resource additions.

However, an important risk with respect to identified capacity shortages is the slope of forecasted demand growth which is almost flat. This outlook implies existing resources will be sufficient for quite some time to meet demand. However, if demand growth accelerates, increased demand could accelerate resource shortages by several years. This "flat demand risk" necessitates close monitoring of signs of accelerating demand and careful evaluation of lead times to acquire preferred incremental resources.

Table 6.3 quantifies the forecasted total demand (net of DSM savings) and unserved demand from the above charts, identifying the amount of deficiencies by region and growth in deficiencies over time. The next step is to determine the best risk/least cost resources to satisfy these deficiencies.

Table 6.3 Peak Day Demand - Served and Unserved (MDth/d)
Before Resource Additions & Net of DSM Savings

Case	Gas Year	La Grande Served	La Grande Unserved	La Grande Total	WA/ID Served	WA/ID Unserved	WA/ID Total
Expected	2009-2010	7.98	-	7.98	274.58	-	274.58
Expected	2010-2011	7.89	-	7.89	271.79	-	271.79
Expected	2011-2012	7.98	-	7.98	275.53	-	275.53
Expected	2012-2013	8.07	-	8.07	279.44	-	279.44
Expected	2013-2014	8.14	-	8.14	283.44	-	283.44
Expected	2014-2015	8.22	-	8.22	287.44	-	287.44
Expected	2015-2016	8.14	-	8.14	285.63	-	285.63
Expected	2016-2017	8.21	-	8.21	289.48	-	289.48
Expected	2017-2018	8.29	-	8.29	293.50	-	293.50
Expected	2018-2019	8.36	-	8.36	297.54	-	297.54
Expected	2019-2020	8.43	-	8.43	301.83	-	301.83
Expected	2020-2021	8.51	-	8.51	306.29	-	306.29
Expected	2021-2022	8.58	-	8.58	310.81	-	310.81
Expected	2022-2023	8.66	-	8.66	314.48	0.94	315.42
Expected	2023-2024	8.74	-	8.74	314.41	5.62	320.03
Expected	2024-2025	8.82	-	8.82	314.32	10.45	324.78
Expected	2025-2026	8.90	-	8.90	314.24	15.28	329.53
Expected	2026-2027	8.98	-	8.98	314.16	20.03	334.20
Expected	2027-2028	9.06	-	9.06	314.08	25.50	339.58
Expected	2028-2029	9.14		9.14	314.04	30.74	344.79
Case	Gas Year	Klamath Falls Served	Klamath Falls Unserved	Klamath Falls Total	Medford/ Roseburg Served	Medford/ Roseburg Unserved	Medford/ Roseburg Total
Expected	2009-2010	12.71	-	12.71	70.44	-	70.44
Expected	2010-2011	12.67	-	12.67	70.01	-	70.01
Expected	2011-2012	12.94	-	12.94	71.18	-	71.18
Expected	2012-2013	13.27	-	13.27	73.37	-	73.37
Expected	2013-2014	13.62	-	13.62	75.47	-	75.47
Expected	2014-2015	13.86	-	13.86	77.65	-	77.65
Expected	2015-2016	13.84	-	13.84	78.47	-	78.47
Expected	2016-2017	14.08	-	14.08	80.67	-	80.67
Expected	2017-2018	14.31	-	14.31	82.78	-	82.78
Expected	2018-2019	14.55	-	14.55	84.08	0.69	84.78
Expected	2019-2020	14.79	-	14.79	84.09	2.60	86.68
Expected	2020-2021	15.03	-	15.03	84.08	4.54	88.62
Expected	2021-2022	15.03	0.23	15.26	84.09	6.46	90.55
Expected	2022-2023	15.03	0.47	15.50	84.09	8.40	92.48
Expected	2023-2024	15.03	0.72	15.75	84.08	10.36	94.45
Expected	2024-2025	15.03	0.97	16.00	84.09	12.35	96.44
Expected	2025-2026	15.03	1.22	16.25	84.08	14.24	98.32
Expected	2026-2027	15.03	1.47	16.50	84.08	16.05	100.13
Expected	2027-2028	15.03	1.72	16.75	84.09	17.85	101.94
Expected	2028-2029	15.03	1.97	17.00	84.08	19.66	103.75

NEW RESOURCE OPTIONS

The following considerations are important in determining the appropriateness of potential resources:

RESOURCE COST

Resource cost is the primary consideration when evaluating resource options although other factors mentioned below also influence resource decisions. We have found that newly constructed resources are typically more expensive than existing resources, but existing resources are in shorter supply. Newly constructed resources provided by a third party, such as a pipeline, may require a significant contractual commitment. Newly constructed resources are often less expensive per unit if a larger facility is constructed, because of economies of scale.

LEAD TIME REQUIREMENTS

New resource options can take from one to five or more years to put in service. Open season processes, planning and permitting, environmental review, design, construction and testing are some of the aspects contributing to lead time requirements for new physical facilities. Recalls of transportation release capacity typically require advance notice of up to a year. Even DSM programs require significant time from program development and rollout to the point when natural gas savings are realized.

PEAK VERSUS BASE LOAD

Our planning efforts include the ability to serve a peak day as well as all other demand periods. Avista's core loads are considerably higher in the winter than the summer. Due to the winter-peaking nature of Avista's demand, resources that cost-effectively serve the winter without an associated summer commitment may be preferable. Alternatively, it is possible that the costs of a winter-only resource may exceed the cost of annual resources after capacity release or optimization opportunities are considered.

RESOURCE USEFULNESS

It is paramount that an available resource effectively delivers natural gas to the intended geographical region. Given Avista's unique service territories, it is often impossible to deliver resources from a resource option such as storage without acquiring additional pipeline transportation.

"LUMPINESS" OF RESOURCE OPTIONS

Newly constructed resource options are often "lumpy." This means that new resources may only be available in larger than needed quantities and only available every few years. This lumpiness of resources is driven by the cost dynamics of new construction, the fact that lower unit costs are available with larger expansions, and the economics of expansion of existing pipelines or the construction of new resources dictate additions infrequently. Lumpiness provides a cushion for future growth. Given the economies of scale for pipeline construction, we are afforded the opportunity to secure resources to serve future demand increases.

RISKS AND UNCERTAINTIES

Investigation, identification and assessment of risks and uncertainties are critical considerations when evaluating supply resource options. For example, resource costs determinations are subject to various degrees of estimation, partly influenced by the expected timeframe of the resource need and degree of rigor determining estimates or estimation difficulties because of the uniqueness of a resource. Lead times can have varying degrees of certainty ranging from securing currently available transport (high certainty) to contracting for imported LNG (low certainty).

RESOURCE SELECTION

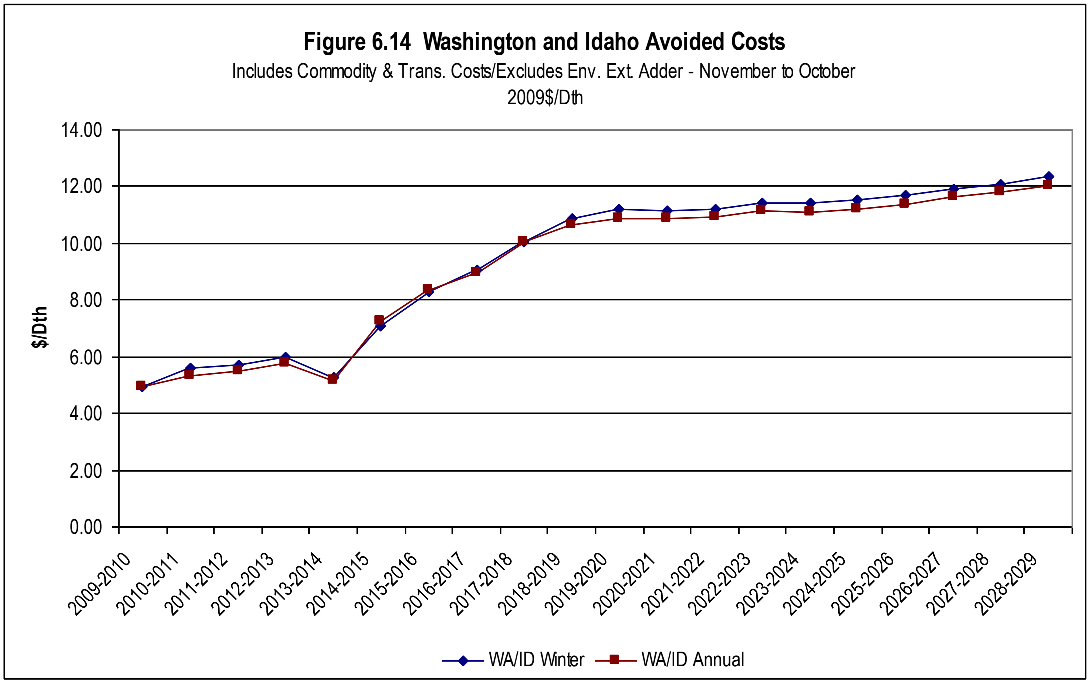
After identifying supply-side resource options and evaluating them based on the above considerations, we entered these supply-side scenarios (see Table 5.2) along with conservation measures (demand-side resources) into the SENDOUT® model for it to select the least cost approach to meeting resource deficiencies. This process is described in Chapter 4 – Demand-side Resources in the Methodology section. SENDOUT® compares demand-side and supply-side resources using PVRR analysis to determine which resource is the best risk adjusted/least cost resource. Appendix 4.3 lists the demand-side measures and Appendix 6.3 lists the supply-side resource options.

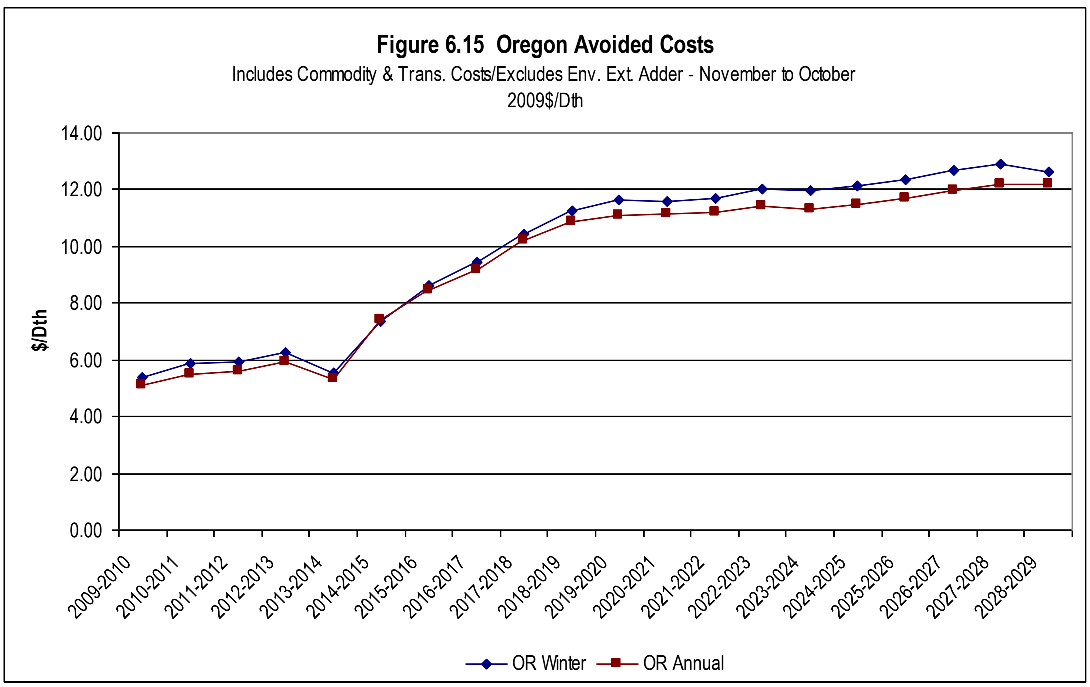
DEMAND-SIDE RESOURCES

Avoided Cost

The SENDOUT® model determined avoided cost figures represent the unit cost to serve the next unit of demand with a supply-side resource option during a given period. If a conservation measure's total resource cost is less than this avoided cost, it will cost effectively reduce customer demand and Avista can "avoid" possible commodity, storage, transportation and other supply resource costs. Measures that reduce heat-related demand are evaluated against a winter avoided cost while measures that reduce non-heat (base load) demand are evaluated against an annual avoided cost.

SENDOUT® calculates marginal cost data by day, month and year for each demand area. A summarized graphical depiction of avoided winter and annual costs for the Washington/Idaho and Oregon areas is in Figure 6.14 and 6.15. The detailed data is presented in Appendix 6.4. The avoided costs do not include environmental externality adders to monetarily recognize adverse environmental impacts. Appendix 4.4 discusses this concept more fully and includes specific requirements required in our Oregon service territory.





Following a small decline in 2013-2014, avoided costs increase rapidly over the next five years when carbon cost adders from anticipated cap-and-trade legislation is phased in.

Selected Measures

Using the above avoided cost thresholds, SENDOUT® selected all cost-effective measures and any mandatory measures. Table 6.4 details anticipated DSM savings in each region from the selected conservation measures for our Expected Case.

Table 6.4 Annual, Annual Average and Peak Day Demand Served by DSM

Case	Gas Year	Annual Klamath DSM (MDth)	Daily Klamath DSM (MDth/day)	Peak Day Klamath DSM (MDth/day)	Annual La Grande DSM (MDth)	Daily La Grande DSM (MDth/day)	Peak Day La Grande DSM (MDth/day)	Annual Medford/ Roseburg DSM (MDth)	Daily Medford/ Roseburg DSM (MDth/day)	Peak Day Medford/ Roseburg DSM (MDth/day)
Expected	2009-2010	6.540	0.018	0.052	3.154	0.009	0.027	22.184	0.061	0.171
Expected	2010-2011	13.084	0.036	0.104	6.231	0.017	0.055	45.948	0.126	0.348
Expected	2011-2012	19.618	0.054	0.156	9.261	0.025	0.082	67.996	0.186	0.522
Expected	2012-2013	25.330	0.069	0.200	11.929	0.033	0.106	87.756	0.240	0.674
Expected	2013-2014	30.960	0.085	0.245	14.564	0.040	0.130	107.443	0.294	0.826
Expected	2014-2015	36.687	0.101	0.290	17.104	0.047	0.154	126.867	0.348	0.978
Expected	2015-2016	42.421	0.116	0.334	19.659	0.054	0.178	146.081	0.399	1.130
Expected	2016-2017	48.049	0.132	0.379	22.100	0.061	0.202	164.829	0.452	1.282
Expected	2017-2018	53.695	0.147	0.424	24.475	0.067	0.226	183.263	0.502	1.434
Expected	2018-2019	59.324	0.163	0.468	26.806	0.073	0.250	201.418	0.552	1.586
Expected	2019-2020	65.018	0.178	0.513	29.314	0.080	0.274	220.444	0.602	1.736
Expected	2020-2021	70.603	0.193	0.557	31.783	0.087	0.298	239.075	0.655	1.887
Expected	2021-2022	75.958	0.208	0.601	34.162	0.094	0.321	256.083	0.702	2.034
Expected	2022-2023	80.360	0.220	0.642	36.077	0.099	0.343	270.585	0.741	2.175
Expected	2023-2024	83.972	0.229	0.675	37.583	0.103	0.361	282.427	0.772	2.292
Expected	2024-2025	87.083	0.239	0.708	38.873	0.107	0.379	292.007	0.800	2.406
Expected	2025-2026	90.025	0.247	0.739	40.067	0.110	0.396	301.099	0.825	2.518
Expected	2026-2027	93.001	0.255	0.771	41.291	0.113	0.414	310.146	0.850	2.631
Expected	2027-2028	95.958	0.262	0.803	42.573	0.116	0.431	319.671	0.873	2.743
Expected	2028-2029	98.806	0.271	0.835	43.640	0.120	0.448	327.820	0.898	2.855

Case	Gas Year	Annual Oregon DSM (MDth)	Daily Oregon DSM (MDth/day)	Peak Day Oregon DSM (MDth/day)	Annual WA/ID DSM (MDth)	Daily WA/ID DSM (MDth/day)	Peak Day WA/ID DSM (MDth/day)	Annual Total System DSM (MDth)	Daily Total System DSM (MDth/day)	Peak Day Total System DSM (MDth/day)
Expected	2009-2010	31.879	0.087	0.250	301.191	0.825	3.336	333.070	0.913	3.585
Expected	2010-2011	65.263	0.179	0.507	600.472	1.645	6.672	665.735	1.824	7.179
Expected	2011-2012	96.875	0.265	0.760	889.351	2.430	10.008	986.226	2.695	10.768
Expected	2012-2013	125.015	0.343	0.981	1,175.141	3.220	13.344	1,300.156	3.562	14.325
Expected	2013-2014	152.967	0.419	1.202	1,460.913	4.003	16.680	1,613.879	4.422	17.882
Expected	2014-2015	180.657	0.495	1.422	1,746.704	4.785	20.016	1,927.362	5.280	21.438
Expected	2015-2016	208.161	0.569	1.643	2,018.933	5.516	23.351	2,227.094	6.085	24.994
Expected	2016-2017	234.978	0.644	1.863	2,287.557	6.267	26.687	2,522.535	6.911	28.550
Expected	2017-2018	261.433	0.716	2.084	2,555.521	7.001	30.022	2,816.954	7.718	32.106
Expected	2018-2019	287.549	0.788	2.304	2,825.361	7.741	33.357	3,112.910	8.529	35.662
Expected	2019-2020	314.776	0.860	2.523	3,099.580	8.469	36.691	3,414.356	9.329	39.213
Expected	2020-2021	341.460	0.936	2.741	3,347.233	9.171	39.967	3,688.694	10.106	42.708
Expected	2021-2022	366.203	1.003	2.957	3,595.802	9.852	43.243	3,962.005	10.855	46.199
Expected	2022-2023	387.021	1.060	3.160	3,844.841	10.534	46.519	4,231.862	11.594	49.679
Expected	2023-2024	403.982	1.104	3.329	4,095.271	11.189	49.795	4,499.253	12.293	53.124
Expected	2024-2025	417.963	1.145	3.493	4,331.296	11.867	53.046	4,749.258	13.012	56.539
Expected	2025-2026	431.191	1.181	3.654	4,573.965	12.531	56.295	5,005.156	13.713	59.950
Expected	2026-2027	444.438	1.218	3.816	4,801.026	13.153	59.544	5,245.464	14.371	63.360
Expected	2027-2028	458.202	1.252	3.977	4,980.468	13.608	62.068	5,438.669	14.860	66.045
Expected	2028-2029	470.266	1.288	4.139	5,156.772	14.128	64.592	5,627.038	15.417	68.731

The list of individual selected measures in the above savings is detailed in Appendix 4.2. Future implementation planning efforts will use these selected measures as a starting point for more detailed planning efforts but we will also investigate other measures that may not have been selected by the SENDOUT® model.

DSM Acquisition Goals

The avoided cost established in SENDOUT®, the demand-side resources selected and the resulting calculated therm savings is the basis for determining DSM acquisition goals and subsequent program implementation planning. The Preliminary Conservation Goal discussion in Chapter 4 – Demand-side Resources, has additional details on this process.

North Division DSM Goals

Changes in avoided costs, specifically adders taking effect in 2015, have driven the potential DSM goals identified in this IRP substantially beyond the 2010 goal of 1,755,829 therms developed in the 2007 IRP. SENDOUT® models escalating avoided costs into the future which are generally higher than the current prices actually experienced by our customers. This is partly due to regulatory lag as well as most customers typically do not explicitly consider higher future gas prices in their purchasing behavior. So customers are not as incented as the model indicates to choose DSM projects in the near term. We compensated for this situation by setting the 2010 DSM acquisition goal at 2,193,338 therms and increasing the DSM goal by 6.5 percent annually. The 6.5 percent annual growth rate results in the full acquisition of the identified potential over a 10-year planning cycle.

Achievement of a 6.5 percent annual increase in acquisition may result in revisions to the Schedule 190 tariff governing natural gas DSM operations. Incentive levels, incentive caps and applicable measures and markets may need to be reviewed to support an implementation plan capable of achieving these long-term goals.

South Division DSM Goals

Based on analyses for this IRP, a cost-effective annual acquisition of 303,300 first-year therms is achievable through utility intervention. The DSM goal originally identified by SENDOUT® significantly exceeds our past IRP goals. This coupled with unprecedented state unemployment and a recessive economy has caused us to constrain the annual ramp-up to 2.2 percent for the first five years. Overall, the acquisition over the entire 5-year planning cycle will accomplish full acquisition.

The identification of this goal does not preclude the addition of other resources that may be identified as cost-effective during later analysis, nor does it preclude the pursuit of unexpected resource acquisition opportunities that may occur between IRP cycles.

Other revisions to regulation, infrastructure or DSM operations are likely to be identified in future implementation planning efforts. Avista is committed to pursuing a more rapid ramp-up of DSM acquisition if it can be achieved without an undue increase in acquisition costs.

SUPPLY-SIDE RESOURCES

SENDOUT® considered all options entered into the model, determined when and what resources were needed, and rejected options that were determined to not be cost effective. These selected resources represent the least cost solution, within given constraints, to serve anticipated customer requirements. Table 6.5 shows the SENDOUT® selected supply-side resources for the Expected Case.

Table 6.5 Supply Side Resource Selected in SENDOUT®

Case	Additional Resources	Jurisdiction	Size	Cost/Rates	Availability	Notes
Expected Case						
	GTN Capacity	WA/ID	25,000 Dth/d	GTN rate	2010	Currently available unsubscribed capacity
	GTN Capacity	OR	25,000 Dth/d	GTN rate	2010	Currently available unsubscribed capacity; requires expansion of Medford Lateral
	GTN Medford Lateral Expansion	OR	25,000 Dth/d	GTN rate	2011	Additional compression to allow more gas to flow from GTN mainline to the lateral
	Klamath Falls Lateral Purchase	OR	6,000 Dth/d	$2.5 million capital cost	November 2010	Agreement with NWPL to purchase the Klamath Falls lateral at net book value. If certain terms are met, can be done with less than one year's notice.
	Malin Backhaul	OR		GTN rate	2010	Backhaul capacity is provided by displacement and is available up to the amount of scheduled forward-haul capacity through a specific point. In order to facilitate additional deliveries to our OR properties an expansion of the Medford Lateral is necessary.

With additional research and investigation, we may later determine that alternative resources are more cost effective than those resources selected in this IRP. We will continue to review and refine knowledge of resource options and will act to secure these best cost/risk options when necessary or advantageous.

RESOURCE SELECTION RESULTS

Figures 6.16 through 6.18 summarize modeling results when comparing regional peak day demand against existing and incremental resources for the Expected Case over the 20-year planning period.

Figure 6.16 WA/ID Selected Resources vs. Peak Day Demand
Expected Case (Net of DSM Savings) November to October

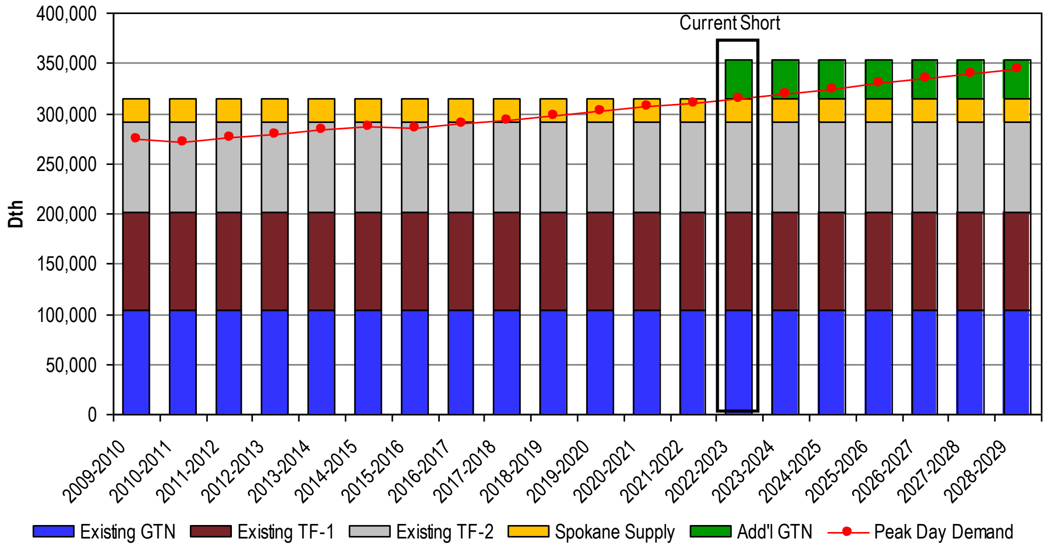


Figure 6.17 Medford/Roseburg Selected Resources vs. Peak Day Demand
Expected Case (Net of DSM Savings) November to October

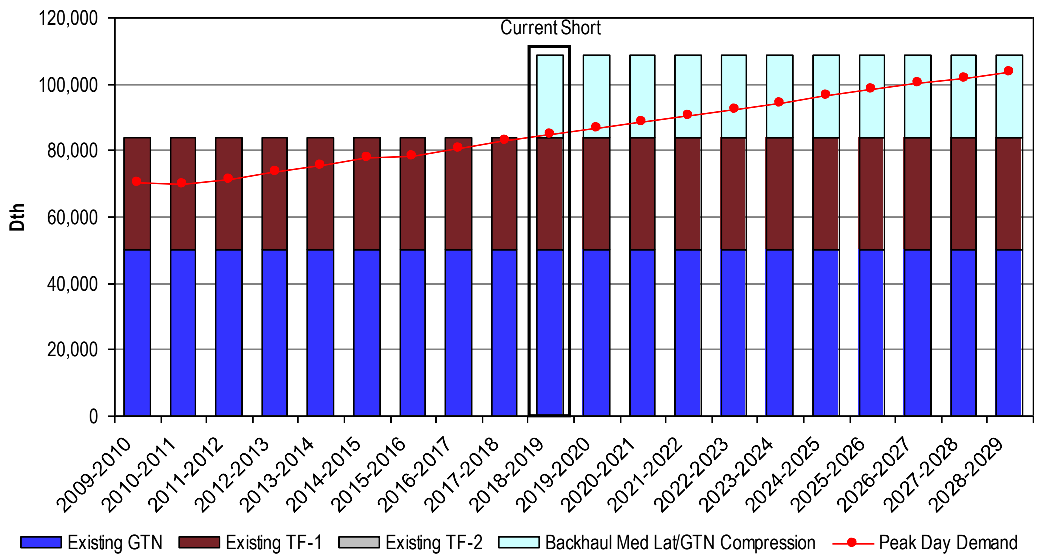
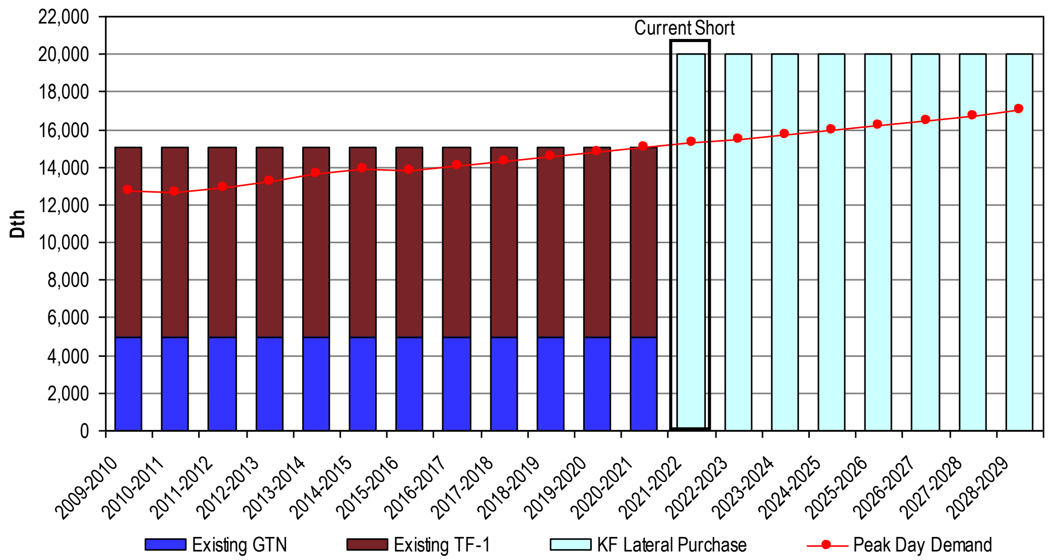


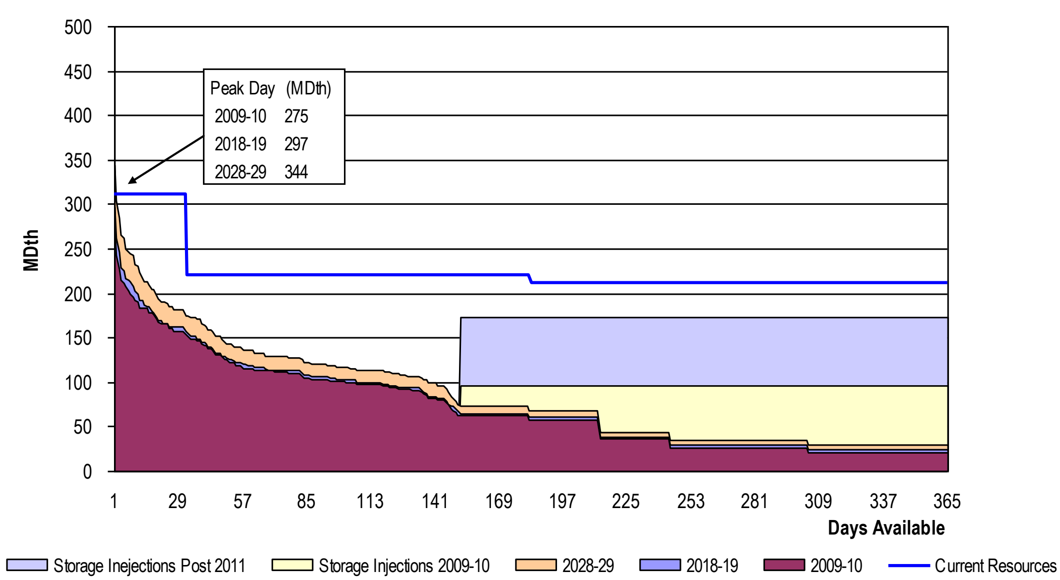
Figure 6.18 Klamath Falls Selected Resources vs. Peak Day Demand
Expected Case (Net of DSM Savings) November to October

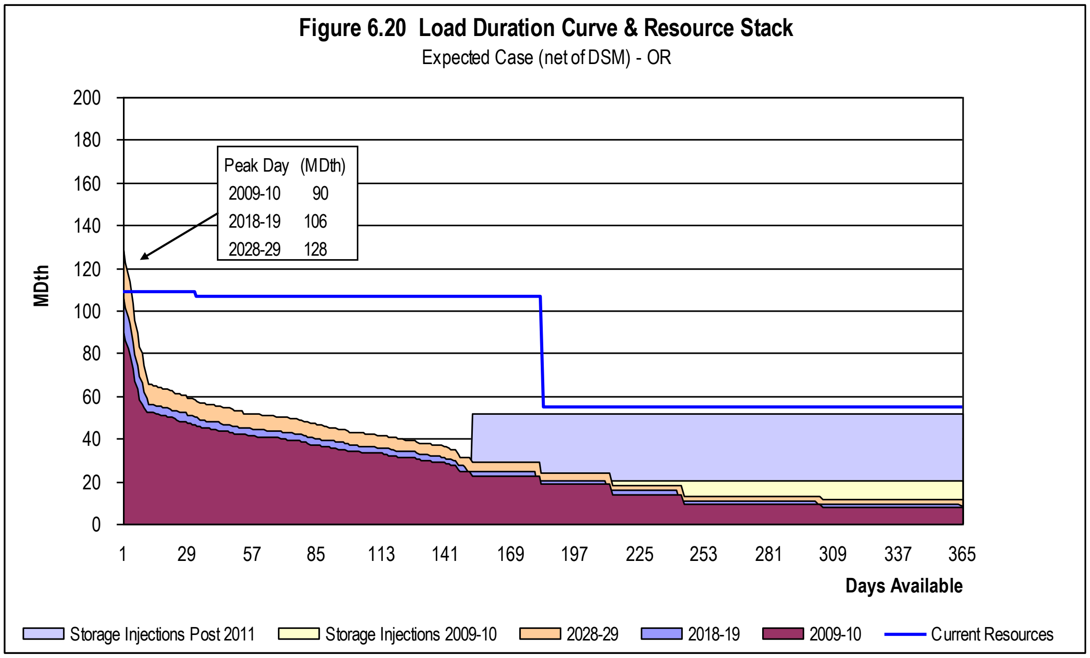


As indicated in the figures, after DSM savings, the model shows a general preference for incremental transportation resources from existing pipelines and supply basins to resolve capacity deficiencies.

Figures 6.19 and 6.20 show load duration curves and the current resource stack for the Expected Case. These graphics compare an entire year of demand to the resource stack for that same year. This enables a review of peak day sufficiency and allows the opportunity to compare all demand days within that year. Although it appears there is excess capacity during non-winter periods, Avista utilizes this capacity for storage injections and transportation optimization opportunities.

Figure 6.19 Load Duration Curve & Resource Stack
Expected Case (net of DSM) - WA/ID





CONCLUSION

The integrated resource portfolio analysis process summarized in this Chapter was performed on our Expected Case demand scenario. We have chosen to utilize the Expected Case for our operational planning activities because this case is the most likely outcome given our experience, industry knowledge and our understanding of future natural gas markets. This case provides for reasonable demand growth given current expectations of natural gas prices over the planning horizon. If realized, this case is at a level that allows us to be reasonably well protected against resource shortages and does not over commit to additional long-term resources.

We fully recognize that there are numerous other potential outcomes. The process described in this chapter was applied to a host of alternate demand and supply resource scenarios and includes a price update to our initial Expected Case which is covered in the Chapter 7 – Alternate Scenarios, Portfolios and Stochastic Analysis.

CHAPTER 7 – ALTERNATE SCENARIOS, PORTFOLIOS AND STOCHASTIC ANALYSIS

OVERVIEW

The integrated resource portfolio analysis process described in Chapter 6 was applied to several alternate demand and supply resource scenarios to develop a broad diversity of possible alternate portfolios. This deterministic modeling approach considered a host of underlying assumptions which were vetted with significant discussion and recommendations from our TAC to develop a consensus number of cases to model and analyze.

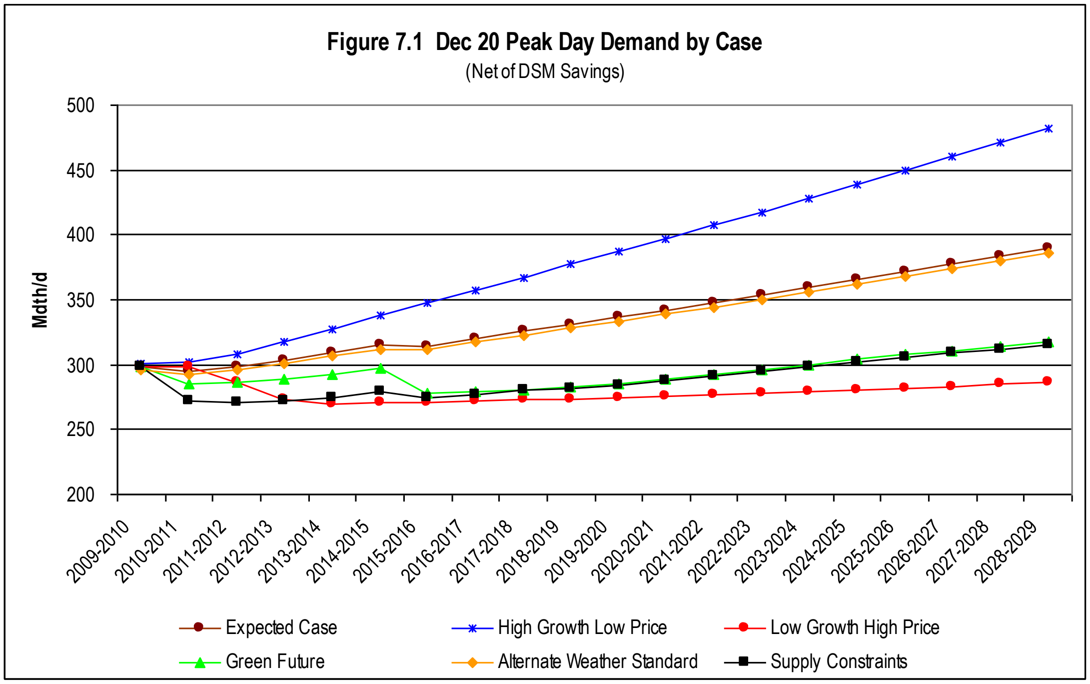
We also performed stochastic modeling for estimating probability distributions of potential outcomes by allowing for random variation in natural gas prices and weather based on fluctuations observed in historical data. This statistical analysis, in conjunction with our deterministic analysis, enabled us to statistically quantify the risk related to resource portfolios under varying price environments. We also developed weather probability distributions to complement our analysis of our weather planning standard.

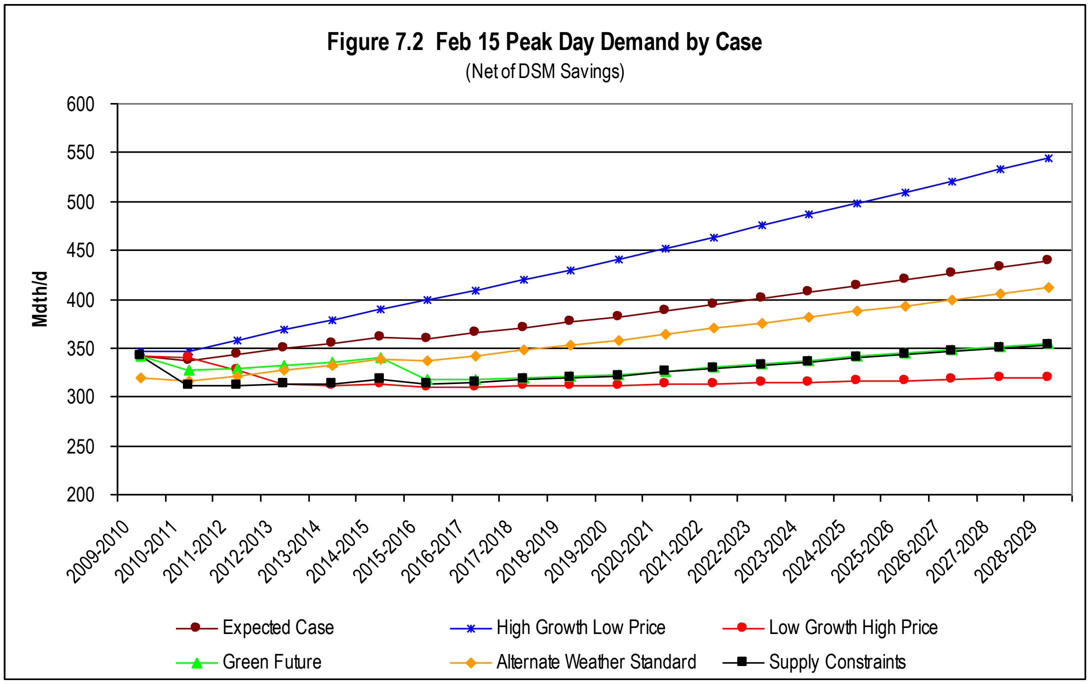
ALTERNATE DEMAND SCENARIOS

As discussed in the Demand Forecasting section, we have identified several alternate scenarios for detailed analysis to capture a wide range of possible outcomes over the planning horizon. These scenarios are summarized in Table 7.1 and are described in detail in the Demand Forecasts Chapter and Appendices 3.6 and 3.7. These alternate scenarios consider different demand influencing factors as well as price elasticity effects for various price influencing factors. This broad range of scenarios is intended to capture most reasonably possible outcomes.

Table 7.1 Alternate Demand Scenarios
Expected Case
High Growth, Low Price
Low Growth, High Price
Green Future
Alternate Weather Standard
Supply Constraints

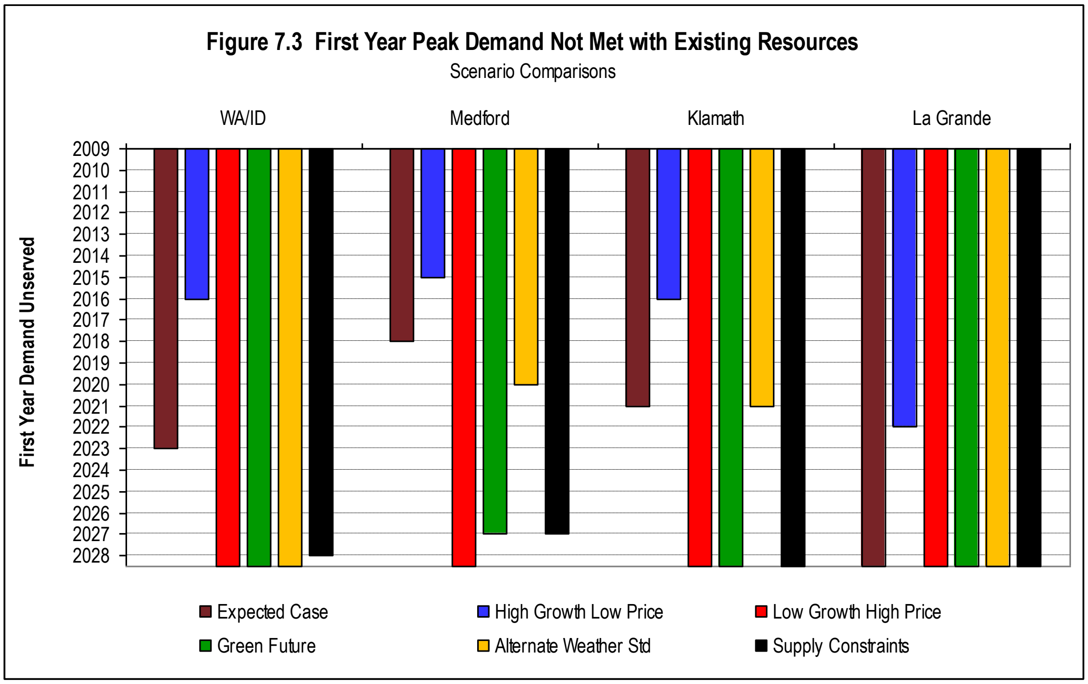
Demand profiles over the planning horizon for each of the alternate scenarios shown in Figures 7.1 and 7.2 reflect the two winter peaks we model for the different service territories (Dec. 20 and Feb. 15).





Noteworthy in these peak demand forecasts are two significant demand decline periods for most scenarios. The first occurs almost immediately followed by a second decline beginning in 2015. These declines are a direct result of customers reacting to steep increases in natural gas prices as modeled. The immediate period assumes that prices rise significantly from the current extremely low prices as the recession ebbs. We assume that customers respond to this price signal by consuming less. The price increase in 2015 is a result of significant carbon cost adders for climate change policy going into effect. Customers again react adversely to this sharp price movement, reducing their consumption in a second round.

As in the Expected Case, we modeled in SENDOUT® the same resource integration and optimization process described in this section for each of the other five demand scenarios (see Appendix 7.1 for a complete listing of all portfolios considered). This identified first year unserved dates for each scenario by service territory (Figure 7.3).



As expected, our High Growth, Low Price scenario has the most rapid growth and the earliest first year unserved dates. Noteworthy is the significant acceleration of first year unserved dates that result from this higher growth scenario across all service territories:

- Washington/Idaho – seven years earlier (February 2016);
- Medford/Roseburg – three years earlier (December 2015);
- Klamath Falls – five years earlier (December 2016); and
- La Grande – at least six years earlier (February 2022).

This "steeper" demand exemplifies the "flat demand risk" discussed earlier. The potential for accelerated unserved dates warrants close monitoring of demand trends and resource lead times.

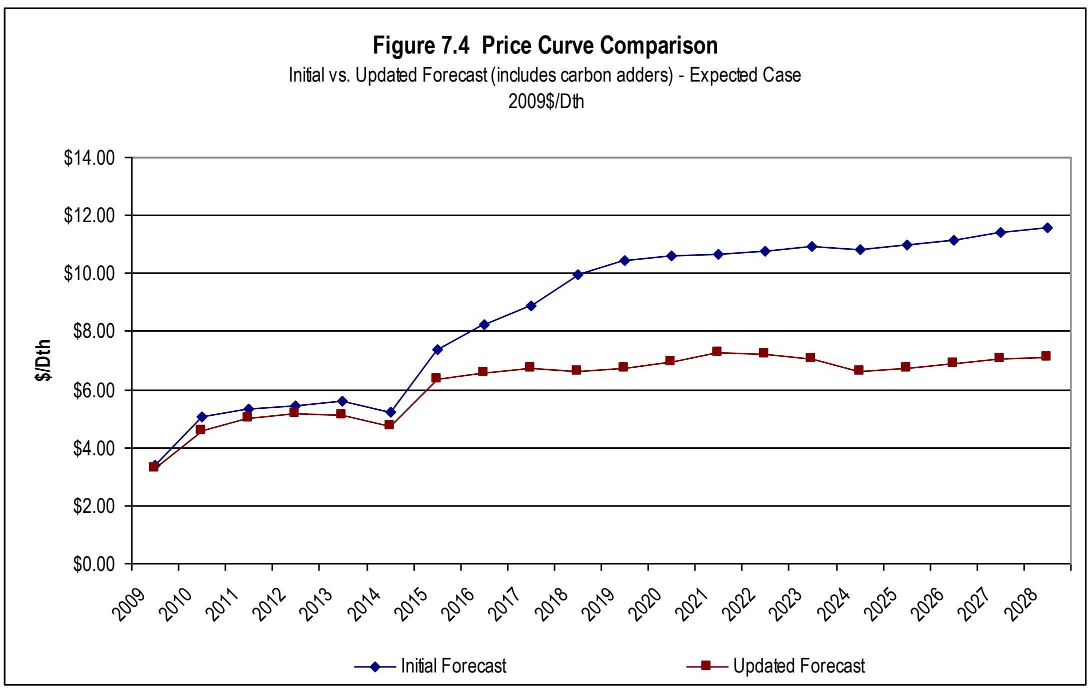
Several scenarios indicate no resource deficiencies over the planning horizon due to very slow or even negative demand growth. A key reason for this is the price elasticity assumptions combined with price forecasts with very steep price increases very early in the planning horizon. This "perfect storm" combination produces a significant curtailment in total demand early in the forecast. A key question for these scenarios is whether this early price shock materializes as forecasted and, if so, is demand really permanently curtailed as predicted in the price elastic response assumption. This condition also warrants close monitoring of actual results.

Analyses of alternative scenarios were extensive. Detailed information on certain selected scenarios is included in the following appendices:

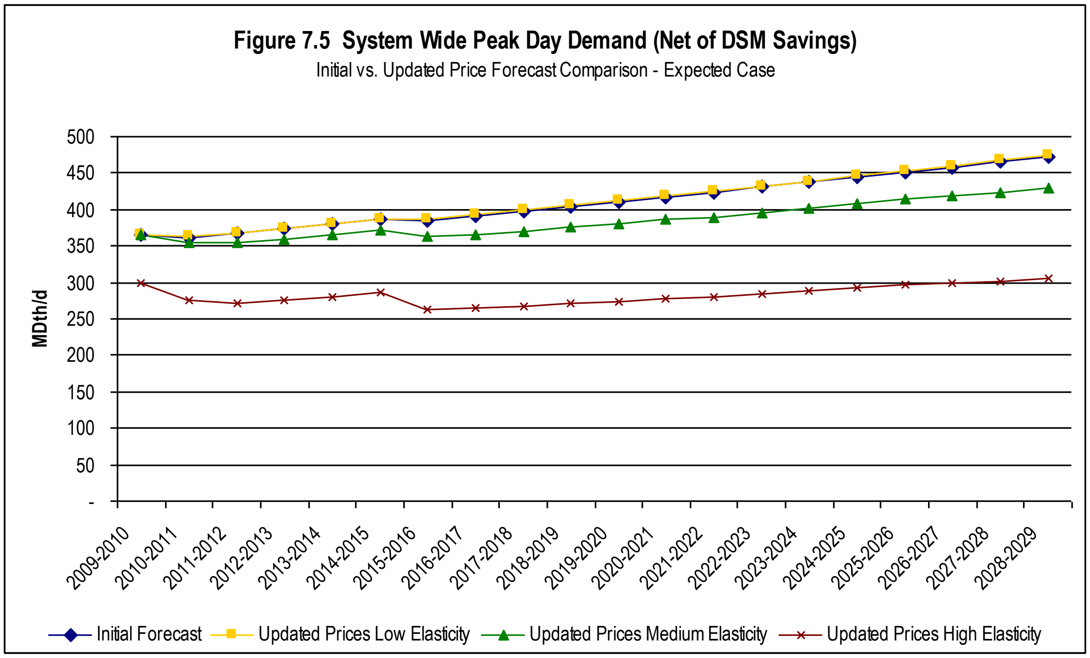
- Demand and Selected Resources graphs by service territory (select cases only) – Appendix 7.2;
- Peak Day Demand, Served and Unserved table (all cases) – Appendix 7.3;
- Load Duration Curve graphs for High Growth and Low Growth cases – Appendix 7.4;
- Avoided cost curve detail and graphs for High Growth and Low Growth cases – Appendix 6.4.

UPDATED PRICE FORECASTS

As discussed in Chapter 3 • Demand Forecasts, a dynamic forward market and several factors that influence fundamental price forecasts evolved quickly in the first half of 2009. We noted significant changes in forward prices and several updates to the forecasts we monitor, including the mid-range forecast we use in many of our scenarios. This prompted us to update our price forecasts in early August 2009. Timing restrictions to meet work plan and filing schedules precluded us from updating all of our prior analyses, limiting our price forecast updates to our Expected Case. A comparison of the initial price curve and the updated price curve is shown in Figure 7.4.



After compiling updated prices, we ran three additional scenarios against our Expected Case assumptions reflecting low, medium and high price elasticity. The demand forecasts for these three new scenarios compared to the initial Expected Case scenario (with low price elasticity) is shown in Figure 7.5.



As anticipated, the Updated Prices, Low Elasticity scenario showed essentially unaffected demand from the changed price curve. Therefore, we determined there would be no change in the timing of unserved demand or resource selections made by SENDOUT®.

In the Updated Prices, High Elasticity scenario, the response to prices resulted in essentially flat demand over the planning horizon. SENDOUT® confirmed our expectation that no region goes resource deficient during the planning horizon.

In the Updated Prices, Medium Elasticity scenario, resource deficiencies did occur but several years later than under the initial Expected Case. The demand scenario was resource optimized in SENDOUT® for all jurisdictions which confirmed our expectation that the same resources would be selected but merely in the later year when the deficit occurred. In WA/ID the shortage was delayed beyond our planning horizon. Medford/Roseburg went resource deficient five years later than initially forecast to 2022. These results are shown in Figures 7.6 through 7.8.

Figure 7.6 WA/ID Existing Resources vs. Peak Day Demand
Expected Case with Medium Price Elasticity (Net of DSM Savings) November to October

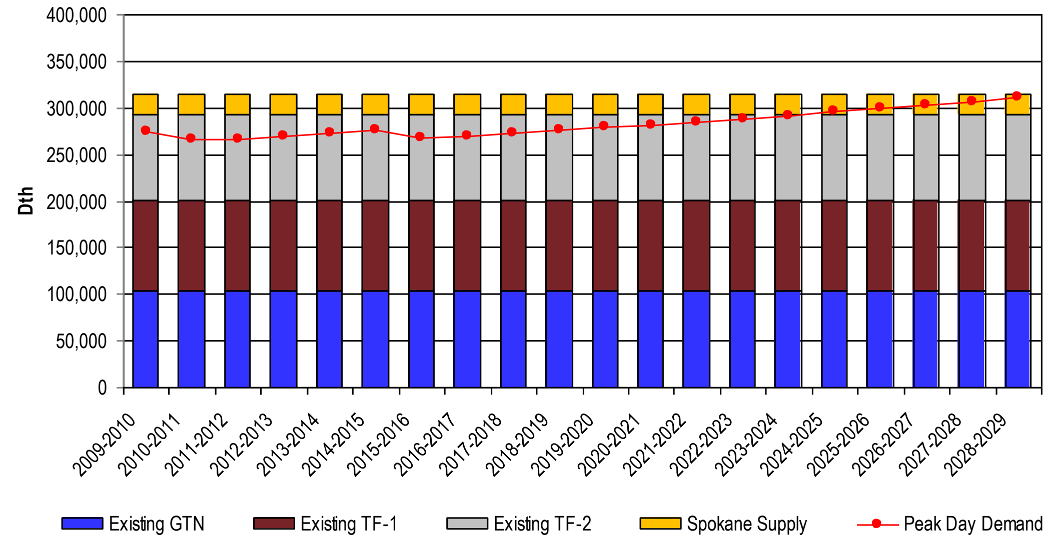
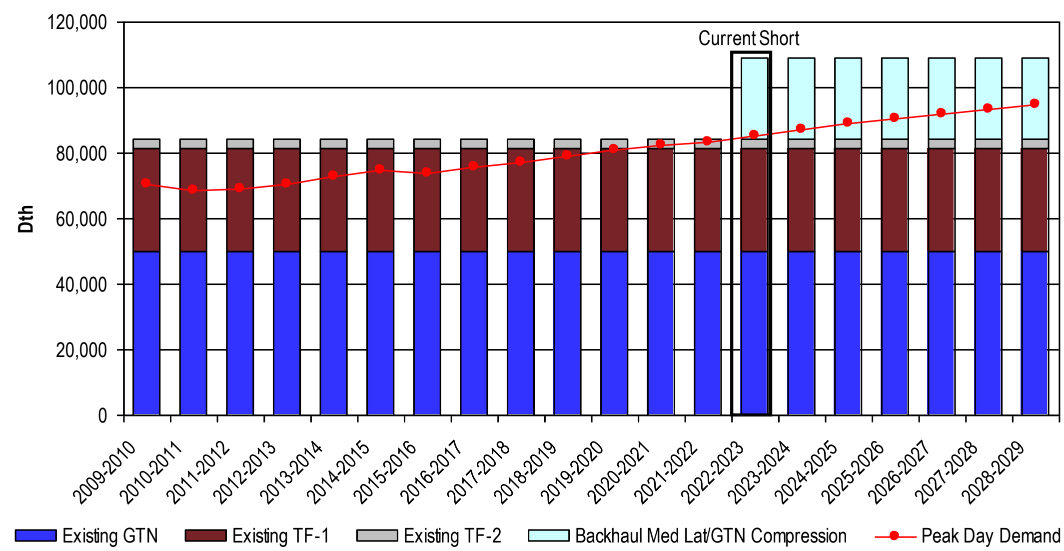
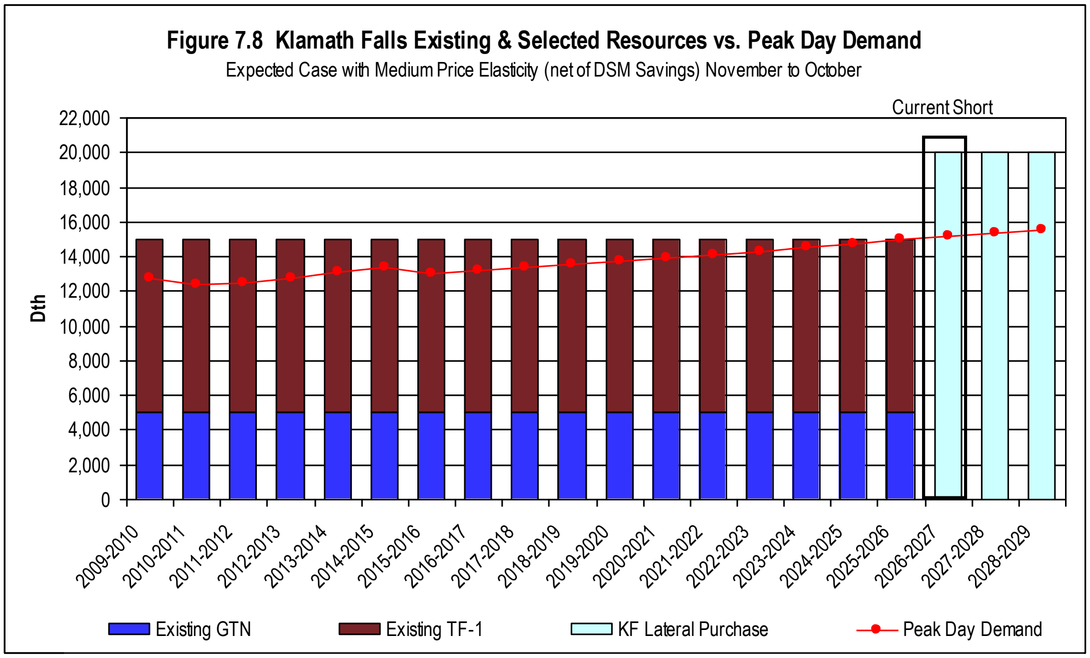


Figure 7.7 Medford/Roseburg Existing & Selected Resources vs. Peak Day Demand
Expected Case with Medium Price Elasticity (Net of DSM Savings) November to October





ALTERNATE SUPPLY SCENARIOS

The list of identified and available supply-side resource options at Appendix 6.3 is extensive and is meant to capture resource options we can reasonably count on if selected by SENDOUT® when running resource optimizations. The list includes other resources we considered but did not input into SENDOUT® because of various restrictions.

For example, contracted city gate deliveries in the form of a structured purchase transaction could be a viable and desirable option to meet super peak conditions. However, the market-based price and other terms are difficult to reliably determine until a formal agreement is negotiated. Exchange agreements also have market-based terms and are hard to reliably model especially when the resource is not needed in the near term.

Another example is Imported LNG. Model assumptions can be reasonably estimated for LNG import facilities but significant uncertainties outside of model assumptions preclude consideration of these resources as “firm” at this time. (See Appendix 5.2 for detailed information about supply-side scenarios.)

For our WA/ID and Medford/Roseburg service territories, unsubscribed firm capacity on GTN and/or backhaul plus lateral expansion is a preferred resource selection from our existing resources plus currently available supply scenario for most demand scenarios. However, assumptions on future availability could change over time. Therefore, we ran two additional alternate supply-side scenarios with changed assumptions on GTN capacity as per Table 7.2.

Table 7.2 Alternate Supply Scenarios
Existing Resources
Existing + Expected Available
GTN Rate Escalation
GTN Fully Subscribed

The first scenario we assumed significant decontracting occurs in the future which leads to much higher rates. The result of this scenario using our Expected Case demand profile is that, in Washington and Idaho, Satellite LNG is selected as the preferred resource portfolio. However, in Medford/Roseburg the model still favors the backhaul with and expansion of the Medford Lateral. (Figures detailing the resources selected based on this scenario are included in Appendix 7.2.)

The second scenario assumes GTN or the upstream pipelines are fully subscribed and therefore, capacity is not an available resource. This scenario resulted in satellite LNG for Washington and Idaho. However in Medford/Roseburg the model selected an expansion of the NWP mainline. Figures detailing the resources selected based on this scenario are included in Appendix 7.2)

PORTFOLIO SELECTION

The alternate demand scenarios and supply scenarios are matched together to form portfolios. Each of these unique portfolios is run through SENDOUT® where the supply resources and demand-side resources are compared and selected on a least cost basis. Once the resources are determined, a net present value of the revenue requirement (PVRR) is calculated.

In the Expected case, the Expected Demand with Existing Resources plus Expected Available portfolio has the lowest PVRR and was therefore selected as our preferred portfolio. In this portfolio, the supply-side resources selected to meet unserved demand include the acquisition of currently available pipeline capacity on GTN, additional compression on the GTN Medford Lateral and the purchase of the Klamath Falls lateral. These resources are the least cost/risk adjusted options available to meet peak day demand.

Table 7.3 summarizes the PVRR of all the portfolios considered. Each of these portfolios is based on unique assumptions and therefore a simple comparison of PVRR cannot be made. Detailed cost information on all portfolios can be found in Appendix 7.5.

Table 7.3 Net Present Value of Revenue Requirement (PVRR) by Portfolio

Portfolio		PVRR in (000's)
Expected Case		
Expected Demand with Existing Resources (before resource additions)	$	(6,514,895)
Expected Demand with Existing Resources plus Expected Available	$	(6,547,705)
Expected Demand with GTN Fully Subscribed	$	(6,593,845)
Expected Demand with GTN Rate Escalation	$	(7,440,510)
Additional Demand Scenarios		
Expected Demand with High Elasticity and Existing Resources	$	(5,856,847)
Expected Demand with Medium Elasticity and Existing Resources	$	(6,249,435)
Alternate Weather Standard Demand with Existing Resources	$	(7,997,147)
High Growth, Low Price Demand with Existing Resources	$	(7,691,204)
High Growth, Low Price Demand with Existing Resource plus Expected Available	$	(10,704,833)
Green Future with Exisiting Resources	$	(9,277,241)
Low Growth, High Price with Existing Resources	$	(10,814,967)
Supply Constraints with Existing Resources	$	(11,782,862)

STOCHASTIC ANALYSIS[1]

The scenario (deterministic) analysis described earlier in this document represents specific "what if" situations based on predetermined assumptions including price and weather. These two factors are an integral part of scenario analysis. To better understand a particular portfolio's response to price and weather, we applied stochastic analysis to generate a wide variety of price and weather events.

Deterministic analysis is a valuable tool for selecting the optimal portfolio. The model selects resources to meet peak weather conditions in each of the 20 years. However, due to the recurrence of design conditions in each of the 20 years, total system costs over the planning horizon can be overstated because of annual recurrence of design conditions and the recurrence of price increases in the forward price curve. As a result, deterministic analysis does not provide a comprehensive look at future events. This type of analysis is only one piece of the puzzle. Utilizing Monte Carlo simulation in conjunction with deterministic analysis provides a more complete picture of how the portfolio performs under multiple weather and price profiles.

For this IRP, Monte Carlo analysis was employed in two ways. The first was to test our weather planning standard and the second was to assess the risk related to costs of our Expected portfolio under varying price environments.

WEATHER

In order to evaluate weather and its effect on our portfolio, we derived 200 simulations (draws) through the use of SENDOUT®'s Monte Carlo capabilities. Unlike deterministic scenarios or sensitivities, the draws have more variability from month-to-month and year-to-year. In the model, random monthly total HDD draw values (subject to Monte Carlo parameters – see Table 7.4) are distributed on a daily basis for a month in history with similar HDD totals. The resulting draws provide a weather pattern with variability in the total HDD values, as well as variability in the shape of the weather pattern. This provides more robust basis for stress testing the deterministic analysis.

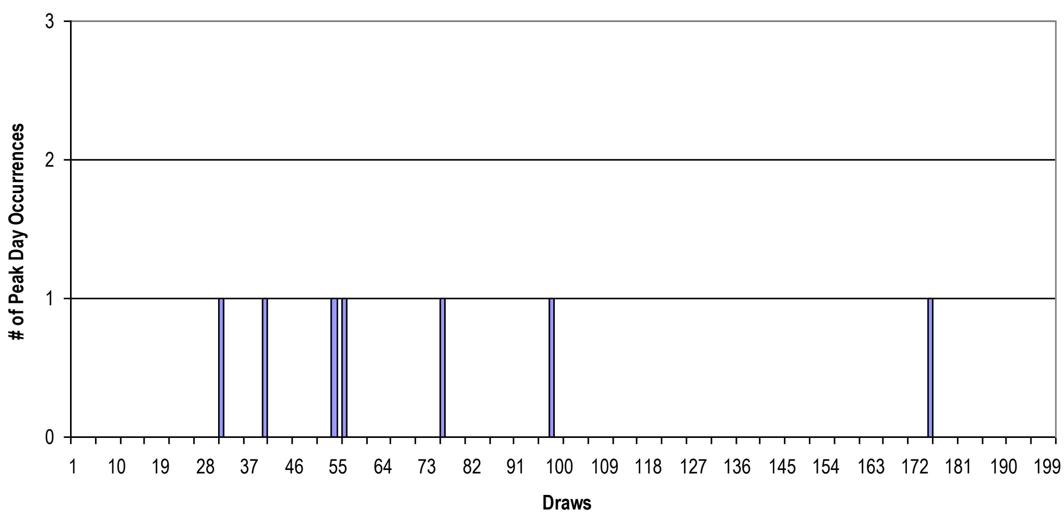
[1] SENDOUT® uses Monte Carlo simulation to support stochastic analysis, which is a mathematical technique for evaluating risk and uncertainty. Monte Carlo simulation is a statistical modeling method used to imitate the many future possibilities that exist with a real-life system.

Table 7.4 Example of Monte Carlo Weather Inputs
Spokane

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
HDD Mean	895	1,152	1,145	913	781	546	331	143	37	37	191	544
HDD Std Dev	132	141	159	115	85	73	72	52	28	28	77	70
HDD Max	1,361	1,506	1,681	1,204	953	694	471	248	151	97	343	677
HDD Min	699	918	897	716	598	392	192	61	-	1	54	361

Avista models five weather areas; Spokane, Medford, Roseburg, Klamath Falls and La Grande. From the simulation data we were able to assess the frequency that the peak day occurs in each area. The stochastic analysis shows that in over 200 twenty-year simulations, while still remote, peak day (or more) does occur with enough frequency to maintain our current planning standard for this IRP, though this topic remains a subject of continued analysis. For example, in our Medford weather pattern over the 200 twenty-year draws (i.e. 4000 years), HDDs at or above peak weather (61 HDD) occurs 128 times. This equates to a peak day occurrence once every 31 years (4000 simulation years divided by 128 occurrences). The Spokane area has the least occurrences of peak day (or more) occurrences in our simulations while La Grande has the most occurrences. This is primarily due to the frequency in which each region's peak day HDD occurs within the historical data as well as near peak day HDDs. See Figures 7.9 through 7.13 for the number of peak day occurrences for a weather area.

Figure 7.9 Frequency of Peak Day Occurrences
Spokane



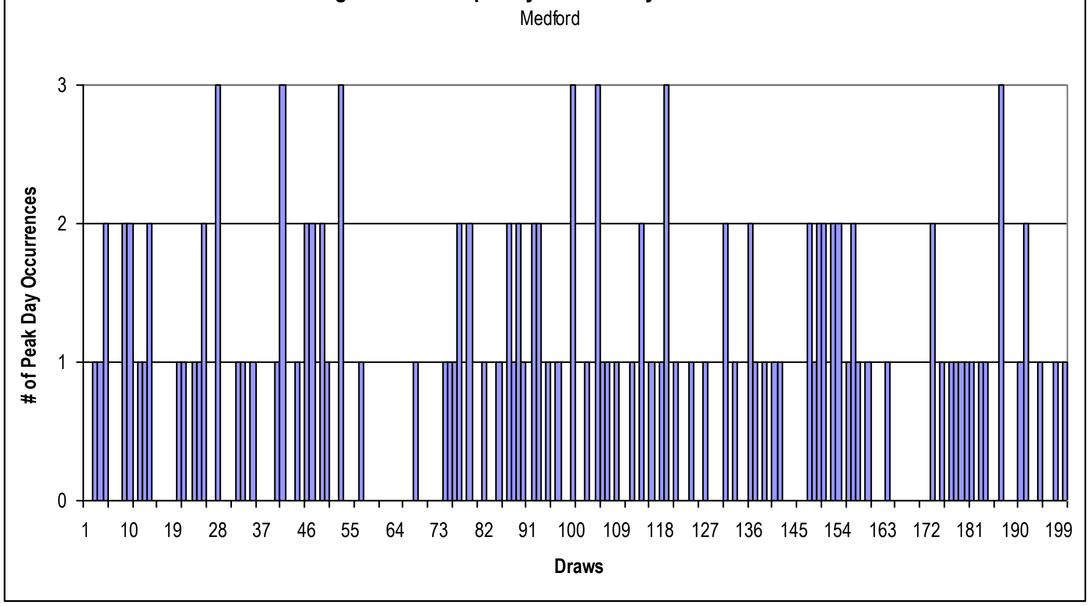


Figure 7.10 Frequency of Peak Day Occurrences

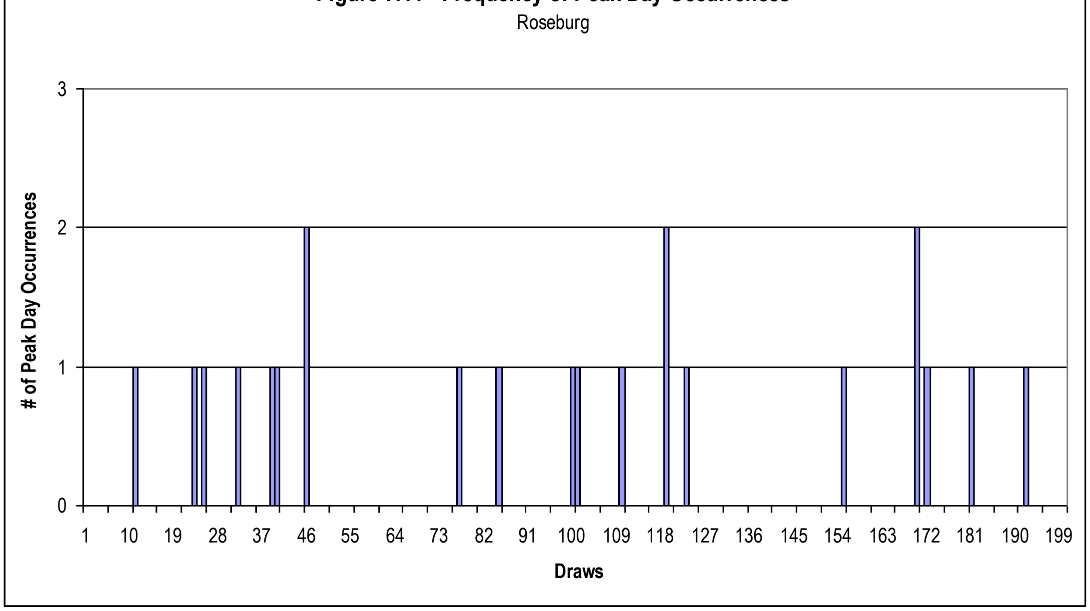


Figure 7.11 - Frequency of Peak Day Occurrences

Figure 7.12 Frequency of Peak Day Occurrences
Klamath Falls

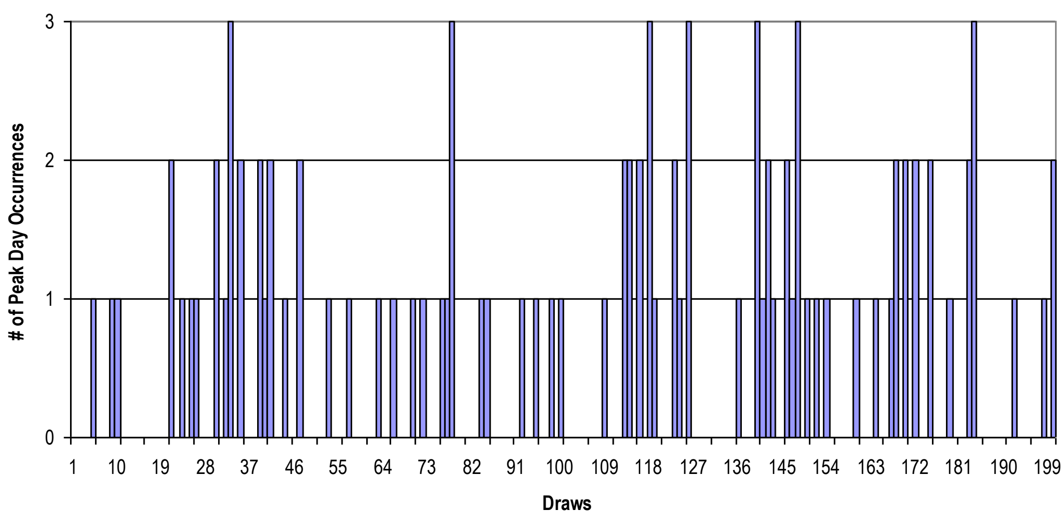
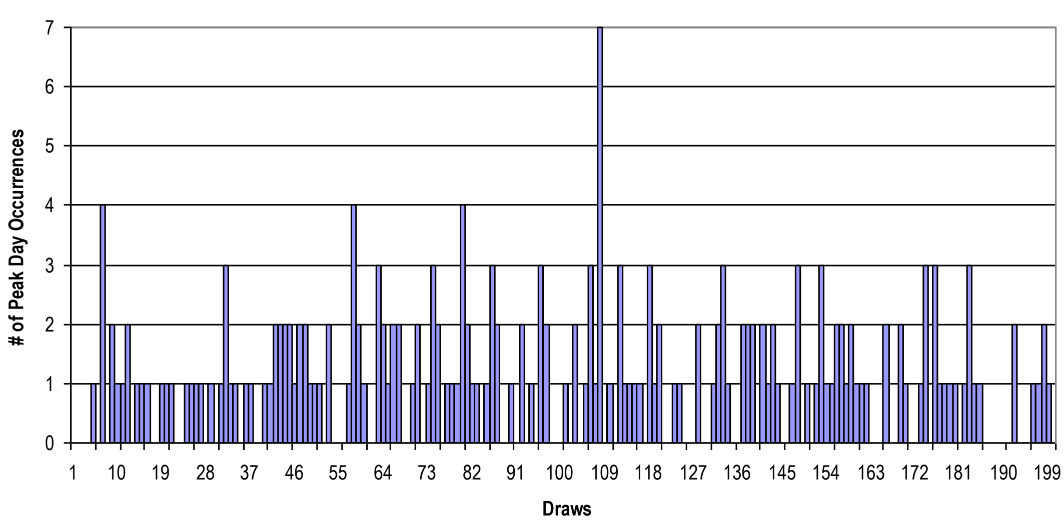


Figure 7.13 Frequency of Peak Day Occurrences
LaGrande

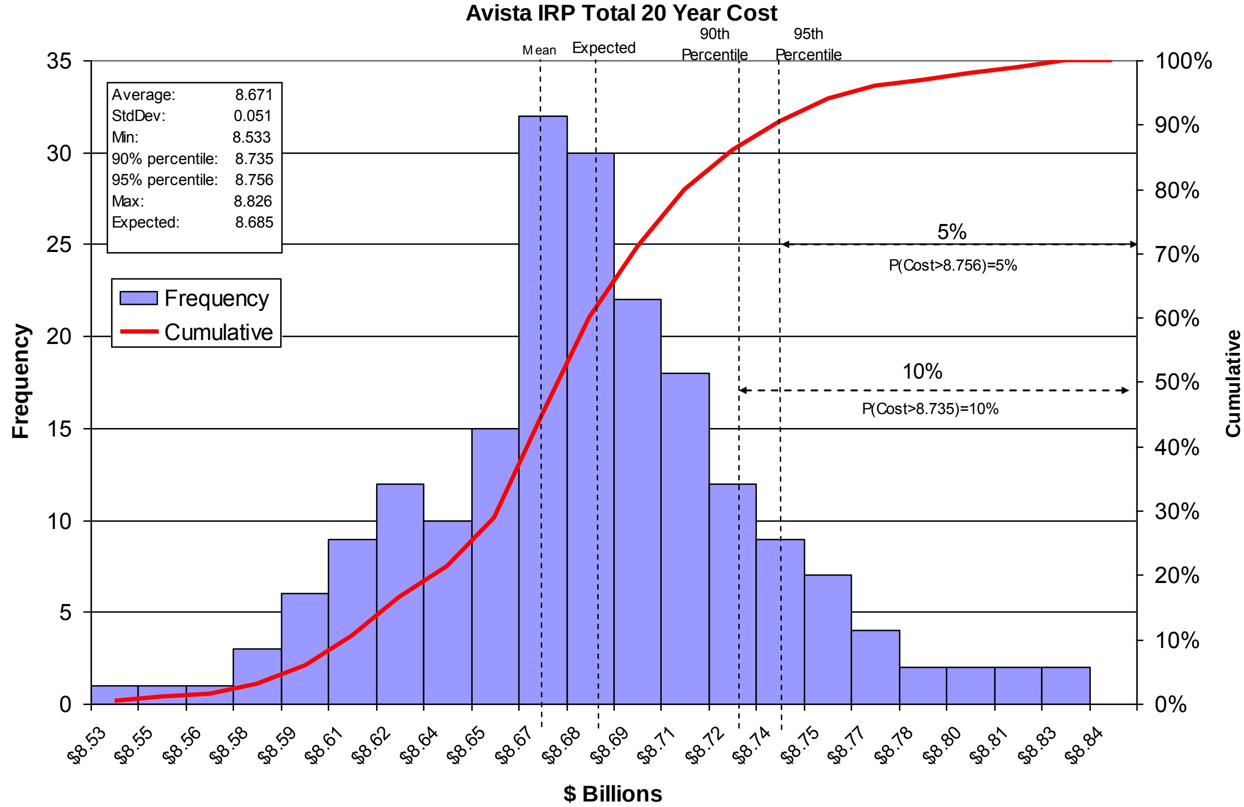


PRICE

While weather is an important driver for IRP planning, price is also important. As seen in recent years, there can be significant price volatility that can affect the portfolio. In deterministic modeling, a single price curve for each scenario is used to perform analysis. There is risk, however, that the price curve used in the scenario will not reflect actual results.

Through Monte Carlo simulation, we are able to test our portfolio and quantify the risk to our customers when prices do not materialize as forecasted. We performed a simulation of 200 draws, varying prices, to investigate whether the Expected Case total portfolio costs from our deterministic analysis is within the range of occurrences in our stochastic analysis. Figure 7.14 shows a histogram of the total portfolio cost of all 200 draws, plus the Expected Case results. This histogram depicts the frequency and the total cost of the portfolio among all the draws, the mean of the draws, the standard deviation of the total costs, and the total costs from the Expected Case. The figure confirms that our Expected Case total portfolio cost is within an acceptable range of total portfolio costs based on 200 unique pricing scenarios. This provides us comfort that our Expected Case price curve and the resultant total portfolio cost is adequately statistically supported.

Figure 7.14
Avista IRP Total 20 Year Cost



Performing stochastic analysis on two key variables of weather and price in our demand analysis provided a statistically supported approach to evaluate and confirm the findings reached from our scenario analysis with respect to adequacy and reasonableness of our weather planning standard and our selected natural gas price forecast. This alternative analytical perspective provides us better confidence in our conclusions and helps us stress test our assumption, thereby mitigating analytical risks.

REGULATORY REQUIREMENTS

IRP regulatory requirements in Washington, Oregon and Idaho call for several key components. The completed plan must demonstrate that we have:

- Examined a range of demand forecasts;

- Examined feasible means of meeting demand with both supply-side and demand-side resources;
- Treated supply-side and demand-side resources equally;
- Described our long-term plan for meeting expected demand growth;
- Described our plan for resource acquisitions between planning cycles;
- Taken planning uncertainties into consideration; and
- Involved the public in the planning process.

We have addressed the applicable requirements throughout this document. Appendix 2.1 lists the specific requirements and guidelines of each jurisdiction and describes our compliance in detail.

We are also required to consider risks and uncertainties throughout our planning and analysis. Our approach in addressing this requirement was to identify factors that could cause significant deviation from our Expected Case planning conclusions. We employed dynamic demand analytical methods and incorporated sensitivity analysis on various demand drivers that impacted demand forecast assumptions. From this, we created 15 demand sensitivities and modeled 6 demand scenario alternatives, which incorporated differing customer growth, use per customer, weather and price elasticity assumptions. We developed four supply scenarios to consider various risks of resource uncertainties. This resulted in 13 distinct portfolios analyzed within SENDOUT®.

We performed analysis on our peak day weather planning standard, performing sensitivity on HDDs and modeling an alternate weather planning standard using coldest day in 20 years. We supplemented this analysis with stochastic analysis running Monte Carlo simulations in SENDOUT®. We also used simulations from SENDOUT® to analyze price uncertainty and the effect on total portfolio cost.

We examined risk factors and uncertainties that could impact expectations and assumptions with respect to DSM programs and supply-side scenarios. From this, we developed four supply-side scenarios and included numerous DSM programs for evaluation.

This investigation, identification and assessment of risks and uncertainties in our IRP process should reasonably mitigate surprise outcomes.

CONCLUSION

Given the extreme increase and decrease in demand levels over the full planning horizon framed by the Low Growth and High Growth cases, we believe that we have modeled a sufficient range to capture all reasonably possible but less likely outcomes from our Expected Case.

Our portfolio and resource analysis indicates several strategies that should be pursued to fully optimize available resources. The effectiveness of any strategy will be in the flexibility to take advantage of market opportunities. These strategies indicate the following:

- A total system supply portfolio should be maintained to provide the greatest flexibility for dispatching resources, while maintaining lower supply costs due to the diverse weather within our service territory.
- Long-term and short-term capacity releases and recalls should continue to be reviewed periodically.

We will continue to monitor demand levels and peak day requirements for signposts (e.g. greater than or less than expected customer growth or use per customer) that indicate demand levels are moving toward another case. We believe that through this analysis and monitoring process, and given that we have sufficient time before potential resource shortages, there is little chance of being surprised by resource shortages.

CHAPTER 8 – DISTRIBUTION PLANNING

OVERVIEW

Avista's integrated resource planning encompasses evaluation of safe, economical and reliable full-path delivery of natural gas from basin to burner tip. Securing adequate natural gas supply and ensuring sufficient pipeline transportation capacity to our city gates become secondary issues if the distribution system behind the city gates is not adequately planned and becomes severely constrained. An important part of the planning process is to forecast future local demand growth, determine potential areas of distribution system constraints, analyze possible solutions and estimate costs for eliminating constraints.

Analyzing our resource needs to this point has focused on ensuring adequate capacity to our city gates, especially during a peak event (i.e. "Is there adequate volume for a peak day?"). Distribution planning focuses on "Is there adequate pressure during a peak hour?" Despite this altered perspective, distribution planning shares many of the same goals, objectives, risks and solutions.

Avista's natural gas distribution system consists of approximately 3,400 miles of distribution main pipelines in Washington, 1,900 miles in Idaho and 2,300 miles in Oregon, as well as numerous regulator stations, service distribution lines, monitoring and metering devices, and other equipment. Currently, there are no storage facilities or compression systems within our distribution system. System pressure is maintained by pressure regulating stations that utilize pipeline pressures from the interstate transportation pipelines before natural gas enters our distribution networks.

DISTRIBUTION SYSTEM PLANNING

Avista conducts two primary types of evaluations in its distribution system planning efforts to determine the need for resource additions, including distribution system reinforcements and expansions. Reinforcements are upgrades in existing infrastructure or new system additions that increase system capacity, reliability and safety. Expansions are new system additions to accommodate new demand. Collectively we refer to these as distribution enhancements.

Ongoing evaluations of each distribution network in our four primary service territories are conducted to identify strategies for addressing local distribution requirements resulting from customer growth. Customer growth assessments are made based on many factors including our IRP demand forecasts[1], monitoring of gate station flows and other system metering, ongoing communication with construction staff and local area management regarding new service requests, field personnel discussion and inquiries from major developers.

[1] Distribution Planning forecasts customer growth rates by town code to generate local demand growth projections in its forecasting model consistent with the broader IRP customer forecasting methodology facilitating consistent integrated planning efforts. A town code is an unincorporated area within a county or a municipality within a county.

Additionally, Avista regularly conducts integrity assessments of its distribution systems. This type of ongoing system evaluation can also indicate distribution upgrading requirements, but as a result of system maintenance needs rather than customer and load growth. In some cases, however, the timing for system integrity upgrades can coincide with growth related expansion requirements.

These planning efforts provide a long-term planning and strategy outlook and are integrated into our capital planning and budgeting process which incorporates planning for other types of distribution capital expenditures and infrastructure upgrades.

NETWORK DESIGN FUNDAMENTALS

Natural gas distribution networks rely on pressure differentials to flow gas from one place to another. When pressures are the same on both ends of a pipe, the gas does not move. When gas is removed from a point on the network, the pressure at that point drops lower than the pressure upstream in the network. Gas then moves from the higher pressure in the network to the point of removal, attempting to equalize the pressure throughout the network. If gas removed is not sufficiently replaced by new gas entering the network, the pressure differential will decrease and flow will stall and the network could run out of pressure. Therefore, it is important to design a distribution network so that the intake pressure (from gate stations and/or regulator stations) within the network is high enough to maintain an adequate pressure differential when gas leaves the network.

Not all gas flows equally throughout a network. Certain points within the network can constrain flow and thus restrict overall network capacity. Network constraints can occur over time as demand requirements on the network evolve. Anticipating these demand requirements, identifying potential constraints and forming cost effective solutions with sufficient lead times without overbuilding infrastructure are the key challenges in network design.

COMPUTER MODELING

Developing and maintaining effective network design is significantly aided by computer modeling to perform network demand studies. Demand studies have evolved with technology in the past decade to become a highly technical and powerful means for analyzing the operation of a distribution system. Using a pipeline fluid flow formula, a specified parameter of each pipe element can be simultaneously solved. A variety of pipeline equations exist, each tailored to a specific flow behavior. Through years of research, these equations have been refined to the point where modeling solutions produced closely resemble actual system behavior.

Avista conducts network load studies using Advantica's SynerGEE® 4.3.0 software. This computer-based modeling tool runs on a Windows operating system and allows users to analyze and interpret solutions graphically. Appendix 8.1 describes in detail our computer modeling methodology while Appendix 8.2 provides an example load study presentation including graphical interface and output examples.

DETERMINING PEAK DEMAND

For ease of maintenance and operation, safety to the public, reliable service and cost considerations, distribution networks operate at a relatively low pressure. Avista operates its distribution networks at a maximum operating pressure of 60 pounds per square inch (psig). Since distribution systems operate at pressure through relatively small diameter pipes, there is essentially no line-pack capability for managing hourly demand fluctuations.

Core demand typically has a morning peaking period between 6 a.m. and 10 a.m. and an evening peaking period between 5 p.m. and 9 pm. 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 our distribution systems are based on peak hour demand[2]. Included in Appendix 8.1 is the detailed methodology we use for determining peak demand.

DISTRIBUTION SYSTEM ENHANCEMENTS

Computer-aided demand studies facilitate modeling numerous "what if" demand forecasting scenarios, constraint identification and corresponding optimum combination of pipe modification and pressure modification solutions to maintain adequate pressures throughout the network over time.

Distribution system enhancements do not reduce demand nor do they create additional supply. However, they can increase the overall capacity of a distribution pipeline system while utilizing existing gate station supply points. The three broad categories of distribution enhancement solutions are pipelines, regulators and compression.

PIPELINES

Pipeline solutions consist of looping, upsizing and uprating.

- Pipeline looping is the most common method of increasing capacity within an existing distribution system. It involves constructing new pipe parallel to an existing pipeline that has, or may become, a constraint point. Constraint points inhibit pressure capacities downstream of the constraint creating inadequate pressure during periods of high demand. When the parallel line is connected to the system, this second alternative path allows natural gas flow to bypass the original constraint point and bolster downstream pressure capacities. The feasibility of looping a pipeline is primarily dependant upon the location where the pipeline will be constructed. Installing gas pipelines through private easements, residential areas, existing asphalt, and steep or rocky terrain can greatly increase the cost to amounts that are unjustifiable so that other alternative solutions offer a more cost effective solution.

[2] This method differs from the approach that we use for broader IRP peak demand planning which focuses on peak day requirements to the city gate.

- Pipeline upsizing is simply replacing existing pipe with a larger size pipe. The increased pipe capacity relative to surface area of the pipe results in less friction and therefore a lower pressure drop. This option is usually pursued when there is damaged pipe or pipe integrity issues exist. If the existing pipe is otherwise in satisfactory condition, looping is usually pursued, allowing the existing pipe to remain in use.
- Pipeline uprating involves increasing the maximum allowable operating pressure of an existing pipeline. This enhancement can be a quick and relatively inexpensive method of increasing capacity in the existing distribution system before constructing more costly additional system facilities. However, safety considerations and pipe regulations may prohibit feasibility or lengthen the time before completion of this option. Also, increasing line pressure may produce leaks and other pipeline damage creating unanticipated costly repairs.

REGULATORS

Regulators or regulator stations are used to reduce pipeline pressure at various stages within the distribution. The primary purpose of regulation is to provide a specified and constant outlet pressure before gas continues its downstream travel to a city's distribution system, customer's property, or gas appliance. Regulators also ensure that flow requirements are met at a desired pressure regardless of fluctuations upstream of the regulator. Regulators can be found at city gate stations, district regulators stations, farm taps and customer services.

COMPRESSION

Compressor stations present a capacity enhancing option for pipelines with significant gas flow and the ability to operate at higher pressures. For pipelines experiencing a relatively high and constant flow of gas, a single, large volume compressor can be installed in the optimal position along the pipeline to boost downstream pressure. However, this type of compressor configuration will not function effectively if the flow in the pipeline has high variability.

A second option is the installation of multiple, smaller compressors located close together or strategically placed in different locations along a pipeline. Multiple compressors accommodate a large flow range and the use of smaller and very reliable compressors. These smaller compressor stations are well suited for areas where gas demand is growing at a relatively slow and steady pace so that purchasing and installing these less expensive compressors can be done over time allowing a pipeline to serve growing customer demand for many years into the future.

Compressors can be a cost effective, feasible option to resolving constraint points; however, regulatory and environmental approvals to install a station along with engineering and construction time can be a significant deterrent. Also, adding compressor stations within a distribution system typically involves considerable capital expenditure. Based on our detailed knowledge of our distribution system, we do not currently envision or have any foreseeable plans to add compressors to our distribution network.

CONSERVATION RESOURCES

Included in our evaluation of distribution system constraints is consideration of targeted conservation resources that could reduce or delay distribution system enhancements. We are mindful, however, that the consumer is still the ultimate decision-maker regarding the purchase of a conservation measure. Because of this, we attempt to influence these decisions but we do not depend on estimates of peak day demand reductions from conservation to eliminate near-term distribution system constraint areas. Over longer-term planning, we do recognize that targeted conservation programs provide a cumulative benefit that offsets potential constraint areas and may be an effective strategy.

PLANNING RESULTS

Table 8.1 summarizes the cost of major distribution system enhancement projects which address future growth-related system constraints as well as system integrity issues and the anticipated timing of expenditures. These proposed projects are preliminary estimates of timing and costs of reinforcement solutions. The scope and needs of these projects can evolve over time with new information requiring ongoing reassessment. Actual solutions may be different due to differences in actual growth patterns and/or construction conditions from those assumed in the initial assessment.

The following discussion provides further information on our key near-term projects:

3203 - East Medford Reinforcement – This project will install a high-pressure (HP) steel line from North Phoenix Road, ending in White City. The total length of the line will be about nine miles. The 2010 project will install approximately 3000 feet of HP main into an open right-of-way in conjunction with road reconstruction by third parties. The remainder of the project, approximately 14,000 feet will be completed in the future.

Observed local growth and our IRP indicate increased gas deliveries will likely be needed from the TransCanada Pipeline source at Phoenix Road Gate Station in southeast Medford. To facilitate distribution receipt of the increased gas volumes, a new HP gas line encircling Medford to the east and tying into an existing high-pressure feeder in White City will improve delivery capacity and provide a much needed reinforcement in the East Medford area which is forecasting higher growth.

3204 - Roseburg Reinforcement – This is a three-part project to bring HP gas into the central and east Roseburg areas. The first phase, completed in 2008, extended HP steel from an existing main located in south Roseburg to the downtown area. The second phase will extend HP pipe to the east side of Roseburg and install a regulator station. The final phase of the project will complete the main extension from south Roseburg to Winston where it will be connected to a new HP source.

The Roseburg distribution system is fed entirely from the west side of town where Northwest Pipeline is located. There is currently no HP source located on the east side of town. Current and projected growth is heavy on the east side of Roseburg, causing pressure problems in the winter months. This project will ease this problem and position the system for future growth.

The scope of this project was modified in 2008. Due to excessive construction costs to complete the previously proposed second phase of the project, an alternate temporary solution was implemented. The sequence for completing the final two phases of the project was changed to fully utilize the 2008 temporary system enhancement while completing the necessary reinforcement for the east side of Roseburg.

3237 – U.S. 2 North Spokane Reinforcement – This project will reinforce the area north of Spokane along U.S. Highway 2. This mixed-use area with residential, commercial and industrial demand experiences low pressure at unpredictable times given varied demand profiles of the diverse customer base. Completion of this reinforcement will improve pressures in the U.S. 2 north Kaiser area. Approximately 8,000 feet of HP steel will be installed in a newly established easement along U.S. Highway 2.

3240 – Grants Pass Reinforcement – This project will extend approximately two miles of HP main from near the existing Jones Creek Gate Station to the downtown Grants Pass area. This project will provide two benefits to our customers. First, it will provide for necessary additional delivery volumes into Grants Pass. Grants Pass high-pressure gas delivery is constrained by the size of the existing distribution main. Secondly, the project will replace a section of HP main that has a number of identified high-consequence areas (HCAs) that must be mitigated under the PHMSA Integrity Management Regulation.

Contingencies include extension of other HP sources into Grants Pass. The identified solution is currently the low cost alternative based on length of pipe installed. Installation of new main as identified allows for a pressure reduction in the existing portion of the HP transmission main into Grants Pass. Installation of the new main avoids integrity management mitigation costs and reduces the consequences and risks associated with a pipeline incident.

3269 – Clarkston Reinforcement – This project will reinforce the southwest area of Clarkston. The existing HP feeder serving the Clarkston Heights area is capacity constrained on a peak day. Reinforcement is required to reliably serve the area. The project will include the installation of 14,400 feet of HP steel main from the existing source in Clarkston to Critchfield Road.

Table 8.1 Distribution Planning Capital Projects

	Ref #	TITLE	Sate	Project Type	Estimated Budget and Timing 2010	2011	2012	2013	Beyond 2013	Total
	3112	Re-Route Kettle Falls Feed & Gate Station	WA	compliance			1,800,000	2,760,000		4,560,000
	3245	Cheney HP Feeder Project	WA	reinforcement				3,600,000		3,600,000
*	3269	Clarkston Reinforcement	WA	reinforcement	2,000,000					2,000,000
*	3237	US2 N Spokane Reinforcement	WA	reinforcement	1,200,000					1,200,000
	3102	N-S Freeway/Gas	WA	road requiremnt	50,000	100,000	100,000	100,000	100,000	450,000
	3107	Bridging the Valley	WA	road requiremnt	50,000	100,000	100,000	100,000	100,000	450,000
	3268	Reinforcement - Appleway Bridge Crossing	WA	reinforcement	275,000					275,000
	3273	Relocation, Stevenson Bridge Bore	WA	enhancement				250,000		250,000
	3260	Reinforcement, Install casing and pipe on Bridge Spokane	WA	reinforcement	100,000					100,000
	3274	Reinforcement, Loop existing HP from Tolo to White City	OR	reinforcement					6,615,000	6,615,000
*	3204	Roseburg Reinforcement	OR	reinforcement		1,934,000	3,347,000			5,281,000
*	3203	East Medford Reinforcement	OR	reinforcement	600,000				4,100,000	4,700,000
	3242	Reinforce Talent OR Gate Station & Piping	OR	reinforcement					3,600,000	3,600,000
*	3240	Grants Pass Reinforcement	OR	reinforcement	2,000,000					2,000,000
	3277	IMP Pipe Replacements Medford	OR	compliance		1,500,000				1,500,000
	3209	Elgin Line Reinforcement	OR	reinforcement					1,500,000	1,500,000
	3267	Rebuild - Jackie St/Winston Gate Station, Roseburg	OR	reinforcement	1,000,000					1,000,000
	TBD	Relocation - N Ross Ln. (2010 Road Project), Medford	OR	road requiremnt	200,000					200,000
	3257	Oakland Bridge Bore and Relocation, Oakland	OR	compliance	180,000					180,000
	3227	Tri-City Hwy 99 Road Project, Roseburg	OR	road requiremnt	150,000					150,000
	3261	Brown Bridge Relocation, Roseburg	OR	road requiremnt	136,000					136,000
	3258	Relocation, Davis Creek, Roseburg	OR	compliance	125,000					125,000
	3213	Altamont & Crosby Road Project, K Falls	OR	road requiremnt	100,000					100,000
	3278	Relocation - Reg Station, Medford	OR	compliance			100,000			100,000
	3276	Reinforcement, Wolf Lodge Tap, Coeur d'Alene	ID	reinforcement					2,700,000	2,700,000
	3246	Chase Rd Gate Station, Post Falls	ID	reinforcement		2,100,000				2,100,000
	3270	Reinforcement - Southeast Coeur d'Alene	ID	reinforcement	255,000	285,000	245,000	450,000		1,235,000
	TBD	Reinforcement - Spirit lake Main, Athol	ID	reinforcement			1,000,000			1,000,000
	3275	Upgrade - Coeur d'Alene East Tap, Coeur d'Alene	ID	reinforcement				700,000		700,000
	3279	Reinforcement - Main Extension south from CDA East Gate	ID	reinforcement			450,000			450,000
	TBD	Reinforcement - Pack Saddle Area, CDA ID	ID	reinforcement	170,000					170,000
	3271	Rebuild - Reg Station, Sandpoint ID	ID	reliability	150,000					150,000
*		Details of project described in IRP			8,741,000	6,019,000	7,142,000	7,960,000	18,715,000	48,577,000

CONCLUSION

Avista’s goal is to maintain its distribution systems to reliably and cost effectively deliver natural gas to every customer. This goal can be achieved with computer modeling, which increases the reliability of the distribution system by identifying specific areas within the system that may require changes.

The ability to meet our goal of reliable cost effective gas delivery is also enhanced through the recent integration of customer growth forecasting at the town code level and localized distribution planning enabling coordinated targeting of distribution projects that are responsive to detailed customer growth patterns.

CHAPTER 9 – ACTION PLAN

2008-2009 ACTION PLAN REVIEW

The 2008-2009 Action Plan focused on the following areas:

- Integrated Resource Portfolio
- Demand Forecasting
- Demand-Side Management
- Supply-Side Resources

A discussion of the specific action items and the plan results follows:

INTEGRATED RESOURCE PORTFOLIO

Action Item:

We will refine our specific resource acquisition action plans for Klamath Falls and Medford service areas that address the projected unserved Expected Case demand in 2011-2012 and 2013-2014, respectively. We will monitor timelines, milestones, status and progress reporting, ongoing plan risk assessment and consideration of alternative actions.

For Klamath Falls we will:

- Reassess the necessary operational steps and timing (current estimate is six months) to acquire the Klamath Falls lateral,
- Monitor actual demand trends to forecasted demand to refine a target date for initiating the purchase of the lateral.

For Medford we will:

- Commission a pipeline expansion study from GTN to identify specific costs and issues,
- Monitor actual demand trends to forecasted demand to refine the timing of action steps,
- Assess the impacts of project timing from possible changes in our weather planning standard.

Results:

The economic downturn and resultant weak demand delayed the projected unserved demand in all of our service territory regions.

Klamath Falls • In 2008, we performed an internal assessment of our standing option to purchase the Klamath Falls lateral from NWP. This agreement requires relocation of maximum daily quantities from Klamath Falls to another point (or points) on NWP's system to maintain our total contract demand. We explored numerous possible areas that might benefit from increased capacity. None are currently constrained and our current assessment does not indicate a resource need in the near term. We also explored the potential for new large demand customers with our marketing team which indicated limited near-term prospects, especially in light of the current economic environment. Although purchasing the lateral benefits our Oregon customers, the lack of actual, anticipated or prospective need for additional capacity that could fulfill the maximum daily quantities relocation requirement (either within the Klamath Falls service territory or elsewhere on the NWP system) restricts the purchase of the lateral at this time.

Medford • Demand trends for Medford have tracked to the low end of our IRP forecasts for some time. We, therefore, have deferred incurring the cost of a formal pipeline expansion study given sufficient time exists to monitor actual demand trends which we have updated in our 2009 IRP.

Action Item:

We will re-evaluate our current peak day weather standard to ascertain if it still provides the best risk-adjusted methodology in evaluating resource planning.

Results:

In re-evaluating our weather standard we performed the following analyses:

- Sensitivities around one and two HDD weather adjustments
- Monte Carlo simulations to analyze probabilities of encountering peak weather
- Applied confidence levels to review upper-limit exposure in conjunction with the regressions performed during our gate station demand and resources work, as well as use per customer coefficient development
- Examined important qualitative factors around safety and reliability

While other planning assumptions allow for continuous monitoring for reasonableness and corrective adjustments over time, peak day weather can occur with no warning which severely limits any response adjustments. Significant safety risk, property damage and inconvenience can occur if actual weather exceeds our peak day weather planning standard. Because there have been limited recent extreme cold weather events, more uncertainty and potential error exists in predicting cold weather usage. The recent actual data we do have on very cold weather events indicate instances when demand has been higher than the projected usage from our regression analysis. Because of these factors, we are maintaining our current "coldest day on record" planning standard for our Expected Case.

Action Item:

We will meet regularly with Commission Staff members to provide information on market activities, material changes to risk management programs, and significant changes in assumptions and/or status of company activity related to the IRP or procurement practices.

Results:

We have met with Commission Staff several times since our last acknowledged IRP to provide information on market activities, risk management programs, the IRP and procurement practices. Schedules permitting, we attempt to meet on a quarterly basis.

DEMAND FORECASTING

Action Item:

We will further integrate the VectorGas™ module in our SENDOUT® modeling software to strengthen our ability to analyze the demand impacts under varying weather and price scenarios as well as conduct sensitivity analysis to identify, quantify, and manage risk around these demand-influencing components.

Results:

VectorGas™ (now incorporated into SENDOUT®) has provided statistically-based analysis in support of our peak day weather standard evaluation. We developed statistical modeling and analysis of potential price outcomes and the impacts on total portfolio cost and alternate resource selections. Looking forward for the next IRP, we are also exploring potential applications for simulating probabilistic weather outcomes in a possible global warming scenario. We continue to review other applications to employ the VectorGas™ analytical tool in our 2011 IRP.

Action Item:

We will study ways to further refine our ability to model demand by region. Town code forecasting was the first step in enhancing our demand forecasting. We now want to explore incorporating these town code forecasts into regions for analysis in SENDOUT®, especially within the broad Washington/Idaho division to investigate potential resource needs that may materialize earlier than the broader region indicates.

Results:

Town code forecasting continues to be an effective method for developing and monitoring expectations for customer growth rates providing benefits beyond the IRP, including corporate budgeting and distribution planning. The use per customer coefficient is the other key driver in determining forecasted demand in SENDOUT®. We have explored several potential methods for developing sub-regional use per customer coefficients that enhance predicting reasonable expectations of forecasted demand while reconciling tightly back to actual results with backcasting.

We use linear regression on daily observable temperature/demand data to produce coefficients. Allocations of monthly customer demand by class are applied to our gate station data as necessary, given few customers have daily metering. Our attempts to build daily town code level coefficients by customer class from allocations of monthly town code level data have not produced satisfactory results. It appears that billing period and cutoff issues are magnified when constructing coefficients with smaller customer groupings. Consequently, unacceptable distortions arise in backcasting to actual demand.

We have been more successful in refining our coefficient development into monthly factors from broader regional data. Using more data points, this method provides improved capturing of the seasonal consumption profile. The regressions on the coldest data points from this method were also used in our reassessment and analysis of our peak day weather standard. Because of the superior backcasting that regional coefficients provide, we will forego sub-regional/town code level use per customer coefficient development at this time.

DEMAND-SIDE MANAGEMENT

Action Item:

The IRP analysis has indicated a set of cost effective measures and achievable resource potential for a future DSM portfolio. We established targets for first-year energy savings goals for 2008 of 1,425,000 therms in Washington/Idaho and 350,000 therms in Oregon. In 2009 the goals for first-year energy savings are 1,581,000 therms in Washington/Idaho and 300,000 therms in Oregon. The completion of the IRP analysis is the midpoint, not the end point, of a larger reassessment of the DSM resource portfolio. Further evaluation is required to facilitate the development of program plans and to incorporate them into an updated DSM implementation plan. Following detailed investigation of the natural gas efficiency technologies identified as cost effective resource options, we will incorporate these efforts into the larger Heritage Project ramp-up of Avista's energy-efficiency efforts.

Results:

Washington/Idaho DSM energy savings achieved in 2008 totaled 1,888,061 therms, reflecting an increase over our initial 2007 IRP goal. Oregon DSM energy savings achieved in 2008 totaled 287,476 therms, a shortfall from our 2008 goal of 350,000 therms. Additional detail around actual-to-goal results is discussed in Appendix 4.1.

Action Item:

We will file our cost effectiveness limits based upon the avoided costs derived from this IRP process.

Additionally, we are investigating the applicability of recently completed quantifications of electric distribution capacity, the customer value of risk reduction and greenhouse gas emissions to determine if similar quantifications are possible for our natural gas system.

Results:

Cost effectiveness limits were filed on June 9, 2008 with an effective date of July 1, 2008.

We reviewed the value components of our electric avoided costs to determine if conceptually there was applicability to our natural gas customers. We have initiated analysis to assess the potential value that our customers place on the value of reduced volatility. This work continues. Regarding quantifying the value customers ascribe to reduced distribution capacity and greenhouse gas emissions, we concluded quantifications were not reliably determinable.

SUPPLY-SIDE RESOURCES

Action Item:

We will continue to monitor several issues identified in this chapter with respect to commodity, storage and supply resources. These include:

- Tight production/productive capacity
- Pipeline constraints in our region
- Pipeline expansions that move volumes away from our region
- Pipeline cost escalations
- Large scale LNG activity

Results:

Through our various information sources (retainer services, industry publications, seminars, and conversations with industry participants) we monitor ongoing developments on the above items. The following are brief summaries of our current assessments:

Tight production/productive capacity – The economic downturn has dramatically reversed this previously very tight situation, producing significant excess capacity. Massive rig count reduction in response to demand destruction has significant potential to overshoot when demand stabilizes, triggering a return to very tight conditions, prompting spikes in prices and volatility.

Pipeline constraints in our region – Several regional pipeline projects were proposed in early 2008. We monitor their progress and assess how they may fit into our resource strategy. We currently have non-binding participation agreements on some of these projects.

Pipeline expansions that move volumes away from our region – Rockies Express eastward expansion has experienced some delays but will ultimately facilitate more Rockies production to reach East Coast markets.

Pipeline cost escalations – Much lower steel commodity prices and delayed/cancelled projects appear to have reversed the cost-escalation trend in the near term.

Large scale LNG activity – Regional proposed projects continue to be challenged by regional market prices that trade at a discount to other potential markets for LNG as well as complex environmental issues.

Action Item:

We will refine our analysis of acquiring or constructing resource alternatives to improve project cost estimating, assessment of project feasibility issues, determination of project siting issues and risks, and improved accuracy of construction/acquisition lead times. Specifically, we will further study these issues with respect to satellite LNG, company owned LNG, pipeline expansions, distribution system enhancements and storage facility diversification.

We will explore creative, non-traditional resource possibilities to address our needle peaking exposures with emphasis on potential structured transactions (e.g. transportation and storage exchanges) with neighboring utilities and other market participants that leverage existing regional infrastructure as an alternative to incremental infrastructure additions.

Results:

Given likely deferred resource needs, we have deferred any expenditure for formal cost and project feasibility studies. We have collected information from publicly available sources and informal inquiries. We also have gained insights on expansion rates/costs/timelines from our non-binding participation in various proposed interstate pipeline projects. This information provides useful proxies for project costs for use in resource modeling.

Although the easing of regional demand correspondingly eases the urgency for needle peaking solutions in the near term, we continue to evaluate the region’s participants and their resources for possible transactions. We have engaged in discussions with a neighboring utility regarding a potential mutual assistance agreement around transport assets with dialogue continuing. We also receive and solicit information on various structured product transactions.

Action Item:

We will continue to assess methods for capturing additional value related to existing storage assets, including methods of optimizing recently recalled releases while implementing its storage strategy of providing balanced storage opportunities. This includes exploring storage diversification options including AECO and northern California facilities.

Results:

We periodically see solicitations for storage leasing. We evaluate the project economics and consider our resource needs. In some cases, we have placed bids; however, our bids have not been selected. We have entered into a month-to-month storage agreement at Clay Basin for interruptible service which facilitates daily/short-term demand balancing for scheduling. Finally, we continue to engage in intra-seasonal optimization tractions as market pricing conditions warrant to capture value for our customers.

Action Item:

We will continue to analyze natural gas procurement practices for strategy-enhancing ideas such as basis diversification, storage injection/withdrawal timing and structured products.

Results:

Our annual procurement plan development process undertaken each fall provides a comprehensive assessment of existing and potential new procurement practices and strategies. The result is a targeted but flexible procurement plan that serves as a base to evaluate changing conditions throughout the year and modify strategy and actions as necessary.

Action Item:

Since much of our supply comes from Canadian natural gas exports, the notion that this supply could diminish significantly is of concern. We will continue to monitor the discussion around diminishing Canadian gas exports, looking for signals that indicate increased risk of disrupted supply over the 20-year planning horizon.

Results:

We utilize multiple information sources to monitor and track developments on declining Canadian exports including our retainer services, industry news subscriptions, seminars and market pricing behavior. Historical information from the Energy Information Administration indicates a rebound in export volumes in recent months following a decade low volume in June 2008. Lower oil sands production in the face of sharp oil price declines is likely a significant factor in this near-term trend reversal. Longer term, we see the oil/gas price relationship as a primary driver of Canadian domestic natural gas demand and correspondingly, export volumes. Significant unconventional gas discoveries in British Columbia have both the potential to reverse export declines with prolific potential production or accelerate export declines if these volumes are diverted to oil sands extraction in a high oil price environment.

In our 2009 IRP, we included sensitivity analysis on estimated price implications resulting from a more severe decline in Canadian exports than included in our base price forecasts. We then included a price adder in alternate demand scenarios. Additional detail is contained in Chapter 3 and Appendices 3.6 and 3.7.

2010-2011 ACTION PLAN

Key components for our 2010-2011 Action Plan include:

Action Item:

Monitor actual demand closely for indications of faster growth exceeding our forecasted growth to respond aggressively to address potential accelerated resource deficiencies arising from our exposure to "flat demand" risk. This includes researching and refining the evaluation of resource alternatives, including implementation risk factors and timelines, updated cost estimates, and feasibility assessments, targeting options for the service territories with nearer-term unserved demand exposure.

Action Item:

Analyze actual use per customer data and DSM program results for indications of price elasticity response trends that may have been influenced by evolving economic conditions. Investigate contemporary analytical sources for information on natural gas price elasticity. Explore persuading the AGA to update their analytical work and/or consider hiring a third party price elasticity study including assessing interest of other utilities in pursuing a regional project.

Action Item:

Continue our pursuit of cost effective demand-side solutions to reduce demand. In Washington and Idaho, conservation measures are targeted to reduce demand by approximately 2,193,000 therms in the first year. In Oregon conservation measures are targeted to reduce demand by approximately 303,000 therms in the first year. These goals represent increases of 54 percent in Washington and Idaho and 1 percent in Oregon from our prior 2007 IRP.

Action Item:

Research and engage a conservation consultant to perform an updated assessment of conservation technical and achievable potential in our service territories prior to the next IRP.

Action Item:

As much of our supply comes from Canadian natural gas exports, the notion that this supply could diminish significantly remains a concern. We will continue to monitor the discussion around diminishing Canadian gas exports looking for signals that indicate increased risk of disrupted supply over the 20-year planning horizon.

Action Item:

We believe our forecasting methodology is sound, cost effective and adequate but will explore and evaluate alternative and additional forecasting methodologies for potential inclusion in our next IRP. Methodologies to be evaluated include statistical, non-statistical, quantitative, qualitative and terrain overview approaches.

Action Item:

We will meet regularly with Commission Staff members to provide information on market activities, material changes to risk management programs, and significant changes in assumptions and/or status of company activity related to the IRP or procurement practices.

CHAPTER 10 – GLOSSARY OF TERMS AND ACRONYMS

Achievable Potential
Represents a realistic assessment of expected energy savings recognizing and accounting for economic and other constraints that preclude full installation of every identified conservation measure.

Annual Measures
Conservation measures that achieve generally uniform year round energy savings independent of weather temperature changes. Annual measures are also often called base load measures.

Avista
The regulated Operating Division of Avista Corp.; separated into north (Washington and Idaho) and south (Oregon) regions; Avista Utilities generates, transmits and distributes electricity in addition to the transmission and distribution of natural gas.

Backhaul
A transaction where gas is transported the opposite direction of normal flow on a unidirectional pipeline.

Base Load
As applied to natural gas, a given demand for natural gas that remains fairly constant over a period of time, usually not temperature sensitive.

Base Load Measures
Conservation measures that achieve generally uniform year round energy savings independent of weather temperature changes. Base load measures are also often called annual measures.

Basis Differential
The difference in price between any two natural gas pricing points or time periods. One of the more common references to basis differential is the pricing difference between Henry Hub and any other pricing point in the continent.

British Thermal Unit (BTU)
The amount of heat required to raise the temperature of one pound of pure water one degree Fahrenheit under stated conditions of pressure and temperature; a therm (see below) of natural gas has an energy value of 100,000 BTUs and is approximately equivalent to 100 cubic feet of natural gas.

City Gate (also known as gate station or pipeline delivery point)
The point at which natural gas deliveries transfer from the interstate pipelines to Avista’s distribution system.

Compression
Increasing the pressure of natural gas in a pipeline by means of a mechanically driven compressor station to increase flow capacity.

Conservation Measures
Installations of appliances, products or facility upgrades that result in energy savings.

Contract Demand (CD)
The maximum daily, monthly, seasonal or annual quantities of natural gas, which the supplier agrees to furnish, or the pipeline agrees to transport, and for which the buyer or shipper agrees to pay a demand charge.

Core Load
Firm delivery requirements of Avista, which are comprised of residential, commercial and firm industrial customers.

Cost Effectiveness
The determination of whether the present value of the therm savings for any given conservation measure is greater than the cost to achieve the savings.

CPI
Consumer Price Index, as calculated and published by the U.S. Department of Labor, Bureau of Labor Statistics

Cubic Foot (cf)
A measure of natural gas required to fill a volume of one cubic foot under stated conditions of temperature, pressure and water vapor; one cubic foot of natural gas has the energy value of approximately 1,000 BTUs and 100 cubic feet of natural gas equates to one therm (see below).

Curtailment
A restriction or interruption of natural gas supplies or deliveries; may be caused by production shortages, pipeline capacity or operational constraints or a combination of operational factors.

Dekatherm
Unit of measurement for natural gas; a dekatherm is 10 therms, which is one thousand cubic feet (volume) or one million BTUs (energy).

Demand-Side Management (DSM)
The activity pursued by an energy utility to influence its customers to reduce their energy consumption or change their patterns of energy use away from peak consumption periods.

Demand-Side Resources
Energy resources obtained through assisting customers to reduce their "demand" or use of natural gas. Also represents the aggregate energy savings attained from installation of conservation measures.

Dth
Unit of measurement for natural gas; a dekatherm is 10 therms, which is one thousand cubic feet (volume) or one million BTUs (energy).

External Energy Efficiency Board
Also known as the "Triple-E" board, this non-binding external oversight group was established in 1999 to provide Avista with input on DSM issues.

Externalities
Cost and benefits that are not reflected in the price paid for goods or services.

Federal Energy Regulatory Commission (FERC)
The government agency charged with the regulation and oversight of interstate natural gas pipelines, wholesale electric rates and hydroelectric licensing; the FERC regulates the interstate pipelines with which Avista does business and determines rates charged in interstate transactions.

Firm Service
Service offered to customers under schedules or contracts that anticipate no interruptions; the highest quality of service offered to customers.

Force Majeure
An unexpected event or occurrence not within the control of the parties to a contract, which alters the application of the terms of a contract; sometimes referred to as "an act of God;" examples include severe weather, war, strikes, pipeline failure and other similar events.

Forward Price
The future price for a quantity of natural gas to be delivered at a specified time.

Gas Transmission Northwest (GTN)
A subsidiary of TransCanada Pipeline which owns and operates a natural gas pipeline that runs from the Canada/USA border to the Oregon/California border. One of the six natural gas pipelines Avista transacts with directly.

Geographic Information System (GIS)
A system of computer software, hardware and spatially referenced data that allows information to be modeled and analyzed geographically.

Global Insight, Inc.
A national economic forecasting company.

Heating Degree Day (HDD)
A measure of the coldness of the weather experienced, based on the extent to which the daily average temperature falls below 65 degrees Fahrenheit; a daily average temperature represents the sum of the high and low readings divided by two.

Henry Hub
The physical location found in Louisiana that is widely recognized as the most important pricing point in the United States. It is also the trading hub for the New York Mercantile Exchange (NYMEX).

Injection
The process of putting natural gas into a storage facility; also called liquefaction when the storage facility is a liquefied natural gas plant.

Integrity Management Plan
A federally regulated program that requires companies to evaluate the integrity of their natural gas pipelines based on population density. The program requires companies to identify high consequence areas, assess the risk of a pipeline failure in the identified areas and provide appropriate mitigation measures when necessary.

Interruptible Service
A service of lower priority than firm service offered to customers under schedules or contracts that anticipate and permit interruptions on short notice; the interruption happens when the demand of all firm customers exceeds the capability of the system to continue deliveries to all of those customers.

IPUC
Idaho Public Utilities Commission

IRP
Integrated Resource Plan; the document that explains Avista's plans and preparations to maintain sufficient resources to meet customer needs at a reasonable price.

Jackson Prairie
An underground storage project jointly owned by Avista Corp., Puget Sound Energy, and NWP; the project is a naturally occurring aquifer near Chehalis, Washington, which is located some 1,800 feet beneath the surface and capped with a very thick layer of dense shale.

Liquefaction
Any process in which natural gas is converted from the gaseous to the liquid state; for natural gas, this process is accomplished through lowering the temperature of the natural gas (see LNG).

Liquefied Natural Gas (LNG)
Natural gas that has been liquefied by reducing its temperature to minus 260 degrees Fahrenheit at atmospheric pressure.

Linear Programming
A mathematical method of solving problems by means of linear functions where the multiple variables involved are subject to constraints; this method is utilized in the SENDOUT® Gas Model.

Load Duration Curve
An array of daily send outs observed that is sorted from highest send out day to lowest to demonstrate both the peak requirements and the number of days it persists.

Load Factor
The average load of a customer, a group of customers, or an entire system, divided by the maximum load; can be calculated over any time period.

Local Distribution Company (LDC)
A utility that purchases natural gas for resale to end-use customers and/or delivers customer's natural gas or electricity to end users' facilities.

Looping
The construction of a second pipeline parallel to an existing pipeline over the whole or any part of its length, thus increasing the capacity of that section of the system.

MCF
A unit of volume equal to a thousand cubic feet.

MDQ
Maximum Daily Quantity.

MMbtu
A unit of heat equal to one million British thermal units (BTUs) or 10 therms. Can be used interchangeably with Dth.

National Energy Board
The Canadian equivalent to the Federal Energy Regulatory Commission (FERC).

National Oceanic Atmospheric Administration (NOAA)
Publishes the latest weather data; the 30-year weather study included in this IRP is based on this information.

Natural Gas
A naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in porous geologic formations beneath the earth's surface, often in association with petroleum; the principal constituent is methane, and it is lighter than air.

New York Mercantile Exchange (NYMEX)
An organization that facilitates the trading of several commodities including natural gas.

Nominal
Discounting method that includes inflation.

Nomination
The scheduling of daily natural gas requirements.

Non-Coincidental Peak Demand
The demand forecast for a 24-hour period for multiple regions that includes at least one peak day and one non-peak day.

Non-Firm Open Market Supplies
Natural gas purchased via short-term purchase arrangements; may be used to supplement firm contracts during times of high demand or to displace other volumes when it is cost-effective to do so; also referred to as spot market supplies.

Northwest Pipeline Corporation (NWP)
A principal interstate pipeline serving the Pacific Northwest and one of six natural gas pipelines Avista transacts with directly. NWP is a subsidiary of The Williams Companies and is headquartered in Salt Lake City, Utah.

NOVA Gas Transmission (NOVA)
See TransCanada Alberta System

Northwest Power and Conservation Council (NPCC)
A regional energy planning and analysis organization headquartered in Portland, Ore.

OPUC
Public Utility Commission of Oregon

Peak Day
The greatest total natural gas demand forecasted in a 24-hour period used as a basis for planning peak capacity requirements.

Peak Day Curtailment
Curtailment imposed on a day-to-day basis during periods of extremely cold weather when demands for natural gas exceed the maximum daily delivery capability of a pipeline system.

Peaking Capacity
The capability of facilities or equipment normally used to supply incremental natural gas under extreme demand conditions (i.e. peaks); generally available for a limited number of days at this maximum rate.

Peaking Factor
A ratio of the peak hourly flow and the total daily flow at the city-gate stations used to convert daily loads to hourly loads.

Prescriptive Measures
Avista's DSM tariffs require the application of a formula to determine customer incentives for natural gas-efficiency projects. For commonly encountered efficiency applications that are relatively uniform in their characteristics the utility has the option to define a standardized incentive based upon the typical application of the efficiency measure. This standardized incentive takes the place of a customized calculation for each individual customer. This streamlining reduces both the utility and customer administrative costs of program participation and enhances the marketability of the program.

Psig
Pounds per square inch gauge • a measure of the pressure at which natural gas is delivered.

Rate Base
The investment value established by a regulatory authority upon which a utility is permitted to earn a specified rate of return; generally this represents the amount of property used and useful in service to the public.

Real
Discounting method that excludes inflation.

Resource Stack
Sources of natural gas infrastructure or supply available to serve Avista's customers.

Seasonal Capacity
Natural gas transportation capacity designed to service in the winter months.

Sendout
The amount of natural gas consumed on any given day.

SENDOUT®
Natural gas planning system from Ventix; a linear programming model used to solve gas supply and transportation optimization questions.

Service Area
Territory in which a utility system is required or has the right to provide natural gas service to ultimate customers.

Spot Market Gas
Natural gas purchased under short-term agreements as available on the open market; prices are set by market pressure of supply and demand.

Storage
The utilization of facilities for storing natural gas which has been transferred from its original location for the purposes of serving peak loads, load balancing and the optimization of basis differentials; the facilities are usually natural geological reservoirs such as depleted oil or natural gas fields or water-bearing sands sealed on the top by an impermeable cap rock; the facilities may be man-made or natural caverns. LNG storage facilities generally utilize above ground insulated tanks.

Tariff
A published volume of regulated rate schedules plus general terms and conditions under which a product or service will be supplied.

TF-I
NWP's rate schedule under which Avista moves natural gas supplies on a firm basis.

TF-2
NWP's rate schedule under which Avista moves natural gas supplies out of storage projects on a firm basis.

Technical Advisory Committee (TAC)
Industry, customer and regulatory representatives that advise Avista during the IRP planning process.

Technical Potential
An estimate of all energy savings that could theoretically be accomplished if every customer that could potentially install a conservation measure did so without consideration of market barriers such as cost and customer awareness.

Therm
A unit of heating value used with natural gas that is equivalent to 100,000 British thermal units (BTU); also approximately equivalent to 100 cubic feet of natural gas.

Town Code
A town code is an unincorporated area within a county and a municipality within a county served by Avista natural gas retail services.

TransCanada Alberta System
Previously known as NOVA Gas Transmission; a natural gas gathering and transmission corporation in Alberta that delivers natural gas into the TransCanada BC System pipeline at the Alberta/British Columbia border; one of six natural gas pipelines Avista transacts with directly.

TransCanada BC System
Previously known as Alberta Natural Gas; a natural gas transmission corporation of British Columbia that delivers natural gas between the TransCanada-Alberta System and GTN pipelines that runs from the Alberta/British Columbia border to the United States border; one of six natural gas pipelines Avista transacts with directly.

Transportation Gas
Natural gas purchased either directly from the producer or through a broker and is used for either system supply or for specific end-use customers, depending on the transportation arrangements; NWP and GTN transportation may be firm or interruptible.

Tuscarora Gas Transmission Company
Tuscarora is a subsidiary of Sierra Pacific Resources and TransCanada; this natural gas pipeline runs from the Oregon/California border to Reno, Nevada; one of the six natural gas pipelines Avista transacts with directly;

Vaporization
Any process in which natural gas is converted from the liquid to the gaseous state.

Weighted Average Cost of Gas (WACOG)
The price paid for a volume of natural gas and associated transportation based on the prices of individual volumes of natural gas that make up the total quantity supplied over an established time period.

Weather Normalization
The estimation of the average annual temperature in a typical or "normal" year based on examination of historical weather data; the normal year temperature is used to forecast utility sales revenue under a procedure called sales normalization.

Weather Sensitive Measures
Conservation measures whose energy savings are influenced by weather temperature changes. Weather sensitive measures are also often referred to as winter measures.

Winter Measures
Conservation measures whose energy savings are influenced by weather temperature changes. Winter measures are also often referred to as weather sensitive measures.

Withdrawal
The process of removing natural gas from a storage facility, making it available for delivery into the connected pipelines; vaporization is necessary to make withdrawals from an LNG plant.

WUTC
Washington Utilities and Transportation Commission.

2009

Natural Gas Integrated Resource Plan Appendices

December 31, 2009

www.avistautilities.com

AVISTA

AVISTA CORPORATION

2009 NATURAL GAS
INTEGRATED RESOURCE PLAN
APPENDICIES

TABLE OF CONTENTS

APPENDIX 1.1

TAC MEMBERS

Appendix 1.1
2009 IRP TAC Member List

Name	Organization
Bob Jenks	Oregon CUB
Bruce Folsom	Avista
Carrie Dolwick	NW Energy
Chau Lau	Cascade Natural Gas Company
Dan Kirschner	Northwest Gas Association
Dave Allred	Northwest Pipeline
Dave Sloan	Gas Transmission Northwest
David Nightingale	WUTC
Deborah Reynolds	WUTC
Greg Rahn	Avista
Gurvinder Singh	Puget Sound Energy
Inara Scott	Northwest Natural
Joe Ross	Gas Transmission Northwest
Jon Powell	Avista
Kelly Irvine	Avista
Ken Ross	Terasen Gas
Kerry Shroy	Avista
Ken Zimmerman	OPUC
Kevin Christie	Avista
Lea Daischel	Washington Attorney General's Office
Linda Gervais	Avista
Lisa Gorsuch	OPUC
Lori Hermanson	Avista
Lynn Kittilson	OPUC
Mark Sellers-Vaughn	Cascade Natural Gas Company
Matt Elam	IPUC
Megan Clark	Northwest Gas Association
Paula Pyron	Northwest Industrial Gas Users
Randy Barcus	Avista
Rich Cowan	Gas Transmission Northwest
Steven Johnson	WUTC
Steven Simmons	Northwest Natural
Terrence Browne	Avista
Terri Carlock	IPUC
Terry Morlan	Northwest Power and Conservation Coucil
Vonda Novak	WUTC

APPENDIX 1.2

WORK PLAN

Avista Corporation 2009 Natural Gas Integrated Resource Plan
Work Plan

IRP Work Plan Requirements

Section 480-90-238 (4), of the natural gas Integrated Resource Plan ("IRP") rules, specify requirements for the IRP Work Plan:

> Not later than twelve months prior to the due date of a plan, the utility must provide a work plan for informal commission review. The work plan must outline the content of the integrated resource plan to be developed by the utility and the method for assessing potential resources.

Additionally, Section 480-90-238 (5) of the WAC states:

The work plan must outline the timing and extent of public participation.

Overview

This Work Plan outlines the process Avista will follow to complete its 2009 Natural Gas IRP by December 31, 2009. Avista uses a public process to obtain technical expertise and guidance throughout the planning period via Technical Advisory Committee (TAC) meetings. The TAC provided input into this work plan and will be providing input into assumptions, scenarios, and modeling techniques.

Process

The 2009 IRP process will be similar to that used to produce the previously published plan. Avista will use SENDOUT® (a PC based linear programming model widely used to solve natural gas supply and transportation optimization questions) to develop the risk adjusted least-cost resource mix for the 20 year planning period.

For this plan, Avista intends to incorporate action plan items identified in the 2007 Natural Gas IRP including regional demand modeling, weather standard evaluation, Canadian natural gas imports monitoring, and analyze (using SENDOUT® and VectorGas™) realistic alternative situations in which the company may have to operate during the next 20 years. VectorGas™ is the Monte Carlo risk assessment element of SENDOUT® which evaluates the cost and reliability impact of market price and demand volatility.

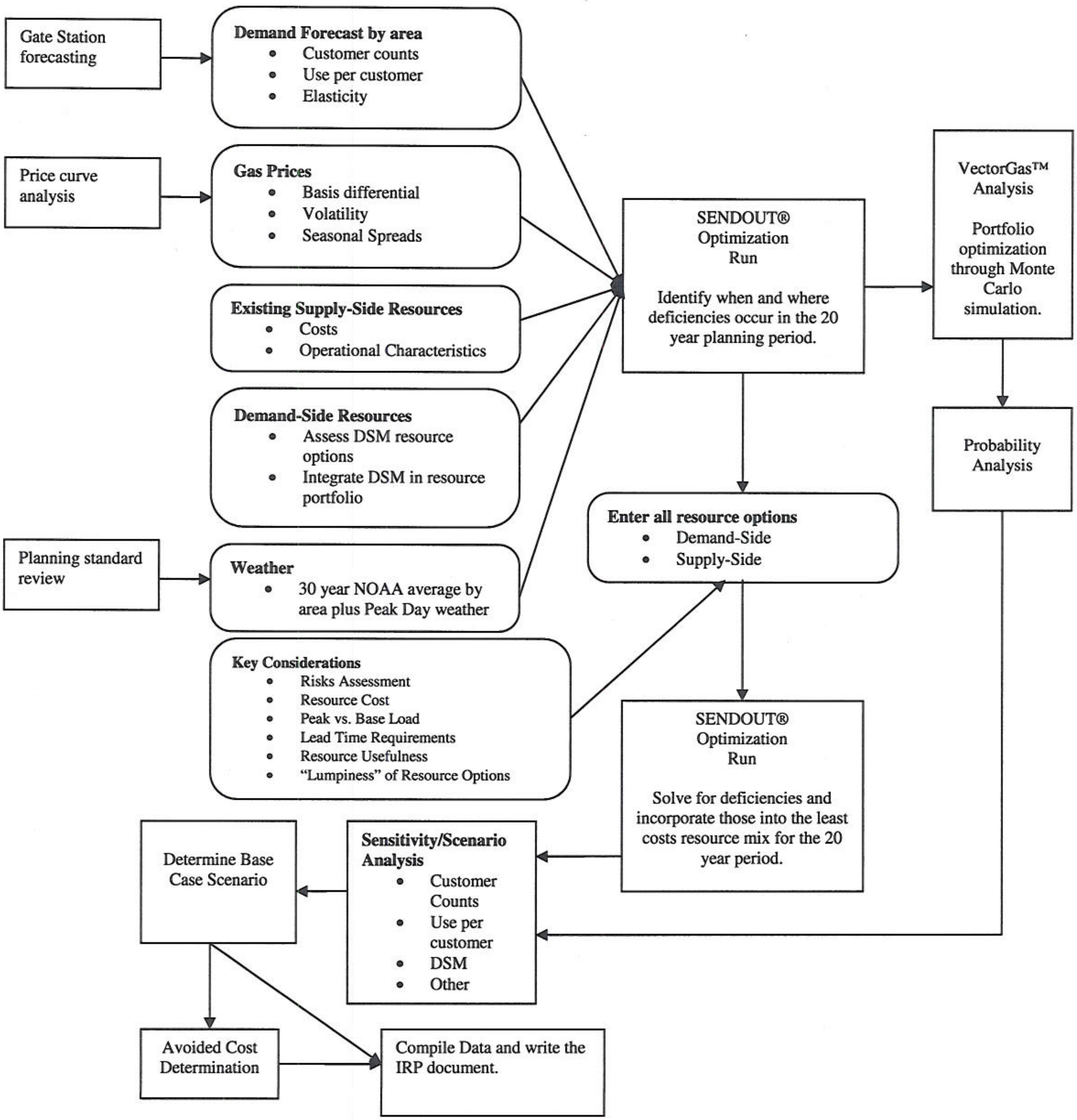
This plan will continue to include demand analysis, detailed demand side management program analysis and avoided cost determination, distribution planning, existing and potential supply-side resource analysis and resource integration. Further details about Avista's process for determining the risk adjusted least-cost resource mix is shown in Exhibit 1.

Timeline

The following is Avista's TENTATIVE 2009 Natural Gas IRP timeline:

- **December 29, 2008** – Work Plan filed with WUTC
- **April through July 2009** – Technical Advisory Committee meetings (exact meeting dates ***subject to change***). Meeting topics will include:
  - Demand Forecast & Demand-Side Management – April 28
  - Distribution Planning & Supply/Infrastructure – May 19
  - SENDOUT® Preliminary Output Results and Potential Case Discussion – June 16
  - SENDOUT® and VectorGas™ results – July 16
- **September 1, 2009 –** Draft of IRP document to TAC
- **October 30, 2009 –** Comments on draft due back to Avista
- **November 6, 2009 –** TAC final review meeting (if necessary)
- **December 31, 2009 –** File finalized IRP document

Exhibit 1: Avista's 2009 Natural Gas IRP Modeling Process



APPENDIX 2.1

IRP REGULATORY GUIDELINES

Appendix 2.1 IDAHO Public Utility Commission IRP Policies and Guidelines - ORDER NO. 25342

REF #	DESCRIPTION OF REQUIREMENT	FULLFILLMENT OF REQUIREMENT
1	Purpose and Process. Each gas utility regulated by the Idaho Public Utilities Commission with retail sales of more than 10,000,000,000 cubic feet in a calendar year (except gas utilities doing business in Idaho that are regulated by contract with a regulatory commission of another State) has the responsibility to meet system demand at least cost to the utility and its ratepayers. Therefore, an ‘‘integrated resource plan’’ shall be developed by each gas utility subject to this rule.	Avista prepares a comprehensive 20 year Integrated Resource Plan every two years. Avista will be filing its 2009 IRP on or before December 31, 2009.
2	Definition. Integrated resource planning. ‘‘Integrated resource planning’’ means planning by the use of any standard, regulation, practice, or policy to undertake a systematic comparison between demand-side management measures and the supply of gas by a gas utility to minimize life-cycle costs of adequate and reliable utility services to gas customers. Integrated resource planning shall take into account necessary features for system operation such as diversity, reliability, dispatchability, and other factors of risk and shall treat demand and supply to gas consumers on a consistent and integrated basis.	Avista's IRP brings together dynamic demand forecasts and matches them against demand-side and supply-side resources in order to evaluate the least cost/best risk portfoio for its core customers.
3	Elements of Plan. Each gas utility shall submit to the Commission on a biennial basis an integrated resource plan that shall include:	2009 IRP to be filed on or before Dec 31, 2009 within 2 years of our 2007 IRP filing.
a.	A range of forecasts of future gas demand in firm and interruptible markets for each customer class for one, five, and twenty years using methods that examine the effect of economic forces on the consumption of gas and that address changes in the number, type and e-fficiency of gas end-uses.	See **Chapter 3 - Demand Forecasts** and **Appendix 2.1 et. al.** for a detailed discussion of how demand was forecasted for this IRP.
b.	An assessment for each customer class of the technically feasible improvements in the efficient use of gas, including load management, as well as the policies and programs needed to obtain the efficiency improvements.	See **Chapter 4 - Demand Side Management** and **DSM Appendicies 4.1 et.al.** for detailed information on the DSM measures evaluated and selected for this IRP and the implementation process.

Appendix 2.1 IDAHO Public Utility Commission IRP Policies and Guidelines - ORDER NO. 25342

REF #	DESCRIPTION OF REQUIREMENT	FULLFILLMENT OF REQUIREMENT
c.	An analysis for each customer class of gas supply options, including: (1) a projection of spot market versus long-term purchases for both firm and interruptible markets; (2) an evaluation of the opportunities for using company-owned or contracted storage or production; (3) an analysis of prospects for company participation in a gas futures market; and (4) an assessment of opportunities for access to multiple pipeline suppliers or direct purchases from producers.	See **Chapter 5 - Supply-Side Resources** for details about the market, storage, and pipeline transportation as well as other resource options considered in this IRP. See also the procurement plan section in this same chapter for supply procurement strategies.
d.	A comparative evaluation of gas purchasing options and improvements in the efficient use of gas based on a consistent method for calculating cost-effectiveness.	See Methodology section of **Chapter 4 - Demand-Side Resources** where we describe our process on how demand-side and supply-side resources are compared on par with each other in the SENDOUT® model.
e.	The integration of the demand forecast and resource evaluations into a long-range (e.g., twenty-year) integrated resource plan describing the strategies designed to meet current and future needs at the lowest cost to the utility and its ratepayers.	See **Chapter 6 - Integrated Resource Portfolio** for details on how we model demand and supply coming together to provide the least cost/best risk portfolio of resources.
f.	A short-term (e.g., two-year) plan outlining the specific actions to be taken by the utility in implementing the integrated resource plan.	See **Chapter 8 - Action Plan** for actions to be taken in implementing the IRP.
4	Relationship Between Plans. All plans following the initial integrated resource plan shall include a progress report that relates the new plan to the previously filed plan.	Avista strives to meet at least quarterly with Staff and/or Commisioners to discuss the state of the market, procurement planning practices, and any other issues that may impact resource needs or other analysis within the IRP.
5	Plans to Be Considered in Rate Cases. The integrated resource plan will be considered with other available information to evaluate the performance of the utility in rate proceedings before the Commission.	We prepare and file our plan in part to establish a public record of our plan.
6	Public Participation. In formulating its plan, the gas utility must provide an opportunity for public participation and comment and must provide methods that will be available to the public of validating predicted performance.	Avista held four Technical Advisory Committee meetings beginning in April and ending in August. See **Chapter 1 - Introduction** for more detail about public participation in the IRP process.

Appendix 2.1 IDAHO Public Utility Commission IRP Policies and Guidelines - ORDER NO. 25342

REF #	DESCRIPTION OF REQUIREMENT	FULLFILLMENT OF REQUIREMENT
7	Legal Effect of Plan. The plan constitutes the base line against which the utility's performance will ordinarily be measured. The requirement for implementation of a plan does not mean that the plan must be followed without deviation. The requirement of implementation of a plan means that a gas utility, having made an integrated resource plan to provide adequate and reliable service to its gas customers at the lowest system cost, may and should deviate from that plan when presented with responsible, reliable opportunities to further lower its planned system cost not anticipated or identified in existing or earlier plans and not undermining the utility's reliability. In order to encourage prudent planning and prudent deviation from past planning when presented with opportunities for improving upon a plan, a gas utility's plan must be on file with the Commission and available for public inspection. But the filing of a plan does not constitute approval or disa-pproval of the plan having the force and effect of law, and deviation from the plan would not constitute violation of the Commission's Orders or rules. The prudence of a utility's plan and the utility's prudence in following or not following a plan are matters that may be considered in a general rate proceeding or other proce-edings in which those issues have been noticed.	See section titled "Avista's Procurement Plan" in **Chapter 5 - Supply-Side Resources**. Among other details we discuss plan revisions in response to changing market conditions. See also section titled "Alternate Supply-Side Scenarios" in **Chapter 6 - Integrated Resource Portfolio** where we discuss different supply portfolios that are resonsive to changing assumptions about resource alternatives.

Appendix 2.1 Oregon Public Utility Commission IRP Standard and Guidelines – Order 07- 002

Guideline Number	Description of Requirement	Fulfillment of Requirement
Guideline 1: Substantive Requirements		
1.a.1	All resources must be evaluated on a consistent and comparable basis.	All resource options including demand-side and supply-side are modeled in SENDOUT® utilizing the same common general assumptions, approach and methodology.
1.a.2	All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.	Avista considered a range of resources including demand-side management, distribution system enhancements, interstate pipeline transportation, transport backhauls, and storage options including liquefied natural gas. Chapter 4 and Appendix 4.3 documents Avista's demand-side management resources considered. Chapter 5 and Appendix 6.3 documents supply-side resources. Chapter 6 documents how Avista developed and assessed each of these resources.
1.a.3	Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.	Avista considered various combinations of technologies, lead times, in-service dates, durations, and locations. Chapter 6 provides details about the modeling methodology and results. Chapter 5 describes resource attributes and Appendix 6.3 summarizes the resources' lead times, in-service dates and locations.
1.a.4	Consistent assumptions and methods should be used for evaluation of all resources.	Appendix 6.2 documents general assumptions used in Avista's SENDOUT® modeling software. All portfolio resources both demand and supply-side were evaluated within SENDOUT® using the same sets of inputs.
1.a.5	The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.	Avista applied its after-tax WACC of 4.18% to discount all future resource costs. (See general assumptions at Appendix 6.2)
1.b.1	Risk and uncertainty must be considered. Electric utilities only	Not Applicable
1.b.2	Risk and uncertainty must be considered. Natural gas utilities should consider demand (peak, swing and base-load), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas (GHG) emissions.	After considering the influencers on demand, Avista performed 15 sensitivities on demand. From there nine demand scenarios were developed (Table 1.1) for SENDOUT® modeling purposes. Monthly demand coefficients were developed for base, heating demand (Appendix 3.3) while peak demand was contemplated through modeling a weather planning standard of the coldest day on record (see heating degree day data in Appendix 3.4). Avista evaluated several price forecasts (Figure 6.3) and selected high, medium and low price scenarios for modeling purposes (Figures 6.4 & 6.5).

Guideline Number	Description of Requirement	Fulfillment of Requirement
		An updated price forecast was also analyzed as it incorporated more current market conditions. This forecast became our expected case forecast and is also shown in Figures 6.4 & 6.5. Four supply scenarios were also evaluated, see Table 5.3. These supply scenarios were combined with demand scenarios in order to establish portfolios for evaluation. Ultimately 13 portfolios were evaluated. Avista also ran Monte Carlo simulations using VectorGas™ for price and weather variables to analyze demand sensitivity to weather and to quantify the risk to customers under varying price environments. Avista considered GHG emissions regulatory compliance costs in Appendix 4.2 .
	Utilities should identify in their plans any additional sources of risk and uncertainty.	Avista evaluated additional risks and uncertainties. Risks associated with the planning environment are detailed in Chapter 1 Introduction. Avista also analyzed demand risk which is detailed in Chapter 3. Chapter 4 discusses the uncertainty around how much DSM is achievable. Supply-side resource risks are discussed in Chapter 5. Chapter 6 discusses the variables modeled for scenario and stochastic risk analysis.
1c	The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.	Avista evaluated cost/risk tradeoffs for each of the risk analysis portfolios considered. See Chapter 6 and supporting information at Appendix 6.8 for Avista's portfolio risk analysis and determination of the preferred portfolio.
	The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.	Avista used a 20-year study period for portfolio modeling. Avista contemplated possible costs beyond the planning period that could affect rates including end effects such as infrastructure decommission costs and concluded there were no significant costs reasonably likely to impact rates under different resource selection scenarios.
	Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs of all long-lived resources such as power plants, gas storage facilities and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.	Avista's SENDOUT® modeling software utilizes a PVRR cost metric methodology applied to both long and short-lived resources.

Guideline Number	Description of Requirement	Fulfillment of Requirement
	To address risk, the plan should include at a minimum: 1) Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes. 2) Discussion of the proposed use and impact on costs and risks of physical and financial hedging.	Avista, through its VectorGas™ software, modeled 200 scenarios around varying gas price inputs via Monte Carlo iterations developing a distribution of Total 20 year cost estimates utilizing SENDOUT®'s PVRR methodology. Chapter 6 further describes this analysis while Figure 6.35 summarizes this analysis graphically. The variability of costs is plotted against the Expected Case while the scenarios beyond the 95^{th} percentile capture the severity of bad outcomes. Chapter 5 discusses Avista's physical and financial hedging methodology.
	The utility should explain in its plan how its resource choices appropriately balance cost and risk.	Chapter 6 Regulatory Requirements section summarizes the results of Avista's cost/risk tradeoff analysis considered throughout the IRP process. Chapter 5 and 6 describe various specific resource considerations and related risks, and describes what criteria we used to determine what resource combinations provide an appropriate balance between cost and risk.
1d	The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	Avista considered current and expected state and federal energy policies in portfolio modeling. Chapter 6 describes the decision process used to derive portfolios, which includes consideration of state resource policy directions.
Guideline 2: Procedural Requirements		
2a	The public, including other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan.	Chapter 1 provides an overview of the public process and documents the details on public meetings held for the 2009 IRP.
	While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan.	The entire IRP, as well as the TAC process, includes all of the non-confidential information the company used for portfolio evaluation and selection. Avista also provided stakeholders with non-confidential information to support public meeting discussions via email. The draft plan and subsequent TAC meeting presentations were also made available on Avista's website for public viewing during this period.
	The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.	Avista distributed a draft IRP document for external review to TAC members on September 4, 2009 and requested comments by October 15, 2009. The draft plan was also made available on Avista's website for public viewing during this period.

Guideline Number	Description of Requirement	Fulfillment of Requirement
Guideline 3: Plan Filing, Review and Updates		
3a	Utility must file an IRP within two years of its previous IRP acknowledgement order.	This Plan complies with this requirement as the 2007 Natural Gas IRP was acknowledged on 6/02/2008.
3b	Utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.	Avista will work with Staff to fulfill this guideline following filing of the IRP.
3c - g	These guides discuss Commission comments and acknowledgement and the IRP annual update.	Not applicable.
Guideline 4: Plan Components		
	At a minimum, the plan must include the following elements:	
4a	An explanation of how the utility met each of the substantive and procedural requirements.	This table summarizes guideline compliance by providing an overview of how Avista met each of the substantive and procedural requirements for a natural gas IRP.
4b	Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions.	Avista developed nine demand growth forecasts for scenario analysis. Stochastic variability of demand was also captured in the risk analysis. Chapter 2 describes the demand forecast data and Chapter 6 provides the scenario and risk analysis results. Appendix 6.2 details major assumptions.
4c	For electric utilities only	Not Applicable
4d	A determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources.	Figures 1.11 and 1.12 summarize graphically projected annual peak day demand and the existing and selected resources by year to meet demand for the expected case. Appendix 6.6 summarizes the high, low, and other demand scenarios.
4e	Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology	Chapter 4 and Appendix 4.3 identify the demand-side resources included in this IRP. Chapter 5 and 6 and Appendix 6.3 identify the supply-side resources.
4f	Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs.	Chapter 7 discusses the modeling tools, customer growth forecasting and cost-risk considerations used to maintain and plan a reliable gas delivery system. The Chapter also captures a summary of the reliability analysis process demonstrated at the second TAC meeting. Chapter 5 discusses the diversified infrastructure and multiple supply basin approach that acts to mitigate certain reliability risks.

Guideline Number	Description of Requirement	Fulfillment of Requirement
4g	Identification of key assumptions about the future (e.g. fuel prices and environmental compliance costs) and alternative scenarios considered.	Appendix 6.2 and Chapter 6 describe the key assumptions and alternative scenarios used in this IRP.
4h	Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations - system-wide or delivered to a specific portion of the system.	This Plan documents the development and results for portfolios evaluated in this IRP (see Table 5.3 for supply scenarios considered).
4i	Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties.	We evaluated our candidate portfolio by performing stochastic analysis using VectorGas™ varying price under 200 different scenarios. Additionally, we test the portfolio of options with the use of SENDOUT® under deterministic scenarios where demand and price vary. For resources selected, we assess other risk factors such as varying lead times required and potential for cost overruns outside of the amounts included in the modeling assumptions.
4j	Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results	Avista's four distinct geographic Oregon service territories limit many resource option synergies which inherently reduces available portfolio options. Feasibility uncertainty, lead time variability and uncertain cost escalation around certain resource options also reduce reasonably viable options. Chapter 5 describes resource options reviewed including discussion on uncertainties in lead times and costs as well as viability and resource availability (e.g. LNG). Appendix 6.3 summarizes the potential resource options identifying investment and variable costs, asset availability and lead time requirements while results of resources selected are identified in Table 6.5 as well as graphically presented in Figure 6.17 and 6.18 for the expect case and Appendix 6.8 for High and Low demand cases. (Alternate scenarios are in Appendix 6.5)
4k	Analysis of the uncertainties associated with each portfolio evaluated	See the responses to 1.b above.
4l	Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers	Avista evaluated cost/risk tradeoffs for each of the risk analysis portfolios considered. Chapter 6 shows the company's portfolio risk analysis, as well as the process and determination of the preferred portfolio.
4m	Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation	This IRP is presumed to have no inconsistencies.

Guideline Number	Description of Requirement	Fulfillment of Requirement
4n	An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.	Chapter 8 presents the IRP Action Plan with focus on the following areas: • Modeling • Supply/capacity • Forecasting • Regulatory communication • DSM Goals
Guideline 5: Transmission		
5	Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.	Not applicable to Avista's gas utility operations.
Guideline 6: Conservation		
6a	Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.	Our last third party conservation potential study was in 2005. We expect to conduct a new study prior to our 2011 IRP. Avista incorporates a comprehensive assessment of the potential for utility acquisition of energy-efficiency resources into the regularly-scheduled Integrated Resource Planning process. The assessment that occurred within this IRP process began with over 300 conceptual measures and applications. This is in addition to the site-specific program coverage of any cost-effective non-residential measure.
6b	To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.	In Avista's Action Plan in Chapter 8 we include our conservation programs annual savings targets and reference to Chapter 4 and Appendix 4.1 for the program's specific details. A discussion on the treatment of conservation programs is included in Chapter 4 while selection methodology is documented in Chapter 6.
6c	To the extent that an outside party administers	Not applicable. See the response for 6.b above.

Guideline Number	Description of Requirement	Fulfillment of Requirement
	conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should: 1) determine the amount of conservation resources in the best cost/ risk portfolio without regard to any limits on funding of conservation programs; and 2) identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.	
Guideline 7: Demand Response		
7	Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).	Avista has periodically evaluated conceptual approaches to meeting capacity constraints using demand-response and similar voluntary programs. Technology, customer characteristics and cost issues are hurdles for developing effective programs. See chapter 4 Demand Response section for more discussion.
Guideline 8: Environmental Costs		
8	Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for CO2, NOx, SO2, and Hg emissions. Utilities should analyze the range of potential CO2 regulatory costs in Order No. 93-695, from $0 - $40 (1990$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for NOx, SO2, and Hg, if applicable.	Avista's current direct gas distribution system infrastructure does not result in any CO2, NOx, SO2, or Hg emissions. Upstream gas system infrastructure (pipelines, storage facilities, and gathering systems) do produce CO2 emissions via compressors used to pressurize and move gas throughout the system. The Environmental Externalities discussion in Appendix 4.2 describes our analysis performed. See also the guidelines addendum reflecting revised guidance for environmental costs per Order 08-339.
Guideline 9: Direct Access Loads		
9	An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.	Not applicable to Avista's gas utility operations.
Guideline 10: Multi-state utilities		
10	Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that	The 2009 IRP conforms to the multi-state planning approach.

Guideline Number	Description of Requirement	Fulfillment of Requirement
	achieves a best cost/risk portfolio for all their retail customers.	
Guideline 11: Reliability		
11	Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.	Avista's storage and transport resources while planned around meeting a peak day planning standard, also provides opportunities to capture off season pricing while providing system flexibility to meet swing and base-load requirements. Diversity in our transport options enables at least dual fuel source options in event of a transport disruption. For areas with only one fuel source option the cost of duplicative infrastructure is not feasible relative to the risk of generally high reliability infrastructure.
Guideline 12: Distributed Generation		
12	Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.	Not applicable to Avista's gas utility operations.
Guideline 13: Resource Acquisition		
13a	An electric utility should: identify its proposed acquisition strategy for each resource in its action plan; Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party; identify any Benchmark Resources it plans to consider in competitive bidding.	Not applicable to Avista's gas utility operations.
13b	Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment.	A discussion of Avista's procurement practices is detailed in Chapter 5.

Appendix 2.1 Oregon Public Utility Commission IRP Standard and Guidelines – Order 08 - 339

Guideline Number	Description of Requirement	Fulfillment of Requirement
Guideline 8: Environmental Costs		
a.	BASE CASE AND OTHER COMPLIANCE SCENARIOS: The utility should construct a base-case scenario to reflect what it considers to be the most likely regulatory compliance future for carbon dioxide (CO_2), nitrogen oxides, sulfur oxides, and mercury emissions. The utility also should develop several compliance scenarios ranging from the present CO_2 regulatory level to the upper reaches of credible proposals by governing entities. Each compliance scenario should include a time profile of CO_2 compliance requirements. The utility should identify whether the basis of those requirements, or "costs", would be CO_2 taxes, a ban on certain types of resources, or CO_2 caps (with or without flexibility mechanisms such as allowance or credit trading or a safety valve). The analysis should recognize significant and important upstream emissions that would likely have a significant impact on its resource decisions. Each compliance scenario should maintain logical consistency, to the extent practicable, between the CO_2 regulatory requirements and other key inputs.	Avista's current direct gas distribution system infrastructure does not result in any CO2, NOx, SO2, or Hg emissions. Upstream gas system infrastructure (pipelines, storage facilities, and gathering systems) do produce CO2 emissions via compressors used to pressurize and move gas throughout the system. The Environmental Externalities discussion in Chapter 4 describes our process for addressing these costs.
b.	TESTING ALTERNATIVE PORTFOLIOS AGAINST THE COMPLIANCE SCENARIOS: The utility should estimate, under each of the compliance scenarios, the present value of revenue requirement (PVRR) costs and risk measures, over at least 20 years, for a set of reasonable alternative portfolios from which the preferred portfolio is selected. The utility should incorporate end-effect considerations in the analyses to allow for comparisons of portfolios containing resources with economic or physical lives that extend beyond the planning period. The utility should also modify projected lifetimes as necessary to be consistent with the compliance scenario under analysis. In addition, the utility should include, if material, sensitivity analyses on a range of reasonably possible regulatory futures for nitrogen oxides, sulfur oxides, and mercury to further inform the preferred portfolio selection.	The Environmental Externalities discussion in Chapter 4 describes our process for addressing these costs.

Guideline Number	Description of Requirement	Fulfillment of Requirement
c.	TRIGGER POINT ANALYSIS: The utility should identify as least one CO_2 compliance “turning point” scenario which, if anticipated now, would lead to, or “trigger” the selection of a portfolio of resources that is substantially different from the preferred portfolio. The utility should develop a substitute portfolio appropriate for this trigger-point scenario and compare the substitute portfolio’s expected cost and risk performance to that of the preferred portfolio – under the base case and each of the above CO_2 compliance scenarios. The utility should provide its assessment of whether a CO_2 regulatory future that is equally or more stringent than the identified trigger point will be mandated.	The Environmental Externalities discussion in Chapter 4 describes our process for addressing these costs.
d.	OREGON COMPLIANCE PORTFOLIO: If none of the above portfolios is consistent with Oregon energy policies (including state goals for reducing greenhouse gas emissions) as those policies are applied to the utility, the utility should construct the best cost/risk portfolio that achieves that consistency, present its cost and risk parameters, and compare it to those of the preferred and alternative portfolios.	The Environmental Externalities discussion in Chapter 4 describes our process for addressing these costs.

Appendix 2.1 Washington Public Utility Commission IRP Policies and Guidelines - WAC 480-90-238

Avista Natural Gas IRP Review

Rule	Requirement	Plan Citation	Notes
WAC 480-90-238(4)	Work plan filed no later than 12 months before next IRP due date.	Work plan submitted to the WUTC on December 30, 2008, See attachment to this Appendix 1.1	
WAC 480-90-238(4)	Work plan outlines content of IRP.	See workplan attached to this Appendix 1.1.	
WAC 480-90-238(4)	Work plan outlines method for assessing potential resources. (See LRC analysis below)	See Appendix 1.3	
WAC 480-90-238(5)	Work plan outlines timing and extent of public participation.	See Appendix 1.3	
WAC 480-90-238(4)	Integrated resource plan submitted within two years of previous plan.	IRP will be submitted on or before December 31, 2009 within 2 years of our previous plan submitted December 31, 2007	
WAC 480-90-238(5)	Commission issues notice of public hearing after company files plan for review.	TBD	
WAC 480-90-238(5)	Commission holds public hearing.	TBD	
WAC 480-90-238(2)(a)	Plan describes mix of natural gas supply resources.	See Chapter 5 on Supply Side Resources	
WAC 480-90-238(2)(a)	Plan describes conservation supply.	See Chapter 4 on Demand Side Resources	
WAC 480-90-238(2)(a)	Plan addresses supply in terms of current and future needs of utility and ratepayers.	See Chapter 5 on Supply Side Resources and Chapter 6 Integrated Resource Portfolio	
WAC 480-90-238(2)(a)&(b)	Plan uses lowest reasonable cost (LRC) analysis to select mix of resources.	See Chapters 4 and 5 for Demand and Supply Side Resources along with Appendix 4.3 for detailed Demand Side Management programs. Chapter 6 details how Demand and Supply come together to select the least cost/best risk portfolio for ratepayers.	
WAC 480-90-238(2)(b)	LRC analysis considers resource costs.	See Chapters 4 and 5 for Demand and Supply Side Resources along with Appendix 4.3 for detailed Demand Side Management programs. Chapter 6 details how Demand and Supply come together to select the least cost/best risk portfolio for ratepayers.	
WAC 480-90-238(2)(b)	LRC analysis considers market-volatility risks.	See Chapter 5 on Supply Side Resources	
WAC 480-90-238(2)(b)	LRC analysis considers demand side uncertainties.	See Chapter 3 Demand Forecasting	
WAC 480-90-238(2)(b)	LRC analysis considers resource effect on system operation.	See Chapter 5 and Chapter 6	
WAC 480-90-238(2)(b)	LRC analysis considers risks imposed on ratepayers.	See Chapter 5 procurement plan section. We seek to minimize but cannot eliminate price risk for our customers.	
WAC 480-90-238(2)(b)	LRC analysis considers public policies regarding resource preference adopted by Washington state or federal government.	See Chapter 3 demand scenarios	
WAC 480-90-238(2)(b)	LRC analysis considers cost of risks associated with environmental effects including emissions of carbon dioxide.	See Chapter 3 carbon cases used in Alternate Demand Scenarios and Appendix 4.2	

Appendix 2.1 Washington Public Utility Commission IRP Policies and Guidelines - WAC 480-90-238

Avista Natural Gas IRP Review

Rule	Requirement	Plan Citation	Notes
WAC 480-90-238(2)(b)	LRC analysis considers need for security of supply.	See Chapter 5 on Supply Side Resources	
WAC 480-90-238(2)(c)	Plan defines conservation as any reduction in natural gas consumption that results from increases in the efficiency of energy use or distribution.	See Chapter 4 on Demand Side Resources	
WAC 480-90-238(3)(a)	Plan includes a range of forecasts of future demand.	See Chapter 3 on Demand Forecast	
WAC 480-90-238(3)(a)	Plan develops forecasts using methods that examine the effect of economic forces on the consumption of natural gas.	See Chapter 3 on Demand Forecast	
WAC 480-90-238(3)(a)	Plan develops forecasts using methods that address changes in the number, type and efficiency of natural gas end-uses.	See Chapter 3 on Demand Forecast	
WAC 480-90-238(3)(b)	Plan includes an assessment of commercially available conservation, including load management.	See Chapter 4 on Demand Side Management including demand response section.	
WAC 480-90-238(3)(b)	Plan includes an assessment of currently employed and new policies and programs needed to obtain the conservation improvements.	See Chapter 4 and Appendix 4.1	
WAC 480-90-238(3)(c)	Plan includes an assessment of conventional and commercially available nonconventional gas supplies.	See Chapter 5 on Supply Side Resources	
WAC 480-90-238(3)(d)	Plan includes an assessment of opportunities for using company-owned or contracted storage.	See Chapter 5 on Supply Side Resources	
WAC 480-90-238(3)(e)	Plan includes an assessment of pipeline transmission capability and reliability and opportunities for additional pipeline transmission resources.	See Chapter 5 on Supply Side Resources	
WAC 480-90-238(3)(f)	Plan includes a comparative evaluation of the cost of natural gas purchasing strategies, storage options, delivery resources, and improvements in conservation using a consistent method to calculate cost-effectiveness.	See Chapter 5 on Supply Side Resources	
WAC 480-90-238(3)(g)	Plan includes at least a 10 year long-range planning horizon.	Our plan is a comprehensive 20 year plan.	
WAC 480-90-238(3)(g)	Demand forecasts and resource evaluations are integrated into the long range plan for resource acquisition.	Chapter 6 Integrated Resource Portfolio details how demand and supply come together to form the least cost/best risk portfolio.	
WAC 480-90-238(3)(h)	Plan includes a two-year action plan that implements the long range plan.	See Section 8 Action Plan	
WAC 480-90-238(3)(i)	Plan includes a progress report on the implementation of the previously filed plan.	See Section 8 Action Plan	
WAC 480-90-238(5)	Plan includes description of consultation with commission staff. (Description not required)	See Section 1 Introduction	
WAC 480-90-238(5)	Plan includes description of completion of work plan. (Description not required)	See Appendix 1.3	

APPENDIX 2.2

COMMENTS AND RESPONSES TO 2009 DRAFT IRP

Appendix 2.2 Comments and Responses to 2009 DRAFT Integrated Resource Plan

The following table summarizes the significant comments on our DRAFT as submitted by TAC members and Avista's responses. The planning environment in this IRP cycle was especially challenging given some of the most challenging economic volatility seen in decades coupled with industry changing dynamics in natural gas production. We responded with a more robust, flexible demand forecasting methodology that captured a broader range of demand forecasts fully vetted with our TAC. This IRP produced significantly reduced forecasted demand scenarios (primarily due to significantly lower actual demand since our previous IRP) and no near term resource needs even in our most robust demand scenario. We appreciate the time and effort invested by all our TAC members throughout the IRP process. Many good suggestions have been made and we have incorporated those that enhance the document or we believe could materially change the outcome of this IRP. Recognizing implementation cost/benefit tradeoffs and best use of resources, some suggestions have been deferred for consideration in future IRPs.

Document Reference[1]	Comment/Question	Avista Response
4.9	We are happy to see the increase of 25 percent in Washington and Idaho DSM targets, reducing demand by 2,193,338 therms in the first year (2010). We commend Avista for analyzing each measure separately for this plan. Even though it was more time consuming, it adds confidence to the results.	We are committed to pursuing this aggressive goal recognizing significant challenges exist to overcome tough economic conditions.
4.4	We prefer that an updated assessment of technical and achievable potential would have occurred for this IRP, but are glad to see plans to research and engage a conservation consultant to this analysis prior to the 2011 IRP. Since this current IRP is using a 2005 analysis for the base, it is timely and crucial to update the research for the next round.	An updated external assessment is planned for our next full IRP.

[1] All references are to the September 4th 2009 DRAFT IRP. NP means "not provided". Some referencing has subsequently changed with respect to the FINAL IRP.

Document Reference[1]	Comment/Question	Avista Response
4.4	Achievable potential is covered on page 4.4. We are concerned about the percentage of technical potential that is considered achievable in the North and South territories. In appendix 4.1, it states, "Avista's achievable potential as a percentage of technical potential appears to be lower than other regional utilities", and it explains a few reasons why it is different. We are not satisfied with the explanations. Cascade Natural Gas is using 75% achievable potential for natural gas. Analysis by the Energy Trust of Oregon shows up to 88%. We believe that Avista should consider in more detail why the larger gap between technical and achievable, and determine ways to close the gap. For example, is their technology penetration that may be underestimated? How is this overcome?	As stated in appendix 4.1, Avista acknowledges its achievable potential as a percentage of technical potential appears to be lower than other regional utilities. The methodologies employed by consultants can be quite different between utilities and cannot necessary be comparable on an apples to apples basis. We have agreed to engage a third party consultant prior to our next IRP to improve analysis and development of new baselines for technical potential for us.
4.9	Table 4.3 uses the terms acquirable and DSM goal, and it is not clear how these relate to technical versus achievable. We believe that the terms should be consistent if they are meant to be the same thing, or the terms should be clearly defined.	We have replaced all instances of acquirable with achievable as they are synonymous. DSM goal is slightly different reflecting a phase in of achievable therm savings. Glossary definitions for Technical, Achievable, and DSM goal have been clarified.
4.8	There is a footnote on page 4.8 that accompanies a statement on carbon adders to the price forecast of natural gas. It says, "Adder reflects price impacts to comply with anticipated climate change legislation. Section Two – Demand Forecasts has detailed discussion on our modeling of climate change policy." This discussion is not found in Section Two or anywhere in the base document. Mr. Rahn directed me to Appendix 3.6 and 3.7, where the carbon adder and carbon adder discussion is found. We suggest that some explanation is included in the base document, or it is clearer, where the information can be found.	This was a drafting reference error and has been corrected to reference Appendix 3.6 and 3.7.

Document Reference[1]	Comment/Question	Avista Response
4.11	DSM sensitivities are included on page 4.11. There is an analysis of accelerated and delayed DSM. The accelerated DSM is important because of increased awareness of energy efficiency nationally, accompanied with increased tax credits and incentives. We understand that resource shortages are not expected for many years; therefore it is not imperative to take this sensitivity to the next level and analyze the cost advantages of accelerated DSM in a scenario. Yet, to the extent that resources may be needed in the future, we believe Avista should consider accelerated DSM in alternate scenarios. Avista should continue to carefully watch for signs of either DSM sensitivity occurring and for signs that the demand for new resources should trigger an analysis of an accelerated DSM scenario.	Avista's DSM team monitors actual trends relative to forecast as part of overall program evaluation. We will include monitoring and comparisons to the two alternate sensitivities considering their possible impacts on supply resource needs should they become more imminent.
NP	Although somewhat covered in your scenarios, It would be helpful to clearly illustrate benchmarks in the following areas and how you've arrived at them: a) quantifying the impacts of policy change (fracking and $ per ton carbon legislation)	a) fracking was included in a TAC consensus estimate of broader drilling constraints potential cost adder of $.30 (Drilling Constraints Sensitivity, Appendix 3.7). Carbon legislation impacts were captured in our two Carbon Mitigation sensitivities.
NP	b) recessionary demand (small commercial customers recovering at different rates)	b) for this IRP, we have not modeled demand at this level of granularity
NP	c) shale gas plays	c) impacts of shale gas production are captured in the consultant price forecasts
NP	d) currency valuation (US vs. Canada)	d) Our Canadian Imports Decline sensitivity (Appendix 3.7) considers a generalized escalated cost assumption to compete for higher priced imports whether it be from demand competition from oil sands, LNG exports, long term FX trends, or other price escalating factors.
NP	e) LNG Demand	e) impacts of LNG are captured in the consultant price forecasts

Document Reference[1]	Comment/Question	Avista Response
NP	f) new pipeline infrastructure (impact of connectivity)	g) impacts of pipeline infrastructure are captured in the consultant price forecasts
5.17	Under the "Supply Issues" section, you may include a timeline of when Avista estimates pertinent "Climate Change Policy" to occur.	We have added the following to the section: "Our Expected Case incorporates 2015 policy implementation in accordance with the Western Climate Initiative".
5.17	In the same "Supply Issues" section, you may wish to include the impact of currency exchanges under "Supply from Canada". Fiscal spending will eventually have an impact on inflation, how do you expect this to impact natural gas imports?	Our Canadian Imports Decline sensitivity (Appendix 3.7) considers a generalized escalated cost assumption to compete for higher priced imports whether it be demand competition from oil sands, LNG exports, long term FX trends, or other price escalating factors.
	When describing the "National pipeline infrastructure", you may add a map of completed pipelines, pending pipelines, and a timeline of expected progress (given financial constraints) and impact on natural gas prices.	We were not able to find a suitable map for inclusion in this IRP prior to publication.
NP	More detail and clear positions on the conclusions drawn regarding issues of uncertainty is always helpful.	Comment noted.
1.2	"Avista uses the IRP process to develop two types of demand forecasts – annual average daily and peak day." For the next IRP, add the following measures: seasonal annual average and regional/service areas averages.	Text edited to read "develop two primary types of demand forecasts". These demand profiles as summarized here are derived from detailed daily, regional demand forecasts.
1.3	Peak Day Demand – "Coincidental peak day, system-wide core demand . . ." For the next IRP examine and include alternative definitions of peak demand.	In this plan we included an alternate Coldest Day in 20 years sensitivity analysis to ascertain effect on demand and incorporated into a scenario for resource analysis (Appendices 3.6 and 3.7).
1.3	Figure 1.1 demand growth NET of DSM. Commission wants to see demand growth without DSM and then a discussion of how much of growth is being met by EE.	Table added to Appendix showing gross demand, DSM savings, and Net Demand for Expected Case. Footnote added at 1.3 and 3.10 referencing the table.

Document Reference[1]	Comment/Question	Avista Response
2.6	"We have also incorporated the Monte Carlo simulation module within SENDOUT® (formerly called VectorGas™), to simulate weather and price uncertainty." For the next IRP, add demand uncertainty, resource availability uncertainty, and risk of non-performance.	Demand, resource availability, and non-performance risks are important risks we consider outside of the SENDOUT model. The Monte Carlo simulation module in SENDOUT only has specific functionality around statistically modeling weather and price uncertainty which is what we are highlighting in this statement.
Figure 2.4	This graph needs to cover at least 5 years, and 7 if possible. Otherwise the picture it presents is misleading.	We were merely illustrating the price movement during the most recent IRP planning cycle. We have added additional years with a band highlighting the most recent planning cycle.
2.8 – 2.9	Whenever there is a statement of summary of approach, objectives and commitment, please list the measures, steps, actions or criteria to meet these objectives, example: IRP PLANNING STRATEGY.	Comment noted.
3.1	Demand Forecast Methodology The methodology is overly limited. It's time to include additional methods to forecast demand. Demand for natural gas has always been complex and difficult to predict and is growing more so every day. Avista should make changes to this assessment in the next IRP. It should include other available approaches that could be applied and are within the capabilities of Avista. The following should be considered: 1. Prediction markets; 2. Systems approaches; 3. Game theory; and 4. Behavioral economics. Delphi approaches might also be very useful as well as certain forms of data mining. Techniques developed by Economic/Financial Anthropology and Sociology should also be evaluated.	We believe our methodology is sound, cost effective and adequate for forecasting demand but are open to evaluating alternative demand forecasting methodologies in future IRPs. This IRP's methodology was presented to STAFF for feedback in early 2009 and disclosed in our annual update. It was developed to encompass a wide range of demand forecasts by focusing on key demand drivers and varying assumptions. Numerous demand drivers and assumptions were explored with significant input from TAC members during our TAC meeting process.

Document Reference[1]	Comment/Question	Avista Response
3.2	Demand Modeling Equation Weather and simple price are not the only factors effecting customer use of natural gas. Environmental concerns, pressure from community groups (e.g., political, religious, etc.), ethnic background, socioeconomic status, urban/rural location, occupation, etc. also effect usage.	The equations show the methodology and inputs used by the SENDOUT model, namely number of customers, weather and use per customer. We capture other considerations through use per customer cooeficient adjustments as more fully explained later in Chapter 3 and in Appendix 3.6 & 3.7 which was discussed with STAFF in March 2009 and extensively vetted with our TAC throughout the summer.
3.2	Number the "word equations" in these two tables so it's clear the second table is a detailed presentation of the first.	Numbering added.
3.2	Customer Forecasts Need to look at factors related to customers' choices about energy uses and the types of energy to use. These are not alone economic decisions. See above for other methods that could be applied to meet this goal.	We believe our methodology is sound and adequate for forecasting customer growth but are open to evaluating alternative demand forecasting methodologies in future IRPs.
3.3	"Forecasting customer growth is an inexact science so it is important to consider alternative forecasts. Two alternative forecasts were developed for consideration in this IRP. During the last 25 years, customer growth during five-year periods has ranged between one-half and one-and-a-half times the 25-year average customer growth rate. Since both patterns have been observed, Avista has created low and high customer growth alternatives with these parameters." This is wholly extrapolation based. Results need to be checked and assessed using other methods.	The alternative forecasts are reflective of and derived from our actual historical growth patterns seen over various periods. These forecasts develop a range of possible customer forecast outcomes that compares reasonably with detailed independent consultant population, household, employment and business growth forecasts we obtain and consider when preparing our forecasts (Appendix 3.1).

Document Reference[1]	Comment/Question	Avista Response
3.4	"The first step in developing demand coefficients was gathering daily historical gas flow data for all of our city gates. Three years of data were gathered, segregated by service territory/temperature zone and then by month." For reliable statistical analysis at least 5 years of data should be used. Three years is simply too small a sample unless we were to use techniques specifically for small samples, which are difficult to use and risky.	We performed extensive analysis on historical demand and development of predictive coefficients as part of our 2007 Action Plan (page 8.3, Demand Forecasting, second item). Our coefficients are derived from daily demand data representing over 90 data points for each monthly coefficient per sub region that derives a baseline use per customer (over 8000 data points total). These were checked through backcasting against actual demand in the most recent year. Older data has risks of diluting the most recent customer usage habits, DSM efforts, new customers, etc.
3.4 and Figure 3.3	"We then applied linear regression to the data to develop a linear relationship of usage to HDD." This is obviously not a linear relationship. Non-linear regression would be best to use, but since that is complex and difficult to apply, I suggest using log-linear lines fitted either by trial and error, or just by eye.	Figure 3.3 shows twelve sets of data designated by color for each MONTHLY coefficient. Linear regression on these individual data sets produces very high R^2 in excess of .9 supporting a strong linear relationship (Appendix 3.3). The graphic was instructive in our TAC meeting when we discussed in detail our monthly coefficient development but we agree the graphic is confusing here and is removed.
3.5	"One inherent drawback to this methodology is the lack of sufficient data points to develop a strong linear relationship. More years of data can help, but the older data becomes less and less relevant to current demand relationships." This is the strongest reason to find a nonlinear (if still using statistical approaches) alternative here.	Our challenge with consumption patterns in extreme temperatures is collecting sufficient, current data to determine a sufficiently predictive relationship. We are exploring using confidence intervals to quantify probabilities of consumption patterns under extreme temperature conditions for our next IRP.

Document Reference[1]	Comment/Question	Avista Response
5.8	"Determining the appropriate level of firm transportation is a complex evaluation of many factors, including the projected number of firm customers and their expected annual and peak day demand, opportunities for future pipeline or storage expansions, and relative costs between pipelines and their upstream supplies. It is important to maintain an appropriate time cushion to allow for required lead times for securing new capacity. Also, the ability to release capacity offsets the cost of holding underutilized capacity." A full transportation capacity needs study should be performed every 5 years or so to verify the levels and mix of pipeline capacity contracted for and its cost. When was the last such study performed by Avista? If not within the last 5 years, it should be completed as part of this IRP or the next IRP. Without a study, how has risk to meet demand been mitigated?	Our IRP analyses demand and the preferred resources to serve it. Transportation needs and resources are part of this analysis. This IRP indicates no near term resource needs for any of the range of demand forecasts modeled. Where existing capacity is not available for future needs, we utilize estimates for pipeline expansions as commissioning formal pipeline cost studies apply only to specific paths, are costly to perform, have limited shelf life, and are not binding commitments.
5.13	"In our modeling, we utilized available cost and other information to develop more generic pipeline resource alternatives rather than specifically modeling the various segments." Specifically, what pipeline capacity modeling approach(es) was employed?	The region's specific proposed pipelines do not provide full path deliverability to our service territories. In our model we input transport resources that assume full path deliverability while considering cost and other characteristics of the region's proposed specific pipelines.

Document Reference[1]	Comment/Question	Avista Response
5.13	"To accurately assess costs and location feasibility of potential expansion scenarios requires detailed engineering studies by the pipelines. These studies can be expensive and of limited shelf life for projects that might be developed well into the future. Consequently, we employ estimates derived from our knowledge of historical costs, reasonable price escalations, and site specific issues that may impact a specific scenario. We combine this knowledge with past information from the pipelines to develop a reasonable basis for our transportation analysis." See above comment on the need for a full and complete transportation needs and costs study every 5 years or so.	Our IRP serves as a transportation needs study which indicates no near term needs. Because of this, we are not advocating engaging a detailed cost study.
6.1	This chapter is too long primarily because it repeats many items and data from previous chapters. Please reduce this repetitiveness, use references more and less repeated explanations. Most importantly emphasize the integration process. How does SENDOUT examine and compare supply-side and demand-side resources on a comparable basis, if not a totally identical basis?	We have separated the information into two chapters encompassing our expected case and alternate scenarios/portfolios/stochastic analysis.
6.2 (Figure 6.1)	General comment – make sure figures are brought in at high enough resolution to be clear.	Acknowledged. Figure 6.1 presents challenges as it is an image extracted out of the SENDOUT software in bitmap format, a low resolution format. We have added a larger version of the figure at Appendix 6.5.
6.29	Place the tables in Appendix 6.9 somewhere around here and explain the choice among the portfolios clearly and concisely. Once completed it should be clear to the reader why the portfolio chosen was the best price, least risk selection in terms of Avista's criteria and the IRP guidelines. The cost criteria must be NPVRR, per the IRP guidelines. Similarly, portfolios not selected should be clearly and concisely explained so as to make it clear why they were not selected.	Summary information added to a new chapter indicating portfolios examined, portfolio selection, and NPVRR criteria used.

Document Reference[1]	Comment/Question	Avista Response
Appendix – general comment	Make sure all pages are numbered	Page numbers added.
Appendix 3.7	How Avista's budget constraints would limit DSM acquisition?	Budget constraints aren't necessarily the source of the limitation on Avista's acquisition of DSM resources. However, the results of the SENDOUT model do not incorporate the aggregate infrastructure costs associated with major year-to-year changes in DSM infrastructure and strategy. Thus, when SENDOUT identifies the need for a <u>major</u> shift in the direction of our DSM resource acquisition, it must then be filtered through an implementation planning process that takes these previously unidentified costs into account. The result is a plan which will meet the long-term resource acquisition objectives identified by SENDOUT without unduly accelerating infrastructure costs. Examples of the improvements to the raw SENDOUT results might include the phasing in or out of incentives based upon market considerations, acceleration or deferral of certain programs to allow for coordination with non-Avista stakeholders (manufacturers, ETO, regional or national initiatives), shaping the ramp-up of acquisition to avoid inducing market shortages and increases in retail prices and constraining year-to-year increases in Avista DSM infrastructure to avoid increasing administrative or productivity costs due to excessively rapid growth.

Document Reference[1]	Comment/Question	Avista Response
Appendix 6.2	Projected Long-Term Cost of Capital -- Avista Utilities for Net Present Value Analysis Why is Avista using a cost of capital rate different from its authorized (current) cost of capital by OPUC for its NPVRR analysis? Is this an error?	There is no error. Consistent with past IRP's we utilize a blended rate reflecting all three jurisdictions using the most recent rates at the time of initiating our analysis.
Appendix 6.9	Move most if not all of Appendix 6.9 into the body of the IRP document. Label these tables as NPVRR if that is what they are, per the guidelines requirement. If these are not NPVRR calculations, please correct the table to reflect such.	Summary information added to a new chapter indicating portfolios examined, portfolio selection, and NPVRR criteria used.
Appendix 6.9	How is the diversity of a portfolio valued? Avista should consider developing a portfolio matrix with the NPVRR, ranking of diversity, ranking of risk and whatever else the company will inevitably subjectively use to choose a portfolio.	Each portfolio has varying assumptions around price, customer counts, weather, resource availability, etc. Portfolios are then compared and ranked based on the NVPRR as detailed in Appendix 6.9 and now summarized in a new chapter as per the response to the comment at document reference 6.1 above. Also, appendix 3.6 and 3.7 includes detailed descriptions of the assumptions of each portfolio.
4.11	DSM accelerated sensitivities are limited to Tax credits. There are other factors that can incite customers to pursue DSM measures such as higher commodity prices, high demand, weather, and revenue incentive mechanisms. Please include and discuss all factors that affect this scenario.	This was a specific TAC recommended scenario to address the potential impacts of then recently passed tax credits. We considered a host of use per customer adjustments including price elasticity and weather in our other sensitivities and scenarios analysis (Chapter 3 & Appendix 3.6, 3.7)

Document Reference[1]	Comment/Question	Avista Response
4.11	DSM Delayed Please explain the specific budget constraints influence customer incentives. Does the absence of a regulatory incentive mechanism such as decoupling or public purpose funding present a conflict for the company to promote energy efficiency and conservation?	Avista is committed to budgeting for the acquisition of cost-effective DSM resources. This can be a challenging era when rapid growth in DSM acquisition may be called for. It is our intent to be responsibly responsive to the changing DSM resource environment. This may include tempering our year-to-year response in consideration of the potential impacts upon infrastructure cost, coordination with other stakeholders and impacts upon retail markets for energy-efficiency goods and services. The opportunity for Avista to obtain full fixed cost recovery on measures implemented through the DSM program removes adverse shareholder impact upon increasing acquisition through the DSM portfolio. The Company continues to monitor mechanisms which provide for fixed cost recovery for decreases in usage.
4.9	Table 4.3: The cumulative goal in the North Division increases from approximately 2.2 million therms in CY 2010 to 54.7 million therms in 2029, i.e. 27 times while it increases in the South Division by approximately 15 times. Given that Avista's independent study to identify potential energy savings was based on Oregon service territories and then extrapolated the methodology to the North Division, how did Avista base its projections for much higher savings in the North Division?	North Division includes a significant phase in whereas the South Division uses a modest phase in (Figures 4.4, 4.5). Using the Cumulative Potential results in a generally comparable relationship of approximately 17 and 14 times for North and South Divisions, respectively. Also, the colder temperature of the North Division inherently facilitates increased therm savings for weather sensitive measures.

Document Reference[1]	Comment/Question	Avista Response
Appendix 4.2	Please explain why measures with the same description are listed multiple times. Also explain why the savings are different. Several measures as Duct sealing (#21), high efficiency water heater (#50), Tankless Water Heaters (#66) show very significant technical savings. How does Avista plan to identify and take steps to increase the acquirable savings since these measures could achieve significant results?	A column was omitted in error from the published table which delineates customer type such as single family residential, multifamily residential, mobile home, etc. The table has been updated to include the customer type information. Appendix 4.1 discusses the errors encountered with technical potential in our most recent external study. An updated external assessment is planned for our next full IRP.
Action Plan 8.5	With regard to monitoring commodity, storage and supply resources, has the economy rebounding sooner rather than later been taken into consideration in the associated results?	Yes. Our high growth scenario considers a robust economic recovery while recognizing significant supply capacity exists from previous dramatic production cuts.
Action Plan 8.7	Avista included analysis of realistic alternative world situations in which Avista may have to operate during the next 20 years, particularly in light of current, new and proposed state, federal and Canadian energy policies and the ongoing evolution of North American and world natural gas, oil and coal markets, in its action plan as required in the acknowledgement of its last IRP. The need of additional action items for this IRP has not been determined at this point.	We cannot address potential additional recommended action items until they are known.

Document Reference[1]	Comment/Question	Avista Response
4.7	What is the logic behind the adjustment for non-residential program duplication on page 4.7 in Table 4.2? The description in the text says it is an adjustment for site-specific programs and the measures accepted in SENDOUT, but the non-residential program number in the table is only 75,601. Please explain.	Table 4.2 summarizes the achievable potential by customer type (residential and non-residential). For non-residential, individual prescriptive measures are entered into SENDOUT but the customized nature of site specific acquisition requires estimation. The 811,920 therms (for 2010) is the estimated total gross technical potential for site specific bundled programs which **includes** certain prescriptive measures included in the bundle. The estimated technical potential for the prescriptive measures (on a standalone basis) included in the 810,920 therm estimate is 685,440 therms which is conceptually already captured in the technical and achievable potential for the individual prescriptive measures entered into SENDOUT and therefore needs to be netted out to avoid double counting. The net amount of 126,480 therms is the estimated net non-residential, non-prescriptive therm savings, essentially the highly customized measures which are not able to be standardized and input into SENDOUT. The 75,601 Dth represents the achievable potential of the individual non-residential prescriptive measures that were entered, tested and selected in SENDOUT.

APPENDIX 3.1

CUSTOMER FORECASTS

APPENDIX 3.1 – CUSTOMER FORECASTS

OVERVIEW

Avista presented their 2009 Natural Gas Demand Forecast to the Technical Advisory Committee (TAC) in April 2009. What follows in narrative is the process of preparing the base customer growth forecast. The first step is a framework forecast of the national economy, followed by regional economic forecasts consistent with the national outlook. The employment and population forecasts are the key drivers for the natural gas customer forecast.

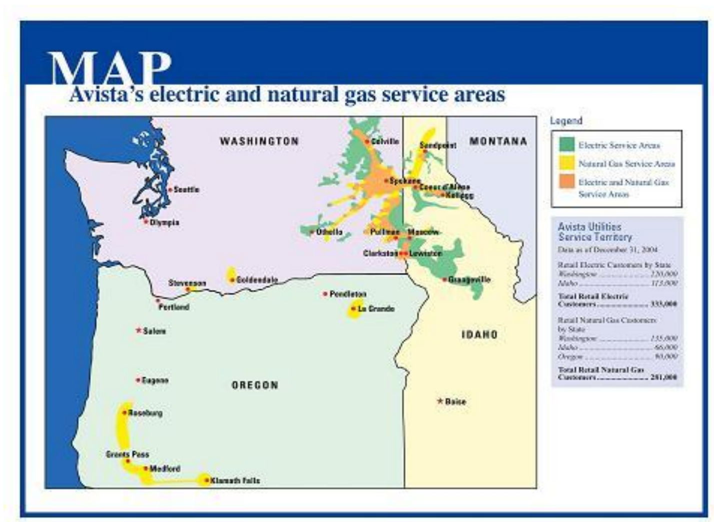
NATIONAL ECONOMIC OUTLOOK

Avista has contracted for national economic forecasts with Global Insight, Inc. for over two decades. The Spring 2008 twenty-five year long term forecast was used as the basis for the 2009 effort; the Spring 2009 county forecast update took into account the depth of the current recession but was largely unchanged after the anticipated economic recovery. The following narrative has Avista remarks and Global Insight forecasts (used with permission) which are consistent with the presentation at the TAC in April 2009, with a focus on the near term national outlook.

The U.S. Gross Domestic Product is expected to rebound to levels in 2010 to the 2.5 to 3.0 percent range after the severe recession in 2008 and 2009. Longer term the rate settles in at 2.6 percent.

REGIONAL ECONOMIC OUTLOOK

Avista serves natural gas in eastern Washington, northern Idaho, and in portions of five counties in Oregon. The principal county in Washington is Spokane, while in Idaho there are two counties; Kootenai and Bonner are barometers of service area growth. Kootenai County includes Coeur d'Alene, Post Falls, Hayden and a host of smaller municipalities and Bonner County is anchored by Sandpoint. The primary cities in Spokane County are the City of Spokane, City of Spokane Valley and Liberty Lake. In Oregon, the counties (principal city) of Jackson (Medford), Josephine (Grants Pass), Douglas (Roseburg), Klamath (Klamath Falls) and Union (La Grande) round out the service territory. The map below shows the breadth of the service area.



Global Insight, Inc. has been providing county-level forecasts to Avista for several years. These forecasts are consistent with and driven by their national forecast.

The economic concepts provided are forecast forward for 30 years. We report below forecast data ending in the year 2030, the twenty-year horizon IRP horizon.

Overall, the results of the economic forecasts suggest the following impacts on Avista's customer growth: Near term the weakness in construction will be mirrored with slow customer growth, while longer term, underlying employment and population growth will drive customer growth.

The following table indicates a listing of 21 counties served with natural gas by Avista. We purchased economic forecasts for the 15 principal counties.

Table of Counties Served (All or Portions)

Washington	**Idaho**	**Oregon**
Adams*	Benewah	Douglas
Asotin	Bonner	Jackson
Franklin*	Boundary	Josephine
Grant*	Latah	Klamath
Klickitat*	Nez Perce	Union
Lincoln*	Shosone	
Skamania*		
Spokane		
Stevens		
Whitman		

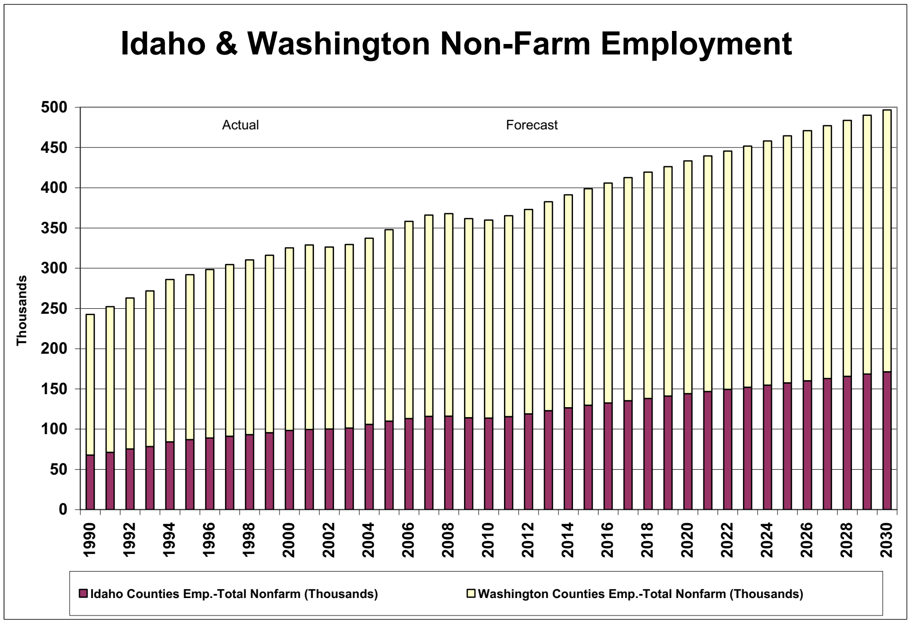
*Did not purchase economic data, few customers served

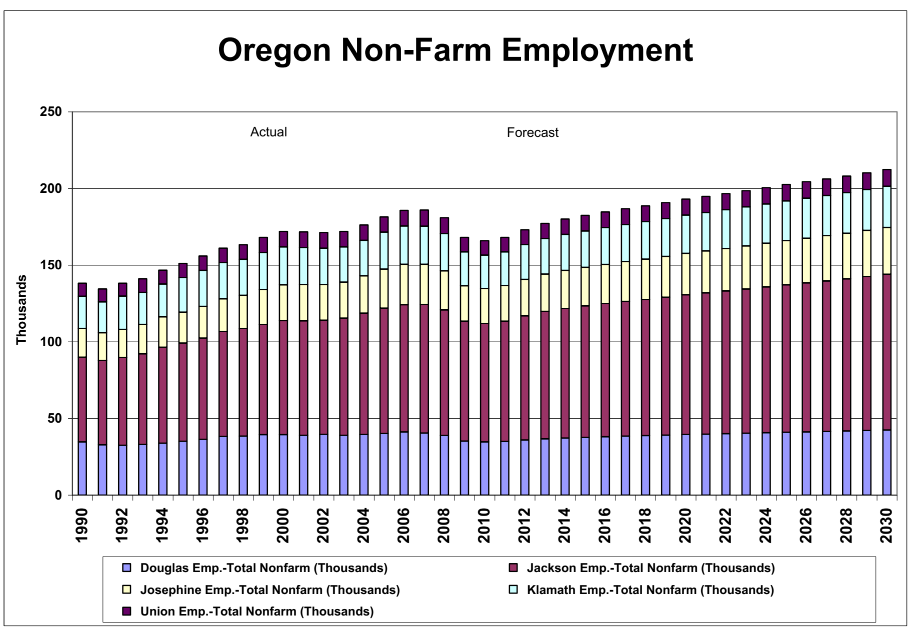
The charts that follow are the actual employment, population, population age 65 and over, number of households and personal income forecasts used to produce the natural gas customer forecasts by state, by customer class (residential, commercial and industrial) and by rate schedule (firm – small, medium and large-sized customers).

Although the forecasts are prepared in detail by county, the charts aggregate the data by State.

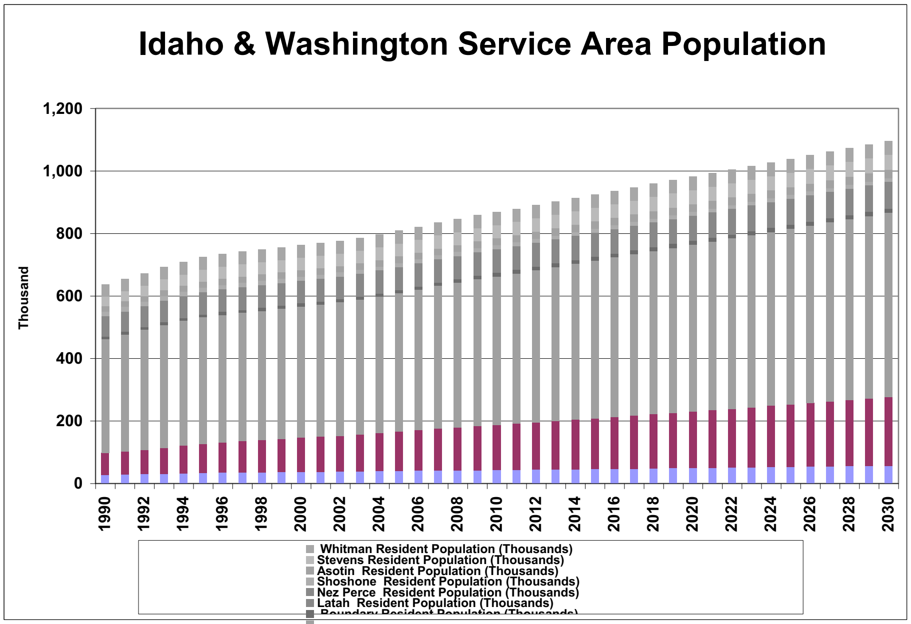
The first pair of charts is Non-Farm Employment. During the last decade, fairly consistent growth in jobs was observed except during recession periods in 2000-01 and at the present time.

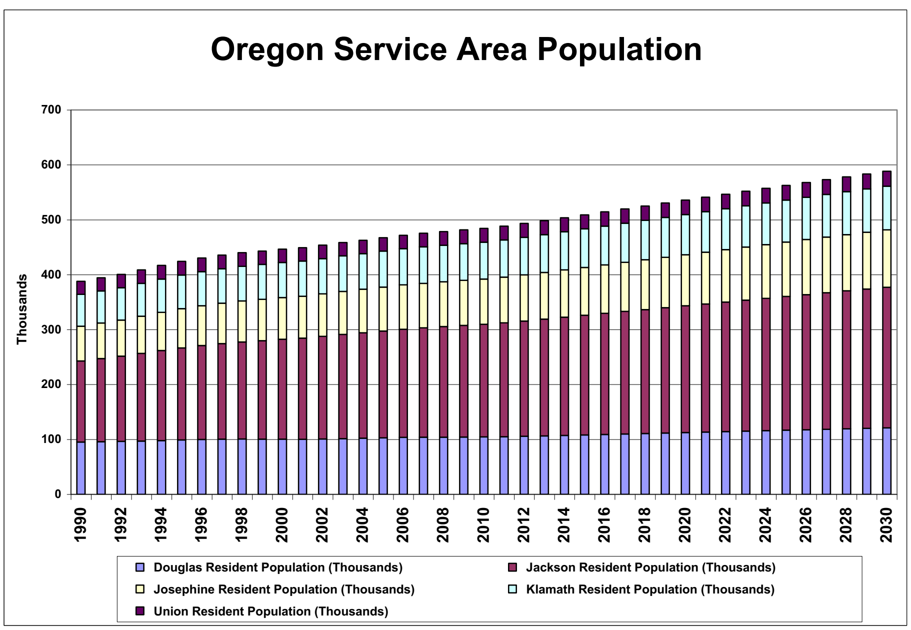
The twenty year average compounded growth rate in jobs for Idaho Counties was 2.6 percent from 1990-2010, and is forecast to be 2.1 percent for the period 2010-2030. Washington Counties were 1.7 percent from 1990-2010, and is forecast to be 1.4 percent for the period 2010-2030. And Oregon Counties were 0.9 percent from 1990-2010, and is forecast to be 1.2 percent for the period 2010-2030.



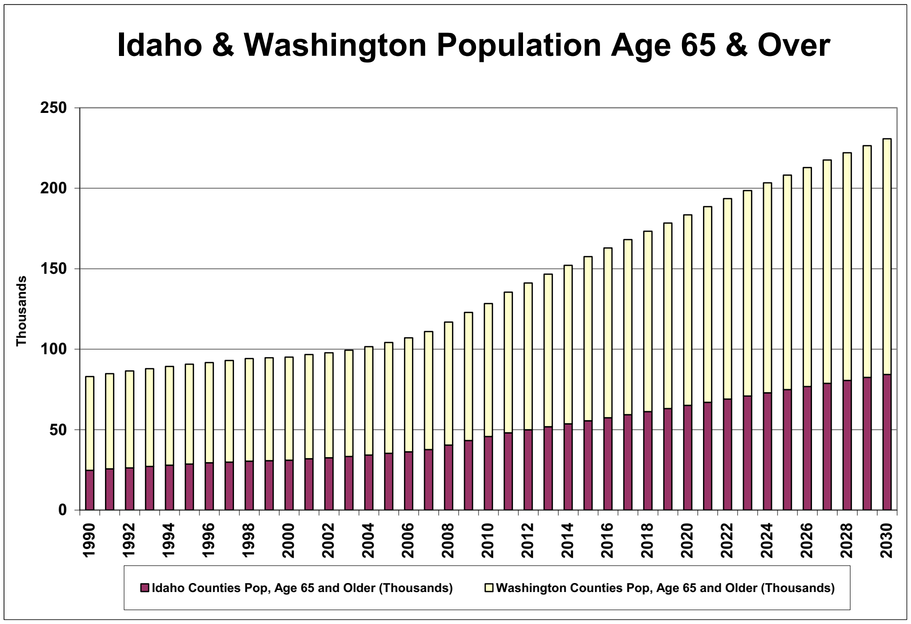


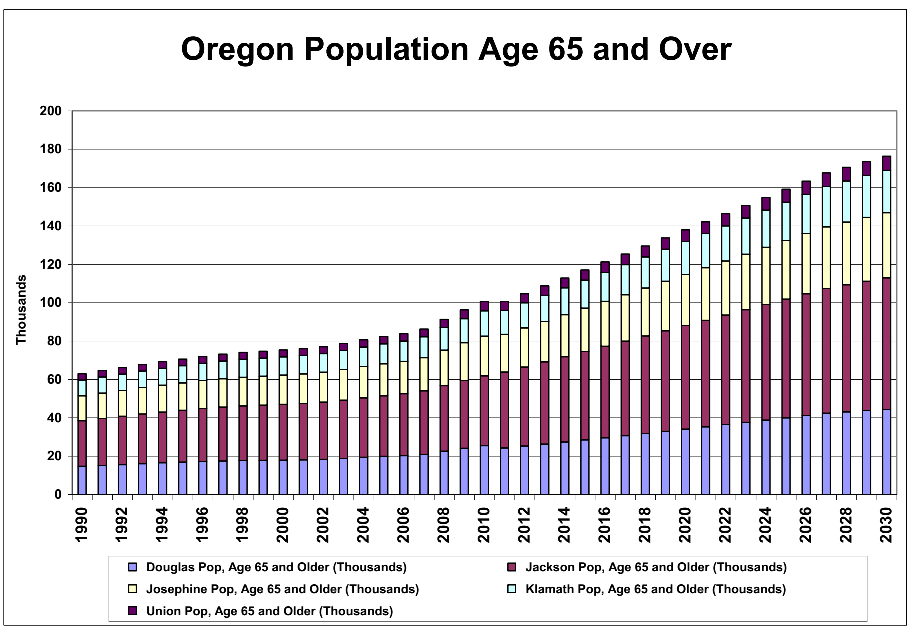
Next is resident population. The twenty year average compounded growth rate in population for Idaho Counties was 2.2 percent from 1990-2010, and is forecast to be 1.5 percent for the period 2010-2030. Washington Counties were 1.3 percent from 1990-2010, and is forecast to be 1.0 percent for the period 2010-2030. And Oregon Counties were 1.1 percent from 1990-2010, and is forecast to be 1.0 percent for the period 2010-2030.



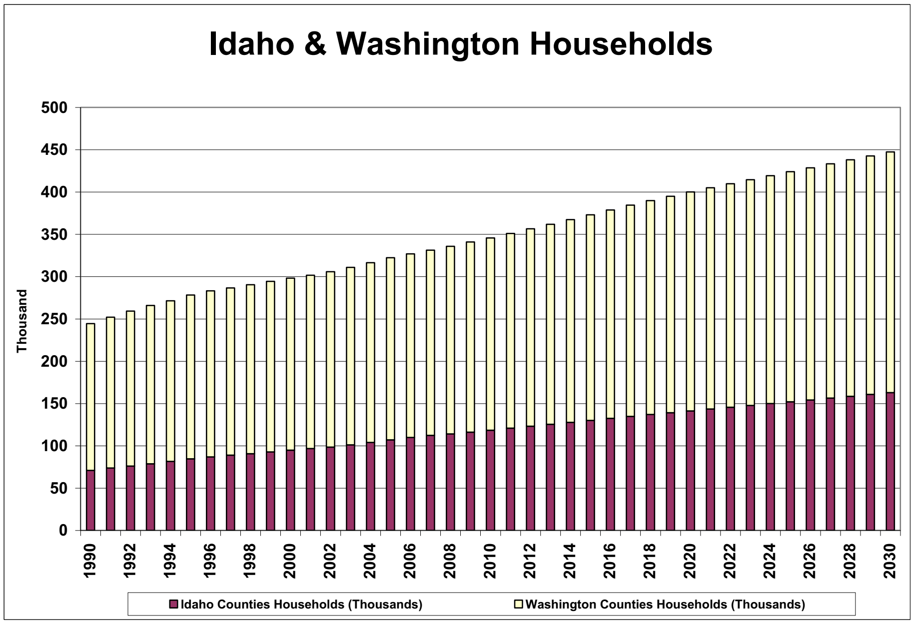


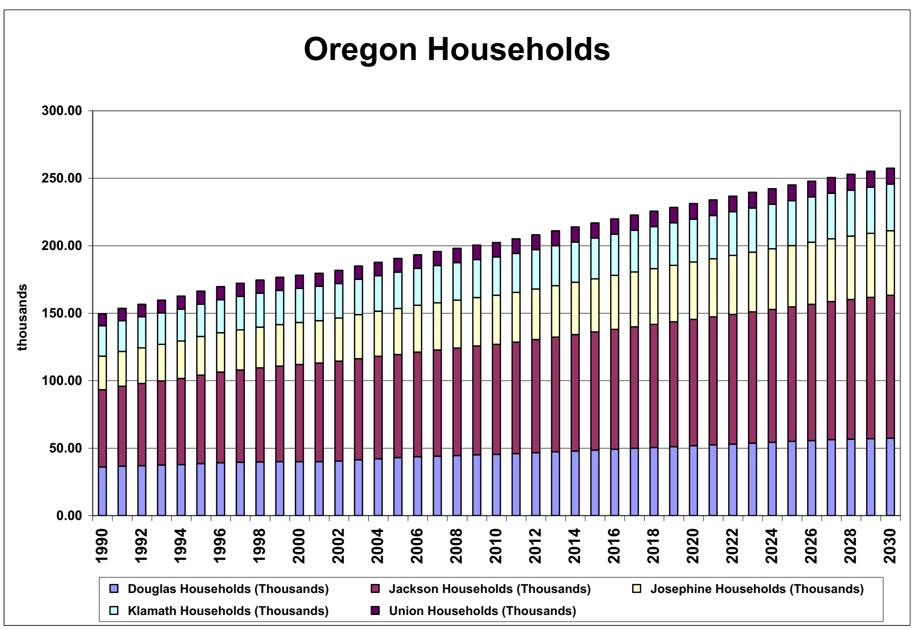
The next pair of charts is persons 65 years and over. The twenty year average compounded growth rate in persons 65 and over for Idaho Counties was 3.1 percent from 1990-2010, and is forecast to be 3.1 percent for the period 2010-2030. Washington Counties were 1.8 percent from 1990-2010, and is forecast to be 2.9 percent for the period 2010-2030. And Oregon Counties were 2.4 percent from 1990-2010, and is forecast to be 2.8 percent for the period 2010-2030.





The next economic variable used in the preparation of Avista's forecast is number of resident households in the service area. The household growth rate for Idaho Counties was 2.6 percent from 1990-2010, and is forecast to be 1.6 percent for the period 2010-2030. Washington Counties were 1.4 percent from 1990-2010, and is forecast to be 1.1 percent for the period 2010-2030. And Oregon Counties were 1.5 percent from 1990-2010, and is forecast to be 1.2 percent for the period 2010-2030.





REFERENCE CASE FORECASTS OF CUSTOMERS SERVED

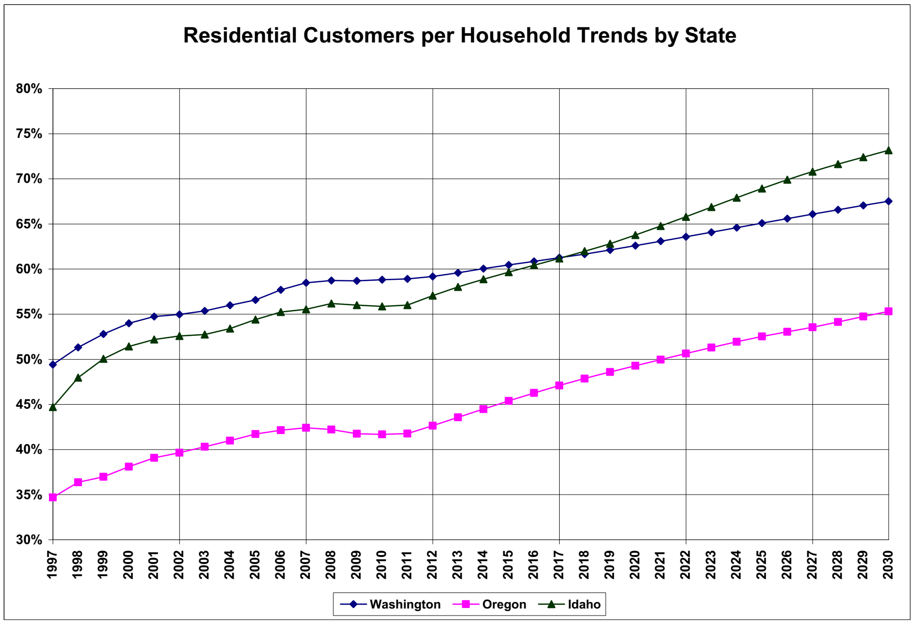
Reference case customer forecasts for residential customers are consistent with our economic forecasts. The relationship has been changing over the last decade, and the forecasts take into account the most recent trends. As shown on the next figure, the number of residential customers per household grew rapidly between 1997 and 2001, while it has slowed during the present economic downturn. About half of the growth between 1997 and 2001 was due to fuel switching of existing homes from other heating sources to natural gas. Although fuel switching continues to occur, today it represents only 15 percent of customer additions.

To produce the customer forecast, we look at recent trends in housing construction and the likelihood those homes will be served with natural gas. For example, in Washington, the number of single family homes being constructed has declined, with apartment dwellings taking a larger market share. Multi-family housing has traditionally been served with electricity only, limiting the number of available dwellings for natural gas service.

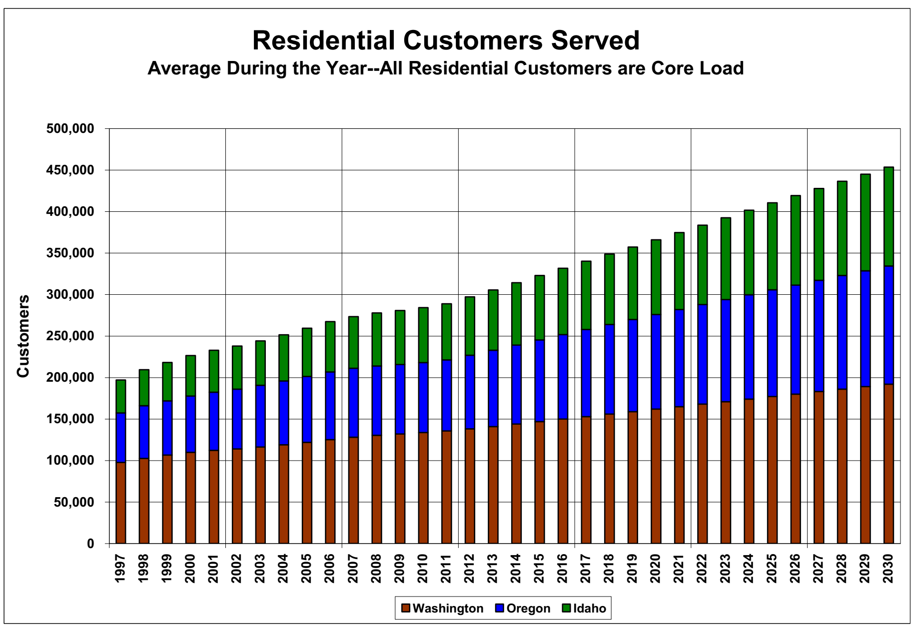
However, in the areas outside of the urban core of Spokane, including the rest of Washington, much of Idaho and Oregon, housing construction activity has maintained very high levels of single family homes, whether detached-style homes on individual lots or attached-style homes, like duplexes, townhomes, or condominiums. This market is traditionally served with natural gas water and space heat, and many of these homes now are being built with natural gas clothes dryers, gas ranges and ovens and natural gas fire places.

Because growth management laws are in place in all of Avista's natural gas service areas, we assume these construction trends in the urban growth areas will be served with natural gas, and do not anticipate any switching to electricity. We have an effort under way to encourage multi-family builders, who typically are building apartments for rental purposes, to include natural gas appliances, but this forecast does not assume this effort will lead to a change in construction practices. We will continue to monitor activity in the multi-family housing segment.

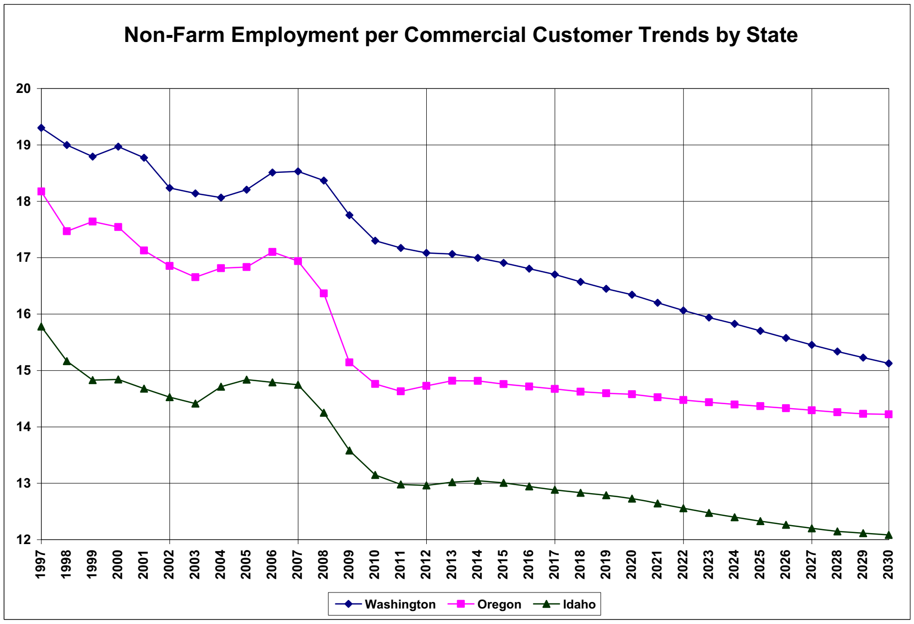
The forecast assumes that the trends of the last five years continue into the future, adjusted for the sharp building cycle presently under way and based on the household forecasts provided by Global Insight. The next chart shows the number of residential customers per household. The reason this ratio is increasing in the forecast period is because the ratio of homes being added is higher than the current ratio. This is largely driven by the assumption of nearly 100 percent of new homes having at least one natural gas service. Also, outside of the Medford and Spokane metropolitan areas, the multi-family construction market is very small. The only exception would be in Pullman and Moscow where growth in university enrollments is leading to apartment construction activity in those special areas. To a lesser extent, La Grande, Klamath Falls, and Ashland are seeing student growth-driven apartment construction, but to a small extent.



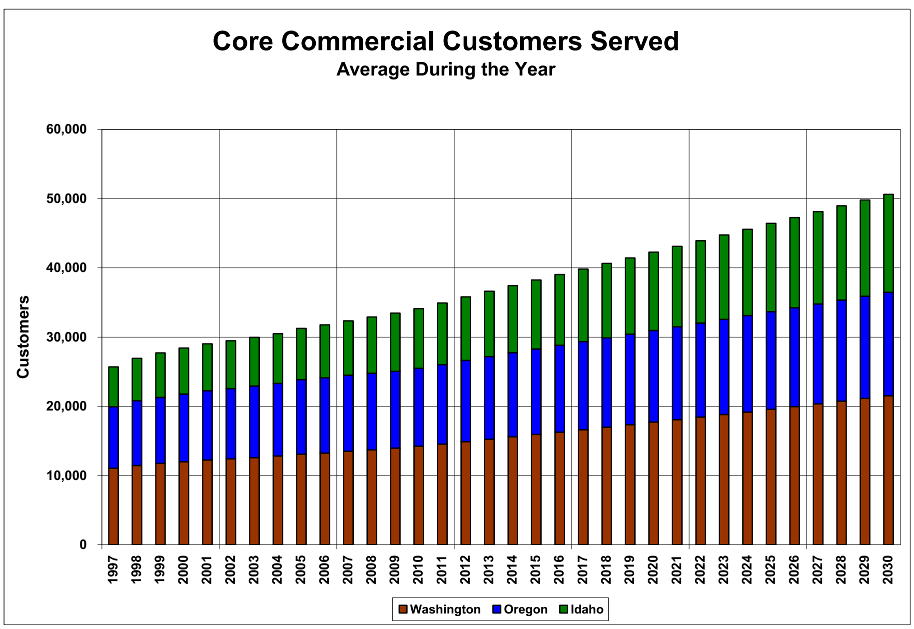
The residential customer forecast is the product of the customers-per-household forecast and the household forecast from Global Insight.



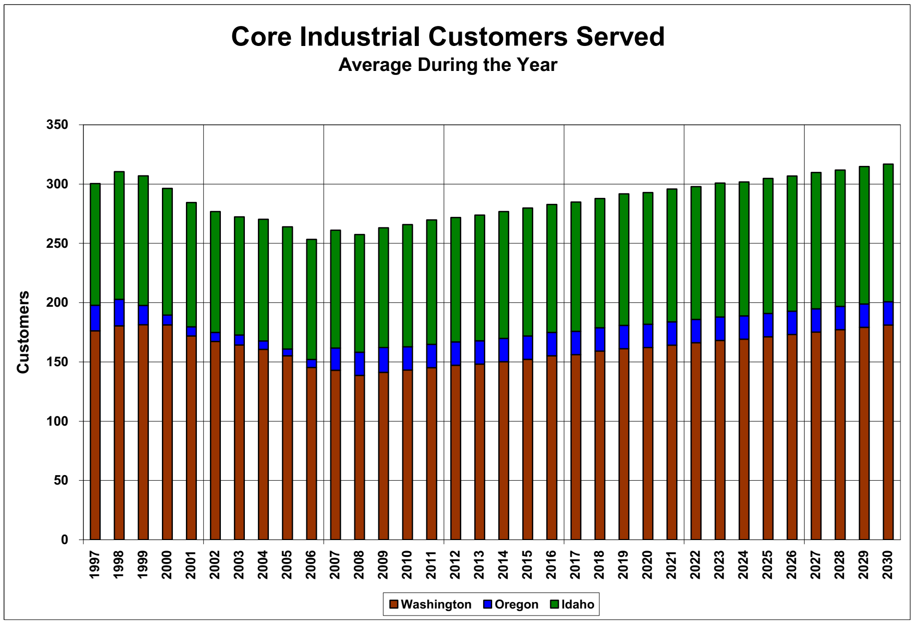
Core commercial customers served are based on job forecasts for each county, as well as the number of residential customers. The figure below shows ratio of non-farm workers per commercial customer. The previous ten years show declines in numbers of workers early in the period, followed by a buildup until recently. This build up is due to an increase in the number of big-box retail stores, which have moved from the very large metro areas into the smaller metro areas served by Avista. We believe that build out is largely complete. We do not anticipate new large mall-type complexes will be built in to any great extent. Therefore, in a few more years we expect the number of workers will again begin to decline as smaller shops and strip-mall developments fill into the neighborhood developments. We have taken into account the known shopping areas that have been either permitted or have a high probability of being built in the near term forecast. As shown in the chart, although declines are forecast, they are very modest and reflect the particular characteristics of the existing mix of commercial developments in each state.



The commercial customer forecast is based on job forecasts multiplied times the forecasted ratio of workers per customer as described above.



Core industrial customers served are based on manufacturing job forecasts for each county. The number of manufacturing workers is expected to be growing slowly over the forecast period, leading to little change in the number of core firm industrial customers.


Core Industrial Customers Served
Average During the Year
Customers
350
300
250
200
150
100
50
0
1997 1998 1999 2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030
Washington
Oregon
Idaho

APPENDIX 3.2

CUSTOMER FORECASTS DATA

Appendix 3.2 - Customer Forecast - Number by Region
Expected Case

	WA/ID				Medford				Roseburg				Klamath Falls				La Grande			
	WA/ID Res	WA/ID Com	WA/ID Firm Ind	WA/ID Total	MFR Res	MFR Com	MFR Firm Ind	MFR Total	ROS Res	ROS Com	ROS Firm Ind	ROS Total	KLA Res	KLA Com	KLA Firm Ind	KLA Total	LGD Res	LGD Com	LGD Firm Ind	LGD Total
Nov-09	198,391	22,419	244	221,054	50,414	6,436	10	56,860	13,075	2,140	2	15,217	13,863	1,623	5	15,491	6,465	885	5	7,355
Dec-09	199,080	22,487	245	221,812	50,685	6,469	10	57,164	13,139	2,145	2	15,286	14,007	1,639	5	15,651	6,508	914	1	7,423
Jan-10	199,523	22,676	242	222,441	50,982	6,497	10	57,489	13,190	2,153	2	15,345	14,092	1,658	5	15,755	6,575	903	1	7,479
Feb-10	199,531	22,685	244	222,460	50,882	6,518	11	57,411	13,209	2,152	2	15,363	14,120	1,686	5	15,811	6,559	902	1	7,462
Mar-10	199,433	22,687	242	222,362	50,788	6,482	10	57,280	13,191	2,198	2	15,391	14,067	1,686	5	15,758	6,518	903	1	7,422
Apr-10	198,981	22,859	248	222,088	51,015	6,529	10	57,554	13,198	2,168	2	15,368	14,048	1,661	5	15,714	6,493	892	1	7,386
May-10	198,853	22,862	248	221,963	50,853	6,520	10	57,383	13,163	2,169	2	15,334	13,983	1,644	5	15,632	6,461	892	1	7,354
Jun-10	198,659	22,926	244	221,829	50,690	6,526	10	57,226	13,059	2,164	2	15,225	13,863	1,638	5	15,506	6,450	884	1	7,335
Jul-10	199,204	22,948	247	222,399	50,630	6,480	10	57,120	13,042	2,176	2	15,220	13,803	1,638	5	15,446	6,376	890	1	7,267
Aug-10	199,177	22,932	248	222,357	50,434	6,476	10	56,920	13,035	2,166	2	15,203	13,726	1,635	5	15,366	6,350	892	1	7,243
Sep-10	199,855	22,935	245	223,035	50,353	6,474	10	56,837	12,955	2,167	2	15,124	13,748	1,640	5	15,393	6,348	889	10	7,247
Oct-10	200,460	23,000	248	223,708	50,542	6,480	10	57,032	13,094	2,173	2	15,269	13,883	1,651	5	15,539	6,439	894	7	7,340
Nov-10	201,401	22,955	248	224,604	51,014	6,536	10	57,560	13,225	2,200	2	15,427	14,013	1,673	5	15,691	6,490	890	5	7,385
Dec-10	202,090	23,023	249	225,362	51,285	6,569	10	57,864	13,289	2,205	2	15,496	14,157	1,689	5	15,851	6,533	919	1	7,453
Jan-11	202,744	23,237	244	226,225	51,682	6,602	10	58,294	13,340	2,225	2	15,567	14,242	1,725	5	15,972	6,625	913	1	7,539
Feb-11	202,752	23,246	248	226,246	51,582	6,623	11	58,216	13,359	2,224	2	15,585	14,270	1,753	5	16,028	6,609	912	1	7,522
Mar-11	202,654	23,248	246	226,148	51,488	6,587	10	58,085	13,341	2,270	2	15,613	14,217	1,753	5	15,975	6,568	913	1	7,482
Apr-11	202,202	23,420	252	225,874	51,815	6,634	10	58,459	13,398	2,240	2	15,640	14,248	1,728	5	15,981	6,543	902	1	7,446
May-11	202,074	23,423	252	225,749	51,653	6,625	10	58,288	13,363	2,241	2	15,606	14,183	1,711	5	15,899	6,511	902	1	7,414
Jun-11	201,880	23,487	248	225,615	51,490	6,631	10	58,131	13,259	2,236	2	15,497	14,063	1,705	5	15,773	6,500	894	1	7,395
Jul-11	202,925	23,509	251	226,685	51,530	6,585	10	58,125	13,242	2,248	2	15,492	14,003	1,705	5	15,713	6,426	900	1	7,327
Aug-11	202,898	23,493	252	226,643	51,334	6,581	10	57,925	13,235	2,238	2	15,475	13,926	1,702	5	15,633	6,400	902	1	7,303
Sep-11	203,576	23,496	249	227,321	51,253	6,579	10	57,842	13,155	2,239	2	15,396	13,948	1,707	5	15,660	6,398	899	10	7,307
Oct-11	204,181	23,561	252	227,994	51,542	6,585	10	58,137	13,344	2,245	2	15,591	14,133	1,718	5	15,856	6,489	904	7	7,400
Nov-11	205,122	23,516	252	228,890	52,014	6,641	10	58,665	13,475	2,272	2	15,749	14,263	1,740	5	16,008	6,540	900	5	7,445
Dec-11	205,811	23,584	253	229,648	52,285	6,674	10	58,969	13,539	2,277	2	15,818	14,407	1,756	5	16,168	6,583	929	1	7,513
Jan-12	207,852	23,843	246	231,940	53,554	6,713	10	60,276	14,110	2,296	2	16,408	14,574	1,791	5	16,370	6,737	923	1	7,661
Feb-12	207,860	23,852	250	231,962	53,450	6,734	11	60,195	14,130	2,295	2	16,428	14,603	1,820	5	16,428	6,721	922	1	7,644
Mar-12	207,759	23,854	248	231,861	53,353	6,697	10	60,060	14,111	2,343	2	16,456	14,548	1,820	5	16,374	6,679	923	1	7,603
Apr-12	207,296	24,031	254	231,581	53,691	6,745	10	60,447	14,171	2,312	2	16,485	14,580	1,794	5	16,380	6,653	912	1	7,566
May-12	207,165	24,034	254	231,452	53,524	6,736	10	60,270	14,134	2,313	2	16,449	14,514	1,777	5	16,295	6,621	912	1	7,534
Jun-12	206,966	24,099	250	231,315	53,355	6,742	10	60,107	14,024	2,308	2	16,334	14,391	1,771	5	16,166	6,610	904	1	7,515
Jul-12	208,037	24,122	253	232,412	53,396	6,695	10	60,101	14,006	2,320	2	16,329	14,329	1,771	5	16,105	6,534	910	1	7,445
Aug-12	208,010	24,106	254	232,369	53,193	6,691	10	59,894	13,999	2,310	2	16,311	14,251	1,767	5	16,023	6,508	912	1	7,421
Sep-12	208,705	24,109	251	233,064	53,109	6,689	10	59,808	13,914	2,311	2	16,227	14,273	1,773	5	16,051	6,506	909	10	7,425
Oct-12	209,325	24,175	254	233,754	53,408	6,695	10	60,114	14,114	2,317	2	16,433	14,462	1,784	5	16,251	6,599	914	7	7,520
Nov-12	210,290	24,129	254	234,673	53,898	6,752	10	60,660	14,253	2,345	2	16,600	14,595	1,807	5	16,407	6,650	910	5	7,565
Dec-12	210,996	24,199	255	235,450	54,178	6,786	10	60,974	14,321	2,350	2	16,673	14,743	1,824	5	16,571	6,694	939	1	7,634
Jan-13	213,150	24,449	248	237,846	55,425	6,807	10	62,242	14,880	2,356	2	17,238	15,017	1,841	5	16,863	6,849	933	1	7,783
Feb-13	213,158	24,458	252	237,868	55,318	6,829	11	62,158	14,901	2,355	2	17,258	15,046	1,871	5	16,922	6,832	932	1	7,765
Mar-13	213,055	24,460	250	237,765	55,217	6,792	10	62,019	14,881	2,403	2	17,287	14,990	1,871	5	16,866	6,790	933	1	7,724
Apr-13	212,580	24,641	256	237,477	55,568	6,840	10	62,418	14,945	2,372	2	17,319	15,023	1,845	5	16,872	6,764	922	1	7,687
May-13	212,445	24,644	256	237,346	55,394	6,831	10	62,235	14,906	2,373	2	17,281	14,954	1,826	5	16,786	6,731	922	1	7,654
Jun-13	212,241	24,712	252	237,205	55,219	6,837	10	62,066	14,790	2,367	2	17,159	14,828	1,820	5	16,653	6,719	914	1	7,634
Jul-13	213,340	24,735	255	238,330	55,262	6,790	10	62,062	14,771	2,380	2	17,153	14,765	1,820	5	16,590	6,643	920	1	7,564
Aug-13	213,312	24,718	256	238,286	55,052	6,786	10	61,847	14,763	2,370	2	17,135	14,683	1,817	5	16,505	6,616	922	1	7,539
Sep-13	214,025	24,721	253	238,999	54,965	6,783	10	61,759	14,674	2,371	2	17,047	14,707	1,822	5	16,534	6,614	919	10	7,543
Oct-13	214,661	24,790	256	239,706	55,275	6,790	10	62,075	14,885	2,377	2	17,264	14,902	1,834	5	16,740	6,708	924	7	7,639
Nov-13	215,650	24,742	256	240,648	55,781	6,847	10	62,639	15,031	2,406	2	17,438	15,039	1,857	5	16,901	6,761	920	5	7,686
Dec-13	216,374	24,814	257	241,445	56,072	6,881	10	62,963	15,102	2,411	2	17,515	15,191	1,874	5	17,070	6,805	950	1	7,756
Jan-14	218,547	25,055	251	243,852	57,407	6,902	10	64,319	15,650	2,415	2	18,068	15,348	1,875	5	17,228	6,961	938	1	7,900
Feb-14	218,555	25,064	255	243,875	57,296	6,924	11	64,230	15,673	2,414	2	18,089	15,379	1,905	5	17,289	6,944	937	1	7,882
Mar-14	218,450	25,066	253	243,769	57,191	6,886	10	64,087	15,652	2,464	2	18,118	15,322	1,905	5	17,232	6,901	938	1	7,840
Apr-14	217,962	25,252	259	243,473	57,554	6,935	10	64,500	15,718	2,431	2	18,152	15,355	1,878	5	17,238	6,874	927	1	7,802
May-14	217,825	25,255	259	243,339	57,375	6,926	10	64,310	15,677	2,433	2	18,112	15,285	1,859	5	17,149	6,841	927	1	7,769
Jun-14	217,615	25,324	255	243,194	57,193	6,932	10	64,136	15,555	2,427	2	17,985	15,156	1,853	5	17,013	6,829	919	1	7,749
Jul-14	218,742	25,348	258	244,348	57,238	6,884	10	64,132	15,535	2,440	2	17,978	15,091	1,853	5	16,949	6,751	925	1	7,677
Aug-14	218,713	25,331	259	244,302	57,020	6,880	10	63,910	15,527	2,429	2	17,959	15,008	1,850	5	16,863	6,724	927	1	7,652
Sep-14	219,444	25,334	256	245,033	56,930	6,878	10	63,818	15,433	2,430	2	17,866	15,032	1,855	5	16,892	6,722	924	10	7,656
Oct-14	220,096	25,404	259	245,759	57,251	6,884	10	64,145	15,655	2,437	2	18,094	15,231	1,867	5	17,103	6,818	929	7	7,754
Nov-14	221,110	25,355	259	246,724	57,776	6,943	10	64,728	15,809	2,466	2	18,277	15,371	1,891	5	17,267	6,871	925	5	7,801
Dec-14	221,853	25,429	260	247,542	58,077	6,977	10	65,064	15,884	2,472	2	18,358	15,526	1,908	5	17,440	6,916	955	1	7,872
Jan-15	223,945	25,660	254	249,859	59,499	6,996	10	66,505	16,421	2,487	2	18,909	15,680	1,908	5	17,593	7,072	943	1	8,017
Feb-15	223,954	25,670	258	249,882	59,383	7,019	11	66,413	16,444	2,485	2	18,931	15,711	1,939	5	17,655	7,055	942	1	7,998
Mar-15	223,845	25,672	256	249,774	59,275	6,980	10	66,266	16,422	2,537	2	18,961	15,653	1,939	5	17,597	7,012	943	1	7,956
Apr-15	223,346	25,862	262	249,471	59,652	7,030	10	66,692	16,492	2,503	2	18,997	15,687	1,911	5	17,603	6,985	932	1	7,918
May-15	223,205	25,866	262	249,332	59,465	7,021	10	66,496	16,449	2,504	2	18,955	15,615	1,892	5	17,513	6,951	932	1	7,884
Jun-15	222,990	25,936	258	249,185	59,277	7,027	10	66,315	16,321	2,499	2	18,822	15,483	1,886	5	17,374	6,939	924	1	7,864
Jul-15	224,145	25,961	261	250,366	59,324	6,978	10	66,312	16,300	2,512	2	18,814	15,417	1,886	5	17,308	6,860	930	1	7,791
Aug-15	224,115	25,943	262	250,320	59,098	6,974	10	66,082	16,291	2,501	2	18,794	15,333	1,883	5	17,220	6,832	932	1	7,765
Sep-15	224,864	25,946	259	251,069	59,005	6,972	10	65,987	16,193	2,502	2	18,697	15,357	1,888	5	17,250	6,830	929	10	7,769
Oct-15	225,532	26,018	262	251,812	59,337	6,978	10	66,326	16,426	2,509	2	18,936	15,560	1,900	5	17,466	6,927	934	7	7,868

Appendix 3.2 - Customer Forecast - Number by Region
Expected Case

	WA/ID				Medford				Roseburg				Klamath Falls				La Grande			
	WA/ID Res	WA/ID Com	WA/ID Firm Ind	WA/ID Total	MFR Res	MFR Com	MFR Firm Ind	MFR Total	ROS Res	ROS Com	ROS Firm Ind	ROS Total	KLA Res	KLA Com	KLA Firm Ind	KLA Total	LGD Res	LGD Com	LGD Firm Ind	LGD Total
Nov-15	226,571	25,968	262	252,802	59,881	7,038	10	66,928	16,587	2,539	2	19,128	15,704	1,925	5	17,633	6,982	930	5	7,916
Dec-15	227,332	26,044	263	253,639	60,193	7,073	10	67,275	16,666	2,545	2	19,212	15,862	1,942	5	17,809	7,028	960	1	7,988
Jan-16	229,342	26,266	257	255,864	61,590	7,086	10	68,686	17,191	2,546	2	19,739	16,012	1,941	5	17,959	7,184	948	1	8,133
Feb-16	229,351	26,276	261	255,888	61,471	7,108	11	68,590	17,215	2,545	2	19,762	16,044	1,973	5	18,022	7,167	947	1	8,115
Mar-16	229,240	26,279	259	255,777	61,359	7,070	10	68,439	17,192	2,597	2	19,791	15,984	1,973	5	17,962	7,122	948	1	8,072
Apr-16	228,728	26,473	265	255,467	61,749	7,120	10	68,879	17,265	2,563	2	19,831	16,019	1,945	5	17,969	7,095	937	1	8,033
May-16	228,584	26,476	265	255,325	61,556	7,110	10	68,676	17,220	2,564	2	19,787	15,946	1,926	5	17,877	7,061	937	1	7,998
Jun-16	228,364	26,549	261	255,174	61,361	7,117	10	68,488	17,086	2,559	2	19,647	15,811	1,919	5	17,735	7,049	929	1	7,978
Jul-16	229,546	26,574	264	256,384	61,409	7,067	10	68,487	17,064	2,572	2	19,639	15,744	1,919	5	17,667	6,968	935	1	7,904
Aug-16	229,516	26,556	265	256,336	61,176	7,063	10	68,249	17,055	2,561	2	19,618	15,657	1,915	5	17,578	6,940	937	1	7,878
Sep-16	230,283	26,559	262	257,104	61,079	7,061	10	68,150	16,952	2,562	2	19,516	15,682	1,921	5	17,608	6,938	934	10	7,882
Oct-16	230,967	26,632	265	257,865	61,423	7,067	10	68,501	17,196	2,569	2	19,767	15,890	1,933	5	17,828	7,037	939	7	7,983
Nov-16	232,032	26,582	265	258,878	61,986	7,128	10	69,123	17,365	2,600	2	19,966	16,036	1,958	5	17,999	7,092	935	5	8,032
Dec-16	232,811	26,658	266	259,736	62,309	7,163	10	69,482	17,447	2,605	2	20,055	16,198	1,976	5	18,179	7,139	965	1	8,105
Jan-17	234,735	26,871	259	261,864	63,572	7,170	10	70,752	17,961	2,605	2	20,568	16,344	1,975	5	18,324	7,296	953	1	8,250
Feb-17	234,744	26,881	263	261,888	63,449	7,193	11	70,652	17,986	2,604	2	20,593	16,376	2,007	5	18,388	7,278	952	1	8,232
Mar-17	234,630	26,884	261	261,775	63,333	7,154	10	70,497	17,962	2,658	2	20,622	16,316	2,007	5	18,327	7,233	953	1	8,188
Apr-17	234,107	27,083	267	261,457	63,735	7,205	10	70,950	18,039	2,623	2	20,664	16,351	1,978	5	18,334	7,206	942	1	8,149
May-17	233,959	27,086	267	261,312	63,536	7,195	10	70,741	17,992	2,624	2	20,618	16,277	1,959	5	18,240	7,170	942	1	8,113
Jun-17	233,734	27,160	263	261,157	63,336	7,201	10	70,547	17,852	2,618	2	20,472	16,139	1,952	5	18,096	7,158	933	1	8,093
Jul-17	234,944	27,186	266	262,396	63,385	7,151	10	70,546	17,829	2,632	2	20,463	16,070	1,952	5	18,027	7,077	940	1	8,018
Aug-17	234,913	27,167	267	262,347	63,144	7,147	10	70,301	17,819	2,621	2	20,442	15,982	1,948	5	17,935	7,048	942	1	7,991
Sep-17	235,698	27,171	264	263,132	63,044	7,145	10	70,199	17,712	2,622	2	20,336	16,007	1,954	5	17,966	7,046	939	10	7,995
Oct-17	236,398	27,246	267	263,911	63,400	7,151	10	70,561	17,966	2,629	2	20,597	16,219	1,967	5	18,191	7,146	944	7	8,097
Nov-17	237,488	27,194	267	264,949	63,980	7,212	10	71,202	18,143	2,660	2	20,805	16,368	1,992	5	18,365	7,202	940	5	8,147
Dec-17	238,285	27,272	268	265,826	64,314	7,248	10	71,572	18,229	2,666	2	20,897	16,534	2,010	5	18,549	7,250	970	1	8,221
Jan-18	240,226	27,497	262	267,985	65,443	7,254	10	72,707	18,731	2,653	2	21,386	16,676	2,008	5	18,689	7,408	958	1	8,367
Feb-18	240,236	27,507	266	268,009	65,317	7,277	11	72,605	18,758	2,652	2	21,411	16,709	2,041	5	18,755	7,390	957	1	8,348
Mar-18	240,120	27,510	264	267,893	65,198	7,237	10	72,445	18,732	2,707	2	21,441	16,647	2,041	5	18,693	7,344	958	1	8,304
Apr-18	239,584	27,713	270	267,567	65,612	7,289	10	72,911	18,812	2,671	2	21,485	16,683	2,011	5	18,700	7,316	947	1	8,264
May-18	239,432	27,717	270	267,419	65,407	7,279	10	72,696	18,763	2,672	2	21,437	16,607	1,992	5	18,604	7,280	947	1	8,228
Jun-18	239,203	27,793	266	267,261	65,200	7,286	10	72,496	18,617	2,666	2	21,285	16,467	1,985	5	18,456	7,268	938	1	8,208
Jul-18	240,441	27,819	269	268,528	65,251	7,235	10	72,496	18,593	2,680	2	21,276	16,396	1,985	5	18,386	7,185	945	1	8,131
Aug-18	240,409	27,800	270	268,478	65,003	7,231	10	72,244	18,584	2,668	2	21,254	16,306	1,981	5	18,292	7,156	947	1	8,104
Sep-18	241,212	27,803	267	269,282	64,900	7,229	10	72,139	18,471	2,670	2	21,143	16,332	1,987	5	18,324	7,154	944	10	8,108
Oct-18	241,929	27,880	270	270,079	65,266	7,235	10	72,511	18,737	2,677	2	21,415	16,549	2,000	5	18,553	7,256	949	7	8,212
Nov-18	243,044	27,827	270	271,141	65,864	7,297	10	73,171	18,921	2,709	2	21,632	16,701	2,025	5	18,731	7,313	945	5	8,263
Dec-18	243,860	27,907	271	272,039	66,207	7,333	10	73,550	19,010	2,715	2	21,727	16,869	2,044	5	18,919	7,361	975	1	8,337
Jan-19	245,719	28,122	265	274,107	67,205	7,333	10	74,548	19,501	2,700	2	22,204	17,008	2,041	5	19,054	7,520	963	1	8,484
Feb-19	245,729	28,133	270	274,132	67,075	7,356	11	74,442	19,529	2,699	2	22,230	17,042	2,074	5	19,121	7,502	962	1	8,465
Mar-19	245,610	28,136	268	274,013	66,953	7,316	10	74,279	19,503	2,755	2	22,260	16,978	2,074	5	19,058	7,455	963	1	8,419
Apr-19	245,062	28,344	274	273,680	67,378	7,368	10	74,756	19,586	2,719	2	22,307	17,015	2,045	5	19,065	7,427	952	1	8,379
May-19	244,907	28,347	274	273,529	67,167	7,358	10	74,535	19,535	2,720	2	22,257	16,938	2,025	5	18,967	7,390	952	1	8,343
Jun-19	244,672	28,425	270	273,367	66,955	7,365	10	74,330	19,383	2,714	2	22,099	16,794	2,018	5	18,817	7,378	943	1	8,322
Jul-19	245,938	28,452	273	274,663	67,007	7,314	10	74,331	19,358	2,728	2	22,088	16,723	2,018	5	18,745	7,294	950	1	8,245
Aug-19	245,906	28,432	274	274,612	66,752	7,309	10	74,072	19,348	2,716	2	22,066	16,631	2,014	5	18,650	7,264	952	1	8,217
Sep-19	246,727	28,436	271	275,434	66,647	7,307	10	73,964	19,231	2,717	2	21,950	16,657	2,020	5	18,682	7,262	949	10	8,221
Oct-19	247,461	28,514	274	276,249	67,023	7,314	10	74,347	19,507	2,725	2	22,234	16,878	2,033	5	18,916	7,365	954	7	8,326
Nov-19	248,601	28,460	274	277,335	67,637	7,376	10	75,023	19,699	2,758	2	22,458	17,033	2,059	5	19,097	7,423	950	5	8,378
Dec-19	249,436	28,542	275	278,254	67,989	7,413	10	75,412	19,792	2,764	2	22,558	17,205	2,078	5	19,288	7,472	980	1	8,453
Jan-20	251,410	28,772	266	280,448	68,966	7,422	10	76,398	20,271	2,748	2	23,021	17,340	2,075	5	19,420	7,632	968	1	8,601
Feb-20	251,420	28,783	271	280,474	68,833	7,446	11	76,290	20,300	2,747	2	23,049	17,374	2,108	5	19,488	7,613	967	1	8,582
Mar-20	251,299	28,785	269	280,353	68,707	7,405	10	76,123	20,273	2,804	2	23,078	17,310	2,108	5	19,423	7,566	968	1	8,535
Apr-20	250,738	28,998	275	280,012	69,144	7,458	10	76,612	20,359	2,767	2	23,128	17,347	2,078	5	19,431	7,537	957	1	8,495
May-20	250,579	29,002	275	279,857	68,928	7,448	10	76,386	20,306	2,768	2	23,076	17,268	2,058	5	19,331	7,500	957	1	8,458
Jun-20	250,339	29,081	271	279,691	68,710	7,455	10	76,175	20,148	2,762	2	22,912	17,122	2,051	5	19,178	7,488	948	1	8,437
Jul-20	251,635	29,109	274	281,017	68,764	7,403	10	76,176	20,122	2,776	2	22,901	17,049	2,051	5	19,105	7,402	955	1	8,358
Aug-20	251,601	29,089	275	280,965	68,502	7,398	10	75,910	20,112	2,764	2	22,878	16,955	2,047	5	19,007	7,372	957	1	8,330
Sep-20	252,442	29,093	272	281,806	68,394	7,396	10	75,800	19,990	2,765	2	22,757	16,982	2,053	5	19,040	7,370	954	10	8,334
Oct-20	253,192	29,173	275	282,640	68,780	7,403	10	76,192	20,277	2,773	2	23,052	17,207	2,066	5	19,279	7,475	959	7	8,441
Nov-20	254,359	29,117	275	283,751	69,409	7,466	10	76,885	20,476	2,806	2	23,284	17,366	2,093	5	19,463	7,534	955	5	8,493
Dec-20	255,213	29,201	276	284,691	69,771	7,503	10	77,284	20,574	2,812	2	23,388	17,541	2,112	5	19,658	7,583	985	1	8,570
Jan-21	257,202	29,423	269	286,895	70,728	7,506	10	78,244	21,041	2,796	2	23,839	17,672	2,108	5	19,785	7,743	973	1	8,718
Feb-21	257,212	29,435	274	286,921	70,591	7,530	11	78,132	21,071	2,794	2	23,868	17,707	2,142	5	19,854	7,725	972	1	8,698
Mar-21	257,088	29,437	272	286,797	70,462	7,489	10	77,961	21,043	2,852	2	23,897	17,641	2,142	5	19,788	7,677	973	1	8,651
Apr-21	256,515	29,655	278	286,448	70,910	7,543	10	78,462	21,133	2,814	2	23,949	17,680	2,112	5	19,796	7,648	962	1	8,610
May-21	256,352	29,659	278	286,289	70,688	7,532	10	78,230	21,078	2,816	2	23,895	17,599	2,091	5	19,695	7,610	962	1	8,573
Jun-21	256,106	29,740	274	286,120	70,465	7,539	10	78,014	20,914	2,809	2	23,725	17,450	2,083	5	19,538	7,597	953	1	8,552
Jul-21	257,432	29,768	277	287,477	70,520	7,487	10	78,017	20,887	2,824	2	23,713	17,376	2,083	5	19,464	7,511	960	1	8,471
Aug-21	257,398	29,747	278	287,423	70,252	7,482	10	77,744	20,876	2,812	2	23,690	17,280	2,080	5	19,365	7,480	962	1	8,443
Sep-21	258,258	29,751	275	288,284	70,141	7,480	10	77,631	20,750	2,813	2	23,565	17,307	2,086	5	19,398	7,478	959	10	8,447
Oct-21	259,025	29,834	278	289,137	70,536	7,487	10	78,033	21,048	2,821	2	23,870	17,537	2,099	5	19,641	7,584	964	7	8,555

Appendix 3.2 - Customer Forecast - Number by Region
Expected Case

	WA/ID				Medford				Roseburg				Klamath Falls				La Grande			
	WA/ID Res	WA/ID Com	WA/ID Firm Ind	WA/ID Total	MFR Res	MFR Com	MFR Firm Ind	MFR Total	ROS Res	ROS Com	ROS Firm Ind	ROS Total	KLA Res	KLA Com	KLA Firm Ind	KLA Total	LGD Res	LGD Com	LGD Firm Ind	LGD Total
Nov-21	260,219	29,777	278	290,274	71,182	7,550	10	78,743	21,254	2,855	2	24,111	17,698	2,126	5	19,829	7,644	960	5	8,609
Dec-21	261,093	29,863	279	291,235	71,553	7,588	10	79,151	21,355	2,861	2	24,218	17,877	2,146	5	20,028	7,694	991	1	8,686
Jan-22	263,093	30,074	271	293,438	72,489	7,590	10	80,090	21,812	2,843	2	24,657	18,004	2,141	5	20,150	7,855	979	1	8,835
Feb-22	263,103	30,085	276	293,464	72,349	7,614	11	79,974	21,843	2,842	2	24,686	18,039	2,176	5	20,220	7,836	977	1	8,815
Mar-22	262,976	30,088	274	293,338	72,217	7,573	10	79,800	21,813	2,901	2	24,716	17,972	2,176	5	20,153	7,788	979	1	8,767
Apr-22	262,390	30,311	280	292,980	72,676	7,627	10	80,313	21,906	2,862	2	24,771	18,012	2,145	5	20,162	7,758	967	1	8,726
May-22	262,223	30,314	280	292,818	72,449	7,617	10	80,075	21,849	2,864	2	24,715	17,929	2,124	5	20,058	7,720	967	1	8,688
Jun-22	261,972	30,397	276	292,645	72,220	7,624	10	79,854	21,679	2,857	2	24,538	17,778	2,116	5	19,899	7,707	958	1	8,666
Jul-22	263,328	30,426	279	294,033	72,276	7,571	10	79,857	21,651	2,872	2	24,526	17,702	2,116	5	19,823	7,619	965	1	8,585
Aug-22	263,293	30,405	280	293,978	72,001	7,566	10	79,577	21,640	2,860	2	24,502	17,605	2,113	5	19,722	7,588	967	1	8,556
Sep-22	264,173	30,409	277	294,858	71,888	7,564	10	79,461	21,509	2,861	2	24,372	17,632	2,119	5	19,756	7,586	964	10	8,560
Oct-22	264,958	30,493	280	295,731	72,293	7,571	10	79,874	21,818	2,869	2	24,689	17,866	2,133	5	20,004	7,694	969	7	8,670
Nov-22	266,179	30,435	280	296,894	72,955	7,635	10	80,600	22,032	2,903	2	24,937	18,031	2,160	5	20,195	7,754	965	5	8,724
Dec-22	267,073	30,523	281	297,877	73,335	7,673	10	81,018	22,137	2,910	2	25,049	18,213	2,180	5	20,397	7,805	996	1	8,802
Jan-23	269,084	30,723	274	300,082	74,251	7,674	10	81,935	22,582	2,891	2	25,474	18,336	2,175	5	20,516	7,967	984	1	8,952
Feb-23	269,095	30,735	279	300,109	74,107	7,699	11	81,817	22,614	2,889	2	25,505	18,372	2,210	5	20,587	7,948	982	1	8,931
Mar-23	268,965	30,738	276	299,979	73,972	7,657	10	81,639	22,583	2,949	2	25,535	18,304	2,210	5	20,519	7,899	984	1	8,883
Apr-23	268,365	30,965	283	299,613	74,442	7,711	10	82,163	22,680	2,910	2	25,592	18,344	2,178	5	20,527	7,868	972	1	8,841
May-23	268,195	30,969	283	299,448	74,209	7,701	10	81,920	22,621	2,911	2	25,534	18,260	2,157	5	20,422	7,830	972	1	8,803
Jun-23	267,938	31,054	279	299,270	73,975	7,708	10	81,693	22,445	2,905	2	25,352	18,106	2,149	5	20,260	7,817	963	1	8,781
Jul-23	269,325	31,083	282	300,690	74,032	7,655	10	81,697	22,416	2,921	2	25,338	18,028	2,149	5	20,183	7,728	970	1	8,698
Aug-23	269,289	31,062	283	300,634	73,751	7,650	10	81,411	22,404	2,908	2	25,314	17,929	2,146	5	20,080	7,697	972	1	8,669
Sep-23	270,189	31,066	280	301,534	73,634	7,648	10	81,292	22,269	2,909	2	25,179	17,957	2,152	5	20,114	7,694	968	10	8,673
Oct-23	270,992	31,152	283	302,426	74,050	7,655	10	81,714	22,589	2,917	2	25,507	18,196	2,166	5	20,366	7,804	974	7	8,784
Nov-23	272,240	31,092	283	303,616	74,728	7,720	10	82,457	22,810	2,952	2	25,764	18,363	2,194	5	20,562	7,865	970	5	8,839
Dec-23	273,155	31,182	284	304,621	75,117	7,758	10	82,885	22,919	2,958	2	25,879	18,548	2,214	5	20,767	7,917	1,001	1	8,918
Jan-24	275,076	31,374	275	306,725	76,012	7,753	10	83,775	23,352	2,950	2	26,304	18,668	2,208	5	20,881	8,079	989	1	9,069
Feb-24	275,087	31,386	280	306,752	75,865	7,778	11	83,654	23,385	2,949	2	26,336	18,705	2,244	5	20,953	8,059	988	1	9,048
Mar-24	274,954	31,389	277	306,620	75,727	7,735	10	83,472	23,354	3,010	2	26,365	18,635	2,244	5	20,884	8,009	989	1	8,999
Apr-24	274,340	31,621	284	306,245	76,208	7,791	10	84,009	23,453	2,970	2	26,425	18,676	2,212	5	20,893	7,979	977	1	8,957
May-24	274,167	31,625	284	306,076	75,970	7,780	10	83,760	23,392	2,971	2	26,365	18,591	2,190	5	20,786	7,940	977	1	8,918
Jun-24	273,904	31,711	280	305,895	75,730	7,787	10	83,527	23,210	2,965	2	26,177	18,433	2,182	5	20,621	7,926	968	1	8,896
Jul-24	275,321	31,741	283	307,345	75,789	7,733	10	83,532	23,180	2,981	2	26,163	18,355	2,182	5	20,542	7,836	975	1	8,812
Aug-24	275,285	31,719	284	307,288	75,500	7,728	10	83,239	23,168	2,967	2	26,137	18,254	2,178	5	20,437	7,805	977	1	8,782
Sep-24	276,205	31,723	281	308,209	75,381	7,726	10	83,117	23,028	2,969	2	25,999	18,283	2,185	5	20,472	7,802	973	10	8,786
Oct-24	277,026	31,811	284	309,121	75,806	7,733	10	83,549	23,359	2,977	2	26,337	18,525	2,199	5	20,729	7,913	979	7	8,899
Nov-24	278,302	31,750	284	310,337	76,501	7,799	10	84,309	23,588	3,012	2	26,603	18,695	2,227	5	20,928	7,975	975	5	8,955
Dec-24	279,237	31,842	285	311,365	76,899	7,838	10	84,747	23,700	3,019	2	26,721	18,884	2,248	5	21,137	8,028	1,006	1	9,035
Jan-25	281,067	32,049	278	313,394	77,774	7,832	10	85,616	24,012	2,998	2	27,012	19,000	2,241	5	21,246	8,191	994	1	9,185
Feb-25	281,078	32,061	283	313,422	77,623	7,857	11	85,491	24,046	2,996	2	27,044	19,037	2,278	5	21,320	8,171	993	1	9,165
Mar-25	280,943	32,064	280	313,287	77,482	7,814	10	85,306	24,014	3,058	2	27,074	18,967	2,278	5	21,249	8,120	994	1	9,115
Apr-25	280,316	32,301	287	312,905	77,974	7,870	10	85,854	24,116	3,018	2	27,136	19,008	2,245	5	21,258	8,089	982	1	9,072
May-25	280,139	32,305	287	312,731	77,730	7,859	10	85,599	24,053	3,019	2	27,075	18,921	2,223	5	21,149	8,050	982	1	9,032
Jun-25	279,870	32,394	283	312,546	77,485	7,866	10	85,361	23,866	3,012	2	26,881	18,761	2,215	5	20,981	8,036	973	1	9,010
Jul-25	281,318	32,424	286	314,028	77,545	7,812	10	85,367	23,836	3,029	2	26,866	18,681	2,215	5	20,901	7,945	979	1	8,925
Aug-25	281,281	32,402	287	313,970	77,250	7,807	10	85,067	23,823	3,015	2	26,840	18,578	2,211	5	20,795	7,913	982	1	8,895
Sep-25	282,221	32,406	284	314,911	77,128	7,805	10	84,943	23,679	3,016	2	26,697	18,608	2,218	5	20,831	7,910	978	10	8,899
Oct-25	283,059	32,496	287	315,843	77,563	7,812	10	85,385	24,019	3,025	2	27,046	18,854	2,232	5	21,092	8,023	984	7	9,013
Nov-25	284,364	32,434	287	317,085	78,273	7,878	10	86,162	24,255	3,061	2	27,318	19,028	2,261	5	21,294	8,086	979	5	9,070
Dec-25	285,319	32,528	288	318,135	78,681	7,917	10	86,608	24,370	3,068	2	27,440	19,220	2,282	5	21,507	8,139	1,011	1	9,151
Jan-26	287,059	32,724	280	320,063	79,425	7,911	10	87,346	24,672	3,045	2	27,719	19,332	2,275	5	21,611	8,303	999	1	9,302
Feb-26	287,070	32,737	285	320,092	79,271	7,936	11	87,218	24,707	3,044	2	27,753	19,370	2,312	5	21,686	8,283	998	1	9,281
Mar-26	286,931	32,740	282	319,953	79,127	7,893	10	87,030	24,674	3,107	2	27,783	19,298	2,312	5	21,614	8,231	999	1	9,231
Apr-26	286,291	32,982	289	319,563	79,629	7,949	10	87,589	24,779	3,066	2	27,847	19,340	2,279	5	21,623	8,200	987	1	9,187
May-26	286,110	32,986	289	319,386	79,381	7,938	10	87,329	24,715	3,067	2	27,784	19,252	2,256	5	21,513	8,160	987	1	9,147
Jun-26	285,836	33,076	285	319,196	79,130	7,946	10	87,086	24,522	3,060	2	27,585	19,089	2,248	5	21,342	8,146	978	1	9,125
Jul-26	287,315	33,107	288	320,710	79,191	7,890	10	87,092	24,491	3,077	2	27,570	19,007	2,248	5	21,261	8,053	984	1	9,039
Aug-26	287,277	33,085	289	320,651	78,890	7,886	10	86,786	24,478	3,063	2	27,543	18,903	2,244	5	21,152	8,021	987	1	9,008
Sep-26	288,237	33,089	286	321,612	78,766	7,883	10	86,659	24,330	3,064	2	27,396	18,933	2,251	5	21,189	8,018	983	10	9,011
Oct-26	289,093	33,180	289	322,563	79,210	7,890	10	87,110	24,680	3,073	2	27,754	19,184	2,265	5	21,454	8,132	989	7	9,128
Nov-26	290,426	33,117	289	323,832	79,935	7,957	10	87,903	24,922	3,109	2	28,033	19,360	2,294	5	21,660	8,196	984	5	9,186
Dec-26	291,401	33,213	290	324,905	80,352	7,997	10	88,359	25,040	3,116	2	28,159	19,556	2,315	5	21,876	8,250	1,016	1	9,267
Jan-27	292,951	33,399	283	326,633	81,076	7,990	10	89,076	25,332	3,093	2	28,427	19,664	2,308	5	21,977	8,414	1,004	1	9,419
Feb-27	292,962	33,412	288	326,662	80,920	8,015	11	88,946	25,368	3,091	2	28,462	19,702	2,345	5	22,053	8,394	1,003	1	9,398
Mar-27	292,821	33,415	285	326,521	80,772	7,971	10	88,754	25,334	3,155	2	28,491	19,629	2,345	5	21,980	8,342	1,004	1	9,347
Apr-27	292,167	33,662	292	326,122	81,285	8,028	10	89,323	25,442	3,114	2	28,558	19,672	2,312	5	21,989	8,310	992	1	9,303
May-27	291,982	33,667	292	325,942	81,031	8,017	10	89,058	25,376	3,115	2	28,493	19,582	2,289	5	21,876	8,270	992	1	9,262
Jun-27	291,702	33,759	288	325,749	80,775	8,025	10	88,810	25,178	3,108	2	28,288	19,417	2,281	5	21,703	8,256	983	1	9,240
Jul-27	293,212	33,790	291	327,294	80,838	7,969	10	88,817	25,146	3,125	2	28,273	19,334	2,281	5	21,620	8,162	989	1	9,152
Aug-27	293,173	33,767	292	327,233	80,531	7,964	10	88,505	25,133	3,111	2	28,246	19,227	2,277	5	21,510	8,129	992	1	9,121
Sep-27	294,153	33,772	289	328,213	80,403	7,962	10	88,375	24,981	3,112	2	28,095	19,258	2,284	5	21,547	8,126	988	10	9,124
Oct-27	295,027	33,865	292	329,184	80,857	7,969	10	88,836	25,340	3,121	2	28,462	19,513	2,299	5	21,817	8,242	994	7	9,243

Appendix 3.2 - Customer Forecast - Number by Region
Expected Case

	WA/ID				Medford				Roseburg				Klamath Falls				La Grande			
	WA/ID Res	WA/ID Com	WA/ID Firm Ind	WA/ID Total	MFR Res	MFR Com	MFR Firm Ind	MFR Total	ROS Res	ROS Com	ROS Firm Ind	ROS Total	KLA Res	KLA Com	KLA Firm Ind	KLA Total	LGD Res	LGD Com	LGD Firm Ind	LGD Total
Nov-27	296,387	33,800	292	330,479	81,597	8,037	10	89,644	25,589	3,158	2	28,749	19,693	2,328	5	22,026	8,306	989	5	9,301
Dec-27	297,382	33,898	293	331,574	82,022	8,077	10	90,109	25,710	3,165	2	28,877	19,892	2,349	5	22,246	8,361	1,021	1	9,383
Jan-28	298,842	34,075	285	333,202	82,728	8,068	10	90,806	25,992	3,140	2	29,135	19,996	2,341	5	22,342	8,526	1,009	1	9,536
Feb-28	298,854	34,088	290	333,232	82,568	8,094	11	90,673	26,029	3,139	2	29,170	20,035	2,379	5	22,419	8,506	1,008	1	9,514
Mar-28	298,710	34,091	287	333,088	82,417	8,050	10	90,477	25,994	3,204	2	29,200	19,961	2,379	5	22,345	8,453	1,009	1	9,463
Apr-28	298,043	34,343	294	332,681	82,941	8,108	10	91,058	26,105	3,161	2	29,269	20,004	2,345	5	22,354	8,421	997	1	9,418
May-28	297,855	34,347	294	332,496	82,681	8,097	10	90,788	26,037	3,163	2	29,202	19,913	2,322	5	22,240	8,380	997	1	9,377
Jun-28	297,569	34,441	290	332,300	82,420	8,104	10	90,534	25,835	3,156	2	28,992	19,744	2,314	5	22,063	8,365	988	1	9,354
Jul-28	299,109	34,474	293	333,876	82,485	8,048	10	90,542	25,801	3,173	2	28,976	19,660	2,314	5	21,979	8,270	994	1	9,266
Aug-28	299,069	34,450	294	333,814	82,171	8,043	10	90,224	25,788	3,159	2	28,948	19,552	2,310	5	21,867	8,237	997	1	9,234
Sep-28	300,069	34,454	291	334,814	82,041	8,040	10	90,091	25,632	3,160	2	28,794	19,583	2,317	5	21,905	8,234	993	10	9,237
Oct-28	300,960	34,550	294	335,805	82,504	8,048	10	90,561	26,000	3,168	2	29,171	19,843	2,332	5	22,179	8,351	999	7	9,357
Nov-28	302,347	34,484	294	337,126	83,259	8,116	10	91,385	26,255	3,207	2	29,464	20,025	2,362	5	22,392	8,417	994	5	9,416
Dec-28	303,363	34,583	295	338,242	83,693	8,156	10	91,859	26,380	3,214	2	29,596	20,227	2,383	5	22,616	8,472	1,026	1	9,500
Jan-29	304,634	34,725	288	339,647	84,379	8,147	10	92,536	26,652	3,200	2	29,854	20,328	2,375	5	22,707	8,638	1,014	1	9,653
Feb-29	304,646	34,739	293	339,677	84,216	8,173	11	92,400	26,690	3,198	2	29,891	20,368	2,413	5	22,786	8,617	1,013	1	9,631
Mar-29	304,499	34,742	290	339,531	84,062	8,129	10	92,201	26,654	3,264	2	29,921	20,292	2,413	5	22,710	8,564	1,014	1	9,579
Apr-29	303,820	34,999	297	339,116	84,596	8,187	10	92,793	26,768	3,221	2	29,992	20,336	2,379	5	22,720	8,531	1,002	1	9,534
May-29	303,628	35,003	297	338,928	84,332	8,176	10	92,517	26,698	3,223	2	29,923	20,243	2,355	5	22,604	8,489	1,002	1	9,492
Jun-29	303,336	35,099	293	338,727	84,066	8,183	10	92,259	26,491	3,216	2	29,708	20,072	2,347	5	22,424	8,475	993	1	9,469
Jul-29	304,906	35,132	296	340,334	84,131	8,126	10	92,267	26,457	3,233	2	29,691	19,987	2,347	5	22,339	8,379	999	1	9,379
Aug-29	304,866	35,108	297	340,271	83,811	8,121	10	91,942	26,443	3,218	2	29,663	19,877	2,343	5	22,225	8,345	1,002	1	9,347
Sep-29	305,884	35,112	294	341,290	83,679	8,119	10	91,808	26,283	3,220	2	29,505	19,908	2,350	5	22,263	8,342	998	10	9,350
Oct-29	306,793	35,209	297	342,300	84,151	8,126	10	92,287	26,660	3,228	2	29,891	20,172	2,365	5	22,542	8,461	1,004	7	9,472
Nov-29	308,207	35,142	297	343,647	84,921	8,195	10	93,127	26,922	3,267	2	30,191	20,358	2,395	5	22,758	8,527	999	5	9,532
Dec-29	309,243	35,244	299	344,785	85,364	8,236	10	93,610	27,050	3,274	2	30,327	20,563	2,417	5	22,985	8,583	1,032	1	9,616

Appendix 3.2 - Customer Forecast - Number by Region
Low Growth

	WA/ID				Medford				Roseburg				Klamath Falls				La Grande			
	WA/ID Res	WA/ID Com	WA/ID Firm Ind	WA/ID Total	MFR Res	MFR Com	MFR Firm Ind	MFR Total	ROS Res	ROS Com	ROS Firm Ind	ROS Total	KLA Res	KLA Com	KLA Firm Ind	KLA Total	LGD Res	LGD Com	LGD Firm Ind	LGD Total
Nov-09	199,086	22,553	246	221,884	50,231	6,426	10	56,667	13,043	2,146	2	15,191	13,775	1,618	5	15,398	6,423	879	5	7,307
Dec-09	199,433	22,587	247	222,266	50,366	6,442	10	56,818	13,075	2,149	2	15,225	13,846	1,626	5	15,477	6,444	893	1	7,338
Jan-10	199,656	22,683	245	222,583	50,513	6,456	10	56,979	13,100	2,153	2	15,254	13,888	1,635	5	15,528	6,477	887	1	7,366
Feb-10	199,660	22,687	246	222,593	50,464	6,466	11	56,941	13,109	2,152	2	15,263	13,902	1,649	5	15,556	6,469	887	1	7,357
Mar-10	199,610	22,688	245	222,544	50,417	6,448	10	56,875	13,100	2,175	2	15,278	13,875	1,649	5	15,530	6,449	887	1	7,338
Apr-10	199,383	22,775	248	222,406	50,530	6,472	10	57,012	13,104	2,160	2	15,266	13,866	1,637	5	15,508	6,437	882	1	7,320
May-10	199,318	22,777	248	222,343	50,449	6,467	10	56,927	13,086	2,161	2	15,249	13,834	1,628	5	15,467	6,421	882	1	7,304
Jun-10	199,221	22,809	246	222,276	50,368	6,470	10	56,849	13,035	2,158	2	15,195	13,775	1,625	5	15,405	6,416	878	1	7,295
Jul-10	199,495	22,820	248	222,563	50,339	6,447	10	56,796	13,026	2,164	2	15,192	13,745	1,625	5	15,376	6,379	881	1	7,261
Aug-10	199,482	22,812	248	222,542	50,241	6,445	10	56,697	13,023	2,159	2	15,184	13,707	1,624	5	15,336	6,366	882	1	7,249
Sep-10	199,823	22,814	247	222,883	50,201	6,444	10	56,656	12,983	2,160	2	15,145	13,718	1,626	5	15,349	6,365	881	10	7,256
Oct-10	200,128	22,847	248	223,222	50,295	6,447	10	56,752	13,052	2,163	2	15,217	13,785	1,632	5	15,421	6,410	883	7	7,300
Nov-10	200,601	22,824	248	223,673	50,529	6,475	10	57,015	13,117	2,176	2	15,295	13,849	1,643	5	15,497	6,435	881	5	7,321
Dec-10	200,948	22,858	249	224,055	50,664	6,492	10	57,165	13,149	2,179	2	15,330	13,920	1,651	5	15,576	6,457	895	1	7,353
Jan-11	201,278	22,966	246	224,490	50,861	6,508	10	57,379	13,175	2,189	2	15,365	13,962	1,669	5	15,635	6,502	892	1	7,395
Feb-11	201,282	22,971	248	224,501	50,811	6,519	11	57,340	13,184	2,188	2	15,374	13,976	1,682	5	15,663	6,494	892	1	7,387
Mar-11	201,232	22,972	247	224,451	50,764	6,501	10	57,275	13,175	2,211	2	15,388	13,949	1,682	5	15,637	6,474	892	1	7,367
Apr-11	201,005	23,059	250	224,314	50,927	6,524	10	57,461	13,203	2,196	2	15,402	13,965	1,670	5	15,640	6,462	887	1	7,350
May-11	200,940	23,061	250	224,251	50,846	6,520	10	57,376	13,186	2,197	2	15,385	13,933	1,662	5	15,599	6,446	887	1	7,334
Jun-11	200,843	23,093	248	224,184	50,765	6,523	10	57,298	13,134	2,194	2	15,331	13,873	1,659	5	15,537	6,440	883	1	7,324
Jul-11	201,369	23,104	250	224,722	50,785	6,500	10	57,295	13,126	2,200	2	15,328	13,844	1,659	5	15,507	6,404	886	1	7,291
Aug-11	201,355	23,096	250	224,701	50,688	6,498	10	57,196	13,122	2,195	2	15,320	13,806	1,657	5	15,468	6,391	887	1	7,279
Sep-11	201,696	23,097	249	225,043	50,648	6,497	10	57,155	13,082	2,196	2	15,280	13,817	1,660	5	15,481	6,390	885	10	7,285
Oct-11	202,001	23,130	250	225,382	50,791	6,500	10	57,301	13,176	2,199	2	15,377	13,908	1,665	5	15,578	6,435	888	7	7,330
Nov-11	202,475	23,108	250	225,833	51,026	6,528	10	57,563	13,242	2,212	2	15,456	13,972	1,676	5	15,653	6,460	886	5	7,351
Dec-11	202,822	23,142	251	226,214	51,160	6,544	10	57,714	13,274	2,215	2	15,490	14,043	1,684	5	15,732	6,481	900	1	7,383
Jan-12	203,849	23,273	247	227,369	51,790	6,563	10	58,363	13,558	2,225	2	15,784	14,126	1,702	5	15,832	6,557	897	1	7,456
Feb-12	203,853	23,278	249	227,380	51,738	6,574	11	58,323	13,568	2,224	2	15,794	14,140	1,716	5	15,861	6,549	897	1	7,447
Mar-12	203,803	23,279	248	227,330	51,690	6,556	10	58,256	13,558	2,248	2	15,808	14,113	1,716	5	15,834	6,529	897	1	7,427
Apr-12	203,570	23,368	251	227,189	51,858	6,580	10	58,448	13,588	2,232	2	15,823	14,129	1,703	5	15,837	6,516	892	1	7,409
May-12	203,503	23,370	251	227,124	51,775	6,575	10	58,360	13,570	2,233	2	15,805	14,096	1,694	5	15,795	6,500	892	1	7,393
Jun-12	203,403	23,403	249	227,055	51,691	6,578	10	58,279	13,515	2,230	2	15,747	14,035	1,691	5	15,732	6,494	888	1	7,383
Jul-12	203,943	23,414	251	227,608	51,712	6,555	10	58,276	13,506	2,237	2	15,745	14,005	1,691	5	15,701	6,457	891	1	7,349
Aug-12	203,929	23,406	251	227,586	51,611	6,553	10	58,173	13,502	2,231	2	15,736	13,966	1,690	5	15,661	6,444	892	1	7,337
Sep-12	204,279	23,407	250	227,936	51,569	6,552	10	58,131	13,460	2,232	2	15,694	13,977	1,692	5	15,674	6,443	890	10	7,344
Oct-12	204,591	23,441	251	228,283	51,718	6,555	10	58,283	13,560	2,235	2	15,797	14,071	1,698	5	15,774	6,489	893	7	7,389
Nov-12	205,077	23,418	251	228,746	51,961	6,583	10	58,554	13,629	2,249	2	15,880	14,136	1,709	5	15,851	6,515	891	5	7,410
Dec-12	205,432	23,453	252	229,137	52,100	6,600	10	58,710	13,662	2,252	2	15,916	14,209	1,718	5	15,932	6,536	905	1	7,442
Jan-13	206,517	23,580	248	230,344	52,719	6,611	10	59,339	13,941	2,255	2	16,197	14,344	1,727	5	16,076	6,612	902	1	7,516
Feb-13	206,521	23,584	250	230,356	52,666	6,621	11	59,297	13,951	2,254	2	16,207	14,359	1,741	5	16,105	6,604	902	1	7,507
Mar-13	206,469	23,585	249	230,304	52,615	6,603	10	59,228	13,941	2,278	2	16,222	14,331	1,741	5	16,077	6,583	902	1	7,487
Apr-13	206,230	23,677	252	230,159	52,790	6,627	10	59,427	13,973	2,263	2	16,238	14,347	1,728	5	16,080	6,571	897	1	7,468
May-13	206,162	23,679	252	230,093	52,703	6,622	10	59,336	13,954	2,263	2	16,219	14,313	1,719	5	16,037	6,554	897	1	7,452
Jun-13	206,060	23,713	250	230,022	52,617	6,625	10	59,252	13,896	2,260	2	16,158	14,251	1,716	5	15,972	6,549	893	1	7,442
Jul-13	206,613	23,724	252	230,589	52,638	6,602	10	59,250	13,886	2,267	2	16,155	14,220	1,716	5	15,941	6,511	896	1	7,408
Aug-13	206,598	23,716	252	230,566	52,533	6,600	10	59,143	13,883	2,261	2	16,146	14,180	1,714	5	15,899	6,498	897	1	7,395
Sep-13	206,957	23,717	251	230,925	52,490	6,599	10	59,099	13,838	2,262	2	16,102	14,191	1,717	5	15,913	6,497	895	10	7,402
Oct-13	207,278	23,752	252	231,282	52,644	6,602	10	59,256	13,943	2,265	2	16,210	14,287	1,723	5	16,015	6,543	898	7	7,448
Nov-13	207,776	23,728	252	231,756	52,895	6,631	10	59,536	14,016	2,280	2	16,297	14,355	1,734	5	16,094	6,569	896	5	7,470
Dec-13	208,140	23,764	253	232,157	53,040	6,648	10	59,697	14,051	2,282	2	16,335	14,430	1,743	5	16,178	6,591	910	1	7,502
Jan-14	209,234	23,886	250	233,370	53,702	6,658	10	60,370	14,324	2,284	2	16,610	14,508	1,743	5	16,256	6,668	905	1	7,573
Feb-14	209,239	23,891	252	233,381	53,647	6,669	11	60,326	14,335	2,284	2	16,621	14,523	1,758	5	16,286	6,659	904	1	7,565
Mar-14	209,185	23,892	251	233,328	53,595	6,650	10	60,255	14,325	2,309	2	16,636	14,495	1,758	5	16,258	6,638	905	1	7,544
Apr-14	208,940	23,986	254	233,180	53,776	6,674	10	60,460	14,358	2,293	2	16,652	14,511	1,745	5	16,261	6,625	899	1	7,525
May-14	208,871	23,988	254	233,112	53,686	6,670	10	60,366	14,337	2,293	2	16,633	14,477	1,736	5	16,217	6,608	899	1	7,509
Jun-14	208,765	24,022	252	233,039	53,597	6,673	10	60,279	14,277	2,290	2	16,569	14,413	1,732	5	16,150	6,603	895	1	7,499
Jul-14	209,333	24,034	253	233,620	53,619	6,649	10	60,277	14,267	2,297	2	16,566	14,381	1,732	5	16,118	6,564	898	1	7,464
Aug-14	209,318	24,026	254	233,597	53,511	6,647	10	60,167	14,263	2,291	2	16,556	14,340	1,731	5	16,075	6,551	899	1	7,451
Sep-14	209,686	24,027	252	233,965	53,466	6,646	10	60,122	14,216	2,292	2	16,510	14,352	1,733	5	16,090	6,550	898	10	7,458
Oct-14	210,014	24,063	254	234,331	53,625	6,649	10	60,284	14,326	2,295	2	16,624	14,450	1,739	5	16,194	6,597	900	7	7,504
Nov-14	210,525	24,038	254	234,817	53,885	6,678	10	60,573	14,403	2,310	2	16,715	14,519	1,751	5	16,275	6,624	898	5	7,527
Dec-14	210,899	24,075	254	235,228	54,035	6,695	10	60,740	14,440	2,313	2	16,755	14,596	1,760	5	16,361	6,646	913	1	7,560
Jan-15	211,952	24,193	251	236,396	54,741	6,705	10	61,455	14,707	2,320	2	17,029	14,672	1,760	5	16,436	6,723	907	1	7,631
Feb-15	211,957	24,198	253	236,407	54,684	6,716	11	61,410	14,719	2,320	2	17,041	14,687	1,775	5	16,467	6,714	907	1	7,622
Mar-15	211,902	24,199	252	236,353	54,630	6,697	10	61,337	14,708	2,346	2	17,055	14,658	1,775	5	16,438	6,693	907	1	7,601
Apr-15	211,651	24,295	255	236,201	54,817	6,722	10	61,548	14,743	2,329	2	17,073	14,675	1,761	5	16,441	6,680	902	1	7,582
May-15	211,580	24,296	255	236,131	54,724	6,717	10	61,451	14,721	2,329	2	17,053	14,640	1,752	5	16,397	6,663	902	1	7,565
Jun-15	211,472	24,332	253	236,057	54,631	6,720	10	61,361	14,658	2,326	2	16,986	14,574	1,749	5	16,328	6,657	898	1	7,556
Jul-15	212,053	24,345	255	236,652	54,654	6,696	10	61,360	14,647	2,333	2	16,982	14,542	1,749	5	16,296	6,618	901	1	7,520
Aug-15	212,038	24,336	255	236,629	54,542	6,694	10	61,246	14,643	2,328	2	16,972	14,500	1,747	5	16,252	6,604	902	1	7,507
Sep-15	212,415	24,337	254	237,006	54,496	6,693	10	61,198	14,594	2,328	2	16,924	14,512	1,750	5	16,267	6,603	900	10	7,513
Oct-15	212,751	24,374	255	237,380	54,661	6,696	10	61,367	14,710	2,332	2	17,043	14,613	1,756	5	16,373	6,651	903	7	7,561

Appendix 3.2 - Customer Forecast - Number by Region
Low Growth

	WA/ID				Medford				Roseburg				Klamath Falls				La Grande			
	WA/ID Res	WA/ID Com	WA/ID Firm Ind	WA/ID Total	MFR Res	MFR Com	MFR Firm Ind	MFR Total	ROS Res	ROS Com	ROS Firm Ind	ROS Total	KLA Res	KLA Com	KLA Firm Ind	KLA Total	LGD Res	LGD Com	LGD Firm Ind	LGD Total
Nov-15	213,275	24,348	255	237,878	54,930	6,725	10	61,666	14,790	2,347	2	17,139	14,683	1,768	5	16,456	6,678	901	5	7,584
Dec-15	213,658	24,386	256	238,300	55,085	6,743	10	61,838	14,829	2,349	2	17,181	14,761	1,777	5	16,543	6,701	915	1	7,617
Jan-16	214,670	24,499	252	239,421	55,779	6,749	10	62,538	15,090	2,350	2	17,442	14,836	1,776	5	16,617	6,778	910	1	7,689
Feb-16	214,674	24,504	255	239,433	55,720	6,761	11	62,491	15,103	2,350	2	17,454	14,851	1,792	5	16,648	6,769	909	1	7,680
Mar-16	214,618	24,505	254	239,377	55,664	6,741	10	62,416	15,091	2,376	2	17,469	14,822	1,792	5	16,619	6,747	910	1	7,658
Apr-16	214,361	24,604	257	239,221	55,858	6,766	10	62,634	15,128	2,359	2	17,488	14,839	1,778	5	16,622	6,734	904	1	7,639
May-16	214,288	24,605	257	239,150	55,762	6,762	10	62,533	15,105	2,359	2	17,466	14,803	1,768	5	16,576	6,717	904	1	7,622
Jun-16	214,177	24,642	255	239,074	55,665	6,765	10	62,440	15,038	2,356	2	17,397	14,736	1,765	5	16,506	6,711	900	1	7,612
Jul-16	214,773	24,655	256	239,683	55,689	6,740	10	62,439	15,028	2,363	2	17,393	14,703	1,765	5	16,473	6,671	903	1	7,576
Aug-16	214,757	24,645	257	239,660	55,573	6,738	10	62,321	15,023	2,358	2	17,383	14,660	1,763	5	16,429	6,658	904	1	7,563
Sep-16	215,143	24,647	255	240,046	55,525	6,737	10	62,272	14,972	2,358	2	17,332	14,672	1,766	5	16,444	6,657	903	10	7,569
Oct-16	215,488	24,684	257	240,429	55,696	6,740	10	62,446	15,093	2,362	2	17,457	14,775	1,772	5	16,552	6,705	905	7	7,617
Nov-16	216,024	24,659	257	240,939	55,975	6,770	10	62,756	15,177	2,377	2	17,556	14,847	1,785	5	16,637	6,732	903	5	7,641
Dec-16	216,416	24,698	257	241,371	56,136	6,788	10	62,934	15,218	2,380	2	17,600	14,927	1,794	5	16,726	6,756	918	1	7,674
Jan-17	217,385	24,805	253	242,443	56,763	6,791	10	63,564	15,474	2,380	2	17,856	14,999	1,793	5	16,797	6,833	912	1	7,746
Feb-17	217,390	24,810	256	242,456	56,702	6,803	11	63,515	15,486	2,379	2	17,868	15,015	1,809	5	16,829	6,824	912	1	7,737
Mar-17	217,332	24,812	255	242,399	56,644	6,783	10	63,437	15,474	2,407	2	17,883	14,985	1,809	5	16,799	6,802	912	1	7,715
Apr-17	217,069	24,912	258	242,239	56,844	6,809	10	63,662	15,512	2,389	2	17,903	15,003	1,794	5	16,802	6,789	907	1	7,696
May-17	216,994	24,914	258	242,166	56,745	6,804	10	63,559	15,489	2,389	2	17,880	14,966	1,785	5	16,756	6,771	907	1	7,679
Jun-17	216,881	24,951	256	242,088	56,645	6,807	10	63,462	15,419	2,387	2	17,808	14,898	1,781	5	16,684	6,765	902	1	7,669
Jul-17	217,490	24,964	257	242,712	56,670	6,782	10	63,462	15,408	2,394	2	17,803	14,864	1,781	5	16,650	6,725	906	1	7,632
Aug-17	217,475	24,955	258	242,687	56,550	6,780	10	63,340	15,403	2,388	2	17,793	14,820	1,780	5	16,605	6,711	907	1	7,618
Sep-17	217,870	24,957	256	243,083	56,501	6,779	10	63,289	15,350	2,388	2	17,740	14,833	1,783	5	16,620	6,710	905	10	7,625
Oct-17	218,223	24,995	258	243,475	56,677	6,782	10	63,469	15,476	2,392	2	17,870	14,938	1,789	5	16,732	6,759	908	7	7,674
Nov-17	218,771	24,968	258	243,997	56,965	6,812	10	63,788	15,564	2,408	2	17,974	15,011	1,801	5	16,818	6,787	906	5	7,698
Dec-17	219,173	25,008	258	244,439	57,131	6,830	10	63,971	15,607	2,411	2	18,019	15,093	1,810	5	16,908	6,810	920	1	7,732
Jan-18	220,150	25,122	255	245,527	57,692	6,833	10	64,535	15,857	2,404	2	18,263	15,163	1,809	5	16,978	6,888	915	1	7,804
Feb-18	220,155	25,127	257	245,539	57,629	6,845	11	64,484	15,870	2,403	2	18,275	15,180	1,826	5	17,010	6,880	914	1	7,795
Mar-18	220,096	25,128	256	245,481	57,570	6,825	10	64,405	15,857	2,431	2	18,290	15,149	1,826	5	16,979	6,857	915	1	7,773
Apr-18	219,827	25,231	259	245,317	57,775	6,851	10	64,636	15,897	2,413	2	18,312	15,167	1,811	5	16,983	6,843	909	1	7,753
May-18	219,750	25,233	259	245,243	57,673	6,846	10	64,529	15,873	2,414	2	18,288	15,129	1,801	5	16,935	6,825	909	1	7,736
Jun-18	219,635	25,271	257	245,163	57,571	6,849	10	64,430	15,800	2,411	2	18,213	15,060	1,798	5	16,863	6,819	905	1	7,725
Jul-18	220,258	25,285	259	245,801	57,596	6,824	10	64,430	15,788	2,418	2	18,208	15,025	1,798	5	16,828	6,779	908	1	7,688
Aug-18	220,242	25,275	259	245,776	57,473	6,822	10	64,305	15,783	2,412	2	18,197	14,981	1,796	5	16,782	6,764	909	1	7,674
Sep-18	220,646	25,277	258	246,181	57,422	6,821	10	64,253	15,727	2,412	2	18,142	14,993	1,799	5	16,797	6,763	907	10	7,681
Oct-18	221,007	25,316	259	246,582	57,604	6,824	10	64,437	15,859	2,416	2	18,277	15,100	1,805	5	16,911	6,813	910	7	7,730
Nov-18	221,569	25,289	259	247,117	57,900	6,855	10	64,765	15,951	2,432	2	18,385	15,175	1,818	5	16,998	6,841	908	5	7,754
Dec-18	221,980	25,329	260	247,569	58,071	6,873	10	64,953	15,996	2,435	2	18,433	15,259	1,827	5	17,091	6,865	923	1	7,789
Jan-19	222,916	25,438	257	248,611	58,566	6,872	10	65,448	16,240	2,428	2	18,670	15,327	1,826	5	17,158	6,944	917	1	7,862
Feb-19	222,920	25,444	259	248,623	58,501	6,884	11	65,396	16,254	2,427	2	18,683	15,344	1,842	5	17,191	6,935	917	1	7,852
Mar-19	222,861	25,445	258	248,564	58,441	6,864	10	65,315	16,241	2,455	2	18,698	15,312	1,842	5	17,160	6,912	917	1	7,830
Apr-19	222,585	25,550	261	248,396	58,652	6,890	10	65,552	16,282	2,437	2	18,721	15,331	1,828	5	17,163	6,898	912	1	7,810
May-19	222,507	25,552	261	248,320	58,547	6,885	10	65,442	16,257	2,438	2	18,696	15,292	1,818	5	17,115	6,880	912	1	7,792
Jun-19	222,388	25,591	259	248,239	58,442	6,888	10	65,341	16,181	2,435	2	18,617	15,222	1,814	5	17,041	6,874	907	1	7,782
Jul-19	223,026	25,605	261	248,892	58,468	6,863	10	65,341	16,169	2,442	2	18,612	15,186	1,814	5	17,005	6,832	910	1	7,744
Aug-19	223,010	25,595	261	248,866	58,341	6,861	10	65,212	16,163	2,436	2	18,601	15,141	1,812	5	16,958	6,818	912	1	7,730
Sep-19	223,423	25,597	260	249,280	58,289	6,860	10	65,159	16,105	2,436	2	18,544	15,154	1,815	5	16,974	6,816	910	10	7,736
Oct-19	223,792	25,637	261	249,690	58,476	6,863	10	65,349	16,243	2,440	2	18,685	15,263	1,822	5	17,090	6,867	913	7	7,787
Nov-19	224,367	25,609	261	250,237	58,780	6,894	10	65,684	16,338	2,457	2	18,797	15,340	1,835	5	17,179	6,896	910	5	7,811
Dec-19	224,787	25,651	262	250,700	58,955	6,912	10	65,877	16,385	2,460	2	18,846	15,424	1,844	5	17,274	6,920	926	1	7,847
Jan-20	225,781	25,767	257	251,805	59,440	6,917	10	66,367	16,623	2,452	2	19,077	15,491	1,842	5	17,339	6,999	920	1	7,919
Feb-20	225,786	25,772	260	251,818	59,374	6,929	11	66,313	16,637	2,451	2	19,091	15,508	1,859	5	17,372	6,990	919	1	7,910
Mar-20	225,725	25,774	259	251,757	59,312	6,909	10	66,230	16,624	2,480	2	19,105	15,476	1,859	5	17,340	6,966	920	1	7,887
Apr-20	225,443	25,881	262	251,586	59,528	6,935	10	66,473	16,667	2,461	2	19,130	15,495	1,844	5	17,344	6,952	914	1	7,867
May-20	225,363	25,883	262	251,508	59,421	6,930	10	66,361	16,640	2,462	2	19,104	15,456	1,834	5	17,295	6,934	914	1	7,849
Jun-20	225,242	25,923	260	251,425	59,313	6,933	10	66,256	16,562	2,459	2	19,022	15,383	1,831	5	17,219	6,928	910	1	7,838
Jul-20	225,894	25,937	261	252,093	59,340	6,907	10	66,257	16,549	2,466	2	19,017	15,347	1,831	5	17,183	6,886	913	1	7,800
Aug-20	225,877	25,927	262	252,066	59,210	6,905	10	66,125	16,544	2,460	2	19,005	15,301	1,829	5	17,135	6,871	914	1	7,786
Sep-20	226,301	25,929	260	252,490	59,156	6,904	10	66,070	16,483	2,460	2	18,946	15,314	1,832	5	17,151	6,870	912	10	7,792
Oct-20	226,678	25,970	262	252,910	59,348	6,907	10	66,265	16,626	2,464	2	19,092	15,426	1,838	5	17,269	6,921	915	7	7,843
Nov-20	227,266	25,942	262	253,469	59,660	6,939	10	66,609	16,725	2,481	2	19,208	15,504	1,851	5	17,360	6,950	913	5	7,868
Dec-20	227,696	25,984	262	253,943	59,840	6,957	10	66,807	16,773	2,484	2	19,260	15,590	1,861	5	17,456	6,975	928	1	7,904
Jan-21	228,697	26,096	259	255,053	60,315	6,959	10	67,284	17,006	2,476	2	19,484	15,655	1,859	5	17,519	7,054	922	1	7,977
Feb-21	228,702	26,102	261	255,066	60,247	6,971	11	67,228	17,021	2,475	2	19,498	15,672	1,876	5	17,553	7,045	922	1	7,967
Mar-21	228,640	26,103	260	255,003	60,183	6,950	10	67,143	17,007	2,504	2	19,513	15,640	1,876	5	17,521	7,021	922	1	7,944
Apr-21	228,351	26,214	263	254,828	60,405	6,977	10	67,392	17,052	2,485	2	19,539	15,659	1,861	5	17,524	7,007	916	1	7,924
May-21	228,269	26,216	263	254,748	60,295	6,972	10	67,277	17,024	2,486	2	19,512	15,619	1,851	5	17,474	6,988	916	1	7,906
Jun-21	228,146	26,257	261	254,663	60,184	6,975	10	67,170	16,943	2,483	2	19,427	15,545	1,847	5	17,397	6,982	912	1	7,895
Jul-21	228,813	26,271	263	255,347	60,211	6,949	10	67,171	16,929	2,490	2	19,421	15,509	1,847	5	17,360	6,939	915	1	7,856
Aug-21	228,796	26,260	263	255,320	60,078	6,947	10	67,035	16,924	2,484	2	19,410	15,461	1,845	5	17,311	6,924	916	1	7,842
Sep-21	229,229	26,262	262	255,753	60,023	6,946	10	66,979	16,861	2,485	2	19,348	15,475	1,848	5	17,328	6,923	915	10	7,848
Oct-21	229,615	26,304	263	256,183	60,220	6,949	10	67,179	17,009	2,488	2	19,500	15,588	1,855	5	17,448	6,976	917	7	7,900

Appendix 3.2 - Customer Forecast - Number by Region
Low Growth

	WA/ID				Medford				Roseburg				Klamath Falls				La Grande			
	WA/ID Res	WA/ID Com	WA/ID Firm Ind	WA/ID Total	MFR Res	MFR Com	MFR Firm Ind	MFR Total	ROS Res	ROS Com	ROS Firm Ind	ROS Total	KLA Res	KLA Com	KLA Firm Ind	KLA Total	LGD Res	LGD Com	LGD Firm Ind	LGD Total
Nov-21	230,216	26,275	263	256,755	60,540	6,981	10	67,531	17,112	2,505	2	19,619	15,668	1,868	5	17,541	7,005	915	5	7,925
Dec-21	230,656	26,319	264	257,239	60,724	7,000	10	67,734	17,162	2,509	2	19,673	15,756	1,878	5	17,639	7,030	931	1	7,961
Jan-22	231,663	26,426	260	258,349	61,189	7,001	10	68,200	17,389	2,500	2	19,891	15,819	1,876	5	17,699	7,109	925	1	8,035
Feb-22	231,669	26,431	262	258,362	61,119	7,013	11	68,143	17,405	2,499	2	19,906	15,836	1,893	5	17,734	7,100	924	1	8,025
Mar-22	231,605	26,433	261	258,298	61,054	6,992	10	68,056	17,390	2,528	2	19,921	15,803	1,893	5	17,701	7,076	925	1	8,001
Apr-22	231,309	26,545	264	258,119	61,282	7,019	10	68,311	17,437	2,509	2	19,948	15,823	1,877	5	17,705	7,061	919	1	7,981
May-22	231,226	26,547	264	258,037	61,169	7,014	10	68,193	17,408	2,510	2	19,920	15,782	1,867	5	17,654	7,042	919	1	7,962
Jun-22	231,099	26,589	262	257,950	61,055	7,017	10	68,083	17,323	2,507	2	19,832	15,707	1,863	5	17,575	7,036	915	1	7,952
Jul-22	231,782	26,604	264	258,649	61,083	6,991	10	68,084	17,310	2,514	2	19,826	15,670	1,863	5	17,538	6,993	918	1	7,912
Aug-22	231,764	26,593	264	258,622	60,947	6,989	10	67,945	17,304	2,508	2	19,814	15,622	1,861	5	17,488	6,977	919	1	7,897
Sep-22	232,207	26,595	263	259,065	60,890	6,988	10	67,888	17,239	2,509	2	19,749	15,635	1,864	5	17,505	6,976	917	10	7,904
Oct-22	232,602	26,638	264	259,504	61,092	6,991	10	68,093	17,393	2,512	2	19,907	15,751	1,871	5	17,627	7,030	920	7	7,956
Nov-22	233,217	26,608	264	260,090	61,420	7,023	10	68,453	17,499	2,530	2	20,031	15,832	1,885	5	17,722	7,059	918	5	7,982
Dec-22	233,667	26,653	265	260,585	61,609	7,042	10	68,661	17,551	2,533	2	20,086	15,922	1,895	5	17,821	7,085	933	1	8,019
Jan-23	234,680	26,754	261	261,696	62,063	7,043	10	69,116	17,773	2,523	2	20,298	15,983	1,892	5	17,880	7,164	927	1	8,093
Feb-23	234,685	26,760	264	261,709	61,992	7,055	11	69,057	17,789	2,523	2	20,313	16,000	1,910	5	17,915	7,155	927	1	8,082
Mar-23	234,620	26,762	263	261,644	61,925	7,034	10	68,969	17,773	2,553	2	20,328	15,967	1,910	5	17,881	7,131	927	1	8,059
Apr-23	234,318	26,877	266	261,460	62,158	7,061	10	69,229	17,821	2,533	2	20,357	15,986	1,894	5	17,885	7,116	921	1	8,038
May-23	234,232	26,879	266	261,377	62,043	7,056	10	69,109	17,792	2,534	2	20,328	15,945	1,883	5	17,833	7,097	921	1	8,019
Jun-23	234,103	26,921	264	261,288	61,926	7,059	10	68,996	17,704	2,531	2	20,237	15,869	1,880	5	17,753	7,090	917	1	8,008
Jul-23	234,801	26,936	265	262,003	61,955	7,033	10	68,998	17,690	2,538	2	20,230	15,831	1,880	5	17,715	7,046	920	1	7,967
Aug-23	234,783	26,925	266	261,974	61,815	7,030	10	68,856	17,684	2,532	2	20,218	15,782	1,878	5	17,665	7,031	921	1	7,953
Sep-23	235,236	26,927	264	262,428	61,757	7,029	10	68,797	17,617	2,533	2	20,151	15,796	1,881	5	17,682	7,030	920	10	7,959
Oct-23	235,640	26,971	266	262,877	61,964	7,033	10	69,006	17,776	2,537	2	20,314	15,913	1,888	5	17,806	7,084	922	7	8,013
Nov-23	236,269	26,941	266	263,476	62,300	7,065	10	69,375	17,886	2,554	2	20,442	15,996	1,902	5	17,903	7,114	920	5	8,039
Dec-23	236,730	26,986	267	263,982	62,493	7,084	10	69,588	17,940	2,557	2	20,500	16,087	1,912	5	18,004	7,139	936	1	8,076
Jan-24	237,697	27,083	262	265,042	62,938	7,082	10	70,030	18,156	2,553	2	20,711	16,146	1,909	5	18,060	7,220	930	1	8,150
Feb-24	237,702	27,089	264	265,056	62,865	7,094	11	69,969	18,172	2,553	2	20,727	16,165	1,927	5	18,096	7,210	929	1	8,140
Mar-24	237,635	27,091	263	264,989	62,796	7,073	10	69,879	18,157	2,583	2	20,742	16,130	1,927	5	18,062	7,185	930	1	8,116
Apr-24	237,327	27,208	266	264,801	63,035	7,101	10	70,145	18,206	2,563	2	20,772	16,150	1,911	5	18,066	7,170	924	1	8,095
May-24	237,239	27,210	266	264,716	62,917	7,095	10	70,022	18,176	2,564	2	20,742	16,108	1,900	5	18,013	7,151	924	1	8,076
Jun-24	237,107	27,254	264	264,625	62,798	7,099	10	69,906	18,085	2,561	2	20,648	16,031	1,896	5	17,932	7,144	920	1	8,065
Jul-24	237,820	27,269	266	265,355	62,827	7,072	10	69,909	18,070	2,569	2	20,641	15,992	1,896	5	17,893	7,100	923	1	8,023
Aug-24	237,802	27,258	266	265,327	62,684	7,070	10	69,763	18,064	2,562	2	20,628	15,942	1,894	5	17,841	7,084	924	1	8,009
Sep-24	238,265	27,260	265	265,790	62,625	7,068	10	69,703	17,995	2,563	2	20,559	15,956	1,897	5	17,859	7,083	922	10	8,015
Oct-24	238,679	27,305	266	266,250	62,835	7,072	10	69,917	18,159	2,567	2	20,728	16,076	1,904	5	17,985	7,138	925	7	8,070
Nov-24	239,321	27,274	266	266,862	63,180	7,105	10	70,295	18,273	2,585	2	20,860	16,160	1,918	5	18,083	7,168	923	5	8,096
Dec-24	239,792	27,320	267	267,379	63,378	7,124	10	70,512	18,329	2,588	2	20,919	16,253	1,928	5	18,187	7,194	938	1	8,133
Jan-25	240,714	27,425	263	268,402	63,812	7,121	10	70,943	18,484	2,577	2	21,063	16,310	1,925	5	18,241	7,275	932	1	8,208
Feb-25	240,719	27,431	266	268,416	63,737	7,134	11	70,882	18,501	2,577	2	21,080	16,329	1,943	5	18,277	7,265	932	1	8,198
Mar-25	240,651	27,433	265	268,348	63,667	7,112	10	70,790	18,485	2,608	2	21,095	16,294	1,943	5	18,242	7,240	932	1	8,173
Apr-25	240,335	27,553	268	268,156	63,911	7,140	10	71,062	18,536	2,587	2	21,125	16,314	1,927	5	18,246	7,225	926	1	8,152
May-25	240,246	27,555	268	268,069	63,790	7,135	10	70,935	18,505	2,588	2	21,095	16,271	1,916	5	18,193	7,205	926	1	8,132
Jun-25	240,110	27,599	266	267,976	63,669	7,138	10	70,817	18,412	2,585	2	20,998	16,192	1,912	5	18,110	7,198	922	1	8,121
Jul-25	240,840	27,615	267	268,722	63,699	7,111	10	70,820	18,396	2,593	2	20,991	16,153	1,912	5	18,070	7,153	925	1	8,079
Aug-25	240,821	27,604	268	268,693	63,552	7,109	10	70,671	18,390	2,586	2	20,978	16,102	1,910	5	18,018	7,137	926	1	8,065
Sep-25	241,294	27,606	266	269,166	63,492	7,108	10	70,609	18,318	2,587	2	20,907	16,117	1,914	5	18,035	7,136	925	10	8,071
Oct-25	241,717	27,651	268	269,636	63,707	7,111	10	70,829	18,488	2,591	2	21,081	16,239	1,921	5	18,164	7,192	927	7	8,126
Nov-25	242,373	27,620	268	270,261	64,060	7,144	10	71,214	18,605	2,609	2	21,216	16,324	1,935	5	18,264	7,223	925	5	8,153
Dec-25	242,854	27,667	269	270,790	64,262	7,164	10	71,436	18,662	2,612	2	21,277	16,419	1,945	5	18,369	7,249	941	1	8,191
Jan-26	243,730	27,767	264	271,761	64,632	7,161	10	71,802	18,813	2,601	2	21,416	16,474	1,942	5	18,421	7,330	935	1	8,266
Feb-26	243,736	27,773	267	271,776	64,555	7,173	11	71,739	18,830	2,600	2	21,433	16,493	1,960	5	18,458	7,320	934	1	8,255
Mar-26	243,666	27,774	266	271,706	64,484	7,152	10	71,645	18,813	2,632	2	21,448	16,457	1,960	5	18,423	7,295	935	1	8,230
Apr-26	243,344	27,897	269	271,510	64,733	7,180	10	71,923	18,866	2,611	2	21,479	16,478	1,944	5	18,427	7,279	929	1	8,209
May-26	243,253	27,899	269	271,421	64,610	7,174	10	71,794	18,834	2,612	2	21,448	16,435	1,933	5	18,372	7,259	929	1	8,189
Jun-26	243,114	27,945	267	271,326	64,485	7,178	10	71,673	18,738	2,609	2	21,349	16,354	1,929	5	18,288	7,253	924	1	8,178
Jul-26	243,859	27,960	268	272,088	64,516	7,150	10	71,676	18,722	2,617	2	21,341	16,314	1,929	5	18,248	7,207	928	1	8,135
Aug-26	243,840	27,949	269	272,058	64,366	7,148	10	71,524	18,716	2,610	2	21,328	16,262	1,927	5	18,194	7,191	929	1	8,120
Sep-26	244,323	27,951	267	272,542	64,305	7,147	10	71,461	18,642	2,611	2	21,255	16,277	1,930	5	18,212	7,190	927	10	8,127
Oct-26	244,755	27,997	269	273,021	64,525	7,150	10	71,685	18,816	2,615	2	21,433	16,401	1,937	5	18,343	7,246	930	7	8,183
Nov-26	245,426	27,965	269	273,660	64,885	7,184	10	72,079	18,937	2,634	2	21,572	16,488	1,952	5	18,445	7,277	928	5	8,210
Dec-26	245,917	28,014	270	274,200	65,092	7,204	10	72,305	18,996	2,637	2	21,635	16,585	1,962	5	18,552	7,304	943	1	8,248
Jan-27	246,697	28,108	266	275,071	65,451	7,200	10	72,661	19,141	2,625	2	21,768	16,638	1,958	5	18,601	7,385	937	1	8,323
Feb-27	246,703	28,115	268	275,086	65,374	7,212	11	72,597	19,159	2,624	2	21,785	16,657	1,977	5	18,639	7,375	937	1	8,313
Mar-27	246,631	28,116	267	275,015	65,300	7,191	10	72,501	19,142	2,657	2	21,800	16,621	1,977	5	18,603	7,349	937	1	8,287
Apr-27	246,302	28,241	271	274,814	65,555	7,219	10	72,784	19,196	2,636	2	21,833	16,642	1,960	5	18,608	7,334	931	1	8,266
May-27	246,209	28,243	271	274,723	65,429	7,214	10	72,653	19,163	2,636	2	21,801	16,598	1,949	5	18,552	7,314	931	1	8,246
Jun-27	246,068	28,290	268	274,626	65,302	7,217	10	72,529	19,064	2,633	2	21,699	16,516	1,945	5	18,466	7,307	927	1	8,235
Jul-27	246,828	28,306	270	275,404	65,333	7,190	10	72,533	19,048	2,641	2	21,692	16,475	1,945	5	18,425	7,260	930	1	8,191
Aug-27	246,809	28,294	271	275,374	65,180	7,187	10	72,378	19,042	2,634	2	21,678	16,423	1,943	5	18,371	7,244	931	1	8,176
Sep-27	247,302	28,297	269	275,867	65,117	7,186	10	72,313	18,966	2,635	2	21,603	16,438	1,946	5	18,389	7,243	930	10	8,182
Oct-27	247,742	28,344	271	276,357	65,342	7,190	10	72,542	19,145	2,639	2	21,786	16,564	1,954	5	18,522	7,300	932	7	8,239

Appendix 3.2 - Customer Forecast - Number by Region
Low Growth

	WA/ID				Medford				Roseburg				Klamath Falls				La Grande			
	WA/ID Res	WA/ID Com	WA/ID Firm Ind	WA/ID Total	MFR Res	MFR Com	MFR Firm Ind	MFR Total	ROS Res	ROS Com	ROS Firm Ind	ROS Total	KLA Res	KLA Com	KLA Firm Ind	KLA Total	LGD Res	LGD Com	LGD Firm Ind	LGD Total
Nov-27	248,427	28,311	271	277,009	65,710	7,223	10	72,943	19,269	2,658	2	21,928	16,652	1,968	5	18,626	7,332	930	5	8,267
Dec-27	248,928	28,361	271	277,560	65,921	7,243	10	73,174	19,329	2,661	2	21,992	16,751	1,979	5	18,735	7,359	946	1	8,306
Jan-28	249,663	28,450	267	278,380	66,271	7,239	10	73,520	19,469	2,649	2	22,120	16,802	1,975	5	18,782	7,440	940	1	8,381
Feb-28	249,669	28,457	269	278,395	66,192	7,252	11	73,454	19,488	2,648	2	22,138	16,821	1,994	5	18,820	7,430	939	1	8,370
Mar-28	249,597	28,458	268	278,323	66,117	7,230	10	73,357	19,470	2,681	2	22,153	16,785	1,994	5	18,783	7,404	940	1	8,345
Apr-28	249,261	28,586	272	278,118	66,377	7,259	10	73,645	19,526	2,660	2	22,187	16,806	1,977	5	18,788	7,388	934	1	8,323
May-28	249,166	28,588	272	278,026	66,248	7,253	10	73,511	19,492	2,660	2	22,154	16,761	1,966	5	18,732	7,368	934	1	8,302
Jun-28	249,022	28,635	269	277,927	66,119	7,257	10	73,385	19,391	2,657	2	22,050	16,678	1,961	5	18,644	7,361	929	1	8,291
Jul-28	249,798	28,652	271	278,720	66,150	7,229	10	73,389	19,374	2,665	2	22,042	16,636	1,961	5	18,603	7,314	932	1	8,247
Aug-28	249,778	28,640	272	278,689	65,995	7,226	10	73,231	19,368	2,658	2	22,028	16,583	1,959	5	18,547	7,297	934	1	8,232
Sep-28	250,281	28,642	270	279,193	65,930	7,225	10	73,165	19,290	2,659	2	21,951	16,598	1,963	5	18,566	7,296	932	10	8,238
Oct-28	250,730	28,690	272	279,692	66,160	7,229	10	73,399	19,473	2,663	2	22,138	16,726	1,970	5	18,702	7,354	935	7	8,296
Nov-28	251,428	28,657	272	280,357	66,535	7,263	10	73,808	19,600	2,682	2	22,285	16,816	1,985	5	18,807	7,386	932	5	8,324
Dec-28	251,939	28,707	272	280,919	66,750	7,283	10	74,043	19,662	2,686	2	22,350	16,916	1,996	5	18,917	7,414	948	1	8,363
Jan-29	252,580	28,779	268	281,627	67,091	7,278	10	74,379	19,798	2,679	2	22,479	16,966	1,992	5	18,962	7,496	942	1	8,439
Feb-29	252,586	28,786	271	281,642	67,010	7,291	11	74,312	19,817	2,678	2	22,497	16,985	2,011	5	19,001	7,485	942	1	8,428
Mar-29	252,511	28,787	270	281,568	66,934	7,269	10	74,213	19,799	2,711	2	22,512	16,948	2,011	5	18,964	7,459	942	1	8,402
Apr-29	252,170	28,917	273	281,360	67,199	7,298	10	74,507	19,855	2,690	2	22,547	16,970	1,994	5	18,969	7,443	936	1	8,380
May-29	252,073	28,920	273	281,265	67,067	7,293	10	74,370	19,821	2,690	2	22,513	16,924	1,982	5	18,911	7,422	936	1	8,359
Jun-29	251,926	28,968	271	281,165	66,935	7,296	10	74,241	19,717	2,687	2	22,406	16,840	1,978	5	18,822	7,415	932	1	8,348
Jul-29	252,717	28,985	273	281,974	66,968	7,268	10	74,246	19,700	2,695	2	22,398	16,797	1,978	5	18,780	7,367	935	1	8,303
Aug-29	252,696	28,973	273	281,942	66,809	7,265	10	74,084	19,693	2,688	2	22,384	16,743	1,976	5	18,724	7,351	936	1	8,288
Sep-29	253,209	28,975	271	282,455	66,743	7,264	10	74,017	19,614	2,689	2	22,305	16,759	1,979	5	18,743	7,349	934	10	8,294
Oct-29	253,667	29,024	273	282,964	66,977	7,268	10	74,255	19,802	2,693	2	22,497	16,889	1,987	5	18,881	7,408	937	7	8,352
Nov-29	254,379	28,990	273	283,642	67,360	7,302	10	74,672	19,932	2,713	2	22,647	16,981	2,002	5	18,987	7,441	935	5	8,381
Dec-29	254,900	29,041	274	284,215	67,580	7,323	10	74,912	19,996	2,716	2	22,714	17,082	2,013	5	19,100	7,468	951	1	8,420

Appendix 3.2 - Customer Forecast - Number by Region
High Growth

	WA/ID				Medford				Roseburg				Klamath Falls				La Grande			
	WA/ID Res	WA/ID Com	WA/ID Firm Ind	WA/ID Total	MFR Res	MFR Com	MFR Firm Ind	MFR Total	ROS Res	ROS Com	ROS Firm Ind	ROS Total	KLA Res	KLA Com	KLA Firm Ind	KLA Total	LGD Res	LGD Com	LGD Firm Ind	LGD Total
Nov-09	200,475	22,820	250	223,545	49,866	6,405	10	56,280	12,978	2,158	2	15,138	13,598	1,608	5	15,211	6,339	866	5	7,210
Dec-09	201,516	22,923	252	224,691	50,270	6,454	10	56,733	13,074	2,166	2	15,241	13,811	1,632	5	15,448	6,403	909	1	7,312
Jan-10	202,185	23,210	247	225,642	50,712	6,496	10	57,218	13,150	2,178	2	15,329	13,937	1,660	5	15,602	6,502	892	1	7,395
Feb-10	202,197	23,223	250	225,671	50,563	6,527	10	57,100	13,178	2,176	2	15,356	13,979	1,702	5	15,686	6,478	891	1	7,370
Mar-10	202,049	23,227	247	225,523	50,423	6,473	10	56,906	13,151	2,246	2	15,399	13,900	1,702	5	15,607	6,418	892	1	7,311
Apr-10	201,367	23,488	256	225,110	50,761	6,544	10	57,315	13,162	2,200	2	15,364	13,872	1,665	5	15,542	6,381	876	1	7,258
May-10	201,173	23,492	256	224,922	50,520	6,530	10	57,060	13,109	2,202	2	15,313	13,776	1,639	5	15,420	6,333	876	1	7,210
Jun-10	200,880	23,589	250	224,720	50,277	6,539	10	56,826	12,954	2,194	2	15,150	13,598	1,630	5	15,233	6,317	864	1	7,182
Jul-10	201,704	23,623	255	225,581	50,188	6,470	10	56,668	12,929	2,212	2	15,143	13,509	1,630	5	15,145	6,207	873	1	7,082
Aug-10	201,663	23,598	256	225,517	49,896	6,464	10	56,370	12,918	2,197	2	15,118	13,395	1,626	5	15,026	6,169	876	1	7,046
Sep-10	202,687	23,603	252	226,541	49,775	6,461	10	56,246	12,799	2,199	2	15,000	13,428	1,633	5	15,066	6,166	872	10	7,048
Oct-10	203,601	23,702	256	227,559	50,057	6,470	10	56,537	13,006	2,208	2	15,216	13,628	1,650	5	15,282	6,301	879	7	7,187
Nov-10	205,022	23,633	256	228,912	50,759	6,554	10	57,324	13,202	2,249	2	15,452	13,820	1,683	5	15,508	6,376	873	5	7,254
Dec-10	206,063	23,737	258	230,057	51,163	6,603	10	57,777	13,297	2,256	2	15,556	14,033	1,706	5	15,745	6,440	916	1	7,357
Jan-11	207,051	24,061	250	231,362	51,754	6,653	10	58,418	13,374	2,286	2	15,662	14,159	1,760	5	15,924	6,576	907	1	7,484
Feb-11	207,063	24,075	256	231,394	51,605	6,685	10	58,300	13,402	2,285	2	15,689	14,201	1,801	5	16,007	6,552	906	1	7,459
Mar-11	206,915	24,078	253	231,246	51,465	6,631	10	58,106	13,375	2,354	2	15,731	14,122	1,801	5	15,929	6,492	907	1	7,400
Apr-11	206,232	24,339	262	230,833	51,952	6,701	10	58,664	13,460	2,309	2	15,771	14,168	1,764	5	15,937	6,455	891	1	7,347
May-11	206,039	24,344	262	230,645	51,711	6,688	10	58,409	13,408	2,310	2	15,720	14,072	1,739	5	15,816	6,407	891	1	7,299
Jun-11	205,746	24,441	256	230,443	51,468	6,697	10	58,175	13,253	2,303	2	15,558	13,894	1,730	5	15,629	6,391	879	1	7,271
Jul-11	207,324	24,474	261	232,059	51,528	6,628	10	58,166	13,227	2,321	2	15,550	13,805	1,730	5	15,540	6,281	888	1	7,170
Aug-11	207,283	24,450	262	231,996	51,236	6,622	10	57,868	13,217	2,306	2	15,525	13,691	1,725	5	15,422	6,243	891	1	7,135
Sep-11	208,307	24,454	258	233,020	51,115	6,619	10	57,744	13,097	2,307	2	15,407	13,724	1,733	5	15,462	6,240	886	10	7,136
Oct-11	209,221	24,553	262	234,037	51,546	6,628	10	58,184	13,379	2,316	2	15,698	13,998	1,749	5	15,752	6,375	894	7	7,276
Nov-11	210,643	24,485	262	235,390	52,249	6,711	10	58,970	13,575	2,357	2	15,934	14,190	1,782	5	15,977	6,450	888	5	7,343
Dec-11	211,683	24,588	264	236,535	52,652	6,761	10	59,423	13,671	2,365	2	16,037	14,404	1,806	5	16,214	6,514	931	1	7,446
Jan-12	214,766	24,981	253	240,000	54,541	6,818	11	61,370	14,523	2,394	2	16,919	14,651	1,859	5	16,515	6,742	922	1	7,665
Feb-12	214,778	24,995	259	240,032	54,387	6,850	11	61,248	14,553	2,392	2	16,947	14,693	1,902	5	16,601	6,718	921	1	7,639
Mar-12	214,626	24,998	256	239,881	54,242	6,795	11	61,048	14,525	2,464	2	16,991	14,613	1,902	5	16,520	6,656	922	1	7,579
Apr-12	213,927	25,266	265	239,458	54,746	6,867	11	61,624	14,615	2,417	2	17,034	14,660	1,864	5	16,529	6,618	906	1	7,525
May-12	213,728	25,271	265	239,264	54,496	6,853	11	61,360	14,559	2,419	2	16,980	14,561	1,837	5	16,404	6,570	906	1	7,477
Jun-12	213,428	25,370	259	239,057	54,245	6,862	10	61,118	14,395	2,411	2	16,808	14,379	1,828	5	16,213	6,553	894	1	7,448
Jul-12	215,046	25,405	264	240,715	54,307	6,792	10	61,109	14,368	2,430	2	16,800	14,289	1,828	5	16,122	6,442	903	1	7,346
Aug-12	215,004	25,380	265	240,649	54,004	6,786	10	60,801	14,357	2,414	2	16,773	14,172	1,823	5	16,000	6,403	906	1	7,310
Sep-12	216,054	25,384	261	241,699	53,879	6,783	10	60,673	14,231	2,416	2	16,649	14,205	1,831	5	16,041	6,400	901	10	7,311
Oct-12	216,991	25,486	265	242,742	54,325	6,792	10	61,128	14,529	2,425	2	16,956	14,486	1,848	5	16,339	6,537	909	7	7,452
Nov-12	218,448	25,415	265	244,129	55,054	6,877	11	61,942	14,736	2,467	2	17,205	14,683	1,882	5	16,570	6,614	903	5	7,521
Dec-12	219,515	25,521	267	245,304	55,472	6,928	11	62,410	14,837	2,475	2	17,314	14,901	1,907	5	16,813	6,678	946	1	7,625
Jan-13	222,769	25,901	256	248,925	57,328	6,960	11	64,299	15,673	2,484	2	18,158	15,306	1,934	5	17,245	6,907	937	1	7,845
Feb-13	222,781	25,915	262	248,959	57,169	6,992	11	64,172	15,704	2,482	2	18,188	15,350	1,978	5	17,333	6,883	935	1	7,819
Mar-13	222,626	25,918	259	248,803	57,018	6,936	11	63,966	15,674	2,555	2	18,232	15,267	1,978	5	17,250	6,820	937	1	7,758
Apr-13	221,908	26,193	268	248,369	57,541	7,009	11	64,561	15,769	2,508	2	18,279	15,316	1,938	5	17,259	6,782	920	1	7,703
May-13	221,705	26,198	268	248,171	57,282	6,995	11	64,288	15,711	2,509	2	18,222	15,214	1,911	5	17,130	6,733	920	1	7,654
Jun-13	221,397	26,300	262	247,959	57,022	7,004	11	64,037	15,538	2,501	2	18,041	15,027	1,902	5	16,933	6,716	908	1	7,625
Jul-13	223,056	26,335	267	249,658	57,085	6,933	11	64,030	15,509	2,520	2	18,032	14,933	1,902	5	16,840	6,603	917	1	7,521
Aug-13	223,013	26,309	268	249,591	56,772	6,927	11	63,710	15,498	2,504	2	18,004	14,813	1,897	5	16,715	6,563	920	1	7,484
Sep-13	224,090	26,314	264	250,668	56,643	6,924	11	63,578	15,365	2,506	2	17,872	14,847	1,905	5	16,757	6,560	916	10	7,486
Oct-13	225,051	26,418	268	251,737	57,105	6,933	11	64,049	15,679	2,515	2	18,197	15,136	1,922	5	17,063	6,699	923	7	7,629
Nov-13	226,545	26,346	268	253,160	57,858	7,020	11	64,889	15,897	2,559	2	18,458	15,339	1,957	5	17,301	6,777	917	5	7,699
Dec-13	227,639	26,455	270	254,364	58,291	7,071	11	65,373	16,004	2,567	2	18,572	15,564	1,983	5	17,552	6,843	961	1	7,805
Jan-14	230,921	26,820	261	258,001	60,279	7,101	11	67,392	16,822	2,573	2	19,397	15,798	1,983	5	17,786	7,073	944	1	8,018
Feb-14	230,934	26,835	267	258,036	60,114	7,134	11	67,259	16,855	2,572	2	19,429	15,842	2,029	5	17,876	7,048	943	1	7,992
Mar-14	230,774	26,838	264	257,876	59,958	7,078	11	67,047	16,824	2,647	2	19,473	15,758	2,029	5	17,791	6,984	944	1	7,930
Apr-14	230,038	27,120	273	257,431	60,499	7,151	11	67,662	16,924	2,598	2	19,523	15,807	1,988	5	17,800	6,945	928	1	7,874
May-14	229,830	27,125	273	257,228	60,231	7,137	11	67,379	16,862	2,599	2	19,464	15,704	1,961	5	17,669	6,895	928	1	7,824
Jun-14	229,514	27,229	267	257,010	59,962	7,146	11	67,119	16,680	2,591	2	19,273	15,512	1,951	5	17,468	6,878	916	1	7,795
Jul-14	231,216	27,265	271	258,752	60,028	7,074	11	67,113	16,650	2,611	2	19,263	15,416	1,951	5	17,372	6,763	925	1	7,689
Aug-14	231,172	27,239	273	258,684	59,704	7,068	11	66,783	16,638	2,594	2	19,235	15,293	1,946	5	17,244	6,723	928	1	7,652
Sep-14	232,276	27,244	268	259,788	59,570	7,065	11	66,646	16,498	2,596	2	19,096	15,329	1,954	5	17,288	6,720	923	10	7,653
Oct-14	233,261	27,350	273	260,884	60,048	7,074	11	67,133	16,829	2,606	2	19,437	15,624	1,972	5	17,601	6,861	931	7	7,799
Nov-14	234,793	27,277	273	262,343	60,828	7,162	11	68,002	17,058	2,650	2	19,711	15,831	2,008	5	17,844	6,941	925	5	7,870
Dec-14	235,915	27,388	275	263,577	61,277	7,214	12	68,502	17,170	2,658	2	19,831	16,061	2,033	5	18,100	7,007	969	1	7,977
Jan-15	239,074	27,740	265	267,079	63,394	7,242	12	70,648	17,972	2,681	2	20,654	16,289	2,033	5	18,327	7,238	952	1	8,191
Feb-15	239,088	27,755	271	267,114	63,223	7,276	12	70,510	18,006	2,679	2	20,688	16,335	2,079	5	18,419	7,213	950	1	8,164
Mar-15	238,924	27,758	268	266,951	63,061	7,219	12	70,292	17,973	2,757	2	20,732	16,249	2,079	5	18,333	7,148	952	1	8,101
Apr-15	238,170	28,046	278	266,494	63,622	7,293	12	70,927	18,078	2,706	2	20,786	16,299	2,038	5	18,342	7,109	935	1	8,045
May-15	237,957	28,051	278	266,286	63,344	7,279	12	70,635	18,014	2,708	2	20,724	16,193	2,010	5	18,208	7,058	935	1	7,994
Jun-15	237,633	28,159	271	266,063	63,065	7,288	12	70,365	17,823	2,699	2	20,524	15,997	2,000	5	18,002	7,041	923	1	7,965
Jul-15	239,376	28,196	276	267,848	63,133	7,216	11	70,360	17,791	2,720	2	20,513	15,900	2,000	5	17,905	6,924	932	1	7,857
Aug-15	239,331	28,169	278	267,778	62,797	7,209	11	70,018	17,779	2,703	2	20,483	15,774	1,995	5	17,774	6,883	935	1	7,819
Sep-15	240,463	28,174	273	268,909	62,659	7,206	11	69,876	17,632	2,704	2	20,338	15,810	2,003	5	17,818	6,880	930	10	7,820
Oct-15	241,472	28,283	278	270,032	63,154	7,216	12	70,381	17,979	2,715	2	20,695	16,112	2,021	5	18,138	7,023	938	7	7,969

Appendix 3.2 - Customer Forecast - Number by Region
High Growth

	WA/ID				Medford				Roseburg				Klamath Falls				La Grande			
	WA/ID Res	WA/ID Com	WA/ID Firm Ind	WA/ID Total	MFR Res	MFR Com	MFR Firm Ind	MFR Total	ROS Res	ROS Com	ROS Firm Ind	ROS Total	KLA Res	KLA Com	KLA Firm Ind	KLA Total	LGD Res	LGD Com	LGD Firm Ind	LGD Total
Nov-15	243,042	28,207	278	271,527	63,963	7,304	12	71,279	18,220	2,760	2	20,982	16,324	2,058	5	18,386	7,104	932	5	8,041
Dec-15	244,192	28,321	279	272,792	64,428	7,357	12	71,796	18,337	2,768	2	21,108	16,558	2,084	5	18,647	7,172	976	1	8,149
Jan-16	247,227	28,659	269	276,155	66,509	7,376	12	73,897	19,121	2,770	2	21,893	16,781	2,083	5	18,868	7,404	959	1	8,364
Feb-16	247,240	28,675	276	276,191	66,331	7,410	12	73,753	19,158	2,769	2	21,928	16,827	2,130	5	18,962	7,378	958	1	8,337
Mar-16	247,073	28,678	273	276,024	66,165	7,352	12	73,529	19,123	2,848	2	21,973	16,739	2,130	5	18,874	7,312	959	1	8,273
Apr-16	246,300	28,973	282	275,556	66,745	7,427	12	74,184	19,233	2,796	2	22,031	16,791	2,088	5	18,884	7,272	942	1	8,216
May-16	246,082	28,978	282	275,342	66,457	7,413	12	73,882	19,165	2,798	2	21,965	16,683	2,059	5	18,747	7,221	942	1	8,164
Jun-16	245,750	29,088	276	275,114	66,168	7,423	12	73,603	18,965	2,789	2	21,757	16,483	2,049	5	18,537	7,203	930	1	8,134
Jul-16	247,536	29,126	281	276,942	66,239	7,349	12	73,600	18,933	2,810	2	21,745	16,383	2,049	5	18,437	7,084	939	1	8,025
Aug-16	247,490	29,098	282	276,871	65,891	7,342	12	73,245	18,919	2,793	2	21,714	16,255	2,044	5	18,304	7,043	942	1	7,986
Sep-16	248,648	29,104	277	278,029	65,748	7,339	12	73,098	18,765	2,795	2	21,562	16,291	2,052	5	18,349	7,040	938	10	7,987
Oct-16	249,682	29,215	282	279,179	66,260	7,349	12	73,621	19,129	2,805	2	21,936	16,599	2,071	5	18,675	7,186	946	7	8,138
Nov-16	251,290	29,138	282	280,710	67,098	7,439	12	74,549	19,381	2,852	2	22,234	16,816	2,108	5	18,929	7,267	939	5	8,212
Dec-16	252,467	29,255	284	282,006	67,579	7,492	12	75,083	19,504	2,860	2	22,366	17,056	2,135	5	19,195	7,337	984	1	8,321
Jan-17	255,373	29,577	272	285,222	69,460	7,502	12	76,974	20,271	2,860	2	23,133	17,272	2,132	5	19,410	7,570	967	1	8,537
Feb-17	255,387	29,593	279	285,259	69,277	7,536	12	76,825	20,309	2,858	2	23,169	17,320	2,180	5	19,505	7,543	965	1	8,510
Mar-17	255,215	29,597	276	285,088	69,104	7,477	12	76,594	20,273	2,940	2	23,214	17,230	2,180	5	19,415	7,477	967	1	8,444
Apr-17	254,425	29,899	285	284,609	69,703	7,554	12	77,270	20,387	2,887	2	23,276	17,283	2,137	5	19,425	7,436	950	1	8,387
May-17	254,201	29,904	285	284,390	69,407	7,539	12	76,958	20,317	2,888	2	23,207	17,172	2,108	5	19,286	7,384	950	1	8,334
Jun-17	253,862	30,016	279	284,157	69,108	7,549	12	76,669	20,108	2,880	2	22,989	16,968	2,098	5	19,071	7,366	937	1	8,304
Jul-17	255,689	30,055	284	286,028	69,181	7,474	12	76,668	20,074	2,901	2	22,976	16,866	2,098	5	18,969	7,245	947	1	8,193
Aug-17	255,642	30,027	285	285,954	68,822	7,468	12	76,302	20,060	2,883	2	22,945	16,735	2,093	5	18,833	7,203	950	1	8,153
Sep-17	256,828	30,032	281	287,140	68,674	7,464	12	76,150	19,899	2,885	2	22,786	16,773	2,102	5	18,879	7,199	945	10	8,155
Oct-17	257,886	30,146	285	288,317	69,203	7,474	12	76,690	20,279	2,895	2	23,176	17,087	2,120	5	19,213	7,348	953	7	8,308
Nov-17	259,531	30,067	285	289,884	70,068	7,565	12	77,645	20,542	2,943	2	23,487	17,308	2,158	5	19,471	7,431	947	5	8,383
Dec-17	260,736	30,186	287	291,210	70,564	7,619	13	78,196	20,670	2,952	2	23,624	17,553	2,185	5	19,743	7,501	991	1	8,494
Jan-18	263,668	30,527	277	294,472	72,247	7,627	13	79,887	21,420	2,932	2	24,354	17,764	2,182	5	19,951	7,735	974	1	8,710
Feb-18	263,682	30,543	283	294,509	72,058	7,662	13	79,733	21,460	2,930	2	24,392	17,813	2,231	5	20,048	7,709	973	1	8,682
Mar-18	263,507	30,547	280	294,334	71,881	7,603	13	79,497	21,422	3,013	2	24,437	17,721	2,231	5	19,956	7,641	974	1	8,616
Apr-18	262,698	30,856	290	293,844	72,498	7,680	13	80,190	21,542	2,959	2	24,502	17,774	2,187	5	19,967	7,599	957	1	8,558
May-18	262,469	30,861	290	293,620	72,192	7,665	13	79,870	21,468	2,961	2	24,431	17,662	2,158	5	19,824	7,546	957	1	8,505
Jun-18	262,122	30,976	283	293,381	71,885	7,675	13	79,572	21,250	2,952	2	24,204	17,454	2,147	5	19,606	7,528	945	1	8,474
Jul-18	263,992	31,016	288	295,296	71,960	7,600	13	79,572	21,215	2,973	2	24,190	17,350	2,147	5	19,502	7,406	954	1	8,361
Aug-18	263,944	30,987	290	295,220	71,591	7,593	12	79,196	21,200	2,955	2	24,157	17,216	2,142	5	19,363	7,363	957	1	8,321
Sep-18	265,157	30,992	285	296,434	71,438	7,590	12	79,040	21,032	2,957	2	23,991	17,254	2,151	5	19,410	7,359	952	10	8,322
Oct-18	266,240	31,109	290	297,639	71,983	7,600	13	79,595	21,428	2,968	2	24,398	17,575	2,170	5	19,750	7,510	960	7	8,477
Nov-18	267,924	31,028	290	299,242	72,873	7,692	13	80,577	21,703	3,016	2	24,721	17,800	2,208	5	20,013	7,594	954	5	8,553
Dec-18	269,157	31,150	292	300,599	73,384	7,746	13	81,143	21,837	3,025	2	24,864	18,050	2,236	5	20,291	7,666	999	1	8,666
Jan-19	271,965	31,477	283	303,724	74,870	7,745	13	82,628	22,570	3,004	2	25,575	18,256	2,232	5	20,492	7,901	982	1	8,883
Feb-19	271,979	31,493	289	303,762	74,676	7,780	13	82,470	22,611	3,002	2	25,615	18,305	2,281	5	20,591	7,874	980	1	8,855
Mar-19	271,800	31,497	286	303,583	74,494	7,720	13	82,228	22,572	3,086	2	25,660	18,211	2,281	5	20,497	7,805	982	1	8,788
Apr-19	270,972	31,813	296	303,081	75,127	7,798	13	82,939	22,696	3,031	2	25,729	18,266	2,237	5	20,508	7,763	965	1	8,728
May-19	270,738	31,818	296	302,853	74,814	7,783	13	82,610	22,620	3,033	2	25,655	18,151	2,207	5	20,363	7,709	965	1	8,675
Jun-19	270,383	31,936	289	302,608	74,498	7,793	13	82,304	22,393	3,024	2	25,418	17,939	2,196	5	20,140	7,691	952	1	8,644
Jul-19	272,296	31,976	294	304,567	74,576	7,717	13	82,305	22,356	3,046	2	25,403	17,833	2,196	5	20,034	7,566	961	1	8,529
Aug-19	272,247	31,947	296	304,490	74,196	7,710	13	81,919	22,340	3,027	2	25,370	17,697	2,191	5	19,893	7,523	965	1	8,488
Sep-19	273,488	31,953	291	305,731	74,039	7,707	13	81,759	22,166	3,029	2	25,197	17,736	2,200	5	19,941	7,519	960	10	8,489
Oct-19	274,595	32,072	296	306,963	74,599	7,717	13	82,329	22,578	3,040	2	25,620	18,063	2,219	5	20,287	7,672	968	7	8,647
Nov-19	276,318	31,989	296	308,603	75,513	7,810	13	83,336	22,864	3,090	2	25,956	18,293	2,258	5	20,556	7,758	961	5	8,724
Dec-19	277,579	32,114	298	309,991	76,038	7,865	13	83,916	23,004	3,099	2	26,104	18,547	2,286	5	20,839	7,830	1,007	1	8,838
Jan-20	280,561	32,463	284	313,308	77,493	7,879	14	85,385	23,719	3,075	2	26,796	18,747	2,281	5	21,034	8,066	989	1	9,056
Feb-20	280,576	32,479	291	313,347	77,294	7,914	14	85,222	23,762	3,073	2	26,838	18,798	2,332	5	21,134	8,039	988	1	9,028
Mar-20	280,393	32,483	288	313,164	77,107	7,854	13	84,975	23,721	3,159	2	26,882	18,702	2,332	5	21,039	7,969	989	1	8,959
Apr-20	279,546	32,806	298	312,650	77,757	7,933	14	85,703	23,851	3,103	2	26,956	18,758	2,287	5	21,050	7,926	972	1	8,899
May-20	279,306	32,812	298	312,416	77,435	7,918	13	85,366	23,771	3,105	2	26,878	18,641	2,256	5	20,902	7,872	972	1	8,845
Jun-20	278,943	32,932	291	312,166	77,111	7,928	13	85,052	23,535	3,096	2	26,633	18,424	2,246	5	20,675	7,853	959	1	8,813
Jul-20	280,900	32,974	296	314,170	77,191	7,850	13	85,054	23,497	3,118	2	26,617	18,316	2,246	5	20,567	7,727	969	1	8,697
Aug-20	280,850	32,944	298	314,091	76,801	7,844	13	84,658	23,481	3,099	2	26,582	18,177	2,240	5	20,423	7,683	972	1	8,655
Sep-20	282,120	32,949	293	315,362	76,640	7,840	13	84,494	23,299	3,101	2	26,403	18,217	2,249	5	20,471	7,679	967	10	8,656
Oct-20	283,253	33,071	298	316,622	77,215	7,850	13	85,078	23,728	3,113	2	26,843	18,551	2,269	5	20,824	7,834	975	7	8,816
Nov-20	285,016	32,987	298	318,300	78,153	7,944	14	86,111	24,025	3,163	2	27,190	18,785	2,308	5	21,098	7,921	969	5	8,895
Dec-20	286,306	33,115	299	319,720	78,691	8,000	14	86,705	24,170	3,172	2	27,345	19,045	2,337	5	21,387	7,995	1,014	1	9,010
Jan-21	289,310	33,451	289	323,050	80,116	8,005	14	88,134	24,869	3,147	2	28,018	19,239	2,331	5	21,575	8,232	997	1	9,229
Feb-21	289,325	33,469	296	323,090	79,912	8,040	14	87,966	24,913	3,145	2	28,060	19,290	2,382	5	21,677	8,204	995	1	9,200
Mar-21	289,138	33,472	292	322,902	79,721	7,979	14	87,714	24,871	3,232	2	28,105	19,193	2,382	5	21,580	8,133	997	1	9,131
Apr-21	288,272	33,803	302	322,377	80,387	8,059	14	88,460	25,005	3,175	2	28,182	19,250	2,337	5	21,591	8,090	979	1	9,070
May-21	288,026	33,809	302	322,137	80,057	8,044	14	88,114	24,923	3,177	2	28,102	19,130	2,306	5	21,441	8,035	979	1	9,015
Jun-21	287,655	33,932	296	321,882	79,725	8,054	14	87,792	24,678	3,168	2	27,848	18,910	2,295	5	21,209	8,016	967	1	8,983
Jul-21	289,657	33,974	301	323,932	79,806	7,976	14	87,795	24,638	3,191	2	27,830	18,800	2,295	5	21,099	7,888	976	1	8,865
Aug-21	289,605	33,943	302	323,851	79,407	7,969	13	87,389	24,621	3,172	2	27,795	18,658	2,289	5	20,952	7,843	979	1	8,823
Sep-21	290,904	33,949	297	325,151	79,242	7,965	13	87,221	24,433	3,174	2	27,609	18,698	2,298	5	21,002	7,839	975	10	8,824
Oct-21	292,064	34,074	302	326,440	79,831	7,976	14	87,820	24,878	3,185	2	28,065	19,038	2,318	5	21,362	7,997	982	7	8,986

Appendix 3.2 - Customer Forecast - Number by Region
High Growth

	WA/ID				Medford				Roseburg				Klamath Falls				La Grande			
	WA/ID Res	WA/ID Com	WA/ID Firm Ind	WA/ID Total	MFR Res	MFR Com	MFR Firm Ind	MFR Total	ROS Res	ROS Com	ROS Firm Ind	ROS Total	KLA Res	KLA Com	KLA Firm Ind	KLA Total	LGD Res	LGD Com	LGD Firm Ind	LGD Total
Nov-21	293,867	33,988	302	328,157	80,793	8,071	14	88,877	25,186	3,236	2	28,424	19,277	2,358	5	21,641	8,085	976	5	9,066
Dec-21	295,187	34,118	304	329,609	81,345	8,127	14	89,486	25,337	3,246	2	28,585	19,542	2,388	5	21,934	8,159	1,022	1	9,182
Jan-22	298,208	34,439	292	332,939	82,739	8,130	14	90,884	26,018	3,219	2	29,239	19,730	2,381	5	22,116	8,397	1,004	1	9,402
Feb-22	298,224	34,456	299	332,979	82,530	8,166	14	90,711	26,064	3,217	2	29,283	19,783	2,433	5	22,220	8,369	1,002	1	9,373
Mar-22	298,032	34,460	295	332,787	82,334	8,104	14	90,453	26,020	3,305	2	29,328	19,683	2,433	5	22,121	8,297	1,004	1	9,302
Apr-22	297,146	34,798	305	332,249	83,017	8,185	14	91,216	26,160	3,248	2	29,409	19,742	2,386	5	22,133	8,254	987	1	9,241
May-22	296,895	34,804	305	332,004	82,678	8,170	14	90,862	26,074	3,250	2	29,326	19,620	2,355	5	21,980	8,197	987	1	9,185
Jun-22	296,515	34,930	299	331,743	82,338	8,180	14	90,532	25,820	3,240	2	29,062	19,395	2,344	5	21,744	8,178	974	1	9,153
Jul-22	298,563	34,973	304	333,840	82,422	8,101	14	90,536	25,779	3,263	2	29,044	19,283	2,344	5	21,632	8,048	983	1	9,033
Aug-22	298,510	34,942	305	333,757	82,012	8,094	14	90,120	25,762	3,244	2	29,008	19,139	2,338	5	21,482	8,002	987	1	8,990
Sep-22	299,839	34,947	300	335,087	81,843	8,091	14	89,948	25,567	3,246	2	28,814	19,180	2,347	5	21,532	7,999	982	10	8,991
Oct-22	301,025	35,075	305	336,405	82,447	8,101	14	90,562	26,028	3,257	2	29,287	19,526	2,368	5	21,899	8,159	990	7	9,155
Nov-22	302,869	34,987	305	338,161	83,432	8,197	14	91,644	26,347	3,309	2	29,659	19,770	2,409	5	22,183	8,248	983	5	9,237
Dec-22	304,220	35,120	307	339,647	83,998	8,254	14	92,267	26,504	3,319	2	29,825	20,039	2,438	5	22,482	8,324	1,029	1	9,354
Jan-23	307,258	35,424	296	342,979	85,362	8,256	15	93,633	27,168	3,290	2	30,460	20,222	2,430	5	22,657	8,563	1,011	1	9,576
Feb-23	307,274	35,443	303	343,020	85,148	8,292	15	93,455	27,216	3,288	2	30,506	20,275	2,483	5	22,763	8,535	1,010	1	9,545
Mar-23	307,078	35,447	300	342,824	84,947	8,230	15	93,191	27,170	3,379	2	30,551	20,174	2,483	5	22,662	8,462	1,011	1	9,474
Apr-23	306,172	35,792	310	342,273	85,647	8,312	15	93,973	27,314	3,320	2	30,636	20,233	2,436	5	22,674	8,417	994	1	9,412
May-23	305,915	35,798	310	342,023	85,300	8,296	15	93,610	27,226	3,322	2	30,549	20,109	2,404	5	22,518	8,360	994	1	9,355
Jun-23	305,526	35,926	303	341,755	84,951	8,306	14	93,272	26,963	3,312	2	30,277	19,881	2,393	5	22,278	8,340	981	1	9,323
Jul-23	307,621	35,970	308	343,900	85,037	8,226	14	93,278	26,920	3,335	2	30,257	19,766	2,393	5	22,164	8,209	991	1	9,200
Aug-23	307,567	35,938	310	343,815	84,618	8,219	14	92,851	26,902	3,316	2	30,220	19,619	2,387	5	22,012	8,162	994	1	9,157
Sep-23	308,926	35,944	305	345,175	84,444	8,216	14	92,674	26,700	3,318	2	30,020	19,661	2,397	5	22,063	8,159	989	10	9,158
Oct-23	310,139	36,075	310	346,524	85,063	8,226	14	93,303	27,178	3,330	2	30,509	20,014	2,417	5	22,436	8,321	997	7	9,325
Nov-23	312,026	35,984	310	348,320	86,072	8,324	15	94,411	27,509	3,383	2	30,893	20,262	2,459	5	22,726	8,412	991	5	9,407
Dec-23	313,407	36,121	312	349,839	86,652	8,381	15	95,048	27,670	3,392	2	31,065	20,536	2,489	5	23,030	8,488	1,037	1	9,526
Jan-24	316,309	36,412	298	353,018	87,985	8,374	15	96,374	28,317	3,380	2	31,699	20,713	2,480	5	23,199	8,729	1,019	1	9,749
Feb-24	316,325	36,430	305	353,060	87,766	8,411	15	96,192	28,367	3,378	2	31,747	20,768	2,534	5	23,306	8,700	1,017	1	9,718
Mar-24	316,124	36,434	301	352,860	87,560	8,348	15	95,923	28,320	3,470	2	31,792	20,665	2,534	5	23,203	8,626	1,019	1	9,646
Apr-24	315,198	36,787	311	352,296	88,276	8,430	15	96,721	28,469	3,410	2	31,881	20,725	2,486	5	23,216	8,581	1,001	1	9,583
May-24	314,935	36,793	311	352,040	87,922	8,414	15	96,351	28,377	3,412	2	31,791	20,599	2,453	5	23,057	8,523	1,001	1	9,525
Jun-24	314,538	36,924	305	351,767	87,565	8,425	15	96,004	28,105	3,402	2	31,509	20,366	2,442	5	22,813	8,503	989	1	9,492
Jul-24	316,679	36,969	310	353,958	87,652	8,344	15	96,011	28,061	3,426	2	31,489	20,250	2,442	5	22,696	8,369	998	1	9,368
Aug-24	316,624	36,936	311	353,872	87,223	8,337	14	95,574	28,043	3,406	2	31,451	20,100	2,436	5	22,541	8,322	1,001	1	9,325
Sep-24	318,014	36,943	306	355,262	87,046	8,333	15	95,394	27,834	3,408	2	31,244	20,143	2,446	5	22,594	8,319	997	10	9,325
Oct-24	319,254	37,076	311	356,641	87,678	8,344	15	96,037	28,327	3,420	2	31,750	20,502	2,467	5	22,974	8,483	1,005	7	9,495
Nov-24	321,182	36,984	311	358,477	88,712	8,442	15	97,170	28,670	3,474	2	32,146	20,754	2,509	5	23,268	8,575	998	5	9,578
Dec-24	322,594	37,123	313	360,030	89,306	8,500	15	97,821	28,837	3,484	2	32,323	21,034	2,539	5	23,578	8,653	1,045	1	9,698
Jan-25	325,359	37,437	302	363,098	90,608	8,492	15	99,115	29,302	3,452	2	32,756	21,205	2,530	5	23,740	8,894	1,026	1	9,922
Feb-25	325,375	37,456	309	363,140	90,384	8,529	15	98,928	29,353	3,450	2	32,805	21,260	2,584	5	23,849	8,865	1,025	1	9,891
Mar-25	325,170	37,460	306	362,936	90,173	8,465	15	98,654	29,305	3,543	2	32,850	21,156	2,584	5	23,745	8,790	1,026	1	9,817
Apr-25	324,224	37,820	316	362,360	90,906	8,548	15	99,470	29,458	3,482	2	32,942	21,217	2,536	5	23,757	8,744	1,009	1	9,754
May-25	323,956	37,826	316	362,098	90,543	8,532	15	99,091	29,364	3,484	2	32,850	21,088	2,503	5	23,596	8,686	1,009	1	9,695
Jun-25	323,549	37,960	309	361,819	90,178	8,543	15	98,736	29,085	3,474	2	32,561	20,851	2,491	5	23,347	8,665	996	1	9,662
Jul-25	325,738	38,006	314	364,058	90,268	8,462	15	98,744	29,039	3,499	2	32,540	20,733	2,491	5	23,229	8,530	1,005	1	9,536
Aug-25	325,681	37,973	316	363,970	89,828	8,454	15	98,298	29,020	3,478	2	32,500	20,581	2,485	5	23,071	8,482	1,009	1	9,492
Sep-25	327,101	37,979	311	365,391	89,647	8,451	15	98,113	28,805	3,480	2	32,288	20,624	2,495	5	23,124	8,479	1,004	10	9,493
Oct-25	328,368	38,115	316	366,799	90,294	8,462	15	98,771	29,313	3,492	2	32,808	20,990	2,516	5	23,511	8,645	1,012	7	9,664
Nov-25	330,338	38,021	316	368,675	91,352	8,561	15	99,928	29,665	3,547	2	33,214	21,246	2,559	5	23,810	8,739	1,005	5	9,749
Dec-25	331,781	38,163	318	370,262	91,959	8,619	16	100,594	29,837	3,557	2	33,396	21,531	2,590	5	24,126	8,817	1,052	1	9,870
Jan-26	334,409	38,462	305	373,176	93,067	8,610	16	101,692	30,288	3,524	2	33,813	21,697	2,579	5	24,281	9,060	1,034	1	10,095
Feb-26	334,426	38,481	312	373,219	92,838	8,647	16	101,501	30,340	3,521	2	33,864	21,753	2,635	5	24,392	9,030	1,032	1	10,063
Mar-26	334,216	38,485	309	373,010	92,623	8,583	16	101,222	30,290	3,616	2	33,909	21,646	2,635	5	24,286	8,954	1,034	1	9,989
Apr-26	333,250	38,853	319	372,422	93,372	8,667	16	102,054	30,448	3,554	2	34,004	21,709	2,585	5	24,299	8,908	1,016	1	9,925
May-26	332,976	38,859	319	372,154	93,001	8,651	16	101,667	30,351	3,557	2	33,910	21,578	2,552	5	24,135	8,848	1,016	1	9,865
Jun-26	332,561	38,996	312	371,869	92,628	8,661	15	101,305	30,064	3,546	2	33,612	21,337	2,540	5	23,882	8,828	1,003	1	9,832
Jul-26	334,796	39,043	317	374,156	92,719	8,579	15	101,314	30,017	3,571	2	33,590	21,216	2,540	5	23,761	8,691	1,013	1	9,704
Aug-26	334,738	39,009	319	374,066	92,271	8,572	15	100,858	29,998	3,550	2	33,550	21,061	2,534	5	23,601	8,642	1,016	1	9,659
Sep-26	336,188	39,015	314	375,517	92,086	8,568	15	100,669	29,777	3,552	2	33,331	21,106	2,544	5	23,655	8,639	1,011	10	9,660
Oct-26	337,482	39,154	319	376,956	92,747	8,579	15	101,341	30,299	3,565	2	33,865	21,477	2,566	5	24,048	8,807	1,019	7	9,834
Nov-26	339,495	39,058	319	378,872	93,827	8,679	16	102,522	30,660	3,621	2	34,283	21,739	2,609	5	24,353	8,902	1,013	5	9,920
Dec-26	340,968	39,203	321	380,493	94,447	8,739	16	103,202	30,837	3,631	2	34,470	22,028	2,640	5	24,674	8,982	1,060	1	10,043
Jan-27	343,308	39,487	310	383,105	95,526	8,727	16	104,270	31,273	3,595	2	34,870	22,188	2,629	5	24,822	9,225	1,041	1	10,268
Feb-27	343,326	39,506	317	383,149	95,293	8,765	16	104,074	31,327	3,593	2	34,922	22,245	2,685	5	24,935	9,195	1,040	1	10,236
Mar-27	343,112	39,511	313	382,936	95,073	8,700	16	103,789	31,276	3,690	2	34,967	22,137	2,685	5	24,827	9,118	1,041	1	10,160
Apr-27	342,125	39,886	324	382,335	95,837	8,785	16	104,638	31,437	3,627	2	35,066	22,200	2,635	5	24,841	9,071	1,023	1	10,096
May-27	341,846	39,892	324	382,062	95,459	8,769	16	104,244	31,338	3,629	2	34,969	22,068	2,601	5	24,674	9,011	1,023	1	10,035
Jun-27	341,423	40,032	317	381,771	95,078	8,780	16	103,873	31,043	3,618	2	34,664	21,822	2,589	5	24,416	8,990	1,010	1	10,002
Jul-27	343,703	40,080	322	384,105	95,171	8,697	16	103,884	30,995	3,643	2	34,641	21,699	2,589	5	24,294	8,851	1,020	1	9,872
Aug-27	343,645	40,045	324	384,013	94,713	8,689	16	103,418	30,975	3,622	2	34,600	21,542	2,583	5	24,130	8,802	1,023	1	9,827
Sep-27	345,124	40,052	318	385,494	94,524	8,686	16	103,226	30,749	3,625	2	34,375	21,587	2,593	5	24,185	8,799	1,019	10	9,827
Oct-27	346,445	40,193	324	386,962	95,199	8,697	16	103,912	31,284	3,637	2	34,923	21,965	2,615	5	24,585	8,970	1,027	7	10,003

Appendix 3.2 - Customer Forecast - Number by Region
High Growth

	WA/ID				Medford				Roseburg				Klamath Falls				La Grande			
	WA/ID Res	WA/ID Com	WA/ID Firm Ind	WA/ID Total	MFR Res	MFR Com	MFR Firm Ind	MFR Total	ROS Res	ROS Com	ROS Firm Ind	ROS Total	KLA Res	KLA Com	KLA Firm Ind	KLA Total	LGD Res	LGD Com	LGD Firm Ind	LGD Total
Nov-27	348,499	40,095	324	388,918	96,302	8,798	16	105,116	31,656	3,694	2	35,351	22,231	2,659	5	24,895	9,066	1,020	5	10,091
Dec-27	350,002	40,244	326	390,572	96,935	8,858	16	105,809	31,837	3,704	2	35,543	22,526	2,691	5	25,222	9,146	1,067	1	10,215
Jan-28	352,208	40,512	313	393,032	97,985	8,845	16	106,847	32,258	3,667	2	35,927	22,680	2,679	5	25,364	9,391	1,049	1	10,441
Feb-28	352,226	40,532	320	393,077	97,747	8,884	16	106,647	32,313	3,665	2	35,980	22,738	2,736	5	25,478	9,360	1,047	1	10,409
Mar-28	352,008	40,536	316	392,860	97,523	8,818	16	106,357	32,261	3,763	2	36,026	22,628	2,736	5	25,368	9,282	1,049	1	10,332
Apr-28	351,001	40,919	327	392,247	98,303	8,904	16	107,223	32,427	3,699	2	36,128	22,692	2,685	5	25,382	9,235	1,031	1	10,266
May-28	350,716	40,926	327	391,969	97,916	8,887	16	106,820	32,325	3,701	2	36,028	22,557	2,651	5	25,213	9,174	1,031	1	10,205
Jun-28	350,284	41,068	320	391,672	97,528	8,898	16	106,442	32,023	3,690	2	35,715	22,308	2,638	5	24,951	9,153	1,018	1	10,171
Jul-28	352,611	41,117	325	394,053	97,623	8,814	16	106,453	31,973	3,716	2	35,691	22,183	2,638	5	24,826	9,012	1,027	1	10,040
Aug-28	352,551	41,081	327	393,959	97,156	8,807	16	105,979	31,953	3,695	2	35,649	22,023	2,632	5	24,660	8,962	1,031	1	9,994
Sep-28	354,060	41,088	321	395,470	96,963	8,803	16	105,782	31,720	3,697	2	35,419	22,068	2,642	5	24,716	8,958	1,026	10	9,994
Oct-28	355,407	41,233	327	396,967	97,652	8,814	16	106,482	32,270	3,710	2	35,981	22,453	2,665	5	25,123	9,132	1,034	7	10,173
Nov-28	357,502	41,133	327	398,962	98,777	8,917	16	107,710	32,651	3,767	2	36,420	22,723	2,709	5	25,438	9,229	1,027	5	10,261
Dec-28	359,036	41,284	329	400,649	99,423	8,977	17	108,416	32,837	3,778	2	36,617	23,023	2,742	5	25,769	9,311	1,075	1	10,387
Jan-29	360,957	41,499	317	402,773	100,445	8,963	17	109,424	33,243	3,757	2	37,002	23,171	2,729	5	25,905	9,557	1,056	1	10,614
Feb-29	360,975	41,519	324	402,818	100,201	9,002	17	109,220	33,300	3,754	2	37,057	23,230	2,786	5	26,021	9,526	1,055	1	10,581
Mar-29	360,752	41,524	321	402,597	99,973	8,935	17	108,925	33,246	3,854	2	37,103	23,118	2,786	5	25,909	9,447	1,056	1	10,504
Apr-29	359,727	41,914	331	401,972	100,768	9,022	17	109,807	33,416	3,789	2	37,208	23,184	2,735	5	25,924	9,398	1,038	1	10,437
May-29	359,436	41,921	331	401,688	100,374	9,006	17	109,396	33,312	3,791	2	37,105	23,047	2,700	5	25,751	9,336	1,038	1	10,376
Jun-29	358,996	42,066	324	401,386	99,978	9,017	16	109,011	33,002	3,780	2	36,784	22,793	2,687	5	25,485	9,315	1,025	1	10,341
Jul-29	361,368	42,116	330	403,813	100,075	8,932	16	109,023	32,951	3,806	2	36,760	22,666	2,687	5	25,359	9,172	1,035	1	10,208
Aug-29	361,306	42,080	331	403,717	99,599	8,924	16	108,539	32,930	3,785	2	36,717	22,503	2,681	5	25,190	9,122	1,038	1	10,161
Sep-29	362,845	42,086	326	405,257	99,402	8,921	16	108,339	32,692	3,787	2	36,481	22,550	2,692	5	25,246	9,118	1,033	10	10,162
Oct-29	364,218	42,234	331	406,783	100,104	8,932	17	109,053	33,255	3,800	2	37,057	22,941	2,714	5	25,660	9,294	1,041	7	10,342
Nov-29	366,354	42,132	331	408,817	101,252	9,035	17	110,304	33,646	3,859	2	37,507	23,216	2,759	5	25,980	9,392	1,035	5	10,432
Dec-29	367,918	42,286	333	410,537	101,911	9,096	17	111,024	33,837	3,869	2	37,708	23,520	2,792	5	26,317	9,475	1,082	1	10,559

APPENDIX 3.3

DEMAND COEFFICIENTS

Appendix 3.3 - Demand Coefficients

HEAT COEFFICIENTS

	January	February	March	April	May	June	July	August	September	October	November	December
WA/ID Res	0.010161	0.009844	0.009304	0.007734	0.005345	0.004028	0.000608	0.000922	0.002525	0.006699	0.009053	0.010008
WA/ID Com	0.053275	0.051052	0.045140	0.036351	0.022150	0.018202	0.000792	0.009813	0.024243	0.037242	0.044417	0.049912
WA/ID Ind	0.029537	0.022645	0.014240	0.006666	0.000440	0.000647	0.000103	0.000655	0.005619	0.024302	0.017250	0.030898
Rose Res	0.011740	0.012002	0.010662	0.008797	0.006684	0.006365	0.002005	0.000131	0.002339	0.006930	0.009309	0.010696
Rose Com	0.051194	0.046536	0.042102	0.034251	0.026890	0.012130	0.006173	0.005015	0.022451	0.042320	0.041711	0.044943
Rose Ind	0.143683	0.382986	0.454116	6.433516	0.073323	0.733043	0.001168	0.620961	0.871054	0.581124	0.430739	0.171302
Medford Res	0.0117059	0.0112635	0.0103266	0.0089624	0.0065806	0.0049395	0.0000000	0.0015629	0.0035456	0.0067777	0.0094898	0.0109030
Medford Com	0.0463831	0.0444072	0.0407981	0.0333211	0.0215413	0.0187994	0.0000000	0.0128279	0.0246833	0.0412677	0.0407016	0.0434298
Medford Ind	0.0077249	0.0218908	0.0155278	0.0089999	0.0020867	0.0000000	0.0000000	0.0000000	0.0000156	0.0050760	0.3650654	0.0194449
LaGrande Res	0.0100328	0.0094154	0.0087315	0.0076290	0.0052489	0.0048472	0.0022910	0.0118836	0.0011452	0.0038170	0.0087451	0.0094379
LaGrande Com	0.0440837	0.0420294	0.0369415	0.0305153	0.0198406	0.0170519	0.0106129	0.0799977	0.0106923	0.0192863	0.0356774	0.0398303
LaGrande Ind	0.0000000	0.0000000	0.0000000	0.0000000	0.0026585	0.0338869	0.4529151	2.2414711	5.5710995	4.7131820	0.0000000	0.0000000
Klamath Res	0.007863	0.007266	0.007048	0.006408	0.004342	0.003034	0.000667	0.000485	0.002265	0.004698	0.007090	0.007764
Klamath Com	0.033613	0.030405	0.027491	0.022579	0.012706	0.006995	0.002275	0.007427	0.016473	0.029815	0.029336	0.032226
Klamath Ind	0.0000000	0.0000000	0.0000000	0.0000000	0.000056	0.0000000	0.0000000	0.0000000	0.0009360	0.0012714	0.0000000	0.0000000

BASE COEFFICIENTS

WA/ID Res	0.056042	0.056042	0.056042	0.056042	0.056042	0.056042	0.056042	0.056042	0.056042	0.056042	0.056042	0.056042
WA/ID Com	0.369928	0.369928	0.369928	0.369928	0.369928	0.369928	0.369928	0.369928	0.369928	0.369928	0.369928	0.369928
WA/ID Ind	3.898256	3.898256	3.898256	3.898256	3.898256	3.898256	3.898256	3.898256	3.898256	3.898256	3.898256	3.898256
Rose Res	0.054292	0.054292	0.054292	0.054292	0.054292	0.054292	0.054292	0.054292	0.054292	0.054292	0.054292	0.054292
Rose Com	0.370630	0.370630	0.370630	0.370630	0.370630	0.370630	0.370630	0.370630	0.370630	0.370630	0.370630	0.370630
Rose Ind	13.780757	13.780757	13.780757	13.780757	13.780757	13.780757	13.780757	13.780757	13.780757	13.780757	13.780757	13.780757
Medford Res	0.048520	0.048520	0.048520	0.048520	0.048520	0.048520	0.048520	0.048520	0.048520	0.048520	0.048520	0.048520
Medford Com	0.343742	0.343742	0.343742	0.343742	0.343742	0.343742	0.343742	0.343742	0.343742	0.343742	0.343742	0.343742
Medford Ind	1.613195	1.613195	1.613195	1.613195	1.613195	1.613195	1.613195	1.613195	1.613195	1.613195	1.613195	1.613195
LaGrande Res	0.057597	0.057597	0.057597	0.057597	0.057597	0.057597	0.057597	0.057597	0.057597	0.057597	0.057597	0.057597
LaGrande Com	0.247762	0.247762	0.247762	0.247762	0.247762	0.247762	0.247762	0.247762	0.247762	0.247762	0.247762	0.247762
LaGrande Ind	9.582906	9.582906	9.582906	9.582906	9.582906	9.582906	9.582906	9.582906	9.582906	9.582906	9.582906	9.582906
Klamath Res	0.043256	0.043256	0.043256	0.043256	0.043256	0.043256	0.043256	0.043256	0.043256	0.043256	0.043256	0.043256
Klamath Com	0.336197	0.336197	0.336197	0.336197	0.336197	0.336197	0.336197	0.336197	0.336197	0.336197	0.336197	0.336197
Klamath Ind	3.515359	3.515359	3.515359	3.515359	3.515359	3.515359	3.515359	3.515359	3.515359	3.515359	3.515359	3.515359

Appendix 3.3 - WA/ID Base Coeffcient Calculation

Average Actual Demand by Class

		Month		
Year	Data	7	8	Grand Total
2005	Average of Res Demand	11,098	10,607	10,852
	Average of Com Demand	7,729	8,406	8,067
	Average of Ind Demand	991	1,001	996
2006	Average of Res Demand	9,988	10,513	10,250
	Average of Com Demand	6,956	8,331	7,643
	Average of Ind Demand	892	992	942
2007	Average of Res Demand	10,032	10,433	10,232
	Average of Com Demand	6,987	8,267	7,627
	Average of Ind Demand	896	984	940
2008	Average of Res Demand	10,684	10,495	10,590
	Average of Com Demand	7,441	8,317	7,879
	Average of Ind Demand	954	990	972
Total Average of Res Demand		10,450	10,512	10,481
Total Average of Com Demand		7,278	8,330	7,804
Total Average of Ind Demand		933	992	962

Average Actual Customer Count by Class

		Month		
Year	Data	7	8	Grand Total
2005	Average of Res Cust	179,140	179,447	179,294
	Average of Com Cust	20,450	20,427	20,439
	Average of Ind Cust	263	260	262
2006	Average of Res Cust	185,182	185,455	185,319
	Average of Com Cust	20,748	20,856	20,802
	Average of Ind Cust	246	242	244
2007	Average of Res Cust	189,577	190,087	189,832
	Average of Com Cust	21,291	21,336	21,314
	Average of Ind Cust	244	241	243
2008	Average of Res Cust	193,667	193,643	193,655
	Average of Com Cust	21,847	21,815	21,831
	Average of Ind Cust	239	240	240
Total Average of Res Cust		186,892	187,158	187,025
Total Average of Com Cust		21,084	21,109	21,096
Total Average of Ind Cust		248	246	247

Base Coefficients

(Actual Average Demand/Customer Count)

0.056042	Res Base Usage
0.369928	Com Base Usage
3.898256	Ind Base Usage

Appendix 3.3 - WA/ID Regression Stats

WA/ID Residential

	January	February	March	April	May	June	July	August	September	October	November	December
						Regression Statistics						
Multiple R	0.998398723	0.995750934	0.994490863	0.983623734	0.969333647	0.939778657	0.335222502	0.752299466	0.941398214	0.986521604	0.995938325	0.997695538
R Square	0.99680001	0.991519923	0.989012077	0.967515651	0.93960772	0.883183924	0.112374126	0.565954486	0.886230597	0.973224875	0.991893148	0.995396386
Adjusted R Sc	0.985930445	0.979615161	0.978142511	0.956279696	0.928738154	0.871947969	0.101504561	0.555084921	0.874994642	0.962355309	0.980657192	0.98452682
Standard Errc	0.022033904	0.030732888	0.026342574	0.030074362	0.016078288	0.010418248	0.00185167	0.002476787	0.007801887	0.021630349	0.024635913	0.027253246
Observations	93	85	93	90	93	90	93	93	90	93	90	93
						Coefficients						
Intercept	0	0	0	0	0	0	0	0	0	0	0	0
X Variable 1	0.010161371	0.009844216	0.009304356	0.007733501	0.005344796	0.004028185	0.000608084	0.000921821	0.002524987	0.006699091	0.00905327	0.010007757

WA/ID Commercial

	January	February	March	April	May	June	July	August	September	October	November	December
						Regression Statistics						
Multiple R	0.998205563	0.995422216	0.993514039	0.978724692	0.946895526	0.915462071	0.259337381	0.742496607	0.948760581	0.983665598	0.994646858	0.997342233
R Square	0.996414345	0.990865388	0.987070146	0.957902023	0.896611138	0.838070803	0.067255877	0.551301212	0.900146641	0.967598008	0.989322371	0.99469153
Adjusted R Sc	0.98554478	0.978960626	0.976200581	0.946666068	0.885741572	0.826834848	0.056386312	0.540431646	0.888910686	0.956728443	0.978086416	0.983821964
Standard Errc	0.122309206	0.165472366	0.138772667	0.161734208	0.089249524	0.056897097	0.003194496	0.027159875	0.069633124	0.132664609	0.138894328	0.146007905
Observations	93	85	93	90	93	90	93	93	90	93	90	93
						Coefficients						
Intercept	0	0	0	0	0	0	0	0	0	0	0	0
X Variable 1	0.053275318	0.051052228	0.045140487	0.036351273	0.022150311	0.01820155	0.000791714	0.009812502	0.024243202	0.037241593	0.044416725	0.049912097

WA/ID Industrial

	January	February	March	April	May	June	July	August	September	October	November	December
						Regression Statistics						
Multiple R	0.983068858	0.98946309	0.970782442	0.864451536	0.542191066	0.654513296	0.474285435	0.900826006	0.958139923	0.979266163	0.973451995	0.987504551
R Square	0.96642438	0.979037207	0.942418549	0.747276459	0.293971152	0.428387654	0.224946674	0.811487493	0.918032112	0.958962219	0.947608786	0.975165238
Adjusted R Sc	0.955554815	0.967132446	0.931548984	0.736040504	0.283101587	0.417151699	0.214077108	0.800617928	0.906796157	0.948092653	0.936372831	0.964295673
Standard Errc	7.01262933	4.887622022	6.445493864	10.66927823	9.970168364	5.376631886	0.953858066	1.332094749	2.469011204	3.943486882	6.889674699	6.310446154
Observations	93	85	93	90	93	90	93	93	90	93	90	93
						Coefficients						
Intercept	0	0	0	0	0	0	0	0	0	0	0	0
X Variable 1	0.029537303	0.022644728	0.014240273	0.006666253	0.000440254	0.000647201	0.000103312	0.000654992	0.005618723	0.02430201	0.017250182	0.030898324

Appendix 3.3 - Medford Base Coeffcient Calculation

Average Actual Demand by Class

		Month		
Year	Data	7	8	Grand Total
2005	Average of Res Demand	2,422	2,367	2,395
	Average of Com Demand	2,136	2,219	2,178
	Average of Ind Demand	8	7	8
2006	Average of Res Demand	2,245	2,306	2,276
	Average of Com Demand	1,979	2,163	2,071
	Average of Ind Demand	8	7	7
2007	Average of Res Demand	2,319	2,285	2,302
	Average of Com Demand	2,044	2,142	2,093
	Average of Ind Demand	8	7	7
2008	Average of Res Demand	2,300	2,688	2,494
	Average of Com Demand	2,027	2,520	2,274
	Average of Ind Demand	8	8	8
Total Average of Res Demand		2,321	2,412	2,366
Total Average of Com Demand		2,047	2,261	2,154
Total Average of Ind Demand		8	7	8

Average Actual Customer Count by Class

		Month		
Year	Data	7	8	Grand Total
2005	Average of Res Customer	47,286	47,191	47,239
	Average of Com Customer	6,085	6,094	6,090
	Average of Ind Customer	-	-	-
2006	Average of Res Customer	48,666	48,531	48,599
	Average of Com Customer	6,225	6,229	6,227
	Average of Ind Customer	-	-	-
2007	Average of Res Customer	49,448	49,391	49,420
	Average of Com Customer	6,356	6,352	6,354
	Average of Ind Customer	9	9	9
2008	Average of Res Customer	49,930	49,734	49,832
	Average of Com Customer	6,395	6,391	6,393
	Average of Ind Customer	10	10	10
Total Average of Res Customer		48,833	48,712	48,772
Total Average of Com Customer		6,265	6,267	6,266
Total Average of Ind Customer		5	5	5

Base Coefficients

(Actual Average Demand/Customer Count)

0.04852	Res Base Usage
0.343742	Com Base Usage
1.613195	Ind Base Usage

Appendix 3.3 - Medford Regression Stats

Medford Residential

	January	February	March	April	May	June	July	August	September	October	November	December
Regression Statistics												
Multiple R	0.997134455	0.9956274	0.991885136	0.992020827	0.971083997	0.951603992	1	0.932017098	0.93846896	0.979085299	0.994286808	0.997032867
R Square	0.994277122	0.991273919	0.983836123	0.98410532	0.943004129	0.905550157	1	0.86865587	0.880723988	0.958608022	0.988606256	0.994074538
Adjusted R Sq	0.983407557	0.979369158	0.972966558	0.972869365	0.932134564	0.894314202	0.978494624	0.857786305	0.869488033	0.947738457	0.977370301	0.983204972
Standard Erro	0.024793168	0.024268254	0.02636742	0.016960252	0.011758493	0.005471504	0	0.000510824	0.005468033	0.016468298	0.021179782	0.023241593
Observations	93	85	93	90	93	90	93	93	90	93	90	93
Coefficients												
Intercept	0	0	0	0	0	0	0	0	0	0	0	0
X Variable 1	0.011705871	0.011263499	0.010326571	0.008962427	0.006580555	0.004939512	0	0.001562886	0.003545602	0.006777695	0.009489786	0.010903024

Medford Commercial

	January	February	March	April	May	June	July	August	September	October	November	December
Regression Statistics												
Multiple R	0.996784908	0.994461134	0.987386868	0.987224704	0.947022126	0.949396645	1	0.917991079	0.937475383	0.977343321	0.991152773	0.996731693
R Square	0.993580153	0.988952947	0.974932828	0.974612616	0.896850908	0.901353989	1	0.842707622	0.878860094	0.955199968	0.982383819	0.993474067
Adjusted R Sq	0.982710588	0.977048185	0.964063262	0.963376661	0.885981343	0.890118034	0.978494624	0.831838057	0.867624139	0.944330403	0.971147864	0.982604502
Standard Erro	0.104086797	0.107780652	0.130318333	0.080078125	0.05309695	0.0213312	0	0.004658366	0.038403579	0.104503728	0.11331058	0.097184676
Observations	93	85	93	90	93	90	93	93	90	93	90	93
Coefficients												
Intercept	0	0	0	0	0	0	0	0	0	0	0	0
X Variable 1	0.046383127	0.044407158	0.040798114	0.033321104	0.021541343	0.018799439	0	0.012827896	0.024683314	0.041267734	0.040701618	0.043429764

Medford Industrial

	January	February	March	April	May	June	July	August	September	October	November	December
Regression Statistics												
Multiple R	0.789420263	0.793717904	0.704505615	0.732204638	0.517931489	0	1	0	0.430000967	0.631909117	0.463225574	0.937903107
R Square	0.623184352	0.629988111	0.496328161	0.536123632	0.268253027	0	1	0	0.184900832	0.399309132	0.214577932	0.879662239
Adjusted R Sq	0.612314787	0.61808335	0.485458596	0.524887677	0.257383462	-0.011111111	0.978494624	-0.010752688	0.173664877	0.388439567	0.203341977	0.868792674
Standard Erro	17.13717432	13.96883719	14.1375431	10.1415113	6.21734101	3.410767265	0	0.836017184	3.783464912	9.062638562	18.42447239	9.577855007
Observations	93	85	93	90	93	90	93	93	90	93	90	93
Coefficients												
Intercept	0	0	0	0	0	0	0	0	0	0	0	0
X Variable 1	0.00772489	0.021890782	0.015527802	0.008999948	0.002086688	0	0	0	1.56271E-05	0.005075985	0.365065388	0.01944488

Appendix 3.3 - Roseburg Base Coeffcient Calculation

Average Actual Demand by Class

		Month		
Year	Data	7	8	Grand Total
2005	Average of Res Demand	859	849	854
	Average of Com Demand	910	1,040	975
	Average of Ind Demand	32	46	39
2006	Average of Res Demand	702	611	657
	Average of Com Demand	744	748	746
	Average of Ind Demand	26	33	29
2007	Average of Res Demand	634	619	627
	Average of Com Demand	672	757	715
	Average of Ind Demand	24	33	28
2008	Average of Res Demand	632	585	609
	Average of Com Demand	670	716	693
	Average of Ind Demand	23	31	27
Total Average of Res Demand		707	666	686
Total Average of Com Demand		749	815	782
Total Average of Ind Demand		26	36	31

Average Actual Customer Count by Class

		Month		
Year	Data	7	8	Grand Total
2005	Average of Res Customer	12,311	12,257	12,284
	Average of Com Customer	2,093	2,093	2,093
	Average of Ind Customer	2	2	2
2006	Average of Res Customer	12,570	12,511	12,541
	Average of Com Customer	2,128	2,112	2,120
	Average of Ind Customer	3	4	4
2007	Average of Res Customer	12,900	12,777	12,839
	Average of Com Customer	2,126	2,105	2,116
	Average of Ind Customer	2	1	2
2008	Average of Res Customer	12,942	12,885	12,914
	Average of Com Customer	2,116	2,106	2,111
	Average of Ind Customer	2	2	2
Total Average of Res Customer		12,681	12,608	12,644
Total Average of Com Customer		2,116	2,104	2,110
Total Average of Ind Customer		2	2	2

Base Coefficients

(Actual Average Demand/Customer Count)

0.054292	Res Base Usage
0.37063	Com Base Usage
13.78076	Ind Base Usage

Appendix 3.3 - Roseburg Regression Stats

Roseburg Residential

	January	February	March	April	May	June	July	August	September	October	November	December
Regression Statistics												
Multiple R	0.991367883	0.990994199	0.988973116	0.982896977	0.964808013	0.913479404	0.901282988	0.442373441	0.903573229	0.97329924	0.991649071	0.99351331
R Square	0.98281028	0.982069503	0.978067824	0.966086467	0.930854503	0.834444621	0.812311025	0.195694261	0.81644458	0.94731141	0.98336788	0.987068697
Adjusted R Sc	0.971940714	0.970164741	0.967198258	0.954850512	0.919984938	0.823208666	0.80144146	0.184824696	0.805208625	0.936441844	0.972131925	0.976199132
Standard Errc	0.040415547	0.034729716	0.029928677	0.024955649	0.015657803	0.013462314	0.00093196	0.000307506	0.004773063	0.019669774	0.023163079	0.02976046
Observations	93	85	93	90	93	90	93	93	90	93	90	93
Coefficients												
Intercept	0	0	0	0	0	0	0	0	0	0	0	0
X Variable 1	0.011739765	0.012002059	0.01066242	0.008796645	0.006684316	0.006364556	0.002005321	0.000131182	0.00233934	0.006930492	0.009308506	0.01069573

Roseburg Commercial

	January	February	March	April	May	June	July	August	September	October	November	December
Regression Statistics												
Multiple R	0.992265812	0.991074226	0.986097496	0.976906522	0.949873574	0.853735613	0.813329036	0.726798867	0.929317717	0.971654909	0.988621839	0.992886275
R Square	0.984591442	0.982228121	0.972388271	0.954346353	0.902259807	0.728864497	0.661504121	0.528236593	0.863631418	0.944113263	0.977373141	0.985823155
Adjusted R Sc	0.973721876	0.970323359	0.961518706	0.943110398	0.891390241	0.717628542	0.650634556	0.517367028	0.852395463	0.933243697	0.966137186	0.97495359
Standard Errc	0.166708416	0.134049982	0.132985425	0.113430363	0.076067558	0.035131124	0.004269241	0.005480161	0.03838982	0.123910636	0.121433297	0.131017601
Observations	93	85	93	90	93	90	93	93	90	93	90	93
Coefficients												
Intercept	0	0	0	0	0	0	0	0	0	0	0	0
X Variable 1	0.051193529	0.046535659	0.042101905	0.034250846	0.026890317	0.012129519	0.006172839	0.005015183	0.022451199	0.042319727	0.041711454	0.044942538

Roseburg Industrial

	January	February	March	April	May	June	July	August	September	October	November	December
Regression Statistics												
Multiple R	0.918530171	0.963015396	0.954353828	0.735987825	0.711794929	0.411154682	0.431331093	0.174892794	0.464784791	0.902308321	0.968157638	0.923289039
R Square	0.843697675	0.927398653	0.910791228	0.541678078	0.506652021	0.169048172	0.186046512	0.030587489	0.216024902	0.814160306	0.937329213	0.852462649
Adjusted R Sc	0.83282811	0.915493891	0.899921663	0.530442123	0.495782455	0.157812217	0.175176946	0.019717924	0.204788947	0.803290741	0.926093258	0.841593084
Standard Errc	10.29134657	5.770224964	5.59859604	10.25082009	6.036836982	4.328790887	0.872278376	1.138447354	3.810085613	5.187912461	4.789973446	9.337545902
Observations	93	85	93	90	93	90	93	93	90	93	90	93
Coefficients												
Intercept	0	0	0	0	0	0	0	0	0	0	0	0
X Variable 1	0.14368321	0.382986079	0.454116065	6.43351624	0.073323445	0.733042531	0.001168185	0.62096138	0.871053897	0.581124251	0.430738696	0.171301851

Appendix 3.3 - Klamath Falls Base Coeffcient Calculation

Average Actual Demand by Class

		Month		
Year	Data	7	8	Grand Total
2005	Average of Res Demand	752	674	713
	Average of Com Demand	632	682	657
	Average of Ind Demand	9	12	11
2006	Average of Res Demand	541	533	537
	Average of Com Demand	455	539	497
	Average of Ind Demand	7	10	8
2007	Average of Res Demand	576	540	558
	Average of Com Demand	484	547	515
	Average of Ind Demand	7	10	8
2008	Average of Res Demand	494	508	501
	Average of Com Demand	416	514	465
	Average of Ind Demand	6	9	8
Total Average of Res Demand		591	564	577
Total Average of Com Demand		497	570	534
Total Average of Ind Demand		7	10	9

Average Actual Customer Count by Class

		Month		
Year	Data	7	8	Grand Total
2005	Average of Res Customer	12,977	12,855	12,916
	Average of Com Customer	1,576	1,566	1,571
	Average of Ind Customer	-	-	-
2006	Average of Res Customer	13,240	13,135	13,188
	Average of Com Customer	1,582	1,576	1,579
	Average of Ind Customer	-	-	-
2007	Average of Res Customer	13,675	13,610	13,643
	Average of Com Customer	1,605	1,598	1,602
	Average of Ind Customer	5	5	5
2008	Average of Res Customer	13,703	13,576	13,640
	Average of Com Customer	1,603	1,590	1,597
	Average of Ind Customer	5	5	5
Total Average of Res Customer		13,399	13,294	13,346
Total Average of Com Customer		1,592	1,583	1,587
Total Average of Ind Customer		3	3	3

Base Coefficients

(Actual Average Demand/Customer Count)

0.043256	Res Base Usage
0.336197	Com Base Usage
3.515359	Ind Base Usage

Appendix 3.3 - Klamath Falls Regression Stats

Klamath Falls Residential

	January	February	March	April	May	June	July	August	September	October	November	December
						Regression Statistics						
Multiple R	0.993062364	0.994783204	0.992335858	0.984431794	0.90204138	0.943498977	0.579473888	0.590914942	0.905460706	0.981467019	0.993478035	0.99483772
R Square	0.986172859	0.989593624	0.984730455	0.969105957	0.813678651	0.89019032	0.335789987	0.349180469	0.81985909	0.963277509	0.986998606	0.98970209
Adjusted R Sc	0.975303294	0.977688862	0.97386089	0.957870002	0.802809086	0.878954365	0.324920421	0.338310903	0.808623135	0.952407944	0.975762651	0.978832524
Standard Errc	0.035652592	0.02567037	0.02588898	0.027423238	0.030798103	0.00980396	0.001655684	0.002471344	0.011285938	0.018299672	0.022703065	0.030326521
Observations	93	85	93	90	93	90	93	93	90	93	90	93
						Coefficients						
Intercept	0	0	0	0	0	0	0	0	0	0	0	0
X Variable 1	0.007863049	0.007265615	0.007048129	0.006407522	0.004341971	0.003034126	0.000666518	0.000484551	0.002265305	0.004697918	0.007089624	0.007764077

Klamath Falls Commercial

	January	February	March	April	May	June	July	August	September	October	November	December
						Regression Statistics						
Multiple R	0.99126788	0.993538491	0.987434685	0.964267296	0.760031127	0.750273218	0.45023922	0.728985915	0.89961323	0.976689555	0.989089275	0.994348689
R Square	0.982612009	0.987118733	0.975027257	0.929811419	0.577647314	0.562909902	0.202715355	0.531420464	0.809303963	0.953922487	0.978297594	0.988729316
Adjusted R Sc	0.971742444	0.975213971	0.964157692	0.918575464	0.566777749	0.551673947	0.19184579	0.520550899	0.798068008	0.943052922	0.967061639	0.977859751
Standard Errc	0.171220984	0.119668112	0.129777997	0.148701981	0.161043709	0.05671166	0.0079703	0.026053637	0.084987919	0.130726554	0.121910441	0.131749433
Observations	93	85	93	90	93	90	93	93	90	93	90	93
						Coefficients						
Intercept	0	0	0	0	0	0	0	0	0	0	0	0
X Variable 1	0.033613433	0.030405028	0.027490939	0.022578968	0.012705896	0.006995477	0.002275434	0.007426894	0.016472813	0.029814558	0.029335794	0.032225664

Klamath Falls Industrial

	January	February	March	April	May	June	July	August	September	October	November	December
						Regression Statistics						
Multiple R	0	0	0	0	0.190476487	0	0	0	0.390765841	0.358970161	0	0
R Square	0	0	0	0	0.036281292	0	0	0	0.152697943	0.128859576	0	0
Adjusted R Sc	-0.010752688	-0.011764706	-0.010752688	-0.011111111	0.025292281	-0.011111111	-0.010752688	-0.010752688	0.141461988	0.117990011	-0.011111111	-0.010752688
Standard Errc	38.0857832	34.25063331	29.33858702	23.83694611	14.5873647	9.148770409	1.756707575	1.756707575	9.783484642	18.62050906	27.74587056	38.0857832
Observations	93	85	93	90	92	90	93	93	90	93	90	93
						Coefficients						
Intercept	0	0	0	0	0	0	0	0	0	0	0	0
X Variable 1	0	0	0	0	5.5682E-05	0	0	0	0.000935955	0.00127142	0	0

Appendix 3.3 - LaGrande Base Coeffcient Calculation

Average Actual Demand by Class

		Month	
Year	Data	7	Grand Total
2005	Average of Res Demand	368	368
	Average of Com Demand	224	224
	Average of Ind Demand	17	17
2006	Average of Res Demand	360	360
	Average of Com Demand	219	219
	Average of Ind Demand	17	17
2007	Average of Res Demand	360	360
	Average of Com Demand	219	219
	Average of Ind Demand	17	17
2008	Average of Res Demand	365	365
	Average of Com Demand	222	222
	Average of Ind Demand	17	17
Total Average of Res Demand		364	364
Total Average of Com Demand		221	221
Total Average of Ind Demand		17	17

Average Actual Customer Count by Class

		Month	
Year	Data	7	Grand Total
2005	Average of Res Customers	6,475	6,475
	Average of Com Customers	949	949
	Average of Ind Customers	3	3
2006	Average of Res Customers	6,163	6,163
	Average of Com Customers	873	873
	Average of Ind Customers	2	2
2007	Average of Res Customers	6,259	6,259
	Average of Com Customers	868	868
	Average of Ind Customers	1	1
2008	Average of Res Customers	6,351	6,351
	Average of Com Customers	880	880
	Average of Ind Customers	1	1
Total Average of Res Customers		6,312	6,312
Total Average of Com Customers		893	893
Total Average of Ind Customers		2	2

Base Coefficients

(Actual Average Demand/Customer Count)

0.057597	Res Base Usage
0.247762	Com Base Usage
9.582906	Ind Base Usage

Appendix 3.3 - LaGrande Regression Stats

LaGrande Residential

	January	February	March	April	May	June	July	August	September	October	November	December
Regression Statistics												
Multiple R	0.994589872	0.994689217	0.983701811	0.976803952	0.909994946	0.914751317	0.818086637	0.708928486	0.583127441	0.957903564	0.985673476	0.996323896
R Square	0.989209014	0.989406639	0.967669253	0.954145961	0.828090802	0.836769971	0.669265746	0.502579598	0.340037612	0.917579238	0.971552202	0.992661306
Adjusted R Sc	0.978339449	0.977501877	0.956799688	0.942910006	0.817221237	0.825534016	0.658396181	0.491710033	0.328801657	0.906709672	0.960316247	0.98179174
Standard Errc	0.036928346	0.028857126	0.039769899	0.034178424	0.028547421	0.014599672	0.00143458	0.037345249	0.01428263	0.020632378	0.038187972	0.028290967
Observations	93	85	93	90	93	90	93	93	90	93	90	93
Coefficients												
Intercept	0	0	0	0	0	0	0	0	0	0	0	0
X Variable 1	0.010032753	0.00941539	0.008731541	0.007629031	0.005248865	0.004847228	0.002290957	0.011883615	0.001145173	0.003817002	0.008745128	0.009437935

LaGrande Commercial

	January	February	March	April	May	June	July	August	September	October	November	December
Regression Statistics												
Multiple R	0.9942758	0.994924902	0.983584571	0.97556244	0.8950851	0.889506261	0.850734185	0.735492775	0.705875052	0.965396013	0.985553463	0.99585588
R Square	0.988584366	0.98987556	0.967438609	0.951722075	0.801177337	0.791221388	0.723748654	0.540949622	0.498259589	0.931989462	0.971315628	0.991728934
Adjusted R Sc	0.9777148	0.977970798	0.956569043	0.94048612	0.790307772	0.779985433	0.712879089	0.530080057	0.487023634	0.921119897	0.960079673	0.980859369
Standard Errc	0.16694532	0.125902205	0.168878038	0.140455244	0.117981709	0.059733575	0.005840607	0.232786043	0.096056046	0.093964113	0.156460606	0.126811832
Observations	93	85	93	90	93	90	93	93	90	93	90	93
Coefficients												
Intercept	0	0	0	0	0	0	0	0	0	0	0	0
X Variable 1	0.044083686	0.04202937	0.036941473	0.030515287	0.019840618	0.017051862	0.010612854	0.079997745	0.010692319	0.019286303	0.035677411	0.039830301

LaGrande Industrial

	January	February	March	April	May	June	July	August	September	October	November	December
Regression Statistics												
Multiple R	0	0	0	0	0.20961698	0.638087506	0.636751222	0.592660516	0.909857698	0.983767201	0	0
R Square	0	0	0	0	0.043939278	0.407155665	0.405452118	0.351246488	0.827841031	0.967797907	0	0
Adjusted R Sc	-0.010869565	-0.011764706	-0.010752688	-0.011111111	0.033069713	0.39591971	0.394582553	0.340376922	0.816605076	0.956928341	-0.011111111	-0.010752688
Standard Errc	35.04096981	29.44526328	24.78401323	20.32240143	11.67168629	5.250770625	0.686848469	2.544293966	3.714547661	3.236476622	25.37715508	34.67483361
Observations	92	85	93	90	93	90	93	93	90	93	90	93
Coefficients												
Intercept	0	0	0	0	0	0	0	0	0	0	0	0
X Variable 1	0	0	0	0	0.002658518	0.033886923	0.452915064	2.241471101	5.571099508	4.713182014	0	0

APPENDIX 3.4

HEATING DEGREE DAY (HDD) DATA

Appendix 3.4 - Heating Degree Day Data Monthly Totals

Temp Pattern	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Klam Falls	2009	1042	935	772	593	393	169	36	48	188	487	825	1212	6700
Klam Falls	2010	1042	935	772	593	393	169	36	48	188	487	825	1212	6700
Klam Falls	2011	1042	935	772	593	393	169	36	48	188	487	825	1212	6700
Klam Falls	2012	1032	930	772	593	393	169	36	48	188	487	820	1202	6670
Klam Falls	2013	1015	923	762	586	393	169	36	48	188	486	809	1187	6602
Klam Falls	2014	1011	915	746	580	389	169	36	48	188	479	803	1187	6551
Klam Falls	2015	1011	912	745	578	386	169	36	48	187	475	799	1187	6533
Klam Falls	2016	1011	912	743	572	383	164	36	48	186	472	798	1186	6511
Klam Falls	2017	1006	909	742	571	378	161	36	48	186	470	794	1181	6482
Klam Falls	2018	1001	907	741	571	377	160	36	47	186	467	792	1177	6462
Klam Falls	2019	992	903	738	568	372	160	36	47	182	466	788	1169	6421
Klam Falls	2020	992	903	738	568	372	160	36	47	182	466	788	1169	6421
Klam Falls	2021	990	902	737	567	372	160	36	47	182	466	788	1169	6416
Klam Falls	2022	990	902	737	567	372	160	36	47	182	466	788	1169	6416
Klam Falls	2023	990	902	737	567	372	160	36	47	182	466	788	1169	6416
Klam Falls	2024	990	902	737	567	372	160	36	47	182	466	788	1169	6416
Klam Falls	2025	989	902	737	566	372	160	36	47	182	466	785	1167	6409
Klam Falls	2026	989	902	737	566	372	160	36	47	182	466	784	1167	6408
Klam Falls	2027	989	902	737	566	372	160	36	47	182	466	784	1167	6408
Klam Falls	2028	987	901	737	564	371	159	36	46	180	464	781	1166	6392
Klam Falls	2029	987	901	737	564	371	159	36	46	180	464			

Temp Pattern	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
LaGrande	2009	1019	969	712	511	343	145	29	37	122	484	775	1146	6292
LaGrande	2010	996	958	706	510	343	145	29	37	122	484	766	1127	6223
LaGrande	2011	985	946	682	492	335	144	29	37	120	464	745	1119	6098
LaGrande	2012	964	935	675	487	324	139	28	37	117	460	736	1101	6003
LaGrande	2013	948	924	663	474	320	136	27	36	115	447	722	1084	5896
LaGrande	2014	931	912	652	468	311	134	27	34	113	445	706	1070	5803
LaGrande	2015	914	902	635	454	307	129	26	33	111	431	693	1058	5693
LaGrande	2016	894	890	625	451	302	127	26	33	109	423	682	1039	5601
LaGrande	2017	877	880	616	438	295	124	25	31	107	420	666	1026	5505
LaGrande	2018	860	868	598	430	288	121	24	31	104	409	655	1010	5398
LaGrande	2019	841	854	587	419	284	119	24	30	100	399	640	995	5292
LaGrande	2020	838	853	586	419	283	119	24	30	100	399	637	993	5281
LaGrande	2021	836	852	580	418	281	119	24	30	99	395	633	991	5258
LaGrande	2022	832	852	579	418	281	119	24	30	99	395	632	985	5246
LaGrande	2023	830	852	578	418	281	119	24	30	99	395	630	984	5240
LaGrande	2024	828	846	576	415	279	118	23	30	97	392	627	982	5213
LaGrande	2025	823	845	576	415	277	116	23	30	96	391	626	981	5199
LaGrande	2026	820	842	571	411	275	116	23	30	96	389	622	978	5173
LaGrande	2027	816	840	571	411	275	116	23	30	96	389	621	974	5162
LaGrande	2028	812	840	571	411	275	116	23	30	96	389	621	971	5155
LaGrande	2029	806	833	566	406	274	116	23	30	95	385			

Temp Pattern	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Medford	2009	823	667	560	394	220	58	7	7	68	316	622	966	4708
Medford	2010	792	646	536	379	218	58	7	7	68	308	622	966	4607
Medford	2011	768	633	533	377	218	58	7	7	68	308	611	944	4532
Medford	2012	761	627	514	367	216	58	7	7	68	303	596	940	4464
Medford	2013	758	623	507	361	212	58	7	7	68	293	591	938	4423
Medford	2014	745	619	505	358	207	56	7	7	67	287	587	925	4370
Medford	2015	736	610	502	355	204	56	7	7	66	287	581	917	4328
Medford	2016	726	607	490	351	199	56	7	7	65	282	570	912	4272
Medford	2017	716	605	486	344	197	53	7	7	65	280	561	900	4221
Medford	2018	711	595	482	339	195	53	7	7	62	278	556	893	4178
Medford	2019	696	588	474	333	195	53	7	7	62	270	551	888	4124
Medford	2020	694	586	471	333	195	53	7	7	62	270	545	882	4105
Medford	2021	694	586	471	333	195	53	7	7	62	270	545	882	4105
Medford	2022	688	585	465	328	191	50	7	6	59	268	544	878	4069
Medford	2023	686	584	465	328	191	50	7	6	59	268	543	874	4061
Medford	2024	686	583	461	327	189	50	7	6	59	267	538	872	4045
Medford	2025	685	580	461	327	187	50	7	6	59	266	537	871	4036
Medford	2026	683	576	459	322	187	50	7	6	59	265	533	868	4015
Medford	2027	683	576	459	322	187	50	7	6	59	265	533	868	4015
Medford	2028	677	575	458	322	187	50	7	6	59	265	530	867	4003
Medford	2029	673	574	454	319	185	49	7	6	58	262			

Appendix 3.4 - Heating Degree Day Data Monthly Totals

Temp Pattern	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Roseburg	2009	677	623	491	354	219	79	13	6	66	275	501	831	4135
Roseburg	2010	677	623	491	354	219	79	13	6	66	275	501	830	4134
Roseburg	2011	660	611	483	353	219	79	13	6	66	274	497	817	4078
Roseburg	2012	650	604	471	344	214	79	13	6	66	264	476	808	3995
Roseburg	2013	646	601	464	337	210	79	13	6	66	263	472	802	3959
Roseburg	2014	634	593	460	332	206	78	13	6	64	262	470	795	3913
Roseburg	2015	630	588	452	327	203	77	13	6	64	255	467	788	3870
Roseburg	2016	617	586	450	322	201	76	13	6	62	253	460	779	3825
Roseburg	2017	609	580	443	322	201	76	13	6	62	249	454	772	3787
Roseburg	2018	604	571	437	315	194	72	12	6	58	242	443	765	3719
Roseburg	2019	596	569	430	309	193	72	12	6	58	240	439	762	3686
Roseburg	2020	586	565	428	305	189	69	11	6	57	239	435	756	3646
Roseburg	2021	583	563	425	303	189	69	11	6	57	238	434	750	3628
Roseburg	2022	579	557	421	303	188	69	11	6	57	237	429	747	3604
Roseburg	2023	577	556	420	303	188	69	11	6	57	236	427	743	3593
Roseburg	2024	575	552	417	300	186	69	11	6	56	236	426	740	3574
Roseburg	2025	569	551	411	300	186	69	11	6	56	232	422	736	3549
Roseburg	2026	566	551	411	300	186	69	11	6	56	232	422	733	3543
Roseburg	2027	560	546	406	295	179	62	10	5	54	228	416	729	3490
Roseburg	2028	556	543	404	293	179	62	10	5	54	228	412	728	3474
Roseburg	2029	553	538	401	290	176	62	10	5	54	227			

Temp Pattern	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
WA/ID	2009	1128	1155	761	548	317	145	35	34	187	541	886	1184	6921
WA/ID	2010	1128	1155	761	548	317	145	35	34	187	541	886	1184	6921
WA/ID	2011	1111	1143	760	548	317	145	35	34	187	541	875	1167	6863
WA/ID	2012	1097	1134	734	536	317	145	35	34	187	531	856	1158	6764
WA/ID	2013	1092	1126	730	527	313	145	35	34	185	525	856	1156	6724
WA/ID	2014	1081	1123	730	525	303	144	35	34	180	518	855	1150	6678
WA/ID	2015	1078	1118	729	522	301	142	35	34	178	516	845	1141	6639
WA/ID	2016	1071	1106	719	518	296	141	34	34	175	507	835	1131	6567
WA/ID	2017	1051	1102	712	515	296	137	34	34	173	506	829	1126	6515
WA/ID	2018	1044	1098	703	506	295	134	32	34	173	501	820	1120	6460
WA/ID	2019	1040	1092	700	500	295	134	32	34	173	499	815	1113	6427
WA/ID	2020	1035	1088	700	500	295	134	32	34	173	499	815	1109	6414
WA/ID	2021	1035	1085	697	499	293	130	32	32	171	494	812	1106	6386
WA/ID	2022	1028	1084	695	496	292	130	32	32	171	492	810	1101	6363
WA/ID	2023	1025	1082	692	495	292	130	32	32	171	490	808	1101	6350
WA/ID	2024	1023	1078	688	495	291	130	32	32	170	489	804	1098	6330
WA/ID	2025	1017	1074	685	495	291	130	32	32	170	489	798	1097	6310
WA/ID	2026	1016	1074	685	495	291	130	32	32	170	489	797	1094	6305
WA/ID	2027	1014	1072	682	492	286	129	31	31	168	484	793	1093	6275
WA/ID	2028	1006	1069	681	492	286	129	31	31	168	484	792	1091	6260
WA/ID	2029	1005	1067	680	491	281	129	31	31	166	482			

Appendix 3.4 - Heating Degree Days by Day (Includes Peak Weather Event and Additional Winter Storm)

Temperature Pattern	Day	January	February	March	April	May	June	July	August	September	October	November	December
Klamath Falls	1	29	32	26	30	11	0	9	0	3	7	30	29
Klamath Falls	2	33	39	22	31	8	0	2	0	5	8	21	29
Klamath Falls	3	33	44	19	27	4	0	0	0	6	7	20	31
Klamath Falls	4	33	43	13	25	4	0	0	0	7	6	19	31
Klamath Falls	5	23	36	18	23	6	0	0	0	7	7	15	29
Klamath Falls	6	22	41	27	20	12	0	1	0	10	9	10	35
Klamath Falls	7	28	34	22	23	14	1	2	0	10	14	10	39
Klamath Falls	8	31	30	22	29	15	4	0	0	8	27	23	38
Klamath Falls	9	32	35	24	33	23	15	0	0	1	25	31	42
Klamath Falls	10	25	40	23	29	20	17	0	0	1	23	29	43
Klamath Falls	11	28	28	29	27	21	17	0	0	4	21	33	50
Klamath Falls	12	30	33	25	32	16	17	0	0	3	21	37	42
Klamath Falls	13	24	42	26	28	16	15	0	0	1	25	28	41
Klamath Falls	14	35	51	29	21	12	16	0	0	3	23	31	37
Klamath Falls	15	41	54	32	17	18	15	0	0	12	13	25	34
Klamath Falls	16	34	53	29	18	15	10	0	0	16	6	22	37
Klamath Falls	17	30	47	24	12	10	5	0	0	19	10	26	0
Klamath Falls	18	37	26	33	10	4	0	0	0	11	12	28	54
Klamath Falls	19	42	25	34	7	0	0	0	0	4	13	19	66
Klamath Falls	20	39	23	33	7	1	0	2	0	7	14	14	72
Klamath Falls	21	42	26	28	8	2	0	6	0	11	13	23	68
Klamath Falls	22	44	23	28	18	14	0	9	0	11	9	24	58
Klamath Falls	23	42	19	28	15	27	0	5	0	4	10	33	36
Klamath Falls	24	38	21	27	17	26	0	0	0	0	19	31	36
Klamath Falls	25	36	23	22	25	24	0	0	10	0	17	34	28
Klamath Falls	26	40	20	22	18	21	0	0	13	5	16	33	42
Klamath Falls	27	34	23	25	18	14	0	0	9	7	29	39	28
Klamath Falls	28	32	24	26	12	11	7	0	4	7	22	44	33
Klamath Falls	29	34		24	9	11	17	0	5	1	23	51	35
Klamath Falls	30	33		18	4	13	13	0	4	4	20	42	35
Klamath Falls	31	38		14		0		0	3		18		34

Temperature Pattern	Day	January	February	March	April	May	June	July	August	September	October	November	December
LaGrande	1	28	30	28	26	8	2	0	0	0	0	26	37
LaGrande	2	27	28	26	26	10	0	1	0	0	1	20	27
LaGrande	3	29	28	28	25	14	7	0	0	0	7	18	27
LaGrande	4	32	23	25	22	20	4	0	0	8	9	18	27
LaGrande	5	32	31	25	18	21	5	0	0	4	16	26	23
LaGrande	6	27	33	27	26	12	5	0	0	3	8	25	23
LaGrande	7	17	32	23	28	8	9	0	0	0	13	19	31
LaGrande	8	23	31	26	28	18	11	0	0	0	22	20	32
LaGrande	9	28	32	31	26	18	5	4	0	0	23	27	28
LaGrande	10	30	31	27	24	17	4	5	0	0	26	25	31
LaGrande	11	27	24	30	22	13	8	0	0	0	24	21	36
LaGrande	12	22	20	30	24	10	13	0	0	0	22	21	34
LaGrande	13	31	61	30	27	14	10	0	0	0	22	23	28
LaGrande	14	34	68	25	18	7	10	0	0	4	16	24	30
LaGrande	15	33	74	23	10	6	6	0	0	2	23	20	29
LaGrande	16	36	61	24	12	9	0	0	0	13	15	22	38
LaGrande	17	36	60	16	15	6	0	0	0	17	12	22	40
LaGrande	18	35	31	16	9	16	0	0	0	8	8	27	51
LaGrande	19	30	24	15	4	11	0	0	0	7	16	28	58
LaGrande	20	32	26	10	12	11	0	10	0	3	14	33	64
LaGrande	21	32	28	17	17	7	0	8	0	3	25	28	58
LaGrande	22	38	28	18	11	1	1	1	0	3	25	34	51
LaGrande	23	34	28	16	7	9	5	0	1	0	15	35	26
LaGrande	24	29	27	28	7	7	2	0	9	0	21	27	28
LaGrande	25	23	27	29	17	1	0	0	5	0	15	31	35
LaGrande	26	33	26	21	16	3	0	0	7	1	25	25	40
LaGrande	27	43	24	17	18	16	0	0	7	16	15	30	46
LaGrande	28	49	22	20	9	16	13	0	4	14	17	32	42
LaGrande	29	51		21	5	13	16	0	0	10	16	28	41
LaGrande	30	39		19	1	11	9	0	0	6	1	31	37
LaGrande	31	36		15		10		0	4		12		29

Temperature Pattern	Day	January	February	March	April	May	June	July	August	September	October	November	December
Medford	1	29	15	13	14	10	0	2	4	0	0	10	30
Medford	2	30	12	15	14	8	0	1	0	0	1	13	27
Medford	3	31	15	17	20	2	0	0	0	3	9	11	21
Medford	4	28	14	18	18	6	0	0	0	4	7	16	25
Medford	5	32	21	20	9	19	0	0	0	2	3	16	24
Medford	6	29	25	20	0	19	4	0	0	0	0	21	19
Medford	7	27	13	18	18	10	6	0	0	0	0	21	23
Medford	8	31	17	21	19	6	1	0	0	0	3	21	23
Medford	9	30	22	23	15	5	0	1	0	0	11	19	22
Medford	10	32	19	15	17	7	0	0	0	0	13	18	19
Medford	11	30	14	12	12	9	0	0	0	0	14	17	27
Medford	12	31	23	15	22	12	0	0	0	0	15	19	26
Medford	13	36	32	14	25	11	6	0	0	5	6	27	25
Medford	14	31	36	10	18	8	4	0	0	8	9	23	28
Medford	15	26	38	14	13	8	3	0	0	5	13	21	28
Medford	16	20	32	13	13	3	10	0	0	2	10	22	21
Medford	17	22	28	13	18	7	9	0	0	7	10	25	27
Medford	18	20	25	10	20	0	6	0	0	1	9	21	50
Medford	19	23	26	13	17	4	4	0	0	4	7	19	59
Medford	20	24	26	19	14	7	2	0	0	5	13	14	61
Medford	21	27	23	19	8	9	1	0	0	3	20	16	56
Medford	22	23	21	21	5	11	1	0	0	4	19	24	55
Medford	23	23	24	17	10	9	0	0	1	3	12	32	28
Medford	24	20	25	19	9	12	0	0	0	0	14	28	30
Medford	25	15	22	21	5	3	0	0	0	0	7	19	29
Medford	26	16	26	24	4	0	0	0	0	0	10	18	36
Medford	27	20	27	19	4	1	0	0	0	1	13	24	35
Medford	28	17	25	20	7	0	0	0	0	1	13	29	29
Medford	29	22		20	6	4	1	0	0	0	15	34	29
Medford	30	24		23	5	5	0	0	2	10	14	24	25
Medford	31	23		20		3		3	0		18		29

Appendix 3.4 - Heating Degree Days by Day (Includes Peak Weather Event and Additional Winter Storm)

Temperature Pattern	Day	January	February	March	April	May	June	July	August	September	October	November	December
Roseburg	1	26	25	16	19	15	3	0	0	0	0	14	10
Roseburg	2	30	27	18	12	8	2	0	0	1	2	14	19
Roseburg	3	29	23	16	13	9	9	5	0	0	8	14	19
Roseburg	4	32	18	16	15	6	2	3	0	0	7	20	21
Roseburg	5	30	11	22	19	4	0	1	0	0	7	21	19
Roseburg	6	25	23	22	15	9	4	0	0	0	2	17	23
Roseburg	7	27	25	21	10	14	1	0	0	0	0	15	23
Roseburg	8	29	23	11	13	14	3	0	0	0	0	15	17
Roseburg	9	28	26	8	14	13	1	4	0	0	0	19	16
Roseburg	10	28	27	16	13	5	4	0	0	0	0	15	18
Roseburg	11	29	25	14	12	11	5	0	0	5	5	18	27
Roseburg	12	24	20	14	8	12	5	0	0	10	4	18	28
Roseburg	13	27	32	10	7	3	5	0	2	6	5	13	31
Roseburg	14	28	37	11	14	0	3	0	0	5	1	16	19
Roseburg	15	22	42	14	21	0	0	0	0	5	5	11	24
Roseburg	16	15	34	12	20	0	0	0	0	0	9	13	35
Roseburg	17	12	28	11	20	0	0	0	0	0	14	16	41
Roseburg	18	6	16	12	13	0	0	0	1	3	17	17	40
Roseburg	19	12	14	17	9	0	0	0	0	9	22	20	53
Roseburg	20	11	12	15	7	7	0	0	0	6	15	20	55
Roseburg	21	17	15	21	14	12	0	0	0	0	15	25	46
Roseburg	22	18	14	23	13	14	0	0	0	0	15	25	48
Roseburg	23	16	26	26	8	15	4	0	0	2	16	23	8
Roseburg	24	21	21	26	9	4	3	0	0	2	16	20	11
Roseburg	25	20	17	21	5	6	0	0	0	0	13	7	12
Roseburg	26	15	11	19	10	5	5	0	0	2	16	16	17
Roseburg	27	19	10	13	5	3	6	0	0	5	19	13	27
Roseburg	28	20	21	13	0	10	8	0	0	4	18	16	29
Roseburg	29	20		10	6	7	3	0	0	0	8	15	28
Roseburg	30	22		8	10	3	3	0	0	1	8	15	32
Roseburg	31	19		15		10		0	3		8		34

Temperature Pattern	Day	January	February	March	April	May	June	July	August	September	October	November	December
WA/ID	1	38	31	21	25	4	8	0	0	1	9	22	25
WA/ID	2	40	35	25	29	13	0	0	0	0	10	27	29
WA/ID	3	43	43	23	28	14	0	0	0	0	6	30	32
WA/ID	4	43	53	25	25	10	4	4	0	0	15	32	29
WA/ID	5	51	49	30	19	13	8	7	0	0	22	29	30
WA/ID	6	44	47	27	11	11	1	3	5	0	25	27	33
WA/ID	7	40	48	25	7	5	0	0	4	0	15	30	38
WA/ID	8	40	47	26	11	1	0	0	0	0	17	36	34
WA/ID	9	43	55	16	20	2	6	0	0	8	15	35	36
WA/ID	10	43	47	22	23	5	8	0	0	9	13	26	43
WA/ID	11	43	39	26	23	15	6	0	0	8	12	25	38
WA/ID	12	44	30	30	21	11	4	0	0	2	10	33	36
WA/ID	13	51	62	22	19	4	0	0	0	0	9	28	47
WA/ID	14	57	72	21	18	14	1	0	0	0	11	29	41
WA/ID	15	61	82	27	21	10	0	0	0	0	20	32	36
WA/ID	16	49	67	28	20	0	3	0	0	0	22	26	41
WA/ID	17	36	57	29	20	14	12	0	0	9	22	26	40
WA/ID	18	26	27	30	22	17	15	7	0	16	18	26	51
WA/ID	19	21	16	28	22	10	12	9	0	18	18	26	56
WA/ID	20	23	14	27	22	14	2	5	0	14	17	23	61
WA/ID	21	24	26	24	21	10	3	0	0	11	14	33	58
WA/ID	22	26	31	22	17	4	8	0	2	4	14	37	53
WA/ID	23	25	33	17	15	10	10	0	3	11	7	27	51
WA/ID	24	26	34	22	10	13	7	0	6	13	15	21	33
WA/ID	25	29	30	20	17	14	7	0	4	15	20	28	32
WA/ID	26	26	29	19	19	7	1	0	6	15	22	34	29
WA/ID	27	25	28	21	9	5	6	0	3	14	28	38	31
WA/ID	28	26	23	21	8	18	6	0	1	6	27	35	31
WA/ID	29	28		28	12	15	7	0	0	4	28	35	31
WA/ID	30	29		33	14	18	0	0	0	9	30	30	32
WA/ID	31	28		26		16		0	0		30		27

APPENDIX 3.5

GLOBAL WARMING SUMMARY AND GRAPHS

Global Warming

- Peak and trough weather appears more volatile
- Reduce annual consumption over time
- Decrease **non peak** HDDs over time to reflect warming trend

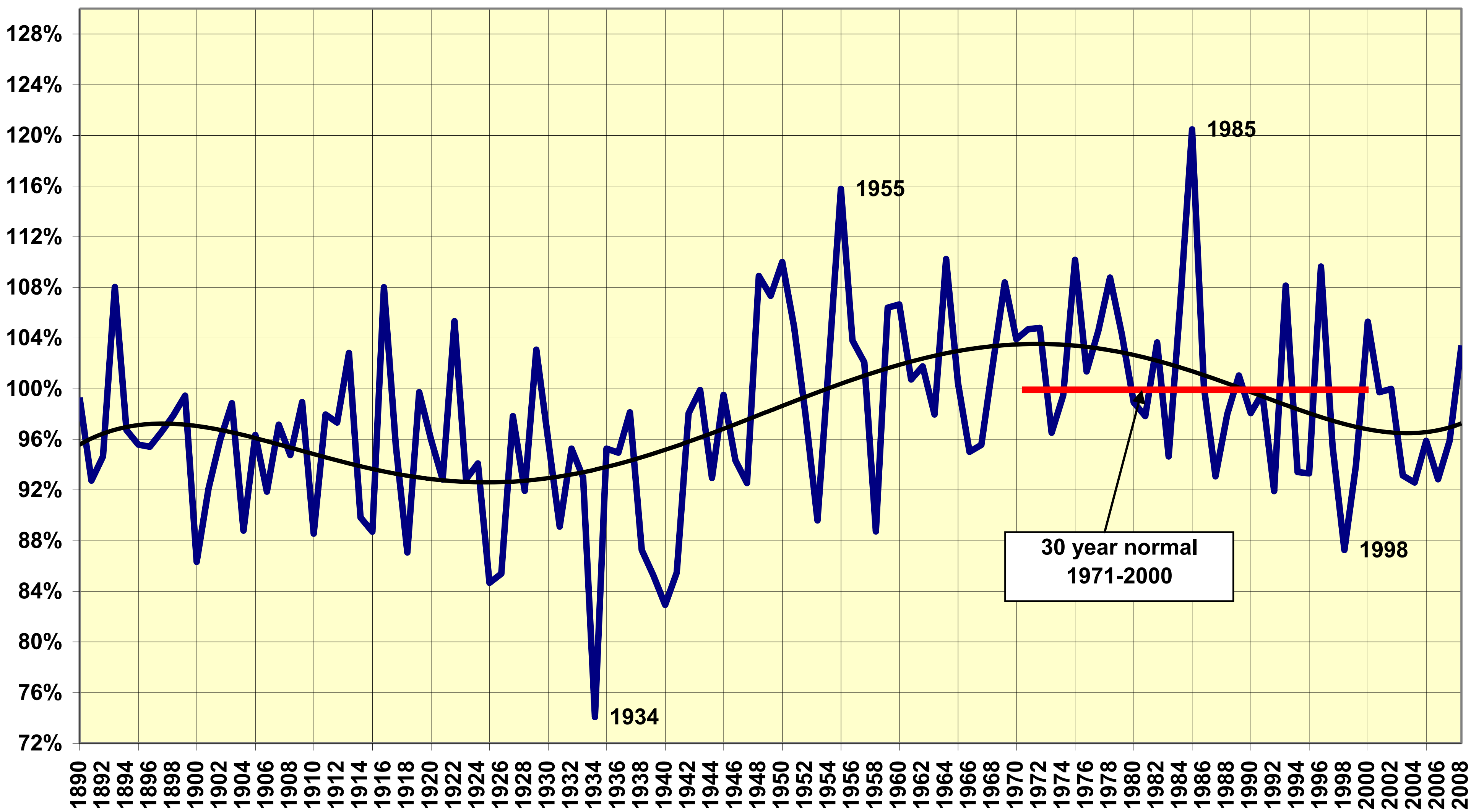
GLOBAL WARMING ADJUSTMENT

- Heating degree day data is obtained from the National Weather Service (NWS). Avista uses the most recent 30-year period, which goes from 1979-2008. For Oregon, Avista uses four weather stations as the weather basis, corresponding to the areas within which natural gas services are provided, all of which are official National Weather Service stations. Heating degree day weather patterns between these areas are uncorrelated.

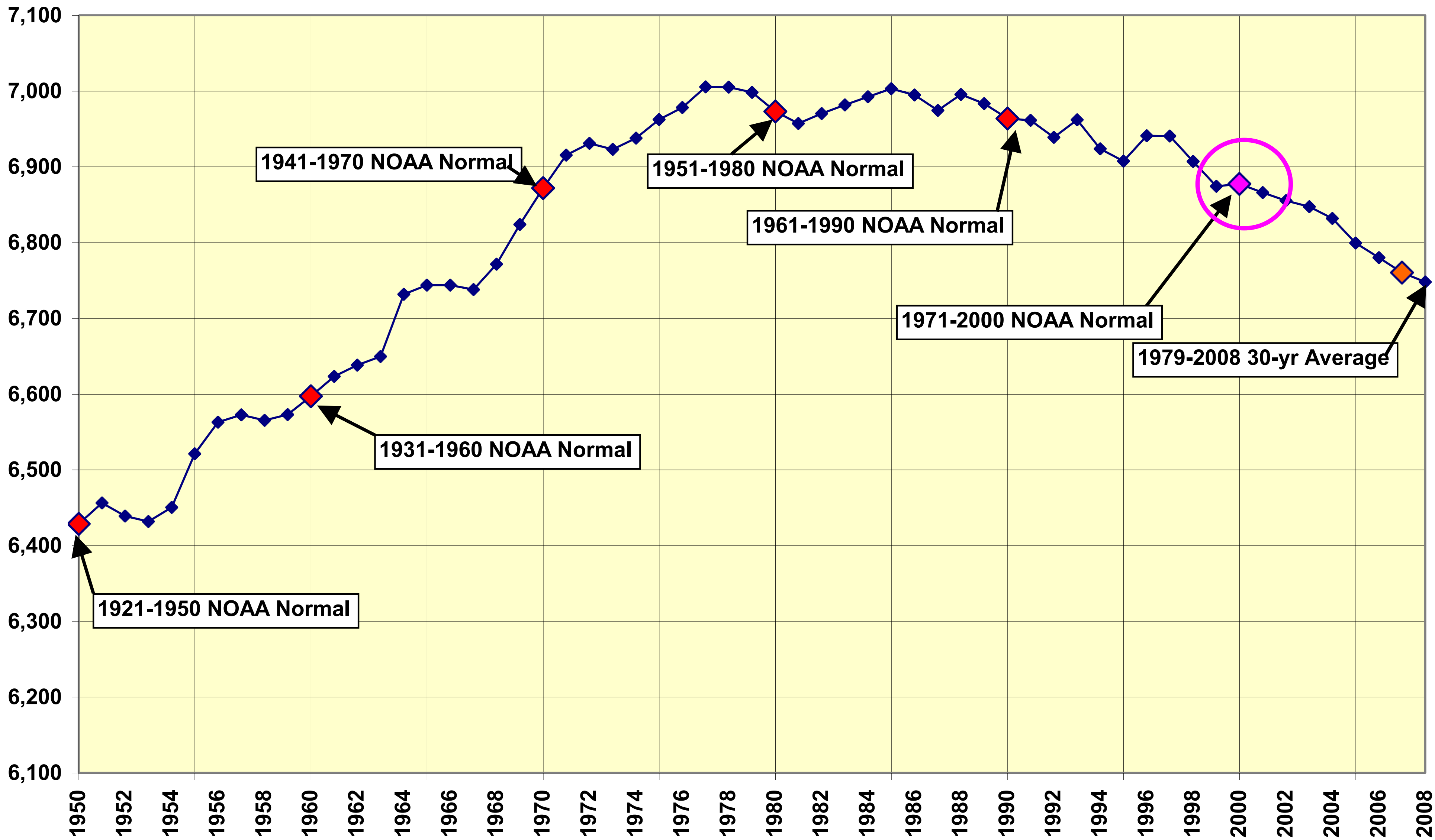
- At the April 2009 Technical Advisory Committee meeting, Avista presented some data and information regarding trends in heating degree days for its service area. Avista has adopted a “Global Warming” baseline for forecasting which captures the modest warming trend (i.e. gradually declining heating degree days) expected through the 20 year forecast period.

- By 2030, as compared to the “official” NWS normal figures based on the 1971-2000 period, the number of annual heating degree days as a percentage of the official period are:
    - Spokane 93.9%
    - Medford 88.4%
    - Roseburg 86.8%
    - Klamath Falls 94.9%
    - La Grande 81.6%

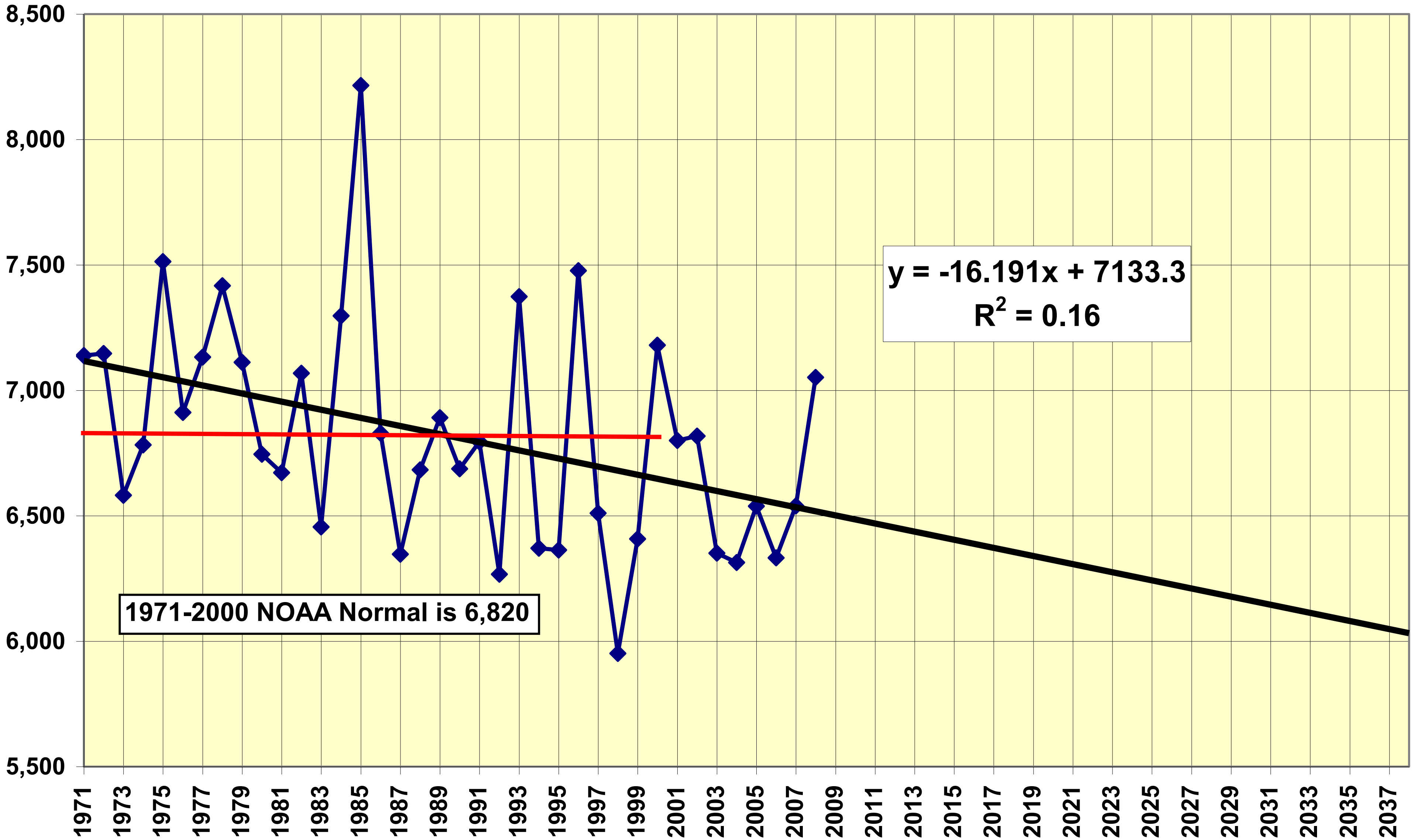
Annual Heating Degree Days, Percent of Normal
Spokane, Washington



30-year Rolling Average Spokane HDD

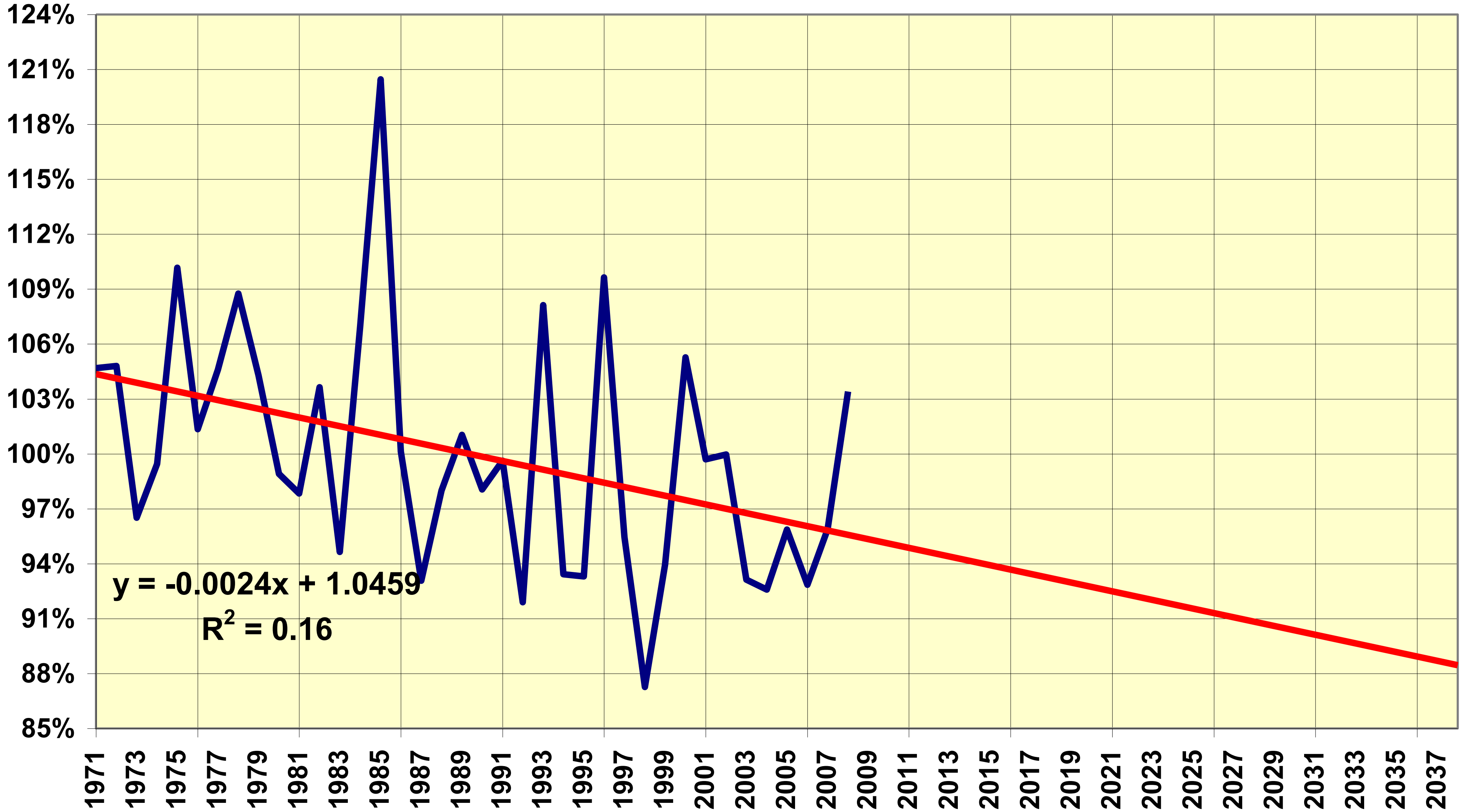


1971-2007 Spokane HDD Trend

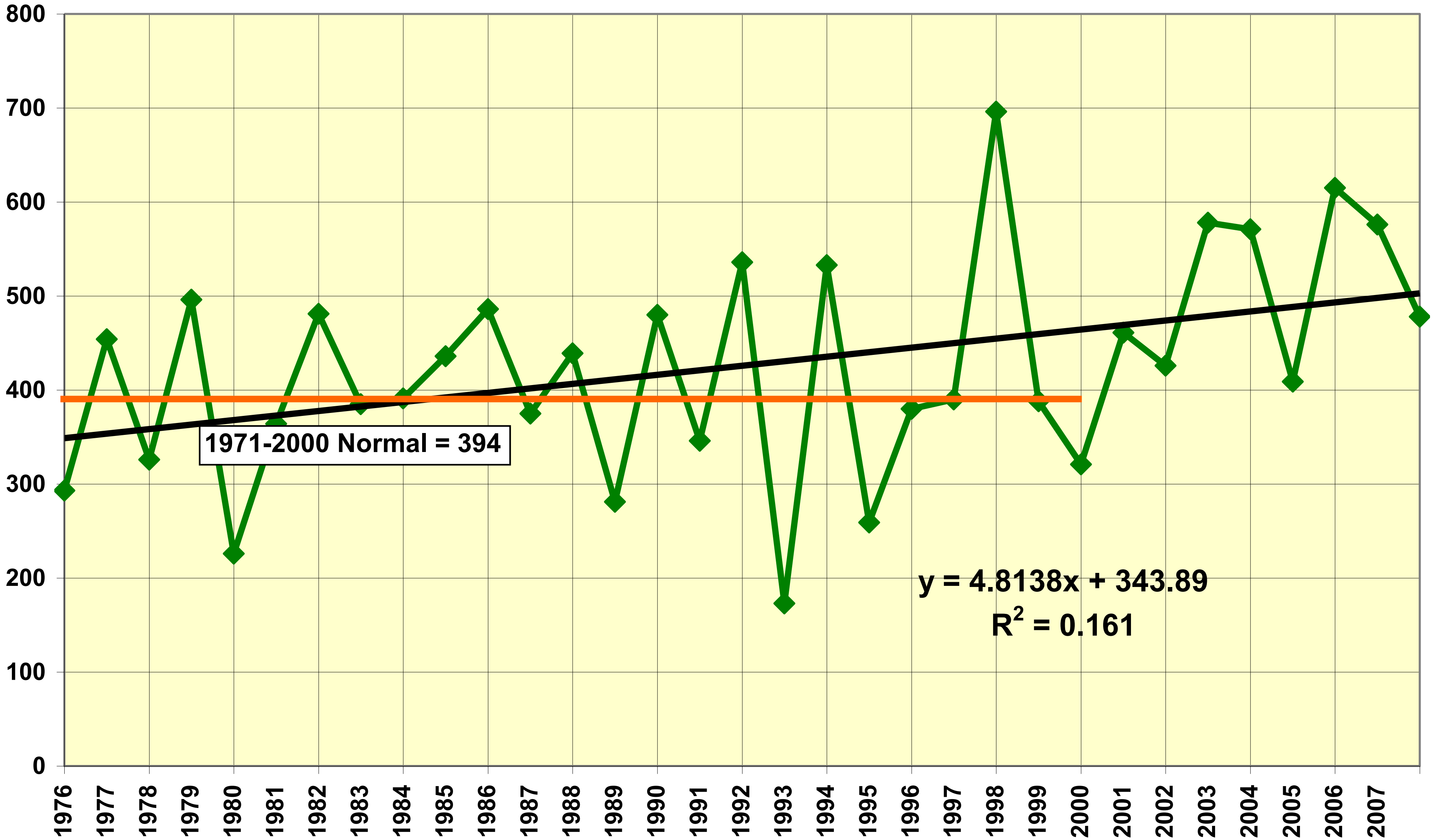


HDD Trends 1971-2007 and Projected 30 Years

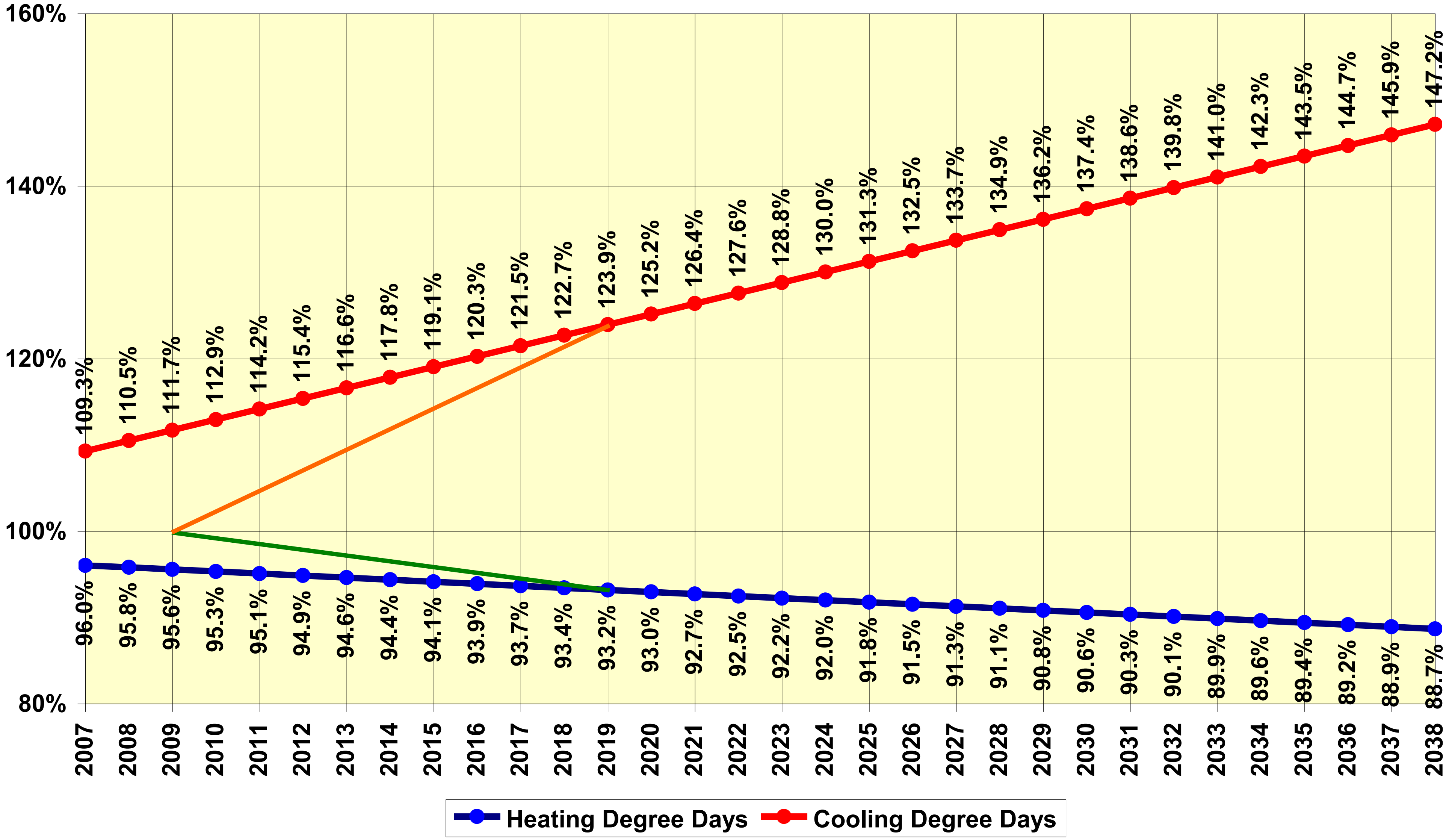
Spokane, Washington



1976-2007 Cooling Degree Day Trends

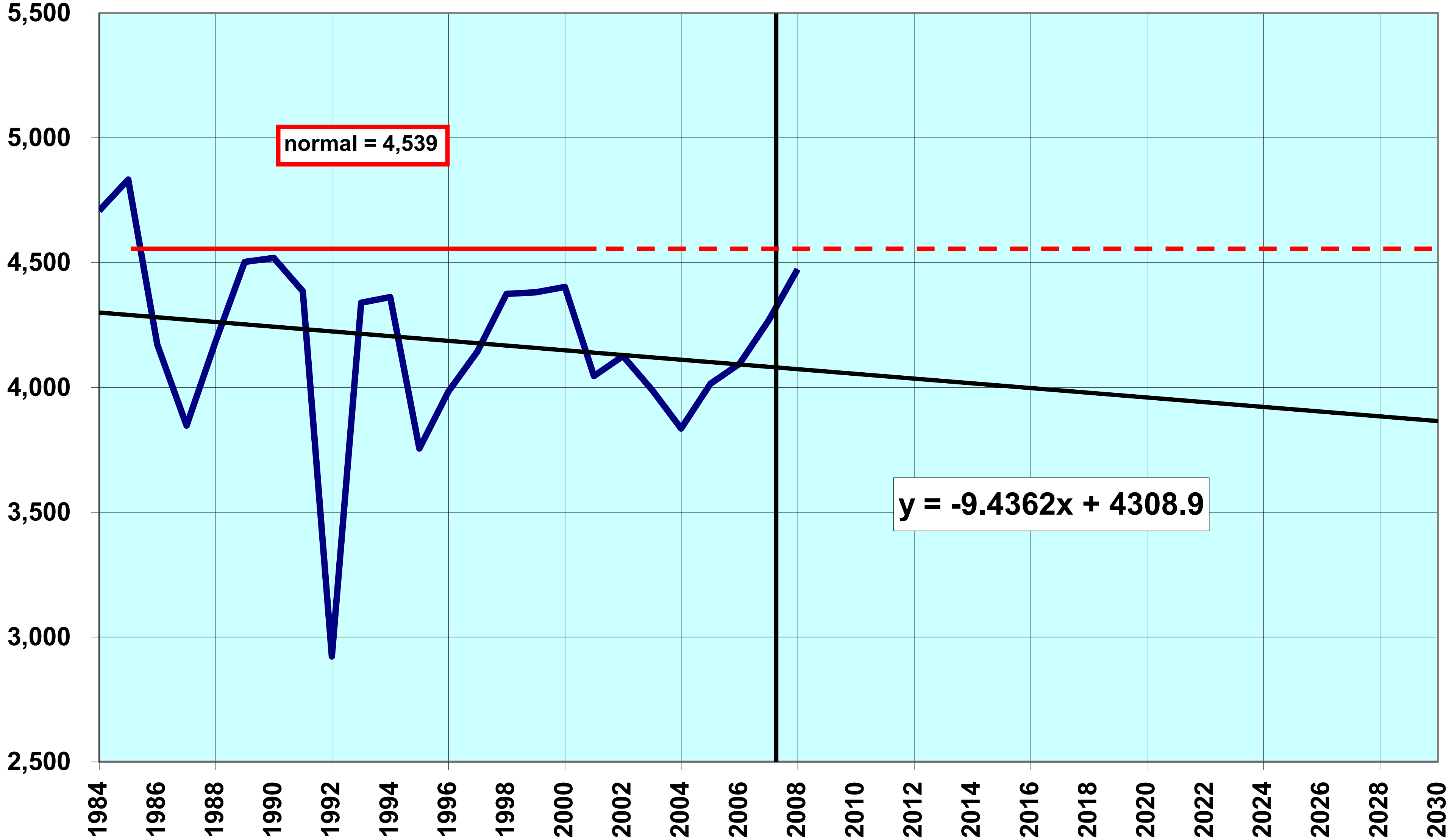


Spokane NWS Global Warming Degree Day Trends
2007-2038

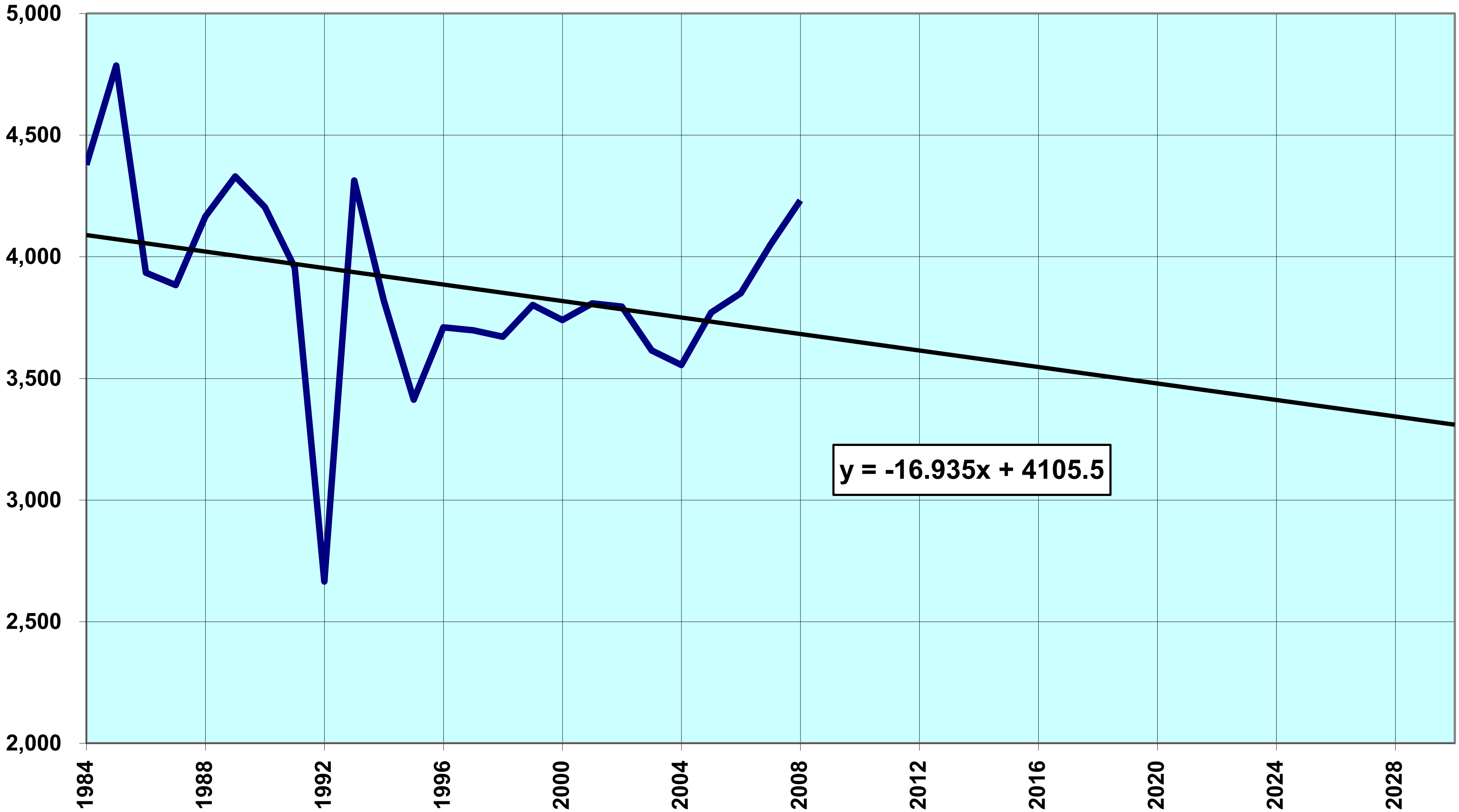


Medford Heating Degree Day Trends

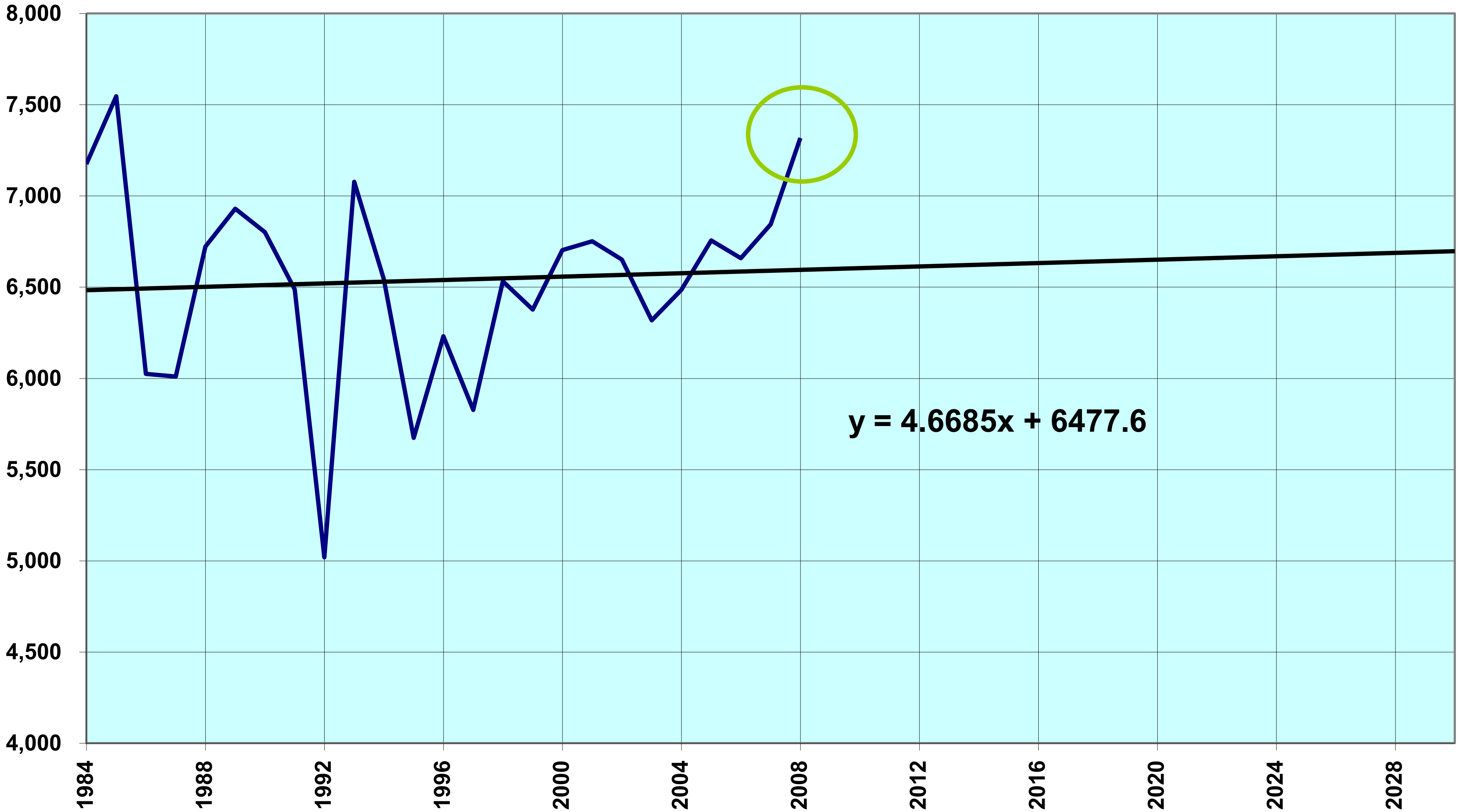
excluding Summer



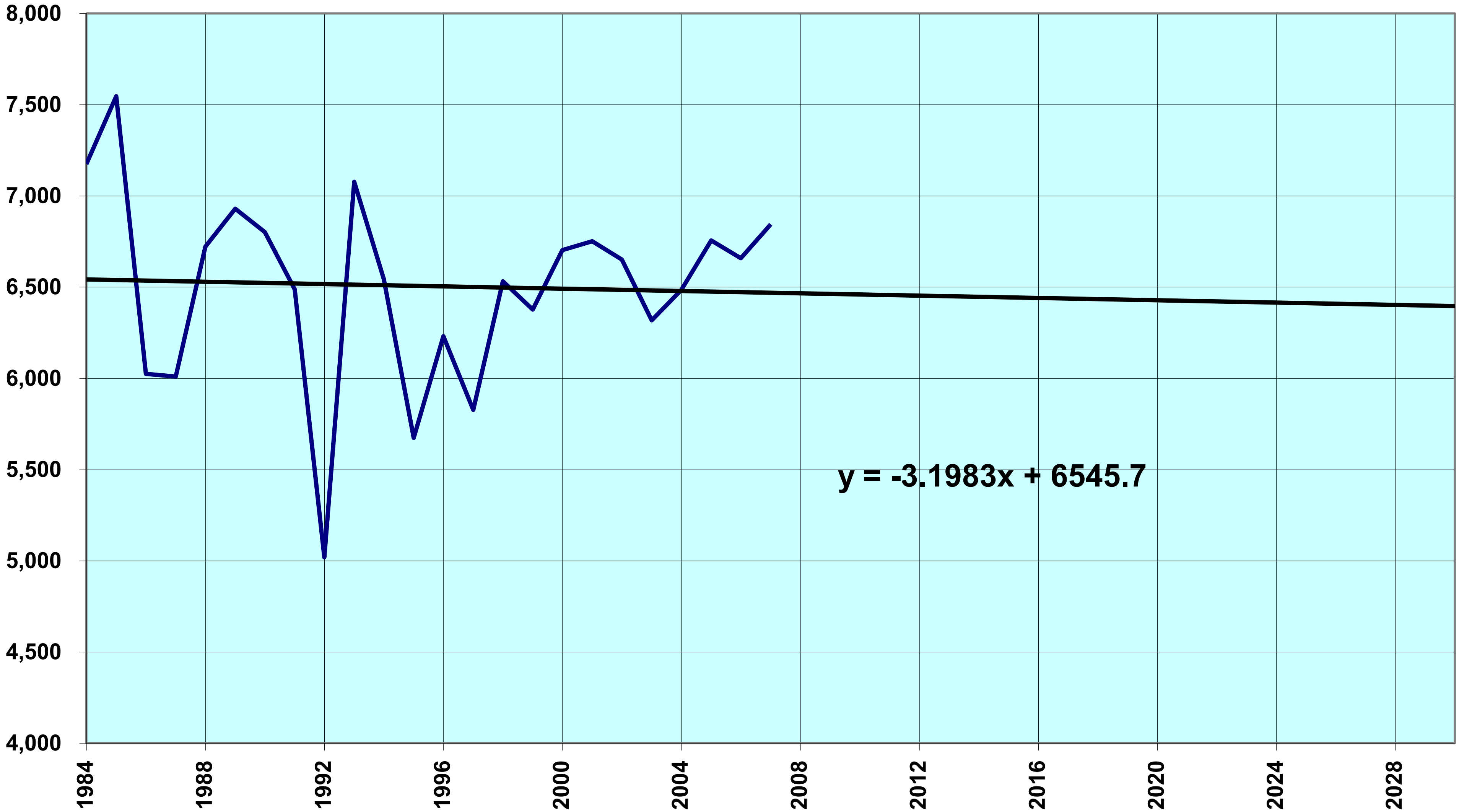
Roseburg HDD Trends
excluding Summer

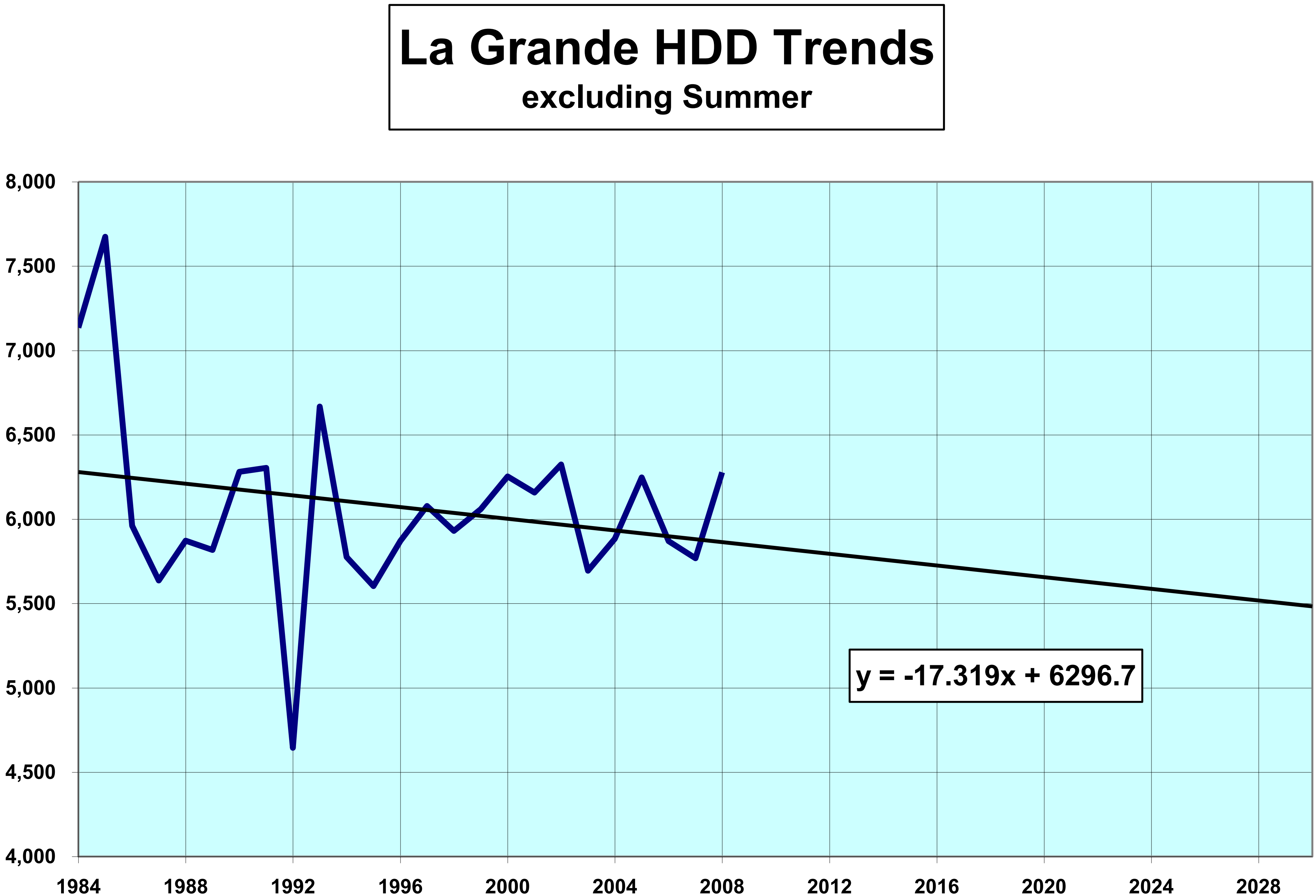


Klamath Falls HDD Trends
excluding Summer

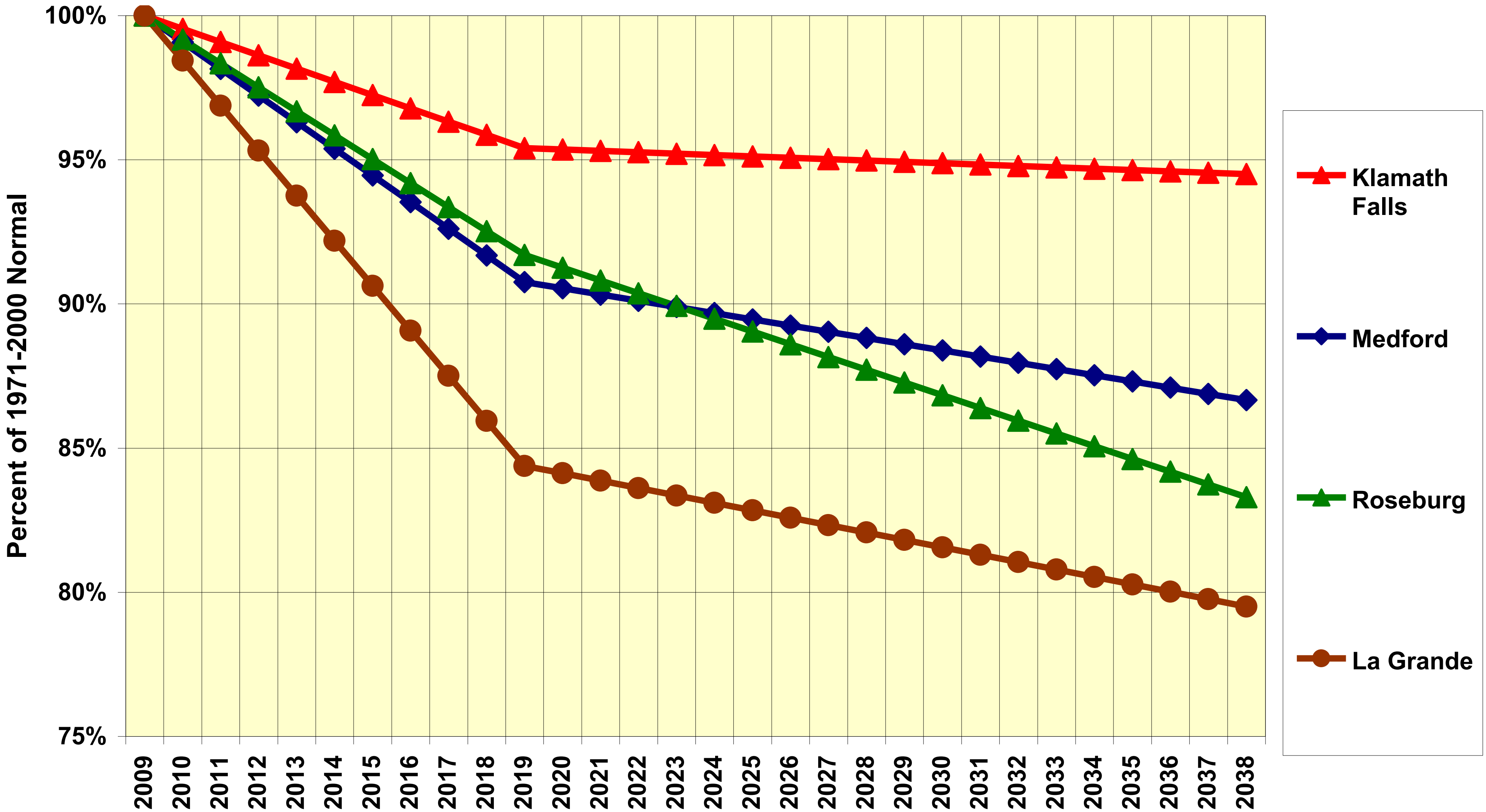


Klamath Falls HDD Trends
excluding Summer




La Grande HDD Trends
excluding Summer
8,000
7,500
7,000
6,500
6,000
5,500
5,000
4,500
4,000
1984
1988
1992
1996
2000
2004
2008
2012
2016
2020
2024
2028
y = -17.319x + 6296.7

Oregon Degree Day Trends



APPENDIX 3.6

ALTERNATE DEMAND SCENARIOS SUMMARY OF ASSUMPTIONS

Appendix 3.6 – Sensitivities
Demand Influencing (Direct)
Summary of Assumptions

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%	50% Decrease in Cust Growth Rates	50% Increase in Cust Growth Rates				???	???	
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				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

Appendix 3.6 – Sensitivities

Price Influencing (Indirect)
Summary of Assumptions

Model Sensitivities			PRICE INFLUENCING - INDIRECT								
		Reference Case	Expect 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	Expected	Low	High	Expected	Expected	Expected	Expected	Expected	Expected
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

Appendix 3.6 – Demand 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 + Price Elast.	Flat + Price Elast.	Flat + Price Elast.	Flat + Price Elast.	Flat + Price Elast.	Flat + 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	Expected
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	2020	N/A	2014	N/A	2026	N/A
Medford	2018	N/A	2015	2027	2020	2027
Klamath	2021	N/A	2016	N/A	2021	N/A
La Grande	2029	N/A	2018	N/A	2029	N/A

APPENDIX 3.7

ALTERNATE DEMAND SCENARIOS DESCRIPTIONS

Appendix 3.7

Avista 2009 Natural Gas IRP Demand Forecast Sensitivities and Scenarios Update

A. Definitions

Dynamic Demand Methodology – Avista's demand forecasting approach wherein we 1) identify key demand drivers 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 (see **Tables & Graphs**, *Figure 1* below). 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 (Wood Mackinzie, an industry information & analysis consultant) with first five years modified to include blend of recent market prices (Nymex forward prices). The resulting real price forecast (2009$) is included in *Figure 2*.

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 (*Figure 1*).

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 (*Figure 2*).

Expected, Low, and High Elasticity – For our expected 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% (*Figure 3*).

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 (*Figure 4*).

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.

*****

Following are other Sensitivities we evaluated:

Compressed Natural Gas (CNG) Vehicles – CNG vehicles assumed to produce a 15% cumulative incremental demand over our 20 year planning horizon. Our assumption utilized market consumption estimates from an independent analysis on CNG vehicle viability. The analysis indicates significant challenges exist to widespread adoption but did provide a scenario for significant market penetration (10% in 10 years). Although we concur significant system demand from CNG vehicle purchases in our service territories is unlikely at this time, we were motivated to run this sensitivity to learn how our system would respond to an emerging application that would grow significant new natural gas demand. This sensitivity, although instructive on understanding underlying incremental change in demand, is not currently used in any Scenario.

1HDD Lower Weather Standard – Peak Day weather temperature is reduced by 1 heating degree (Fahrenheit) in each service region. This sensitivity, although instructive on understanding underlying incremental change in demand, is not used in any Scenario.

Northern Migration – Economic and water issues in south western states spur increased migration to Pacific Northwest states. After discussion, it was determined that the **High Customer Growth** sensitivity would likely encompass this sensitivity's demand impacts therefore we did not pursue further analysis.

Stagnant Growth – Current economic conditions spur much slower and possibly negative customer growth rates for an extended period with a return to trend rates at some point. It was noted that we have not experienced widespread negative growth in our actual recent data. Our significant residential customer base has historically been very stable and not prone to extreme boom or bust cycles in four of our five service regions. Medford/Roseburg would appear most vulnerable to a severe impact though a sustained negative growth trend appears remote. Also noted were the very low long term growth rates in our **Low Customer Growth** sensitivity. After discussion, it was determined that the **Low Customer Growth** sensitivity would likely encompass this sensitivity's demand impacts therefore we did not pursue further analysis.

Global Warming – Adjust the regional peak day weather temperatures lower to account for global warming. Although we have developed analysis supporting adjustment to historical average daily temperatures for our forecasted average daily temperatures, we searched unsuccessfully for information that would provide a basis for adjusting peak day temperatures. Our data does suggest more volatile temperatures recently but is inconclusive on a trend of lower (or higher) peak temperatures. One TAC member provided information from a study that could not conclude global warming influenced peak day temperatures. Another TAC member offered reliable assessments of global warming applied to specific service regions would be challenging given local weather dynamics and conjectured overall global warming weather dynamics might produce possible peak day cooling trends for regions situated in transition areas. After discussion and feedback, we determined that a reliable basis for global warming temperature adjustment is too uncertain. We also believe the **Atlernate Weather Standard** sensitivity may encompass many possible demand impacts for this sensitivity therefore we did not pursue further analysis.

*****

The following two DSM Sensitivities were also conducted:

DSM Accelerated – Federal stimulus funded residential audit programs and tax credits in combination with our program rebates induce increased conservation in 2010 beyond what is assumed in the IRP base case.

DSM Delayed – A combination of reduced customer disposable income from the economic recession and a freeze in customer incentives due to Avista budget constraints result in a reduction in energy-efficiency measures from what is assumed in the IRP base case.

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, 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.

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 CO_2 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 CO_2 adders from our **Carbon Mitigation 1 Sensitivity (CM1)**. The Scenario also includes a 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 CO_2 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 CO_2 adders from our **Carbon Mitigation 1 Sensitivity (CM1)**. The Scenario also includes incremental cost adders for declining Canadian imports and drilling restrictions.

E. Tables & Graphs

Figure 1 – Customer Growth Rates

Customer Growth Rates

		Reference Case	Low Cust Growth	High Cust Growth
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%		

Figure 2 – Henry Hub Natural Gas Price Forecasts (2009$)

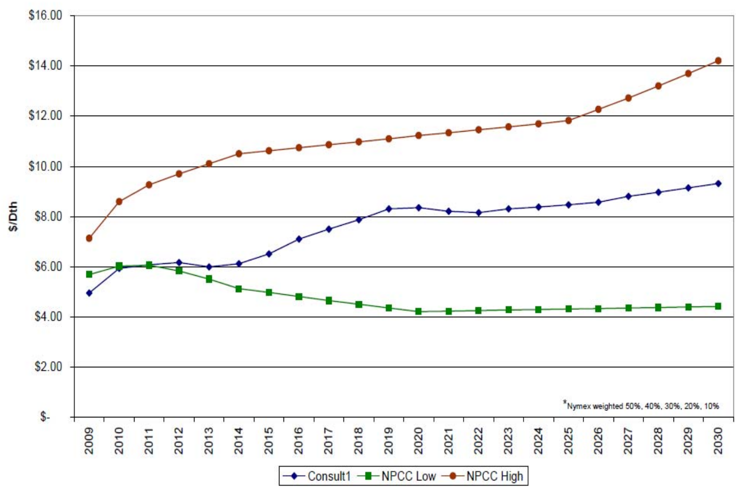
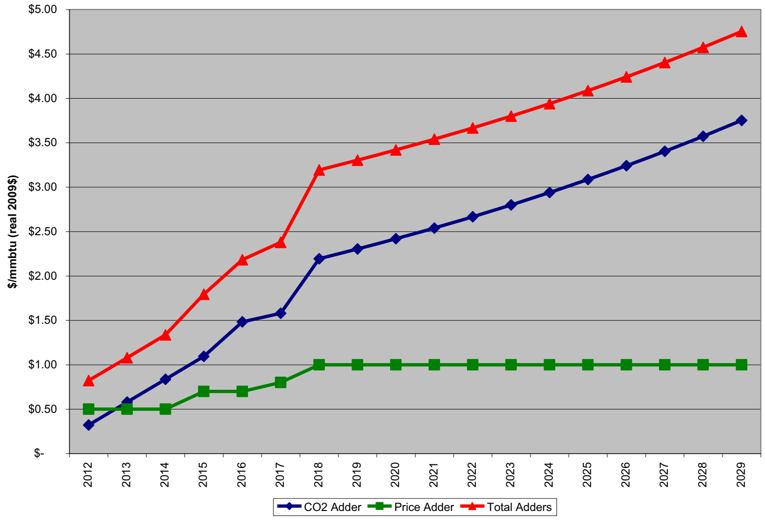


Figure 3 – Price Elasticity Factors

	Real Price annual increase within 30%	Real Price annual increase exceeds 30%
High	Negative .20	Negative .30
Expected	Negative .13	Negative .13
Low	No response	Negative .10

Figure 4 –Carbon Cost Adders (Carbon Mitigation 1)



APPENDIX 3.8

ANNUAL AND PEAK DAY DEMAND DATA

Appendix 3.8 - Annual Demand, Average Day Demand and Peak Day Demand (Net of DSM)

Case	Gas Year	Annual Demand Klamath (MDth)	Daily Demand Klamath (MDth/day)	Peak Day Klamath (MDth/day)	Annual Demand La Grande (MDth)	Daily Demand La Grande (MDth/day)	Peak Day La Grande (MDth/day)	Annual Demand Medford/Roseburg (MDth)	Daily Demand Medford/Roseburg (MDth/day)	Peak Day Medford/Roseburg (MDth/day)
High	2009-2010	1,340.72	3.673	12.577	770.71	2.112	7.882	6,720.22	18.412	70.11
High	2010-2011	1,362.56	3.733	12.668	756.85	2.074	7.843	6,740.68	18.468	70.34
High	2011-2012	1,412.17	3.858	13.097	760.50	2.078	7.989	6,931.09	18.937	72.20
High	2012-2013	1,456.60	3.991	13.610	763.86	2.093	8.135	7,164.78	19.630	75.56
High	2013-2014	1,488.65	4.078	14.156	766.61	2.100	8.260	7,412.83	20.309	78.80
High	2014-2015	1,523.77	4.175	14.535	766.98	2.101	8.383	7,667.70	21.007	82.16
High	2015-2016	1,560.02	4.262	14.852	769.78	2.103	8.478	7,918.70	21.636	85.40
High	2016-2017	1,593.14	4.365	15.232	770.41	2.111	8.600	8,146.22	22.318	88.84
High	2017-2018	1,627.06	4.458	15.610	770.44	2.111	8.726	8,352.58	22.884	92.14
High	2018-2019	1,658.91	4.545	15.991	770.55	2.111	8.847	8,538.84	23.394	95.27
High	2019-2020	1,695.62	4.633	16.369	777.50	2.124	8.973	8,773.99	23.973	98.26
High	2020-2021	1,730.59	4.741	16.750	784.74	2.150	9.095	9,000.59	24.659	101.30
High	2021-2022	1,768.46	4.845	17.132	793.60	2.174	9.217	9,218.80	25.257	104.32
High	2022-2023	1,807.17	4.951	17.514	802.96	2.200	9.345	9,461.76	25.923	107.35
High	2023-2024	1,848.58	5.051	17.906	812.32	2.219	9.473	9,710.37	26.531	110.41
High	2024-2025	1,886.39	5.168	18.297	820.97	2.249	9.604	9,928.93	27.203	113.50
High	2025-2026	1,925.47	5.275	18.690	829.89	2.274	9.733	10,147.89	27.802	116.43
High	2026-2027	1,965.33	5.384	19.081	839.46	2.300	9.865	10,362.38	28.390	119.25
High	2027-2028	2,005.57	5.480	19.475	850.19	2.323	9.993	10,590.38	28.935	122.07
High	2028-2029	2,042.90	5.597	19.868	856.91	2.348	10.126	10,784.57	29.547	124.89

Case	Gas Year	Annual Demand Oregon (MDth)	Daily Demand Oregon (MDth/day)	Peak Day Demand Oregon (MDth/day)	Annual Demand WA/ID (MDth)	Daily Demand WA/ID (MDth/day)	Peak Day WA/ID (MDth/day)	Annual Demand Total System (MDth)	Daily Demand Total System (MDth/day)	Peak Day Demand Total System (MDth/day)
High	2009-2010	8,831.658	24.196	90.573	26,676.459	73.086	279.384	35,508.117	97.283	369.957
High	2010-2011	8,860.098	24.274	90.855	26,733.275	73.242	279.897	35,593.373	97.516	370.752
High	2011-2012	9,103.768	24.874	93.286	27,127.241	74.118	287.303	36,231.009	98.992	380.589
High	2012-2013	9,385.241	25.713	97.310	27,650.283	75.754	294.956	37,035.525	101.467	392.265
High	2013-2014	9,668.089	26.488	101.221	28,293.395	77.516	302.748	37,961.483	104.004	403.969
High	2014-2015	9,958.455	27.283	105.081	28,962.324	79.349	310.536	38,920.778	106.632	415.616
High	2015-2016	10,248.502	28.001	108.731	29,516.994	80.648	316.840	39,765.497	108.649	425.571
High	2016-2017	10,509.774	28.794	112.673	30,027.442	82.267	324.559	40,537.216	111.061	437.231
High	2017-2018	10,750.075	29.452	116.477	30,622.956	83.899	332.552	41,373.031	113.351	449.029
High	2018-2019	10,968.303	30.050	120.108	31,253.974	85.627	340.559	42,222.276	115.677	460.667
High	2019-2020	11,247.113	30.730	123.605	31,976.453	87.367	348.961	43,223.567	118.097	472.566
High	2020-2021	11,515.923	31.550	127.147	32,697.751	89.583	357.585	44,213.675	121.133	484.732
High	2021-2022	11,780.858	32.276	130.671	33,441.452	91.620	366.311	45,222.310	123.897	496.982
High	2022-2023	12,071.896	33.074	134.206	34,206.603	93.717	375.171	46,278.499	126.790	509.377
High	2023-2024	12,371.274	33.801	137.784	35,016.400	95.673	384.021	47,387.674	129.475	521.805
High	2024-2025	12,636.299	34.620	141.397	35,754.261	97.957	393.081	48,390.560	132.577	534.478
High	2025-2026	12,903.252	35.351	144.854	36,578.506	100.215	402.133	49,481.758	135.566	546.987
High	2026-2027	13,167.164	36.074	148.198	37,341.572	102.306	411.069	50,508.736	138.380	559.267
High	2027-2028	13,446.137	36.738	151.536	38,196.855	104.363	420.723	51,642.992	141.101	572.258
High	2028-2029	13,684.391	37.491	154.883	38,985.923	106.811	430.079	52,670.314	144.302	584.962

Appendix 3.8 - Annual Demand, Average Day Demand and Peak Day Demand (Net of DSM)

Case	Gas Year	Annual Demand Klamath (MDth)	Daily Demand Klamath (MDth/day)	Peak Day Klamath (MDth/day)	Annual Demand La Grande (MDth)	Daily Demand La Grande (MDth/day)	Peak Day La Grande (MDth/day)	Annual Demand Medford/Roseburg (MDth)	Daily Demand Medford/Roseburg (MDth/day)	Peak Day Medford/Roseburg (MDth/day)
Low	2009-2010	1,337.12	3.663	12.583	773.82	2.120	7.862	6,701.22	18.360	70.10
Low	2010-2011	1,345.15	3.685	12.641	763.00	2.090	7.870	6,686.26	18.319	70.38
Low	2011-2012	1,314.43	3.591	12.224	732.83	2.002	7.569	6,487.96	17.727	67.93
Low	2012-2013	1,272.33	3.486	11.775	699.75	1.917	7.235	6,295.55	17.248	65.62
Low	2013-2014	1,266.76	3.471	11.695	690.64	1.892	7.226	6,307.21	17.280	65.29
Low	2014-2015	1,272.43	3.486	11.781	683.19	1.872	7.249	6,347.52	17.390	66.17
Low	2015-2016	1,278.76	3.494	11.729	677.97	1.852	7.203	6,386.87	17.450	66.53
Low	2016-2017	1,282.85	3.515	11.784	671.00	1.838	7.212	6,415.18	17.576	67.31
Low	2017-2018	1,287.63	3.528	11.853	663.81	1.819	7.226	6,436.69	17.635	68.13
Low	2018-2019	1,291.00	3.537	11.902	656.79	1.799	7.232	6,450.39	17.672	68.79
Low	2019-2020	1,298.30	3.547	11.974	655.74	1.792	7.247	6,502.85	17.767	69.51
Low	2020-2021	1,304.16	3.573	12.046	654.74	1.794	7.264	6,548.36	17.941	70.24
Low	2021-2022	1,312.31	3.595	12.121	655.32	1.795	7.280	6,590.31	18.056	70.98
Low	2022-2023	1,321.46	3.620	12.204	656.35	1.798	7.302	6,650.98	18.222	71.75
Low	2023-2024	1,332.74	3.641	12.288	657.49	1.796	7.323	6,716.34	18.351	72.53
Low	2024-2025	1,341.30	3.675	12.368	657.99	1.803	7.346	6,765.18	18.535	73.30
Low	2025-2026	1,351.12	3.702	12.453	658.96	1.805	7.367	6,818.80	18.682	74.04
Low	2026-2027	1,361.43	3.730	12.527	660.31	1.809	7.386	6,871.65	18.826	74.70
Low	2027-2028	1,372.00	3.749	12.598	662.70	1.811	7.401	6,933.82	18.945	75.34
Low	2028-2029	1,380.59	3.782	12.670	661.89	1.813	7.419	6,972.19	19.102	75.98

Case	Gas Year	Annual Demand Oregon (MDth)	Daily Demand Oregon (MDth/day)	Peak Day Demand Oregon (MDth/day)	Annual Demand WA/ID (MDth)	Daily Demand WA/ID (MDth/day)	Peak Day WA/ID (MDth/day)	Annual Demand Total System (MDth)	Daily Demand Total System (MDth/day)	Peak Day Demand Total System (MDth/day)
Low	2009-2010	8,812.164	24.143	90.540	26,243.358	71.900	274.715	35,055.522	96.043	365.255
Low	2010-2011	8,794.406	24.094	90.889	26,102.370	71.513	274.092	34,896.775	95.608	364.981
Low	2011-2012	8,535.216	23.320	87.721	25,009.310	68.331	262.543	33,544.526	91.652	350.264
Low	2012-2013	8,267.626	22.651	84.635	23,916.075	65.523	249.615	32,183.701	88.175	334.250
Low	2013-2014	8,264.603	22.643	84.207	23,748.996	65.066	248.402	32,013.599	87.708	332.608
Low	2014-2015	8,303.142	22.748	85.203	23,718.724	64.983	248.483	32,021.865	87.731	333.685
Low	2015-2016	8,343.596	22.797	85.462	23,602.714	64.488	245.559	31,946.310	87.285	331.021
Low	2016-2017	8,369.023	22.929	86.310	23,459.001	64.271	244.962	31,828.023	87.200	331.272
Low	2017-2018	8,388.128	22.981	87.207	23,381.299	64.058	244.815	31,769.427	87.040	332.021
Low	2018-2019	8,398.186	23.009	87.923	23,329.666	63.917	244.158	31,727.851	86.926	332.080
Low	2019-2020	8,456.890	23.106	88.732	23,341.516	63.775	244.151	31,798.406	86.881	332.883
Low	2020-2021	8,507.259	23.308	89.551	23,347.980	63.967	244.216	31,855.238	87.275	333.768
Low	2021-2022	8,557.939	23.446	90.385	23,371.023	64.030	244.378	31,928.962	87.477	334.764
Low	2022-2023	8,628.789	23.641	91.257	23,406.708	64.128	244.685	32,035.498	87.768	335.942
Low	2023-2024	8,706.566	23.788	92.136	23,475.594	64.141	244.863	32,182.160	87.929	336.999
Low	2024-2025	8,764.479	24.012	93.017	23,492.075	64.362	245.064	32,256.554	88.374	338.081
Low	2025-2026	8,828.883	24.189	93.858	23,567.569	64.569	245.288	32,396.452	88.757	339.146
Low	2026-2027	8,893.386	24.365	94.608	23,610.600	64.687	245.235	32,503.986	89.052	339.843
Low	2027-2028	8,968.526	24.504	95.334	23,735.620	64.851	245.845	32,704.146	89.356	341.179
Low	2028-2029	9,014.674	24.698	96.070	23,821.781	65.265	246.380	32,836.455	89.963	342.450

Appendix 3.8 - Annual Demand, Average Day Demand and Peak Day Demand (Net of DSM)

Case	Gas Year	Annual Demand Klamath (MDth)	Daily Demand Klamath (MDth/day)	Peak Day Klamath (MDth/day)	Annual Demand La Grande (MDth)	Daily Demand La Grande (MDth/day)	Peak Day La Grande (MDth/day)	Annual Demand Medford/Roseburg (MDth)	Daily Demand Medford/Roseburg (MDth/day)	Peak Day Medford/Roseburg (MDth/day)
Coldest in 20	2009-2010	1,352.83	3.706	12.714	782.49	2.144	7.980	6,705.62	18.372	67.86
Coldest in 20	2010-2011	1,355.22	3.713	12.632	762.62	2.089	7.865	6,647.39	18.212	67.27
Coldest in 20	2011-2012	1,385.92	3.787	12.901	761.53	2.081	7.953	6,742.72	18.423	68.40
Coldest in 20	2012-2013	1,410.62	3.865	13.230	759.82	2.082	8.045	6,872.22	18.828	70.51
Coldest in 20	2013-2014	1,426.96	3.909	13.581	758.04	2.077	8.121	7,016.72	19.224	72.53
Coldest in 20	2014-2015	1,447.85	3.967	13.822	754.18	2.066	8.196	7,164.50	19.629	74.64
Coldest in 20	2015-2016	1,449.60	3.961	13.802	742.36	2.028	8.116	7,215.42	19.714	75.43
Coldest in 20	2016-2017	1,468.46	4.023	14.038	738.99	2.025	8.189	7,341.97	20.115	77.55
Coldest in 20	2017-2018	1,487.99	4.077	14.274	735.26	2.014	8.263	7,454.14	20.422	79.58
Coldest in 20	2018-2019	1,505.78	4.125	14.509	731.58	2.004	8.336	7,552.67	20.692	81.51
Coldest in 20	2019-2020	1,527.98	4.175	14.746	734.54	2.007	8.410	7,695.62	21.026	83.35
Coldest in 20	2020-2021	1,548.51	4.242	14.981	737.71	2.021	8.484	7,830.69	21.454	85.22
Coldest in 20	2021-2022	1,571.74	4.306	15.218	742.47	2.034	8.558	7,959.91	21.808	87.07
Coldest in 20	2022-2023	1,595.92	4.372	15.458	747.77	2.049	8.634	8,111.05	22.222	88.94
Coldest in 20	2023-2024	1,622.47	4.433	15.705	753.01	2.057	8.713	8,267.14	22.588	90.84
Coldest in 20	2024-2025	1,645.98	4.510	15.953	757.65	2.076	8.793	8,400.13	23.014	92.76
Coldest in 20	2025-2026	1,670.60	4.577	16.202	762.63	2.089	8.874	8,535.62	23.385	94.57
Coldest in 20	2026-2027	1,695.99	4.647	16.450	768.16	2.105	8.954	8,668.45	23.749	96.32
Coldest in 20	2027-2028	1,721.59	4.704	16.699	774.78	2.117	9.034	8,813.14	24.080	98.06
Coldest in 20	2028-2029	1,744.75	4.780	16.948	777.78	2.131	9.114	8,928.54	24.462	99.81

Case	Gas Year	Annual Demand Oregon (MDth)	Daily Demand Oregon (MDth/day)	Peak Day Demand Oregon (MDth/day)	Annual Demand WA/ID (MDth)	Daily Demand WA/ID (MDth/day)	Peak Day WA/ID (MDth/day)	Annual Demand Total System (MDth)	Daily Demand Total System (MDth/day)	Peak Day Demand Total System (MDth/day)
Coldest in 20	2009-2010	8,840.943	24.222	88.557	26,134.146	71.600	252.675	34,975.090	95.822	341.233
Coldest in 20	2010-2011	8,765.222	24.014	87.771	25,834.207	70.779	249.428	34,599.430	94.793	337.199
Coldest in 20	2011-2012	8,890.171	24.290	89.251	25,908.593	70.789	252.868	34,798.763	95.079	342.119
Coldest in 20	2012-2013	9,042.658	24.774	91.781	26,089.316	71.478	256.456	35,131.974	96.252	348.237
Coldest in 20	2013-2014	9,201.719	25.210	94.236	26,382.370	72.280	260.127	35,584.089	97.491	354.363
Coldest in 20	2014-2015	9,366.538	25.662	96.656	26,700.351	73.152	263.800	36,066.888	98.813	360.456
Coldest in 20	2015-2016	9,407.379	25.703	97.348	26,513.151	72.440	262.175	35,920.530	98.144	359.523
Coldest in 20	2016-2017	9,549.419	26.163	99.778	26,687.201	73.116	265.710	36,236.620	99.278	365.489
Coldest in 20	2017-2018	9,677.386	26.513	102.120	26,936.822	73.800	269.412	36,614.208	100.313	371.532
Coldest in 20	2018-2019	9,790.033	26.822	104.355	27,217.476	74.568	273.119	37,007.509	101.390	377.474
Coldest in 20	2019-2020	9,958.131	27.208	106.505	27,574.517	75.340	277.060	37,532.648	102.548	383.565
Coldest in 20	2020-2021	10,116.912	27.718	108.682	27,929.417	76.519	281.155	38,046.329	104.237	389.837
Coldest in 20	2021-2022	10,274.121	28.148	110.851	28,303.189	77.543	285.316	38,577.310	105.691	396.167
Coldest in 20	2022-2023	10,454.739	28.643	113.033	28,693.670	78.613	289.555	39,148.409	107.256	402.588
Coldest in 20	2023-2024	10,642.620	29.078	115.255	29,123.372	79.572	293.788	39,765.991	108.650	409.043
Coldest in 20	2024-2025	10,803.760	29.599	117.502	29,491.036	80.797	298.156	40,294.796	110.397	415.659
Coldest in 20	2025-2026	10,968.847	30.052	119.649	29,931.132	82.003	302.521	40,899.979	112.055	422.170
Coldest in 20	2026-2027	11,132.598	30.500	121.722	30,324.657	83.081	306.816	41,457.255	113.582	428.538
Coldest in 20	2027-2028	11,309.498	30.900	123.795	30,804.986	84.167	311.768	42,114.484	115.067	435.563
Coldest in 20	2028-2029	11,451.065	31.373	125.869	31,234.040	85.573	316.548	42,685.105	116.945	442.417

Appendix 3.8 - Annual Demand, Average Day Demand and Peak Day Demand (Net of DSM)

Case	Gas Year	Annual Demand Klamath (MDth)	Daily Demand Klamath (MDth/day)	Peak Day Klamath (MDth/day)	Annual Demand La Grande (MDth)	Daily Demand La Grande (MDth/day)	Peak Day La Grande (MDth/day)	Annual Demand Medford/Roseburg (MDth)	Daily Demand Medford/Roseburg (MDth/day)	Peak Day Medford/Roseburg (MDth/day)
Supply Constrained	2009-2010	1,352.83	3.706	12.714	782.49	2.144	7.980	6,740.51	18.467	70.44
Supply Constrained	2010-2011	1,278.99	3.504	11.685	718.19	1.968	7.265	6,321.62	17.320	64.58
Supply Constrained	2011-2012	1,293.12	3.533	11.747	708.91	1.937	7.231	6,345.09	17.336	64.63
Supply Constrained	2012-2013	1,304.49	3.574	11.900	700.97	1.920	7.223	6,413.14	17.570	65.80
Supply Constrained	2013-2014	1,308.74	3.586	12.074	693.53	1.900	7.205	6,497.34	17.801	66.90
Supply Constrained	2014-2015	1,327.55	3.637	12.284	690.16	1.891	7.269	6,634.70	18.177	68.82
Supply Constrained	2015-2016	1,318.29	3.602	12.118	673.93	1.841	7.109	6,632.97	18.123	68.71
Supply Constrained	2016-2017	1,327.77	3.638	12.228	667.32	1.828	7.117	6,715.59	18.399	70.09
Supply Constrained	2017-2018	1,339.61	3.670	12.357	661.43	1.812	7.136	6,793.69	18.613	71.49
Supply Constrained	2018-2019	1,346.42	3.689	12.440	654.00	1.792	7.129	6,843.05	18.748	72.52
Supply Constrained	2019-2020	1,362.04	3.721	12.586	654.74	1.789	7.159	6,954.23	19.001	73.83
Supply Constrained	2020-2021	1,376.22	3.770	12.736	655.65	1.796	7.192	7,057.83	19.337	75.18
Supply Constrained	2021-2022	1,392.05	3.814	12.877	657.68	1.802	7.220	7,154.14	19.600	76.47
Supply Constrained	2022-2023	1,409.39	3.861	13.027	660.53	1.810	7.254	7,271.79	19.923	77.79
Supply Constrained	2023-2024	1,429.64	3.906	13.191	663.80	1.814	7.295	7,398.16	20.214	79.19
Supply Constrained	2024-2025	1,448.58	3.969	13.378	667.16	1.828	7.350	7,510.15	20.576	80.74
Supply Constrained	2025-2026	1,466.90	4.019	13.542	670.11	1.836	7.392	7,616.65	20.868	82.05
Supply Constrained	2026-2027	1,483.51	4.064	13.675	672.48	1.842	7.417	7,709.81	21.123	83.12
Supply Constrained	2027-2028	1,500.33	4.099	13.804	675.79	1.846	7.441	7,813.03	21.347	84.16
Supply Constrained	2028-2029	1,514.46	4.149	13.932	675.91	1.852	7.464	7,888.96	21.614	85.19

Case	Gas Year	Annual Demand Oregon (MDth)	Daily Demand Oregon (MDth/day)	Peak Day Demand Oregon (MDth/day)	Annual Demand WA/ID (MDth)	Daily Demand WA/ID (MDth/day)	Peak Day WA/ID (MDth/day)	Annual Demand Total System (MDth)	Daily Demand Total System (MDth/day)	Peak Day Demand Total System (MDth/day)
Supply Constrained	2009-2010	8,875.829	24.317	91.131	26,220.981	71.838	274.582	35,096.810	96.156	365.713
Supply Constrained	2010-2011	8,318.804	22.791	83.526	24,370.873	66.770	249.938	32,689.676	89.561	333.464
Supply Constrained	2011-2012	8,347.110	22.806	83.606	24,138.467	65.952	249.057	32,485.577	88.758	332.663
Supply Constrained	2012-2013	8,418.607	23.065	84.919	24,061.976	65.923	249.092	32,480.583	88.988	334.012
Supply Constrained	2013-2014	8,499.604	23.287	86.182	24,097.684	66.021	249.288	32,597.288	89.308	335.471
Supply Constrained	2014-2015	8,652.408	23.705	88.372	24,367.409	66.760	252.452	33,019.816	90.465	340.824
Supply Constrained	2015-2016	8,625.187	23.566	87.934	23,966.825	65.483	247.261	32,592.011	89.049	335.195
Supply Constrained	2016-2017	8,710.677	23.865	89.432	23,962.795	65.651	248.159	32,673.472	89.516	337.591
Supply Constrained	2017-2018	8,794.731	24.095	90.985	24,059.442	65.916	249.642	32,854.172	90.011	340.626
Supply Constrained	2018-2019	8,843.468	24.229	92.090	24,111.136	66.058	250.065	32,954.604	90.287	342.155
Supply Constrained	2019-2020	8,971.000	24.511	93.574	24,327.999	66.470	252.100	33,298.999	90.981	345.673
Supply Constrained	2020-2021	9,089.708	24.903	95.113	24,546.519	67.251	254.368	33,636.227	92.154	349.481
Supply Constrained	2021-2022	9,203.881	25.216	96.562	24,768.553	67.859	256.440	33,972.435	93.075	353.002
Supply Constrained	2022-2023	9,341.713	25.594	98.075	25,015.271	68.535	258.726	34,356.984	94.129	356.801
Supply Constrained	2023-2024	9,491.598	25.933	99.680	25,309.744	69.152	261.179	34,801.342	95.086	360.859
Supply Constrained	2024-2025	9,625.883	26.372	101.468	25,580.405	70.083	264.248	35,206.287	96.456	365.715
Supply Constrained	2025-2026	9,753.664	26.722	102.988	25,876.686	70.895	266.741	35,630.349	97.617	369.729
Supply Constrained	2026-2027	9,865.800	27.030	104.212	26,089.390	71.478	268.463	35,955.190	98.507	372.675
Supply Constrained	2027-2028	9,989.157	27.293	105.406	26,381.226	72.080	270.804	36,370.383	99.373	376.210
Supply Constrained	2028-2029	10,079.331	27.615	106.587	26,617.492	72.925	272.932	36,696.823	100.539	379.519

Appendix 3.8 - Annual Demand, Average Day Demand and Peak Day Demand (Net of DSM)

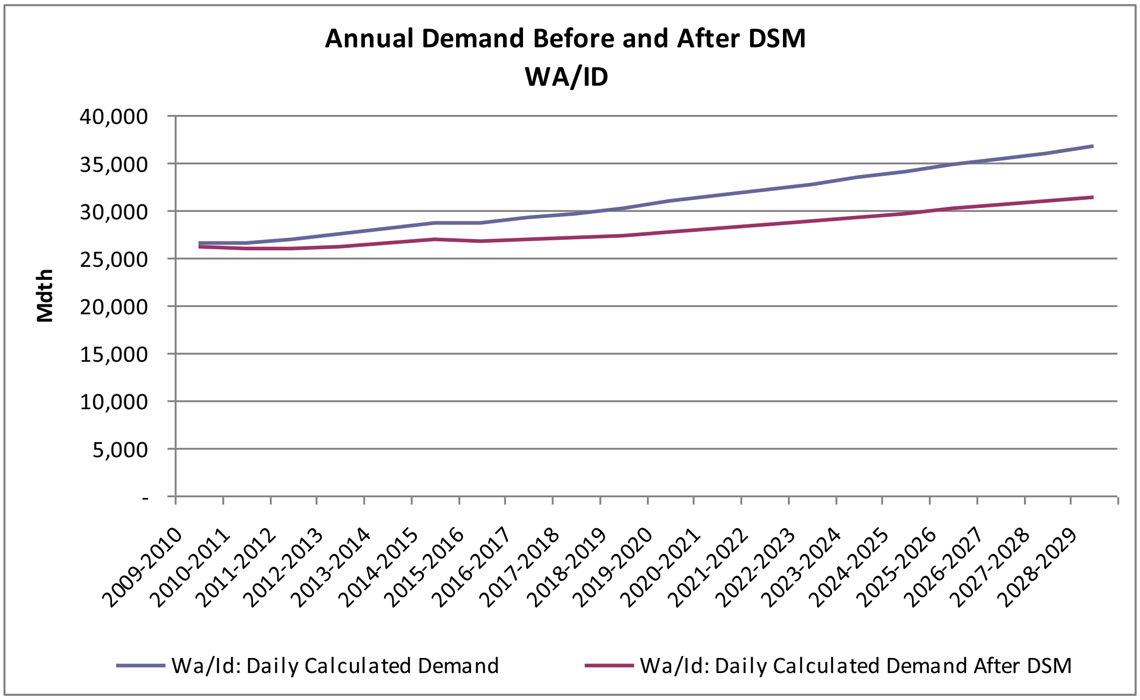
Case	Gas Year	Annual Demand Klamath (MDth)	Daily Demand Klamath (MDth/day)	Peak Day Klamath (MDth/day)	Annual Demand La Grande (MDth)	Daily Demand La Grande (MDth/day)	Peak Day La Grande (MDth/day)	Annual Demand Medford/Roseburg (MDth)	Daily Demand Medford/Roseburg (MDth/day)	Peak Day Medford/Roseburg (MDth/day)
Green Future	2009-2010	1,352.83	3.706	12.714	782.49	2.144	7.980	6,741.43	18.470	70.44
Green Future	2010-2011	1,322.71	3.624	12.228	743.67	2.037	7.609	6,529.13	17.888	67.58
Green Future	2011-2012	1,343.88	3.672	12.378	737.69	2.016	7.626	6,582.61	17.985	68.10
Green Future	2012-2013	1,359.14	3.724	12.585	731.27	2.003	7.646	6,668.88	18.271	69.59
Green Future	2013-2014	1,369.85	3.753	12.853	726.87	1.991	7.678	6,785.74	18.591	71.22
Green Future	2014-2015	1,389.73	3.807	13.079	723.25	1.982	7.748	6,929.01	18.984	73.27
Green Future	2015-2016	1,329.73	3.633	12.265	679.89	1.858	7.197	6,687.18	18.271	69.54
Green Future	2016-2017	1,334.58	3.656	12.315	670.76	1.838	7.168	6,747.63	18.487	70.59
Green Future	2017-2018	1,343.21	3.680	12.404	663.19	1.817	7.163	6,810.42	18.659	71.75
Green Future	2018-2019	1,351.14	3.702	12.502	656.30	1.798	7.165	6,865.35	18.809	72.88
Green Future	2019-2020	1,364.03	3.727	12.612	655.70	1.792	7.174	6,963.67	19.026	73.98
Green Future	2020-2021	1,378.49	3.777	12.766	656.74	1.799	7.209	7,068.61	19.366	75.36
Green Future	2021-2022	1,396.32	3.826	12.932	659.70	1.807	7.252	7,174.33	19.656	76.79
Green Future	2022-2023	1,414.95	3.877	13.099	663.13	1.817	7.295	7,298.19	19.995	78.22
Green Future	2023-2024	1,434.44	3.919	13.254	666.02	1.820	7.331	7,420.96	20.276	79.57
Green Future	2024-2025	1,453.74	3.983	13.446	669.52	1.834	7.388	7,534.69	20.643	81.14
Green Future	2025-2026	1,471.58	4.032	13.603	672.23	1.842	7.426	7,638.86	20.928	82.42
Green Future	2026-2027	1,489.50	4.081	13.753	675.18	1.850	7.460	7,738.24	21.201	83.59
Green Future	2027-2028	1,507.06	4.118	13.892	678.81	1.855	7.489	7,845.01	21.434	84.69
Green Future	2028-2029	1,522.62	4.172	14.039	679.51	1.862	7.522	7,927.56	21.719	85.84

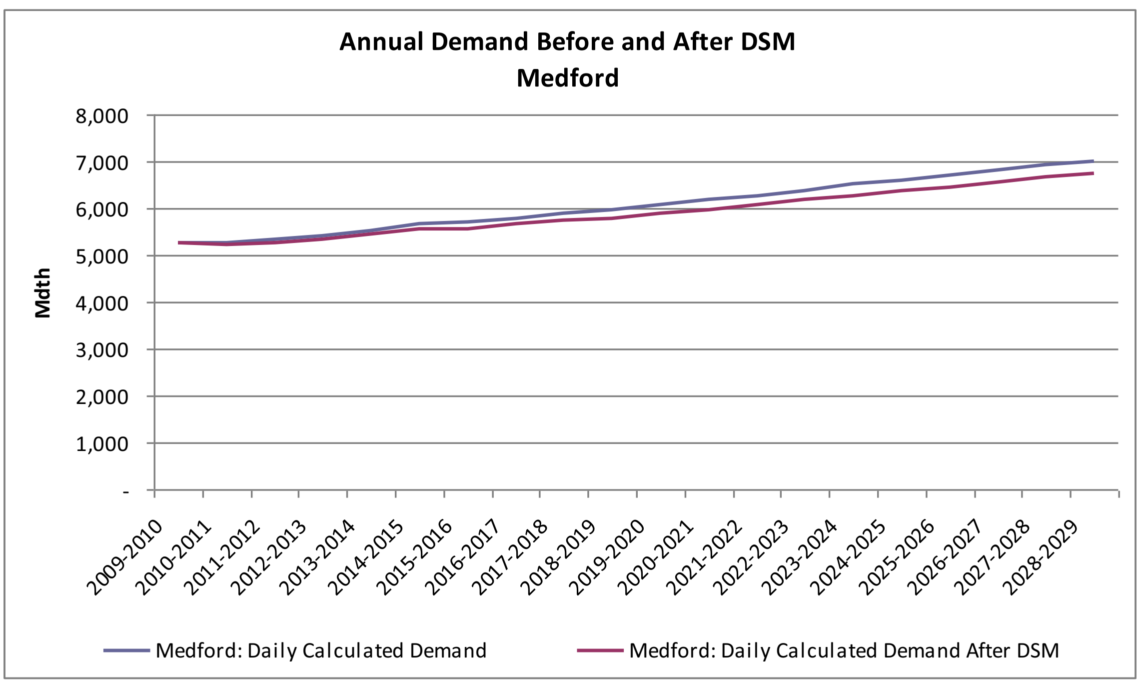
Case	Gas Year	Annual Demand Oregon (MDth)	Daily Demand Oregon (MDth/day)	Peak Day Demand Oregon (MDth/day)	Annual Demand WA/ID (MDth)	Daily Demand WA/ID (MDth/day)	Peak Day WA/ID (MDth/day)	Annual Demand Total System (MDth)	Daily Demand Total System (MDth/day)	Peak Day Demand Total System (MDth/day)
Green Future	2009-2010	8,876.748	24.320	91.133	26,221.195	71.839	274.583	35,097.943	96.159	365.716
Green Future	2010-2011	8,595.502	23.549	87.421	25,259.066	69.203	262.017	33,854.568	92.752	349.438
Green Future	2011-2012	8,664.177	23.673	88.109	25,154.544	68.728	263.103	33,818.721	92.401	351.212
Green Future	2012-2013	8,759.288	23.998	89.820	25,151.067	68.907	264.291	33,910.356	92.905	354.111
Green Future	2013-2014	8,882.456	24.335	91.754	25,324.607	69.382	266.502	34,207.063	93.718	358.256
Green Future	2014-2015	9,041.999	24.773	94.100	25,619.898	70.192	270.087	34,661.898	94.964	364.187
Green Future	2015-2016	8,696.807	23.762	89.000	24,196.578	66.111	250.522	32,893.384	89.873	339.522
Green Future	2016-2017	8,752.969	23.981	90.069	24,097.903	66.022	250.100	32,850.873	90.002	340.169
Green Future	2017-2018	8,816.822	24.156	91.321	24,130.278	66.110	250.658	32,947.100	90.266	341.979
Green Future	2018-2019	8,872.791	24.309	92.542	24,206.037	66.318	251.448	33,078.828	90.627	343.990
Green Future	2019-2020	8,983.401	24.545	93.766	24,368.029	66.579	252.675	33,351.429	91.124	346.441
Green Future	2020-2021	9,103.833	24.942	95.333	24,592.457	67.377	255.025	33,696.291	92.319	350.358
Green Future	2021-2022	9,230.341	25.289	96.977	24,854.409	68.094	257.696	34,084.751	93.383	354.673
Green Future	2022-2023	9,376.272	25.688	98.618	25,127.755	68.843	260.384	34,504.027	94.532	359.002
Green Future	2023-2024	9,521.418	26.015	100.150	25,407.768	69.420	262.620	34,929.186	95.435	362.770
Green Future	2024-2025	9,657.962	26.460	101.977	25,685.438	70.371	265.800	35,343.400	96.831	367.777
Green Future	2025-2026	9,782.670	26.802	103.451	25,972.245	71.157	268.163	35,754.915	97.959	371.614
Green Future	2026-2027	9,902.917	27.131	104.806	26,211.486	71.812	270.278	36,114.403	98.944	375.083
Green Future	2027-2028	10,030.878	27.407	106.074	26,518.640	72.455	272.852	36,549.518	99.862	378.927
Green Future	2028-2029	10,129.690	27.753	107.398	26,784.852	73.383	275.441	36,914.543	101.136	382.839

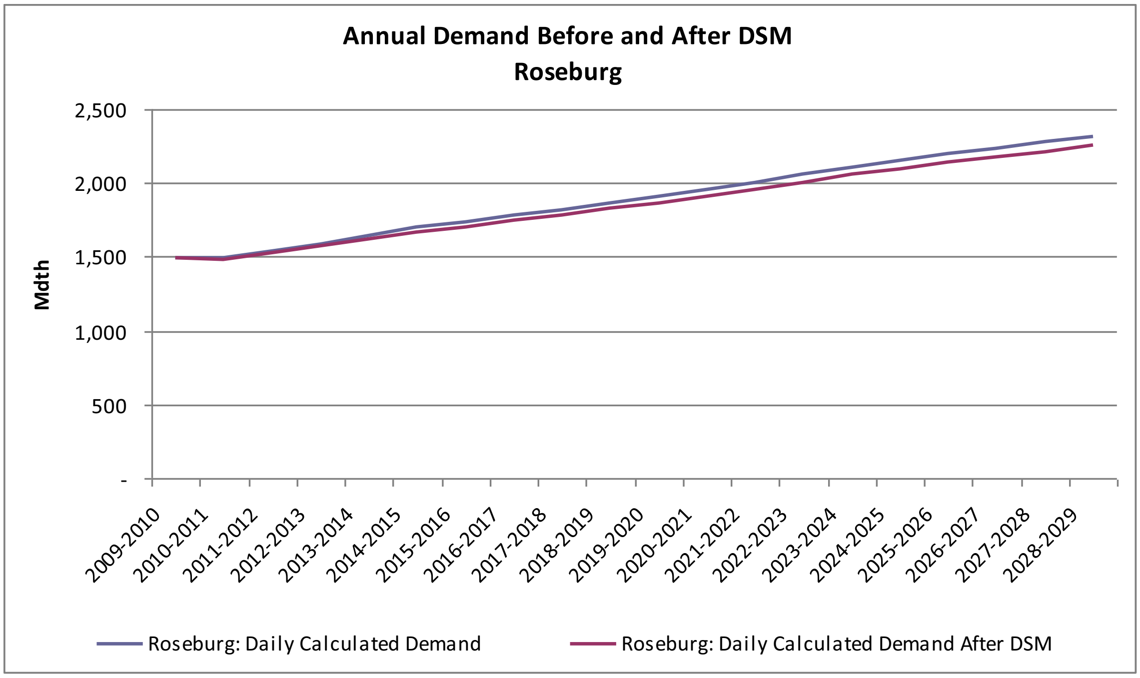
APPENDIX 3.9

ANNUAL DEMAND BY REGION BEFORE AND AFTER DSM

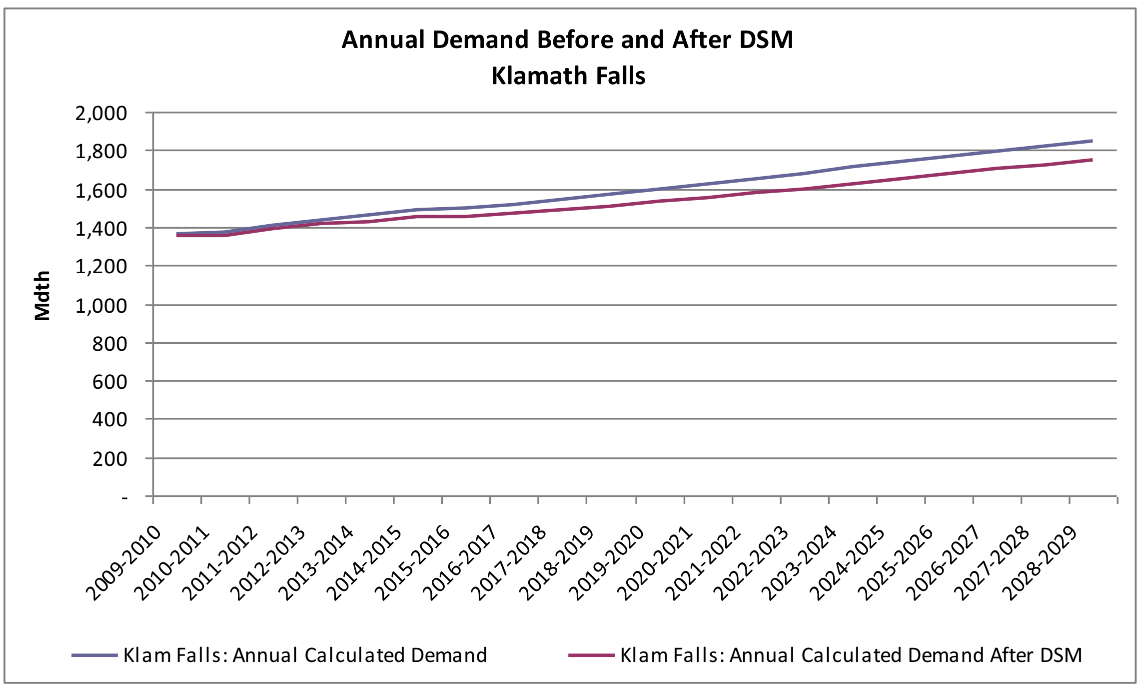
Appendix 3.9 - Annual Demand by Region Before and After DSM
Expected Case (in Mdth)



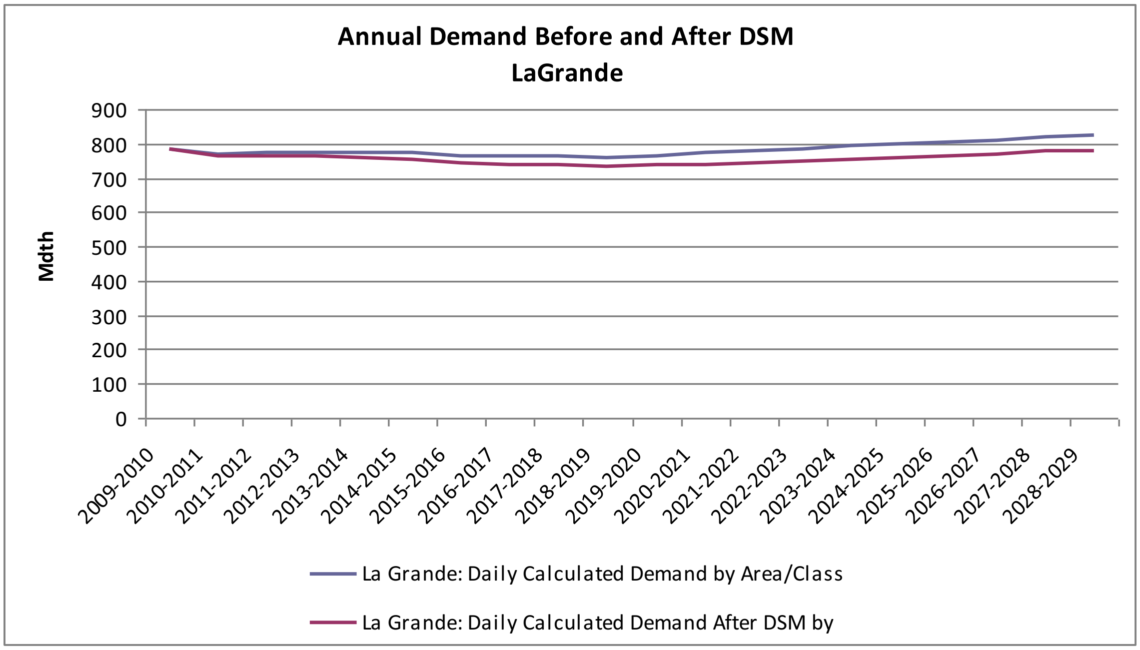




Annual Demand Before and After DSM
Roseburg
Mdth
2,500
2,000
1,500
1,000
500
-
2009-2010
2010-2011
2011-2012
2012-2013
2013-2014
2014-2015
2015-2016
2016-2017
2017-2018
2018-2019
2019-2020
2020-2021
2021-2022
2022-2023
2023-2024
2024-2025
2025-2026
2026-2027
2027-2028
2028-2029
Roseburg: Daily Calculated Demand
Roseburg: Daily Calculated Demand After DSM



Annual Demand Before and After DSM
Klamath Falls
Mdth
2,000
1,800
1,600
1,400
1,200
1,000
800
600
400
200
-
2009-2010
2010-2011
2011-2012
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
Klam Falls: Annual Calculated Demand
Klam Falls: Annual Calculated Demand After DSM



Annual Demand Before and After DSM
LaGrande
Mdth
900
800
700
600
500
400
300
200
100
0
2009-2010
2010-2011
2011-2012
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
La Grande: Daily Calculated Demand by Area/Class
La Grande: Daily Calculated Demand After DSM by

Appendix 3.9 - Annual Demand by Region Before and After DSM

Expected Case (in Mdth)

Gas Year	Wa/Id: Daily Calculated Demand	Wa/Id: Daily Calculated Demand After DSM	Wa/Id: Daily DSM	% of Demand Served by DSM
2009-2010	26,526.09	26,224.90	301.19	1.14%
2010-2011	26,584.84	25,977.00	607.84	2.29%
2011-2012	26,953.24	26,053.00	900.24	3.34%
2012-2013	27,425.32	26,235.81	1,189.51	4.34%
2013-2014	28,010.01	26,531.25	1,478.76	5.28%
2014-2015	28,619.71	26,851.68	1,768.03	6.18%
2015-2016	28,707.45	26,663.92	2,043.53	7.12%
2016-2017	29,155.37	26,839.97	2,315.40	7.94%
2017-2018	29,678.37	27,091.79	2,586.58	8.72%
2018-2019	30,234.41	27,374.74	2,859.67	9.46%
2019-2020	30,871.50	27,734.31	3,137.19	10.16%
2020-2021	31,479.93	28,091.83	3,388.09	10.76%
2021-2022	32,108.14	28,468.23	3,639.91	11.34%
2022-2023	32,753.61	28,861.41	3,892.20	11.88%
2023-2024	33,439.72	29,293.84	4,145.88	12.40%
2024-2025	34,049.31	29,664.20	4,385.11	12.88%
2025-2026	34,738.22	30,107.15	4,631.06	13.33%
2026-2027	35,364.51	30,503.32	4,861.19	13.75%
2027-2028	36,030.35	30,986.56	5,043.79	14.00%
2028-2029	36,641.75	31,418.51	5,223.24	14.25%

Appendix 3.9 - Annual Demand by Region Before and After DSM

Expected Case (in Mdth)

Gas Year	Medford: Daily Calculated Demand	Medford: Daily Calculated Demand After DSM	Medford: DSM	% of Demand Served by DSM
2009-2010	5,271.99	5,254.79	17.19	0.33%
2010-2011	5,247.21	5,210.47	36.74	0.70%
2011-2012	5,320.58	5,266.05	54.53	1.02%
2012-2013	5,421.21	5,350.71	70.49	1.30%
2013-2014	5,535.29	5,448.89	86.40	1.56%
2014-2015	5,649.16	5,547.09	102.07	1.81%
2015-2016	5,686.18	5,568.65	117.53	2.07%
2016-2017	5,785.45	5,652.81	132.64	2.29%
2017-2018	5,875.10	5,727.54	147.56	2.51%
2018-2019	5,949.31	5,787.15	162.16	2.73%
2019-2020	6,064.50	5,886.91	177.60	2.93%
2020-2021	6,172.34	5,979.65	192.69	3.12%
2021-2022	6,271.86	6,065.46	206.40	3.29%
2022-2023	6,387.46	6,169.20	218.25	3.42%
2023-2024	6,503.17	6,275.20	227.97	3.51%
2024-2025	6,605.08	6,369.13	235.95	3.57%
2025-2026	6,705.73	6,462.26	243.48	3.63%
2026-2027	6,813.68	6,562.38	251.29	3.69%
2027-2028	6,925.88	6,666.57	259.30	3.74%
2028-2029	7,010.80	6,744.67	266.12	3.80%

Appendix 3.9 - Annual Demand by Region Before and After DSM
Expected Case (in Mdth)

Gas Year	Roseburg: Daily Calculated Demand	Roseburg: Daily Calculated Demand After DSM	Roseburg: DSM	% of Demand Served by DSM
2009-2010	1,491.78	1,487.33	4.45	0.30%
2010-2011	1,495.81	1,486.30	9.51	0.64%
2011-2012	1,540.63	1,526.74	13.90	0.90%
2012-2013	1,590.67	1,572.84	17.83	1.12%
2013-2014	1,642.17	1,620.42	21.75	1.32%
2014-2015	1,696.96	1,671.32	25.64	1.51%
2015-2016	1,730.65	1,701.12	29.52	1.71%
2016-2017	1,778.11	1,744.82	33.29	1.87%
2017-2018	1,820.37	1,783.45	36.93	2.03%
2018-2019	1,864.07	1,823.47	40.61	2.18%
2019-2020	1,912.12	1,867.80	44.32	2.32%
2020-2021	1,959.32	1,911.33	47.99	2.45%
2021-2022	2,007.29	1,955.88	51.40	2.56%
2022-2023	2,058.62	2,004.47	54.15	2.63%
2023-2024	2,112.05	2,055.76	56.29	2.67%
2024-2025	2,153.90	2,095.99	57.92	2.69%
2025-2026	2,199.00	2,139.49	59.51	2.71%
2026-2027	2,234.05	2,173.29	60.76	2.72%
2027-2028	2,277.19	2,214.90	62.29	2.74%
2028-2029	2,316.90	2,253.26	63.64	2.75%

Appendix 3.9 - Annual Demand by Region Before and After DSM
Expected Case (in Mdth)

Gas Year	Klam Falls: Annual Calculated Demand	Klam Falls: Annual Calculated Demand After DSM	Klam Falls: DSM	% of Demand Served by DSM
2009-2010	1,359.40	1,352.83	6.57	0.48%
2010-2011	1,371.15	1,358.02	13.14	0.96%
2011-2012	1,408.49	1,388.79	19.70	1.40%
2012-2013	1,438.98	1,413.54	25.43	1.77%
2013-2014	1,461.01	1,429.92	31.09	2.13%
2014-2015	1,487.71	1,450.87	36.84	2.48%
2015-2016	1,495.26	1,452.66	42.60	2.85%
2016-2017	1,519.82	1,471.57	48.25	3.17%
2017-2018	1,545.07	1,491.15	53.92	3.49%
2018-2019	1,568.48	1,508.98	59.50	3.79%
2019-2020	1,596.44	1,531.23	65.21	4.08%
2020-2021	1,622.72	1,551.91	70.81	4.36%
2021-2022	1,651.38	1,575.11	76.28	4.62%
2022-2023	1,680.05	1,599.35	80.71	4.80%
2023-2024	1,710.30	1,625.95	84.34	4.93%
2024-2025	1,737.00	1,649.52	87.48	5.04%
2025-2026	1,764.65	1,674.21	90.44	5.13%
2026-2027	1,793.10	1,699.65	93.44	5.21%
2027-2028	1,821.72	1,725.30	96.43	5.29%
2028-2029	1,847.82	1,748.52	99.30	5.37%

Appendix 3.9 - Annual Demand by Region Before and After DSM

Expected Case (in Mdth)

Gas Year	Calculated Demand by Area/Class	Calculated Demand After DSM by Area/Class	La Grande: DSM	% of Demand served by DSM
2009-2010	785.67	782.49	3.17	0.40%
2010-2011	770.51	764.25	6.26	0.81%
2011-2012	772.46	763.16	9.30	1.20%
2012-2013	773.43	761.45	11.99	1.55%
2013-2014	774.29	759.65	14.63	1.89%
2014-2015	772.97	755.79	17.18	2.22%
2015-2016	763.70	743.95	19.75	2.59%
2016-2017	762.77	740.57	22.20	2.91%
2017-2018	761.41	736.82	24.58	3.23%
2018-2019	760.07	733.14	26.93	3.54%
2019-2020	765.55	736.10	29.44	3.85%
2020-2021	771.21	739.28	31.92	4.14%
2021-2022	778.37	744.06	34.32	4.41%
2022-2023	785.61	749.37	36.24	4.61%
2023-2024	792.38	754.62	37.76	4.77%
2024-2025	798.33	759.27	39.06	4.89%
2025-2026	804.52	764.26	40.26	5.00%
2026-2027	811.30	769.80	41.50	5.12%
2027-2028	819.23	776.44	42.79	5.22%
2028-2029	823.31	779.44	43.87	5.33%

APPENDIX 3.10

DETAIL DEMAND DATA

Appendix 3.10 - A
Annual Avg. Demand (Mdth/d)
(Net of DSM Savings)

Updated Expected with Low Elasticity

Area	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019
Klam Falls	3.71	3.72	3.79	3.87	3.92	3.97	3.97	4.03	4.09	4.13
La Grande	2.14	2.09	2.09	2.09	2.08	2.07	2.03	2.03	2.02	2.01
Medford GTN	9.93	9.85	9.93	10.12	10.30	10.49	10.50	10.69	10.83	10.94
Medford NWP	4.46	4.43	4.46	4.54	4.63	4.71	4.72	4.80	4.86	4.92
Roseburg	4.07	4.07	4.17	4.31	4.44	4.58	4.65	4.78	4.89	5.00
OR Sub-Total	24.32	24.16	24.44	24.93	25.37	25.82	25.86	26.33	26.68	26.99
Wa/Id Both	41.64	41.23	41.21	41.59	42.04	42.52	42.09	42.46	42.84	43.26
Wa/Id GTN	5.75	5.69	5.69	5.75	5.82	5.89	5.83	5.88	5.94	6.00
Wa/Id NWP	24.45	24.25	24.28	24.54	24.84	25.16	24.94	25.19	25.45	25.73
WA/ID Sub_Total	71.84	71.17	71.18	71.88	72.69	73.57	72.85	73.53	74.22	75.00
Expected Case Total	96.16	95.33	95.62	96.81	98.06	99.39	98.72	99.86	100.91	101.99

High Growth & Low Price

Area	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019
Klam Falls	3.67	3.73	3.86	3.99	4.08	4.17	4.26	4.36	4.46	4.55
La Grande	2.11	2.07	2.08	2.09	2.10	2.10	2.10	2.11	2.11	2.11
Medford GTN	9.88	9.89	10.09	10.41	10.73	11.06	11.35	11.67	11.93	12.16
Medford NWP	4.44	4.44	4.53	4.68	4.82	4.97	5.10	5.24	5.36	5.46
Roseburg	4.09	4.14	4.31	4.54	4.75	4.98	5.19	5.41	5.59	5.77
OR Sub-Total	24.20	24.27	24.87	25.71	26.49	27.28	28.00	28.79	29.45	30.05
Wa/Id Both	42.36	42.43	42.91	43.84	44.84	45.88	46.61	47.52	48.45	49.43
Wa/Id GTN	5.85	5.86	5.93	6.06	6.20	6.35	6.45	6.58	6.71	6.85
Wa/Id NWP	24.87	24.95	25.27	25.85	26.48	27.12	27.59	28.16	28.74	29.35
Wa/Id Sub-Total	73.09	73.24	74.12	75.75	77.52	79.35	80.65	82.27	83.90	85.63
High Case Total	97.28	97.52	98.99	101.47	104.00	106.63	108.65	111.06	113.35	115.68

Low Growth & High Prices

Area	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019
Klam Falls	3.66	3.69	3.59	3.49	3.47	3.49	3.49	3.51	3.53	3.54
La Grande	2.12	2.09	2.00	1.92	1.89	1.87	1.85	1.84	1.82	1.80
Medford GTN	9.87	9.84	9.49	9.22	9.22	9.26	9.27	9.33	9.35	9.35
Medford NWP	4.43	4.42	4.27	4.14	4.14	4.16	4.17	4.19	4.20	4.20
Roseburg	4.06	4.06	3.97	3.89	3.92	3.97	4.01	4.06	4.09	4.12
OR Sub-Total	24.14	24.09	23.32	22.65	22.64	22.75	22.80	22.93	22.98	23.01
Wa/Id Both	41.68	41.43	39.56	37.91	37.62	37.54	37.24	37.09	36.94	36.84
Wa/Id GTN	5.75	5.72	5.47	5.24	5.21	5.20	5.16	5.14	5.12	5.11
Wa/Id NWP	24.47	24.36	23.31	22.38	22.24	22.24	22.09	22.04	21.99	21.97
Wa/Id Sub-Total	71.90	71.51	68.33	65.52	65.07	64.98	64.49	64.27	64.06	63.92
Low Case Total	96.04	95.61	91.65	88.17	87.71	87.73	87.29	87.20	87.04	86.93

Appendix 3.10 - A
Annual Avg. Demand (Mdth/d)
(Net of DSM Savings)

Updated Expected with Low Elasticity

Area	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029
Klam Falls	4.18	4.25	4.32	4.38	4.44	4.52	4.59	4.66	4.71	4.79
La Grande	2.01	2.03	2.04	2.05	2.06	2.08	2.09	2.11	2.12	2.14
Medford GTN	11.10	11.30	11.47	11.66	11.83	12.04	12.22	12.41	12.57	12.75
Medford NWP	4.99	5.08	5.15	5.24	5.32	5.41	5.49	5.57	5.65	5.73
Roseburg	5.10	5.24	5.36	5.49	5.62	5.74	5.86	5.95	6.05	6.17
OR Sub-Total	27.38	27.90	28.33	28.83	29.27	29.79	30.25	30.70	31.10	31.58
Wa/Id Both	43.69	44.36	44.94	45.54	46.08	46.78	47.46	48.07	48.69	49.50
Wa/Id GTN	6.06	6.16	6.24	6.33	6.40	6.50	6.60	6.69	6.77	6.89
Wa/Id NWP	26.02	26.45	26.82	27.20	27.55	27.99	28.43	28.81	29.20	29.70
WA/ID Sub_Total	75.78	76.96	78.00	79.07	80.04	81.27	82.49	83.57	84.66	86.08
Expected Case Total	103.16	104.86	106.33	107.90	109.30	111.06	112.73	114.27	115.76	117.66

High Growth & Low Price

Area	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029
Klam Falls	4.63	4.74	4.85	4.95	5.05	5.17	5.28	5.38	5.48	5.60
La Grande	2.12	2.15	2.17	2.20	2.22	2.25	2.27	2.30	2.32	2.35
Medford GTN	12.43	12.76	13.04	13.35	13.63	13.96	14.25	14.55	14.81	15.10
Medford NWP	5.59	5.73	5.86	6.00	6.13	6.27	6.40	6.54	6.66	6.79
Roseburg	5.95	6.16	6.36	6.57	6.77	6.97	7.16	7.31	7.47	7.66
OR Sub-Total	30.73	31.55	32.28	33.07	33.80	34.62	35.35	36.07	36.74	37.49
Wa/Id Both	50.42	51.68	52.84	54.04	55.15	56.45	57.74	58.94	60.12	61.52
Wa/Id GTN	6.99	7.17	7.33	7.50	7.65	7.84	8.02	8.18	8.35	8.54
Wa/Id NWP	29.96	30.74	31.45	32.18	32.87	33.67	34.45	35.18	35.90	36.75
Wa/Id Sub-Total	87.37	89.58	91.62	93.72	95.67	97.96	100.22	102.31	104.36	106.81
High Case Total	118.10	121.13	123.90	126.79	129.47	132.58	135.57	138.38	141.10	144.30

Low Growth & High Prices

Area	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029
Klam Falls	3.55	3.57	3.60	3.62	3.64	3.67	3.70	3.73	3.75	3.78
La Grande	1.79	1.79	1.80	1.80	1.80	1.80	1.81	1.81	1.81	1.81
Medford GTN	9.39	9.47	9.52	9.59	9.65	9.74	9.80	9.88	9.94	10.01
Medford NWP	4.22	4.26	4.28	4.31	4.34	4.38	4.40	4.44	4.47	4.50
Roseburg	4.16	4.21	4.26	4.32	4.37	4.42	4.47	4.50	4.54	4.59
OR Sub-Total	23.11	23.31	23.45	23.64	23.79	24.01	24.19	24.37	24.50	24.70
Wa/Id Both	36.73	36.82	36.84	36.87	36.86	36.97	37.07	37.12	37.20	37.42
Wa/Id GTN	5.10	5.12	5.12	5.13	5.13	5.15	5.17	5.17	5.19	5.22
Wa/Id NWP	21.94	22.03	22.07	22.12	22.15	22.24	22.33	22.39	22.46	22.62
Wa/Id Sub-Total	63.77	63.97	64.03	64.13	64.14	64.36	64.57	64.69	64.85	65.27
Low Case Total	86.88	87.27	87.48	87.77	87.93	88.37	88.76	89.05	89.36	89.96

Appendix 3.10 - B
Annual Avg. Demand by Class(Mdth/d)
(Net of DSM Savings)

Updated Expected with Low Elasticity	Area	2009-2010: Residential	2009-2010: Commercial	2009-2010: Ind FirmSale	2010-2011: Residential	2010-2011: Commercial	2010-2011: Ind FirmSale	2011-2012: Residential	2011-2012: Commercial	2011-2012: Ind FirmSale
	Klam Falls	2.30	1.39	0.02	2.28	1.42	0.02	2.31	1.47	0.02
	La Grande	1.29	0.77	0.09	1.26	0.75	0.08	1.25	0.75	0.08
	Medford GTN	6.09	3.82	0.02	6.03	3.80	0.02	6.11	3.80	0.02
	Medford NWP	2.74	1.72	0.01	2.71	1.71	0.01	2.74	1.71	0.01
	Roseburg	2.20	1.83	0.05	2.17	1.85	0.05	2.24	1.89	0.05
	OR Sub-Total	14.62	9.53	0.18	14.45	9.54	0.17	14.66	9.61	0.17
	Wa/Id Both	25.13	15.90	0.61	24.60	16.01	0.62	24.38	16.21	0.62
	Wa/Id GTN	3.47	2.19	0.08	3.40	2.21	0.09	3.37	2.24	0.09
	Wa/Id NWP	14.77	9.32	0.36	14.50	9.39	0.36	14.41	9.50	0.36
	Wa/Id Sub-Total	43.37	27.42	1.05	42.50	27.61	1.06	42.17	27.94	1.07
	Expected Case Total	68.49	43.33	1.66	67.10	43.62	1.68	66.55	44.15	1.70

High Growth & Low Price	Area	2009-2010: Residential	2009-2010: Commercial	2009-2010: Ind FirmSale	2010-2011: Residential	2010-2011: Commercial	2010-2011: Ind FirmSale	2011-2012: Residential	2011-2012: Commercial	2011-2012: Ind FirmSale
	Klam Falls	2.27	1.39	0.02	2.27	1.45	0.02	2.32	1.52	0.02
	La Grande	1.27	0.76	0.09	1.24	0.75	0.08	1.25	0.75	0.08
	Medford GTN	6.05	3.82	0.02	6.04	3.84	0.02	6.21	3.87	0.02
	Medford NWP	2.72	1.72	0.01	2.71	1.72	0.01	2.79	1.74	0.01
	Roseburg	2.19	1.86	0.05	2.18	1.91	0.05	2.30	1.97	0.05
	OR Sub-Total	14.48	9.54	0.18	14.44	9.66	0.17	14.86	9.84	0.17
	Wa/Id Both	25.45	16.29	0.63	25.18	16.61	0.64	25.26	17.01	0.65
	Wa/Id GTN	3.51	2.25	0.09	3.48	2.29	0.09	3.49	2.35	0.09
	Wa/Id NWP	14.96	9.55	0.37	14.84	9.74	0.37	14.92	9.98	0.38
	Wa/Id Sub-Total	43.93	28.08	1.08	43.49	28.64	1.10	43.67	29.34	1.12
	High Case Total	69.38	44.36	1.71	68.67	45.26	1.74	68.92	46.35	1.76

Low Growth & High Price	Area	2009-2010: Residential	2009-2010: Commercial	2009-2010: Ind FirmSale	2010-2011: Residential	2010-2011: Commercial	2010-2011: Ind FirmSale	2011-2012: Residential	2011-2012: Commercial	2011-2012: Ind FirmSale
	Klam Falls	2.27	1.37	0.02	2.27	1.39	0.02	2.20	1.37	0.02
	La Grande	1.28	0.76	0.09	1.26	0.75	0.09	1.21	0.71	0.08
	Medford GTN	6.05	3.80	0.02	6.03	3.79	0.02	5.82	3.66	0.02
	Medford NWP	2.72	1.71	0.01	2.71	1.70	0.01	2.61	1.65	0.01
	Roseburg	2.19	1.83	0.05	2.18	1.84	0.05	2.12	1.80	0.05
	OR Sub-Total	14.50	9.46	0.18	14.44	9.48	0.17	13.96	9.19	0.17
	Wa/Id Both	25.16	15.90	0.61	24.79	16.02	0.62	23.42	15.52	0.62
	Wa/Id GTN	3.47	2.19	0.08	3.43	2.21	0.09	3.24	2.14	0.09
	Wa/Id NWP	14.79	9.32	0.36	14.61	9.40	0.36	13.84	9.10	0.36
	Wa/Id Sub-Total	43.42	27.42	1.06	42.82	27.63	1.06	40.50	26.77	1.06
	Low Case Total	68.58	43.32	1.67	67.60	43.66	1.68	63.92	42.29	1.68

Appendix 3.10 - B
Annual Avg. Demand by Class(Mdth/d)
(Net of DSM Savings)

Updated Expected with Low Elasticity	Area	2012-2013: Residential	2012-2013: Commercial	2012-2013: Ind FirmSale	2013-2014: Residential	2013-2014: Commercial	2013-2014: Ind FirmSale	2014-2015: Residential	2014-2015: Commercial	2014-2015: Ind FirmSale
	Klam Falls	2.36	1.50	0.02	2.39	1.51	0.02	2.42	1.53	0.02
	La Grande	1.26	0.75	0.08	1.26	0.74	0.08	1.26	0.73	0.08
	Medford GTN	6.27	3.83	0.02	6.43	3.85	0.02	6.60	3.87	0.02
	Medford NWP	2.82	1.72	0.01	2.89	1.73	0.01	2.97	1.74	0.01
	Roseburg	2.34	1.92	0.05	2.44	1.95	0.05	2.54	1.99	0.05
	OR Sub-Total	15.04	9.72	0.17	15.41	9.79	0.17	15.79	9.86	0.17
	Wa/Id Both	24.44	16.53	0.63	24.54	16.86	0.63	24.67	17.21	0.64
	Wa/Id GTN	3.38	2.28	0.09	3.40	2.33	0.09	3.42	2.38	0.09
	Wa/Id NWP	14.48	9.69	0.37	14.57	9.89	0.37	14.68	10.10	0.38
	Wa/Id Sub-Total	42.30	28.50	1.08	42.51	29.08	1.09	42.77	29.69	1.11
	Expected Case Total	66.73	45.03	1.71	67.05	45.95	1.73	67.44	46.90	1.75

High Growth & Low Price	Area	2012-2013: Residential	2012-2013: Commercial	2012-2013: Ind FirmSale	2013-2014: Residential	2013-2014: Commercial	2013-2014: Ind FirmSale	2014-2015: Residential	2014-2015: Commercial	2014-2015: Ind FirmSale
	Klam Falls	2.40	1.58	0.02	2.45	1.61	0.02	2.52	1.64	0.02
	La Grande	1.26	0.75	0.08	1.28	0.74	0.08	1.28	0.74	0.08
	Medford GTN	6.47	3.92	0.02	6.75	3.97	0.02	7.03	4.01	0.02
	Medford NWP	2.91	1.76	0.01	3.03	1.78	0.01	3.16	1.80	0.01
	Roseburg	2.46	2.03	0.05	2.62	2.09	0.05	2.78	2.16	0.05
	OR Sub-Total	15.50	10.04	0.17	16.13	10.19	0.17	16.77	10.35	0.17
	Wa/Id Both	25.64	17.55	0.65	26.08	18.09	0.66	26.55	18.66	0.68
	Wa/Id GTN	3.55	2.42	0.09	3.61	2.50	0.09	3.68	2.57	0.09
	Wa/Id NWP	15.18	10.29	0.38	15.47	10.61	0.39	15.78	10.94	0.40
	Wa/Id Sub-Total	44.37	30.26	1.13	45.17	31.20	1.15	46.01	32.17	1.17
	High Case Total	70.01	47.80	1.78	71.25	49.30	1.81	72.55	50.83	1.84

Low Growth & High Price	Area	2012-2013: Residential	2012-2013: Commercial	2012-2013: Ind FirmSale	2013-2014: Residential	2013-2014: Commercial	2013-2014: Ind FirmSale	2014-2015: Residential	2014-2015: Commercial	2014-2015: Ind FirmSale
	Klam Falls	2.13	1.34	0.02	2.12	1.33	0.02	2.13	1.34	0.02
	La Grande	1.16	0.68	0.08	1.14	0.67	0.08	1.13	0.66	0.08
	Medford GTN	5.65	3.55	0.02	5.67	3.53	0.02	5.72	3.52	0.02
	Medford NWP	2.54	1.59	0.01	2.55	1.59	0.01	2.57	1.58	0.01
	Roseburg	2.09	1.76	0.04	2.12	1.76	0.04	2.16	1.77	0.04
	OR Sub-Total	13.57	8.92	0.16	13.60	8.88	0.16	13.71	8.87	0.16
	Wa/Id Both	22.20	15.09	0.62	21.84	15.15	0.62	21.63	15.29	0.62
	Wa/Id GTN	3.07	2.08	0.09	3.03	2.09	0.09	3.00	2.11	0.09
	Wa/Id NWP	13.16	8.85	0.36	12.99	8.89	0.36	12.90	8.97	0.37
	Wa/Id Sub-Total	38.44	26.02	1.06	37.86	26.13	1.07	37.53	26.38	1.07
	Low Case Total	60.63	41.12	1.68	59.71	41.29	1.69	59.16	41.67	1.70

Appendix 3.10 - B
Annual Avg. Demand by Class(Mdth/d)
(Net of DSM Savings)

Updated Expected with Low Elasticity

Area	2015-2016: Residential	2015-2016: Commercial	2015-2016: Ind FirmSale	2016-2017: Residential	2016-2017: Commercial	2016-2017: Ind FirmSale	2017-2018: Residential	2017-2018: Commercial	2017-2018: Ind FirmSale
Klam Falls	2.42	1.53	0.02	2.46	1.55	0.02	2.50	1.57	0.02
La Grande	1.24	0.71	0.08	1.25	0.71	0.08	1.25	0.70	0.08
Medford GTN	6.65	3.83	0.02	6.82	3.85	0.02	6.96	3.86	0.02
Medford NWP	2.99	1.72	0.01	3.07	1.73	0.01	3.13	1.73	0.01
Roseburg	2.60	2.00	0.04	2.70	2.04	0.04	2.79	2.05	0.04
OR Sub-Total	15.91	9.79	0.16	16.30	9.87	0.16	16.61	9.91	0.16
Wa/Id Both	24.22	17.22	0.65	24.29	17.52	0.65	24.35	17.83	0.66
Wa/Id GTN	3.36	2.38	0.09	3.38	2.42	0.09	3.39	2.46	0.09
Wa/Id NWP	14.46	10.10	0.38	14.53	10.28	0.38	14.60	10.46	0.39
Wa/Id Sub-Total	42.04	29.69	1.11	42.19	30.22	1.12	42.34	30.75	1.13
Expected Case Total	66.27	46.91	1.76	66.48	47.74	1.78	66.70	48.57	1.79

High Growth & Low Price

Area	2015-2016: Residential	2015-2016: Commercial	2015-2016: Ind FirmSale	2016-2017: Residential	2016-2017: Commercial	2016-2017: Ind FirmSale	2017-2018: Residential	2017-2018: Commercial	2017-2018: Ind FirmSale
Klam Falls	2.58	1.67	0.02	2.65	1.70	0.02	2.71	1.73	0.02
La Grande	1.29	0.73	0.08	1.31	0.73	0.08	1.31	0.72	0.08
Medford GTN	7.29	4.04	0.02	7.57	4.08	0.02	7.80	4.11	0.02
Medford NWP	3.27	1.82	0.01	3.40	1.83	0.01	3.50	1.85	0.01
Roseburg	2.93	2.21	0.04	3.09	2.27	0.04	3.24	2.31	0.04
OR Sub-Total	17.36	10.47	0.17	18.01	10.62	0.17	18.56	10.72	0.17
Wa/Id Both	26.83	19.09	0.69	27.23	19.60	0.69	27.63	20.12	0.70
Wa/Id GTN	3.72	2.63	0.09	3.78	2.70	0.10	3.84	2.78	0.10
Wa/Id NWP	15.98	11.20	0.40	16.25	11.50	0.41	16.52	11.81	0.41
Wa/Id Sub-Total	46.54	32.93	1.18	47.26	33.81	1.20	47.98	34.70	1.21
High Case Total	73.37	52.02	1.87	74.49	53.41	1.89	75.61	54.82	1.92

Low Growth & High Price

Area	2015-2016: Residential	2015-2016: Commercial	2015-2016: Ind FirmSale	2016-2017: Residential	2016-2017: Commercial	2016-2017: Ind FirmSale	2017-2018: Residential	2017-2018: Commercial	2017-2018: Ind FirmSale
Klam Falls	2.14	1.34	0.02	2.15	1.35	0.02	2.16	1.35	0.02
La Grande	1.13	0.65	0.07	1.12	0.64	0.07	1.11	0.64	0.07
Medford GTN	5.75	3.50	0.02	5.81	3.50	0.02	5.84	3.49	0.02
Medford NWP	2.59	1.57	0.01	2.61	1.57	0.01	2.63	1.57	0.01
Roseburg	2.19	1.78	0.04	2.23	1.79	0.04	2.26	1.79	0.04
OR Sub-Total	13.79	8.85	0.16	13.92	8.85	0.16	14.00	8.83	0.16
Wa/Id Both	21.27	15.34	0.63	21.02	15.44	0.63	20.76	15.55	0.63
Wa/Id GTN	2.96	2.12	0.09	2.92	2.13	0.09	2.89	2.15	0.09
Wa/Id NWP	12.73	9.00	0.37	12.61	9.06	0.37	12.49	9.13	0.37
Wa/Id Sub-Total	36.96	26.45	1.08	36.55	26.64	1.08	36.15	26.82	1.09
Low Case Total	58.23	41.79	1.71	57.56	42.08	1.71	56.91	42.37	1.72

Appendix 3.10 - B
Annual Avg. Demand by Class(Mdth/d)
(Net of DSM Savings)

Updated Expected with Low Elasticity

Area	2018-2019: Residential	2018-2019: Commercial	2018-2019: Ind FirmSale	2019-2020: Residential	2019-2020: Commercial	2019-2020: Ind FirmSale	2020-2021: Residential	2020-2021: Commercial	2020-2021: Ind FirmSale
Klam Falls	2.53	1.58	0.02	2.56	1.60	0.02	2.61	1.62	0.02
La Grande	1.25	0.69	0.07	1.25	0.69	0.07	1.27	0.69	0.07
Medford GTN	7.07	3.86	0.02	7.21	3.88	0.02	7.38	3.91	0.02
Medford NWP	3.18	1.73	0.01	3.24	1.74	0.01	3.31	1.76	0.01
Roseburg	2.88	2.07	0.04	2.97	2.09	0.04	3.07	2.12	0.04
OR Sub-Total	16.90	9.94	0.16	17.23	10.00	0.16	17.64	10.10	0.16
Wa/Id Both	24.45	18.15	0.67	24.55	18.48	0.67	24.81	18.88	0.68
Wa/Id GTN	3.40	2.50	0.09	3.42	2.55	0.09	3.46	2.61	0.09
Wa/Id NWP	14.69	10.65	0.39	14.78	10.85	0.39	14.97	11.08	0.40
Wa/Id Sub-Total	42.54	31.31	1.15	42.75	31.87	1.16	43.23	32.57	1.17
Expected Case Total	66.99	49.46	1.82	67.30	50.35	1.83	68.04	51.44	1.84

High Growth & Low Price

Area	2018-2019: Residential	2018-2019: Commercial	2018-2019: Ind FirmSale	2019-2020: Residential	2019-2020: Commercial	2019-2020: Ind FirmSale	2020-2021: Residential	2020-2021: Commercial	2020-2021: Ind FirmSale
Klam Falls	2.76	1.76	0.02	2.82	1.79	0.02	2.90	1.83	0.02
La Grande	1.32	0.71	0.08	1.34	0.71	0.08	1.36	0.71	0.07
Medford GTN	8.00	4.13	0.02	8.24	4.18	0.02	8.50	4.24	0.02
Medford NWP	3.60	1.86	0.01	3.70	1.88	0.01	3.82	1.90	0.01
Roseburg	3.38	2.35	0.04	3.53	2.38	0.04	3.69	2.43	0.04
OR Sub-Total	19.07	10.81	0.17	19.62	10.94	0.17	20.27	11.11	0.17
Wa/Id Both	28.05	20.66	0.72	28.49	21.20	0.72	29.12	21.83	0.73
Wa/Id GTN	3.90	2.85	0.10	3.96	2.93	0.10	4.05	3.01	0.10
Wa/Id NWP	16.81	12.12	0.42	17.10	12.44	0.42	17.49	12.81	0.43
Wa/Id Sub-Total	48.76	35.63	1.24	49.56	36.56	1.25	50.66	37.65	1.27
High Case Total	76.81	56.28	1.96	78.05	57.76	1.97	79.78	59.48	2.00

Low Growth & High Price

Area	2018-2019: Residential	2018-2019: Commercial	2018-2019: Ind FirmSale	2019-2020: Residential	2019-2020: Commercial	2019-2020: Ind FirmSale	2020-2021: Residential	2020-2021: Commercial	2020-2021: Ind FirmSale
Klam Falls	2.17	1.35	0.02	2.17	1.36	0.02	2.19	1.37	0.02
La Grande	1.10	0.63	0.07	1.10	0.62	0.07	1.10	0.62	0.07
Medford GTN	5.86	3.47	0.02	5.91	3.47	0.02	5.98	3.48	0.02
Medford NWP	2.63	1.56	0.01	2.65	1.56	0.01	2.69	1.56	0.01
Roseburg	2.29	1.79	0.04	2.33	1.79	0.04	2.37	1.80	0.04
OR Sub-Total	14.06	8.80	0.15	14.16	8.79	0.15	14.33	8.82	0.15
Wa/Id Both	20.53	15.67	0.64	20.30	15.79	0.64	20.21	15.98	0.64
Wa/Id GTN	2.86	2.16	0.09	2.83	2.18	0.09	2.82	2.21	0.09
Wa/Id NWP	12.39	9.20	0.37	12.29	9.27	0.37	12.27	9.38	0.38
Wa/Id Sub-Total	35.79	27.04	1.10	35.43	27.24	1.10	35.30	27.56	1.10
Low Case Total	56.31	42.71	1.73	55.73	43.04	1.74	55.50	43.54	1.74

Appendix 3.10 - B
Annual Avg. Demand by Class(Mdth/d)
(Net of DSM Savings)

Updated Expected with Low Elasticity

Area	2021-2022: Residential	2021-2022: Commercial	2021-2022: Ind FirmSale	2022-2023: Residential	2022-2023: Commercial	2022-2023: Ind FirmSale	2023-2024: Residential	2023-2024: Commercial	2023-2024: Ind FirmSale
Klam Falls	2.65	1.64	0.02	2.70	1.67	0.02	2.73	1.69	0.02
La Grande	1.28	0.69	0.07	1.29	0.69	0.07	1.30	0.69	0.07
Medford GTN	7.52	3.93	0.02	7.68	3.97	0.02	7.82	3.99	0.02
Medford NWP	3.38	1.77	0.01	3.45	1.78	0.01	3.51	1.79	0.01
Roseburg	3.17	2.15	0.04	3.27	2.18	0.04	3.36	2.21	0.04
OR Sub-Total	18.00	10.17	0.16	18.39	10.28	0.16	18.74	10.37	0.16
Wa/Id Both	25.02	19.24	0.68	25.25	19.61	0.69	25.44	19.95	0.69
Wa/Id GTN	3.49	2.66	0.09	3.52	2.71	0.10	3.55	2.75	0.10
Wa/Id NWP	15.12	11.30	0.40	15.29	11.51	0.40	15.44	11.71	0.41
Wa/Id Sub-Total	43.63	33.19	1.18	44.06	33.83	1.19	44.43	34.41	1.19
Expected Case Total	68.64	52.43	1.86	69.30	53.43	1.88	69.88	54.35	1.89

High Growth & Low Price

Area	2021-2022: Residential	2021-2022: Commercial	2021-2022: Ind FirmSale	2022-2023: Residential	2022-2023: Commercial	2022-2023: Ind FirmSale	2023-2024: Residential	2023-2024: Commercial	2023-2024: Ind FirmSale
Klam Falls	2.96	1.86	0.02	3.03	1.90	0.02	3.10	1.94	0.02
La Grande	1.39	0.71	0.07	1.41	0.72	0.07	1.43	0.72	0.07
Medford GTN	8.74	4.28	0.02	8.99	4.34	0.02	9.23	4.38	0.02
Medford NWP	3.93	1.92	0.01	4.04	1.95	0.01	4.15	1.97	0.01
Roseburg	3.84	2.47	0.04	4.01	2.52	0.04	4.15	2.58	0.04
OR Sub-Total	20.86	11.25	0.17	21.48	11.42	0.17	22.05	11.58	0.17
Wa/Id Both	29.69	22.41	0.74	30.28	23.00	0.75	30.84	23.55	0.76
Wa/Id GTN	4.13	3.09	0.10	4.22	3.17	0.10	4.30	3.25	0.10
Wa/Id NWP	17.86	13.16	0.43	18.24	13.50	0.44	18.60	13.83	0.44
Wa/Id Sub-Total	51.68	38.66	1.28	52.74	39.68	1.30	53.73	40.63	1.31
High Case Total	81.37	61.07	2.02	83.02	62.68	2.05	84.57	64.19	2.06

Low Growth & High Price

Area	2021-2022: Residential	2021-2022: Commercial	2021-2022: Ind FirmSale	2022-2023: Residential	2022-2023: Commercial	2022-2023: Ind FirmSale	2023-2024: Residential	2023-2024: Commercial	2023-2024: Ind FirmSale
Klam Falls	2.21	1.37	0.02	2.22	1.38	0.02	2.23	1.39	0.02
La Grande	1.11	0.62	0.07	1.11	0.62	0.07	1.11	0.61	0.07
Medford GTN	6.03	3.48	0.02	6.09	3.49	0.02	6.14	3.49	0.02
Medford NWP	2.71	1.56	0.01	2.74	1.57	0.01	2.76	1.57	0.01
Roseburg	2.41	1.81	0.04	2.45	1.82	0.04	2.49	1.83	0.04
OR Sub-Total	14.46	8.83	0.15	14.62	8.87	0.15	14.74	8.90	0.15
Wa/Id Both	20.07	16.13	0.64	19.94	16.28	0.65	19.80	16.42	0.65
Wa/Id GTN	2.81	2.23	0.09	2.79	2.25	0.09	2.78	2.27	0.09
Wa/Id NWP	12.22	9.47	0.38	12.18	9.56	0.38	12.12	9.64	0.38
Wa/Id Sub-Total	35.10	27.83	1.11	34.92	28.10	1.11	34.70	28.33	1.12
Low Case Total	55.16	43.95	1.75	54.86	44.38	1.76	54.50	44.74	1.77

Appendix 3.10 - B
Annual Avg. Demand by Class(Mdth/d)
(Net of DSM Savings)

Updated Expected with Low Elasticity	Area	2024-2025: Residential	2024-2025: Commercial	2024-2025: Ind FirmSale	2025-2026: Residential	2025-2026: Commercial	2025-2026: Ind FirmSale	2026-2027: Residential	2026-2027: Commercial	2026-2027: Ind FirmSale
	Klam Falls	2.78	1.72	0.02	2.82	1.75	0.02	2.87	1.77	0.02
	La Grande	1.32	0.69	0.07	1.33	0.69	0.07	1.34	0.69	0.07
	Medford GTN	7.99	4.03	0.02	8.14	4.06	0.02	8.29	4.10	0.02
	Medford NWP	3.59	1.81	0.01	3.66	1.83	0.01	3.72	1.84	0.01
	Roseburg	3.46	2.24	0.04	3.54	2.28	0.04	3.61	2.30	0.04
	OR Sub-Total	19.14	10.50	0.16	19.49	10.60	0.16	19.83	10.71	0.16
	Wa/Id Both	25.73	20.35	0.70	26.00	20.76	0.70	26.23	21.13	0.71
	Wa/Id GTN	3.60	2.81	0.10	3.64	2.87	0.10	3.67	2.92	0.10
	Wa/Id NWP	15.63	11.95	0.41	15.82	12.19	0.41	15.99	12.41	0.42
	Wa/Id Sub-Total	44.95	35.11	1.20	45.46	35.82	1.21	45.89	36.46	1.23
	Expected Case Total	70.68	55.47	1.90	71.45	56.57	1.92	72.12	57.59	1.94

High Growth & Low Price	Area	2024-2025: Residential	2024-2025: Commercial	2024-2025: Ind FirmSale	2025-2026: Residential	2025-2026: Commercial	2025-2026: Ind FirmSale	2026-2027: Residential	2026-2027: Commercial	2026-2027: Ind FirmSale
	Klam Falls	3.17	1.98	0.02	3.24	2.02	0.02	3.31	2.06	0.02
	La Grande	1.45	0.72	0.07	1.47	0.73	0.07	1.50	0.73	0.07
	Medford GTN	9.49	4.44	0.02	9.73	4.50	0.02	9.97	4.56	0.02
	Medford NWP	4.27	2.00	0.01	4.37	2.02	0.01	4.48	2.05	0.01
	Roseburg	4.29	2.63	0.04	4.43	2.68	0.04	4.54	2.72	0.04
	OR Sub-Total	22.68	11.77	0.17	23.24	11.95	0.17	23.79	12.12	0.17
	Wa/Id Both	31.49	24.20	0.77	32.14	24.83	0.77	32.72	25.43	0.79
	Wa/Id GTN	4.39	3.34	0.11	4.48	3.43	0.11	4.57	3.51	0.11
	Wa/Id NWP	19.01	14.20	0.45	19.42	14.58	0.45	19.79	14.93	0.46
	Wa/Id Sub-Total	54.90	41.74	1.32	56.04	42.84	1.34	57.08	43.87	1.35
	High Case Total	86.39	65.93	2.09	88.17	67.67	2.11	89.80	69.30	2.14

Low Growth & High Price	Area	2024-2025: Residential	2024-2025: Commercial	2024-2025: Ind FirmSale	2025-2026: Residential	2025-2026: Commercial	2025-2026: Ind FirmSale	2026-2027: Residential	2026-2027: Commercial	2026-2027: Ind FirmSale
	Klam Falls	2.25	1.41	0.02	2.27	1.42	0.02	2.28	1.43	0.02
	La Grande	1.12	0.62	0.07	1.12	0.62	0.07	1.12	0.62	0.07
	Medford GTN	6.21	3.51	0.02	6.27	3.52	0.02	6.33	3.54	0.02
	Medford NWP	2.79	1.58	0.01	2.82	1.58	0.01	2.84	1.59	0.01
	Roseburg	2.53	1.85	0.04	2.57	1.86	0.04	2.59	1.87	0.04
	OR Sub-Total	14.91	8.95	0.15	15.04	9.00	0.15	15.17	9.04	0.15
	Wa/Id Both	19.72	16.60	0.65	19.63	16.79	0.65	19.52	16.94	0.66
	Wa/Id GTN	2.77	2.29	0.09	2.76	2.32	0.09	2.74	2.34	0.09
	Wa/Id NWP	12.11	9.75	0.38	12.09	9.86	0.38	12.05	9.96	0.39
	Wa/Id Sub-Total	34.59	28.65	1.12	34.47	28.97	1.13	34.31	29.24	1.13
	Low Case Total	54.31	45.25	1.77	54.10	45.75	1.78	53.83	46.19	1.79

Appendix 3.10 - B
Annual Avg. Demand by Class(Mdth/d)
(Net of DSM Savings)

	Area	2027-2028: Residential	2027-2028: Commercial	2027-2028: Ind FirmSale	2028-2029: Residential	2028-2029: Commercial	2028-2029: Ind FirmSale
Updated Expected with Low Elasticity	Klam Falls	2.90	1.79	0.02	2.95	1.82	0.02
	La Grande	1.35	0.69	0.07	1.37	0.70	0.07
	Medford GTN	8.42	4.13	0.02	8.57	4.17	0.02
	Medford NWP	3.78	1.86	0.01	3.85	1.87	0.01
	Roseburg	3.68	2.33	0.04	3.77	2.36	0.04
	OR Sub-Total	20.14	10.80	0.16	20.50	10.92	0.16
	Wa/Id Both	26.50	21.47	0.72	26.88	21.89	0.72
	Wa/Id GTN	3.71	2.96	0.10	3.77	3.02	0.10
	Wa/Id NWP	16.17	12.61	0.42	16.42	12.86	0.42
	Wa/Id Sub-Total	46.38	37.05	1.23	47.06	37.77	1.25
	Expected Case Total	72.88	58.52	1.95	73.95	59.66	1.97

	Area	2027-2028: Residential	2027-2028: Commercial	2027-2028: Ind FirmSale	2028-2029: Residential	2028-2029: Commercial	2028-2029: Ind FirmSale
High Growth & Low Price	Klam Falls	3.37	2.09	0.02	3.44	2.14	0.02
	La Grande	1.52	0.73	0.07	1.54	0.74	0.07
	Medford GTN	10.18	4.61	0.02	10.42	4.66	0.03
	Medford NWP	4.57	2.07	0.01	4.68	2.09	0.01
	Roseburg	4.66	2.77	0.04	4.79	2.83	0.04
	OR Sub-Total	24.30	12.27	0.17	24.86	12.46	0.17
	Wa/Id Both	33.33	25.99	0.79	34.08	26.64	0.80
	Wa/Id GTN	4.65	3.59	0.11	4.76	3.68	0.11
	Wa/Id NWP	20.17	15.26	0.47	20.63	15.64	0.47
	Wa/Id Sub-Total	58.16	44.84	1.37	59.47	45.95	1.39
	High Case Total	91.49	70.83	2.16	93.55	72.59	2.19

	Area	2027-2028: Residential	2027-2028: Commercial	2027-2028: Ind FirmSale	2028-2029: Residential	2028-2029: Commercial	2028-2029: Ind FirmSale
Low Growth & High Price	Klam Falls	2.29	1.44	0.02	2.31	1.45	0.02
	La Grande	1.13	0.62	0.07	1.13	0.62	0.07
	Medford GTN	6.38	3.55	0.02	6.43	3.56	0.02
	Medford NWP	2.86	1.59	0.01	2.89	1.60	0.01
	Roseburg	2.62	1.88	0.04	2.66	1.89	0.04
	OR Sub-Total	15.28	9.07	0.15	15.42	9.13	0.15
	Wa/Id Both	19.46	17.08	0.66	19.49	17.28	0.66
	Wa/Id GTN	2.74	2.36	0.09	2.74	2.38	0.09
	Wa/Id NWP	12.04	10.04	0.39	12.08	10.15	0.39
	Wa/Id Sub-Total	34.24	29.47	1.14	34.31	29.81	1.14
	Low Case Total	53.70	46.55	1.80	53.79	47.09	1.81

Appendix 3.10 - C
Annual Demand by Class(Mdth/d)
(Net of DSM Savings)

Updated Expected with Low Elasticity	Area	2009-2010: Residential	2009-2010: Commercial	2009-2010: Ind FirmSale	2010-2011: Residential	2010-2011: Commercial	2010-2011: Ind FirmSale	2011-2012: Residential	2011-2012: Commercial	2011-2012: Ind FirmSale
	Klam Falls	839.01	507.40	6.42	833.19	518.41	6.42	846.13	536.23	6.44
	La Grande	470.53	280.08	31.88	459.27	274.27	30.71	459.26	273.48	30.42
	Medford GTN	2,223.95	1,395.83	6.03	2,201.04	1,388.19	5.99	2,235.29	1,392.31	5.97
	Medford NWP	999.17	627.10	2.71	988.89	623.67	2.69	1,004.28	625.51	2.68
	Roseburg	802.00	668.28	17.04	793.21	676.22	16.88	819.62	690.37	16.75
	OR Sub-Total	5,334.65	3,478.70	64.09	5,275.60	3,480.75	62.69	5,364.58	3,517.89	62.27
	Wa/Id Both	9,171.63	5,805.07	222.44	8,979.46	5,843.56	225.40	8,924.85	5,931.05	227.82
	Wa/Id GTN	1,266.27	800.74	30.68	1,240.97	806.10	31.09	1,234.61	818.21	31.42
	Wa/Id NWP	5,390.48	3,403.48	130.39	5,291.73	3,426.56	132.13	5,273.14	3,478.35	133.55
	Wa/Id Sub-Total	15,828.39	10,009.29	383.51	15,512.15	10,076.22	388.63	15,432.60	10,227.61	392.79
	Expected Case Total	21,163.04	13,487.99	447.60	20,787.75	13,556.97	451.32	20,797.17	13,745.51	455.06

High Growth & Low Price	Area	2009-2010: Residential	2009-2010: Commercial	2009-2010: Ind FirmSale	2010-2011: Residential	2010-2011: Commercial	2010-2011: Ind FirmSale	2011-2012: Residential	2011-2012: Commercial	2011-2012: Ind FirmSale
	Klam Falls	826.93	507.37	6.42	827.65	528.49	6.42	849.40	556.33	6.44
	La Grande	462.65	276.18	31.88	453.87	272.22	30.76	457.06	272.96	30.48
	Medford GTN	2,206.63	1,394.54	5.99	2,203.68	1,399.99	5.96	2,271.43	1,415.34	6.13
	Medford NWP	991.39	626.53	2.69	990.07	628.97	2.68	1,020.52	635.86	2.75
	Roseburg	798.22	677.19	17.04	795.83	696.62	16.89	840.60	721.71	16.77
	OR Sub-Total	5,285.81	3,481.81	64.03	5,271.10	3,526.29	62.71	5,439.01	3,602.20	62.56
	Wa/Id Both	9,290.47	5,944.14	228.59	9,190.29	6,063.46	233.32	9,243.69	6,226.27	236.82
	Wa/Id GTN	1,282.66	819.93	31.53	1,270.05	836.43	32.18	1,278.58	858.93	32.66
	Wa/Id NWP	5,460.14	3,485.00	134.00	5,415.32	3,555.47	136.77	5,460.04	3,651.41	138.82
	Wa/Id Sub-Total	16,033.27	10,249.07	394.12	15,875.65	10,455.35	402.27	15,982.32	10,736.62	408.31
	High Case Total	21,319.08	13,730.89	458.15	21,146.75	13,981.64	464.98	21,421.32	14,338.82	470.87

Low Growth & High Price	Area	2009-2010: Residential	2009-2010: Commercial	2009-2010: Ind FirmSale	2010-2011: Residential	2010-2011: Commercial	2010-2011: Ind FirmSale	2011-2012: Residential	2011-2012: Commercial	2011-2012: Ind FirmSale
	Klam Falls	829.60	501.10	6.42	830.30	508.43	6.42	806.04	501.96	6.44
	La Grande	466.13	275.81	31.88	459.54	272.34	31.11	441.59	261.40	29.84
	Medford GTN	2,207.98	1,387.56	6.03	2,199.80	1,384.81	6.03	2,128.52	1,340.38	5.92
	Medford NWP	992.00	623.39	2.71	988.33	622.15	2.71	956.31	602.18	2.66
	Roseburg	797.68	666.82	17.04	794.01	671.43	17.01	777.54	657.87	16.57
	OR Sub-Total	5,293.39	3,454.68	64.09	5,271.97	3,459.16	63.28	5,110.00	3,363.78	61.43
	Wa/Id Both	9,183.80	5,804.42	223.77	9,046.88	5,848.87	225.38	8,571.30	5,681.25	225.83
	Wa/Id GTN	1,267.95	800.66	30.86	1,250.27	806.83	31.09	1,185.84	783.76	31.15
	Wa/Id NWP	5,397.62	3,403.11	131.18	5,331.25	3,429.67	132.12	5,065.88	3,331.91	132.38
	Wa/Id Sub-Total	15,849.36	10,008.18	385.81	15,628.40	10,085.38	388.59	14,823.03	9,796.92	389.36
	Low Case Total	21,142.76	13,462.86	449.90	20,900.38	13,544.53	451.87	19,933.03	13,160.70	450.80

Appendix 3.10 - C
Annual Demand by Class(Mdth/d)
(Net of DSM Savings)

Updated Expected with Low Elasticity

Area	2012-2013: Residential	2012-2013: Commercial	2012-2013: Ind FirmSale	2013-2014: Residential	2013-2014: Commercial	2013-2014: Ind FirmSale	2014-2015: Residential	2014-2015: Commercial	2014-2015: Ind FirmSale
Klam Falls	860.15	546.97	6.42	870.95	552.55	6.42	885.02	559.43	6.42
La Grande	459.60	271.96	29.88	460.32	269.63	29.70	460.20	266.45	29.13
Medford GTN	2,288.32	1,397.75	5.92	2,348.33	1,405.50	5.91	2,409.42	1,412.18	5.89
Medford NWP	1,028.11	627.95	2.66	1,055.08	631.42	2.65	1,082.53	634.42	2.65
Roseburg	854.84	701.39	16.60	891.07	712.84	16.52	927.64	727.25	16.43
OR Sub-Total	5,491.02	3,546.04	61.48	5,625.75	3,571.95	61.19	5,764.82	3,599.72	60.52
Wa/Id Both	8,919.73	6,032.46	228.89	8,957.04	6,155.38	231.33	9,003.54	6,283.42	233.96
Wa/Id GTN	1,235.05	832.24	31.57	1,241.35	849.24	31.91	1,248.92	866.95	32.27
Wa/Id NWP	5,283.41	3,538.29	134.17	5,318.55	3,610.84	135.60	5,359.09	3,686.39	137.15
Wa/Id Sub-Total	15,438.19	10,402.99	394.63	15,516.94	10,615.47	398.84	15,611.55	10,836.76	403.38
Expected Case Total	20,929.22	13,949.03	456.11	21,142.70	14,187.41	460.03	21,376.37	14,436.48	463.89

High Growth & Low Price

Area	2012-2013: Residential	2012-2013: Commercial	2012-2013: Ind FirmSale	2013-2014: Residential	2013-2014: Commercial	2013-2014: Ind FirmSale	2014-2015: Residential	2014-2015: Commercial	2014-2015: Ind FirmSale
Klam Falls	875.05	575.13	6.42	896.03	586.20	6.42	919.41	597.94	6.42
La Grande	461.12	272.81	29.93	465.48	271.38	29.75	468.89	268.91	29.19
Medford GTN	2,363.03	1,430.93	6.47	2,462.72	1,448.30	6.46	2,565.08	1,464.44	6.75
Medford NWP	1,061.68	642.86	2.91	1,106.47	650.66	2.90	1,152.47	657.90	3.03
Roseburg	898.13	742.15	16.62	956.31	762.49	16.53	1,014.58	787.00	16.44
OR Sub-Total	5,659.01	3,663.88	62.35	5,887.00	3,719.03	62.06	6,120.43	3,776.20	61.83
Wa/Id Both	9,358.48	6,404.22	238.76	9,518.90	6,604.19	242.70	9,688.99	6,809.27	246.83
Wa/Id GTN	1,295.57	883.52	32.93	1,318.85	911.14	33.48	1,343.47	939.48	34.05
Wa/Id NWP	5,540.61	3,756.22	139.96	5,647.92	3,873.93	142.27	5,760.90	3,994.65	144.69
Wa/Id Sub-Total	16,194.66	11,043.96	411.66	16,485.68	11,389.26	418.45	16,793.36	11,743.40	425.57
High Case Total	21,853.67	14,707.84	474.01	22,372.68	15,108.29	480.52	22,913.79	15,519.60	487.39

Low Growth & High Price

Area	2012-2013: Residential	2012-2013: Commercial	2012-2013: Ind FirmSale	2013-2014: Residential	2013-2014: Commercial	2013-2014: Ind FirmSale	2014-2015: Residential	2014-2015: Commercial	2014-2015: Ind FirmSale
Klam Falls	777.02	488.89	6.42	773.37	486.97	6.42	777.28	488.73	6.42
La Grande	422.34	249.14	28.27	417.57	244.97	28.10	414.16	241.44	27.58
Medford GTN	2,063.11	1,295.27	5.78	2,071.13	1,288.19	5.74	2,089.07	1,285.56	5.72
Medford NWP	926.93	581.91	2.60	930.54	578.72	2.58	938.60	577.53	2.57
Roseburg	762.84	641.02	16.10	772.90	641.40	16.01	786.74	645.80	15.92
OR Sub-Total	4,952.24	3,256.22	59.16	4,965.51	3,240.25	58.84	5,005.86	3,239.06	58.22
Wa/Id Both	8,102.51	5,508.10	225.02	7,973.03	5,530.72	226.29	7,894.21	5,582.25	227.33
Wa/Id GTN	1,122.33	759.92	31.04	1,105.63	763.08	31.21	1,095.91	770.23	31.36
Wa/Id NWP	4,804.35	3,230.90	131.91	4,741.72	3,244.66	132.65	4,708.80	3,275.36	133.27
Wa/Id Sub-Total	14,029.19	9,498.91	387.97	13,820.38	9,538.46	390.16	13,698.92	9,627.84	391.96
Low Case Total	18,981.43	12,755.14	447.13	18,785.89	12,778.71	449.00	18,704.78	12,866.91	450.17

Appendix 3.10 - C
Annual Demand by Class(Mdth/d)
(Net of DSM Savings)

Updated Expected with Low Elasticity	Area	2015-2016: Residential	2015-2016: Commercial	2015-2016: Ind FirmSale	2016-2017: Residential	2016-2017: Commercial	2016-2017: Ind FirmSale	2017-2018: Residential	2017-2018: Commercial	2017-2018: Ind FirmSale
	Klam Falls	886.14	560.09	6.44	898.98	566.17	6.42	912.13	572.59	6.42
	La Grande	455.10	260.47	28.38	454.97	257.44	28.16	454.75	254.42	27.65
	Medford GTN	2,435.10	1,401.42	5.85	2,490.16	1,404.47	5.81	2,538.96	1,407.26	5.78
	Medford NWP	1,094.07	629.58	2.63	1,118.82	630.95	2.61	1,140.75	632.19	2.60
	Roseburg	952.10	732.77	16.25	985.77	742.86	16.19	1,017.57	749.81	16.06
	OR Sub-Total	5,822.51	3,584.33	59.54	5,948.70	3,601.88	59.19	6,064.16	3,616.29	58.52
	Wa/Id Both	8,865.92	6,301.18	236.66	8,865.11	6,394.75	237.84	8,889.06	6,506.32	240.24
	Wa/Id GTN	1,231.04	869.44	32.64	1,232.01	882.38	32.81	1,236.40	897.81	33.14
	Wa/Id NWP	5,291.05	3,697.27	138.73	5,303.05	3,752.59	139.42	5,329.53	3,818.47	140.83
	Wa/Id Sub-Total	15,388.01	10,867.89	408.03	15,400.18	11,029.73	410.07	15,454.99	11,222.60	414.20
	Expected Case Total	21,210.52	14,452.22	467.57	21,348.88	14,631.60	469.26	21,519.14	14,838.88	472.72

High Growth & Low Price	Area	2015-2016: Residential	2015-2016: Commercial	2015-2016: Ind FirmSale	2016-2017: Residential	2016-2017: Commercial	2016-2017: Ind FirmSale	2017-2018: Residential	2017-2018: Commercial	2017-2018: Ind FirmSale
	Klam Falls	943.17	610.42	6.44	965.45	621.34	6.42	987.99	632.72	6.42
	La Grande	473.71	267.24	28.83	476.95	264.86	28.60	479.97	262.39	28.08
	Medford GTN	2,666.98	1,479.20	7.02	2,761.83	1,490.53	6.97	2,847.35	1,501.27	7.27
	Medford NWP	1,198.25	664.52	3.15	1,240.87	669.61	3.13	1,279.30	674.43	3.27
	Roseburg	1,073.36	809.83	16.39	1,128.43	828.52	16.33	1,180.96	842.51	16.20
	OR Sub-Total	6,355.47	3,831.21	61.82	6,573.52	3,874.85	61.46	6,775.57	3,913.32	61.25
	Wa/Id Both	9,819.49	6,987.82	251.22	9,937.76	7,155.26	253.41	10,083.21	7,343.40	257.09
	Wa/Id GTN	1,362.57	964.15	34.65	1,379.96	987.28	34.95	1,401.11	1,013.27	35.46
	Wa/Id NWP	5,850.04	4,099.79	147.26	5,931.85	4,198.41	148.55	6,029.55	4,309.17	150.71
	Wa/Id Sub-Total	17,032.10	12,051.76	433.13	17,249.57	12,340.95	436.92	17,513.86	12,665.84	443.25
	High Case Total	23,387.57	15,882.97	494.95	23,823.09	16,215.81	498.38	24,289.44	16,579.16	504.50

Low Growth & High Price	Area	2015-2016: Residential	2015-2016: Commercial	2015-2016: Ind FirmSale	2016-2017: Residential	2016-2017: Commercial	2016-2017: Ind FirmSale	2017-2018: Residential	2017-2018: Commercial	2017-2018: Ind FirmSale
	Klam Falls	781.44	490.88	6.44	784.41	492.02	6.42	787.83	493.38	6.42
	La Grande	412.06	238.66	27.25	408.73	235.22	27.04	405.45	231.79	26.56
	Medford GTN	2,106.31	1,282.46	5.72	2,121.24	1,277.48	5.68	2,133.25	1,272.62	5.66
	Medford NWP	946.36	576.13	2.57	953.07	573.89	2.55	958.47	571.71	2.54
	Roseburg	801.30	650.15	15.87	813.48	651.97	15.82	824.49	652.25	15.70
	OR Sub-Total	5,047.47	3,238.28	57.85	5,080.92	3,230.58	57.52	5,109.50	3,221.75	56.88
	Wa/Id Both	7,785.80	5,613.23	229.22	7,670.51	5,636.80	229.43	7,577.46	5,675.64	230.44
	Wa/Id GTN	1,082.06	774.55	31.62	1,067.24	777.84	31.65	1,055.49	783.24	31.78
	Wa/Id NWP	4,657.88	3,294.00	134.37	4,602.77	3,308.28	134.50	4,560.66	3,331.51	135.08
	Wa/Id Sub-Total	13,525.73	9,681.78	395.20	13,340.51	9,722.91	395.58	13,193.61	9,790.39	397.30
	Low Case Total	18,573.20	12,920.06	453.05	18,421.44	12,953.49	453.09	18,303.10	13,012.14	454.18

Appendix 3.10 - C
Annual Demand by Class(Mdth/d)
(Net of DSM Savings)

Updated Expected with Low Elasticity	Area	2018-2019: Residential	2018-2019: Commercial	2018-2019: Ind FirmSale	2019-2020: Residential	2019-2020: Commercial	2019-2020: Ind FirmSale	2020-2021: Residential	2020-2021: Commercial	2020-2021: Ind FirmSale
	Klam Falls	924.10	578.46	6.42	938.78	586.01	6.44	952.82	592.67	6.42
	La Grande	454.58	251.44	27.12	458.25	250.72	27.13	462.18	250.16	26.94
	Medford GTN	2,579.60	1,407.76	5.77	2,637.32	1,418.88	5.76	2,692.74	1,427.48	5.74
	Medford NWP	1,159.01	632.41	2.59	1,184.95	637.40	2.59	1,209.85	641.26	2.58
	Roseburg	1,050.63	756.87	15.97	1,085.94	765.94	15.93	1,121.17	774.30	15.86
	OR Sub-Total	6,167.92	3,626.95	57.86	6,305.24	3,658.96	57.85	6,438.77	3,685.88	57.53
	Wa/Id Both	8,923.16	6,624.82	243.55	8,984.21	6,762.06	245.48	9,053.86	6,890.56	247.17
	Wa/Id GTN	1,242.19	914.20	33.59	1,251.72	933.17	33.86	1,262.32	950.94	34.09
	Wa/Id NWP	5,362.05	3,888.40	142.77	5,410.56	3,969.34	143.90	5,462.87	4,045.13	144.89
	Wa/Id Sub-Total	15,527.39	11,427.42	419.92	15,646.49	11,664.58	423.24	15,779.05	11,886.63	426.16
	Expected Case Total	21,695.31	15,054.37	477.78	21,951.73	15,323.53	481.09	22,217.82	15,572.50	483.69

High Growth & Low Price	Area	2018-2019: Residential	2018-2019: Commercial	2018-2019: Ind FirmSale	2019-2020: Residential	2019-2020: Commercial	2019-2020: Ind FirmSale	2020-2021: Residential	2020-2021: Commercial	2020-2021: Ind FirmSale
	Klam Falls	1,009.17	643.40	6.42	1,033.29	655.97	6.44	1,056.73	667.53	6.42
	La Grande	482.98	260.03	27.54	490.04	259.92	27.55	497.37	260.02	27.35
	Medford GTN	2,921.39	1,509.09	7.49	3,014.06	1,528.88	7.60	3,104.06	1,545.87	7.96
	Medford NWP	1,312.57	677.94	3.37	1,354.20	686.83	3.42	1,394.65	694.45	3.58
	Roseburg	1,234.76	856.13	16.10	1,290.96	871.97	16.06	1,347.01	887.02	16.00
	OR Sub-Total	6,960.87	3,946.59	60.92	7,182.55	4,003.58	61.06	7,399.82	4,054.89	61.30
	Wa/Id Both	10,239.78	7,539.50	262.20	10,428.84	7,758.21	265.15	10,627.55	7,967.57	267.90
	Wa/Id GTN	1,423.79	1,040.36	36.17	1,450.98	1,070.57	36.57	1,479.38	1,099.49	36.95
	Wa/Id NWP	6,133.86	4,424.60	153.71	6,257.42	4,553.29	155.43	6,385.38	4,676.48	157.05
	Wa/Id Sub-Total	17,797.44	13,004.46	452.07	18,137.24	13,382.07	457.15	18,492.31	13,743.53	461.90
	High Case Total	24,758.30	16,951.05	512.99	25,319.79	17,385.65	518.21	25,892.13	17,798.42	523.21

Low Growth & High Price	Area	2018-2019: Residential	2018-2019: Commercial	2018-2019: Ind FirmSale	2019-2020: Residential	2019-2020: Commercial	2019-2020: Ind FirmSale	2020-2021: Residential	2020-2021: Commercial	2020-2021: Ind FirmSale
	Klam Falls	790.24	494.34	6.42	795.07	496.79	6.44	799.29	498.46	6.42
	La Grande	402.29	228.45	26.06	402.54	227.13	26.07	402.96	225.89	25.89
	Medford GTN	2,140.42	1,266.06	5.64	2,162.54	1,268.56	5.64	2,182.72	1,268.79	5.61
	Medford NWP	961.70	568.75	2.53	971.64	569.87	2.53	980.71	569.96	2.52
	Roseburg	836.74	652.94	15.61	850.97	655.52	15.57	865.17	657.36	15.51
	OR Sub-Total	5,131.39	3,210.53	56.26	5,182.76	3,217.87	56.25	5,230.85	3,220.45	55.96
	Wa/Id Both	7,493.10	5,720.23	232.05	7,430.45	5,780.09	233.39	7,374.93	5,831.44	233.78
	Wa/Id GTN	1,044.94	789.43	32.01	1,037.41	797.73	32.19	1,030.75	804.85	32.25
	Wa/Id NWP	4,523.74	3,358.13	136.03	4,499.74	3,393.70	136.82	4,478.67	3,424.27	137.05
	Wa/Id Sub-Total	13,061.79	9,867.79	400.08	12,967.60	9,971.51	402.41	12,884.34	10,060.56	403.08
	Low Case Total	18,193.17	13,078.33	456.35	18,150.36	13,189.39	458.66	18,115.19	13,281.01	459.03

Appendix 3.10 - C
Annual Demand by Class(Mdth/d)
(Net of DSM Savings)

Updated Expected with Low Elasticity

Area	2021-2022: Residential	2021-2022: Commercial	2021-2022: Ind FirmSale	2022-2023: Residential	2022-2023: Commercial	2022-2023: Ind FirmSale	2023-2024: Residential	2023-2024: Commercial	2023-2024: Ind FirmSale
Klam Falls	968.29	600.40	6.42	983.85	609.08	6.42	1,000.48	619.04	6.44
La Grande	467.00	250.12	26.94	471.86	250.57	26.94	476.71	251.16	26.75
Medford GTN	2,744.34	1,435.09	5.74	2,803.29	1,447.72	5.73	2,862.77	1,461.37	5.74
Medford NWP	1,233.04	644.68	2.58	1,259.53	650.35	2.58	1,286.26	656.47	2.58
Roseburg	1,156.63	783.40	15.85	1,194.23	794.40	15.84	1,231.39	808.55	15.82
OR Sub-Total	6,569.30	3,713.69	57.52	6,712.77	3,752.12	57.51	6,857.61	3,796.60	57.32
Wa/Id Both	9,130.54	7,022.74	249.06	9,214.64	7,156.65	251.52	9,312.80	7,299.88	253.34
Wa/Id GTN	1,273.90	969.21	34.35	1,286.50	987.72	34.69	1,301.05	1,007.52	34.94
Wa/Id NWP	5,519.34	4,123.08	146.00	5,580.18	4,202.05	147.44	5,649.32	4,286.49	148.51
Wa/Id Sub-Total	15,923.78	12,115.04	429.41	16,081.33	12,346.43	433.65	16,263.17	12,593.89	436.79
Expected Case Total	22,493.07	15,828.73	486.93	22,794.09	16,098.55	491.16	23,120.78	16,390.49	494.11

High Growth & Low Price

Area	2021-2022: Residential	2021-2022: Commercial	2021-2022: Ind FirmSale	2022-2023: Residential	2022-2023: Commercial	2022-2023: Ind FirmSale	2023-2024: Residential	2023-2024: Commercial	2023-2024: Ind FirmSale
Klam Falls	1,081.81	680.33	6.42	1,106.78	693.97	6.42	1,133.01	709.13	6.44
La Grande	505.62	260.63	27.35	513.94	261.67	27.35	522.19	262.98	27.15
Medford GTN	3,189.26	1,561.50	8.03	3,282.96	1,582.48	8.21	3,377.05	1,604.17	8.57
Medford NWP	1,432.93	701.47	3.61	1,475.03	710.89	3.69	1,517.31	720.63	3.85
Roseburg	1,403.15	902.88	15.98	1,461.84	920.70	15.97	1,519.83	943.01	15.95
OR Sub-Total	7,612.76	4,106.81	61.39	7,840.55	4,169.71	61.64	8,069.39	4,239.92	61.96
Wa/Id Both	10,835.33	8,180.71	270.78	11,052.90	8,395.55	274.57	11,286.95	8,621.07	277.07
Wa/Id GTN	1,509.04	1,128.93	37.35	1,540.06	1,158.61	37.87	1,573.35	1,189.76	38.22
Wa/Id NWP	6,518.70	4,801.89	158.73	6,657.78	4,928.30	160.95	6,806.58	5,060.98	162.42
Wa/Id Sub-Total	18,863.07	14,111.53	466.86	19,250.74	14,482.47	473.39	19,666.88	14,871.81	477.71
High Case Total	26,475.82	18,218.34	528.24	27,091.29	18,652.17	535.03	27,736.27	19,111.73	539.68

Low Growth & High Price

Area	2021-2022: Residential	2021-2022: Commercial	2021-2022: Ind FirmSale	2022-2023: Residential	2022-2023: Commercial	2022-2023: Ind FirmSale	2023-2024: Residential	2023-2024: Commercial	2023-2024: Ind FirmSale
Klam Falls	804.85	501.03	6.42	810.42	504.62	6.42	816.93	509.37	6.44
La Grande	404.20	225.23	25.89	405.50	224.95	25.89	406.82	224.95	25.71
Medford GTN	2,200.16	1,268.44	5.61	2,223.59	1,272.68	5.61	2,247.71	1,278.29	5.62
Medford NWP	988.55	569.80	2.52	999.09	571.70	2.52	1,009.93	574.22	2.52
Roseburg	879.75	659.97	15.50	896.01	664.29	15.49	912.10	670.47	15.47
OR Sub-Total	5,277.52	3,224.47	55.94	5,334.61	3,238.25	55.93	5,393.50	3,257.31	55.76
Wa/Id Both	7,324.69	5,886.57	234.70	7,279.57	5,943.47	236.04	7,245.97	6,008.31	237.15
Wa/Id GTN	1,024.82	812.50	32.37	1,019.60	820.39	32.56	1,015.97	829.37	32.71
Wa/Id NWP	4,460.74	3,457.05	137.58	4,445.83	3,490.88	138.37	4,437.73	3,529.36	139.02
Wa/Id Sub-Total	12,810.24	10,156.13	404.66	12,745.00	10,254.74	406.97	12,699.68	10,367.04	408.88
Low Case Total	18,087.76	13,380.60	460.60	18,079.61	13,492.99	462.90	18,093.17	13,624.35	464.64

Appendix 3.10 - C
Annual Demand by Class(Mdth/d)
(Net of DSM Savings)

Updated Expected with Low Elasticity	Area	2024-2025: Residential	2024-2025: Commercial	2024-2025: Ind FirmSale	2025-2026: Residential	2025-2026: Commercial	2025-2026: Ind FirmSale	2026-2027: Residential	2026-2027: Commercial	2026-2027: Ind FirmSale
	Klam Falls	1,015.41	627.69	6.42	1,030.73	637.06	6.42	1,046.55	646.68	6.42
	La Grande	481.01	251.62	26.65	485.44	252.24	26.59	490.18	253.03	26.59
	Medford GTN	2,917.30	1,471.68	5.72	2,969.65	1,483.60	5.71	3,025.07	1,497.27	5.70
	Medford NWP	1,310.76	661.10	2.57	1,334.29	666.45	2.57	1,359.19	672.59	2.56
	Roseburg	1,261.35	818.87	15.78	1,292.96	830.76	15.77	1,318.09	839.53	15.68
	OR Sub-Total	6,985.83	3,830.95	57.13	7,113.06	3,870.10	57.06	7,239.08	3,909.10	56.95
	Wa/Id Both	9,389.75	7,428.92	254.99	9,489.16	7,577.13	256.92	9,573.54	7,713.18	259.37
	Wa/Id GTN	1,312.62	1,025.33	35.17	1,327.32	1,045.78	35.44	1,339.88	1,064.54	35.78
	Wa/Id NWP	5,705.43	4,362.52	149.47	5,775.05	4,449.76	150.61	5,835.14	4,529.84	152.05
	Wa/Id Sub-Total	16,407.81	12,816.76	439.63	16,591.53	13,072.66	442.96	16,748.55	13,307.57	447.20
	Expected Case Total	23,393.64	16,647.72	496.76	23,704.59	16,942.76	500.02	23,987.64	17,216.67	504.15

High Growth & Low Price	Area	2024-2025: Residential	2024-2025: Commercial	2024-2025: Ind FirmSale	2025-2026: Residential	2025-2026: Commercial	2025-2026: Ind FirmSale	2026-2027: Residential	2026-2027: Commercial	2026-2027: Ind FirmSale
	Klam Falls	1,157.34	722.64	6.42	1,182.07	736.98	6.42	1,207.37	751.54	6.42
	La Grande	529.82	264.09	27.06	537.59	265.31	26.99	545.69	266.77	26.99
	Medford GTN	3,465.24	1,621.95	8.57	3,549.65	1,641.46	8.80	3,637.30	1,662.87	9.12
	Medford NWP	1,556.94	728.61	3.85	1,594.87	737.37	3.95	1,634.25	746.99	4.10
	Roseburg	1,567.62	960.24	15.91	1,616.99	978.91	15.90	1,658.04	993.91	15.81
	OR Sub-Total	8,276.96	4,297.53	61.81	8,481.16	4,360.03	62.06	8,682.64	4,422.09	62.44
	Wa/Id Both	11,494.79	8,831.27	279.83	11,729.39	9,064.37	282.83	11,942.93	9,282.58	286.77
	Wa/Id GTN	1,602.97	1,218.76	38.60	1,636.32	1,250.91	39.01	1,666.69	1,281.01	39.55
	Wa/Id NWP	6,939.42	5,184.59	164.04	7,088.29	5,321.59	165.80	7,224.09	5,449.83	168.11
	Wa/Id Sub-Total	20,037.17	15,234.62	482.47	20,454.00	15,636.87	487.63	20,833.72	16,013.42	494.43
	High Case Total	28,314.14	19,532.15	544.27	28,935.16	19,996.90	549.70	29,516.35	20,435.51	556.87

Low Growth & High Price	Area	2024-2025: Residential	2024-2025: Commercial	2024-2025: Ind FirmSale	2025-2026: Residential	2025-2026: Commercial	2025-2026: Ind FirmSale	2026-2027: Residential	2026-2027: Commercial	2026-2027: Ind FirmSale
	Klam Falls	822.03	512.85	6.42	827.49	517.21	6.42	833.34	521.67	6.42
	La Grande	407.66	224.72	25.62	408.65	224.75	25.56	409.90	224.85	25.56
	Medford GTN	2,267.90	1,281.12	5.59	2,287.52	1,285.50	5.59	2,309.91	1,291.37	5.58
	Medford NWP	1,019.00	575.49	2.51	1,027.82	577.45	2.51	1,037.89	580.08	2.51
	Roseburg	924.00	674.12	15.43	937.65	679.33	15.43	946.78	682.20	15.34
	OR Sub-Total	5,440.60	3,268.30	55.58	5,489.14	3,284.24	55.51	5,537.82	3,300.16	55.41
	Wa/Id Both	7,196.06	6,060.04	237.72	7,164.23	6,127.26	238.75	7,123.30	6,184.92	240.10
	Wa/Id GTN	1,010.04	836.52	32.79	1,006.64	845.79	32.93	1,001.92	853.75	33.12
	Wa/Id NWP	4,419.48	3,560.07	139.35	4,412.16	3,599.84	139.96	4,398.79	3,633.96	140.75
	Wa/Id Sub-Total	12,625.59	10,456.62	409.87	12,583.03	10,572.89	411.64	12,524.01	10,672.63	413.96
	Low Case Total	18,066.18	13,724.93	465.44	18,072.17	13,857.13	467.15	18,061.83	13,972.79	469.37

Appendix 3.10 - C
Annual Demand by Class(Mdth/d)
(Net of DSM Savings)

Updated Expected with Low Elasticity	Area	2027-2028: Residential	2027-2028: Commercial	2027-2028: Ind FirmSale	2028-2029: Residential	2028-2029: Commercial	2028-2029: Ind FirmSale
	Klam Falls	1,062.32	656.54	6.44	1,076.89	665.21	6.42
	La Grande	495.65	254.18	26.60	498.85	254.18	26.41
	Medford GTN	3,081.87	1,512.35	5.71	3,127.00	1,521.13	5.69
	Medford NWP	1,384.71	679.36	2.57	1,405.00	683.29	2.56
	Roseburg	1,348.11	851.12	15.67	1,374.87	862.79	15.60
	OR Sub-Total	7,372.66	3,953.55	56.99	7,482.62	3,986.60	56.67
	Wa/Id Both	9,700.08	7,858.91	261.92	9,812.47	7,989.85	263.75
	Wa/Id GTN	1,358.06	1,084.65	36.13	1,374.28	1,102.71	36.38
	Wa/Id NWP	5,917.66	4,615.61	153.54	5,991.76	4,692.70	154.61
	Wa/Id Sub-Total	16,975.80	13,559.18	451.59	17,178.50	13,785.27	454.74
	Expected Case Total	24,348.47	17,512.73	508.57	24,661.13	17,771.87	511.41

High Growth & Low Price	Area	2027-2028: Residential	2027-2028: Commercial	2027-2028: Ind FirmSale	2028-2029: Residential	2028-2029: Commercial	2028-2029: Ind FirmSale
	Klam Falls	1,232.60	766.53	6.44	1,256.45	780.04	6.42
	La Grande	554.59	268.59	27.00	560.94	269.16	26.81
	Medford GTN	3,726.48	1,685.86	9.14	3,801.49	1,701.79	9.37
	Medford NWP	1,674.32	757.31	4.10	1,708.03	764.46	4.21
	Roseburg	1,705.18	1,012.19	15.80	1,748.17	1,031.34	15.72
	OR Sub-Total	8,893.18	4,490.48	62.48	9,075.08	4,546.78	62.53
	Wa/Id Both	12,200.19	9,512.24	290.44	12,439.23	9,722.62	293.32
	Wa/Id GTN	1,702.90	1,312.69	40.06	1,736.59	1,341.71	40.46
	Wa/Id NWP	7,383.25	5,584.81	170.26	7,531.58	5,708.46	171.94
	Wa/Id Sub-Total	21,286.34	16,409.75	500.77	21,707.40	16,772.80	505.72
	High Case Total	30,179.53	20,900.22	563.24	30,782.48	21,319.58	568.25

Low Growth & High Price	Area	2027-2028: Residential	2027-2028: Commercial	2027-2028: Ind FirmSale	2028-2029: Residential	2028-2029: Commercial	2028-2029: Ind FirmSale
	Klam Falls	839.19	526.38	6.44	844.01	530.16	6.42
	La Grande	411.78	225.35	25.57	411.78	224.72	25.39
	Medford GTN	2,333.45	1,298.44	5.59	2,348.17	1,300.10	5.57
	Medford NWP	1,048.47	583.25	2.51	1,055.09	583.99	2.50
	Roseburg	959.48	687.29	15.33	969.85	691.67	15.26
	OR Sub-Total	5,592.36	3,320.72	55.45	5,628.90	3,330.63	55.15
	Wa/Id Both	7,123.00	6,250.75	241.61	7,112.18	6,305.64	242.15
	Wa/Id GTN	1,002.60	862.83	33.33	1,001.82	870.41	33.40
	Wa/Id NWP	4,406.96	3,672.90	141.63	4,408.83	3,705.41	141.95
	Wa/Id Sub-Total	12,532.56	10,786.49	416.57	12,522.83	10,881.46	417.50
	Low Case Total	18,124.92	14,107.21	472.02	18,151.73	14,212.08	472.65

APPENDIX 4.1

DSM IMPLEMENTATION AND OPERATIONS

APPENDIX 4.1 – DSM IMPLEMENTATION & OPERATIONS

AVISTA DSM COMMITMENT

Avista recognizes our obligation to meet the resource needs of customers in the most cost-effective manner. The delivery of conservation programs is anticipated to represent an increasing portion of the optimal resource portfolio. The IRP process is an opportunity to comprehensively review the conservation program portfolio and make necessary revisions to daily DSM operations and longer-term implementation plans in order to meet those commitments in the years to follow.

This document summarizes a broad evaluation of applicable conservation measures and identifies those worthy of testing against all other supply-side resources to assist us in making decisions about which measures would be suitable to carry forward into program development and implementation.

Through our TAC process we solicited comments from key stakeholders regarding the selection, characterization and testing of conservation measures within the IRP process. After much discussion and some revision, the general consensus of those stakeholders was that this approach was sufficient to represent conservation opportunities within the IRP.

There are concerns about our South Division due to the economic condition and high levels of unemployment that could constrain participation. We remain open to alternative approaches to overcoming those market barriers to include enhanced outreach efforts, revised incentives, and innovative marketing of conservation programs and cooperative arrangements with other agents in the market, with particular attention to other natural gas utilities, the Energy Trust of Oregon and regional market transformation efforts with an interest in natural gas efficiency.

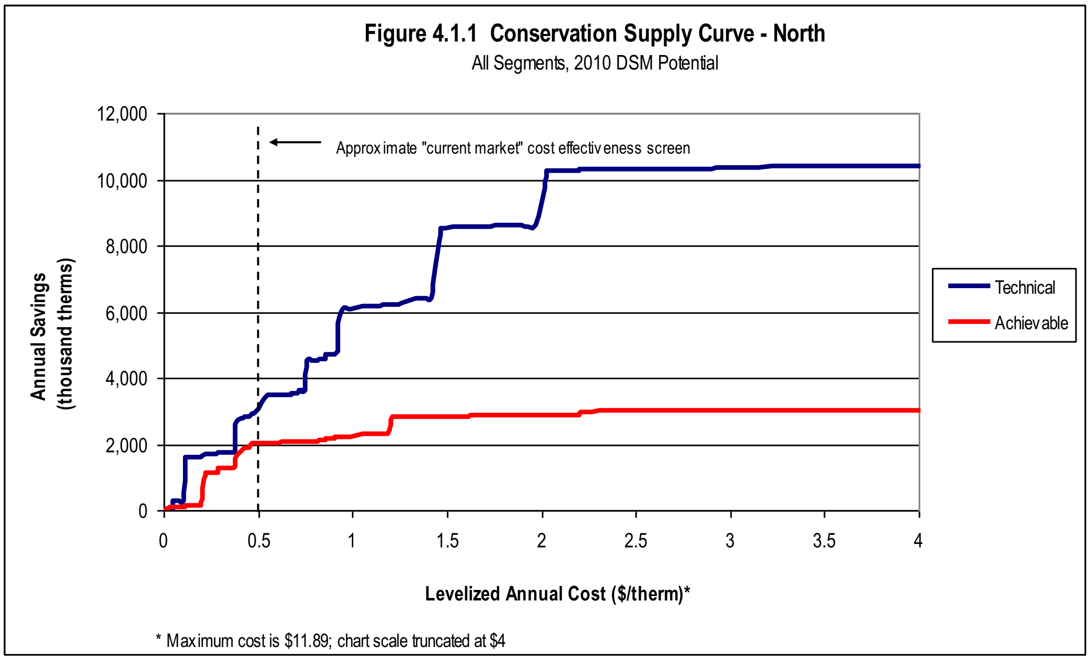
Additionally, we are committed to maintaining a collaborative relationship with all stakeholders who may contribute to the improvement of DSM efforts as programs are further developed and launched. We continue to improve the management of these programs through development of additional metrics, improved reporting and benchmarking for determining the regulatory prudence of these programs.

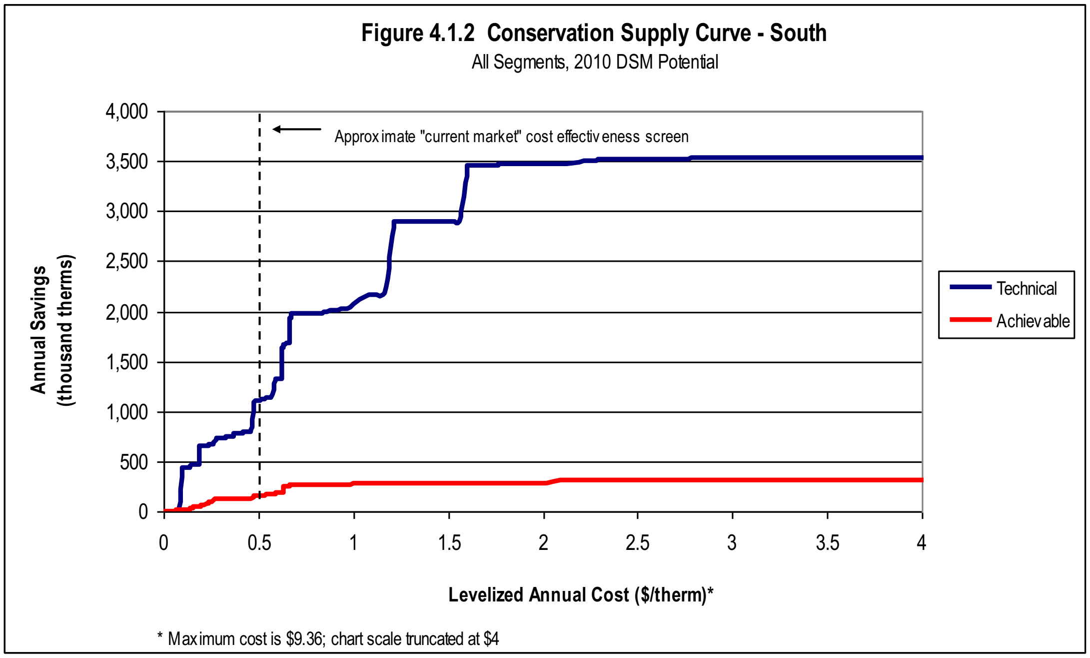
Avista recognizes that acquiring all cost-effective conservation potential is not limited by the therm acquisition goals established in this IRP. The implementation of the results of this planning will be sufficiently flexible to realize opportunities even if they are well in excess of expectations. Human and financial resources will be made available to the extent necessary to achieve the cost-effective potential without regard to those goals.

TECHNICAL AND ACHIEVABLE POTENTIAL

In 2005, Avista contracted with RLW Analytics, a conservation consultant, to independently identify and analyze the potential energy savings for our Oregon service territories. The methodology from this study was extrapolated to Washington and Idaho and served as the initial basis for determining conservation technical potential for all of Avista's natural gas service territories. The energy savings data for weather-sensitive measures were adjusted to incorporate local HDD data appropriate to each geographic area. Avista DSM engineers, program implementers and analysts also reviewed the RLW estimates of incremental measure costs, measure lives, energy savings, and other inputs and assumptions making adjustments when knowledge of local factors differed from the more generalized assumptions used in the study. Since 2005, we have made adjustments and updates to incorporate new information regarding measure cost and energy savings, and have augmented the study with additional measures not previously evaluated.

Figures 4.1.1 and 4.1.2 depict supply curves for technical and achievable potential for our North and South divisions.





Avista's achievable potential as a percentage of technical potential appears to be lower than other regional utilities. However, our actual per customer savings acquired compare favorably with other regional utilities. Unlike other regional utilities that have selected an overall percentage of their technical potential to estimate achievable potential, Avista analyzes each measure's likely installation rate to establish measure by measure achievable potential. Engineers and program implementers begin their evaluation with the number of customers in a division broken down by the estimated percentage that is single family, multifamily or manufactured homes. The applications are evaluated based on how many have or could have access to an application in their home or facility and, finally, how many applications would be replaced with a higher efficiency option over the standard option over the twenty year horizon. This methodology used to develop achievable potential tracks with our actual results and is comparable with other regional utilities.

For perspective, we indicate a cost effectiveness screen of $0.50 per therm based on an approximate current market commodity cost of $5 per Dth. Around this level, Avista's achievable potential tracks much closer with the technical potential and is similar to other regional utilities.

We have tried to identify differences that create the large gap between our achievable potential and RLW's technical potential. We did not identify every difference but we did make changes to technical potential that we could support and document. Some examples were:

- The pre-rinse sprayer program was a one-time, non-recurring, non-residential program where Avista pursued installations of sprayers in all existing applications. Since these sprayers are now code, the savings will not recur. Therefore, we removed savings associated with pre-rinse sprayers from the RLW technical potential.
- The same technical potential was listed for all water heater applications, so it appears that RLW failed to consider the mutually exclusivity of the various types of water heaters. A

single-family residential customer typically only has one water heater application in their home. However, RLW included that same customer in the technical potential for tanked, tankless, and passive solar water heaters. We think this same issue may exist for other measures but we could not verify this, so an adjustment was made only to the water heaters technical potential.

- In the past, Oregon Staff has generally disapproved faucet aerators and low-flow showerheads as viable measures with demonstrable savings, so we removed the savings associated with these two measures.
- RLW included nearly 3,000 units of thermal vent dampers in a multi-family application. Based on our market knowledge, we felt this number of the entire population was overestimated and was more realistic at 1,000 units. This resulted in a decrease in technical potential of 54,000 therms.

While this is not a complete list of potential differences with RLW's estimate of technical potential, this concern should be resolved with a new external study of technical potential which we intend to pursue prior to completion of the 2011 IRP.

The following sections discuss Avista's DSM programs and how the IRP results are incorporated into DSM operations.

SOUTH DIVISION DSM PORTFOLIO

Avista's residential measures are available to approximately 84,000 customers (Avista Rate Schedule 410) with an annual consumption of 50.5 million therms. The commercial measures are available to nearly 11,200 mostly small-to-medium-sized customers (Avista Rate Schedules 420 and 424) with an annual consumption of approximately 32.3 million therms. The largest segment of qualified non-residential customers use natural gas for space, water heating and cooking with an average consumption of nearly 2,900 therms each.

The measures offer a mix of both currently cost effective and market transformation measures which are expected to be cost-effective over time. The combined residential and non-residential therm goal for 2010 is 326,314 and 324,314 for 2011. Details on individual measures such as measure life, levelized TRC, unit goal, and therm goal can be found in Appendix 4.2.

RESIDENTIAL SEGMENT

Avista's residential program consists of site specific and prescriptive measures and includes a mix of currently cost effective measures and market transformation measures which are expected to be cost-effective. The 2010 residential therm goal is 215,580 and 206,333 in 2011.

Avista's residential site specific program is primarily focused on cost effective shell measures. Changes made to the program in early 2007 include: higher incentive levels, removal of all non cost effective measures and requiring window upgrades to be included with at least one other major measure. We will consider additional enhancements as they are identified to increase program participation.

We also offer prescriptive incentives such as tankless water heaters, high-efficiency direct vent space heaters, external chimney dampers, programmable thermostats, high efficiency forced air furnaces and high efficiency tank water heaters.

In the majority of cases, tank water heaters are replaced on “burn out” with the high efficiency models costing, on average, $120 more than standard efficiency models. Product availability has gotten better, but continues to be an issue going forward. We believe that to affect the incremental cost and maintain availability, that high efficiency tank water heaters should be retained as a “market transformation” program in 2010 and 2011.

We also believe building a strong trade ally network is the best way to promote the acceptance of higher efficiency equipment. Our trade allies currently include HVAC dealers, plumbers, retailers, manufacturers, distributors along with builders and developers. Avista has also established relationships with groups such as the home builders association and landlord associations throughout its service territory.

NON-RESIDENTIAL SEGMENT

Prior to 2007, our non-residential measures were site-specific offerings only. In early 2007, Avista added several cost effective prescriptive measures such as high-efficiency space heating equipment, Energy Star gas fryers, Energy Star three pan gas steam cookers and high-efficiency gas rack ovens.

The non-residential therm acquisition goal for 2010 is 110,734 and 118,650 for 2011. Avista also expects to add new prescriptive measures in 2009. Measures being considered include cost effective shell measures and additional commercial kitchen measures. Measures with low achievable potential, technologies new to the marketplace or where natural gas is used for process will continue to be evaluated on a site specific basis.

We believe that by adding additional prescriptive measures, the program will be accessible by a greater number of customers, will be easier to manage at less cost and will result in higher participation levels in the small to medium sized customer segments. Measures not included in the prescriptive program will continue to be evaluated on a site specific basis.

Avista plans to increase efforts to identify cost effective, site specific opportunities with our larger non-residential customers. Resources will be reallocated to support this initiative.

In addition, we will continue to look for opportunities to work cooperatively with the ETO where site specific efficiency projects are identified. We will also work closely with local land-use planners and energy consultants on new non-residential projects to influence energy efficiency decisions during the design phase.

MEASURE DEVELOPMENT

Avista will continue to look at the “best fit” for program implementation. Implementation options could include a combined effort between Avista’s North and South divisions, additional staffing, Energy Trust of Oregon (ETO), trade partners, and if developed, regional transformation efforts through a natural gas Northwest Energy Efficiency Alliance (NEEA).

NORTH DIVISION DSM PORTFOLIO

Conservation measures have been offered to Washington and Idaho customers without interruption since 2001 and periodically prior to that time.

A non-binding external oversight group, the External Energy Efficiency (“Triple-E”) Board, has been established to provide guidance for the implementation of DSM measures. This board is provided with monthly and quarterly updates, convenes twice a year and receives a comprehensive annual evaluation of acquisition and cost-effectiveness.

Avista’s Rate Schedule 190 provides the regulatory guidelines for the implementation of DSM measures. This tariff prescribes a set of tiered, direct financial incentives, as illustrated in Table 4.1.1, based on the customer simple payback of the measure.

Table 4.1.1 - Natural Gas Efficiency Measures Incentive Levels

Simple Pay-back Period	Incentive Level ($/first year therm)
1 to 2 years	$2.00
2 to 4 years	$2.50
4 to 6 years	$3.00
Over 6 years	$3.50

Exceptions to these tiered incentives allow us flexibility to respond to unexpected or unique opportunities. This flexibility includes an additional set of tiered incentives, permitting higher incentives for the development of new technologies and market transformation efforts.

The original 2001 Schedule 190 tariff established an annual goal of 240,000 first-year therms. Almost immediately upon launch of the renewed gas-efficiency program, commodity-driven escalations in retail rates during the 2001 Western energy crisis drove acquisition well beyond these levels. Initial concerns that this higher level of acquisition may be unsustainable proved to be unfounded. A reassessment of the market in the 2007 Gas IRP process resulted in the establishment of a 1,425,070 annual therm goal for 2008 and 1,581,828 for 2009. The 2008 goal has proven to be achievable. Whether or not the 2009 goal is achievable remains to be seen as customers react within a struggling economy.

Beginning in 2015, carbon mitigation and other cost adders we model lead to significantly increased avoided cost in later years. The corresponding increased measure selection by our model results in preliminary 2010 and 2011 savings goals which will be a challenge. Current declining retail rates for our customers make it difficult to influence them to react to forecasted price increases. Alternate scenarios modeled without the adders result in goals more inline with historical IRP goals.

It is possible that detailed implementation planning will result in the recommendation for revisions to the incentive levels, caps and applicable markets, and technologies as part of an overall strategy to meet the commitments made for increased long-term resource acquisition identified within this IRP.

Our conservation offerings within our North Division are accompanied by a mix of electric measures. In 2008 the natural gas share of the total BTU savings from the overall portfolio was 88 percent. This share shifts over time depending on resource opportunities, retail rates, technical advancements and customer interest. DSM implementation efforts within the North Division are further subdivided into three different portfolios; (1) the non-residential portfolio, (2) the residential portfolio and (3) the low-income residential portfolio. The approaches to the implementation of these three portfolios differ significantly in recognition of the differences in these market segments.

NON-RESIDENTIAL SEGMENT

While the non-residential portfolio has access to prescriptive measures, it is mainly characterized by its non-prescriptive approach to this market which provides incentives for any cost-effective project. Financial incentives are offered for projects based on the tiered incentive structure described above. This approach ensures that the unique operating characteristics of commercial and industrial customers are recognized. Prescriptive programs are limited to measures and applications with standard energy savings and cost characteristics or where a standardized approach can be developed. To simplify programs for our customers and trade allies and maximize program participation, we have been shifting towards more prescriptive non-residential programs.

In 2008, Avista acquired 1,036,424 therms from this portfolio (55 percent of the total acquisition of all three segments). Fifty-four percent of the total non-interactive energy (electric and natural gas) acquisition is attributable to therm saving within this segment.

Large projects, those resulting in incentives of $100,000 or larger, are disclosed to the Triple-E board to provide them with the information necessary to provide oversight of DSM programs.

RESIDENTIAL SEGMENT

Due to the large volume and relatively small size of individual projects, the residential portfolio is exclusively composed of prescriptive programs. In 2008 this portfolio was responsible for the acquisition of 749,199 first-year therms (40% of the total acquisition of all three segments). Of the non-interactive total energy (electric and natural gas) savings in 2008 from this portfolio, 39 percent are attributable to therm savings of this segment.

Incentives available for residential programs are calculated based on the application of the measure in a typical residential home or, in some cases, based on deemed savings. Calculations are made in accordance with Avista Rate Schedule 190 tiered incentives with appropriate modifications for potential differences in application, multiple measure programs and rounding for purposes of offering a customer and trade ally-friendly program. The prescriptive residential programs currently available are natural gas furnaces/boilers, high efficiency water heaters, tankless water heaters, ceiling/attic insulation, floor/wall insulation, windows, and rooftop dampers.

Notably, several multifamily housing measures are incorporated within the residential segment due to the non-residential electric and natural gas rate schedules that many of these customers are billed. Many of the multifamily measures evaluated as part of this IRP analysis (e.g. pool and spa water heating efficiencies in multifamily housing) will be forwarded to the residential segment implementation team for further evaluation.

Avista is continuing an outreach effort targeted at residential customers within our service territory through involvement at area community events. The outreach effort is geared toward improving conservation by providing continuing educational messages regarding behavioral effects on energy use as well as encouraging customers to participate in programs that improve the efficiency of key natural gas appliances or shell measures.

In addition, we continue our multi-channel, multi-year educational outreach effort, known as Every Little Bit. Included in this effort is an website, www.everylittlebit.com, which provides a one-stop shop for energy efficiency information and tips, available rebates, latest information on renewable energy, as well as an interactive audit tool where customers can audit their home's energy efficiency and gain insight on improvements that can be made.

LOW-INCOME RESIDENTIAL SEGMENT

Avista's north division low income programs are implemented in cooperation with six community action partnership (CAP) agencies. These CAP agencies are awarded an annual funding contract specifying the maximum funding amounts and the conditions for program implementation. Contracts can be revised on 30 days' notice, a provision that allows Avista flexibility to reallocate funds among the CAP agencies during the year to maximize their value to the customer base.

The CAP agencies and 2008/2009 funding levels are summarized in Table 4.1.2.

Table 4.1.2 - 2008/2009 Low Income Funding Levels

Community Action Partner	2008 Budget	2009 Budget
Lewiston CAP	$480,937	$660,000
North Columbia CAC (Moses Lake)	97,316	125,000
Rural Resources CA (Colville)	81,990	105,000
SNAP (Spokane)	722,919	950,000
Whitman County CAC (Pullman)	95,758	125,000
WGAP (White Salmon)	3,080	7,000
	$1,482,000	$1,972,000

The distribution of funding for the low income segment has been approached with the intent to provide the maximum flexibility possible. This permits the agencies to respond to unexpected urgent needs and energy-efficiency opportunities that may not have been anticipated when the annual contracts were signed.

As part of this flexibility, the CAP agencies are permitted to expend their contractual funding on either electric or natural gas-efficiency measures. The funding available includes an allowable 15 percent remuneration to the agency for administrative and outreach costs. Up to 15 percent of the funds can be expended for health and human safety measures with an emphasis on the safe use of energy, and maintenance and repairs necessary to ensure the longevity of installed efficiency measures and continued habitability of the home.

The low income residential segment delivered 102,438 first-year therms to the overall natural gas DSM program in 2008. This therm acquisition represented 5 percent of the total BTUs acquired by the combined electric and natural gas programs.

PROGRAM FUNDING

Avista's approach to conservation cost-recovery is through a public purpose surcharge on our customer's energy bill (the tariff rider). We currently manage separate tariff riders for Washington and Idaho natural gas investments. Based upon the demand for funds and incoming tariff rider contributions, this balance can be positive (shareholders owe customers) or negative (customers owe shareholders) at any particular point in time.

The aggregate natural gas tariff rider balance for the north division is a negative (customer owes shareholders) $4,047,415 as of July 30, 2009. Recent demand for conservation services has exceeded tariff rider revenue. Therefore, we recently requested increases to Schedule 191, the most recent of which went into effect in Idaho on August 1, 2009. The most recent projection forecasts a positive (shareholders owe customers) $74 thousand balance in the Washington natural gas DSM tariff rider and just below $21 thousand positive in the Idaho natural gas tariff balance by year end 2010.

Funding for the natural gas efficiency programs is derived through a surcharge on retail rates authorized under Schedule 191. The recent increases to the Washington and Idaho natural gas surcharges were necessary to eliminate a persistent imbalance of tariff rider contributions and natural gas program expenditures. This imbalance tends to grow during the periods of increasing commodity costs and we continue to see higher than budgeted demand in program incentives. For example, in 2008 natural gas tariff rider contributions were over $4.3 million while we paid customers nearly $5.1 million in natural gas incentives, making incentives 117% of tariff rider contributions collected. Prior to consideration of infrastructure and other implementation costs, this puts Avista in a situation of a negative balance.

Only those customers contributing to the program funding through Avista Rate Schedule 191 are eligible to receive financial incentives. This limits availability to core natural gas customers. Periodically we claim the acquisition of natural gas savings from transport customers if those efficiencies result from involvement in a project that is tightly interwoven with an electric-efficiency project that was being evaluated and funded under the company's electric DSM program.

COOPERATIVE REGIONAL PROGRAMS

Avista has and remains interested in testing the viability of a regional market transformation approach to the acquisition of natural gas-efficiency potential. This model has proven to be successful within Northwest electric markets as evidenced by the success of the Northwest Energy Efficiency Alliance (NEEA). Though recent efforts at partnering with NEEA and establishing limited ad hoc regional efforts on the natural gas side have been unsuccessful, we will continue to seek alliances with other Northwest utilities to advance this concept.

CONCLUSION

We have explicitly recognized within this IRP our obligation to achieve all natural gas-efficiency resources available through utility intervention of cost-effective programs. Given the rapid changes within the natural gas market, many new efficiency opportunities may arise in the market. The Company will continue to consider and evaluate any developing technologies for inclusion in our programs between IRPs. Considerable uncertainty remains regarding the customer response to these programs, since this is a time of economic uncertainty at a time when retail gas prices are declining. Historically, we have seen less participation as prices decline. However, this uncertainty does not preclude us from pursuing the planned aggressive ramp-up of natural gas-efficiency programs. Additionally, we have, and will continue to actively seek, opportunities for new or enhanced resource acquisition through the development of cooperative regional programs.

One of the results of the IRP process is a 20-year forecast of avoided costs for each of the eight geographic areas. The detailed nature of these avoided costs makes it possible to continue to evaluate measures and applications as technology and markets change without the need to await the next IRP process. This is of value in determining program cost effectiveness based upon updated inputs, revised program plans and the ability to determine the value of targeting specific markets. Avoided cost determination is discussed in detail in Chapter 6 – Integrated Resource Portfolio.

The completion of the IRP analysis is the midpoint, not the ending point, of a larger reassessment of the DSM resource portfolio. The IRP analysis presented has generally indicated a set of cost effective measures and achievable resource potential for a future DSM portfolio. These results remain in need of further evaluation to facilitate the development of program plans and to incorporate them into an updated DSM implementation plan for use in daily DSM operations.

APPENDIX 4.2

CONSERVATION MEASURES DETAIL

Appendix 4.2 - Oregon DSM Programs Details

Measure #	Measure	Original measure application	Market segment	Program bundle	Incremental TRC cost / unit	Non-Energy Benefits	First yr therm svgs / unit	Winter or Annual	Measure life	**Levelized TRC cost / therm**	Levelized TRC cost/therm w/o NEBs	New Acquirable Potential (units)	Technical Potential	Annual therm acquirable potential	Annual total (for whole pgm) cost less NEB credit	Achieveable Therms Entered into SENDOUT®	SENDOUT® Code
1	Air sealing weatherstripping	SFH replacement	Residential	Shell	$ 250	$ -	51	W	10	**$ 0.61**	$ 0.61	33		1,645	$ 8,128.13	1,645	ResYel1
2	Air sealing weatherstripping	MFH replacement	Residential	Shell	$ 150	$ -	30	W	10	**$ 0.61**	$ 0.61	8		232	$ 1,147.50	232	ResYel2
3	Air sealing weatherstripping	MH retro	Residential	Shell	$ -	$ -	0	W	25	**$ -**	$ -	5,000	814	100	$ -	100	ResMTW
4	Attic insulation	MFH retro	Residential	Shell	$ 1	$ -	0	W	45	**$ 1.90**	$ 1.90	10,000	415	366	$ 14,000.00	366	ResRed1
5	Attic insulation	SFH retro	Residential	Shell	$ 666	$ -	59	W	45	**$ 0.56**	$ 0.56	217	16,678	12,786	$ 144,355.50	12,786	ResMTW
6	Blow-in insulation for roof	MH retro	Residential	Shell	$ 1	$ -	0	W	25	**$ 1.30**	$ 1.30	2,000		100	$ 2,000.00	100	ResRed1
7	Boiler tune-up	MFH retro	Residential	HVAC	$ 100	$ -	27	W	5	**$ 0.85**	$ 0.85	9	11,447	226	$ 850.00	226	ResYel3
8	Combo boiler	SFH retro	Residential	DHW	$ 3,850	$ -	180	A	20	**$ 1.60**	$ 1.60	4	494,749	650	$ 13,908.13	650	ResRed2
9	Combo boiler (air)	MFH retro	Residential	DHW	$ 3,850	$ -	180	A	20	**$ 1.60**	$ 1.60	2	57,058	383	$ 8,181.25	383	ResRed2
10	Combo boiler (air)	New SFH	Residential	DHW	$ 2,700	$ -	71	A	20	**$ 2.84**	$ 2.84	1	11,087	54	$ 2,065.50	54	ResRed2
11	Combo boiler (hydronic)	New SFH	Residential	DHW	$ 2,200	$ -	71	A	20	**$ 2.32**	$ 2.32	3	11,087	217	$ 6,732.00	217	ResRed2
12	Condensing boiler	MFH replacement	Residential	HVAC	$ 570	$ -	80	W	20	**$ 0.53**	$ 0.53	2	429	122	$ 872.10	122	ResMTW
13	Condensing boiler	New MFH	Residential	HVAC	$ 570	$ -	80	W	20	**$ 0.53**	$ 0.53	2	1,563	122	$ 872.10	122	ResMTW
14	Condensing boiler	MFH replacement	Residential	DHW	$ 570	$ -	80	W	20	**$ 0.53**	$ 0.53	1	308	61	$ 436.05	61	ResMTW
15	Condensing boiler	New MFH	Residential	DHW	$ 570	$ -	80	W	20	**$ 0.53**	$ 0.53	1	912	61	$ 436.05	61	ResMTW
16	Direct vent gas unit heater	SFH replacement	Residential	HVAC	$ 713	$ -	127	W	20	**$ 0.42**	$ 0.42	1	1,214	77	$ 436.36	77	ResMTW
17	Direct vent gas unit heater	SFH retro	Residential	HVAC	$ 1,560	$ -	127	W	20	**$ 0.92**	$ 0.92	4	24,270	457	$ 5,635.50	457	ResYel4
18	Duct commissioning	New SFH	Residential	HVAC	$ 300	$ -	60	W	20	**$ 0.37**	$ 0.37	7	7,027	390	$ 1,950.75	390	ResMTW
19	Duct insulation retrofit	SFH retro	Residential	HVAC	$ 459	$ -	93	W	20	**$ 0.37**	$ 0.37	28	23,649	2,576	$ 12,684.75	2,576	ResMTW
20	Duct insulation retrofit	MFH retro	Residential	HVAC	$ 275	$ -	47	W	20	**$ 0.44**	$ 0.44	1	1,827	40	$ 233.75	40	ResMTW
21	Duct sealing	SFH retro	Residential	HVAC	$ 800	$ -	125	W	20	**$ 0.48**	$ 0.48	31	278,273	3,839	$ 24,565.00	3,839	ResMTW
22	Duct sealing	MFH retro	Residential	HVAC	$ 800	$ -	63	W	20	**$ 0.96**	$ 0.96	4	8,061	266	$ 3,400.00	266	ResYel5
23	Duct sealing	MH retro	Residential	HVAC	$ 200	$ -	75	W	20	**$ 0.20**	$ 0.20	5	8,061	398	$ 1,062.50	398	ResMTW
24	Energy Star Clothes Washers	SFH	Residential	Appliances	$ 150	$ 63	5	A	13	**$ 1.76**	$ 3.04	858		4,290	$ 74,643.28	4,290	ResRed2
25	Energy Star Dishwasher	SFH retro	Residential	Appliances	$ 50	$ 37	5	A	13	**$ 0.26**	$ 1.01	434		2,168	$ 5,635.50	2,168	ResMTA
26	Energy Star Dishwasher	MFH retro	Residential	Appliances	$ 50	$ 37	5	A	13	**$ 0.26**	$ 1.01	43		213	$ 552.50	213	ResMTA
27	Energy Star Dishwasher	MH retro	Residential	Appliances	$ 50	$ 37	5	A	13	**$ 0.26**	$ 1.01	40		199	$ 517.97	199	REsMTA
28	Energy Star Windows	MFH retro	Residential	Shell	$ 392	$ -	68	W	45	**$ 0.29**	$ 0.29	13	4,193	866	$ 4,998.00	866	ResMTW
29	Energy Star Windows	SFH retro	Residential	Shell	$ 500	$ -	89	W	45	**$ 0.28**	$ 0.28	145	67,481	12,796	$ 72,250.00	12,796	ResMTW
30	Fireplace dampers	SFH retro	Residential	Shell	$ 200	$ -	76	W	15	**$ 0.24**	$ 0.24	7		538	$ 1,416.67	538	ResMTW
31	Floor insulation	MFH retro	Residential	Shell	$ 1,200	$ -	45	W	45	**$ 1.32**	$ 1.32	2	718	77	$ 2,040.00	77	ResRed1
32	Floor insulation	SFH retro	Residential	Shell	$ 1,244	$ -	128	W	45	**$ 0.48**	$ 0.48	108	40,692	13,912	$ 134,818.50	13,912	ResMTW
33	Furnace retrofit	SFH retro	Residential	HVAC	$ 600	$ -	71	W	20	**$ 0.64**	$ 0.64	253		17,843	$ 151,725.00	17,843	ResYel6
34	Furnace retrofit	MFH retro	Residential	HVAC	$ 600	$ -	71	W	20	**$ 0.63**	$ 0.63	4		302	$ 2,550.00	302	ResYel7
35	Furnace tune-up	MH retro	Residential	HVAC	$ 200	$ -	10	W	3	**$ 7.23**	$ 7.23	48		478	$ 9,562.50	478	ResRed1
36	Gas Pool Heater	New SFH	Residential	HVAC	$ 3,364	$ -	373	W	20	**$ 0.67**	$ 0.67	1	43,722	373	$ 3,364.00	373	ResYel8
37	Gas Pool Heater	SFH replacement	Residential	HVAC	$ 3,364	$ -	373	W	20	**$ 0.67**	$ 0.67	1	252	364	$ 3,281.16	364	ResYel9
38	Gas Pool Heater	MFH replacement	Residential	HVAC	$ 3,364	$ -	373	W	20	**$ 0.67**	$ 0.67	1	252	190	$ 1,715.64	190	ResYel10
39	Gas Pool Heater	SFH retro	Residential	HVAC	$ 8,651	$ -	373	W	20	**$ 1.73**	$ 1.73	1	5,250	404	$ 9,375.52	404	ResRed1
40	Gas Pool Heater	MFH retro	Residential	HVAC	$ 8,651	$ -	373	W	20	**$ 1.73**	$ 1.73	0	5,250	95	$ 2,206.01	95	ResRed1
41	Heating System Maintenance (filter/tune-up)	SFH	Residential	HVAC	$ 200	$ -	50	W	2	**$ 2.13**	$ 2.13	542		27,094	$ 108,375.00	27,094	ResRed1
42	High efficiency boiler	New SFH	Residential	HVAC	$ 1,000	$ -	40	W	20	**$ 1.87**	$ 1.87	8		312	$ 7,803.00	312	ResRed1
43	High efficiency boiler	MFH replacement	Residential	DHW	$ 5,000	$ -	40	W	20	**$ 9.36**	$ 9.36	2	220	85	$ 10,625.00	85	ResRed1
44	High efficiency furnace	SFH replacement	Residential	HVAC	$ 600	$ -	71	W	20	**$ 0.63**	$ 0.63	325	16,299	23,084	$ 195,075.00	23,084	ResYel11
45	High efficiency furnace	New SFH	Residential	HVAC	$ 600	$ -	71	W	20	**$ 0.63**	$ 0.63	253	17,177	17,954	$ 151,725.00	17,954	ResYel12
46	High efficiency furnace	MFH replacement	Residential	HVAC	$ 600	$ -	71	W	20	**$ 0.63**	$ 0.63	2	393	151	$ 1,275.00	151	ResYel13
47	High efficiency water heater (tanked)	SFH replacement	Residential	DHW	$ 60	$ -	27	A	12	**$ 0.24**	$ 0.24	81	7,635	2,195	$ 4,876.88	2,195	ResMTA
48	High efficiency water heater (tanked)	New SFH	Residential	DHW	$ 60	$ -	27	A	12	**$ 0.24**	$ 0.24	65		1,756	$ 3,901.50	1,756	ResMTA
49	High efficiency water heater (tanked)	New MFH	Residential	DHW	$ 60	$ -	27	A	12	**$ 0.24**	$ 0.24	84		2,272	$ 5,049.00	2,272	ResMTA
50	High efficiency water heater (tanked)	SFH retro	Residential	DHW	$ 260	$ -	27	A	12	**$ 1.04**	$ 1.04	72	91,620	1,936	$ 18,646.88	1,936	ResRed2
51	Horizontal axis clothes washer	New SFH	Residential	Appliances	$ 150	$ 63	5	A	13	**$ 1.77**	$ 3.04	434	4,084	2,168	$ 37,910.16	2,168	ResRed2

Measure #	Measure	Original measure application	Market segment	Program bundle	Incremental TRC cost / unit	Non-Energy Benefits	First yr therm svgs / unit	Winter or Annual	Measure life	**Levelized TRC cost / therm**	Levelized TRC cost/therm w/o NEBs	New Acquirable Potential (units)	Technical Potential	Annual therm acquirable potential	Annual total (for whole pgm) cost less NEB credit	Achieveable Therms Entered into SENDOUT®	SENDOUT® Code
52	Horizontal axis clothes washer	SFH retro	Residential	Appliances	$ 150	$ 63	5	A	13	**$ 1.76**	$ 3.04	461		2,303	$ 40,071.66	2,303	ResRed2
53	Passive solar water heating	SFH retro	Residential	DHW	$ 2,000	$ -	150	A	15	**$ 1.21**	$ 1.21	1	714,637	90	$ 1,200.00	90	ResRed2
54	Passive solar water heating	New SFH	Residential	DHW	$ 2,000	$ -	150	A	15	**$ 1.21**	$ 1.21	2		225	$ 3,000.00	225	ResRed2
55	Pipe insulation	SFH retro	Residential	DHW	$ 121	$ -	10	A	15	**$ 1.10**	$ 1.10	36	51,246	361	$ 4,371.13	361	ResRed2
56	Pipe insulation/wrap - long wrap (min 15ft)	MH retro	Residential	DHW	$ 15	$ -	2	A	15	**$ 0.62**	$ 0.62	4		9	$ 59.77	9	ResYel14
57	Pipe insulation/wrap - short wrap (min 3ft)	MH retro	Residential	DHW	$ 5	$ -	1	A	15	**$ 0.57**	$ 0.57	4		3	$ 19.92	3	ResYel15
58	Pool blanket	New SFH	Residential	DHW	$ 1,100	$0	1,360	A	10	**$ 0.10**	$ 0.10	0	424,728	408	$ 330.00	408	ResMTA
59	Programmable Thermostat	New SFH	Residential	HVAC	$ 75	$0	27	W	20	**$ 0.21**	$ 0.21	200		5,400	$ 15,000.00	5,400	ResMTW
60	Programmable Thermostat	SFH replacement	Residential	HVAC	$ 75	$ -	27	W	20	**$ 0.21**	$ 0.21	200		5,400	$ 15,000.00	5,400	ResMTW
61	Programmable Thermostat	SFH retro	Residential	HVAC	$ 75	$ -	27	W	20	**$ 0.21**	$ 0.21	200		5,400	$ 15,000.00	5,400	ResMTW
62	Tankless water heater	SFH replacement	Residential	DHW	$ 800	$ -	90	A	20	**$ 0.66**	$ 0.66	75	18,782	6,730	$ 59,823.00	6,730	ResYel16
63	Tankless water heater	MFH replacement	Residential	DHW	$ 800	$ -	90	A	20	**$ 0.66**	$ 0.66	0	2,166	38	$ 340.00	38	ResYel17
64	Tankless water heater	SFH retro	Residential	DHW	$ 800	$ -	90	A	20	**$ 0.66**	$ 0.66	72	225,386	6,503	$ 57,800.00	6,503	ResYel18
65	Tankless water heater	MFH retro	Residential	DHW	$ 800	$ -	90	A	20	**$ 0.66**	$ 0.66	0	25,993	38	$ 340.00	38	ResYel19
66	Tankless water heater	SFH	Residential	DHW	$ 700	$ -	102	A	15	**$ 0.63**	$ 0.63	65	300,514	6,633	$ 45,517.50	6,633	ResYel20
67	Thermal Vent Damper	MFH retro	Residential	HVAC	$ 60	$ -	27	W	12	**$ 0.24**	$ 0.24	383	4,770	10,187	$ 22,950.00	10,187	ResMTW
68	Wall insulation	SFH retro	Residential	Shell	$ 2	$ -	0	W	45	**$ 0.15**	$ 0.15	3,853	22,380	1,896	$ 5,780.00	1,896	ResMTW
69	BBQ / Rotisserie Oven	Cooking retrofit	Non-residentia	Cooking	$ 5,746	$ -	198	A	15	**$ 2.64**	$ 2.64	1	112	198	$ 5,746.00	198	ComRed1
70	BBQ / Rotisserie Oven	Cooking replacemer	Non-residentia	Cooking	$ 1,003	$ -	198	A	15	**$ 0.46**	$ 0.46	1	7	198	$ 1,003.00	198	ComMTA
71	Boiler	Water heating repla	Non-residentia	DHW	$ 11,928	$ -	800	W	20	**$ 1.11**	$ 1.11	3	2,398	2,400	$ 35,784.00	2,400	ComYel1
72	Boiler Tune-up	Space heating retro	Non-residentia	HVAC	$ 100	$ -	67	W	5	**$ 0.34**	$ 0.34	5	3,474	333	$ 500.00	333	ComMTW
73	Cheesemelter	Cooking replacemer	Non-residentia	Cooking	$ 408	$ -	203	A	15	**$ 0.18**	$ 0.18	1	11	203	$ 408.00	203	ComMTA
74	Cheesemelter (broiler)	Cooking retrofit	Non-residentia	Cooking	$ 3,937	$ -	203	A	15	**$ 1.77**	$ 1.77	1	159	203	$ 3,937.00	203	ComRed1
75	Clothes Dryer	Miscellaneous retrof	Non-residentia	Appliances	$ 14,415	$ -	740	A	11	**$ 2.25**	$ 2.25	1	23,076	740	$ 14,415.00	740	ComRed1
76	Clothes Dryer	Miscellaneous repla	Non-residentia	Appliances	$ 1,586	$ -	740	A	11	**$ 0.25**	$ 0.25	1	2,098	740	$ 1,586.00	740	ComMTA
77	Clothes washer	Water heating retrof	Non-residentia	Appliances	$ 2,250	$ -	50	A	11	**$ 5.19**	$ 5.19	1	1,559	50	$ 2,250.00	50	ComRed1
78	Clothes washer	Water heating repla	Non-residentia	Appliances	$ 900	$ 224	50	A	11	**$ 1.56**	$ 2.07	1	142	50	$ 675.82	50	ComRed1
79	Coin-Op Clothers Dryer	Miscellaneous retrof	Non-residentia	Appliances	$ 5,573	$0	419	A	11	**$ 1.53**	$ 1.53	4	7,241	1,676	$ 22,292.00	1,676	ComRed1
80	Coin-Op Clothers Dryer	Miscellaneous repla	Non-residentia	Appliances	$ 613	$ -	419	A	11	**$ 0.17**	$ 0.17	4	658	1,676	$ 2,452.00	1,676	ComMTA
81	Coin-op clothes washer	Water heating retrof	Non-residentia	Appliances	$ 750	$ -	11	A	11	**$ 7.86**	$ 7.86	4	501	44	$ 3,000.00	44	ComRed1
82	Coin-op clothes washer	Water heating repla	Non-residentia	Appliances	$ 300	$145	29	A	11	**$ 0.61**	$ 1.19	4	46	116	$ 618.72	116	ComYel2
83	Combination Oven	Cooking retrofit	Non-residentia	Cooking	$ 5,717	$ 586	403	A	12	**$ 1.37**	$ 1.53	2	727	806	$ 10,262.00	806	ComRed1
84	Combination Oven	Cooking replacemer	Non-residentia	Cooking	$ 5,717	$ 586	403	A	12	**$ 1.37**	$ 1.53	2	49	806	$ 10,262.00	806	ComRed1
85	Condensing Boiler	Water heating repla	Non-residentia	DHW	$ 36,701	$ -	1,200	A	20	**$ 2.29**	$ 2.29	2	4,682	2,400	$ 73,402.00	2,400	ComRed1
86	Condensing Storage Water Heater	Water heating repla	Non-residentia	DHW	$ 2,500	$ -	1,200	A	15	**$ 0.19**	$ 0.19	3	5,124	3,600	$ 7,500.00	3,600	ComMTA
87	Condensing Tank Water Heater	Water heating retrof	Non-residentia	DHW	$ 7,800	$ -	1,200	A	15	**$ 0.59**	$ 0.59	2	172,943	2,400	$ 15,600.00	2,400	ComYel3
88	Convection Oven	Cooking retrofit	Non-residentia	Cooking	$ 1,886	$ -	324	A	12	**$ 0.63**	$ 0.63	5	8,928	1,620	$ 9,430.00	1,620	ComYel4
89	Convection Oven	Cooking replacemer	Non-residentia	Cooking	$ 1,886	$ -	324	A	12	**$ 0.63**	$ 0.63	5	595	1,620	$ 9,430.00	1,620	ComYel5
90	Conveyer Broiler	Cooking retrofit	Non-residentia	Cooking	3674	$ -	661	A	15	**$ 0.51**	$ 0.51	2	327	1,322	$ 7,348.00	1,322	ComYel6
91	Conveyer Broiler	Cooking replacemer	Non-residentia	Cooking	$ 1,182	$ -	661	A	15	**$ 0.16**	$ 0.16	2	22	1,322	$ 2,364.00	1,322	ComMTA
92	Demand control ventilation	HVAC	Non-residentia	HVAC	0.8	$ -	0.3888	W	20	**$ 0.15**	$ 0.15	7,500		2,916	$ 6,000.00	2,916	ComMTW
93	Energy recovery ventilation	HVAC	Non-residentia	HVAC	$ 4	$ -	0	W	20	**$ 0.68**	$ 0.68	10,000		4,403	$ 40,000.00	4,403	ComYel7
94	Energy Star Steamer	Cooking retrofit	Non-residentia	Cooking	$ 3,733	$ 1,083	2,084	A	12	**$ 0.14**	$ 0.19	3	1,672	6,252	$ 7,950.00	6,252	ComMTA
95	Energy Star Steamer	Cooking replacemer	Non-residentia	Cooking	$ 3,733	$ 1,083	2,084	A	12	**$ 0.14**	$ 0.19	3	111	6,252	$ 7,950.00	6,252	ComMTA
96	Fryer	Cooking retrofit	Non-residentia	Cooking	$ 1,219	$ -	505	A	12	**$ 0.26**	$ 0.26	5		2,525	$ 6,095.00	2,525	ComMTA
97	Fryer	Cooking replacemer	Non-residentia	Cooking	$ 1,219	$ -	505	A	12	**$ 0.26**	$ 0.26	5		2,525	$ 6,095.00	2,525	ComMTA
98	Gas Pool Heater	Miscellaneous retrof	Non-residentia	Pool	$ 8,651	$ -	373	A	20	**$ 1.73**	$ 1.73	1	1,744	373	$ 8,651.00	373	ComRed1
99	Gas Pool Heater	Miscellaneous repla	Non-residentia	Pool	$ 3,364	$ -	373	A	20	**$ 0.67**	$ 0.67	1	87	373	$ 3,364.00	373	ComYel8
100	Gas Spa Heater	Miscellaneous retrof	Non-residentia	Pool	$ 1,377	$ -	13	A	20	**$ 7.73**	$ 7.73	1	37	13	$ 1,377.00	13	ComRed1
101	Gas Spa Heater	Miscellaneous repla	Non-residentia	Pool	$ 344	$ -	13	A	20	**$ 1.93**	$ 1.93	1	2	13	$ 344.00	13	ComRed1
102	Griddle	Cooking retrofit	Non-residentia	Cooking	$ 491	$ -	88	A	12	**$ 0.60**	$ 0.60	2		176	$ 982.00	176	ComYel9
103	Griddle	Cooking replacemer	Non-residentia	Cooking	$ 491	$ -	88	A	12	**$ 0.60**	$ 0.60	2		176	$ 982.00	176	ComYel10

Measure #	Measure	Original measure application	Market segment	Program bundle	Incremental TRC cost / unit	Non-Energy Benefits	First yr therm svgs / unit	Winter or Annual	Measure life	**Levelized TRC cost / therm**	Levelized TRC cost/therm w/o NEBs	New Acquirable Potential (units)	Technical Potential	Annual therm acquirable potential	Annual total (for whole pgm) cost less NEB credit	Achieveable Therms Entered into SENDOUT®	SENDOUT® Code
104	High efficiency charbroiler	Cooking retrofit	Non-residentia	Cooking	$ 9,029	$ -	298	A	15	**$ 2.76**	$ 2.76	2	2,604	596	$ 18,058.00	596	ComRed1
105	High efficiency charbroiler	Cooking replacemer	Non-residentia	Cooking	$ 1,313	$ -	298	A	15	**$ 0.40**	$ 0.40	2	174	596	$ 2,626.00	596	ComMTA
106	High efficiency condensing hot water heater	Cooking retrofit	Non-residentia	Cooking	2500	$ -	1200	A	15	**$ 0.19**	$ 0.19	3	172,943	3,600	$ 7,500.00	3,600	ComMTA
107	High efficiency condensing hot water heater	Cooking replacemer	Non-residentia	Cooking	$ 7,800	$ -	1,200	A	15	**$ 0.59**	$ 0.59	5	5,124	6,000	$ 39,000.00	6,000	ComYel11
108	High efficiency hot water heater	Cooking retrofit	Non-residentia	Cooking	$ 551	$ -	13	A	15	**$ 3.86**	$ 3.86	10		130	$ 5,510.00	130	ComRed1
109	High efficiency hot water heater	Cooking replacemer	Non-residentia	Cooking	$ 175	$ -	12	A	15	**$ 1.33**	$ 1.33	10		120	$ 1,750.00	120	ComRed1
110	Infrared Fryer Griddle	Cooking retrofit	Non-residentia	Cooking	$ 5,899	$ -	194	A	20	**$ 2.27**	$ 2.27	1	1,825	194	$ 5,899.00	194	ComRed1
111	Infrared Fryer Griddle	Cooking replacemer	Non-residentia	Cooking	$ 2,146	$ -	194	A	20	**$ 0.83**	$ 0.83	1	122	194	$ 2,146.00	194	ComYel12
112	Infrared General Purpose Fryer	Cooking retrofit	Non-residentia	Cooking	$ 5,889	$ -	300	A	15	**$ 1.79**	$ 1.79	1	7,355	300	$ 5,889.00	300	ComRed1
113	Infrared General Purpose Fryer	Cooking replacemer	Non-residentia	Cooking	$ 3,186	$ -	300	A	15	**$ 0.97**	$ 0.97	1	490	300	$ 3,186.00	300	ComYel13
114	Multi-tank conveyer dishwasher	Cooking retrofit	Non-residentia	Cooking	$ 4,000	$ -	993	A	15	**$ 0.37**	$ 0.37	1		993	$ 4,000.00	993	ComMTA
115	Multi-tank conveyer dishwasher	Cooking replacemer	Non-residentia	Cooking	$ 4,000	$ -	993	A	15	**$ 0.37**	$ 0.37	1		993	$ 4,000.00	993	ComMTA
116	Oven Conveyer	Cooking replacemer	Non-residentia	Cooking	$ 5,933	$ -	364	A	20	**$ 1.22**	$ 1.22	4	26	1,456	$ 23,732.00	1,456	ComRed1
117	Pizza / Deck Oven	Cooking replacemer	Non-residentia	Cooking	$ 466	$ -	256	A	20	**$ 0.14**	$ 0.14	1	95	256	$ 466.00	256	ComMTA
118	Point of Use hot water heater	Cooking retrofit	Non-residentia	Cooking	$ 1,118	$ -	18	A	15	**$ 5.66**	$ 5.66	1		18	$ 1,118.00	18	ComRed1
119	Point of Use hot water heater	Cooking replacemer	Non-residentia	Cooking	$ 371	$ -	17	A	15	**$ 1.99**	$ 1.99	1		17	$ 371.00	17	ComRed1
120	Pool blanket	Water heating repla	Non-residentia	Pool	$ 2,200	$ -	2,720	A	10	**$ 0.10**	$ 0.10	3	3,264	8,160	$ 6,600.00	8,160	ComMTA
121	Power Burner	Space heating retro	Non-residentia	HVAC	$ 913	$ -	134	W	12	**$ 0.73**	$ 0.73	2	975	269	$ 1,826.00	269	ComYel14
122	Programmable Thermostats	Space heating retro	Non-residentia	HVAC	$ 100	$ -	117	W	20	**$ 0.06**	$ 0.06	20		2,344	$ 2,000.00	2,344	ComMTW
123	Programmable Thermostats	Space heating repla	Non-residentia	HVAC	25	$ -	117.1802578	W	20	**$ 0.02**	$ 0.02	20		2,344	$ 500.00	2,344	ComMTW
124	Rack / Tray Oven	Cooking retrofit	Non-residentia	Cooking	$ 4,933	$ -	1,034	A	12	**$ 0.51**	$ 0.51	2	10,671	2,068	$ 9,866.00	2,068	ComYel15
125	Rack / Tray Oven	Cooking replacemer	Non-residentia	Cooking	$ 4,933	$ -	1,034	A	12	**$ 0.51**	$ 0.51	2	711	2,068	$ 9,866.00	2,068	ComYel16
126	Radiant heat	Space heating repla	Non-residentia	HVAC	$ 25	$ -	117	W	20	**$ 0.02**	$ 0.02	5		586	$ 125.00	586	ComMTW
127	Recirculation Controls	Water heating retrof	Non-residentia	DHW	$ 1,311	$ -	386	A	10	**$ 0.42**	$ 0.42	1	11,267	386	$ 1,311.00	386	ComMTA
128	Recirculation Controls	HVAC	Non-residentia	HVAC	$ 200	$ -	35	W	25	**$ 0.37**	$ 0.37	1		35	$ 200.00	35	ComMTW
129	Retro-Commissioning	Space heating retro	Non-residentia	HVAC	$ 3,000	$ -	2,000	W	7	**$ 0.25**	$ 0.25	5		10,000	$ 15,000.00	10,000	ComMTW
130	Roof insulation	Envelope retrofit	Non-residentia	Shell	$ 0	$ -	0	W	30	**$ 0.11**	$ 0.11	20	2,561	4	$ 8.00	4	ComMTW
131	Rooftop Maintenance	Space heating retro	Non-residentia	HVAC	$ 100	$ -	117	W	20	**$ 0.06**	$ 0.06	50		5,859	$ 5,000.00	5,859	ComMTW
132	Salamander	Cooking replacemer	Non-residentia	Cooking	$ 300	$ -	137	A	15	**$ 0.20**	$ 0.20	1	9	137	$ 300.00	137	ComMTA
133	Salamander (Broiler)	Cooking retrofit	Non-residentia	Cooking	$ 2,221	$ -	137	A	15	**$ 1.48**	$ 1.48	1	142	137	$ 2,221.00	137	ComRed1
134	Single tank conveyer dishwasher	Cooking retrofit	Non-residentia	Cooking	$ 3,000	$ -	508	A	15	**$ 0.54**	$ 0.54	2		1,016	$ 6,000.00	1,016	ComYel17
135	Single tank conveyer dishwasher	Cooking replacemer	Non-residentia	Cooking	$ 3,000	$ -	508	A	15	**$ 0.54**	$ 0.54	2		1,016	$ 6,000.00	1,016	ComYel18
136	Single tank door type dishwasher	Cooking retrofit	Non-residentia	Cooking	$ 2,000	$ -	554	A	15	**$ 0.33**	$ 0.33	2		1,108	$ 4,000.00	1,108	ComMTA
137	Single tank door type dishwasher	Cooking replacemer	Non-residentia	Cooking	$ 2,000	$ -	554	A	15	**$ 0.33**	$ 0.33	2		1,108	$ 4,000.00	1,108	ComMTA
138	Solar water	Water heating retrof	Non-residentia	DHW	$ 2,000	$ -	150	A	11	**$ 1.54**	$ 1.54	2		300	$ 4,000.00	300	ComRed1
139	Tankless Water Heater	Water heating repla	Non-residentia	DHW	$ 600	$ -	211	A	20	**$ 0.21**	$ 0.21	5	1,312	1,055	$ 3,000.00	1,055	ComMTA
140	Time clock control of hot water heater circulati	Cooking retrofit	Non-residentia	Cooking	$ 224	$ -	11	A	15	**$ 1.85**	$ 1.85	20		220	$ 4,480.00	220	ComRed1
141	Time clock control of hot water heater circulati	Cooking replacemer	Non-residentia	Cooking	$ 224	$ -	11	A	15	**$ 1.85**	$ 1.85	10		110	$ 2,240.00	110	ComRed1
142	Under counter dishwashers	Cooking retrofit	Non-residentia	Cooking	$ 1,000	$ -	217	A	15	**$ 0.42**	$ 0.42	2		434	$ 2,000.00	434	ComMTA
143	Under counter dishwashers	Cooking replacemer	Non-residentia	Cooking	$ 1,000	$ -	217	A	15	**$ 0.42**	$ 0.42	2		434	$ 2,000.00	434	ComMTA
144	Vent Damper	Space heating retro	Non-residentia	HVAC	$ 304	$ -	134	W	12	**$ 0.24**	$ 0.24	20	1,949	2,690	$ 6,080.00	2,690	ComMTW
145	Vent Hood Controls	Cooking retrofit	Non-residentia	Cooking	$ 2,160	$ -	293	A	15	**$ 0.67**	$ 0.67	5		1,465	$ 10,800.00	1,465	ComYel19
146	Vent Hood Controls	Cooking replacemer	Non-residentia	Cooking	$ 1,298	$ -	293	A	15	**$ 0.40**	$ 0.40	5		1,465	$ 6,490.00	1,465	ComMTA
147	Wall insulation	Envelope retrofit	Non-residentia	Shell	$ 0	$ -	0	W	30	**$ 0.08**	$ 0.08	10	5,261	3	$ 3.90	3	ComMTW
148	Warm Up Control	Space heating retro	Non-residentia	HVAC	$ 300	$ -	240	W	10	**$ 0.16**	$ 0.16	10	2,082	2,397	$ 3,000.00	2,397	ComMTW
149	Window retrofit	Envelope retrofit	Non-residentia	Shell	$ 30	$ -	2	W	30	**$ 1.17**	$ 1.17	5	5,291	8	$ 150.00	8	ComYel20
													3,529,552	326,413	$ 2,140,843.97	326,413	

Appendix 4.2 - WA/ID DSM Program Details

Measure #	Measure	Original measure application	Market segment	Program bundle	Incremental TRC cost / unit	Non-Energy Benefits	First yr therm svgs / unit	Winter or Annual	Measure life	**Levelized TRC cost / therm**	Levelized TRC cost/therm w/o NEBs	New Acquirable Potential (units)	Technical Potential	Annual therm acquirable potential	Annual total (for whole pgm) cost less NEB credit	Achieveable Therms Entered into SENDOUT®	SENDOUT® Code
1	Air sealing weatherstripping	SFH replacement	Residential	Shell	$ 200	$ -	76	W	15	**$ 0.29**	$ 0.29	561		38,202	$ 112,200.00	38,202	Res MTW
2	Air sealing weatherstripping	MFH replacement	Residential	Shell	$ 150	$ -	30	W	10	**$ 0.71**	$ 0.71	66		2,004	$ 9,900.00	2,004	ResYel1
3	Air sealing weatherstripping	MH retro	Residential	Shell	$ -	$ -	0	W	25	**$ -**	$ -	33	2,443	1		1	ResMTW
4	Attic insulation	MFH retro	Residential	Shell	$ 1	$ -	0	W	45	**$ 2.84**	$ 2.84	44	1,244	1	$ 61.60	1	ResRed1
5	Attic insulation	SFH retro	Residential	Shell	$ 666	$ -	59	W	45	**$ 0.84**	$ 0.84	561	50,034	33,099	$ 373,626.00	33,099	ResYel2
6	Blow-in insulation for roof	MH retro	Residential	Shell	$ 1	$ -	0	W	25	**$ 1.73**	$ 1.73	33		1		1	ResRed1
7	Boiler tune-up	MFH retro	Residential	HVAC	$ 100	$ -	27	W	5	**$ 0.92**	$ 0.92	22	34,340	586	$ 2,200.00	586	Res Yel3
8	Combo boiler	SFH retro	Residential	DHW	$ 3,850	$ -	180	A	20	**$ 2.03**	$ 2.03	37	1,484,246	6,032		6,032	ResRed2
9	Combo boiler (air)	MFH retro	Residential	DHW	$ 3,850	$ -	180	A	20	**$ 2.03**	$ 2.03	22	171,173	3,548		3,548	ResRed2
10	Combo boiler (air)	New SFH	Residential	DHW	$ 2,700	$ -	71	A	20	**$ 3.61**	$ 3.61	40	33,260	2,519		2,519	ResRed2
11	Combo boiler (hydronic)	New SFH	Residential	DHW	$ 2,200	$ -	71	A	20	**$ 2.94**	$ 2.94	8	33,260	504		504	ResRed2
12	Condensing boiler	MFH replacement	Residential	HVAC	$ 570	$ -	80	W	20	**$ 0.68**	$ 0.68	40	1,288	3,164	$ 22,572.00	3,164	ResYel4
13	Condensing boiler	New MFH	Residential	HVAC	$ 570	$ -	80	W	20	**$ 0.68**	$ 0.68	8	4,689	633	$ 4,514.40	633	ResYel5
14	Condensing boiler	MFH replacement	Residential	DHW	$ 570	$ -	80	W	20	**$ 0.68**	$ 0.68	40	925	3,164	$ 22,572.00	3,164	ResYel6
15	Condensing boiler	New MFH	Residential	DHW	$ 570	$ -	80	W	20	**$ 0.68**	$ 0.68	8	2,735	633	$ 4,514.40	633	ResYel7
16	Direct vent gas unit heater	SFH retro	Residential	HVAC	$ 1,560	$ -	127	W	20	**$ 1.17**	$ 1.17	9	72,810	1,183	$ 14,586.00	1,183	ResYel8
17	Direct vent gas unit heater	MFH retro	Residential	HVAC	$ 1,395	$ -	109	W	20	**$ 1.21**	$ 1.21	52		5,112		5,112	ResRed1
18	Distribution controls	MFH retro	Residential	DHW	$ 150	$ -	8	W	15	**$ 2.07**	$ 2.07	22		158		158	ResRed1
19	Duct commissioning	New SFH	Residential	HVAC	$ 300	$ -	60	W	20	**$ 0.48**	$ 0.48	17	21,080	904		904	ResMTW
20	Duct insulation retrofit	SFH retro	Residential	HVAC	$ 459	$ -	93	W	20	**$ 0.47**	$ 0.47	1,987	70,946	165,939	$ 911,975.63	165,939	ResMTW
21	Duct insulation retrofit	MFH retro	Residential	HVAC	$ 275	$ -	47	W	20	**$ 0.56**	$ 0.56	11	5,481	459	$ 3,025.00	459	ResMTW
22	Duct sealing	SFH retro	Residential	HVAC	$ 500	$ -	125	W	20	**$ 0.38**	$ 0.38	1,987	834,818	222,595	$ 993,437.50	222,595	ResMTW
23	Duct sealing	MFH retro	Residential	HVAC	$ 300	$ -	63	W	20	**$ 0.46**	$ 0.46	11	24,184	617	$ 3,300.00	617	ResMTW
24	Duct sealing	MH retro	Residential	HVAC	$ 200	$ -	75	W	20	**$ 0.25**	$ 0.25	69	24,184	4,620		4,620	ResMTW
25	Energy Star Clothes Washers	SFH	Residential	Appliances	$ 70	$ 63	17	A	13	**$ 0.05**	$ 0.49	3,109		47,354		47,354	ResMTA
26	Energy Star Dishwasher	SFH retro	Residential	Appliances	$ 50	$ 37	5	A	13	**$ 0.31**	$ 1.20	3,740		16,755		16,755	ResMTA
27	Energy Star Dishwasher	MFH retro	Residential	Appliances	$ 50	$ 37	5	A	13	**$ 0.31**	$ 1.20	110		493		493	ResMTA
28	Energy Star Dishwasher	MH retro	Residential	Appliances	$ 50	$ 37	5	A	13	**$ 0.31**	$ 1.20	103		462		462	ResMTA
29	Energy Star Windows	MFH retro	Residential	Shell	$ 392	$ -	68	W	45	**$ 0.43**	$ 0.43	110	12,580	6,693	$ 43,120.00	6,693	ResMTW
30	Energy Star Windows	SFH retro	Residential	Shell	$ 500	$ -	89	W	45	**$ 0.42**	$ 0.42	3,740	202,443	296,738	$ 1,870,000.00	296,738	ResMTW
31	Exterior doors	New SFH	Residential	Shell	$ 100	$ -	7	W	30	**$ 1.22**	$ 1.22	126		753		753	ResRed1
32	Exterior doors	New MFH	Residential	Shell	$ 100	$ -	7	W	30	**$ 1.22**	$ 1.22	10		59		59	ResRed1
33	Exterior doors	SFH retro	Residential	Shell	$ 500	$ -	7	W	30	**$ 6.10**	$ 6.10	351		2,092		2,092	ResRed1
34	Exterior doors	MFH retro	Residential	Shell	$ 500	$ -	7	W	30	**$ 6.10**	$ 6.10	18		109		109	ResRed1
35	Faucet aerators (2)	SFH retro	Residential	DHW	$ 12	$ -	6	A	10	**$ 0.29**	$ 0.29	4,675		25,133		25,133	ResMTA
36	Faucet aerators (2)	MFH retro	Residential	DHW	$ 12	$ -	6	A	10	**$ 0.29**	$ 0.29	550		2,957		2,957	ResMTA
37	Faucet aerators (2)	MH retro	Residential	DHW	$ 12	$ -	6	A	10	**$ 0.29**	$ 0.29	275		1,478		1,478	ResMTA
38	Fireplace dampers	SFH retro	Residential	Shell	$ 200	$ -	76	W	15	**$ 0.29**	$ 0.29	733		49,937	$ 146,666.67	49,937	ResMTW
39	Floor insulation	MFH retro	Residential	Shell	$ 1,200	$ -	45	W	45	**$ 1.97**	$ 1.97	4	2,155	178	$ 5,280.00	178	ResRed1
40	Floor insulation	SFH retro	Residential	Shell	$ 1,244	$ -	128	W	45	**$ 0.72**	$ 0.72	9	122,075	1,200	$ 11,631.40	1,200	ResYel9
41	Furnace retrofit	SFH retro	Residential	HVAC	$ 2,300	$ -	180	W	20	**$ 1.21**	$ 1.21	2,945		475,444		475,444	ResRed1
42	Furnace retrofit	MFH retro	Residential	HVAC	$ 1,900	$ -	76	W	20	**$ 2.38**	$ 2.38	11		748		748	ResRed1
43	Furnace tune-up	MH retro	Residential	HVAC	$ 200	$ -	10	W	3	**$ 7.63**	$ 7.63	69		616		616	ResRed1
44	Gas Pool Heater	New SFH	Residential	HVAC	$ 3,364	$ -	373	W	20	**$ 0.86**	$ 0.86	1	131,166	373	$ 3,364.00	373	ResYel10
45	Gas Pool Heater	SFH replacement	Residential	HVAC	$ 3,364	$ -	373	W	20	**$ 0.86**	$ 0.86	70	756	26,146	$ 235,900.50	26,146	ResYel11
46	Gas Pool Heater	New MFH	Residential	HVAC	$ 3,364	$ -	373	W	20	**$ 0.86**	$ 0.86	100		37,285	$ 336,400.00	37,285	ResYel12
47	Gas Pool Heater	MFH replacement	Residential	HVAC	$ 3,364	$ -	373	W	20	**$ 0.86**	$ 0.86	1	756	246	$ 2,220.24	246	ResYel13
48	Gas Pool Heater	SFH retro	Residential	HVAC	$ 8,651	$ -	373	W	20	**$ 2.20**	$ 2.20	84	15,750	28,112		28,112	ResRed1
49	Gas Pool Heater	MFH retro	Residential	HVAC	$ 8,651	$ -	373	W	20	**$ 2.20**	$ 2.20	1	15,750	220		220	ResRed1
50	Heating System Maintenance (filter/tune-up)	SFH	Residential	HVAC	$ 200	$ -	50	W	2	**$ 2.21**	$ 2.21	1,403		62,832		62,832	ResRed1
51	High efficiency boiler	New SFH	Residential	HVAC	$ 1,000	$ -	40	W	20	**$ 2.37**	$ 2.37	842		30,159	$ 841,500.00	30,159	ResRed1
52	High efficiency boiler	MFH replacement	Residential	DHW	$ 5,000	$ -	40	W	20	**$ 11.89**	$ 11.89	2	660	79	$ 11,000.00	79	ResRed1
53	High efficiency furnace	SFH replacement	Residential	HVAC	$ 800	$ -	120	W	20	**$ 0.63**	$ 0.63	140	22,905	16,808	$ 112,200.00	16,808	ResYel14
54	High efficiency furnace	New SFH	Residential	HVAC	$ 800	$ -	72	W	20	**$ 1.06**	$ 1.06	1,683	51,530	121,176	$ 1,346,400.00	121,176	ResYel15
55	High efficiency furnace	MFH replacement	Residential	HVAC	$ 800	$ -	61	W	20	**$ 1.24**	$ 1.24	6	1,180	302	$ 4,400.00	302	ResRed1
56	High Efficiency furnace	New MFH	Residential	HVAC	$ 800	$ -	61	W	20	**$ 1.25**	$ 1.25	50		2,705	$ 39,600.00	2,705	ResRed1
57	High efficiency water heater (tanked)	SFH replacement	Residential	DHW	$ 60	$ -	20	A	12	**$ 0.38**	$ 0.38	1,683		30,159	$ 100,980.00	30,159	ResMTA
58	High efficiency water heater (tanked)	MFH replacement	Residential	DHW	$ 60	$ -	20	A	12	**$ 0.38**	$ 0.38	3		49	$ 165.00	49	ResMTA
59	High efficiency water heater (tanked)	New SFH	Residential	DHW	$ 60	$ -	20	A	12	**$ 0.38**	$ 0.38	1,346		24,127	$ 80,784.00	24,127	ResMTA
60	High efficiency water heater (tanked)	New MFH	Residential	DHW	$ 60	$ -	20	A	12	**$ 0.38**	$ 0.38	158		2,839	$ 9,504.00	2,839	ResMTA
61	High efficiency water heater (tanked)	MFH retro	Residential	DHW	$ 260	$ -	20	A	12	**$ 1.64**	$ 1.64	1,683		30,159	$ 437,580.00	30,159	ResRed2
62	High efficiency water heater (tanked)	SFH retro	Residential	DHW	$ 260	$ -	20	A	12	**$ 1.64**	$ 1.64	3		49	$ 715.00	49	ResRed2
63	High efficiency water heater (tanked)-65 gal	MH	Residential	DHW	$ 95	$ -	7	A	25	**$ 1.17**	$ 1.17	48		337	$ 4,571.88	337	ResRed2
64	High efficiency water heater (tanked)-80 gal	MH retro	Residential	DHW	$ 100	$ -	7	A	25	**$ 1.18**	$ 1.18	48		351	$ 4,812.50	351	ResRed2

Measure #	Measure	Original measure application	Market segment	Program bundle	Incremental TRC cost / unit	Non-Energy Benefits	First yr therm svgs / unit	Winter or Annual	Measure life	**Levelized TRC cost / therm**	Levelized TRC cost/therm w/o NEBs	New Acquirable Potential (units)	Technical Potential	Annual therm acquirable potential	Annual total (for whole pgm) cost less NEB credit	Achieveable Therms Entered into SENDOUT®	SENDOUT® Code
65	Horizontal axis clothes washer	New SFH	Residential	Appliances	$ 70	$53	17	A	13	**$ 0.12**	$ 0.49	505	12,252	7,691	$ 8,735.63	7,691	ResMTA
66	Horizontal axis clothes washer	SFH retro	Residential	Appliances	$ 70	$63	17	A	13	**$ 0.05**	$ 0.49	1,332	274,860	20,295	$ 9,326.63	20,295	ResMTA
67	Installing storm windows	MH	Residential	Shell	$ 15	$ -	1	W	25	**$ 0.90**	$ 0.90	220		308	$ 3,196.60	308	ResYel16
68	Low flow showerheads	SFH retro	Residential	DHW	$ 2	$ 2	6	A	4	**$ 0.02**	$ 0.12	1,870		10,053	$ 748.00	10,053	ResMTA
69	Low flow showerheads	MFH retro	Residential	DHW	$ 2	$ 2	6	A	4	**$ 0.02**	$ 0.12	1,403		7,540	$ 561.00	7,540	ResMTA
70	Low flow showerheads	MH retro	Residential	DHW	$ 2	$ 2	6	A	4	**$ 0.02**	$ 0.12	1,403		7,540	$ 561.00	7,540	ResMTA
71	Passive solar water heating	SFH retro	Residential	DHW	$ 2,000	$ -	150	A	15	**$ 1.47**	$ 1.47	2	2,143,911	269	$ 4,000.00	269	ResRed2
72	Passive solar water heating	New SFH	Residential	DHW	$ 2,000	$ -	150	A	15	**$ 1.47**	$ 1.47	5		672	$ 10,000.00	672	ResRed2
73	Pipe insulation	SFH retro	Residential	DHW	$ 121	$ -	10	A	15	**$ 1.34**	$ 1.34	94	153,739	838	$ 11,313.50	838	ResRed2
74	Pipe insulation/wrap - long wrap (min 15ft)	MH retro	Residential	DHW	$ 15	$ -	2	A	15	**$ 0.75**	$ 0.75	10		23	$ 154.69	23	ResYel17
75	Pipe insulation/wrap - short wrap (min 3ft)	MH retro	Residential	DHW	$ 5	$ -	1	A	15	**$ 0.69**	$ 0.69	10		8	$ 51.56	8	ResYel18
76	Pool blanket	New SFH	Residential	DHW	$ 1,100	$ -	1,360	A	10	**$ 0.12**	$ 0.12	1	1,274,184	1,219	$ 1,100.00	1,219	ResMTA
77	Pool blanket	New MFH	Residential	DHW	$ 25	$ -	41	A	20	**$ 0.06**	$ 0.06	20		740	$ 500.00	740	ResMTA
78	Power burner	MFH retro	Residential	HVAC	$ 180	$ -	27	W	12	**$ 0.85**	$ 0.85	6		146	$ 990.00	146	ResYel19
79	Tankless water heater	SFH replacement	Residential	DHW	$ 800	$ -	82	A	20	**$ 0.93**	$ 0.93	84	56,346	6,900	$ 67,320.00	6,900	ResYel20
80	Tankless water heater	MFH replacement	Residential	DHW	$ 800	$ -	82	A	20	**$ 0.93**	$ 0.93	1	6,498	90	$ 880.00	90	ResYel21
81	Tankless water heater	SFH retro	Residential	DHW	$ 800	$ -	82	A	20	**$ 0.93**	$ 0.93	9	676,157	767	$ 7,480.00	767	ResYel22
82	Tankless water heater	MFH retro	Residential	DHW	$ 800	$ -	82	A	20	**$ 0.93**	$ 0.93	1	77,979	90	$ 880.00	90	ResYel23
83	Tankless water heater	SFH	Residential	DHW	$ 700	$ -	102	A	15	**$ 0.76**	$ 0.76	168	901,542	17,167	$ 117,810.00	17,167	ResYel24
84	Thermal Vent Damper	MFH retro	Residential	HVAC	$ 60	$ -	27	W	12	**$ 0.28**	$ 0.28	990	14,309	23,624	$ 59,400.00	23,624	ResMTW
85	Wall insulation	SFH retro	Residential	Shell	$ 2	$ -	0	W	45	**$ 0.23**	$ 0.23	2,244,000	67,141	989,126	$ 3,366,000.00	989,126	ResMTW
86	Walls insulation	MFH retro	Residential	Shell	$ 1	$ -	0	W	45	**$ 1.39**	$ 1.39	2,750		132	$ 2,750.00	132	ResRed1
87	Zone and Loop Controls	MFH retro	Residential	HVAC	$ 630	$ -	63	W	15	**$ 1.11**	$ 1.11	47		2,926	$ 29,452.50	2,926	ResYel25
88	BBQ / Rotisserie Oven	Cooking replaceme	Non-residenti	Cooking	$ 1,003	$ -	198	A	15	**$ 0.56**	$ 0.56	1	337	198	$ 1,003.00	198	ComYel1
89	Boiler	Water heating repl	Non-residenti	DHW	$ 11,928	$ -	800	W	20	**$ 1.42**	$ 1.42	50	7,194	4,120	$ 596,400.00	4,120	ComRed2
90	Boiler Tune-up	Space heating retro	Non-residenti	HVAC	$ 100	$ -	67	W	5	**$ 0.37**	$ 0.37	10	10,422	69	$ 1,000.00	69	ComMTW
91	Clothes washer	Water heating retro	Non-residenti	Appliances	$ 2,250	$ -	50	A	11	**$ 6.02**	$ 6.02	2	4,678	10	$ 4,500.00	10	ComRed1
92	Clothes washer	Water heating repl	Non-residenti	Appliances	$ 900	$193	50	A	11	**$ 1.89**	$ 2.41	5	425	26	$ 3,535.07	26	ComRed1
93	Coin-Op Clothers Dryer	Miscellaneous retro	Non-residenti	Appliances	$ 5,573	$ -	419	A	11	**$ 1.78**	$ 1.78	2	21,722	86	$ 11,146.00	86	ComRed1
94	Coin-Op Clothers Dryer	Miscellaneous repl	Non-residenti	Appliances	$ 613	$ -	419	A	11	**$ 0.20**	$ 0.20	2	1,975	86	$ 1,226.00	86	ComMTA
95	Coin-op clothes washer	Water heating retro	Non-residenti	Appliances	$ 750	$ -	11	A	11	**$ 9.13**	$ 9.13	5	1,504	6	$ 3,750.00	6	ComRed1
96	Coin-op clothes washer	Water heating repl	Non-residenti	Appliances	$ 300	$125	29	A	11	**$ 0.81**	$ 1.39	10	137	290	$ 1,748.99	290	ComYel2
97	Combination Oven	Cooking retrofit	Non-residenti	Cooking	$ 17,018	$ -	164	A	15	**$ 11.45**	$ 11.45	2	2,182	34	$ 34,036.00	34	ComRed1
98	Combination Oven	Cooking replaceme	Non-residenti	Cooking	$ 1,667	$ -	164	A	15	**$ 1.12**	$ 1.12	7	146	1,148	$ 11,669.00	1,148	ComRed1
99	Condensing Boiler	Water heating repl	Non-residenti	DHW	$ 36,701	$ -	1,200	A	20	**$ 2.90**	$ 2.90	5	14,046	618	$ 183,505.00	618	ComRed1
100	Condensing Storage Water Heater	Water heating repl	Non-residenti	DHW	$ 848	$ -	308	A	15	**$ 0.30**	$ 0.30	10	15,373	317	$ 8,480.00	317	ComMTA
101	Condensing Tank Water Heater	Water heating retro	Non-residenti	DHW	$ 3,855	$ -	771	A	15	**$ 0.55**	$ 0.55	8	518,830	6,168	$ 30,840.00	6,168	ComYel3
102	Convection Oven	Cooking retrofit	Non-residenti	Cooking	$ 5,762	$ -	324	A	20	**$ 1.69**	$ 1.69	2	26,784	67	$ 11,524.00	67	ComRed1
103	Convection Oven	Cooking replaceme	Non-residenti	Cooking	$ 2,696	$ -	324	A	20	**$ 0.79**	$ 0.79	5	1,786	1,620	$ 13,480.00	1,620	ComYel4
104	Conveyer Broiler	Cooking retrofit	Non-residenti	Cooking	$ 3,674	$ -	661	A	15	**$ 0.61**	$ 0.61	1	981	661	$ 3,674.00	661	ComYel5
105	Conveyer Broiler	Cooking replaceme	Non-residenti	Cooking	$ 1,182	$ -	661	A	15	**$ 0.20**	$ 0.20	2	65	136	$ 2,364.00	136	ComMTA
106	Demand control ventilation	HVAC	Non-residenti	HVAC	0.8	$ -	0.3888	W	20	**$ 0.20**	$ 0.20	15		1	$ 12.00	1	ComMTW
107	Energy recovery ventilation	HVAC	Non-residenti	HVAC	4	$ -	0.4403	W	20	**$ 0.86**	$ 0.86	2,500		1,101	$ 10,000.00	1,101	ComYel6
108	Energy Star Steamer	Cooking retrofit	Non-residenti	Cooking	$ 970	$ -	643	A	20	**$ 0.14**	$ 0.14	20	5,015	1,325	$ 19,400.00	1,325	ComMTA
109	Energy Star Steamer	Cooking replaceme	Non-residenti	Cooking	$ 111	$ -	643	A	20	**$ 0.02**	$ 0.02	20	334	1,325	$ 2,220.00	1,325	ComMTA
110	Fryer	Cooking retrofit	Non-residenti	Cooking	$ 3,500	$ -	445	A	15	**$ 0.87**	$ 0.87	2		890	$ 7,000.00	890	ComYel7
111	Fryer	Cooking replaceme	Non-residenti	Cooking	$ 1,219	$ -	404	A	15	**$ 0.33**	$ 0.33	6		250	$ 7,314.00	250	ComMTA
112	Gas Pool Heater	Miscellaneous retro	Non-residenti	Pool	$ 8,651	$ -	373	A	20	**$ 2.20**	$ 2.20	2	5,231	77	$ 17,302.00	77	ComRed1
113	Gas Spa Heater	Miscellaneous retro	Non-residenti	Pool	$ 1,377	$ -	13	A	20	**$ 9.82**	$ 9.82	2	110	3	$ 2,754.00	3	ComRed1
114	Griddle	Cooking retrofit	Non-residenti	Cooking	$ 1,500	$ -	81	A	15	**$ 2.04**	$ 2.04	2		17	$ 3,000.00	17	ComRed1
115	Griddle	Cooking replaceme	Non-residenti	Cooking	$ 491	$ -	75	A	15	**$ 0.72**	$ 0.72	4		300	$ 1,964.00	300	ComYel8
116	High efficiency charbroiler	Cooking replaceme	Non-residenti	Cooking	$ 1,313	$ -	298	A	15	**$ 0.49**	$ 0.49	2	521	61	$ 2,626.00	61	ComMTA
117	High efficiency condensing hot water heater	Cooking retrofit	Non-residenti	Cooking	$ 4,153	$ -	483	A	15	**$ 0.95**	$ 0.95	5	518,830	2,415	$ 20,765.00	2,415	ComYel9
118	High efficiency condensing hot water heater	Cooking replaceme	Non-residenti	Cooking	$ 2,266	$ -	218	A	15	**$ 1.15**	$ 1.15	5	15,373	1,090	$ 11,330.00	1,090	ComRed1
119	High efficiency hot water heater	Cooking retrofit	Non-residenti	Cooking	$ 551	$ -	13	A	15	**$ 4.68**	$ 4.68	5		7	$ 2,755.00	7	ComRed1
120	High efficiency hot water heater	Cooking replaceme	Non-residenti	Cooking	$ 175	$ -	12	A	15	**$ 1.61**	$ 1.61	5		6	$ 875.00	6	ComRed1
121	Multi-tank conveyer dishwasher	Cooking retrofit	Non-residenti	Cooking	$ 24,000	$ -	1,092	A	15	**$ 2.43**	$ 2.43	2		225	$ 48,000.00	225	ComRed1
122	Multi-tank conveyer dishwasher	Cooking replaceme	Non-residenti	Cooking	$ 4,000	$ -	993	A	15	**$ 0.44**	$ 0.44	4		409	$ 16,000.00	409	ComMTA
123	Occupancy sensors for PTAC units	HVAC	Non-residenti	HVAC	200	$ -	34.13	W	20	**$ 0.56**	$ 0.56	200		703	$ 40,000.00	703	ComMTW
124	Pizza / Deck Oven	Cooking retrofit	Non-residenti	Cooking	$ 8,007	$ -	256	A	20	**$ 2.97**	$ 2.97	1		26	$ 8,007.00	26	ComRed1
125	Pizza / Deck Oven	Cooking replaceme	Non-residenti	Cooking	$ 466	$ -	256	A	20	**$ 0.17**	$ 0.17	2	284	53	$ 932.00	53	ComMTA
126	Point of Use hot water heater	Cooking retrofit	Non-residenti	Cooking	$ 1,118	$ -	18	A	15	**$ 6.85**	$ 6.85	2		4	$ 2,236.00	4	ComRed1
127	Point of Use hot water heater	Cooking replaceme	Non-residenti	Cooking	$ 371	$ -	17	A	15	**$ 2.41**	$ 2.41	2		4	$ 742.00	4	ComRed1
128	Pool blanket	Water heating repl	Non-residenti	Pool	$ 2,200	$ -	2,720	A	10	**$ 0.12**	$ 0.12	5	9,792	1,401	$ 11,000.00	1,401	ComMTA
129	Programmable Thermostats	Space heating retro	Non-residenti	HVAC	$ 100	$ -	117	W	20	**$ 0.08**	$ 0.08	10		121	$ 1,000.00	121	ComMTW

Measure #	Measure	Original measure application	Market segment	Program bundle	Incremental TRC cost / unit	Non-Energy Benefits	First yr therm svgs / unit	Winter or Annual	Measure life	**Levelized TRC cost / therm**	Levelized TRC cost/therm w/o NEBs	New Acquirable Potential (units)	Technical Potential	Annual therm acquirable potential	Annual total (for whole pgm) cost less NEB credit	Achieveable Therms Entered into SENDOUT®	SENDOUT® Code
130	Rack / Tray Oven	Cooking replaceme	Non-residenti	Cooking	$ 9,709	$ -	1,013	A	20	**$ 0.91**	$ 0.91	3	2,134	3,039	$ 29,127.00	3,039	ComYel10
131	Radiant heat	Space heating repl	Non-residenti	HVAC	$ 25	$ -	117	W	20	**$ 0.02**	$ 0.02	6		72	$ 150.00	72	ComMTW
132	Recirculation Controls	Water heating retrc	Non-residenti	DHW	$ 1,311	$ -	386	A	10	**$ 0.49**	$ 0.49	8	33,802	318	$ 10,488.00	318	ComMTA
133	Retro-Commissioning	Space heating retr	Non-residenti	HVAC	3000	$ -	2000	W	7	**$ 0.28**	$ 0.28	5		1,030	$ 15,000.00	1,030	ComMTW
134	Roof insulation	Envelope retrofit	Non-residenti	Shell	$ 0	$ -	0	W	30	**$ 0.15**	$ 0.15	30	7,683	1	$ 12.00	1	ComMTW
135	Rooftop Maintenance	Space heating retr	Non-residenti	HVAC	$ 100	$ -	117	W	20	**$ 0.08**	$ 0.08	20		241	$ 2,000.00	241	ComMTW
136	Salamander	Cooking replaceme	Non-residenti	Cooking	$ 300	$ -	137	A	15	**$ 0.24**	$ 0.24	15	28	212	$ 4,500.00	212	ComMTA
137	Salamander (Broiler)	Cooking retrofit	Non-residenti	Cooking	$ 2,221	$ -	137	A	15	**$ 1.79**	$ 1.79	15	425	212	$ 33,315.00	212	ComRed1
138	Single tank conveyer dishwasher	Cooking retrofit	Non-residenti	Cooking	$ 7,000	$ -	559	A	15	**$ 1.38**	$ 1.38	5		288	$ 35,000.00	288	ComRed1
139	Single tank conveyer dishwasher	Cooking replaceme	Non-residenti	Cooking	$ 2,000	$ -	509	A	15	**$ 0.43**	$ 0.43	10		524	$ 20,000.00	524	ComMTA
140	Single tank door type dishwasher	Cooking retrofit	Non-residenti	Cooking	$ 6,000	$ -	669	A	15	**$ 0.99**	$ 0.99	5		3,345	$ 30,000.00	3,345	ComYel11
141	Single tank door type dishwasher	Cooking replaceme	Non-residenti	Cooking	$ 2,000	$ -	608	A	15	**$ 0.36**	$ 0.36	10		626	$ 20,000.00	626	ComMTA
142	Solar water	Water heating retrc	Non-residenti	DHW	$ 2,000	$ -	150	A	11	**$ 1.79**	$ 1.79	1		15	$ 2,000.00	15	ComRed1
143	Tankless Water Heater	Water heating repl	Non-residenti	DHW	$ 600	$ -	211	A	20	**$ 0.27**	$ 0.27	25	3,935	543	$ 15,000.00	543	ComMTA
144	Time clock control of hot water heater circulating pu	Cooking retrofit	Non-residenti	Cooking	$ 224	$ -	11	A	15	**$ 2.25**	$ 2.25	1		1	$ 224.00	1	ComRed1
145	Time clock control of hot water heater circulating pu	Cooking replaceme	Non-residenti	Cooking	$ 224	$ -	11	A	15	**$ 2.25**	$ 2.25	1		1	$ 224.00	1	ComRed1
146	Under counter dishwashers	Cooking retrofit	Non-residenti	Cooking	$ 6,000	$ -	358	A	15	**$ 1.85**	$ 1.85	5		184	$ 30,000.00	184	ComRed1
147	Under counter dishwashers	Cooking replaceme	Non-residenti	Cooking	$ 1,000	$ -	326	A	15	**$ 0.34**	$ 0.34	10		336	$ 10,000.00	336	ComMTA
148	Vent Damper	Space heating retr	Non-residenti	HVAC	$ 304	$ -	134	W	12	**$ 0.29**	$ 0.29	10	5,848	139	$ 3,040.00	139	ComMTW
149	Vent Hood Controls	Cooking retrofit	Non-residenti	Cooking	$ 2,160	$ -	293	A	15	**$ 0.81**	$ 0.81	5		1,465	$ 10,800.00	1,465	ComYel12
150	Vent Hood Controls	Cooking replaceme	Non-residenti	Cooking	$ 1,298	$ -	293	A	15	**$ 0.49**	$ 0.49	5		151	$ 6,490.00	151	ComMTA
151	Wall insulation	Envelope retrofit	Non-residenti	Shell	$ 0	$ -	0	W	30	**$ 0.11**	$ 0.11	500,000	15,782	15,087	$ 195,000.00	15,087	ComMTW
152	Warm Up Control	Space heating retr	Non-residenti	HVAC	$ 300	$ -	240	W	10	**$ 0.18**	$ 0.18	50	6,246	1,234	$ 15,000.00	1,234	ComMTW
153	Window retrofit	Envelope retrofit	Non-residenti	Shell	$ 30	$ -	2	W	30	**$ 1.61**	$ 1.61	150,000	15,874	23,453	$ 4,500,000.00	23,453	ComRed2
													10,387,595	3,016,057	$ 5,153,638.00	3,016,057	

APPENDIX 4.3

SENDOUT® SELECTED CONSERVATION MEASURES

DSM Program	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019
KlaComRed2	227.31	454.62	683.79	909.23	1,136.54	1,363.85	1,595.52	1,818.47	2,045.78	2,273.09
KlaComYel10	2.60	5.20	7.81	10.39	12.99	15.59	18.23	20.78	23.38	25.98
KlaComYel11	88.55	177.11	266.39	354.21	442.77	531.32	621.57	708.43	796.98	885.53
KlaComYel12	2.86	5.73	8.61	11.45	14.32	17.18	20.10	22.91	25.77	28.63
KlaComYel13	4.43	8.86	13.32	17.71	22.14	26.57	31.08	35.42	39.85	44.28
KlaComYel14	5.50	11.01	16.59	22.05	27.27	32.63	37.92	43.20	48.42	53.51
KlaComYel15	30.52	61.04	91.82	122.09	152.61	183.13	214.24	244.17	274.69	305.21
KlaComYel16	30.52	61.04	91.82	122.09	152.61	183.13	214.24	244.17	274.69	305.21
KlaComYel17	15.00	29.99	45.11	59.98	74.98	89.97	105.25	119.96	134.96	149.95
KlaComYel18	15.00	29.99	45.11	59.98	74.98	89.97	105.25	119.96	134.96	149.95
KlaComYel19	21.62	43.24	65.04	86.49	108.11	129.73	151.77	172.97	194.60	216.22
KlaComYel20	-	-	-	0.11	0.37	0.66	0.76	0.98	1.10	1.32
KlaComYel9	2.60	5.20	7.81	10.39	12.99	15.59	18.23	20.78	23.38	25.98
KlamComMTA	953.49	1,906.99	2,868.32	3,813.98	4,767.47	5,720.97	6,692.75	7,627.96	8,581.45	9,534.94
KlamComMTW	611.45	1,222.89	1,830.23	2,419.50	2,991.98	3,579.42	4,160.66	4,738.98	5,312.46	5,870.80
KlamComYel1	49.73	99.46	148.85	196.77	243.33	291.11	338.38	385.41	432.06	477.46
KlamComYel2	1.71	3.42	5.15	6.85	8.56	10.27	12.02	13.70	15.41	17.12
KlamComYel3	35.42	70.84	106.56	141.69	177.11	212.53	248.63	283.37	318.79	354.21
KlamComYel4	23.91	47.82	71.92	95.64	119.55	143.46	167.82	191.28	215.18	239.09
KlamComYel5	23.91	47.82	71.92	95.64	119.55	143.46	167.82	191.28	215.18	239.09
KlamComYel6	19.51	39.02	58.69	78.05	97.56	117.07	136.95	156.09	175.60	195.11
KlamComYel7	91.23	182.46	273.08	361.00	446.42	534.06	620.79	707.08	792.64	875.95
KlamComYel8	5.50	11.01	16.55	22.01	27.51	33.02	38.63	44.02	49.53	55.03
KlamResMTA	211.52	423.03	636.29	846.07	1,057.58	1,269.10	1,484.68	1,692.14	1,903.65	2,115.17
KlamResMTW	1,742.00	3,484.00	5,214.30	6,893.12	8,524.10	10,197.72	11,853.66	13,501.28	15,135.12	16,725.80
KlamResYel1	37.78	75.57	113.10	149.51	184.89	221.19	257.11	292.85	328.28	362.79
KlamResYel2	5.27	10.53	15.88	21.11	26.10	31.23	36.30	41.34	46.35	51.22
KlaResRed1	666.30	1,332.61	1,994.44	1,977.43	1,956.25	1,950.28	1,943.12	1,936.56	1,929.70	1,919.26
KlaResRed2	291.16	582.32	875.88	1,164.65	1,455.81	1,746.97	2,043.71	2,329.29	2,620.45	2,911.61
KlaResYel10	4.31	8.62	12.91	17.19	21.37	25.57	29.72	33.85	37.94	41.93
KlaResYel11	530.17	1,060.34	1,586.95	2,097.90	2,594.28	3,103.64	3,607.62	4,109.06	4,606.32	5,090.43
KlaResYel12	412.36	824.71	1,234.30	1,631.70	2,017.77	2,413.94	2,805.92	3,195.94	3,582.69	3,959.23
KlaResYel13	3.24	6.84	10.24	13.54	16.86	20.29	23.58	26.86	30.11	33.27
KlaResYel14	-	-	-	-	-	-	-	-	1.31	1.45
KlaResYel16	111.37	222.74	335.03	445.48	556.85	668.22	781.73	890.97	1,002.34	1,113.71
KlaResYel17	-	1.17	1.90	2.53	3.16	3.80	4.44	5.06	5.70	6.33
KlaResYel18	107.60	215.21	323.70	430.42	538.02	645.63	755.30	860.84	968.44	1,076.05
KlaResYel19	-	1.17	1.90	2.53	3.16	3.80	4.44	5.06	5.70	6.33
KlaResYel20	109.76	219.51	330.17	439.03	548.78	658.54	770.40	878.05	987.81	1,097.57
KlaResYel3	5.13	10.27	15.48	20.57	25.44	25.36	25.27	25.18	25.10	24.96
KlaResYel4	10.36	20.99	31.42	41.53	51.36	61.44	71.42	81.35	91.19	100.77
KlaResYel5	6.03	12.06	18.19	24.17	29.89	35.76	41.57	47.35	53.08	58.65
KlaResYel6	-	-	-	-	-	-	-	-	-	74.89
KlaResYel7	6.84	13.69	20.74	27.42	33.91	40.57	47.16	53.71	60.21	66.54
KlaResYel8	8.46	17.03	25.63	33.88	41.90	50.13	58.27	66.37	74.40	82.22
KlaResYel9	8.25	16.61	25.00	33.05	40.87	48.89	56.83	64.73	72.57	80.20
LaGrComMTA	463.36	926.73	1,393.90	1,853.45	2,316.82	2,780.18	3,252.43	3,706.91	4,170.27	4,633.63
LaGrComMTW	308.18	604.14	891.87	1,168.84	1,437.88	1,691.44	1,943.32	2,182.68	2,407.15	2,623.83
LaGrComRed2	110.46	220.93	332.30	441.85	552.32	662.78	775.36	883.71	994.17	1,104.64
LaGrComYel1	25.06	49.13	72.53	95.06	116.94	137.56	158.05	177.51	195.77	213.39
LaGrComYel10	1.40	2.81	4.22	5.61	7.02	8.42	9.85	11.23	12.63	14.03
LaGrComYel11	47.84	95.68	143.91	191.36	239.20	287.03	335.79	382.71	430.55	478.39
LaGrComYel12	1.55	3.09	4.65	6.19	7.73	9.28	10.86	12.37	13.92	15.47
LaGrComYel13	2.39	4.78	7.20	9.57	11.96	14.35	16.79	19.14	21.53	23.92
LaGrComYel14	2.66	5.45	8.04	10.54	12.97	15.26	17.63	19.81	21.84	23.92
LaGrComYel15	16.49	32.98	49.60	65.95	82.44	98.93	115.74	131.91	148.40	164.89

DSM Program	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019
LaGrComYel16	16.49	32.98	49.60	65.95	82.44	98.93	115.74	131.91	148.40	164.89
LaGrComYel17	8.10	16.20	24.37	32.40	40.50	48.60	56.86	64.81	72.91	81.01
LaGrComYel18	8.10	16.20	24.37	32.40	40.50	48.60	56.86	64.81	72.91	81.01
LaGrComYel19	11.68	23.36	35.14	46.72	58.40	70.08	81.99	93.45	105.13	116.81
LaGrComYel2	-	1.85	2.78	3.70	4.62	5.55	6.49	7.40	8.32	9.25
LaGrComYel20	-	-	-	-	-	-	-	0.11	0.12	0.34
LaGrComYel3	19.14	38.27	57.56	76.54	95.68	114.81	134.32	153.09	172.22	191.36
LaGrComYel4	12.92	25.83	38.86	51.67	64.58	77.50	90.66	103.33	116.25	129.17
LaGrComYel5	12.92	25.83	38.86	51.67	64.58	77.50	90.66	103.33	116.25	129.17
LaGrComYel6	10.54	21.08	31.71	42.16	52.70	63.24	73.99	84.32	94.86	105.41
LaGrComYel7	45.98	90.14	133.07	174.40	214.54	252.37	289.95	325.66	359.16	391.49
LaGrComYel8	2.97	5.95	8.94	11.89	14.86	17.84	20.87	23.78	26.75	29.73
LaGrComYel9	1.40	2.81	4.22	5.61	7.02	8.42	9.85	11.23	12.63	14.03
LaGrResMTA	88.14	176.28	265.14	352.55	440.69	528.83	618.66	705.11	793.25	881.39
LaGrResMTW	750.12	1,470.48	2,170.80	2,844.96	3,499.80	4,116.96	4,730.04	5,312.64	5,859.00	6,386.40
LaGrResRed1	287.97	564.51	833.36	819.12	806.13	790.24	778.21	764.81	749.74	735.51
LaGrResRed2	121.33	242.65	364.98	485.30	606.63	727.96	851.61	970.61	1,091.94	1,213.26
LaGrResYel1	16.16	32.01	47.26	61.93	76.19	89.62	102.97	115.65	127.55	139.03
LaGrResYel10	1.79	3.50	5.40	7.08	8.71	10.25	11.78	13.23	14.59	15.91
LaGrResYel11	229.13	449.17	663.09	869.02	1,069.05	1,257.57	1,444.84	1,622.80	1,789.69	1,950.79
LaGrResYel12	178.21	349.36	515.74	675.91	831.48	978.11	1,123.76	1,262.18	1,391.98	1,517.28
LaGrResYel13	1.34	2.78	4.10	5.62	6.91	8.13	9.34	10.50	11.58	12.62
LaGrResYel16	51.59	103.18	155.19	206.36	257.95	309.54	362.12	412.72	464.31	515.90
LaGrResYel17	-	-	-	-	1.47	1.76	2.06	2.35	2.64	2.93
LaGrResYel18	49.85	99.69	149.95	199.38	249.23	299.07	349.87	398.76	448.61	498.45
LaGrResYel19	-	-	-	-	1.47	1.76	2.06	2.35	2.64	2.93
LaGrResYel2	2.18	4.38	6.60	8.65	10.64	12.52	14.38	16.16	17.93	19.54
LaGrResYel20	50.84	101.68	152.94	203.37	254.21	305.05	356.87	406.74	457.58	508.42
LaGrResYel3	2.13	4.27	6.43	8.43	10.37	10.17	10.01	9.85	9.65	9.47
LaGrResYel4	4.40	8.80	12.99	17.13	21.07	24.90	28.60	32.13	35.43	38.62
LaGrResYel5	2.50	5.12	7.56	9.91	12.19	14.34	16.47	18.61	20.53	22.48
LaGrResYel6	177.11	347.19	512.54	671.72	826.33	972.05	1,116.80	1,254.36	1,383.36	1,507.88
LaGrResYel7	2.84	5.81	8.57	11.24	13.83	16.27	18.80	21.12	23.39	25.50
LaGrResYel8	3.50	7.18	10.59	13.89	17.19	20.22	23.34	26.21	28.91	31.51
LaGrResYel9	3.42	7.00	10.33	13.55	16.67	19.72	22.76	25.57	28.19	30.73
MedGComRed2	-	808.39	1,215.91	1,616.78	2,020.97	2,425.17	2,837.11	3,233.56	3,637.75	4,041.95
MedGComYel10	7.03	14.07	21.16	28.13	35.17	42.20	49.37	56.27	63.30	70.33
MedGComYel11	239.77	479.55	721.29	959.10	1,198.87	1,438.64	1,683.02	1,918.19	2,157.97	2,397.74
MedGComYel12	7.75	15.51	23.32	31.01	38.76	46.52	54.42	62.02	69.77	77.53
MedGComYel13	11.99	23.98	36.06	47.95	59.94	71.93	84.15	95.91	107.90	119.89
MedGComYel14	10.35	20.50	30.20	39.79	49.25	58.49	67.61	76.44	84.94	93.11
MedGComYel15	82.64	165.28	248.61	330.57	413.21	495.85	580.08	661.14	743.78	826.42
MedGComYel16	82.64	165.28	248.61	330.57	413.21	495.85	580.08	661.14	743.78	826.42
MedGComYel17	40.60	81.20	122.14	162.41	203.01	243.61	284.99	324.81	365.42	406.02
MedGComYel18	40.60	81.20	122.14	162.41	203.01	243.61	284.99	324.81	365.42	406.02
MedGComYel19	58.54	117.09	176.12	234.18	292.72	351.27	410.94	468.36	526.90	585.45
MedGComYel20	-	0.12	0.56	0.87	1.19	1.53	1.76	2.09	2.32	2.55
MedGComYel9	7.03	14.07	21.16	28.13	35.17	42.20	49.37	56.27	63.30	70.33
MedGResRed1	1,150.25	2,279.53	3,357.88	3,318.18	3,285.98	3,252.27	3,211.82	3,177.37	3,138.42	3,096.47
MedGResRed2	480.05	960.11	1,444.10	1,920.21	2,400.27	2,880.32	3,369.58	3,840.42	4,320.48	4,800.53
MedGResYel10	7.42	14.90	21.94	28.91	35.78	42.50	48.96	55.35	61.71	67.65
MedGResYel11	915.24	1,813.80	2,671.83	3,520.32	4,357.69	5,175.59	5,963.09	6,741.85	7,491.61	8,212.76
MedGResYel12	711.86	1,410.73	2,078.09	2,738.03	3,389.31	4,025.46	4,637.96	5,243.66	5,826.81	6,387.70
MedGResYel13	5.80	11.82	17.41	22.94	28.39	33.72	38.85	43.92	48.80	53.50
MedGResYel14	-	-	-	1.46	1.82	2.19	2.56	2.91	3.28	3.64
MedGResYel15	-	-	-	-	-	-	-	-	0.71	1.32

DSM Program	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019
MedGResYel16	279.61	559.21	841.12	1,118.43	1,398.04	1,677.64	1,962.61	2,236.86	2,516.47	2,796.07
MedGResYel17	1.59	3.18	4.78	6.36	7.95	9.53	11.15	12.71	14.30	15.89
MedGResYel18	270.15	540.30	812.68	1,080.61	1,350.76	1,620.91	1,896.25	2,161.22	2,431.37	2,701.52
MedGResYel19	1.59	3.18	4.78	6.36	7.95	9.53	11.15	12.71	14.30	15.89
MedGResYel20	275.56	551.11	828.93	1,102.22	1,377.78	1,653.33	1,934.17	2,204.44	2,480.00	2,755.55
MedGTComYel1	92.59	183.48	270.28	356.11	440.82	523.56	603.22	682.00	757.84	830.80
MedGTComYel2	4.64	9.27	13.94	18.54	23.18	27.81	32.54	37.09	41.72	46.36
MedGTComYel3	95.91	191.82	288.52	383.64	479.55	575.46	673.21	767.28	863.19	959.10
MedGTComYel4	64.74	129.48	194.75	258.96	323.69	388.43	454.41	517.91	582.65	647.39
MedGTComYel5	64.74	129.48	194.75	258.96	323.69	388.43	454.41	517.91	582.65	647.39
MedGTComYel6	52.83	105.66	158.92	211.32	264.15	316.98	370.82	422.64	475.47	528.30
MedGTComYel7	169.86	336.61	495.85	653.32	808.72	960.51	1,106.66	1,251.18	1,390.33	1,524.16
MedGTComYel8	14.90	29.80	44.82	59.60	74.50	89.40	104.58	119.20	134.10	149.00
MedGTNComMTA	1,695.48	3,390.96	5,100.37	6,781.92	8,477.40	10,172.88	11,900.87	13,563.84	15,259.32	16,954.80
MedGTNComMTW	1,105.68	2,191.20	3,227.76	4,252.80	5,264.40	6,252.48	7,203.84	8,144.64	9,050.40	9,921.60
MedGTNResMTA	348.74	697.48	1,049.08	1,394.96	1,743.69	2,092.43	2,447.86	2,789.91	3,138.65	3,487.39
MedGTNResMTW	3,051.64	6,047.63	8,908.50	11,737.57	14,529.55	17,256.61	19,882.33	22,478.90	24,978.77	27,383.25
MedGTResYel1	65.03	129.27	190.42	250.89	310.57	368.86	424.98	480.48	533.92	585.31
MedGTResYel2	9.18	18.19	26.80	35.31	43.70	51.91	59.80	67.83	75.38	82.63
MedGTResYel3	8.95	17.73	26.12	34.41	42.60	42.16	41.63	41.18	40.68	40.13
MedGTResYel4	18.06	35.80	52.73	69.69	86.27	102.46	118.05	133.47	148.31	162.59
MedGTResYel5	10.51	20.84	30.69	40.44	50.05	59.44	68.71	77.68	86.32	94.63
MedGTResYel6	707.44	1,401.99	2,065.21	2,721.06	3,368.31	4,000.51	4,609.22	5,211.17	5,790.70	6,348.12
MedGTResYel7	11.93	23.64	34.82	45.87	56.78	67.65	77.95	88.13	97.93	107.36
MedGTResYel8	14.74	29.21	43.02	56.68	70.38	83.60	96.31	108.89	121.00	132.65
MedGTResYel9	14.38	28.49	41.96	55.28	68.65	81.54	93.94	106.21	118.02	129.38
MedNComRed2	-	363.19	546.28	726.38	907.97	1,089.57	1,274.65	1,452.76	1,634.35	1,815.95
MedNComYel10	3.16	6.32	9.51	12.64	15.80	18.96	22.18	25.28	28.44	31.60
MedNComYel11	107.72	215.45	324.06	430.90	538.62	646.35	756.14	861.80	969.52	1,077.25
MedNComYel12	3.48	6.97	10.48	13.93	17.42	20.90	24.45	27.86	31.35	34.83
MedNComYel13	5.39	10.77	16.20	21.54	26.93	32.32	37.81	43.09	48.48	53.86
MedNComYel14	4.52	9.21	13.57	17.87	22.13	26.28	30.27	34.23	38.03	41.69
MedNComYel15	37.13	74.26	111.69	148.52	185.65	222.77	260.62	297.03	334.16	371.29
MedNComYel16	37.13	74.26	111.69	148.52	185.65	222.77	260.62	297.03	334.16	371.29
MedNComYel17	18.24	36.48	54.87	72.97	91.21	109.45	128.04	145.93	164.17	182.41
MedNComYel18	18.24	36.48	54.87	72.97	91.21	109.45	128.04	145.93	164.17	182.41
MedNComYel19	26.30	52.61	79.12	105.21	131.51	157.82	184.62	210.42	236.72	263.03
MedNComYel20	-	-	-	0.11	0.24	0.49	0.57	0.75	0.83	0.92
MedNComYel9	3.16	6.32	9.51	12.64	15.80	18.96	22.18	25.28	28.44	31.60
MedNResRed1	516.78	1,024.14	1,508.61	1,490.78	1,476.31	1,461.16	1,442.99	1,427.51	1,410.01	1,391.17
MedNResRed2	215.68	431.35	648.80	862.70	1,078.38	1,294.06	1,513.87	1,725.41	1,941.08	2,156.76
MedNResYel10	3.28	6.51	9.86	12.99	16.08	19.09	22.00	24.87	27.63	30.29
MedNResYel11	411.20	814.90	1,200.39	1,581.59	1,957.80	2,325.26	2,679.07	3,028.95	3,365.80	3,689.79
MedNResYel12	319.82	633.81	933.63	1,230.13	1,522.74	1,808.54	2,083.72	2,355.85	2,617.84	2,869.84
MedNResYel13	2.61	5.16	7.82	10.30	12.76	15.15	17.45	19.73	21.93	24.03
MedNResYel14	-	-	-	-	-	-	-	1.31	1.47	1.64
MedNResYel16	125.62	251.24	377.89	502.48	628.10	753.72	881.75	1,004.97	1,130.59	1,256.21
MedNResYel17	-	1.43	2.15	2.86	3.57	4.28	5.01	5.71	6.43	7.14
MedNResYel18	121.37	242.75	365.12	485.49	606.86	728.24	851.94	970.98	1,092.35	1,213.73
MedNResYel19	-	1.43	2.15	2.86	3.57	4.28	5.01	5.71	6.43	7.14
MedNResYel20	123.80	247.60	372.42	495.20	619.00	742.80	868.98	990.40	1,114.20	1,238.00
MedNWComYel1	41.47	82.43	121.43	159.99	198.05	235.22	271.01	306.41	340.48	373.26
MedNWComYel2	2.08	4.17	6.27	8.33	10.41	12.50	14.62	16.66	18.74	20.83
MedNWComYel3	43.09	86.18	129.62	172.36	215.45	258.54	302.46	344.72	387.81	430.90
MedNWComYel4	29.09	58.17	87.50	116.34	145.43	174.51	204.16	232.69	261.77	290.86
MedNWComYel5	29.09	58.17	87.50	116.34	145.43	174.51	204.16	232.69	261.77	290.86

Appendix 4.3 - SENDOUT® Selected Measures (Expected Case) in Dth

DSM Program	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019
MedNWComYel6	23.74	47.47	71.40	94.94	118.68	142.41	166.60	189.88	213.62	237.35
MedNWComYel7	76.31	151.23	222.77	293.52	363.34	431.53	497.19	562.13	624.64	684.77
MedNWComYel8	6.69	13.39	20.14	26.78	33.47	40.16	46.99	53.55	60.25	66.94
MedNWPComMTA	761.74	1,523.47	2,291.47	3,046.95	3,808.69	4,570.42	5,346.77	6,093.90	6,855.64	7,617.37
MedNWPComMTW	506.77	1,004.30	1,479.39	1,949.20	2,412.85	2,865.72	3,301.76	3,732.96	4,148.10	4,547.40
MedNWPResMTA	156.68	313.36	471.33	626.72	783.40	940.08	1,099.76	1,253.44	1,410.12	1,566.80
MedNWPResMTW	1,371.02	2,717.05	4,002.37	5,273.40	6,527.77	7,752.97	8,932.64	10,099.22	11,222.34	12,302.62
MedNWResYel1	29.22	57.90	85.55	112.72	139.53	165.72	190.93	215.87	239.87	262.97
MedNWResYel2	4.01	8.17	12.04	15.86	19.64	23.32	26.87	30.37	33.75	37.00
MedNWResYel3	3.91	7.97	11.73	15.46	19.14	18.94	18.70	18.50	18.28	18.03
MedNWResYel4	8.12	16.08	23.69	31.21	38.63	45.88	52.86	59.77	66.63	73.05
MedNWResYel5	4.59	9.36	13.79	18.17	22.49	26.71	30.77	34.79	38.65	42.37
MedNWResYel6	317.84	629.88	927.85	1,222.51	1,513.30	1,797.33	2,070.81	2,341.25	2,601.62	2,852.05
MedNWResYel7	5.21	10.62	15.64	20.61	25.51	30.30	34.91	39.46	43.85	48.07
MedNWResYel8	6.44	13.12	19.33	25.46	31.52	37.44	43.13	48.76	54.18	59.60
MedNWResYel9	6.28	12.80	18.85	24.84	30.74	36.51	42.07	47.56	52.85	57.93
RosComMTA	693.50	1,387.00	2,086.20	2,774.00	3,467.50	4,161.00	4,867.80	5,548.00	6,241.50	6,935.00
RosComMTW	454.85	900.90	1,328.25	1,746.36	2,157.10	2,560.80	2,957.57	3,344.00	3,699.63	4,062.30
RosComRed2	-	346.97	521.88	693.95	867.43	1,040.92	1,217.73	1,387.89	1,561.38	1,734.86
RosComYel1	40.18	79.70	117.51	154.50	190.84	226.55	261.65	295.84	327.30	359.39
RosComYel10	3.41	6.81	10.25	13.62	17.03	20.44	23.91	27.25	30.65	34.06
RosComYel11	116.11	232.22	349.28	464.44	580.54	696.65	814.99	928.87	1,044.98	1,161.09
RosComYel12	3.75	7.51	11.29	15.02	18.77	22.53	26.35	30.03	33.79	37.54
RosComYel13	5.81	11.61	17.46	23.22	29.03	34.83	40.75	46.44	52.25	58.05
RosComYel14	4.33	8.89	13.11	17.23	21.28	25.27	29.18	33.10	36.62	40.21
RosComYel15	40.02	80.04	120.39	160.08	200.09	240.11	280.90	320.15	360.17	400.19
RosComYel16	40.02	80.04	120.39	160.08	200.09	240.11	280.90	320.15	360.17	400.19
RosComYel17	19.66	39.32	59.14	78.64	98.31	117.97	138.00	157.29	176.95	196.61
RosComYel18	19.66	39.32	59.14	78.64	98.31	117.97	138.00	157.29	176.95	196.61
RosComYel19	28.35	56.70	85.28	113.40	141.75	170.10	198.99	226.80	255.15	283.50
RosComYel2	2.24	4.49	6.75	8.98	11.22	13.47	15.76	17.96	20.20	22.45
RosComYel20	-	-	-	-	0.12	0.37	0.53	0.71	0.79	0.86
RosComYel3	46.44	92.89	139.71	185.77	232.22	278.66	326.00	371.55	417.99	464.44
RosComYel4	31.35	62.70	94.31	125.40	156.75	188.10	220.05	250.79	282.14	313.49
RosComYel5	31.35	62.70	94.31	125.40	156.75	188.10	220.05	250.79	282.14	313.49
RosComYel6	25.58	51.17	76.96	102.33	127.91	153.50	179.57	204.66	230.24	255.83
RosComYel7	73.82	146.22	215.58	283.44	350.11	415.63	480.03	542.75	600.47	659.33
RosComYel8	7.22	14.43	21.70	28.86	36.08	43.29	50.64	57.72	64.94	72.15
RosComYel9	3.41	6.81	10.25	13.62	17.03	20.44	23.91	27.25	30.65	34.06
RosResMTA	115.88	231.76	348.59	463.52	579.40	695.28	813.38	927.04	1,042.91	1,158.79
RosResMTW	992.40	1,965.60	2,898.00	3,810.24	4,706.40	5,587.20	6,452.88	7,296.00	8,071.92	8,863.20
RosResRed1	387.03	766.57	1,130.20	1,114.48	1,101.28	1,089.49	1,078.54	1,067.02	1,049.33	1,036.98
RosResRed2	-	319.03	479.85	638.05	797.56	957.08	1,119.65	1,276.10	1,435.61	1,595.13
RosResYel1	21.85	43.41	64.00	84.27	104.08	123.56	142.71	161.36	178.52	196.01
RosResYel10	2.44	4.82	7.37	9.69	11.97	14.21	16.41	18.56	20.53	22.55
RosResYel11	307.96	609.95	899.29	1,182.37	1,460.46	1,733.79	2,002.42	2,264.05	2,504.83	2,750.38
RosResYel12	239.52	474.41	699.45	919.62	1,135.91	1,348.50	1,557.44	1,760.93	1,948.20	2,139.18
RosResYel13	1.93	3.83	5.75	7.69	9.50	11.28	13.02	14.72	16.29	17.89
RosResYel14	-	-	-	-	-	-	-	-	1.13	1.37
RosResYel16	104.82	209.64	315.32	419.28	524.10	628.92	735.75	838.56	943.38	1,048.20
RosResYel17	-	0.71	1.79	2.38	2.98	3.57	4.18	4.77	5.36	5.96
RosResYel18	101.28	202.55	304.66	405.10	506.38	607.65	710.87	810.20	911.48	1,012.75
RosResYel19	-	0.71	1.79	2.38	2.98	3.57	4.18	4.77	5.36	5.96
RosResYel2	2.98	6.01	9.01	11.84	14.62	17.36	20.05	22.67	25.08	27.54
RosResYel20	103.30	206.60	310.75	413.20	516.50	619.80	725.08	826.40	929.70	1,033.01
RosResYel3	2.90	5.86	8.78	11.54	14.25	14.10	13.96	13.81	13.58	13.42

DSM Program	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019
RosResYel4	5.97	12.02	17.72	23.30	28.77	34.27	39.58	44.75	49.51	54.36
RosResYel5	3.41	7.00	10.31	13.56	16.75	19.88	22.96	25.96	28.72	31.64
RosResYel6	238.04	471.47	463.41	456.96	451.55	446.71	442.22	437.50	430.25	425.18
RosResYel7	3.87	7.94	11.70	15.38	19.00	22.55	26.05	29.55	32.69	35.89
RosResYel8	4.78	9.81	14.46	19.01	23.47	27.87	32.29	36.51	40.39	44.35
RosResYel9	4.66	9.56	14.10	18.54	22.90	27.18	31.50	35.61	39.40	43.26
SpoBComYel10	185.38	370.76	557.66	741.52	926.89	1,112.27	1,301.21	1,483.03	1,668.41	1,853.79
SpoBComYel11	204.04	408.09	613.81	816.18	1,020.22	1,224.27	1,432.23	1,632.36	1,836.41	2,040.45
SpoBComYel12	89.36	178.73	268.83	357.46	446.83	536.19	627.27	714.92	804.29	893.65
SpoBoComMTA	490.66	981.32	1,476.02	1,962.64	2,453.31	2,943.97	3,444.04	3,925.29	4,415.95	4,906.61
SpoBoComMTW	1,145.69	2,281.44	3,373.00	4,453.63	5,533.11	6,612.91	7,632.79	8,642.41	9,646.73	10,658.99
SpoBoComRed1	1,679.53	3,344.50	4,944.68	6,528.84	8,111.30	9,694.25	11,189.35	12,669.40	14,141.69	15,625.63
SpoBoComRed2	-	260.91	392.43	521.81	652.27	782.72	915.68	1,043.63	1,174.08	1,304.54
SpoBoComYel1	12.08	24.16	36.33	48.31	60.39	72.47	84.78	96.62	108.70	120.78
SpoBoComYel2	17.69	35.38	53.22	70.76	88.45	106.14	124.17	141.52	159.21	176.90
SpoBoComYel3	376.25	752.50	1,131.84	1,504.99	1,881.24	2,257.49	2,640.95	3,009.98	3,386.23	3,762.48
SpoBoComYel4	98.82	197.64	297.27	395.28	494.10	592.92	693.64	790.56	889.38	988.20
SpoBoComYel5	40.32	80.64	121.29	161.28	201.61	241.93	283.02	322.57	362.89	403.21
SpoBoComYel6	67.29	134.00	198.11	261.58	324.99	388.41	448.31	507.61	566.60	626.05
SpoBoComYel7	54.29	108.58	163.32	217.16	271.45	325.74	381.07	434.32	488.61	542.90
SpoBoComYel8	21.58	43.17	64.93	86.34	107.93	129.51	151.51	172.68	194.26	215.85
SpoBoComYel9	147.31	294.63	443.16	589.26	736.58	883.89	1,034.03	1,178.52	1,325.83	1,473.15
SpoBoResMTA	12,623.68	25,247.35	37,974.78	50,494.70	63,118.38	75,742.05	88,607.83	100,989.41	113,613.08	126,236.76
SpoBoResMTW	109,351.80	217,755.60	321,940.79	425,083.20	528,115.00	631,178.39	728,522.20	824,886.41	920,745.01	1,017,362.01
SpoBoResRed1	37,290.62	74,257.95	109,786.68	144,959.80	180,095.20	215,241.37	248,437.08	281,298.73	313,987.96	346,935.82
SpoBoResRed2	2,758.45	5,516.89	8,298.01	11,033.78	13,792.23	16,550.68	19,362.02	22,067.57	24,826.02	27,584.46
SpoBoResYel1	122.50	243.93	360.64	476.18	591.60	707.05	816.09	924.04	1,031.42	1,139.65
SpoBoResYel2	2,023.42	4,029.31	5,957.13	7,865.66	9,772.14	11,679.20	13,480.43	15,263.54	17,037.29	18,825.07
SpoBoResYel3	35.82	71.32	105.45	139.23	172.98	172.28	170.45	168.87	167.55	166.62
SpoBoResYel4	193.42	385.15	569.43	751.86	934.10	1,116.39	1,288.57	1,459.01	1,628.56	1,799.45
SpoBoResYel5	38.68	77.03	113.89	150.37	186.82	223.28	257.71	291.80	325.71	359.89
SpoBoResYel6	193.42	385.15	569.43	751.86	934.10	1,116.39	1,288.57	1,459.01	1,628.56	1,799.45
SpoBoResYel7	38.68	77.03	113.89	150.37	186.82	223.28	257.71	291.80	325.71	359.89
SpoBoResYel8	72.31	143.99	212.88	281.08	349.21	417.35	481.72	545.44	608.83	672.71
SpoBoResYel9	73.37	146.11	216.01	285.22	354.35	423.51	488.82	553.48	617.80	682.62
SpoBResYel10	22.79	45.39	67.10	88.60	110.08	131.56	151.85	171.94	191.92	212.06
SpoBResYel11	1,598.36	3,182.86	4,705.71	6,213.31	7,719.29	9,225.73	10,648.58	12,057.10	13,458.24	14,870.46
SpoBResYel12	2,279.30	4,538.84	6,710.46	8,860.33	11,007.90	13,156.13	15,185.14	17,193.73	19,191.78	21,205.65
SpoBResYel13	14.89	29.96	44.29	58.48	72.65	86.83	100.22	113.48	126.67	139.96
SpoBResYel14	1,027.52	2,046.13	3,025.10	3,994.27	4,962.40	5,930.83	6,845.51	7,751.00	8,651.72	9,559.58
SpoBResYel15	7,407.79	14,751.36	21,809.15	28,796.30	35,775.96	42,757.76	49,352.09	55,880.07	62,373.79	68,918.89
SpoBResYel16	18.64	37.49	55.43	73.19	90.93	108.68	125.44	142.03	158.54	175.18
SpoBResYel17	1.38	2.77	4.16	5.54	6.92	8.30	9.71	11.07	12.46	13.84
SpoBResYel18	-	-	1.51	2.01	2.52	3.02	3.53	4.03	4.53	5.03
SpoBResYel19	8.87	17.65	26.36	34.81	43.25	51.68	59.66	67.55	75.40	83.31
SpoBResYel20	420.92	841.84	1,266.21	1,683.67	2,104.59	2,525.51	2,954.50	3,367.35	3,788.26	4,209.18
SpoBResYel21	5.50	11.00	16.55	22.01	27.51	33.01	38.62	44.02	49.52	55.02
SpoBResYel22	44.29	88.57	133.23	177.15	221.44	265.72	310.86	354.30	398.58	442.87
SpoBResYel23	5.50	11.00	16.55	22.01	27.51	33.01	38.62	44.02	49.52	55.02
SpoBResYel24	1,047.16	2,094.33	3,150.09	4,188.65	5,235.81	6,282.98	7,350.22	8,377.30	9,424.46	10,471.63
SpoBResYel25	178.86	356.18	526.59	695.30	863.83	1,032.40	1,191.63	1,349.25	1,506.04	1,664.08
SpoGComYel10	24.31	48.62	73.14	97.25	121.56	145.87	170.65	194.50	218.81	243.12
SpoGComYel11	26.76	53.52	80.50	107.04	133.80	160.56	187.83	214.08	240.84	267.60
SpoGComYel12	11.72	23.44	35.26	46.88	58.60	70.32	82.26	93.76	105.48	117.20
SpoGResYel10	2.82	5.89	8.71	11.50	14.29	17.08	19.91	22.55	25.17	27.81
SpoGResYel11	209.62	417.42	617.14	814.86	1,012.37	1,209.93	1,396.53	1,581.26	1,765.01	1,950.22

DSM Program	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019
SpoGResYel12	298.92	595.26	880.06	1,162.01	1,443.66	1,725.39	1,991.49	2,254.92	2,516.96	2,781.07
SpoGResYel13	1.77	3.81	5.75	7.59	9.43	11.27	13.01	14.73	16.44	18.17
SpoGResYel14	134.76	268.34	396.73	523.84	650.81	777.81	897.77	1,016.52	1,134.65	1,253.72
SpoGResYel15	971.51	1,934.60	2,860.22	3,776.56	4,691.93	5,607.57	6,472.41	7,328.53	8,180.17	9,038.54
SpoGResYel16	2.33	4.87	7.20	9.50	11.80	14.11	16.28	18.43	20.79	22.97
SpoGResYel17	-	-	-	-	-	-	1.27	1.45	1.63	1.81
SpoGResYel19	0.87	2.20	3.25	4.42	5.61	6.71	7.74	8.77	9.79	10.81
SpoGResYel20	55.20	110.40	166.06	220.81	276.01	331.21	387.48	441.62	496.82	552.02
SpoGResYel21	-	1.44	2.17	2.89	3.61	4.33	5.07	5.77	6.49	7.22
SpoGResYel22	6.13	12.27	18.45	24.53	30.67	36.80	43.05	49.07	55.20	61.34
SpoGResYel23	-	1.44	2.17	2.89	3.61	4.33	5.07	5.77	6.49	7.22
SpoGResYel24	137.33	274.67	413.13	549.33	686.66	824.00	963.96	1,098.66	1,236.00	1,373.33
SpoGResYel25	23.46	46.71	69.06	91.19	113.29	135.40	156.28	176.95	197.51	218.24
SpoGTComRed1	220.27	438.62	648.48	856.24	1,063.78	1,271.38	1,467.46	1,661.56	1,854.65	2,049.26
SpoGTComRed2	-	34.22	51.47	68.43	85.54	102.65	120.09	136.87	153.98	171.09
SpoGTComYel1	1.58	3.17	4.77	6.34	7.92	9.50	11.12	12.67	14.26	15.84
SpoGTComYel2	2.32	4.64	6.98	9.28	11.60	13.92	16.28	18.56	20.88	23.20
SpoGTComYel3	49.34	98.69	148.44	197.38	246.72	296.06	346.35	394.75	444.10	493.44
SpoGTComYel4	12.96	25.92	38.99	51.84	64.80	77.76	90.97	103.68	116.64	129.60
SpoGTComYel5	5.29	10.58	15.91	21.15	26.44	31.73	37.12	42.30	47.59	52.88
SpoGTComYel6	8.74	17.40	25.98	34.31	42.62	50.94	58.79	66.57	74.31	82.11
SpoGTComYel7	7.12	14.24	21.42	28.48	35.60	42.72	49.98	56.96	64.08	71.20
SpoGTComYel8	2.40	4.80	7.22	9.60	12.00	14.40	16.85	19.20	21.60	24.00
SpoGTComYel9	19.32	38.64	58.12	77.28	96.60	115.92	135.61	154.56	173.88	193.20
SpoGTNComMTA	64.35	128.70	193.58	257.40	321.75	386.09	451.68	514.79	579.14	643.49
SpoGTNComMTW	149.36	297.43	439.73	580.61	721.34	862.11	995.07	1,126.69	1,257.62	1,389.59
SpoGTNResMTA	1,655.56	3,311.13	4,980.30	6,622.26	8,277.82	9,933.38	11,620.70	13,244.51	14,900.08	16,555.64
SpoGTNResMTW	14,395.68	28,666.56	42,382.08	55,960.32	69,524.00	83,091.84	95,906.72	108,592.64	121,212.00	133,931.20
SpoGTResRed1	4,890.57	9,738.75	14,398.25	19,011.12	23,619.04	28,228.38	32,581.91	36,891.64	41,178.75	45,499.78
SpoGTResRed2	361.76	723.53	1,088.26	1,447.05	1,808.82	2,170.58	2,539.28	2,894.11	3,255.87	3,617.63
SpoGTResYel1	15.90	31.99	47.30	62.45	77.59	92.73	107.03	121.19	135.27	149.46
SpoGTResYel2	265.37	528.43	781.26	1,031.56	1,281.59	1,531.70	1,767.93	2,001.78	2,234.40	2,468.86
SpoGTResYel3	4.55	9.26	13.69	18.07	22.69	22.59	22.35	22.15	21.97	21.85
SpoGTResYel4	25.37	50.51	74.68	98.60	122.50	146.41	168.99	191.35	213.58	235.99
SpoGTResYel5	5.02	10.00	14.78	19.62	24.50	29.28	33.80	38.27	42.72	47.20
SpoGTResYel6	25.37	50.51	74.68	98.60	122.50	146.41	168.99	191.35	213.58	235.99
SpoGTResYel7	5.02	10.00	14.78	19.62	24.50	29.28	33.80	38.27	42.72	47.20
SpoGTResYel8	9.39	18.69	27.92	36.86	45.80	54.74	63.18	71.53	79.85	88.22
SpoGTResYel9	9.53	18.97	28.33	37.41	46.47	55.54	64.11	72.59	81.02	89.52
SpoNComYel10	94.21	188.42	283.40	376.84	471.05	565.25	661.27	753.67	847.88	942.09
SpoNComYel11	103.70	207.39	311.94	414.78	518.48	622.17	727.85	829.56	933.26	1,036.95
SpoNComYel12	45.42	90.83	136.62	181.66	227.08	272.49	318.78	363.32	408.73	454.15
SpoNResYel10	11.47	23.07	34.10	45.03	55.94	66.86	77.17	87.38	97.53	107.77
SpoNResYel11	812.28	1,617.52	2,391.42	3,157.58	3,922.92	4,688.49	5,411.57	6,127.38	6,839.43	7,557.12
SpoNResYel12	1,158.33	2,306.63	3,410.23	4,502.79	5,594.18	6,685.90	7,717.04	8,737.80	9,753.20	10,776.64
SpoNResYel13	7.57	15.07	22.51	29.72	36.92	44.13	50.93	57.67	64.37	71.13
SpoNResYel14	522.18	1,039.84	1,537.34	2,029.87	2,521.88	3,014.03	3,478.87	3,939.03	4,396.78	4,858.15
SpoNResYel15	3,764.62	7,496.59	11,083.34	14,634.19	18,181.23	21,729.35	25,080.57	28,398.07	31,698.16	35,024.36
SpoNResYel16	9.47	18.86	28.17	37.20	46.21	55.23	63.75	72.18	80.57	89.02
SpoNResYel17	-	1.41	2.12	2.81	3.52	4.22	4.94	5.63	6.33	7.03
SpoNResYel18	-	-	-	-	1.18	1.53	1.80	2.05	2.30	2.56
SpoNResYel19	4.41	8.97	13.26	17.51	21.98	26.27	30.32	34.33	38.32	42.34
SpoNResYel20	213.91	427.82	643.49	855.64	1,069.55	1,283.46	1,501.47	1,711.27	1,925.18	2,139.09
SpoNResYel21	2.80	5.59	8.41	11.18	13.98	16.78	19.63	22.37	25.17	27.96
SpoNResYel22	23.77	47.54	71.50	95.07	118.84	142.61	166.83	190.14	213.91	237.68
SpoNResYel23	2.80	5.59	8.41	11.18	13.98	16.78	19.63	22.37	25.17	27.96

Appendix 4.3 - SENDOUT® Selected Measures (Expected Case) in Dth

DSM Program	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019
SpoNResYel24	532.16	1,064.33	1,600.87	2,128.66	2,660.82	3,192.99	3,735.36	4,257.32	4,789.48	5,321.65
SpoNResYel25	90.90	181.01	267.61	353.35	438.99	524.66	605.58	685.68	765.37	845.68
SpoNWComRed1	853.53	1,699.66	2,512.87	3,317.93	4,122.14	4,926.58	5,686.39	6,438.55	7,186.76	7,940.89
SpoNWComRed2	-	132.59	199.43	265.18	331.48	397.78	465.34	530.37	596.66	662.96
SpoNWComYel1	6.14	12.28	18.46	24.55	30.69	36.83	43.08	49.10	55.24	61.38
SpoNWComYel2	8.99	17.98	27.04	35.96	44.95	53.94	63.10	71.92	80.91	89.90
SpoNWComYel3	191.21	382.42	575.20	764.83	956.04	1,147.25	1,342.12	1,529.66	1,720.87	1,912.08
SpoNWComYel4	50.22	100.44	151.07	200.88	251.10	301.32	352.50	401.76	451.98	502.20
SpoNWComYel5	20.49	40.98	61.64	81.96	102.46	122.95	143.83	163.93	184.42	204.91
SpoNWComYel6	34.20	68.10	100.68	132.94	165.16	197.39	227.83	257.97	287.94	318.16
SpoNWComYel7	27.59	55.18	83.00	110.36	137.95	165.54	193.66	220.72	248.31	275.90
SpoNwComYel8	9.30	18.60	27.98	37.20	46.50	55.80	65.28	74.40	83.70	93.00
SpoNWComYel9	74.87	149.73	225.21	299.46	374.32	449.19	525.49	598.92	673.78	748.65
SpoNWPComMTA	249.35	498.70	750.11	997.41	1,246.76	1,496.11	1,750.25	1,994.82	2,244.17	2,493.52
SpoNWPComMTW	578.77	1,152.53	1,703.96	2,249.87	2,795.19	3,340.68	3,855.90	4,365.93	4,873.29	5,384.66
SpoNWPResMTA	6,415.31	12,830.62	19,298.66	25,661.24	32,076.55	38,491.86	45,030.21	51,322.48	57,737.80	64,153.11
SpoNWPResMTW	55,852.47	111,220.74	164,434.32	217,115.28	269,739.75	322,380.36	372,099.63	421,318.56	470,279.25	519,627.30
SpoNWResRed1	18,950.97	37,737.65	55,793.23	73,668.09	91,523.79	109,384.96	126,254.91	142,955.09	159,567.65	176,311.64
SpoNWResRed2	1,401.83	2,803.67	4,217.02	5,607.33	7,009.17	8,411.00	9,839.72	11,214.67	12,616.50	14,018.33
SpoNWResYel1	62.25	123.96	183.28	241.99	300.65	359.32	414.74	469.59	524.16	579.17
SpoNWResYel2	1,028.30	2,047.68	3,027.39	3,997.30	4,966.17	5,935.33	6,850.71	7,756.88	8,658.29	9,566.84
SpoNWResYel3	18.02	36.25	53.59	70.76	87.91	87.55	86.62	85.82	85.15	84.67
SpoNWResYel4	98.29	195.73	289.38	382.09	474.71	567.35	654.85	741.46	827.63	914.47
SpoNWResYel5	19.46	39.15	57.88	76.42	94.94	113.47	130.97	148.29	165.53	182.89
SpoNWResYel6	98.29	195.73	289.38	382.09	474.71	567.35	654.85	741.46	827.63	914.47
SpoNWResYel7	19.46	39.15	57.88	76.42	94.94	113.47	130.97	148.29	165.53	182.89
SpoNWResYel8	36.75	73.17	108.18	142.84	177.47	212.10	244.81	277.19	309.40	341.87
SpoNWResYel9	37.29	74.25	109.78	144.95	180.08	215.22	248.42	281.28	313.96	346.91
Total	333,069.81	665,735.15	986,226.31	1,300,156.08	1,613,879.32	1,927,361.57	2,227,094.37	2,522,535.25	2,816,953.51	3,112,909.80
WA/ID	301,191.24	600,472.36	889,351.16	1,175,141.40	1,460,912.64	1,746,704.10	2,018,933.17	2,287,556.95	2,555,520.64	2,825,361.30
OR	31,878.57	65,262.79	96,875.14	125,014.69	152,966.68	180,657.47	208,161.20	234,978.30	261,432.88	287,548.50

DSM Program	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029
KlaComRed2	2,507.25	2,727.70	2,955.01	3,182.32	3,418.97	3,636.94	3,636.94	3,636.94	3,646.90	3,636.94
KlaComYel10	28.65	31.17	31.17	31.17	31.26	31.17	31.17	31.17	31.26	31.17
KlaComYel11	976.76	1,062.64	1,151.20	1,239.75	1,331.94	1,328.30	1,328.30	1,328.30	1,331.94	1,328.30
KlaComYel12	31.58	34.36	37.22	40.09	43.07	45.81	48.67	51.54	54.55	57.26
KlaComYel13	48.84	53.13	57.56	61.99	66.60	66.42	66.42	66.42	66.60	66.42
KlaComYel14	58.75	64.04	64.04	64.04	64.04	64.02	63.97	63.97	63.85	63.81
KlaComYel15	336.66	366.26	366.26	366.26	367.26	366.26	366.26	366.26	367.26	366.26
KlaComYel16	336.66	366.26	366.26	366.26	367.26	366.26	366.26	366.26	367.26	366.26
KlaComYel17	165.40	179.94	194.94	209.93	225.54	224.93	224.93	224.93	225.54	224.93
KlaComYel18	165.40	179.94	194.94	209.93	225.54	224.93	224.93	224.93	225.54	224.93
KlaComYel19	238.49	259.46	281.08	302.71	325.22	324.33	324.33	324.33	325.22	324.33
KlaComYel20	1.45	1.69	1.83	1.97	2.11	2.25	2.39	2.53	2.66	2.80
KlaComYel9	28.65	31.17	31.17	31.17	31.26	31.17	31.17	31.17	31.26	31.17
KlamComMTA	10,517.17	11,441.93	12,395.43	12,395.43	12,429.39	12,395.43	12,395.43	12,395.43	12,429.39	12,395.43
KlamComMTW	6,445.83	7,026.34	7,611.87	8,197.39	8,197.39	8,194.84	8,188.45	8,187.17	8,171.84	8,166.73
KlamComYel1	524.23	571.44	619.06	666.68	714.30	761.69	808.66	856.09	901.96	948.84
KlamComYel2	18.88	18.83	18.83	18.83	18.88	18.83	18.83	18.83	18.88	18.83
KlamComYel3	390.70	425.06	460.48	495.90	532.78	531.32	531.32	531.32	532.78	531.32
KlamComYel4	263.72	286.91	286.91	286.91	287.70	286.91	286.91	286.91	287.70	286.91
KlamComYel5	263.72	286.91	286.91	286.91	287.70	286.91	286.91	286.91	287.70	286.91
KlamComYel6	215.21	234.14	253.65	273.16	293.47	292.67	292.67	292.67	293.47	292.67
KlamComYel7	961.74	1,048.36	1,135.72	1,223.09	1,310.45	1,397.38	1,483.55	1,570.58	1,654.73	1,740.73
KlamComYel8	60.70	66.03	71.54	77.04	82.77	88.04	93.55	99.05	104.84	110.06
KlamResMTA	2,333.06	2,538.20	2,538.20	2,538.20	2,545.16	2,538.20	2,538.20	2,538.20	2,545.16	2,538.20
KlamResMTW	18,364.06	20,017.92	21,686.08	23,354.24	25,022.40	26,682.24	28,327.78	29,989.44	31,596.24	33,238.40
KlamResYel1	362.11	361.83	361.83	361.83	361.83	361.72	361.43	361.38	360.70	360.47
KlamResYel2	51.12	51.08	51.08	51.08	51.08	51.07	51.03	51.02	50.92	50.89
KlaResRed1	1,915.68	1,914.18	1,914.18	1,914.18	1,914.18	1,913.59	1,912.10	1,911.80	1,908.22	1,907.02
KlaResRed2	3,211.55	3,493.94	3,785.10	4,076.26	4,087.43	4,076.26	4,076.26	4,076.26	4,087.43	4,076.26
KlaResYel10	46.04	50.19	54.37	58.55	62.73	66.89	71.02	75.18	79.21	83.33
KlaResYel11	5,589.03	6,092.38	6,600.08	7,107.78	7,615.47	8,120.64	8,621.45	9,127.17	9,616.20	10,115.98
KlaResYel12	4,347.03	4,738.52	5,133.39	5,528.27	5,923.15	6,316.05	6,705.57	7,098.91	7,479.26	7,867.99
KlaResYel13	36.53	39.82	43.14	46.46	49.77	53.08	56.35	59.65	62.85	66.12
KlaResYel14	1.60	1.74	1.89	2.03	2.18	2.18	2.18	2.18	2.18	2.18
KlaResYel16	1,228.44	1,336.45	1,447.82	1,559.19	1,675.14	1,781.93	1,893.30	2,004.67	2,121.84	2,227.42
KlaResYel17	6.98	7.60	8.23	8.86	9.52	10.13	10.76	11.39	12.06	12.66
KlaResYel18	1,186.89	1,291.26	1,398.86	1,506.47	1,618.49	1,721.67	1,829.28	1,936.88	2,050.09	2,152.09
KlaResYel19	6.98	7.60	8.23	8.86	9.52	10.13	10.76	11.39	12.06	12.66
KlaResYel20	1,210.63	1,317.08	1,426.84	1,536.59	1,650.86	1,646.35	1,646.35	1,646.35	1,650.86	1,646.35
KlaResYel3	24.91	24.89	24.89	24.89	24.89	24.89	24.87	24.86	24.82	24.80
KlaResYel4	110.64	120.61	130.66	140.71	150.76	160.76	170.68	180.69	190.37	200.26
KlaResYel5	64.40	70.20	76.05	81.90	87.75	93.57	99.34	105.17	110.80	116.56
KlaResYel6	82.23	89.63	97.10	104.57	112.04	119.47	126.84	134.28	141.47	148.83
KlaResYel7	73.06	79.64	86.28	92.91	99.55	106.15	112.70	119.31	125.70	132.24
KlaResYel8	90.27	98.40	106.60	114.80	123.00	131.16	139.25	147.42	155.32	163.39
KlaResYel9	88.05	95.98	103.98	111.98	119.97	127.93	135.82	143.79	151.49	159.37
LaGrComMTA	5,110.96	5,560.36	6,023.72	6,023.72	6,040.23	6,023.72	6,023.72	6,023.72	6,040.23	6,023.72
LaGrComMTW	2,866.69	3,114.28	3,366.75	3,618.83	3,601.58	3,589.84	3,575.35	3,566.38	3,560.16	3,538.08
LaGrComRed2	1,218.43	1,325.56	1,436.03	1,546.49	1,661.49	1,767.42	1,767.42	1,767.42	1,772.26	1,767.42
LaGrComYel1	233.14	253.28	273.81	294.31	313.83	333.67	353.09	372.92	392.95	411.07
LaGrComYel10	15.48	16.84	16.84	16.84	16.89	16.84	16.84	16.84	16.89	16.84
LaGrComYel11	527.67	574.07	621.91	669.75	719.55	717.59	717.59	717.59	719.55	717.59
LaGrComYel12	17.06	18.56	20.11	21.66	23.27	24.75	26.30	27.84	29.47	30.94
LaGrComYel13	26.38	28.70	31.10	33.49	35.98	35.88	35.88	35.88	35.98	35.88
LaGrComYel14	26.13	28.39	28.33	28.27	28.14	28.05	27.93	27.86	27.81	27.64
LaGrComYel15	181.87	197.86	197.86	197.86	198.40	197.86	197.86	197.86	198.40	197.86

DSM Program	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029
LaGrComYel16	181.87	197.86	197.86	197.86	198.40	197.86	197.86	197.86	198.40	197.86
LaGrComYel17	89.35	97.21	105.31	113.41	121.84	121.51	121.51	121.51	121.84	121.51
LaGrComYel18	89.35	97.21	105.31	113.41	121.84	121.51	121.51	121.51	121.84	121.51
LaGrComYel19	128.84	140.17	151.85	163.53	175.69	175.21	175.21	175.21	175.69	175.21
LaGrComYel2	10.20	10.17	10.17	10.17	10.20	10.17	10.17	10.17	10.20	10.17
LaGrComYel20	0.37	0.41	0.55	0.69	0.73	0.78	0.83	0.87	0.92	1.07
LaGrComYel3	211.07	229.63	248.76	267.90	287.82	287.03	287.03	287.03	287.82	287.03
LaGrComYel4	142.47	155.00	155.00	155.00	155.42	155.00	155.00	155.00	155.42	155.00
LaGrComYel5	142.47	155.00	155.00	155.00	155.42	155.00	155.00	155.00	155.42	155.00
LaGrComYel6	116.26	126.49	137.03	147.57	158.54	158.11	158.11	158.11	158.54	158.11
LaGrComYel7	427.72	464.66	502.33	539.94	575.75	612.14	647.77	684.15	720.90	754.14
LaGrComYel8	32.79	35.67	38.65	41.62	44.71	47.56	50.54	53.51	56.64	59.46
LaGrComYel9	15.48	16.84	16.84	16.84	16.89	16.84	16.84	16.84	16.89	16.84
LaGrResMTA	972.18	1,057.66	1,057.66	1,057.66	1,060.56	1,057.66	1,057.66	1,057.66	1,060.56	1,057.66
LaGrResMTW	6,977.52	7,580.16	8,194.68	8,808.24	9,392.40	9,985.92	10,567.20	11,160.72	11,760.24	12,302.40
LaGrResRed1	730.53	727.49	725.97	724.59	721.14	718.79	715.89	714.09	712.84	708.42
LaGrResRed2	1,338.24	1,455.91	1,577.24	1,698.57	1,703.22	1,698.57	1,698.57	1,698.57	1,703.22	1,698.57
LaGrResYel1	138.09	137.51	137.23	136.97	136.31	135.87	135.32	134.98	134.75	133.91
LaGrResYel10	17.38	18.99	20.53	22.16	23.63	25.13	26.59	28.08	29.59	30.96
LaGrResYel11	2,131.35	2,315.44	2,503.15	2,690.57	2,869.00	3,050.30	3,227.86	3,409.15	3,592.28	3,757.89
LaGrResYel12	1,657.72	1,800.89	1,946.89	2,092.66	2,231.45	2,372.46	2,510.56	2,651.56	2,794.00	2,922.80
LaGrResYel13	13.79	14.98	16.19	17.50	18.67	19.85	21.00	22.18	23.48	24.56
LaGrResYel16	569.05	619.08	670.67	722.26	775.97	825.44	877.03	928.62	982.90	1,031.80
LaGrResYel17	3.23	3.52	3.81	4.10	4.41	4.69	4.98	5.28	5.59	5.86
LaGrResYel18	549.80	598.15	647.99	697.84	749.73	797.53	847.37	897.22	949.66	996.91
LaGrResYel19	3.23	3.52	3.81	4.10	4.41	4.69	4.98	5.28	5.59	5.86
LaGrResYel2	19.41	19.33	19.28	19.25	19.16	19.10	19.02	18.97	18.94	18.82
LaGrResYel20	560.80	610.11	660.95	711.79	764.72	762.64	762.64	762.64	764.72	762.64
LaGrResYel3	9.40	9.36	9.34	9.33	9.28	9.25	9.21	9.19	9.18	9.12
LaGrResYel4	42.19	45.84	49.55	53.26	56.80	60.39	63.90	67.49	71.12	74.39
LaGrResYel5	24.56	26.68	28.84	31.00	33.06	35.15	37.19	39.28	41.39	43.30
LaGrResYel6	1,647.45	1,789.73	1,934.83	2,079.69	2,217.62	2,357.75	2,495.00	2,635.13	2,776.68	2,904.69
LaGrResYel7	27.86	30.27	32.72	35.17	37.50	39.87	42.19	44.56	46.96	49.12
LaGrResYel8	34.43	37.40	40.43	43.46	46.34	49.27	52.14	55.06	58.02	60.70
LaGrResYel9	33.58	36.48	39.43	42.39	45.20	48.05	50.85	53.71	56.59	59.20
MedGComRed2	4,458.32	4,850.33	5,254.53	5,658.72	6,079.53	6,467.11	6,467.11	6,467.11	6,484.83	6,467.11
MedGComYel10	77.58	84.40	84.40	84.40	84.63	84.40	84.40	84.40	84.63	84.40
MedGComYel11	2,644.74	2,877.29	3,117.06	3,356.84	3,606.46	3,596.61	3,596.61	3,596.61	3,606.46	3,596.61
MedGComYel12	85.51	93.03	100.79	108.54	116.61	124.04	131.80	139.55	147.70	155.05
MedGComYel13	132.24	143.86	155.85	167.84	180.32	179.83	179.83	179.83	180.32	179.83
MedGComYel14	102.00	110.95	110.11	109.90	109.52	109.14	108.71	108.52	108.30	107.68
MedGComYel15	911.55	991.71	991.71	991.71	994.42	991.71	991.71	991.71	994.42	991.71
MedGComYel16	911.55	991.71	991.71	991.71	994.42	991.71	991.71	991.71	994.42	991.71
MedGComYel17	447.84	487.22	527.82	568.42	610.69	609.03	609.03	609.03	610.69	609.03
MedGComYel18	447.84	487.22	527.82	568.42	610.69	609.03	609.03	609.03	610.69	609.03
MedGComYel19	645.76	702.54	761.08	819.63	880.58	878.17	878.17	878.17	880.58	878.17
MedGComYel20	2.79	3.03	3.27	3.51	3.75	3.98	4.21	4.45	4.69	4.91
MedGComYel9	77.58	84.40	84.40	84.40	84.63	84.40	84.40	84.40	84.63	84.40
MedGResRed1	3,083.74	3,074.75	3,051.53	3,045.54	3,035.05	3,024.57	3,012.58	3,007.34	3,001.35	2,984.12
MedGResRed2	5,295.05	5,760.64	6,240.69	6,720.74	6,739.16	6,720.74	6,720.74	6,720.74	6,739.16	6,720.74
MedGResYel10	74.11	80.61	86.67	93.15	99.47	105.73	111.89	118.27	124.59	130.39
MedGResYel11	8,996.89	9,786.18	10,521.63	11,308.74	12,074.78	12,835.27	13,583.44	14,357.43	15,124.87	15,829.53
MedGResYel12	6,997.58	7,611.47	8,183.49	8,795.68	9,391.50	9,982.99	10,564.90	11,166.89	11,763.79	12,311.86
MedGResYel13	58.60	63.96	68.77	73.91	78.92	83.89	88.78	93.84	98.86	103.46
MedGResYel14	4.02	4.37	4.73	5.10	5.48	5.46	5.46	5.46	5.48	5.46
MedGResYel15	1.46	1.59	1.72	1.85	1.99	1.99	1.99	1.99	1.99	1.99

DSM Program	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029
MedGResYel16	3,084.11	3,355.29	3,634.90	3,914.50	4,205.60	4,473.72	4,753.33	5,032.93	5,327.10	5,592.15
MedGResYel17	17.53	19.07	20.66	22.25	23.90	25.43	27.02	28.60	30.28	31.78
MedGResYel18	2,979.82	3,241.83	3,511.98	3,782.13	4,063.38	4,322.43	4,592.59	4,862.74	5,146.95	5,403.04
MedGResYel19	17.53	19.07	20.66	22.25	23.90	25.43	27.02	28.60	30.28	31.78
MedGResYel20	3,039.41	3,306.66	3,582.22	3,857.77	4,144.65	4,133.33	4,133.33	4,133.33	4,144.65	4,133.33
MedGTComYel1	910.12	989.96	1,064.36	1,143.98	1,221.47	1,298.40	1,374.09	1,452.38	1,530.02	1,601.30
MedGTComYel2	51.13	50.99	50.99	50.99	51.13	50.99	50.99	50.99	51.13	50.99
MedGTComYel3	1,057.90	1,150.92	1,246.83	1,342.73	1,442.59	1,438.64	1,438.64	1,438.64	1,442.59	1,438.64
MedGTComYel4	714.08	776.87	776.87	776.87	779.00	776.87	776.87	776.87	779.00	776.87
MedGTComYel5	714.08	776.87	776.87	776.87	779.00	776.87	776.87	776.87	779.00	776.87
MedGTComYel6	582.72	633.96	686.79	739.62	794.62	792.45	792.45	792.45	794.62	792.45
MedGTComYel7	1,669.68	1,816.16	1,952.65	2,098.73	2,240.90	2,382.03	2,520.88	2,664.52	2,806.94	2,937.72
MedGTComYel8	164.35	178.80	193.70	208.60	224.11	238.40	253.30	268.20	283.87	298.00
MedGTNComMTA	18,701.37	20,345.76	22,041.24	22,041.24	22,101.62	22,041.24	22,041.24	22,041.24	22,101.62	22,041.24
MedGTNComMTW	10,868.88	11,822.40	12,710.88	13,661.76	13,614.72	13,567.68	13,513.92	13,490.40	13,463.52	13,386.24
MedGTNResMTA	3,846.64	4,184.87	4,184.87	4,184.87	4,196.33	4,184.87	4,184.87	4,184.87	4,196.33	4,184.87
MedGTNResMTW	29,997.70	32,629.38	35,081.55	37,705.95	40,260.13	42,795.76	45,290.33	47,871.00	50,429.82	52,779.32
MedGTResYel1	582.90	581.20	576.82	575.68	573.70	571.72	569.45	568.46	567.33	564.07
MedGTResYel2	82.29	82.05	81.43	81.27	80.99	80.71	80.39	80.25	80.09	79.63
MedGTResYel3	39.97	39.85	39.56	39.48	39.34	39.21	39.05	38.98	38.91	38.68
MedGTResYel4	178.11	193.73	208.29	223.88	239.04	254.10	268.91	284.23	299.42	313.37
MedGTResYel5	103.67	112.76	121.24	130.31	139.13	147.90	156.52	165.43	174.28	182.40
MedGTResYel6	6,954.21	7,564.30	8,132.78	8,741.18	9,333.30	9,921.12	10,499.42	11,097.69	11,690.89	12,235.56
MedGTResYel7	117.61	127.92	137.54	147.83	157.84	167.78	177.56	187.68	197.71	206.92
MedGTResYel8	145.32	158.06	169.94	182.66	195.03	207.31	219.40	231.90	244.29	255.68
MedGTResYel9	141.74	154.17	165.76	178.16	190.23	202.21	213.99	226.19	238.28	249.38
MedNComRed2	2,003.01	2,179.14	2,360.73	2,542.32	2,731.38	2,905.51	2,905.51	2,905.51	2,913.47	2,905.51
MedNComYel10	34.85	37.92	37.92	37.92	38.02	37.92	37.92	37.92	38.02	37.92
MedNComYel11	1,188.22	1,292.69	1,400.42	1,508.14	1,620.30	1,615.87	1,615.87	1,615.87	1,620.30	1,615.87
MedNComYel12	38.42	41.80	45.28	48.76	52.39	55.73	59.21	62.70	66.36	69.66
MedNComYel13	59.41	64.63	70.02	75.41	81.01	80.79	80.79	80.79	81.01	80.79
MedNComYel14	45.67	49.68	49.31	49.22	49.05	48.88	48.68	48.60	48.50	48.22
MedNComYel15	409.54	445.55	445.55	445.55	446.77	445.55	445.55	445.55	446.77	445.55
MedNComYel16	409.54	445.55	445.55	445.55	446.77	445.55	445.55	445.55	446.77	445.55
MedNComYel17	201.20	218.90	237.14	255.38	274.37	273.62	273.62	273.62	274.37	273.62
MedNComYel18	201.20	218.90	237.14	255.38	274.37	273.62	273.62	273.62	274.37	273.62
MedNComYel19	290.12	315.63	341.94	368.24	395.62	394.54	394.54	394.54	395.62	394.54
MedNComYel20	1.11	1.20	1.30	1.50	1.60	1.70	1.80	1.90	2.11	2.21
MedNComYel9	34.85	37.92	37.92	37.92	38.02	37.92	37.92	37.92	38.02	37.92
MedNResRed1	1,385.45	1,381.41	1,370.98	1,368.29	1,363.57	1,358.86	1,353.48	1,351.12	1,348.43	1,340.69
MedNResRed2	2,378.94	2,588.11	2,803.79	3,019.46	3,027.74	3,019.46	3,019.46	3,019.46	3,027.74	3,019.46
MedNResYel10	33.18	36.09	38.81	41.72	44.54	47.35	50.11	52.96	55.79	58.49
MedNResYel11	4,042.08	4,396.69	4,727.11	5,080.74	5,424.90	5,766.57	6,102.70	6,450.44	6,795.23	7,111.82
MedNResYel12	3,143.84	3,419.65	3,676.64	3,951.68	4,219.37	4,485.11	4,746.55	5,017.01	5,285.18	5,531.41
MedNResYel13	26.33	28.64	30.80	33.10	35.34	37.57	39.76	42.02	44.27	46.33
MedNResYel14	1.80	1.96	2.13	2.29	2.46	2.45	2.45	2.45	2.46	2.45
MedNResYel16	1,385.61	1,507.45	1,633.07	1,758.69	1,889.47	2,009.93	2,135.55	2,261.17	2,393.33	2,512.42
MedNResYel17	7.88	8.57	9.28	10.00	10.74	11.42	12.14	12.85	13.60	14.28
MedNResYel18	1,338.76	1,456.47	1,577.85	1,699.22	1,825.58	1,941.96	2,063.34	2,184.71	2,312.40	2,427.45
MedNResYel19	7.88	8.57	9.28	10.00	10.74	11.42	12.14	12.85	13.60	14.28
MedNResYel20	1,365.53	1,485.60	1,609.40	1,733.20	1,862.09	1,857.00	1,857.00	1,857.00	1,862.09	1,857.00
MedNWComYel1	408.89	444.76	478.19	513.96	548.78	583.34	617.34	652.52	687.40	719.42
MedNWComYel2	22.97	22.91	22.91	22.91	22.97	22.91	22.91	22.91	22.97	22.91
MedNWComYel3	475.29	517.08	560.17	603.26	648.12	646.35	646.35	646.35	648.12	646.35
MedNWComYel4	320.82	349.03	349.03	349.03	349.98	349.03	349.03	349.03	349.98	349.03
MedNWComYel5	320.82	349.03	349.03	349.03	349.98	349.03	349.03	349.03	349.98	349.03

DSM Program	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029
MedNWComYel6	261.80	284.82	308.56	332.29	357.01	356.03	356.03	356.03	357.01	356.03
MedNWComYel7	750.15	815.96	877.28	942.91	1,006.78	1,070.19	1,132.57	1,197.10	1,261.09	1,319.84
MedNWComYel8	73.84	80.33	87.02	93.72	100.69	107.11	113.80	120.49	127.54	133.88
MedNWPComMTA	8,402.07	9,140.85	9,902.58	9,902.58	9,929.71	9,902.58	9,902.58	9,902.58	9,929.71	9,902.58
MedNWPComMTW	4,981.57	5,418.60	5,825.82	6,261.64	6,240.08	6,218.52	6,193.88	6,183.10	6,170.78	6,135.36
MedNWPResMTA	1,728.20	1,880.16	1,880.16	1,880.16	1,885.31	1,880.16	1,880.16	1,880.16	1,885.31	1,880.16
MedNWPResMTW	13,477.23	14,659.58	15,761.28	16,940.35	18,087.88	19,227.08	20,347.83	21,507.26	22,656.87	23,712.45
MedNWResYel1	261.88	261.12	259.15	258.64	257.75	256.86	255.84	255.40	254.89	253.42
MedNWResYel2	36.85	36.74	36.47	36.40	36.27	36.15	36.00	35.94	35.87	35.66
MedNWResYel3	17.96	17.90	17.77	17.74	17.68	17.61	17.54	17.51	17.48	17.38
MedNWResYel4	80.02	87.04	93.58	100.58	107.40	114.16	120.81	127.70	134.52	140.79
MedNWResYel5	46.42	50.49	54.29	58.46	62.42	66.35	70.32	74.33	78.30	81.95
MedNWResYel6	3,124.36	3,398.45	3,653.86	3,927.19	4,193.22	4,457.32	4,717.13	4,985.92	5,252.43	5,497.13
MedNWResYel7	52.66	57.28	61.70	66.32	70.91	75.38	79.77	84.32	88.83	92.96
MedNWResYel8	65.29	71.01	76.35	82.06	87.62	93.14	98.57	104.19	109.76	114.87
MedNWResYel9	63.68	69.27	74.47	80.04	85.46	90.85	96.14	101.62	107.05	112.04
RosComMTA	7,649.40	8,322.00	9,015.50	9,015.50	9,040.20	9,015.50	9,015.50	9,015.50	9,040.20	9,015.50
RosComMTW	4,423.76	4,798.20	5,165.16	5,542.46	5,510.12	5,477.78	5,460.84	5,390.00	5,357.66	5,322.24
RosComRed2	1,913.58	2,081.84	2,255.32	2,428.81	2,609.42	2,775.78	2,775.78	2,775.78	2,783.39	2,775.78
RosComYel1	391.37	424.49	456.96	490.34	522.30	553.85	586.64	613.09	643.27	672.65
RosComYel10	37.57	40.87	40.87	40.87	40.98	40.87	40.87	40.87	40.98	40.87
RosComYel11	1,280.70	1,393.31	1,509.41	1,625.52	1,746.40	1,741.63	1,741.63	1,741.63	1,746.40	1,741.63
RosComYel12	41.41	45.05	48.80	52.56	56.47	60.07	63.82	67.58	71.52	75.08
RosComYel13	64.03	69.67	75.47	81.28	87.32	87.08	87.08	87.08	87.32	87.08
RosComYel14	43.79	47.50	47.20	47.03	46.75	46.48	46.33	45.74	45.47	45.17
RosComYel15	441.41	480.23	480.23	480.23	481.54	480.23	480.23	480.23	481.54	480.23
RosComYel16	441.41	480.23	480.23	480.23	481.54	480.23	480.23	480.23	481.54	480.23
RosComYel17	216.86	235.93	255.59	275.26	295.72	294.92	294.92	294.92	295.72	294.92
RosComYel18	216.86	235.93	255.59	275.26	295.72	294.92	294.92	294.92	295.72	294.92
RosComYel19	312.70	340.20	368.55	396.90	426.41	425.25	425.25	425.25	426.41	425.25
RosComYel2	24.76	24.69	24.69	24.69	24.76	24.69	24.69	24.69	24.76	24.69
RosComYel20	1.04	1.13	1.22	1.41	1.50	1.59	1.68	1.77	1.96	2.05
RosComYel3	512.28	557.32	603.77	650.21	698.56	696.65	696.65	696.65	698.56	696.65
RosComYel4	345.79	376.19	376.19	376.19	377.22	376.19	376.19	376.19	377.22	376.19
RosComYel5	345.79	376.19	376.19	376.19	377.22	376.19	376.19	376.19	377.22	376.19
RosComYel6	282.18	306.99	332.57	358.16	384.79	383.74	383.74	383.74	384.79	383.74
RosComYel7	718.00	778.77	838.33	899.57	958.20	1,016.08	1,076.25	1,124.77	1,180.14	1,234.04
RosComYel8	79.58	86.58	93.80	101.01	108.52	115.44	122.66	129.87	137.46	144.30
RosComYel9	37.57	40.87	40.87	40.87	40.98	40.87	40.87	40.87	40.98	40.87
RosResMTA	1,278.17	1,390.55	1,390.55	1,390.55	1,394.36	1,390.55	1,390.55	1,390.55	1,394.36	1,390.55
RosResMTW	9,651.84	10,468.80	11,269.44	12,092.64	12,880.80	13,658.88	14,467.68	15,120.00	15,864.24	16,588.80
RosResRed1	1,026.59	1,020.69	1,014.23	1,010.58	1,004.69	998.79	995.70	982.79	976.89	970.43
RosResRed2	1,759.45	1,914.15	2,073.66	2,233.18	2,239.30	2,233.18	2,233.18	2,233.18	2,239.30	2,233.18
RosResYel1	194.05	192.94	191.72	191.03	189.91	188.80	188.21	185.77	184.66	183.44
RosResYel10	24.56	26.64	28.67	30.77	32.87	34.86	36.92	38.59	40.49	42.34
RosResYel11	2,995.10	3,248.62	3,497.07	3,752.52	3,997.09	4,238.54	4,489.52	4,691.95	4,922.90	5,147.74
RosResYel12	2,329.52	2,526.70	2,719.94	2,918.62	3,108.85	3,296.64	3,491.85	3,649.29	3,828.92	4,003.80
RosResYel13	19.48	21.13	22.75	24.41	26.00	27.57	29.20	30.53	32.04	33.50
RosResYel14	1.51	1.64	1.77	1.91	2.05	2.05	2.05	2.05	2.05	2.05
RosResYel16	1,156.18	1,257.84	1,362.66	1,467.48	1,576.60	1,677.11	1,781.93	1,886.75	1,997.03	2,096.39
RosResYel17	6.57	7.15	7.74	8.34	8.96	9.53	10.13	10.72	11.35	11.91
RosResYel18	1,117.08	1,215.30	1,316.58	1,417.85	1,523.29	1,620.40	1,721.68	1,822.95	1,929.50	2,025.50
RosResYel19	6.57	7.15	7.74	8.34	8.96	9.53	10.13	10.72	11.35	11.91
RosResYel2	27.27	27.11	26.94	26.84	26.68	26.53	26.44	26.11	25.96	25.78
RosResYel20	1,139.42	1,239.61	1,342.91	1,446.21	1,553.75	1,549.51	1,549.51	1,549.51	1,553.75	1,549.51
RosResYel3	13.29	13.21	13.13	13.08	13.00	12.93	12.89	12.73	12.65	12.57

DSM Program	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029
RosResYel4	59.20	64.31	69.23	74.29	79.13	83.91	88.88	92.89	97.46	101.91
RosResYel5	34.45	37.37	40.23	43.17	45.98	48.76	51.64	53.99	56.64	59.23
RosResYel6	420.92	418.51	415.86	414.36	411.94	409.53	408.26	402.96	400.55	397.90
RosResYel7	39.09	42.40	45.64	48.97	52.16	55.31	58.59	61.25	64.26	67.19
RosResYel8	48.30	52.38	56.39	60.61	64.56	68.46	72.51	75.78	79.51	83.15
RosResYel9	47.11	51.09	55.00	59.02	62.97	66.77	70.73	73.92	77.56	81.10
SpoBComYel10	2,044.76	2,224.55	2,409.93	2,595.31	2,788.30	2,966.06	3,151.44	3,336.82	3,531.85	3,707.58
SpoBComYel11	2,250.64	2,448.54	2,652.59	2,856.63	3,069.06	3,060.68	3,060.68	3,060.68	3,069.06	3,060.68
SpoBComYel12	985.71	1,072.38	1,161.74	1,251.11	1,344.15	1,340.47	1,340.47	1,340.47	1,344.15	1,340.47
SpoBoComMTA	5,412.06	5,887.93	6,378.60	6,869.26	7,380.08	7,850.58	7,850.58	7,850.58	7,872.09	7,850.58
SpoBoComMTW	11,686.65	12,697.43	13,708.20	14,720.97	15,735.22	16,731.26	17,754.45	18,712.42	19,698.53	20,679.01
SpoBoComRed1	17,132.13	18,613.88	20,095.64	21,580.30	23,067.15	24,527.31	26,027.26	27,431.60	28,877.19	30,314.54
SpoBoComRed2	1,438.92	1,565.44	1,695.90	1,826.35	1,962.16	2,087.26	2,217.71	2,217.71	2,223.79	2,217.71
SpoBoComYel1	133.22	144.94	157.01	169.09	181.67	181.17	181.17	181.17	181.67	181.17
SpoBoComYel2	195.12	194.59	194.59	194.59	195.12	194.59	194.59	194.59	195.12	194.59
SpoBoComYel3	4,150.07	4,514.98	4,891.22	5,267.47	5,659.18	5,643.72	5,643.72	5,643.72	5,659.18	5,643.72
SpoBoComYel4	1,090.00	1,185.84	1,284.66	1,383.48	1,486.36	1,581.12	1,679.94	1,778.76	1,882.72	1,976.40
SpoBoComYel5	444.75	483.85	524.17	564.49	606.47	604.81	604.81	604.81	606.47	604.81
SpoBoComYel6	686.41	745.78	805.15	864.63	924.20	982.70	1,042.80	1,099.07	1,156.99	1,214.57
SpoBoComYel7	598.83	651.48	705.77	760.06	816.58	814.35	814.35	814.35	816.58	814.35
SpoBoComYel8	238.09	259.02	280.61	302.19	324.66	323.77	323.77	323.77	324.66	323.77
SpoBoComYel9	1,624.90	1,767.78	1,915.10	2,062.41	2,215.78	2,209.72	2,209.72	2,209.72	2,215.78	2,209.72
SpoBoResMTA	139,240.87	138,860.43	138,860.43	138,860.43	139,240.87	138,860.43	138,860.43	138,860.43	139,240.87	138,860.43
SpoBoResMTW	1,115,448.41	1,211,923.20	1,308,398.00	1,405,062.39	1,501,869.01	1,596,937.60	1,694,597.42	1,786,032.00	1,880,152.56	1,973,736.00
SpoBoResRed1	380,384.76	413,284.12	446,183.50	479,147.51	512,160.03	544,579.85	577,883.32	609,063.90	607,415.16	605,766.42
SpoBoResRed2	30,426.04	33,101.35	35,859.80	38,618.25	41,490.05	41,376.69	41,376.69	41,376.69	41,490.05	41,376.69
SpoBoResYel1	1,135.94	1,131.33	1,127.44	1,124.25	1,121.60	1,118.06	1,116.64	1,111.51	1,108.50	1,105.49
SpoBoResYel2	20,640.04	22,425.19	24,210.34	25,999.00	27,790.29	29,549.42	31,356.50	33,048.39	34,789.98	36,521.63
SpoBoResYel3	166.07	165.40	164.83	164.36	163.98	163.46	163.25	162.50	162.06	161.62
SpoBoResYel4	1,972.94	2,143.58	2,314.22	2,485.19	2,656.42	2,824.57	2,997.30	3,159.03	3,325.50	3,491.03
SpoBoResYel5	394.59	428.72	462.84	497.04	531.28	564.91	599.46	631.81	665.10	698.21
SpoBoResYel6	1,972.94	2,143.58	2,314.22	2,485.19	2,656.42	2,824.57	2,997.30	3,159.03	3,325.50	3,491.03
SpoBoResYel7	394.59	428.72	462.84	497.04	531.28	564.91	599.46	631.81	665.10	698.21
SpoBoResYel8	737.57	801.36	865.15	929.07	993.08	1,055.94	1,120.52	1,180.98	1,243.22	1,305.10
SpoBoResYel9	748.44	813.17	877.90	942.76	1,007.72	1,071.51	1,137.03	1,198.38	1,261.54	1,324.33
SpoBResYel10	232.50	252.61	272.72	292.87	313.05	332.86	353.22	372.28	391.89	411.40
SpoBResYel11	16,304.16	17,714.30	19,124.44	20,537.35	21,952.34	23,341.93	24,769.39	26,105.87	27,481.60	28,849.47
SpoBResYel12	23,250.13	25,261.03	27,271.93	29,286.78	31,304.59	33,286.18	35,321.77	37,227.62	39,189.44	41,140.07
SpoBResYel13	153.45	166.72	179.99	193.29	206.61	219.69	233.12	245.70	258.65	271.52
SpoBResYel14	10,481.24	11,387.76	12,294.28	13,202.58	14,112.22	15,005.53	15,923.18	16,782.34	17,666.74	18,546.09
SpoBResYel15	75,563.53	82,099.00	88,634.47	95,182.78	101,740.73	108,180.94	114,796.68	120,990.71	127,366.70	133,706.29
SpoBResYel16	192.06	208.68	225.29	241.93	258.60	274.97	291.79	307.53	323.74	339.85
SpoBResYel17	15.27	16.61	17.99	19.38	20.82	20.76	20.76	20.76	20.82	20.76
SpoBResYel18	5.55	6.04	6.54	7.05	7.57	7.55	7.55	7.55	7.57	7.55
SpoBResYel19	91.34	99.24	98.90	98.62	98.39	98.08	97.95	97.50	97.24	96.97
SpoBResYel20	4,642.79	5,051.02	5,471.94	5,892.86	6,331.07	6,734.69	7,155.61	7,576.53	8,019.36	8,418.37
SpoBResYel21	60.69	66.03	71.53	77.03	82.76	88.04	93.54	99.04	104.83	110.04
SpoBResYel22	488.49	531.44	575.73	620.02	666.13	708.59	752.88	797.17	843.76	885.74
SpoBResYel23	60.69	66.03	71.53	77.03	82.76	88.04	93.54	99.04	104.83	110.04
SpoBResYel24	11,550.35	12,565.95	13,613.11	14,660.28	15,750.47	15,707.44	15,707.44	15,707.44	15,750.47	15,707.44
SpoBResYel25	1,824.51	1,982.31	2,140.12	2,298.23	2,456.57	2,448.82	2,445.72	2,434.48	2,427.89	2,421.30
SpoGComYel10	268.16	291.74	316.06	340.37	365.68	388.99	413.30	437.62	463.19	486.24
SpoGComYel11	295.17	321.12	347.88	374.64	402.50	428.16	454.92	481.68	509.83	535.20
SpoGComYel12	129.27	140.64	152.36	164.08	176.28	175.80	175.80	175.80	176.28	175.80
SpoGResYel10	30.49	33.13	35.77	38.41	41.06	43.65	46.32	48.82	51.40	53.95
SpoGResYel11	2,138.25	2,323.19	2,508.12	2,693.42	2,879.00	3,061.24	3,248.45	3,423.72	3,604.14	3,783.54

DSM Program	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029
SpoGResYel12	3,049.20	3,312.92	3,576.65	3,840.89	4,105.52	4,365.40	4,632.36	4,882.31	5,139.60	5,395.42
SpoGResYel13	20.12	21.87	23.61	25.35	27.10	28.81	30.57	32.22	33.92	35.61
SpoGResYel14	1,374.59	1,493.48	1,612.36	1,731.49	1,850.78	1,967.94	2,088.29	2,200.96	2,316.95	2,432.27
SpoGResYel15	9,909.97	10,767.08	11,624.19	12,482.99	13,343.05	14,187.66	15,055.30	15,867.63	16,703.83	17,535.25
SpoGResYel16	25.19	27.37	29.55	31.73	33.91	36.06	38.27	40.33	42.46	44.57
SpoGResYel17	2.00	2.18	2.36	2.54	2.73	2.72	2.72	2.72	2.73	2.72
SpoGResYel19	11.86	12.88	12.84	12.80	12.77	12.73	12.72	12.66	12.63	12.59
SpoGResYel20	608.89	662.43	717.63	772.83	830.30	883.24	938.44	993.64	1,051.72	1,104.05
SpoGResYel21	7.96	8.66	9.38	10.10	10.85	11.55	12.27	12.99	13.75	14.43
SpoGResYel22	67.65	73.60	79.74	85.87	92.26	98.14	104.27	110.40	116.86	122.67
SpoGResYel23	7.96	8.66	9.38	10.10	10.85	11.55	12.27	12.99	13.75	14.43
SpoGResYel24	1,514.80	1,647.99	1,785.33	1,922.66	2,065.64	2,059.99	2,059.99	2,059.99	2,065.64	2,059.99
SpoGResYel25	239.28	259.98	280.67	301.41	322.17	321.16	320.75	319.28	318.41	317.55
SpoGTComRed1	2,246.84	2,441.17	2,635.49	2,830.20	3,025.20	3,216.70	3,413.41	3,597.59	3,787.17	3,975.68
SpoGTComRed2	188.71	205.30	222.41	239.52	257.33	273.74	290.85	290.85	291.64	290.85
SpoGTComYel1	17.47	19.01	20.59	22.18	23.83	23.76	23.76	23.76	23.83	23.76
SpoGTComYel2	25.59	25.52	25.52	25.52	25.59	25.52	25.52	25.52	25.59	25.52
SpoGTComYel3	544.27	592.13	641.47	690.82	742.19	740.16	740.16	740.16	742.19	740.16
SpoGTComYel4	142.95	155.52	168.48	181.44	194.93	207.36	220.32	233.28	246.91	259.20
SpoGTComYel5	58.33	63.46	68.74	74.03	79.54	79.32	79.32	79.32	79.54	79.32
SpoGTComYel6	90.02	97.81	105.59	113.39	121.21	128.88	136.76	144.14	151.74	159.29
SpoGTComYel7	78.53	85.44	92.56	99.68	107.09	106.80	106.80	106.80	107.09	106.80
SpoGTComYel8	26.47	28.80	31.20	33.60	36.10	36.00	36.00	36.00	36.10	36.00
SpoGTComYel9	213.10	231.84	251.16	270.48	290.59	289.80	289.80	289.80	290.59	289.80
SpoGTNComMTA	709.78	772.19	836.54	900.89	967.88	1,029.58	1,029.58	1,029.58	1,032.40	1,029.58
SpoGTNComMTW	1,523.56	1,655.34	1,787.11	1,919.14	2,051.37	2,181.22	2,314.61	2,439.50	2,568.05	2,695.88
SpoGTNResMTA	18,261.10	18,211.20	18,211.20	18,211.20	18,261.10	18,211.20	18,211.20	18,211.20	18,261.10	18,211.20
SpoGTNResMTW	146,843.84	159,544.32	172,244.80	184,970.24	197,714.40	210,229.76	223,086.24	235,123.20	247,513.76	259,833.60
SpoGTResRed1	49,886.53	54,201.20	58,515.87	62,839.02	67,168.53	71,420.31	75,787.98	79,877.23	79,661.00	79,444.78
SpoGTResRed2	3,990.30	4,341.16	4,702.92	5,064.69	5,441.32	5,426.45	5,426.45	5,426.45	5,441.32	5,426.45
SpoGTResYel1	148.98	148.37	147.86	147.44	147.09	146.63	146.45	145.77	145.38	144.98
SpoGTResYel2	2,706.89	2,941.01	3,175.13	3,409.71	3,644.63	3,875.33	4,112.33	4,334.21	4,562.62	4,789.72
SpoGTResYel3	21.78	21.69	21.62	21.56	21.51	21.44	21.41	21.31	21.25	21.20
SpoGTResYel4	258.75	281.13	303.50	325.93	348.38	370.44	393.09	414.30	436.13	457.84
SpoGTResYel5	51.75	56.23	60.70	65.19	69.68	74.09	78.62	82.86	87.23	91.57
SpoGTResYel6	258.75	281.13	303.50	325.93	348.38	370.44	393.09	414.30	436.13	457.84
SpoGTResYel7	51.75	56.23	60.70	65.19	69.68	74.09	78.62	82.86	87.23	91.57
SpoGTResYel8	96.73	105.10	113.46	121.85	130.24	138.48	146.95	154.88	163.04	171.16
SpoGTResYel9	98.16	106.65	115.13	123.64	132.16	140.53	149.12	157.17	165.45	173.68
SpoNComYel10	1,039.14	1,130.51	1,224.72	1,318.93	1,417.01	1,507.34	1,601.55	1,695.76	1,794.88	1,884.18
SpoNComYel11	1,143.77	1,244.34	1,348.04	1,451.73	1,559.69	1,555.43	1,555.43	1,555.43	1,559.69	1,555.43
SpoNComYel12	500.93	544.98	590.40	635.81	683.09	681.22	681.22	681.22	683.09	681.22
SpoNResYel10	118.16	128.38	138.60	148.83	159.09	169.16	179.50	189.19	199.16	209.07
SpoNResYel11	8,285.72	9,002.35	9,718.98	10,437.02	11,156.11	11,862.29	12,587.73	13,266.92	13,966.06	14,661.21
SpoNResYel12	11,815.64	12,837.57	13,859.50	14,883.44	15,908.89	16,915.93	17,950.41	18,918.95	19,915.95	20,907.25
SpoNResYel13	77.98	84.73	91.47	98.23	105.00	111.65	118.47	124.87	131.45	137.99
SpoNResYel14	5,326.53	5,787.22	6,247.91	6,709.51	7,171.78	7,625.76	8,092.11	8,528.73	8,978.18	9,425.06
SpoNResYel15	38,401.14	41,722.44	45,043.75	48,371.58	51,704.30	54,977.20	58,339.30	61,487.08	64,727.34	67,949.10
SpoNResYel16	97.61	106.05	114.49	122.95	131.42	139.74	148.28	156.29	164.52	172.71
SpoNResYel17	7.76	8.44	9.14	9.85	10.58	10.55	10.55	10.55	10.58	10.55
SpoNResYel18	2.82	3.07	3.32	3.58	3.85	3.84	3.84	3.84	3.85	3.84
SpoNResYel19	46.42	50.43	50.26	50.12	50.00	49.84	49.78	49.55	49.42	49.28
SpoNResYel20	2,359.45	2,566.91	2,780.82	2,994.73	3,217.43	3,422.55	3,636.46	3,850.37	4,075.41	4,278.19
SpoNResYel21	30.84	33.55	36.35	39.15	42.06	44.74	47.54	50.33	53.27	55.92
SpoNResYel22	262.16	285.21	308.98	332.75	357.49	380.28	404.05	427.82	452.82	475.35
SpoNResYel23	30.84	33.55	36.35	39.15	42.06	44.74	47.54	50.33	53.27	55.92

Appendix 4.3 - SENDOUT® Selected Measures (Expected Case) in Dth

DSM Program	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029
SpoNResYel24	5,869.85	6,385.98	6,918.14	7,450.30	8,004.34	7,982.47	7,982.47	7,982.47	8,004.34	7,982.47
SpoNResYel25	927.21	1,007.41	1,087.60	1,167.95	1,248.42	1,244.48	1,242.91	1,237.19	1,233.84	1,230.49
SpoNWComRed1	8,706.49	9,459.51	10,212.54	10,967.04	11,722.65	12,464.70	13,226.97	13,940.65	14,675.30	15,405.75
SpoNWComRed2	731.25	795.55	861.85	928.14	997.17	1,060.74	1,127.03	1,127.03	1,130.12	1,127.03
SpoNWComYel1	67.70	73.66	79.79	85.93	92.32	92.07	92.07	92.07	92.32	92.07
SpoNWComYel2	99.16	98.89	98.89	98.89	99.16	98.89	98.89	98.89	99.16	98.89
SpoNWComYel3	2,109.05	2,294.50	2,485.70	2,676.91	2,875.98	2,868.12	2,868.12	2,868.12	2,875.98	2,868.12
SpoNWComYel4	553.93	602.64	652.86	703.08	755.36	803.52	853.74	903.96	956.79	1,004.40
SpoNWComYel5	226.02	245.89	266.38	286.87	308.21	307.36	307.36	307.36	308.21	307.36
SpoNWComYel6	348.83	379.00	409.17	439.40	469.68	499.41	529.95	558.54	587.98	617.24
SpoNWComYel7	304.32	331.08	358.67	386.26	414.98	413.85	413.85	413.85	414.98	413.85
SpoNwComYel8	102.58	111.60	120.90	130.20	139.88	139.50	139.50	139.50	139.88	139.50
SpoNWComYel9	825.77	898.38	973.24	1,048.11	1,126.05	1,122.98	1,122.98	1,122.98	1,126.05	1,122.98
SpoNWPComMTA	2,750.39	2,992.23	3,241.58	3,490.93	3,750.53	3,989.64	3,989.64	3,989.64	4,000.57	3,989.64
SpoNWPComMTW	5,903.81	6,414.43	6,925.04	7,436.67	7,949.04	8,452.22	8,969.11	9,453.05	9,951.21	10,446.52
SpoNWPResMTA	70,761.76	70,568.42	70,568.42	70,568.42	70,761.76	70,568.42	70,568.42	70,568.42	70,761.76	70,568.42
SpoNWPResMTW	569,725.86	619,001.29	668,276.70	717,648.96	767,093.85	815,651.02	865,531.71	912,232.80	960,305.81	1,008,104.40
SpoNWResRed1	193,310.29	210,029.64	226,748.99	243,501.19	260,278.05	276,753.70	293,678.41	309,524.28	308,686.40	307,848.51
SpoNWResRed2	15,462.41	16,822.00	18,223.83	19,625.67	21,085.11	21,027.50	21,027.50	21,027.50	21,085.11	21,027.50
SpoNWResYel1	577.28	574.94	572.96	571.34	569.99	568.19	567.47	564.87	563.34	561.81
SpoNWResYel2	10,489.20	11,396.41	12,303.62	13,212.61	14,122.94	15,016.92	15,935.27	16,795.08	17,680.15	18,560.17
SpoNWResYel3	84.40	84.06	83.77	83.53	83.33	83.07	82.96	82.58	82.36	82.14
SpoNWResYel4	1,002.64	1,089.36	1,176.08	1,262.97	1,349.98	1,435.44	1,523.22	1,605.41	1,690.01	1,774.13
SpoNWResYel5	200.53	217.87	235.22	252.59	270.00	287.09	304.64	321.08	338.00	354.83
SpoNWResYel6	1,002.64	1,089.36	1,176.08	1,262.97	1,349.98	1,435.44	1,523.22	1,605.41	1,690.01	1,774.13
SpoNWResYel7	200.53	217.87	235.22	252.59	270.00	287.09	304.64	321.08	338.00	354.83
SpoNWResYel8	374.83	407.25	439.67	472.15	504.68	536.63	569.44	600.17	631.80	663.25
SpoNWResYel9	380.35	413.25	446.15	479.11	512.12	544.54	577.84	609.01	641.11	673.02
Total	3,414,355.93	3,688,693.70	3,962,004.98	4,231,861.99	4,499,252.80	4,749,258.20	5,005,156.30	5,245,464.03	5,438,669.25	5,627,038.16
WA/ID	3,099,579.96	3,347,233.35	3,595,802.18	3,844,841.18	4,095,270.66	4,331,295.65	4,573,965.49	4,801,026.28	4,980,467.56	5,156,772.22
OR	314,775.97	341,460.35	366,202.80	387,020.81	403,982.14	417,962.55	431,190.81	444,437.75	458,201.69	470,265.94

Appendix 4.3 - SENDOUT® Selected Measures (High Growth Low Price Case) in Dth

DSM Program	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019
KlaComRed2	227.31	454.62	683.79	909.23	1,136.54	1,363.85	1,595.52	1,818.47	2,045.78	2,273.09
KlaComYel10	2.60	5.20	7.81	10.39	12.99	15.59	18.23	20.78	23.38	25.98
KlaComYel11	88.55	177.11	266.39	354.21	442.77	531.32	621.57	708.43	796.98	885.53
KlaComYel12	2.86	5.73	8.61	11.45	14.32	17.18	20.10	22.91	25.77	28.63
KlaComYel13	4.43	8.86	13.32	17.71	22.14	26.57	31.08	35.42	39.85	44.28
KlaComYel14	5.50	11.01	16.59	22.05	27.27	32.63	37.92	43.20	48.42	53.51
KlaComYel15	30.52	61.04	91.82	122.09	152.61	183.13	214.24	244.17	274.69	305.21
KlaComYel16	30.52	61.04	91.82	122.09	152.61	183.13	214.24	244.17	274.69	305.21
KlaComYel17	15.00	29.99	45.11	59.98	74.98	89.97	105.25	119.96	134.96	149.95
KlaComYel18	15.00	29.99	45.11	59.98	74.98	89.97	105.25	119.96	134.96	149.95
KlaComYel19	21.62	43.24	65.04	86.49	108.11	129.73	151.77	172.97	194.60	216.22
KlaComYel20	-	-	-	0.11	0.37	0.66	0.76	0.98	1.10	1.32
KlaComYel9	2.60	5.20	7.81	10.39	12.99	15.59	18.23	20.78	23.38	25.98
KlamComMTA	953.49	1,906.99	2,868.32	3,813.98	4,767.47	5,720.97	6,692.75	7,627.96	8,581.45	9,534.94
KlamComMTW	609.70	1,219.40	1,825.01	2,412.59	2,983.44	3,569.20	4,148.78	4,725.45	5,297.29	5,854.03
KlamComYel1	49.73	99.46	148.85	196.77	243.33	291.11	338.38	385.41	432.06	477.46
KlamComYel2	1.71	3.42	5.15	6.85	8.56	10.27	12.02	13.70	15.41	17.12
KlamComYel3	35.42	70.84	106.56	141.69	177.11	212.53	248.63	283.37	318.79	354.21
KlamComYel4	23.91	47.82	71.92	95.64	119.55	143.46	167.82	191.28	215.18	239.09
KlamComYel5	23.91	47.82	71.92	95.64	119.55	143.46	167.82	191.28	215.18	239.09
KlamComYel6	19.51	39.02	58.69	78.05	97.56	117.07	136.95	156.09	175.60	195.11
KlamComYel7	91.23	182.46	273.08	361.00	446.42	534.06	620.79	707.08	792.64	875.95
KlamComYel8	5.50	11.01	16.55	22.01	27.51	33.02	38.63	44.02	49.53	55.03
KlamResMTA	211.52	423.03	636.29	846.07	1,057.58	1,269.10	1,484.68	1,692.14	1,903.65	2,115.17
KlamResMTW	1,762.10	3,524.20	5,274.47	6,972.66	8,622.46	10,315.39	11,990.43	13,657.06	15,309.76	16,918.79
KlamResYel1	37.78	75.57	113.10	149.51	184.89	221.19	257.11	292.85	328.28	362.79
KlamResYel2	5.27	10.53	15.88	21.11	26.10	31.23	36.30	41.34	46.35	51.22
KlaResRed1	663.30	1,326.60	1,985.45	1,968.52	1,947.43	1,941.49	1,934.36	1,927.83	1,921.00	1,910.60
KlaResRed2	291.16	582.32	875.88	1,164.65	1,455.81	1,746.97	2,043.71	2,329.29	2,620.45	2,911.61
KlaResYel10	4.31	8.62	12.91	17.19	21.37	25.57	29.72	33.85	37.94	41.93
KlaResYel11	530.17	1,060.34	1,586.95	2,097.90	2,594.28	3,103.64	3,607.62	4,109.06	4,606.32	5,090.43
KlaResYel12	412.36	824.71	1,234.30	1,631.70	2,017.77	2,413.94	2,805.92	3,195.94	3,582.69	3,959.23
KlaResYel13	3.24	6.84	10.24	13.54	16.86	20.29	23.58	26.86	30.11	33.27
KlaResYel14	-	-	-	-	-	-	-	-	1.31	1.45
KlaResYel16	111.37	222.74	335.03	445.48	556.85	668.22	781.73	890.97	1,002.34	1,113.71
KlaResYel17	-	1.17	1.90	2.53	3.16	3.80	4.44	5.06	5.70	6.33
KlaResYel18	107.60	215.21	323.70	430.42	538.02	645.63	755.30	860.84	968.44	1,076.05
KlaResYel19	-	1.17	1.90	2.53	3.16	3.80	4.44	5.06	5.70	6.33
KlaResYel20	109.76	219.51	330.17	439.03	548.78	658.54	770.40	878.05	987.81	1,097.57
KlaResYel3	5.13	10.27	15.48	20.57	25.44	25.36	25.27	25.18	25.10	24.96
KlaResYel4	10.36	20.99	31.42	41.53	51.36	61.44	71.42	81.35	91.19	100.77
KlaResYel5	6.03	12.06	18.19	24.17	29.89	35.76	41.57	47.35	53.08	58.65
KlaResYel6	-	-	-	-	-	-	-	-	-	-
KlaResYel7	6.84	13.69	20.74	27.42	33.91	40.57	47.16	53.71	60.21	66.54
KlaResYel8	8.46	17.03	25.63	33.88	41.90	50.13	58.27	66.37	74.40	82.22
KlaResYel9	8.25	16.61	25.00	33.05	40.87	48.89	56.83	64.73	72.57	80.20
LaGrComMTA	463.36	926.73	1,393.90	1,853.45	2,316.82	2,780.18	3,252.43	3,706.91	4,170.27	4,633.63
LaGrComMTW	308.17	604.12	891.84	1,168.80	1,437.83	1,691.38	1,943.26	2,182.61	2,407.07	2,623.75
LaGrComRed2	110.46	220.93	332.30	441.85	552.32	662.78	775.36	883.71	994.17	1,104.64
LaGrComYel1	25.06	49.13	72.53	95.06	116.94	137.56	158.05	177.51	195.77	213.39
LaGrComYel10	1.40	2.81	4.22	5.61	7.02	8.42	9.85	11.23	12.63	14.03
LaGrComYel11	47.84	95.68	143.91	191.36	239.20	287.03	335.79	382.71	430.55	478.39
LaGrComYel12	1.55	3.09	4.65	6.19	7.73	9.28	10.86	12.37	13.92	15.47
LaGrComYel13	2.39	4.78	7.20	9.57	11.96	14.35	16.79	19.14	21.53	23.92
LaGrComYel14	2.66	5.45	8.04	10.54	12.97	15.26	17.63	19.81	21.84	23.92
LaGrComYel15	16.49	32.98	49.60	65.95	82.44	98.93	115.74	131.91	148.40	164.89
LaGrComYel16	16.49	32.98	49.60	65.95	82.44	98.93	115.74	131.91	148.40	164.89

DSM Program	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019
LaGrComYel17	8.10	16.20	24.37	32.40	40.50	48.60	56.86	64.81	72.91	81.01
LaGrComYel18	8.10	16.20	24.37	32.40	40.50	48.60	56.86	64.81	72.91	81.01
LaGrComYel19	11.68	23.36	35.14	46.72	58.40	70.08	81.99	93.45	105.13	116.81
LaGrComYel2	-	1.85	2.78	3.70	4.62	5.55	6.49	7.40	8.32	9.25
LaGrComYel20	-	-	-	-	-	-	-	0.11	0.12	0.34
LaGrComYel3	19.14	38.27	57.56	76.54	95.68	114.81	134.32	153.09	172.22	191.36
LaGrComYel4	12.92	25.83	38.86	51.67	64.58	77.50	90.66	103.33	116.25	129.17
LaGrComYel5	12.92	25.83	38.86	51.67	64.58	77.50	90.66	103.33	116.25	129.17
LaGrComYel6	10.54	21.08	31.71	42.16	52.70	63.24	73.99	84.32	94.86	105.41
LaGrComYel7	45.98	90.14	133.07	174.40	214.54	252.37	289.95	325.66	359.16	391.49
LaGrComYel8	2.97	5.95	8.94	11.89	14.86	17.84	20.87	23.78	26.75	29.73
LaGrComYel9	1.40	2.81	4.22	5.61	7.02	8.42	9.85	11.23	12.63	14.03
LaGrResMTA	88.14	176.28	265.14	352.55	440.69	528.83	618.66	705.11	793.25	881.39
LaGrResMTW	762.62	1,494.99	2,206.98	2,892.38	3,558.13	4,185.58	4,808.87	5,401.18	5,956.65	6,492.84
LaGrResRed1	287.55	563.68	832.14	817.93	804.95	789.08	777.08	763.69	748.65	734.44
LaGrResRed2	121.33	242.65	364.98	485.30	606.63	727.96	851.61	970.61	1,091.94	1,213.26
LaGrResYel1	16.16	32.01	47.26	61.93	76.19	89.62	102.97	115.65	127.55	139.03
LaGrResYel10	1.79	3.50	5.40	7.08	8.71	10.25	11.78	13.23	14.59	15.91
LaGrResYel11	229.13	449.17	663.09	869.02	1,069.05	1,257.57	1,444.84	1,622.80	1,789.69	1,950.79
LaGrResYel12	178.21	349.36	515.74	675.91	831.48	978.11	1,123.76	1,262.18	1,391.98	1,517.28
LaGrResYel13	1.34	2.78	4.10	5.62	6.91	8.13	9.34	10.50	11.58	12.62
LaGrResYel16	51.59	103.18	155.19	206.36	257.95	309.54	362.12	412.72	464.31	515.90
LaGrResYel17	-	-	-	-	1.47	1.76	2.06	2.35	2.64	2.93
LaGrResYel18	49.85	99.69	149.95	199.38	249.23	299.07	349.87	398.76	448.61	498.45
LaGrResYel19	-	-	-	-	1.47	1.76	2.06	2.35	2.64	2.93
LaGrResYel2	2.18	4.38	6.60	8.65	10.64	12.52	14.38	16.16	17.93	19.54
LaGrResYel20	50.84	101.68	152.94	203.37	254.21	305.05	356.87	406.74	457.58	508.42
LaGrResYel3	2.13	4.27	6.43	8.43	10.37	10.17	10.01	9.85	9.65	9.47
LaGrResYel4	4.40	8.80	12.99	17.13	21.07	24.90	28.60	32.13	35.43	38.62
LaGrResYel5	2.50	5.12	7.56	9.91	12.19	14.34	16.47	18.61	20.53	22.48
LaGrResYel6	177.11	347.19	512.54	671.72	826.33	972.05	1,116.80	1,254.36	1,383.36	1,507.88
LaGrResYel7	2.84	5.81	8.57	11.24	13.83	16.27	18.80	21.12	23.39	25.50
LaGrResYel8	3.50	7.18	10.59	13.89	17.19	20.22	23.34	26.21	28.91	31.51
LaGrResYel9	3.42	7.00	10.33	13.55	16.67	19.72	22.76	25.57	28.19	30.73
MedGComRed2	404.19	808.39	1,215.91	1,616.78	2,020.97	2,425.17	2,837.11	3,233.56	3,637.75	4,041.95
MedGComYel10	7.03	14.07	21.16	28.13	35.17	42.20	49.37	56.27	63.30	70.33
MedGComYel11	239.77	479.55	721.29	959.10	1,198.87	1,438.64	1,683.02	1,918.19	2,157.97	2,397.74
MedGComYel12	7.75	15.51	23.32	31.01	38.76	46.52	54.42	62.02	69.77	77.53
MedGComYel13	11.99	23.98	36.06	47.95	59.94	71.93	84.15	95.91	107.90	119.89
MedGComYel14	10.35	20.50	30.20	39.79	49.25	58.49	67.61	76.44	84.94	93.11
MedGComYel15	82.64	165.28	248.61	330.57	413.21	495.85	580.08	661.14	743.78	826.42
MedGComYel16	82.64	165.28	248.61	330.57	413.21	495.85	580.08	661.14	743.78	826.42
MedGComYel17	40.60	81.20	122.14	162.41	203.01	243.61	284.99	324.81	365.42	406.02
MedGComYel18	40.60	81.20	122.14	162.41	203.01	243.61	284.99	324.81	365.42	406.02
MedGComYel19	58.54	117.09	176.12	234.18	292.72	351.27	410.94	468.36	526.90	585.45
MedGComYel20	-	0.12	0.56	0.87	1.19	1.53	1.76	2.09	2.32	2.55
MedGComYel9	7.03	14.07	21.16	28.13	35.17	42.20	49.37	56.27	63.30	70.33
MedGResRed1	1,147.14	2,273.37	3,348.80	3,309.21	3,277.09	3,243.47	3,203.14	3,168.77	3,129.93	3,088.10
MedGResRed2	480.05	960.11	1,444.10	1,920.21	2,400.27	2,880.32	3,369.58	3,840.42	4,320.48	4,800.53
MedGResYel10	7.42	14.90	21.94	28.91	35.78	42.50	48.96	55.35	61.71	67.65
MedGResYel11	915.24	1,813.80	2,671.83	3,520.32	4,357.69	5,175.59	5,963.09	6,741.85	7,491.61	8,212.76
MedGResYel12	711.86	1,410.73	2,078.09	2,738.03	3,389.31	4,025.46	4,637.96	5,243.66	5,826.81	6,387.70
MedGResYel13	5.80	11.82	17.41	22.94	28.39	33.72	38.85	43.92	48.80	53.50
MedGResYel14	-	-	-	1.46	1.82	2.19	2.56	2.91	3.28	3.64
MedGResYel15	-	-	-	-	-	-	-	-	0.71	1.32
MedGResYel16	279.61	559.21	841.12	1,118.43	1,398.04	1,677.64	1,962.61	2,236.86	2,516.47	2,796.07
MedGResYel17	1.59	3.18	4.78	6.36	7.95	9.53	11.15	12.71	14.30	15.89

Appendix 4.3 - SENDOUT® Selected Measures (High Growth Low Price Case) in Dth

DSM Program	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019
MedGResYel18	270.15	540.30	812.68	1,080.61	1,350.76	1,620.91	1,896.25	2,161.22	2,431.37	2,701.52
MedGResYel19	1.59	3.18	4.78	6.36	7.95	9.53	11.15	12.71	14.30	15.89
MedGResYel20	275.56	551.11	828.93	1,102.22	1,377.78	1,653.33	1,934.17	2,204.44	2,480.00	2,755.55
MedGTComYel1	92.59	183.48	270.28	356.11	440.82	523.56	603.22	682.00	757.84	830.80
MedGTComYel2	4.64	9.27	13.94	18.54	23.18	27.81	32.54	37.09	41.72	46.36
MedGTComYel3	95.91	191.82	288.52	383.64	479.55	575.46	673.21	767.28	863.19	959.10
MedGTComYel4	64.74	129.48	194.75	258.96	323.69	388.43	454.41	517.91	582.65	647.39
MedGTComYel5	64.74	129.48	194.75	258.96	323.69	388.43	454.41	517.91	582.65	647.39
MedGTComYel6	52.83	105.66	158.92	211.32	264.15	316.98	370.82	422.64	475.47	528.30
MedGTComYel7	169.86	336.61	495.85	653.32	808.72	960.51	1,106.66	1,251.18	1,390.33	1,524.16
MedGTComYel8	14.90	29.80	44.82	59.60	74.50	89.40	104.58	119.20	134.10	149.00
MedGTNComMTA	1,695.48	3,390.96	5,100.37	6,781.92	8,477.40	10,172.88	11,900.87	13,563.84	15,259.32	16,954.80
MedGTNComMTW	1,137.93	2,255.11	3,321.90	4,376.84	5,417.94	6,434.84	7,413.95	8,382.19	9,314.37	10,210.98
MedGTNResMTA	348.74	697.48	1,049.08	1,394.96	1,743.69	2,092.43	2,447.86	2,789.91	3,138.65	3,487.39
MedGTNResMTW	3,049.83	6,044.06	8,903.24	11,730.64	14,520.97	17,246.42	19,870.59	22,465.63	24,964.02	27,367.08
MedGTResYel1	65.03	129.27	190.42	250.89	310.57	368.86	424.98	480.48	533.92	585.31
MedGTResYel2	9.18	18.19	26.80	35.31	43.70	51.91	59.80	67.83	75.38	82.63
MedGTResYel3	8.95	17.73	26.12	34.41	42.60	42.16	41.63	41.18	40.68	40.13
MedGTResYel4	18.06	35.80	52.73	69.69	86.27	102.46	118.05	133.47	148.31	162.59
MedGTResYel5	10.51	20.84	30.69	40.44	50.05	59.44	68.71	77.68	86.32	94.63
MedGTResYel6	707.44	1,401.99	2,065.21	2,721.06	3,368.31	4,000.51	4,609.22	5,211.17	5,790.70	6,348.12
MedGTResYel7	11.93	23.64	34.82	45.87	56.78	67.65	77.95	88.13	97.93	107.36
MedGTResYel8	14.74	29.21	43.02	56.68	70.38	83.60	96.31	108.89	121.00	132.65
MedGTResYel9	14.38	28.49	41.96	55.28	68.65	81.54	93.94	106.21	118.02	129.38
MedNComRed2	181.59	363.19	546.28	726.38	907.97	1,089.57	1,274.65	1,452.76	1,634.35	1,815.95
MedNComYel10	3.16	6.32	9.51	12.64	15.80	18.96	22.18	25.28	28.44	31.60
MedNComYel11	107.72	215.45	324.06	430.90	538.62	646.35	756.14	861.80	969.52	1,077.25
MedNComYel12	3.48	6.97	10.48	13.93	17.42	20.90	24.45	27.86	31.35	34.83
MedNComYel13	5.39	10.77	16.20	21.54	26.93	32.32	37.81	43.09	48.48	53.86
MedNComYel14	4.52	9.21	13.57	17.87	22.13	26.28	30.27	34.23	38.03	41.69
MedNComYel15	37.13	74.26	111.69	148.52	185.65	222.77	260.62	297.03	334.16	371.29
MedNComYel16	37.13	74.26	111.69	148.52	185.65	222.77	260.62	297.03	334.16	371.29
MedNComYel17	18.24	36.48	54.87	72.97	91.21	109.45	128.04	145.93	164.17	182.41
MedNComYel18	18.24	36.48	54.87	72.97	91.21	109.45	128.04	145.93	164.17	182.41
MedNComYel19	26.30	52.61	79.12	105.21	131.51	157.82	184.62	210.42	236.72	263.03
MedNComYel20	-	-	-	0.11	0.24	0.49	0.57	0.75	0.83	0.92
MedNComYel9	3.16	6.32	9.51	12.64	15.80	18.96	22.18	25.28	28.44	31.60
MedNResRed1	515.98	1,022.56	1,506.29	1,488.48	1,474.03	1,458.91	1,440.77	1,425.31	1,407.84	1,389.02
MedNResRed2	215.68	431.35	648.80	862.70	1,078.38	1,294.06	1,513.87	1,725.41	1,941.08	2,156.76
MedNResYel10	3.28	6.51	9.86	12.99	16.08	19.09	22.00	24.87	27.63	30.29
MedNResYel11	411.20	814.90	1,200.39	1,581.59	1,957.80	2,325.26	2,679.07	3,028.95	3,365.80	3,689.79
MedNResYel12	319.82	633.81	933.63	1,230.13	1,522.74	1,808.54	2,083.72	2,355.85	2,617.84	2,869.84
MedNResYel13	2.61	5.16	7.82	10.30	12.76	15.15	17.45	19.73	21.93	24.03
MedNResYel14	-	-	-	-	-	-	-	1.31	1.47	1.64
MedNResYel16	125.62	251.24	377.89	502.48	628.10	753.72	881.75	1,004.97	1,130.59	1,256.21
MedNResYel17	-	1.43	2.15	2.86	3.57	4.28	5.01	5.71	6.43	7.14
MedNResYel18	121.37	242.75	365.12	485.49	606.86	728.24	851.94	970.98	1,092.35	1,213.73
MedNResYel19	-	1.43	2.15	2.86	3.57	4.28	5.01	5.71	6.43	7.14
MedNResYel20	123.80	247.60	372.42	495.20	619.00	742.80	868.98	990.40	1,114.20	1,238.00
MedNWComYel1	41.47	82.43	121.43	159.99	198.05	235.22	271.01	306.41	340.48	373.26
MedNWComYel2	2.08	4.17	6.27	8.33	10.41	12.50	14.62	16.66	18.74	20.83
MedNWComYel3	43.09	86.18	129.62	172.36	215.45	258.54	302.46	344.72	387.81	430.90
MedNWComYel4	29.09	58.17	87.50	116.34	145.43	174.51	204.16	232.69	261.77	290.86
MedNWComYel5	29.09	58.17	87.50	116.34	145.43	174.51	204.16	232.69	261.77	290.86
MedNWComYel6	23.74	47.47	71.40	94.94	118.68	142.41	166.60	189.88	213.62	237.35
MedNWComYel7	76.31	151.23	222.77	293.52	363.34	431.53	497.19	562.13	624.64	684.77
MedNWComYel8	6.69	13.39	20.14	26.78	33.47	40.16	46.99	53.55	60.25	66.94

Appendix 4.3 - SENDOUT® Selected Measures (High Growth Low Price Case) in Dth

DSM Program	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019
MedNWPComMTA	761.74	1,523.47	2,291.47	3,046.95	3,808.69	4,570.42	5,346.77	6,093.90	6,855.64	7,617.37
MedNWPComMTW	511.38	1,013.43	1,492.84	1,966.92	2,434.78	2,891.77	3,331.78	3,766.90	4,185.81	4,588.74
MedNWPResMTA	156.68	313.36	471.33	626.72	783.40	940.08	1,099.76	1,253.44	1,410.12	1,566.80
MedNWPResMTW	1,368.28	2,711.61	3,994.35	5,262.84	6,514.70	7,737.44	8,914.75	10,078.99	11,199.87	12,277.98
MedNWResYel1	29.22	57.90	85.55	112.72	139.53	165.72	190.93	215.87	239.87	262.97
MedNWResYel2	4.01	8.17	12.04	15.86	19.64	23.32	26.87	30.37	33.75	37.00
MedNWResYel3	3.91	7.97	11.73	15.46	19.14	18.94	18.70	18.50	18.28	18.03
MedNWResYel4	8.12	16.08	23.69	31.21	38.63	45.88	52.86	59.77	66.63	73.05
MedNWResYel5	4.59	9.36	13.79	18.17	22.49	26.71	30.77	34.79	38.65	42.37
MedNWResYel6	317.84	629.88	927.85	1,222.51	1,513.30	1,797.33	2,070.81	2,341.25	2,601.62	2,852.05
MedNWResYel7	5.21	10.62	15.64	20.61	25.51	30.30	34.91	39.46	43.85	48.07
MedNWResYel8	6.44	13.12	19.33	25.46	31.52	37.44	43.13	48.76	54.18	59.60
MedNWResYel9	6.28	12.80	18.85	24.84	30.74	36.51	42.07	47.56	52.85	57.93
RosComMTA	727.73	1,455.45	2,189.16	2,910.90	3,638.63	4,366.35	5,108.03	5,821.80	6,549.53	7,277.25
RosComMTW	494.79	980.00	1,444.87	1,899.70	2,346.50	2,785.65	3,217.25	3,637.61	4,024.47	4,418.98
RosComRed2	173.49	346.97	521.88	693.95	867.43	1,040.92	1,217.73	1,387.89	1,561.38	1,734.86
RosComYel1	40.18	79.70	117.51	154.50	190.84	226.55	261.65	295.84	327.30	359.39
RosComYel10	3.41	6.81	10.25	13.62	17.03	20.44	23.91	27.25	30.65	34.06
RosComYel11	116.11	232.22	349.28	464.44	580.54	696.65	814.99	928.87	1,044.98	1,161.09
RosComYel12	3.75	7.51	11.29	15.02	18.77	22.53	26.35	30.03	33.79	37.54
RosComYel13	5.81	11.61	17.46	23.22	29.03	34.83	40.75	46.44	52.25	58.05
RosComYel14	4.33	8.89	13.11	17.23	21.28	25.27	29.18	33.10	36.62	40.21
RosComYel15	40.02	80.04	120.39	160.08	200.09	240.11	280.90	320.15	360.17	400.19
RosComYel16	40.02	80.04	120.39	160.08	200.09	240.11	280.90	320.15	360.17	400.19
RosComYel17	19.66	39.32	59.14	78.64	98.31	117.97	138.00	157.29	176.95	196.61
RosComYel18	19.66	39.32	59.14	78.64	98.31	117.97	138.00	157.29	176.95	196.61
RosComYel19	28.35	56.70	85.28	113.40	141.75	170.10	198.99	226.80	255.15	283.50
RosComYel2	2.24	4.49	6.75	8.98	11.22	13.47	15.76	17.96	20.20	22.45
RosComYel20	-	-	-	-	0.12	0.37	0.53	0.71	0.79	0.86
RosComYel3	46.44	92.89	139.71	185.77	232.22	278.66	326.00	371.55	417.99	464.44
RosComYel4	31.35	62.70	94.31	125.40	156.75	188.10	220.05	250.79	282.14	313.49
RosComYel5	31.35	62.70	94.31	125.40	156.75	188.10	220.05	250.79	282.14	313.49
RosComYel6	25.58	51.17	76.96	102.33	127.91	153.50	179.57	204.66	230.24	255.83
RosComYel7	73.82	146.22	215.58	283.44	350.11	415.63	480.03	542.75	600.47	659.33
RosComYel8	7.22	14.43	21.70	28.86	36.08	43.29	50.64	57.72	64.94	72.15
RosComYel9	3.41	6.81	10.25	13.62	17.03	20.44	23.91	27.25	30.65	34.06
RosResMTA	115.88	231.76	348.59	463.52	579.40	695.28	813.38	927.04	1,042.91	1,158.79
RosResMTW	1,026.80	2,033.73	2,998.44	3,942.30	4,869.52	5,780.85	6,676.53	7,548.87	8,351.68	9,170.39
RosResRed1	384.55	761.67	1,122.97	1,107.35	1,094.24	1,082.52	1,071.64	1,060.20	1,042.62	1,030.35
RosResRed2	159.51	319.03	479.85	638.05	797.56	957.08	1,119.65	1,276.10	1,435.61	1,595.13
RosResYel1	21.85	43.41	64.00	84.27	104.08	123.56	142.71	161.36	178.52	196.01
RosResYel10	2.44	4.82	7.37	9.69	11.97	14.21	16.41	18.56	20.53	22.55
RosResYel11	307.96	609.95	899.29	1,182.37	1,460.46	1,733.79	2,002.42	2,264.05	2,504.83	2,750.38
RosResYel12	239.52	474.41	699.45	919.62	1,135.91	1,348.50	1,557.44	1,760.93	1,948.20	2,139.18
RosResYel13	1.93	3.83	5.75	7.69	9.50	11.28	13.02	14.72	16.29	17.89
RosResYel14	-	-	-	-	-	-	-	-	1.13	1.37
RosResYel16	104.82	209.64	315.32	419.28	524.10	628.92	735.75	838.56	943.38	1,048.20
RosResYel17	-	0.71	1.79	2.38	2.98	3.57	4.18	4.77	5.36	5.96
RosResYel18	101.28	202.55	304.66	405.10	506.38	607.65	710.87	810.20	911.48	1,012.75
RosResYel19	-	0.71	1.79	2.38	2.98	3.57	4.18	4.77	5.36	5.96
RosResYel2	2.98	6.01	9.01	11.84	14.62	17.36	20.05	22.67	25.08	27.54
RosResYel20	103.30	206.60	310.75	413.20	516.50	619.80	725.08	826.40	929.70	1,033.01
RosResYel3	2.90	5.86	8.78	11.54	14.25	14.10	13.96	13.81	13.58	13.42
RosResYel4	5.97	12.02	17.72	23.30	28.77	34.27	39.58	44.75	49.51	54.36
RosResYel5	3.41	7.00	10.31	13.56	16.75	19.88	22.96	25.96	28.72	31.64
RosResYel6	238.04	471.47	463.41	456.96	451.55	446.71	442.22	437.50	430.25	425.18
RosResYel7	3.87	7.94	11.70	15.38	19.00	22.55	26.05	29.55	32.69	35.89

Appendix 4.3 - SENDOUT® Selected Measures (High Growth Low Price Case) in Dth

DSM Program	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019
RosResYel8	4.78	9.81	14.46	19.01	23.47	27.87	32.29	36.51	40.39	44.35
RosResYel9	4.66	9.56	14.10	18.54	22.90	27.18	31.50	35.61	39.40	43.26
SpoBComYel10	185.38	370.76	557.66	741.52	926.89	1,112.27	1,301.21	1,483.03	1,668.41	1,853.79
SpoBComYel11	204.04	408.09	613.81	816.18	1,020.22	1,224.27	1,432.23	1,632.36	1,836.41	2,040.45
SpoBComYel12	89.36	178.73	268.83	357.46	446.83	536.19	627.27	714.92	804.29	893.65
SpoBoComMTA	490.66	981.32	1,476.02	1,962.64	2,453.31	2,943.97	3,444.04	3,925.29	4,415.95	4,906.61
SpoBoComMTW	1,145.69	2,281.44	3,373.00	4,453.63	5,533.11	6,612.91	7,632.79	8,642.41	9,646.73	10,658.99
SpoBoComRed1	1,679.53	3,344.50	4,944.68	6,528.84	8,111.30	9,694.25	11,189.35	12,669.40	14,141.69	15,625.63
SpoBoComRed2	-	260.91	392.43	521.81	652.27	782.72	915.68	1,043.63	1,174.08	1,304.54
SpoBoComYel1	12.08	24.16	36.33	48.31	60.39	72.47	84.78	96.62	108.70	120.78
SpoBoComYel2	17.69	35.38	53.22	70.76	88.45	106.14	124.17	141.52	159.21	176.90
SpoBoComYel3	376.25	752.50	1,131.84	1,504.99	1,881.24	2,257.49	2,640.95	3,009.98	3,386.23	3,762.48
SpoBoComYel4	98.82	197.64	297.27	395.28	494.10	592.92	693.64	790.56	889.38	988.20
SpoBoComYel5	40.32	80.64	121.29	161.28	201.61	241.93	283.02	322.57	362.89	403.21
SpoBoComYel6	67.29	134.00	198.11	261.58	324.99	388.41	448.31	507.61	566.60	626.05
SpoBoComYel7	54.29	108.58	163.32	217.16	271.45	325.74	381.07	434.32	488.61	542.90
SpoBoComYel8	21.58	43.17	64.93	86.34	107.93	129.51	151.51	172.68	194.26	215.85
SpoBoComYel9	147.31	294.63	443.16	589.26	736.58	883.89	1,034.03	1,178.52	1,325.83	1,473.15
SpoBoResMTA	12,623.68	25,247.35	37,974.78	50,494.70	63,118.38	75,742.05	88,607.83	100,989.41	113,613.08	126,236.76
SpoBoResMTW	109,974.69	218,995.98	323,774.64	427,504.55	531,123.26	634,773.72	732,672.01	829,585.12	925,989.76	1,023,157.10
SpoBoResRed1	37,290.62	74,257.95	109,786.68	144,959.80	180,095.20	215,241.37	248,437.08	281,298.73	313,987.96	346,935.82
SpoBoResRed2	2,758.45	5,516.89	8,298.01	11,033.78	13,792.23	16,550.68	19,362.02	22,067.57	24,826.02	27,584.46
SpoBoResYel1	122.50	243.93	360.64	476.18	591.60	707.05	816.09	924.04	1,031.42	1,139.65
SpoBoResYel2	2,023.42	4,029.31	5,957.13	7,865.66	9,772.14	11,679.20	13,480.43	15,263.54	17,037.29	18,825.07
SpoBoResYel3	35.82	71.32	105.45	139.23	172.98	172.28	170.45	168.87	167.55	166.62
SpoBoResYel4	193.42	385.15	569.43	751.86	934.10	1,116.39	1,288.57	1,459.01	1,628.56	1,799.45
SpoBoResYel5	38.68	77.03	113.89	150.37	186.82	223.28	257.71	291.80	325.71	359.89
SpoBoResYel6	193.42	385.15	569.43	751.86	934.10	1,116.39	1,288.57	1,459.01	1,628.56	1,799.45
SpoBoResYel7	38.68	77.03	113.89	150.37	186.82	223.28	257.71	291.80	325.71	359.89
SpoBoResYel8	72.31	143.99	212.88	281.08	349.21	417.35	481.72	545.44	608.83	672.71
SpoBoResYel9	73.37	146.11	216.01	285.22	354.35	423.51	488.82	553.48	617.80	682.62
SpoBResYel10	22.79	45.39	67.10	88.60	110.08	131.56	151.85	171.94	191.92	212.06
SpoBResYel11	1,598.36	3,182.86	4,705.71	6,213.31	7,719.29	9,225.73	10,648.58	12,057.10	13,458.24	14,870.46
SpoBResYel12	2,279.30	4,538.84	6,710.46	8,860.33	11,007.90	13,156.13	15,185.14	17,193.73	19,191.78	21,205.65
SpoBResYel13	14.89	29.96	44.29	58.48	72.65	86.83	100.22	113.48	126.67	139.96
SpoBResYel14	1,027.52	2,046.13	3,025.10	3,994.27	4,962.40	5,930.83	6,845.51	7,751.00	8,651.72	9,559.58
SpoBResYel15	7,407.79	14,751.36	21,809.15	28,796.30	35,775.96	42,757.76	49,352.09	55,880.07	62,373.79	68,918.89
SpoBResYel16	18.64	37.49	55.43	73.19	90.93	108.68	125.44	142.03	158.54	175.18
SpoBResYel17	1.38	2.77	4.16	5.54	6.92	8.30	9.71	11.07	12.46	13.84
SpoBResYel18	-	-	1.51	2.01	2.52	3.02	3.53	4.03	4.53	5.03
SpoBResYel19	8.87	17.65	26.36	34.81	43.25	51.68	59.66	67.55	75.40	83.31
SpoBResYel20	420.92	841.84	1,266.21	1,683.67	2,104.59	2,525.51	2,954.50	3,367.35	3,788.26	4,209.18
SpoBResYel21	5.50	11.00	16.55	22.01	27.51	33.01	38.62	44.02	49.52	55.02
SpoBResYel22	44.29	88.57	133.23	177.15	221.44	265.72	310.86	354.30	398.58	442.87
SpoBResYel23	5.50	11.00	16.55	22.01	27.51	33.01	38.62	44.02	49.52	55.02
SpoBResYel24	1,047.16	2,094.33	3,150.09	4,188.65	5,235.81	6,282.98	7,350.22	8,377.30	9,424.46	10,471.63
SpoBResYel25	178.86	356.18	526.59	695.30	863.83	1,032.40	1,191.63	1,349.25	1,506.04	1,664.08
SpoGComYel10	24.31	48.62	73.14	97.25	121.56	145.87	170.65	194.50	218.81	243.12
SpoGComYel11	26.76	53.52	80.50	107.04	133.80	160.56	187.83	214.08	240.84	267.60
SpoGComYel12	11.72	23.44	35.26	46.88	58.60	70.32	82.26	93.76	105.48	117.20
SpoGResYel10	2.82	5.89	8.71	11.50	14.29	17.08	19.91	22.55	25.17	27.81
SpoGResYel11	209.62	417.42	617.14	814.86	1,012.37	1,209.93	1,396.53	1,581.26	1,765.01	1,950.22
SpoGResYel12	298.92	595.26	880.06	1,162.01	1,443.66	1,725.39	1,991.49	2,254.92	2,516.96	2,781.07
SpoGResYel13	1.77	3.81	5.75	7.59	9.43	11.27	13.01	14.73	16.44	18.17
SpoGResYel14	134.76	268.34	396.73	523.84	650.81	777.81	897.77	1,016.52	1,134.65	1,253.72
SpoGResYel15	971.51	1,934.60	2,860.22	3,776.56	4,691.93	5,607.57	6,472.41	7,328.53	8,180.17	9,038.54
SpoGResYel16	2.33	4.87	7.20	9.50	11.80	14.11	16.28	18.43	20.79	22.97

Appendix 4.3 - SENDOUT® Selected Measures (High Growth Low Price Case) in Dth

DSM Program	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019
SpoGResYel17	-	-	-	-	-	-	1.27	1.45	1.63	1.81
SpoGResYel19	0.87	2.20	3.25	4.42	5.61	6.71	7.74	8.77	9.79	10.81
SpoGResYel20	55.20	110.40	166.06	220.81	276.01	331.21	387.48	441.62	496.82	552.02
SpoGResYel21	-	1.44	2.17	2.89	3.61	4.33	5.07	5.77	6.49	7.22
SpoGResYel22	6.13	12.27	18.45	24.53	30.67	36.80	43.05	49.07	55.20	61.34
SpoGResYel23	-	1.44	2.17	2.89	3.61	4.33	5.07	5.77	6.49	7.22
SpoGResYel24	137.33	274.67	413.13	549.33	686.66	824.00	963.96	1,098.66	1,236.00	1,373.33
SpoGResYel25	23.46	46.71	69.06	91.19	113.29	135.40	156.28	176.95	197.51	218.24
SpoGTComRed1	220.27	438.62	648.48	856.24	1,063.78	1,271.38	1,467.46	1,661.56	1,854.65	2,049.26
SpoGTComRed2	-	34.22	51.47	68.43	85.54	102.65	120.09	136.87	153.98	171.09
SpoGTComYel1	1.58	3.17	4.77	6.34	7.92	9.50	11.12	12.67	14.26	15.84
SpoGTComYel2	2.32	4.64	6.98	9.28	11.60	13.92	16.28	18.56	20.88	23.20
SpoGTComYel3	49.34	98.69	148.44	197.38	246.72	296.06	346.35	394.75	444.10	493.44
SpoGTComYel4	12.96	25.92	38.99	51.84	64.80	77.76	90.97	103.68	116.64	129.60
SpoGTComYel5	5.29	10.58	15.91	21.15	26.44	31.73	37.12	42.30	47.59	52.88
SpoGTComYel6	8.74	17.40	25.98	34.31	42.62	50.94	58.79	66.57	74.31	82.11
SpoGTComYel7	7.12	14.24	21.42	28.48	35.60	42.72	49.98	56.96	64.08	71.20
SpoGTComYel8	2.40	4.80	7.22	9.60	12.00	14.40	16.85	19.20	21.60	24.00
SpoGTComYel9	19.32	38.64	58.12	77.28	96.60	115.92	135.61	154.56	173.88	193.20
SpoGTNComMTA	64.35	128.70	193.58	257.40	321.75	386.09	451.68	514.79	579.14	643.49
SpoGTNComMTW	149.36	297.43	439.73	580.61	721.34	862.11	995.07	1,126.69	1,257.62	1,389.59
SpoGTNResMTA	1,655.56	3,311.13	4,980.30	6,622.26	8,277.82	9,933.38	11,620.70	13,244.51	14,900.08	16,555.64
SpoGTNResMTW	14,395.68	28,666.56	42,382.08	55,960.32	69,524.00	83,091.84	95,906.72	108,592.64	121,212.00	133,931.20
SpoGTResRed1	4,890.57	9,738.75	14,398.25	19,011.12	23,619.04	28,228.38	32,581.91	36,891.64	41,178.75	45,499.78
SpoGTResRed2	361.76	723.53	1,088.26	1,447.05	1,808.82	2,170.58	2,539.28	2,894.11	3,255.87	3,617.63
SpoGTResYel1	15.90	31.99	47.30	62.45	77.59	92.73	107.03	121.19	135.27	149.46
SpoGTResYel2	265.37	528.43	781.26	1,031.56	1,281.59	1,531.70	1,767.93	2,001.78	2,234.40	2,468.86
SpoGTResYel3	4.55	9.26	13.69	18.07	22.69	22.59	22.35	22.15	21.97	21.85
SpoGTResYel4	25.37	50.51	74.68	98.60	122.50	146.41	168.99	191.35	213.58	235.99
SpoGTResYel5	5.02	10.00	14.78	19.62	24.50	29.28	33.80	38.27	42.72	47.20
SpoGTResYel6	25.37	50.51	74.68	98.60	122.50	146.41	168.99	191.35	213.58	235.99
SpoGTResYel7	5.02	10.00	14.78	19.62	24.50	29.28	33.80	38.27	42.72	47.20
SpoGTResYel8	9.39	18.69	27.92	36.86	45.80	54.74	63.18	71.53	79.85	88.22
SpoGTResYel9	9.53	18.97	28.33	37.41	46.47	55.54	64.11	72.59	81.02	89.52
SpoNComYel10	94.21	188.42	283.40	376.84	471.05	565.25	661.27	753.67	847.88	942.09
SpoNComYel11	103.70	207.39	311.94	414.78	518.48	622.17	727.85	829.56	933.26	1,036.95
SpoNComYel12	45.42	90.83	136.62	181.66	227.08	272.49	318.78	363.32	408.73	454.15
SpoNResYel10	11.47	23.07	34.10	45.03	55.94	66.86	77.17	87.38	97.53	107.77
SpoNResYel11	812.28	1,617.52	2,391.42	3,157.58	3,922.92	4,688.49	5,411.57	6,127.38	6,839.43	7,557.12
SpoNResYel12	1,158.33	2,306.63	3,410.23	4,502.79	5,594.18	6,685.90	7,717.04	8,737.80	9,753.20	10,776.64
SpoNResYel13	7.57	15.07	22.51	29.72	36.92	44.13	50.93	57.67	64.37	71.13
SpoNResYel14	522.18	1,039.84	1,537.34	2,029.87	2,521.88	3,014.03	3,478.87	3,939.03	4,396.78	4,858.15
SpoNResYel15	3,764.62	7,496.59	11,083.34	14,634.19	18,181.23	21,729.35	25,080.57	28,398.07	31,698.16	35,024.36
SpoNResYel16	9.47	18.86	28.17	37.20	46.21	55.23	63.75	72.18	80.57	89.02
SpoNResYel17	-	1.41	2.12	2.81	3.52	4.22	4.94	5.63	6.33	7.03
SpoNResYel18	-	-	-	-	1.18	1.53	1.80	2.05	2.30	2.56
SpoNResYel19	4.41	8.97	13.26	17.51	21.98	26.27	30.32	34.33	38.32	42.34
SpoNResYel20	213.91	427.82	643.49	855.64	1,069.55	1,283.46	1,501.47	1,711.27	1,925.18	2,139.09
SpoNResYel21	2.80	5.59	8.41	11.18	13.98	16.78	19.63	22.37	25.17	27.96
SpoNResYel22	23.77	47.54	71.50	95.07	118.84	142.61	166.83	190.14	213.91	237.68
SpoNResYel23	2.80	5.59	8.41	11.18	13.98	16.78	19.63	22.37	25.17	27.96
SpoNResYel24	532.16	1,064.33	1,600.87	2,128.66	2,660.82	3,192.99	3,735.36	4,257.32	4,789.48	5,321.65
SpoNResYel25	90.90	181.01	267.61	353.35	438.99	524.66	605.58	685.68	765.37	845.68
SpoNWComRed1	853.53	1,699.66	2,512.87	3,317.93	4,122.14	4,926.58	5,686.39	6,438.55	7,186.76	7,940.89
SpoNWComRed2	-	132.59	199.43	265.18	331.48	397.78	465.34	530.37	596.66	662.96
SpoNWComYel1	6.14	12.28	18.46	24.55	30.69	36.83	43.08	49.10	55.24	61.38
SpoNWComYel2	8.99	17.98	27.04	35.96	44.95	53.94	63.10	71.92	80.91	89.90

Appendix 4.3 - SENDOUT® Selected Measures (High Growth Low Price Case) in Dth

DSM Program	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019
SpoNWComYel3	191.21	382.42	575.20	764.83	956.04	1,147.25	1,342.12	1,529.66	1,720.87	1,912.08
SpoNWComYel4	50.22	100.44	151.07	200.88	251.10	301.32	352.50	401.76	451.98	502.20
SpoNWComYel5	20.49	40.98	61.64	81.96	102.46	122.95	143.83	163.93	184.42	204.91
SpoNWComYel6	34.20	68.10	100.68	132.94	165.16	197.39	227.83	257.97	287.94	318.16
SpoNWComYel7	27.59	55.18	83.00	110.36	137.95	165.54	193.66	220.72	248.31	275.90
SpoNwComYel8	9.30	18.60	27.98	37.20	46.50	55.80	65.28	74.40	83.70	93.00
SpoNWComYel9	74.87	149.73	225.21	299.46	374.32	449.19	525.49	598.92	673.78	748.65
SpoNWPComMTA	249.35	498.70	750.11	997.41	1,246.76	1,496.11	1,750.25	1,994.82	2,244.17	2,493.52
SpoNWPComMTW	578.77	1,152.53	1,703.96	2,249.87	2,795.19	3,340.68	3,855.90	4,365.93	4,873.29	5,384.66
SpoNWPResMTA	6,415.31	12,830.62	19,298.66	25,661.24	32,076.55	38,491.86	45,030.21	51,322.48	57,737.80	64,153.11
SpoNWPResMTW	55,852.47	111,220.74	164,434.32	217,115.28	269,739.75	322,380.36	372,099.63	421,318.56	470,279.25	519,627.30
SpoNWResRed1	18,950.97	37,737.65	55,793.23	73,668.09	91,523.79	109,384.96	126,254.91	142,955.09	159,567.65	176,311.64
SpoNWResRed2	1,401.83	2,803.67	4,217.02	5,607.33	7,009.17	8,411.00	9,839.72	11,214.67	12,616.50	14,018.33
SpoNWResYel1	62.25	123.96	183.28	241.99	300.65	359.32	414.74	469.59	524.16	579.17
SpoNWResYel2	1,028.30	2,047.68	3,027.39	3,997.30	4,966.17	5,935.33	6,850.71	7,756.88	8,658.29	9,566.84
SpoNWResYel3	18.02	36.25	53.59	70.76	87.91	87.55	86.62	85.82	85.15	84.67
SpoNWResYel4	98.29	195.73	289.38	382.09	474.71	567.35	654.85	741.46	827.63	914.47
SpoNWResYel5	19.46	39.15	57.88	76.42	94.94	113.47	130.97	148.29	165.53	182.89
SpoNWResYel6	98.29	195.73	289.38	382.09	474.71	567.35	654.85	741.46	827.63	914.47
SpoNWResYel7	19.46	39.15	57.88	76.42	94.94	113.47	130.97	148.29	165.53	182.89
SpoNWResYel8	36.75	73.17	108.18	142.84	177.47	212.10	244.81	277.19	309.40	341.87
SpoNWResYel9	37.29	74.25	109.78	144.95	180.08	215.22	248.42	281.28	313.96	346.91
Total	334,773.39	667,296.95	988,536.74	1,303,215.49	1,617,684.94	1,931,911.48	2,232,354.20	2,528,495.50	2,823,605.22	3,120,181.74
WA/ID	301,814.13	601,712.74	891,185.01	1,177,562.75	1,463,920.90	1,750,299.42	2,023,082.98	2,292,255.67	2,560,765.39	2,831,156.39
OR	28,184.13	56,085.76	83,463.49	107,828.20	132,020.36	155,984.57	179,756.19	202,962.26	225,922.66	248,427.17

Appendix 4.3 - SENDOUT® Selected Measures (High Growth Low Price Case) in Dth

DSM Program	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029
KlaComRed2	2,507.25	2,727.70	2,955.01	3,182.32	3,418.97	3,636.94	3,636.94	3,636.94	3,646.90	3,636.94
KlaComYel10	28.65	31.17	31.17	31.17	31.26	31.17	31.17	31.17	31.26	31.17
KlaComYel11	976.76	1,062.64	1,151.20	1,239.75	1,331.94	1,328.30	1,328.30	1,328.30	1,331.94	1,328.30
KlaComYel12	31.58	34.36	37.22	40.09	43.07	45.81	48.67	51.54	54.55	57.26
KlaComYel13	48.84	53.13	57.56	61.99	66.60	66.42	66.42	66.42	66.60	66.42
KlaComYel14	58.75	64.04	64.04	64.04	64.04	64.02	63.97	63.97	63.85	63.81
KlaComYel15	336.66	366.26	366.26	366.26	367.26	366.26	366.26	366.26	367.26	366.26
KlaComYel16	336.66	366.26	366.26	366.26	367.26	366.26	366.26	366.26	367.26	366.26
KlaComYel17	165.40	179.94	194.94	209.93	225.54	224.93	224.93	224.93	225.54	224.93
KlaComYel18	165.40	179.94	194.94	209.93	225.54	224.93	224.93	224.93	225.54	224.93
KlaComYel19	238.49	259.46	281.08	302.71	325.22	324.33	324.33	324.33	325.22	324.33
KlaComYel20	1.45	1.69	1.83	1.97	2.11	2.25	2.39	2.53	2.66	2.80
KlaComYel9	28.65	31.17	31.17	31.17	31.26	31.17	31.17	31.17	31.26	31.17
KlamComMTA	10,517.17	11,441.93	12,395.43	12,395.43	12,429.39	12,395.43	12,395.43	12,395.43	12,429.39	12,395.43
KlamComMTW	6,427.42	7,006.27	7,590.13	8,173.98	8,173.98	8,171.44	8,165.07	8,163.79	8,148.50	8,143.41
KlamComYel1	524.23	571.44	619.06	666.68	714.30	761.69	808.66	856.09	901.96	948.84
KlamComYel2	18.88	18.83	18.83	18.83	18.88	18.83	18.83	18.83	18.88	18.83
KlamComYel3	390.70	425.06	460.48	495.90	532.78	531.32	531.32	531.32	532.78	531.32
KlamComYel4	263.72	286.91	286.91	286.91	287.70	286.91	286.91	286.91	287.70	286.91
KlamComYel5	263.72	286.91	286.91	286.91	287.70	286.91	286.91	286.91	287.70	286.91
KlamComYel6	215.21	234.14	253.65	273.16	293.47	292.67	292.67	292.67	293.47	292.67
KlamComYel7	961.74	1,048.36	1,135.72	1,223.09	1,310.45	1,397.38	1,483.55	1,570.58	1,654.73	1,740.73
KlamComYel8	60.70	66.03	71.54	77.04	82.77	88.04	93.55	99.05	104.84	110.06
KlamResMTA	2,333.06	2,538.20	2,538.20	2,538.20	2,545.16	2,538.20	2,538.20	2,538.20	2,545.16	2,538.20
KlamResMTW	18,575.95	20,248.90	21,936.30	23,623.71	25,311.12	26,990.11	28,654.64	30,335.47	31,960.81	33,621.92
KlamResYel1	362.11	361.83	361.83	361.83	361.83	361.72	361.43	361.38	360.70	360.47
KlamResYel2	51.12	51.08	51.08	51.08	51.08	51.07	51.03	51.02	50.92	50.89
KlaResRed1	1,907.04	1,905.55	1,905.55	1,905.55	1,905.55	1,904.96	1,903.47	1,903.18	1,899.61	1,898.42
KlaResRed2	3,211.55	3,493.94	3,785.10	4,076.26	4,087.43	4,076.26	4,076.26	4,076.26	4,087.43	4,076.26
KlaResYel10	46.04	50.19	54.37	58.55	62.73	66.89	71.02	75.18	79.21	83.33
KlaResYel11	5,589.03	6,092.38	6,600.08	7,107.78	7,615.47	8,120.64	8,621.45	9,127.17	9,616.20	10,115.98
KlaResYel12	4,347.03	4,738.52	5,133.39	5,528.27	5,923.15	6,316.05	6,705.57	7,098.91	7,479.26	7,867.99
KlaResYel13	36.53	39.82	43.14	46.46	49.77	53.08	56.35	59.65	62.85	66.12
KlaResYel14	1.60	1.74	1.89	2.03	2.18	2.18	2.18	2.18	2.18	2.18
KlaResYel16	1,228.44	1,336.45	1,447.82	1,559.19	1,675.14	1,781.93	1,893.30	2,004.67	2,121.84	2,227.42
KlaResYel17	6.98	7.60	8.23	8.86	9.52	10.13	10.76	11.39	12.06	12.66
KlaResYel18	1,186.89	1,291.26	1,398.86	1,506.47	1,618.49	1,721.67	1,829.28	1,936.88	2,050.09	2,152.09
KlaResYel19	6.98	7.60	8.23	8.86	9.52	10.13	10.76	11.39	12.06	12.66
KlaResYel20	1,210.63	1,317.08	1,426.84	1,536.59	1,650.86	1,646.35	1,646.35	1,646.35	1,650.86	1,646.35
KlaResYel3	24.91	24.89	24.89	24.89	24.89	24.89	24.87	24.86	24.82	24.80
KlaResYel4	110.64	120.61	130.66	140.71	150.76	160.76	170.68	180.69	190.37	200.26
KlaResYel5	64.40	70.20	76.05	81.90	87.75	93.57	99.34	105.17	110.80	116.56
KlaResYel6	-	-	-	-	112.04	119.47	126.84	134.28	141.47	148.83
KlaResYel7	73.06	79.64	86.28	92.91	99.55	106.15	112.70	119.31	125.70	132.24
KlaResYel8	90.27	98.40	106.60	114.80	123.00	131.16	139.25	147.42	155.32	163.39
KlaResYel9	88.05	95.98	103.98	111.98	119.97	127.93	135.82	143.79	151.49	159.37
LaGrComMTA	5,110.96	5,560.36	6,023.72	6,023.72	6,040.23	6,023.72	6,023.72	6,023.72	6,040.23	6,023.72
LaGrComMTW	2,866.60	3,114.18	3,366.65	3,618.72	3,601.46	3,589.73	3,575.24	3,566.26	3,560.05	3,537.97
LaGrComRed2	1,218.43	1,325.56	1,436.03	1,546.49	1,661.49	1,767.42	1,767.42	1,767.42	1,772.26	1,767.42
LaGrComYel1	233.14	253.28	273.81	294.31	313.83	333.67	353.09	372.92	392.95	411.07
LaGrComYel10	15.48	16.84	16.84	16.84	16.89	16.84	16.84	16.84	16.89	16.84
LaGrComYel11	527.67	574.07	621.91	669.75	719.55	717.59	717.59	717.59	719.55	717.59
LaGrComYel12	17.06	18.56	20.11	21.66	23.27	24.75	26.30	27.84	29.47	30.94
LaGrComYel13	26.38	28.70	31.10	33.49	35.98	35.88	35.88	35.88	35.98	35.88
LaGrComYel14	26.13	28.39	28.33	28.27	28.14	28.05	27.93	27.86	27.81	27.64
LaGrComYel15	181.87	197.86	197.86	197.86	198.40	197.86	197.86	197.86	198.40	197.86
LaGrComYel16	181.87	197.86	197.86	197.86	198.40	197.86	197.86	197.86	198.40	197.86

DSM Program	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029
LaGrComYel17	89.35	97.21	105.31	113.41	121.84	121.51	121.51	121.51	121.84	121.51
LaGrComYel18	89.35	97.21	105.31	113.41	121.84	121.51	121.51	121.51	121.84	121.51
LaGrComYel19	128.84	140.17	151.85	163.53	175.69	175.21	175.21	175.21	175.69	175.21
LaGrComYel2	10.20	10.17	10.17	10.17	10.20	10.17	10.17	10.17	10.20	10.17
LaGrComYel20	0.37	0.41	0.55	0.69	0.73	0.78	0.83	0.87	0.92	1.07
LaGrComYel3	211.07	229.63	248.76	267.90	287.82	287.03	287.03	287.03	287.82	287.03
LaGrComYel4	142.47	155.00	155.00	155.00	155.42	155.00	155.00	155.00	155.42	155.00
LaGrComYel5	142.47	155.00	155.00	155.00	155.42	155.00	155.00	155.00	155.42	155.00
LaGrComYel6	116.26	126.49	137.03	147.57	158.54	158.11	158.11	158.11	158.54	158.11
LaGrComYel7	427.72	464.66	502.33	539.94	575.75	612.14	647.77	684.15	720.90	754.14
LaGrComYel8	32.79	35.67	38.65	41.62	44.71	47.56	50.54	53.51	56.64	59.46
LaGrComYel9	15.48	16.84	16.84	16.84	16.89	16.84	16.84	16.84	16.89	16.84
LaGrResMTA	972.18	1,057.66	1,057.66	1,057.66	1,060.56	1,057.66	1,057.66	1,057.66	1,060.56	1,057.66
LaGrResMTW	7,093.81	7,706.50	8,331.26	8,955.04	9,548.94	10,152.35	10,743.32	11,346.73	11,956.24	12,507.44
LaGrResRed1	729.47	726.43	724.91	723.53	720.08	717.74	714.84	713.05	711.80	707.39
LaGrResRed2	1,338.24	1,455.91	1,577.24	1,698.57	1,703.22	1,698.57	1,698.57	1,698.57	1,703.22	1,698.57
LaGrResYel1	138.09	137.51	137.23	136.97	136.31	135.87	135.32	134.98	134.75	133.91
LaGrResYel10	17.38	18.99	20.53	22.16	23.63	25.13	26.59	28.08	29.59	30.96
LaGrResYel11	2,131.35	2,315.44	2,503.15	2,690.57	2,869.00	3,050.30	3,227.86	3,409.15	3,592.28	3,757.89
LaGrResYel12	1,657.72	1,800.89	1,946.89	2,092.66	2,231.45	2,372.46	2,510.56	2,651.56	2,794.00	2,922.80
LaGrResYel13	13.79	14.98	16.19	17.50	18.67	19.85	21.00	22.18	23.48	24.56
LaGrResYel16	569.05	619.08	670.67	722.26	775.97	825.44	877.03	928.62	982.90	1,031.80
LaGrResYel17	3.23	3.52	3.81	4.10	4.41	4.69	4.98	5.28	5.59	5.86
LaGrResYel18	549.80	598.15	647.99	697.84	749.73	797.53	847.37	897.22	949.66	996.91
LaGrResYel19	3.23	3.52	3.81	4.10	4.41	4.69	4.98	5.28	5.59	5.86
LaGrResYel2	19.41	19.33	19.28	19.25	19.16	19.10	19.02	18.97	18.94	18.82
LaGrResYel20	560.80	610.11	660.95	711.79	764.72	762.64	762.64	762.64	764.72	762.64
LaGrResYel3	9.40	9.36	9.34	9.33	9.28	9.25	9.21	9.19	9.18	9.12
LaGrResYel4	42.19	45.84	49.55	53.26	56.80	60.39	63.90	67.49	71.12	74.39
LaGrResYel5	24.56	26.68	28.84	31.00	33.06	35.15	37.19	39.28	41.39	43.30
LaGrResYel6	1,647.45	1,789.73	1,934.83	2,079.69	2,217.62	2,357.75	2,495.00	2,635.13	2,776.68	2,904.69
LaGrResYel7	27.86	30.27	32.72	35.17	37.50	39.87	42.19	44.56	46.96	49.12
LaGrResYel8	34.43	37.40	40.43	43.46	46.34	49.27	52.14	55.06	58.02	60.70
LaGrResYel9	33.58	36.48	39.43	42.39	45.20	48.05	50.85	53.71	56.59	59.20
MedGComRed2	4,458.32	4,850.33	5,254.53	5,658.72	6,079.53	6,467.11	6,467.11	6,467.11	6,484.83	6,467.11
MedGComYel10	77.58	84.40	84.40	84.40	84.63	84.40	84.40	84.40	84.63	84.40
MedGComYel11	2,644.74	2,877.29	3,117.06	3,356.84	3,606.46	3,596.61	3,596.61	3,596.61	3,606.46	3,596.61
MedGComYel12	85.51	93.03	100.79	108.54	116.61	124.04	131.80	139.55	147.70	155.05
MedGComYel13	132.24	143.86	155.85	167.84	180.32	179.83	179.83	179.83	180.32	179.83
MedGComYel14	102.00	110.95	110.11	109.90	109.52	109.14	108.71	108.52	108.30	107.68
MedGComYel15	911.55	991.71	991.71	991.71	994.42	991.71	991.71	991.71	994.42	991.71
MedGComYel16	911.55	991.71	991.71	991.71	994.42	991.71	991.71	991.71	994.42	991.71
MedGComYel17	447.84	487.22	527.82	568.42	610.69	609.03	609.03	609.03	610.69	609.03
MedGComYel18	447.84	487.22	527.82	568.42	610.69	609.03	609.03	609.03	610.69	609.03
MedGComYel19	645.76	702.54	761.08	819.63	880.58	878.17	878.17	878.17	880.58	878.17
MedGComYel20	2.79	3.03	3.27	3.51	3.75	3.98	4.21	4.45	4.69	4.91
MedGComYel9	77.58	84.40	84.40	84.40	84.63	84.40	84.40	84.40	84.63	84.40
MedGResRed1	3,075.40	3,066.44	3,043.28	3,037.30	3,026.84	3,016.39	3,004.43	2,999.21	2,993.23	2,976.05
MedGResRed2	5,295.05	5,760.64	6,240.69	6,720.74	6,739.16	6,720.74	6,720.74	6,720.74	6,739.16	6,720.74
MedGResYel10	74.11	80.61	86.67	93.15	99.47	105.73	111.89	118.27	124.59	130.39
MedGResYel11	8,996.89	9,786.18	10,521.63	11,308.74	12,074.78	12,835.27	13,583.44	14,357.43	15,124.87	15,829.53
MedGResYel12	6,997.58	7,611.47	8,183.49	8,795.68	9,391.50	9,982.99	10,564.90	11,166.89	11,763.79	12,311.86
MedGResYel13	58.60	63.96	68.77	73.91	78.92	83.89	88.78	93.84	98.86	103.46
MedGResYel14	4.02	4.37	4.73	5.10	5.48	5.46	5.46	5.46	5.48	5.46
MedGResYel15	1.46	1.59	1.72	1.85	1.99	1.99	1.99	1.99	1.99	1.99
MedGResYel16	3,084.11	3,355.29	3,634.90	3,914.50	4,205.60	4,473.72	4,753.33	5,032.93	5,327.10	5,592.15
MedGResYel17	17.53	19.07	20.66	22.25	23.90	25.43	27.02	28.60	30.28	31.78

Appendix 4.3 - SENDOUT® Selected Measures (High Growth Low Price Case) in Dth

DSM Program	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029
MedGResYel18	2,979.82	3,241.83	3,511.98	3,782.13	4,063.38	4,322.43	4,592.59	4,862.74	5,146.95	5,403.04
MedGResYel19	17.53	19.07	20.66	22.25	23.90	25.43	27.02	28.60	30.28	31.78
MedGResYel20	3,039.41	3,306.66	3,582.22	3,857.77	4,144.65	4,133.33	4,133.33	4,133.33	4,144.65	4,133.33
MedGTComYel1	910.12	989.96	1,064.36	1,143.98	1,221.47	1,298.40	1,374.09	1,452.38	1,530.02	1,601.30
MedGTComYel2	51.13	50.99	50.99	50.99	51.13	50.99	50.99	50.99	51.13	50.99
MedGTComYel3	1,057.90	1,150.92	1,246.83	1,342.73	1,442.59	1,438.64	1,438.64	1,438.64	1,442.59	1,438.64
MedGTComYel4	714.08	776.87	776.87	776.87	779.00	776.87	776.87	776.87	779.00	776.87
MedGTComYel5	714.08	776.87	776.87	776.87	779.00	776.87	776.87	776.87	779.00	776.87
MedGTComYel6	582.72	633.96	686.79	739.62	794.62	792.45	792.45	792.45	794.62	792.45
MedGTComYel7	1,669.68	1,816.16	1,952.65	2,098.73	2,240.90	2,382.03	2,520.88	2,664.52	2,806.94	2,937.72
MedGTComYel8	164.35	178.80	193.70	208.60	224.11	238.40	253.30	268.20	283.87	298.00
MedGTNComMTA	18,701.37	20,345.76	22,041.24	22,041.24	22,101.62	22,041.24	22,041.24	22,041.24	22,101.62	22,041.24
MedGTNComMTW	11,185.89	12,167.22	13,081.61	14,060.23	14,011.82	13,963.40	13,908.08	13,883.87	13,856.21	13,776.67
MedGTNResMTA	3,846.64	4,184.87	4,184.87	4,184.87	4,196.33	4,184.87	4,184.87	4,184.87	4,196.33	4,184.87
MedGTNResMTW	29,979.99	32,610.12	35,060.84	37,683.69	40,236.36	42,770.50	45,263.59	47,842.74	50,400.05	52,748.16
MedGTResYel1	582.90	581.20	576.82	575.68	573.70	571.72	569.45	568.46	567.33	564.07
MedGTResYel2	82.29	82.05	81.43	81.27	80.99	80.71	80.39	80.25	80.09	79.63
MedGTResYel3	39.97	39.85	39.56	39.48	39.34	39.21	39.05	38.98	38.91	38.68
MedGTResYel4	178.11	193.73	208.29	223.88	239.04	254.10	268.91	284.23	299.42	313.37
MedGTResYel5	103.67	112.76	121.24	130.31	139.13	147.90	156.52	165.43	174.28	182.40
MedGTResYel6	6,954.21	7,564.30	8,132.78	8,741.18	9,333.30	9,921.12	10,499.42	11,097.69	11,690.89	12,235.56
MedGTResYel7	117.61	127.92	137.54	147.83	157.84	167.78	177.56	187.68	197.71	206.92
MedGTResYel8	145.32	158.06	169.94	182.66	195.03	207.31	219.40	231.90	244.29	255.68
MedGTResYel9	141.74	154.17	165.76	178.16	190.23	202.21	213.99	226.19	238.28	249.38
MedNComRed2	2,003.01	2,179.14	2,360.73	2,542.32	2,731.38	2,905.51	2,905.51	2,905.51	2,913.47	2,905.51
MedNComYel10	34.85	37.92	37.92	37.92	38.02	37.92	37.92	37.92	38.02	37.92
MedNComYel11	1,188.22	1,292.69	1,400.42	1,508.14	1,620.30	1,615.87	1,615.87	1,615.87	1,620.30	1,615.87
MedNComYel12	38.42	41.80	45.28	48.76	52.39	55.73	59.21	62.70	66.36	69.66
MedNComYel13	59.41	64.63	70.02	75.41	81.01	80.79	80.79	80.79	81.01	80.79
MedNComYel14	45.67	49.68	49.31	49.22	49.05	48.88	48.68	48.60	48.50	48.22
MedNComYel15	409.54	445.55	445.55	445.55	446.77	445.55	445.55	445.55	446.77	445.55
MedNComYel16	409.54	445.55	445.55	445.55	446.77	445.55	445.55	445.55	446.77	445.55
MedNComYel17	201.20	218.90	237.14	255.38	274.37	273.62	273.62	273.62	274.37	273.62
MedNComYel18	201.20	218.90	237.14	255.38	274.37	273.62	273.62	273.62	274.37	273.62
MedNComYel19	290.12	315.63	341.94	368.24	395.62	394.54	394.54	394.54	395.62	394.54
MedNComYel20	1.11	1.20	1.30	1.50	1.60	1.70	1.80	1.90	2.11	2.21
MedNComYel9	34.85	37.92	37.92	37.92	38.02	37.92	37.92	37.92	38.02	37.92
MedNResRed1	1,383.31	1,379.28	1,368.86	1,366.18	1,361.47	1,356.77	1,351.39	1,349.04	1,346.35	1,338.62
MedNResRed2	2,378.94	2,588.11	2,803.79	3,019.46	3,027.74	3,019.46	3,019.46	3,019.46	3,027.74	3,019.46
MedNResYel10	33.18	36.09	38.81	41.72	44.54	47.35	50.11	52.96	55.79	58.49
MedNResYel11	4,042.08	4,396.69	4,727.11	5,080.74	5,424.90	5,766.57	6,102.70	6,450.44	6,795.23	7,111.82
MedNResYel12	3,143.84	3,419.65	3,676.64	3,951.68	4,219.37	4,485.11	4,746.55	5,017.01	5,285.18	5,531.41
MedNResYel13	26.33	28.64	30.80	33.10	35.34	37.57	39.76	42.02	44.27	46.33
MedNResYel14	1.80	1.96	2.13	2.29	2.46	2.45	2.45	2.45	2.46	2.45
MedNResYel16	1,385.61	1,507.45	1,633.07	1,758.69	1,889.47	2,009.93	2,135.55	2,261.17	2,393.33	2,512.42
MedNResYel17	7.88	8.57	9.28	10.00	10.74	11.42	12.14	12.85	13.60	14.28
MedNResYel18	1,338.76	1,456.47	1,577.85	1,699.22	1,825.58	1,941.96	2,063.34	2,184.71	2,312.40	2,427.45
MedNResYel19	7.88	8.57	9.28	10.00	10.74	11.42	12.14	12.85	13.60	14.28
MedNResYel20	1,365.53	1,485.60	1,609.40	1,733.20	1,862.09	1,857.00	1,857.00	1,857.00	1,862.09	1,857.00
MedNWComYel1	408.89	444.76	478.19	513.96	548.78	583.34	617.34	652.52	687.40	719.42
MedNWComYel2	22.97	22.91	22.91	22.91	22.97	22.91	22.91	22.91	22.97	22.91
MedNWComYel3	475.29	517.08	560.17	603.26	648.12	646.35	646.35	646.35	648.12	646.35
MedNWComYel4	320.82	349.03	349.03	349.03	349.98	349.03	349.03	349.03	349.98	349.03
MedNWComYel5	320.82	349.03	349.03	349.03	349.98	349.03	349.03	349.03	349.98	349.03
MedNWComYel6	261.80	284.82	308.56	332.29	357.01	356.03	356.03	356.03	357.01	356.03
MedNWComYel7	750.15	815.96	877.28	942.91	1,006.78	1,070.19	1,132.57	1,197.10	1,261.09	1,319.84
MedNWComYel8	73.84	80.33	87.02	93.72	100.69	107.11	113.80	120.49	127.54	133.88

Appendix 4.3 - SENDOUT® Selected Measures (High Growth Low Price Case) in Dth

DSM Program	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029
MedNWPComMTA	8,402.07	9,140.85	9,902.58	9,902.58	9,929.71	9,902.58	9,902.58	9,902.58	9,929.71	9,902.58
MedNWPComMTW	5,026.86	5,467.86	5,878.78	6,318.56	6,296.81	6,275.05	6,250.19	6,239.31	6,226.88	6,191.14
MedNWPResMTA	1,728.20	1,880.16	1,880.16	1,880.16	1,885.31	1,880.16	1,880.16	1,880.16	1,885.31	1,880.16
MedNWPResMTW	13,450.24	14,630.22	15,729.71	16,906.43	18,051.66	19,188.58	20,307.08	21,464.19	22,611.50	23,664.96
MedNWResYel1	261.88	261.12	259.15	258.64	257.75	256.86	255.84	255.40	254.89	253.42
MedNWResYel2	36.85	36.74	36.47	36.40	36.27	36.15	36.00	35.94	35.87	35.66
MedNWResYel3	17.96	17.90	17.77	17.74	17.68	17.61	17.54	17.51	17.48	17.38
MedNWResYel4	80.02	87.04	93.58	100.58	107.40	114.16	120.81	127.70	134.52	140.79
MedNWResYel5	46.42	50.49	54.29	58.46	62.42	66.35	70.32	74.33	78.30	81.95
MedNWResYel6	3,124.36	3,398.45	3,653.86	3,927.19	4,193.22	4,457.32	4,717.13	4,985.92	5,252.43	5,497.13
MedNWResYel7	52.66	57.28	61.70	66.32	70.91	75.38	79.77	84.32	88.83	92.96
MedNWResYel8	65.29	71.01	76.35	82.06	87.62	93.14	98.57	104.19	109.76	114.87
MedNWResYel9	63.68	69.27	74.47	80.04	85.46	90.85	96.14	101.62	107.05	112.04
RosComMTA	8,026.91	8,732.70	9,460.43	9,460.43	9,486.35	9,460.43	9,460.43	9,460.43	9,486.35	9,460.43
RosComMTW	4,812.18	5,219.50	5,618.68	6,029.10	5,993.92	5,958.74	5,940.32	5,863.26	5,828.08	5,789.55
RosComRed2	1,913.58	2,081.84	2,255.32	2,428.81	2,609.42	2,775.78	2,775.78	2,775.78	2,783.39	2,775.78
RosComYel1	391.37	424.49	456.96	490.34	522.30	553.85	586.64	613.09	643.27	672.65
RosComYel10	37.57	40.87	40.87	40.87	40.98	40.87	40.87	40.87	40.98	40.87
RosComYel11	1,280.70	1,393.31	1,509.41	1,625.52	1,746.40	1,741.63	1,741.63	1,741.63	1,746.40	1,741.63
RosComYel12	41.41	45.05	48.80	52.56	56.47	60.07	63.82	67.58	71.52	75.08
RosComYel13	64.03	69.67	75.47	81.28	87.32	87.08	87.08	87.08	87.32	87.08
RosComYel14	43.79	47.50	47.20	47.03	46.75	46.48	46.33	45.74	45.47	45.17
RosComYel15	441.41	480.23	480.23	480.23	481.54	480.23	480.23	480.23	481.54	480.23
RosComYel16	441.41	480.23	480.23	480.23	481.54	480.23	480.23	480.23	481.54	480.23
RosComYel17	216.86	235.93	255.59	275.26	295.72	294.92	294.92	294.92	295.72	294.92
RosComYel18	216.86	235.93	255.59	275.26	295.72	294.92	294.92	294.92	295.72	294.92
RosComYel19	312.70	340.20	368.55	396.90	426.41	425.25	425.25	425.25	426.41	425.25
RosComYel2	24.76	24.69	24.69	24.69	24.76	24.69	24.69	24.69	24.76	24.69
RosComYel20	1.04	1.13	1.22	1.41	1.50	1.59	1.68	1.77	1.96	2.05
RosComYel3	512.28	557.32	603.77	650.21	698.56	696.65	696.65	696.65	698.56	696.65
RosComYel4	345.79	376.19	376.19	376.19	377.22	376.19	376.19	376.19	377.22	376.19
RosComYel5	345.79	376.19	376.19	376.19	377.22	376.19	376.19	376.19	377.22	376.19
RosComYel6	282.18	306.99	332.57	358.16	384.79	383.74	383.74	383.74	384.79	383.74
RosComYel7	718.00	778.77	838.33	899.57	958.20	1,016.08	1,076.25	1,124.77	1,180.14	1,234.04
RosComYel8	79.58	86.58	93.80	101.01	108.52	115.44	122.66	129.87	137.46	144.30
RosComYel9	37.57	40.87	40.87	40.87	40.98	40.87	40.87	40.87	40.98	40.87
RosResMTA	1,278.17	1,390.55	1,390.55	1,390.55	1,394.36	1,390.55	1,390.55	1,390.55	1,394.36	1,390.55
RosResMTW	9,986.36	10,831.64	11,660.03	12,511.76	13,327.23	14,132.28	14,969.11	15,644.04	16,414.08	17,163.75
RosResRed1	1,020.02	1,014.16	1,007.75	1,004.12	998.26	992.40	989.33	976.50	970.64	964.22
RosResRed2	1,759.45	1,914.15	2,073.66	2,233.18	2,239.30	2,233.18	2,233.18	2,233.18	2,239.30	2,233.18
RosResYel1	194.05	192.94	191.72	191.03	189.91	188.80	188.21	185.77	184.66	183.44
RosResYel10	24.56	26.64	28.67	30.77	32.87	34.86	36.92	38.59	40.49	42.34
RosResYel11	2,995.10	3,248.62	3,497.07	3,752.52	3,997.09	4,238.54	4,489.52	4,691.95	4,922.90	5,147.74
RosResYel12	2,329.52	2,526.70	2,719.94	2,918.62	3,108.85	3,296.64	3,491.85	3,649.29	3,828.92	4,003.80
RosResYel13	19.48	21.13	22.75	24.41	26.00	27.57	29.20	30.53	32.04	33.50
RosResYel14	1.51	1.64	1.77	1.91	2.05	2.05	2.05	2.05	2.05	2.05
RosResYel16	1,156.18	1,257.84	1,362.66	1,467.48	1,576.60	1,677.11	1,781.93	1,886.75	1,997.03	2,096.39
RosResYel17	6.57	7.15	7.74	8.34	8.96	9.53	10.13	10.72	11.35	11.91
RosResYel18	1,117.08	1,215.30	1,316.58	1,417.85	1,523.29	1,620.40	1,721.68	1,822.95	1,929.50	2,025.50
RosResYel19	6.57	7.15	7.74	8.34	8.96	9.53	10.13	10.72	11.35	11.91
RosResYel2	27.27	27.11	26.94	26.84	26.68	26.53	26.44	26.11	25.96	25.78
RosResYel20	1,139.42	1,239.61	1,342.91	1,446.21	1,553.75	1,549.51	1,549.51	1,549.51	1,553.75	1,549.51
RosResYel3	13.29	13.21	13.13	13.08	13.00	12.93	12.89	12.73	12.65	12.57
RosResYel4	59.20	64.31	69.23	74.29	79.13	83.91	88.88	92.89	97.46	101.91
RosResYel5	34.45	37.37	40.23	43.17	45.98	48.76	51.64	53.99	56.64	59.23
RosResYel6	420.92	418.51	415.86	414.36	411.94	409.53	408.26	402.96	400.55	397.90
RosResYel7	39.09	42.40	45.64	48.97	52.16	55.31	58.59	61.25	64.26	67.19

DSM Program	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029
RosResYel8	48.30	52.38	56.39	60.61	64.56	68.46	72.51	75.78	79.51	83.15
RosResYel9	47.11	51.09	55.00	59.02	62.97	66.77	70.73	73.92	77.56	81.10
SpoBComYel10	2,044.76	2,224.55	2,409.93	2,595.31	2,788.30	2,966.06	3,151.44	3,336.82	3,531.85	3,707.58
SpoBComYel11	2,250.64	2,448.54	2,652.59	2,856.63	3,069.06	3,060.68	3,060.68	3,060.68	3,069.06	3,060.68
SpoBComYel12	985.71	1,072.38	1,161.74	1,251.11	1,344.15	1,340.47	1,340.47	1,340.47	1,344.15	1,340.47
SpoBoComMTA	5,412.06	5,887.93	6,378.60	6,869.26	7,380.08	7,850.58	7,850.58	7,850.58	7,872.09	7,850.58
SpoBoComMTW	11,686.65	12,697.43	13,708.20	14,720.97	15,735.22	16,731.26	17,754.45	18,712.42	19,698.53	20,679.01
SpoBoComRed1	17,132.13	18,613.88	20,095.64	21,580.30	23,067.15	24,527.31	26,027.26	27,431.60	28,877.19	30,314.54
SpoBoComRed2	1,438.92	1,565.44	1,695.90	1,826.35	1,962.16	2,087.26	2,217.71	2,217.71	2,223.79	2,217.71
SpoBoComYel1	133.22	144.94	157.01	169.09	181.67	181.17	181.17	181.17	181.67	181.17
SpoBoComYel2	195.12	194.59	194.59	194.59	195.12	194.59	194.59	194.59	195.12	194.59
SpoBoComYel3	4,150.07	4,514.98	4,891.22	5,267.47	5,659.18	5,643.72	5,643.72	5,643.72	5,659.18	5,643.72
SpoBoComYel4	1,090.00	1,185.84	1,284.66	1,383.48	1,486.36	1,581.12	1,679.94	1,778.76	1,882.72	1,976.40
SpoBoComYel5	444.75	483.85	524.17	564.49	606.47	604.81	604.81	604.81	606.47	604.81
SpoBoComYel6	686.41	745.78	805.15	864.63	924.20	982.70	1,042.80	1,099.07	1,156.99	1,214.57
SpoBoComYel7	598.83	651.48	705.77	760.06	816.58	814.35	814.35	814.35	816.58	814.35
SpoBoComYel8	238.09	259.02	280.61	302.19	324.66	323.77	323.77	323.77	324.66	323.77
SpoBoComYel9	1,624.90	1,767.78	1,915.10	2,062.41	2,215.78	2,209.72	2,209.72	2,209.72	2,215.78	2,209.72
SpoBoResMTA	139,240.87	138,860.43	138,860.43	138,860.43	139,240.87	138,860.43	138,860.43	138,860.43	139,240.87	138,860.43
SpoBoResMTW	1,121,802.23	1,218,826.59	1,315,850.87	1,413,065.93	1,510,423.96	1,606,034.09	1,704,250.18	1,796,205.63	1,890,862.33	1,984,978.78
SpoBoResRed1	380,384.76	413,284.12	446,183.50	479,147.51	512,160.03	544,579.85	577,883.32	609,063.90	607,415.16	605,766.42
SpoBoResRed2	30,426.04	33,101.35	35,859.80	38,618.25	41,490.05	41,376.69	41,376.69	41,376.69	41,490.05	41,376.69
SpoBoResYel1	1,135.94	1,131.33	1,127.44	1,124.25	1,121.60	1,118.06	1,116.64	1,111.51	1,108.50	1,105.49
SpoBoResYel2	20,640.04	22,425.19	24,210.34	25,999.00	27,790.29	29,549.42	31,356.50	33,048.39	34,789.98	36,521.63
SpoBoResYel3	166.07	165.40	164.83	164.36	163.98	163.46	163.25	162.50	162.06	161.62
SpoBoResYel4	1,972.94	2,143.58	2,314.22	2,485.19	2,656.42	2,824.57	2,997.30	3,159.03	3,325.50	3,491.03
SpoBoResYel5	394.59	428.72	462.84	497.04	531.28	564.91	599.46	631.81	665.10	698.21
SpoBoResYel6	1,972.94	2,143.58	2,314.22	2,485.19	2,656.42	2,824.57	2,997.30	3,159.03	3,325.50	3,491.03
SpoBoResYel7	394.59	428.72	462.84	497.04	531.28	564.91	599.46	631.81	665.10	698.21
SpoBoResYel8	737.57	801.36	865.15	929.07	993.08	1,055.94	1,120.52	1,180.98	1,243.22	1,305.10
SpoBoResYel9	748.44	813.17	877.90	942.76	1,007.72	1,071.51	1,137.03	1,198.38	1,261.54	1,324.33
SpoBResYel10	232.50	252.61	272.72	292.87	313.05	332.86	353.22	372.28	391.89	411.40
SpoBResYel11	16,304.16	17,714.30	19,124.44	20,537.35	21,952.34	23,341.93	24,769.39	26,105.87	27,481.60	28,849.47
SpoBResYel12	23,250.13	25,261.03	27,271.93	29,286.78	31,304.59	33,286.18	35,321.77	37,227.62	39,189.44	41,140.07
SpoBResYel13	153.45	166.72	179.99	193.29	206.61	219.69	233.12	245.70	258.65	271.52
SpoBResYel14	10,481.24	11,387.76	12,294.28	13,202.58	14,112.22	15,005.53	15,923.18	16,782.34	17,666.74	18,546.09
SpoBResYel15	75,563.53	82,099.00	88,634.47	95,182.78	101,740.73	108,180.94	114,796.68	120,990.71	127,366.70	133,706.29
SpoBResYel16	192.06	208.68	225.29	241.93	258.60	274.97	291.79	307.53	323.74	339.85
SpoBResYel17	15.27	16.61	17.99	19.38	20.82	20.76	20.76	20.76	20.82	20.76
SpoBResYel18	5.55	6.04	6.54	7.05	7.57	7.55	7.55	7.55	7.57	7.55
SpoBResYel19	91.34	99.24	98.90	98.62	98.39	98.08	97.95	97.50	97.24	96.97
SpoBResYel20	4,642.79	5,051.02	5,471.94	5,892.86	6,331.07	6,734.69	7,155.61	7,576.53	8,019.36	8,418.37
SpoBResYel21	60.69	66.03	71.53	77.03	82.76	88.04	93.54	99.04	104.83	110.04
SpoBResYel22	488.49	531.44	575.73	620.02	666.13	708.59	752.88	797.17	843.76	885.74
SpoBResYel23	60.69	66.03	71.53	77.03	82.76	88.04	93.54	99.04	104.83	110.04
SpoBResYel24	11,550.35	12,565.95	13,613.11	14,660.28	15,750.47	15,707.44	15,707.44	15,707.44	15,750.47	15,707.44
SpoBResYel25	1,824.51	1,982.31	2,140.12	2,298.23	2,456.57	2,448.82	2,445.72	2,434.48	2,427.89	2,421.30
SpoGComYel10	268.16	291.74	316.06	340.37	365.68	388.99	413.30	437.62	463.19	486.24
SpoGComYel11	295.17	321.12	347.88	374.64	402.50	428.16	454.92	481.68	509.83	535.20
SpoGComYel12	129.27	140.64	152.36	164.08	176.28	175.80	175.80	175.80	176.28	175.80
SpoGResYel10	30.49	33.13	35.77	38.41	41.06	43.65	46.32	48.82	51.40	53.95
SpoGResYel11	2,138.25	2,323.19	2,508.12	2,693.42	2,879.00	3,061.24	3,248.45	3,423.72	3,604.14	3,783.54
SpoGResYel12	3,049.20	3,312.92	3,576.65	3,840.89	4,105.52	4,365.40	4,632.36	4,882.31	5,139.60	5,395.42
SpoGResYel13	20.12	21.87	23.61	25.35	27.10	28.81	30.57	32.22	33.92	35.61
SpoGResYel14	1,374.59	1,493.48	1,612.36	1,731.49	1,850.78	1,967.94	2,088.29	2,200.96	2,316.95	2,432.27
SpoGResYel15	9,909.97	10,767.08	11,624.19	12,482.99	13,343.05	14,187.66	15,055.30	15,867.63	16,703.83	17,535.25
SpoGResYel16	25.19	27.37	29.55	31.73	33.91	36.06	38.27	40.33	42.46	44.57

Appendix 4.3 - SENDOUT® Selected Measures (High Growth Low Price Case) in Dth

DSM Program	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029
SpoGResYel17	2.00	2.18	2.36	2.54	2.73	2.72	2.72	2.72	2.73	2.72
SpoGResYel19	11.86	12.88	12.84	12.80	12.77	12.73	12.72	12.66	12.63	12.59
SpoGResYel20	608.89	662.43	717.63	772.83	830.30	883.24	938.44	993.64	1,051.72	1,104.05
SpoGResYel21	7.96	8.66	9.38	10.10	10.85	11.55	12.27	12.99	13.75	14.43
SpoGResYel22	67.65	73.60	79.74	85.87	92.26	98.14	104.27	110.40	116.86	122.67
SpoGResYel23	7.96	8.66	9.38	10.10	10.85	11.55	12.27	12.99	13.75	14.43
SpoGResYel24	1,514.80	1,647.99	1,785.33	1,922.66	2,065.64	2,059.99	2,059.99	2,059.99	2,065.64	2,059.99
SpoGResYel25	239.28	259.98	280.67	301.41	322.17	321.16	320.75	319.28	318.41	317.55
SpoGTComRed1	2,246.84	2,441.17	2,635.49	2,830.20	3,025.20	3,216.70	3,413.41	3,597.59	3,787.17	3,975.68
SpoGTComRed2	188.71	205.30	222.41	239.52	257.33	273.74	290.85	290.85	291.64	290.85
SpoGTComYel1	17.47	19.01	20.59	22.18	23.83	23.76	23.76	23.76	23.83	23.76
SpoGTComYel2	25.59	25.52	25.52	25.52	25.59	25.52	25.52	25.52	25.59	25.52
SpoGTComYel3	544.27	592.13	641.47	690.82	742.19	740.16	740.16	740.16	742.19	740.16
SpoGTComYel4	142.95	155.52	168.48	181.44	194.93	207.36	220.32	233.28	246.91	259.20
SpoGTComYel5	58.33	63.46	68.74	74.03	79.54	79.32	79.32	79.32	79.54	79.32
SpoGTComYel6	90.02	97.81	105.59	113.39	121.21	128.88	136.76	144.14	151.74	159.29
SpoGTComYel7	78.53	85.44	92.56	99.68	107.09	106.80	106.80	106.80	107.09	106.80
SpoGTComYel8	26.47	28.80	31.20	33.60	36.10	36.00	36.00	36.00	36.10	36.00
SpoGTComYel9	213.10	231.84	251.16	270.48	290.59	289.80	289.80	289.80	290.59	289.80
SpoGTNComMTA	709.78	772.19	836.54	900.89	967.88	1,029.58	1,029.58	1,029.58	1,032.40	1,029.58
SpoGTNComMTW	1,523.56	1,655.34	1,787.11	1,919.14	2,051.37	2,181.22	2,314.61	2,439.50	2,568.05	2,695.88
SpoGTNResMTA	18,261.10	18,211.20	18,211.20	18,211.20	18,261.10	18,211.20	18,211.20	18,211.20	18,261.10	18,211.20
SpoGTNResMTW	146,843.84	159,544.32	172,244.80	184,970.24	197,714.40	210,229.76	223,086.24	235,123.20	247,513.76	259,833.60
SpoGTResRed1	49,886.53	54,201.20	58,515.87	62,839.02	67,168.53	71,420.31	75,787.98	79,877.23	79,661.00	79,444.78
SpoGTResRed2	3,990.30	4,341.16	4,702.92	5,064.69	5,441.32	5,426.45	5,426.45	5,426.45	5,441.32	5,426.45
SpoGTResYel1	148.98	148.37	147.86	147.44	147.09	146.63	146.45	145.77	145.38	144.98
SpoGTResYel2	2,706.89	2,941.01	3,175.13	3,409.71	3,644.63	3,875.33	4,112.33	4,334.21	4,562.62	4,789.72
SpoGTResYel3	21.78	21.69	21.62	21.56	21.51	21.44	21.41	21.31	21.25	21.20
SpoGTResYel4	258.75	281.13	303.50	325.93	348.38	370.44	393.09	414.30	436.13	457.84
SpoGTResYel5	51.75	56.23	60.70	65.19	69.68	74.09	78.62	82.86	87.23	91.57
SpoGTResYel6	258.75	281.13	303.50	325.93	348.38	370.44	393.09	414.30	436.13	457.84
SpoGTResYel7	51.75	56.23	60.70	65.19	69.68	74.09	78.62	82.86	87.23	91.57
SpoGTResYel8	96.73	105.10	113.46	121.85	130.24	138.48	146.95	154.88	163.04	171.16
SpoGTResYel9	98.16	106.65	115.13	123.64	132.16	140.53	149.12	157.17	165.45	173.68
SpoNComYel10	1,039.14	1,130.51	1,224.72	1,318.93	1,417.01	1,507.34	1,601.55	1,695.76	1,794.88	1,884.18
SpoNComYel11	1,143.77	1,244.34	1,348.04	1,451.73	1,559.69	1,555.43	1,555.43	1,555.43	1,559.69	1,555.43
SpoNComYel12	500.93	544.98	590.40	635.81	683.09	681.22	681.22	681.22	683.09	681.22
SpoNResYel10	118.16	128.38	138.60	148.83	159.09	169.16	179.50	189.19	199.16	209.07
SpoNResYel11	8,285.72	9,002.35	9,718.98	10,437.02	11,156.11	11,862.29	12,587.73	13,266.92	13,966.06	14,661.21
SpoNResYel12	11,815.64	12,837.57	13,859.50	14,883.44	15,908.89	16,915.93	17,950.41	18,918.95	19,915.95	20,907.25
SpoNResYel13	77.98	84.73	91.47	98.23	105.00	111.65	118.47	124.87	131.45	137.99
SpoNResYel14	5,326.53	5,787.22	6,247.91	6,709.51	7,171.78	7,625.76	8,092.11	8,528.73	8,978.18	9,425.06
SpoNResYel15	38,401.14	41,722.44	45,043.75	48,371.58	51,704.30	54,977.20	58,339.30	61,487.08	64,727.34	67,949.10
SpoNResYel16	97.61	106.05	114.49	122.95	131.42	139.74	148.28	156.29	164.52	172.71
SpoNResYel17	7.76	8.44	9.14	9.85	10.58	10.55	10.55	10.55	10.58	10.55
SpoNResYel18	2.82	3.07	3.32	3.58	3.85	3.84	3.84	3.84	3.85	3.84
SpoNResYel19	46.42	50.43	50.26	50.12	50.00	49.84	49.78	49.55	49.42	49.28
SpoNResYel20	2,359.45	2,566.91	2,780.82	2,994.73	3,217.43	3,422.55	3,636.46	3,850.37	4,075.41	4,278.19
SpoNResYel21	30.84	33.55	36.35	39.15	42.06	44.74	47.54	50.33	53.27	55.92
SpoNResYel22	262.16	285.21	308.98	332.75	357.49	380.28	404.05	427.82	452.82	475.35
SpoNResYel23	30.84	33.55	36.35	39.15	42.06	44.74	47.54	50.33	53.27	55.92
SpoNResYel24	5,869.85	6,385.98	6,918.14	7,450.30	8,004.34	7,982.47	7,982.47	7,982.47	8,004.34	7,982.47
SpoNResYel25	927.21	1,007.41	1,087.60	1,167.95	1,248.42	1,244.48	1,242.91	1,237.19	1,233.84	1,230.49
SpoNWComRed1	8,706.49	9,459.51	10,212.54	10,967.04	11,722.65	12,464.70	13,226.97	13,940.65	14,675.30	15,405.75
SpoNWComRed2	731.25	795.55	861.85	928.14	997.17	1,060.74	1,127.03	1,127.03	1,130.12	1,127.03
SpoNWComYel1	67.70	73.66	79.79	85.93	92.32	92.07	92.07	92.07	92.32	92.07
SpoNWComYel2	99.16	98.89	98.89	98.89	99.16	98.89	98.89	98.89	99.16	98.89

Appendix 4.3 - SENDOUT® Selected Measures (High Growth Low Price Case) in Dth

DSM Program	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029
SpoNWComYel3	2,109.05	2,294.50	2,485.70	2,676.91	2,875.98	2,868.12	2,868.12	2,868.12	2,875.98	2,868.12
SpoNWComYel4	553.93	602.64	652.86	703.08	755.36	803.52	853.74	903.96	956.79	1,004.40
SpoNWComYel5	226.02	245.89	266.38	286.87	308.21	307.36	307.36	307.36	308.21	307.36
SpoNWComYel6	348.83	379.00	409.17	439.40	469.68	499.41	529.95	558.54	587.98	617.24
SpoNWComYel7	304.32	331.08	358.67	386.26	414.98	413.85	413.85	413.85	414.98	413.85
SpoNwComYel8	102.58	111.60	120.90	130.20	139.88	139.50	139.50	139.50	139.88	139.50
SpoNWComYel9	825.77	898.38	973.24	1,048.11	1,126.05	1,122.98	1,122.98	1,122.98	1,126.05	1,122.98
SpoNWPComMTA	2,750.39	2,992.23	3,241.58	3,490.93	3,750.53	3,989.64	3,989.64	3,989.64	4,000.57	3,989.64
SpoNWPComMTW	5,903.81	6,414.43	6,925.04	7,436.67	7,949.04	8,452.22	8,969.11	9,453.05	9,951.21	10,446.52
SpoNWPResMTA	70,761.76	70,568.42	70,568.42	70,568.42	70,761.76	70,568.42	70,568.42	70,568.42	70,761.76	70,568.42
SpoNWPResMTW	569,725.86	619,001.29	668,276.70	717,648.96	767,093.85	815,651.02	865,531.71	912,232.80	960,305.81	1,008,104.40
SpoNWResRed1	193,310.29	210,029.64	226,748.99	243,501.19	260,278.05	276,753.70	293,678.41	309,524.28	308,686.40	307,848.51
SpoNWResRed2	15,462.41	16,822.00	18,223.83	19,625.67	21,085.11	21,027.50	21,027.50	21,027.50	21,085.11	21,027.50
SpoNWResYel1	577.28	574.94	572.96	571.34	569.99	568.19	567.47	564.87	563.34	561.81
SpoNWResYel2	10,489.20	11,396.41	12,303.62	13,212.61	14,122.94	15,016.92	15,935.27	16,795.08	17,680.15	18,560.17
SpoNWResYel3	84.40	84.06	83.77	83.53	83.33	83.07	82.96	82.58	82.36	82.14
SpoNWResYel4	1,002.64	1,089.36	1,176.08	1,262.97	1,349.98	1,435.44	1,523.22	1,605.41	1,690.01	1,774.13
SpoNWResYel5	200.53	217.87	235.22	252.59	270.00	287.09	304.64	321.08	338.00	354.83
SpoNWResYel6	1,002.64	1,089.36	1,176.08	1,262.97	1,349.98	1,435.44	1,523.22	1,605.41	1,690.01	1,774.13
SpoNWResYel7	200.53	217.87	235.22	252.59	270.00	287.09	304.64	321.08	338.00	354.83
SpoNWResYel8	374.83	407.25	439.67	472.15	504.68	536.63	569.44	600.17	631.80	663.25
SpoNWResYel9	380.35	413.25	446.15	479.11	512.12	544.54	577.84	609.01	641.11	673.02
Total	3,422,328.51	3,697,358.23	3,971,359.62	4,241,877.10	4,509,973.28	4,760,566.91	5,017,071.09	5,257,940.63	5,451,730.10	5,640,674.84
WA/ID	3,105,933.78	3,354,136.74	3,603,255.05	3,852,844.71	4,103,825.60	4,340,392.14	4,583,618.25	4,811,199.92	4,991,177.33	5,168,015.00
OR	272,083.29	295,243.72	316,709.66	334,892.88	349,861.12	362,267.71	373,952.22	385,992.22	398,268.95	409,028.72

Appendix 4.3 - SENDOUT® Selected Measures (Low Growth High Price Case) in Dth

DSM Program	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019
KlaComRed2	227.31	454.62	683.79	909.23	1,136.54	1,363.85	1,595.52	1,818.47	2,045.78	2,273.09
KlaComYel10	2.60	5.20	7.81	10.39	12.99	15.59	18.23	20.78	23.38	25.98
KlaComYel11	88.55	177.11	266.39	354.21	442.77	531.32	621.57	708.43	796.98	885.53
KlaComYel12	2.86	5.73	8.61	11.45	14.32	17.18	20.10	22.91	25.77	28.63
KlaComYel13	4.43	8.86	13.32	17.71	22.14	26.57	31.08	35.42	39.85	44.28
KlaComYel14	5.50	11.01	16.59	22.05	27.27	32.63	37.92	43.20	48.42	53.51
KlaComYel15	30.52	61.04	91.82	122.09	152.61	183.13	214.24	244.17	274.69	305.21
KlaComYel16	30.52	61.04	91.82	122.09	152.61	183.13	214.24	244.17	274.69	305.21
KlaComYel17	15.00	29.99	45.11	59.98	74.98	89.97	105.25	119.96	134.96	149.95
KlaComYel18	15.00	29.99	45.11	59.98	74.98	89.97	105.25	119.96	134.96	149.95
KlaComYel19	21.62	43.24	65.04	86.49	108.11	129.73	151.77	172.97	194.60	216.22
KlaComYel20	-	-	-	0.11	0.37	0.66	0.76	0.98	1.10	1.32
KlaComYel9	2.60	5.20	7.81	10.39	12.99	15.59	18.23	20.78	23.38	25.98
KlamComMTA	953.49	1,906.99	2,868.32	3,813.98	4,767.47	5,720.97	6,692.75	7,627.96	8,581.45	9,534.94
KlamComMTW	611.04	1,222.08	1,829.02	2,417.89	2,989.99	3,577.05	4,157.90	4,735.83	5,308.93	5,866.90
KlamComYel1	49.73	99.46	148.85	196.77	243.33	291.11	338.38	385.41	432.06	477.46
KlamComYel2	1.71	3.42	5.15	6.85	8.56	10.27	12.02	13.70	15.41	17.12
KlamComYel3	35.42	70.84	106.56	141.69	177.11	212.53	248.63	283.37	318.79	354.21
KlamComYel4	23.91	47.82	71.92	95.64	119.55	143.46	167.82	191.28	215.18	239.09
KlamComYel5	23.91	47.82	71.92	95.64	119.55	143.46	167.82	191.28	215.18	239.09
KlamComYel6	19.51	39.02	58.69	78.05	97.56	117.07	136.95	156.09	175.60	195.11
KlamComYel7	91.23	182.46	273.08	361.00	446.42	534.06	620.79	707.08	792.64	875.95
KlamComYel8	5.50	11.01	16.55	22.01	27.51	33.02	38.63	44.02	49.53	55.03
KlamResMTA	211.52	423.03	636.29	846.07	1,057.58	1,269.10	1,484.68	1,692.14	1,903.65	2,115.17
KlamResMTW	1,767.46	3,534.92	5,290.51	6,993.87	8,648.68	10,346.76	12,026.91	13,698.61	15,356.33	16,970.25
KlamResYel1	37.78	75.57	113.10	149.51	184.89	221.19	257.11	292.85	328.28	362.79
KlamResYel2	5.27	10.53	15.88	21.11	26.10	31.23	36.30	41.34	46.35	51.22
KlaResRed1	666.30	1,332.61	1,994.44	1,977.43	1,956.25	1,950.28	1,943.12	1,936.56	1,929.70	1,919.26
KlaResRed2	291.16	582.32	875.88	1,164.65	1,455.81	1,746.97	2,043.71	2,329.29	2,620.45	2,911.61
KlaResYel10	4.31	8.62	12.91	17.19	21.37	25.57	29.72	33.85	37.94	41.93
KlaResYel11	530.17	1,060.34	1,586.95	2,097.90	2,594.28	3,103.64	3,607.62	4,109.06	4,606.32	5,090.43
KlaResYel12	412.36	824.71	1,234.30	1,631.70	2,017.77	2,413.94	2,805.92	3,195.94	3,582.69	3,959.23
KlaResYel13	3.24	6.84	10.24	13.54	16.86	20.29	23.58	26.86	30.11	33.27
KlaResYel14	-	-	-	-	-	-	-	-	1.31	1.45
KlaResYel16	111.37	222.74	335.03	445.48	556.85	668.22	781.73	890.97	1,002.34	1,113.71
KlaResYel17	-	1.17	1.90	2.53	3.16	3.80	4.44	5.06	5.70	6.33
KlaResYel18	107.60	215.21	323.70	430.42	538.02	645.63	755.30	860.84	968.44	1,076.05
KlaResYel19	-	1.17	1.90	2.53	3.16	3.80	4.44	5.06	5.70	6.33
KlaResYel20	109.76	219.51	330.17	439.03	548.78	658.54	770.40	878.05	987.81	1,097.57
KlaResYel3	5.13	10.27	15.48	20.57	25.44	25.36	25.27	25.18	25.10	24.96
KlaResYel4	10.36	20.99	31.42	41.53	51.36	61.44	71.42	81.35	91.19	100.77
KlaResYel5	6.03	12.06	18.19	24.17	29.89	35.76	41.57	47.35	53.08	58.65
KlaResYel6	-	-	-	-	-	-	-	60.45	67.77	74.89
KlaResYel7	6.84	13.69	20.74	27.42	33.91	40.57	47.16	53.71	60.21	66.54
KlaResYel8	8.46	17.03	25.63	33.88	41.90	50.13	58.27	66.37	74.40	82.22
KlaResYel9	8.25	16.61	25.00	33.05	40.87	48.89	56.83	64.73	72.57	80.20
LaGrComMTA	463.36	926.73	1,393.90	1,853.45	2,316.82	2,780.18	3,252.43	3,706.91	4,170.27	4,633.63
LaGrComMTW	306.30	600.45	886.41	1,161.69	1,429.09	1,681.09	1,931.43	2,169.33	2,392.43	2,607.78
LaGrComRed2	110.46	220.93	332.30	441.85	552.32	662.78	775.36	883.71	994.17	1,104.64
LaGrComYel1	25.06	49.13	72.53	95.06	116.94	137.56	158.05	177.51	195.77	213.39
LaGrComYel10	1.40	2.81	4.22	5.61	7.02	8.42	9.85	11.23	12.63	14.03
LaGrComYel11	47.84	95.68	143.91	191.36	239.20	287.03	335.79	382.71	430.55	478.39
LaGrComYel12	1.55	3.09	4.65	6.19	7.73	9.28	10.86	12.37	13.92	15.47
LaGrComYel13	2.39	4.78	7.20	9.57	11.96	14.35	16.79	19.14	21.53	23.92
LaGrComYel14	2.66	5.45	8.04	10.54	12.97	15.26	17.63	19.81	21.84	23.92
LaGrComYel15	16.49	32.98	49.60	65.95	82.44	98.93	115.74	131.91	148.40	164.89

Appendix 4.3 - SENDOUT® Selected Measures (Low Growth High Price Case) in Dth

DSM Program	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019
LaGrComYel16	16.49	32.98	49.60	65.95	82.44	98.93	115.74	131.91	148.40	164.89
LaGrComYel17	8.10	16.20	24.37	32.40	40.50	48.60	56.86	64.81	72.91	81.01
LaGrComYel18	8.10	16.20	24.37	32.40	40.50	48.60	56.86	64.81	72.91	81.01
LaGrComYel19	11.68	23.36	35.14	46.72	58.40	70.08	81.99	93.45	105.13	116.81
LaGrComYel2	-	1.85	2.78	3.70	4.62	5.55	6.49	7.40	8.32	9.25
LaGrComYel20	-	-	-	-	-	-	-	0.11	0.12	0.34
LaGrComYel3	19.14	38.27	57.56	76.54	95.68	114.81	134.32	153.09	172.22	191.36
LaGrComYel4	12.92	25.83	38.86	51.67	64.58	77.50	90.66	103.33	116.25	129.17
LaGrComYel5	12.92	25.83	38.86	51.67	64.58	77.50	90.66	103.33	116.25	129.17
LaGrComYel6	10.54	21.08	31.71	42.16	52.70	63.24	73.99	84.32	94.86	105.41
LaGrComYel7	45.98	90.14	133.07	174.40	214.54	252.37	289.95	325.66	359.16	391.49
LaGrComYel8	2.97	5.95	8.94	11.89	14.86	17.84	20.87	23.78	26.75	29.73
LaGrComYel9	1.40	2.81	4.22	5.61	7.02	8.42	9.85	11.23	12.63	14.03
LaGrResMTA	88.14	176.28	265.14	352.55	440.69	528.83	618.66	705.11	793.25	881.39
LaGrResMTW	763.87	1,497.44	2,210.60	2,897.12	3,563.96	4,192.44	4,816.76	5,410.04	5,966.42	6,503.48
LaGrResRed1	287.97	564.51	833.36	819.12	806.13	790.24	778.21	764.81	749.74	735.51
LaGrResRed2	121.33	242.65	364.98	485.30	606.63	727.96	851.61	970.61	1,091.94	1,213.26
LaGrResYel1	16.16	32.01	47.26	61.93	76.19	89.62	102.97	115.65	127.55	139.03
LaGrResYel10	1.79	3.50	5.40	7.08	8.71	10.25	11.78	13.23	14.59	15.91
LaGrResYel11	229.13	449.17	663.09	869.02	1,069.05	1,257.57	1,444.84	1,622.80	1,789.69	1,950.79
LaGrResYel12	178.21	349.36	515.74	675.91	831.48	978.11	1,123.76	1,262.18	1,391.98	1,517.28
LaGrResYel13	1.34	2.78	4.10	5.62	6.91	8.13	9.34	10.50	11.58	12.62
LaGrResYel16	51.59	103.18	155.19	206.36	257.95	309.54	362.12	412.72	464.31	515.90
LaGrResYel17	-	-	-	-	1.47	1.76	2.06	2.35	2.64	2.93
LaGrResYel18	49.85	99.69	149.95	199.38	249.23	299.07	349.87	398.76	448.61	498.45
LaGrResYel19	-	-	-	-	1.47	1.76	2.06	2.35	2.64	2.93
LaGrResYel2	2.18	4.38	6.60	8.65	10.64	12.52	14.38	16.16	17.93	19.54
LaGrResYel20	50.84	101.68	152.94	203.37	254.21	305.05	356.87	406.74	457.58	508.42
LaGrResYel3	2.13	4.27	6.43	8.43	10.37	10.17	10.01	9.85	9.65	9.47
LaGrResYel4	4.40	8.80	12.99	17.13	21.07	24.90	28.60	32.13	35.43	38.62
LaGrResYel5	2.50	5.12	7.56	9.91	12.19	14.34	16.47	18.61	20.53	22.48
LaGrResYel6	177.11	347.19	512.54	671.72	826.33	972.05	1,116.80	1,254.36	1,383.36	1,507.88
LaGrResYel7	2.84	5.81	8.57	11.24	13.83	16.27	18.80	21.12	23.39	25.50
LaGrResYel8	3.50	7.18	10.59	13.89	17.19	20.22	23.34	26.21	28.91	31.51
LaGrResYel9	3.42	7.00	10.33	13.55	16.67	19.72	22.76	25.57	28.19	30.73
MedGComRed2	404.19	808.39	1,215.91	1,616.78	2,020.97	2,425.17	2,837.11	3,233.56	3,637.75	4,041.95
MedGComYel10	7.03	14.07	21.16	28.13	35.17	42.20	49.37	56.27	63.30	70.33
MedGComYel11	239.77	479.55	721.29	959.10	1,198.87	1,438.64	1,683.02	1,918.19	2,157.97	2,397.74
MedGComYel12	7.75	15.51	23.32	31.01	38.76	46.52	54.42	62.02	69.77	77.53
MedGComYel13	11.99	23.98	36.06	47.95	59.94	71.93	84.15	95.91	107.90	119.89
MedGComYel14	10.35	20.50	30.20	39.79	49.25	58.49	67.61	76.44	84.94	93.11
MedGComYel15	82.64	165.28	248.61	330.57	413.21	495.85	580.08	661.14	743.78	826.42
MedGComYel16	82.64	165.28	248.61	330.57	413.21	495.85	580.08	661.14	743.78	826.42
MedGComYel17	40.60	81.20	122.14	162.41	203.01	243.61	284.99	324.81	365.42	406.02
MedGComYel18	40.60	81.20	122.14	162.41	203.01	243.61	284.99	324.81	365.42	406.02
MedGComYel19	58.54	117.09	176.12	234.18	292.72	351.27	410.94	468.36	526.90	585.45
MedGComYel20	-	0.12	0.56	0.87	1.19	1.53	1.76	2.09	2.32	2.55
MedGComYel9	7.03	14.07	21.16	28.13	35.17	42.20	49.37	56.27	63.30	70.33
MedGResRed1	1,150.25	2,279.53	3,357.88	3,318.18	3,285.98	3,252.27	3,211.82	3,177.37	3,138.42	3,096.47
MedGResRed2	480.05	960.11	1,444.10	1,920.21	2,400.27	2,880.32	3,369.58	3,840.42	4,320.48	4,800.53
MedGResYel10	7.42	14.90	21.94	28.91	35.78	42.50	48.96	55.35	61.71	67.65
MedGResYel11	915.24	1,813.80	2,671.83	3,520.32	4,357.69	5,175.59	5,963.09	6,741.85	7,491.61	8,212.76
MedGResYel12	711.86	1,410.73	2,078.09	2,738.03	3,389.31	4,025.46	4,637.96	5,243.66	5,826.81	6,387.70
MedGResYel13	5.80	11.82	17.41	22.94	28.39	33.72	38.85	43.92	48.80	53.50
MedGResYel14	-	-	-	1.46	1.82	2.19	2.56	2.91	3.28	3.64
MedGResYel15	-	-	-	-	-	-	-	-	0.71	1.32

Appendix 4.3 - SENDOUT® Selected Measures (Low Growth High Price Case) in Dth

DSM Program	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019
MedGResYel16	279.61	559.21	841.12	1,118.43	1,398.04	1,677.64	1,962.61	2,236.86	2,516.47	2,796.07
MedGResYel17	1.59	3.18	4.78	6.36	7.95	9.53	11.15	12.71	14.30	15.89
MedGResYel18	270.15	540.30	812.68	1,080.61	1,350.76	1,620.91	1,896.25	2,161.22	2,431.37	2,701.52
MedGResYel19	1.59	3.18	4.78	6.36	7.95	9.53	11.15	12.71	14.30	15.89
MedGResYel20	275.56	551.11	828.93	1,102.22	1,377.78	1,653.33	1,934.17	2,204.44	2,480.00	2,755.55
MedGTComYel1	92.59	183.48	270.28	356.11	440.82	523.56	603.22	682.00	757.84	830.80
MedGTComYel2	4.64	9.27	13.94	18.54	23.18	27.81	32.54	37.09	41.72	46.36
MedGTComYel3	95.91	191.82	288.52	383.64	479.55	575.46	673.21	767.28	863.19	959.10
MedGTComYel4	64.74	129.48	194.75	258.96	323.69	388.43	454.41	517.91	582.65	647.39
MedGTComYel5	64.74	129.48	194.75	258.96	323.69	388.43	454.41	517.91	582.65	647.39
MedGTComYel6	52.83	105.66	158.92	211.32	264.15	316.98	370.82	422.64	475.47	528.30
MedGTComYel7	169.86	336.61	495.85	653.32	808.72	960.51	1,106.66	1,251.18	1,390.33	1,524.16
MedGTComYel8	14.90	29.80	44.82	59.60	74.50	89.40	104.58	119.20	134.10	149.00
MedGTNComMTA	1,695.48	3,390.96	5,100.37	6,781.92	8,477.40	10,172.88	11,900.87	13,563.84	15,259.32	16,954.80
MedGTNComMTW	1,137.93	2,255.11	3,321.90	4,376.84	5,417.94	6,434.84	7,413.95	8,382.19	9,314.37	10,210.98
MedGTNResMTA	348.74	697.48	1,049.08	1,394.96	1,743.69	2,092.43	2,447.86	2,789.91	3,138.65	3,487.39
MedGTNResMTW	3,049.83	6,044.06	8,903.24	11,730.64	14,520.97	17,246.42	19,870.59	22,465.63	24,964.02	27,367.08
MedGTResYel1	65.03	129.27	190.42	250.89	310.57	368.86	424.98	480.48	533.92	585.31
MedGTResYel2	9.18	18.19	26.80	35.31	43.70	51.91	59.80	67.83	75.38	82.63
MedGTResYel3	8.95	17.73	26.12	34.41	42.60	42.16	41.63	41.18	40.68	40.13
MedGTResYel4	18.06	35.80	52.73	69.69	86.27	102.46	118.05	133.47	148.31	162.59
MedGTResYel5	10.51	20.84	30.69	40.44	50.05	59.44	68.71	77.68	86.32	94.63
MedGTResYel6	707.44	1,401.99	2,065.21	2,721.06	3,368.31	4,000.51	4,609.22	5,211.17	5,790.70	6,348.12
MedGTResYel7	11.93	23.64	34.82	45.87	56.78	67.65	77.95	88.13	97.93	107.36
MedGTResYel8	14.74	29.21	43.02	56.68	70.38	83.60	96.31	108.89	121.00	132.65
MedGTResYel9	14.38	28.49	41.96	55.28	68.65	81.54	93.94	106.21	118.02	129.38
MedNComRed2	181.59	363.19	546.28	726.38	907.97	1,089.57	1,274.65	1,452.76	1,634.35	1,815.95
MedNComYel10	3.16	6.32	9.51	12.64	15.80	18.96	22.18	25.28	28.44	31.60
MedNComYel11	107.72	215.45	324.06	430.90	538.62	646.35	756.14	861.80	969.52	1,077.25
MedNComYel12	3.48	6.97	10.48	13.93	17.42	20.90	24.45	27.86	31.35	34.83
MedNComYel13	5.39	10.77	16.20	21.54	26.93	32.32	37.81	43.09	48.48	53.86
MedNComYel14	4.52	9.21	13.57	17.87	22.13	26.28	30.27	34.23	38.03	41.69
MedNComYel15	37.13	74.26	111.69	148.52	185.65	222.77	260.62	297.03	334.16	371.29
MedNComYel16	37.13	74.26	111.69	148.52	185.65	222.77	260.62	297.03	334.16	371.29
MedNComYel17	18.24	36.48	54.87	72.97	91.21	109.45	128.04	145.93	164.17	182.41
MedNComYel18	18.24	36.48	54.87	72.97	91.21	109.45	128.04	145.93	164.17	182.41
MedNComYel19	26.30	52.61	79.12	105.21	131.51	157.82	184.62	210.42	236.72	263.03
MedNComYel20	-	-	-	0.11	0.24	0.49	0.57	0.75	0.83	0.92
MedNComYel9	3.16	6.32	9.51	12.64	15.80	18.96	22.18	25.28	28.44	31.60
MedNResRed1	516.78	1,024.14	1,508.61	1,490.78	1,476.31	1,461.16	1,442.99	1,427.51	1,410.01	1,391.17
MedNResRed2	215.68	431.35	648.80	862.70	1,078.38	1,294.06	1,513.87	1,725.41	1,941.08	2,156.76
MedNResYel10	3.28	6.51	9.86	12.99	16.08	19.09	22.00	24.87	27.63	30.29
MedNResYel11	411.20	814.90	1,200.39	1,581.59	1,957.80	2,325.26	2,679.07	3,028.95	3,365.80	3,689.79
MedNResYel12	319.82	633.81	933.63	1,230.13	1,522.74	1,808.54	2,083.72	2,355.85	2,617.84	2,869.84
MedNResYel13	2.61	5.16	7.82	10.30	12.76	15.15	17.45	19.73	21.93	24.03
MedNResYel14	-	-	-	-	-	-	-	1.31	1.47	1.64
MedNResYel16	125.62	251.24	377.89	502.48	628.10	753.72	881.75	1,004.97	1,130.59	1,256.21
MedNResYel17	-	1.43	2.15	2.86	3.57	4.28	5.01	5.71	6.43	7.14
MedNResYel18	121.37	242.75	365.12	485.49	606.86	728.24	851.94	970.98	1,092.35	1,213.73
MedNResYel19	-	1.43	2.15	2.86	3.57	4.28	5.01	5.71	6.43	7.14
MedNResYel20	123.80	247.60	372.42	495.20	619.00	742.80	868.98	990.40	1,114.20	1,238.00
MedNWComYel1	41.47	82.43	121.43	159.99	198.05	235.22	271.01	306.41	340.48	373.26
MedNWComYel2	2.08	4.17	6.27	8.33	10.41	12.50	14.62	16.66	18.74	20.83
MedNWComYel3	43.09	86.18	129.62	172.36	215.45	258.54	302.46	344.72	387.81	430.90
MedNWComYel4	29.09	58.17	87.50	116.34	145.43	174.51	204.16	232.69	261.77	290.86
MedNWComYel5	29.09	58.17	87.50	116.34	145.43	174.51	204.16	232.69	261.77	290.86

Appendix 4.3 - SENDOUT® Selected Measures (Low Growth High Price Case) in Dth

DSM Program	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019
MedNWComYel6	23.74	47.47	71.40	94.94	118.68	142.41	166.60	189.88	213.62	237.35
MedNWComYel7	76.31	151.23	222.77	293.52	363.34	431.53	497.19	562.13	624.64	684.77
MedNWComYel8	6.69	13.39	20.14	26.78	33.47	40.16	46.99	53.55	60.25	66.94
MedNWPComMTA	761.74	1,523.47	2,291.47	3,046.95	3,808.69	4,570.42	5,346.77	6,093.90	6,855.64	7,617.37
MedNWPComMTW	511.38	1,013.43	1,492.84	1,966.92	2,434.78	2,891.77	3,331.78	3,766.90	4,185.81	4,588.74
MedNWPResMTA	156.68	313.36	471.33	626.72	783.40	940.08	1,099.76	1,253.44	1,410.12	1,566.80
MedNWPResMTW	1,370.58	2,716.17	4,001.08	5,271.70	6,525.66	7,750.47	8,929.76	10,095.96	11,218.72	12,298.65
MedNWResYel1	29.22	57.90	85.55	112.72	139.53	165.72	190.93	215.87	239.87	262.97
MedNWResYel2	4.01	8.17	12.04	15.86	19.64	23.32	26.87	30.37	33.75	37.00
MedNWResYel3	3.91	7.97	11.73	15.46	19.14	18.94	18.70	18.50	18.28	18.03
MedNWResYel4	8.12	16.08	23.69	31.21	38.63	45.88	52.86	59.77	66.63	73.05
MedNWResYel5	4.59	9.36	13.79	18.17	22.49	26.71	30.77	34.79	38.65	42.37
MedNWResYel6	317.84	629.88	927.85	1,222.51	1,513.30	1,797.33	2,070.81	2,341.25	2,601.62	2,852.05
MedNWResYel7	5.21	10.62	15.64	20.61	25.51	30.30	34.91	39.46	43.85	48.07
MedNWResYel8	6.44	13.12	19.33	25.46	31.52	37.44	43.13	48.76	54.18	59.60
MedNWResYel9	6.28	12.80	18.85	24.84	30.74	36.51	42.07	47.56	52.85	57.93
RosComMTA	727.73	1,455.45	2,189.16	2,910.90	3,638.63	4,366.35	5,108.03	5,821.80	6,549.53	7,277.25
RosComMTW	494.55	979.52	1,444.17	1,898.77	2,345.36	2,784.29	3,215.69	3,635.84	4,022.51	4,416.83
RosComRed2	173.49	346.97	521.88	693.95	867.43	1,040.92	1,217.73	1,387.89	1,561.38	1,734.86
RosComYel1	40.18	79.70	117.51	154.50	190.84	226.55	261.65	295.84	327.30	359.39
RosComYel10	3.41	6.81	10.25	13.62	17.03	20.44	23.91	27.25	30.65	34.06
RosComYel11	116.11	232.22	349.28	464.44	580.54	696.65	814.99	928.87	1,044.98	1,161.09
RosComYel12	3.75	7.51	11.29	15.02	18.77	22.53	26.35	30.03	33.79	37.54
RosComYel13	5.81	11.61	17.46	23.22	29.03	34.83	40.75	46.44	52.25	58.05
RosComYel14	4.33	8.89	13.11	17.23	21.28	25.27	29.18	33.10	36.62	40.21
RosComYel15	40.02	80.04	120.39	160.08	200.09	240.11	280.90	320.15	360.17	400.19
RosComYel16	40.02	80.04	120.39	160.08	200.09	240.11	280.90	320.15	360.17	400.19
RosComYel17	19.66	39.32	59.14	78.64	98.31	117.97	138.00	157.29	176.95	196.61
RosComYel18	19.66	39.32	59.14	78.64	98.31	117.97	138.00	157.29	176.95	196.61
RosComYel19	28.35	56.70	85.28	113.40	141.75	170.10	198.99	226.80	255.15	283.50
RosComYel2	2.24	4.49	6.75	8.98	11.22	13.47	15.76	17.96	20.20	22.45
RosComYel20	-	-	-	-	0.12	0.37	0.53	0.71	0.79	0.86
RosComYel3	46.44	92.89	139.71	185.77	232.22	278.66	326.00	371.55	417.99	464.44
RosComYel4	31.35	62.70	94.31	125.40	156.75	188.10	220.05	250.79	282.14	313.49
RosComYel5	31.35	62.70	94.31	125.40	156.75	188.10	220.05	250.79	282.14	313.49
RosComYel6	25.58	51.17	76.96	102.33	127.91	153.50	179.57	204.66	230.24	255.83
RosComYel7	73.82	146.22	215.58	283.44	350.11	415.63	480.03	542.75	600.47	659.33
RosComYel8	7.22	14.43	21.70	28.86	36.08	43.29	50.64	57.72	64.94	72.15
RosComYel9	3.41	6.81	10.25	13.62	17.03	20.44	23.91	27.25	30.65	34.06
RosResMTA	115.88	231.76	348.59	463.52	579.40	695.28	813.38	927.04	1,042.91	1,158.79
RosResMTW	1,026.72	2,033.58	2,998.22	3,942.01	4,869.16	5,780.42	6,676.04	7,548.32	8,351.07	9,169.72
RosResRed1	387.03	766.57	1,130.20	1,114.48	1,101.28	1,089.49	1,078.54	1,067.02	1,049.33	1,036.98
RosResRed2	159.51	319.03	479.85	638.05	797.56	957.08	1,119.65	1,276.10	1,435.61	1,595.13
RosResYel1	21.85	43.41	64.00	84.27	104.08	123.56	142.71	161.36	178.52	196.01
RosResYel10	2.44	4.82	7.37	9.69	11.97	14.21	16.41	18.56	20.53	22.55
RosResYel11	307.96	609.95	899.29	1,182.37	1,460.46	1,733.79	2,002.42	2,264.05	2,504.83	2,750.38
RosResYel12	239.52	474.41	699.45	919.62	1,135.91	1,348.50	1,557.44	1,760.93	1,948.20	2,139.18
RosResYel13	1.93	3.83	5.75	7.69	9.50	11.28	13.02	14.72	16.29	17.89
RosResYel14	-	-	-	-	-	-	-	-	1.13	1.37
RosResYel16	104.82	209.64	315.32	419.28	524.10	628.92	735.75	838.56	943.38	1,048.20
RosResYel17	-	0.71	1.79	2.38	2.98	3.57	4.18	4.77	5.36	5.96
RosResYel18	101.28	202.55	304.66	405.10	506.38	607.65	710.87	810.20	911.48	1,012.75
RosResYel19	-	0.71	1.79	2.38	2.98	3.57	4.18	4.77	5.36	5.96
RosResYel2	2.98	6.01	9.01	11.84	14.62	17.36	20.05	22.67	25.08	27.54
RosResYel20	103.30	206.60	310.75	413.20	516.50	619.80	725.08	826.40	929.70	1,033.01
RosResYel3	2.90	5.86	8.78	11.54	14.25	14.10	13.96	13.81	13.58	13.42

Appendix 4.3 - SENDOUT® Selected Measures (Low Growth High Price Case) in Dth

DSM Program	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019
RosResYel4	5.97	12.02	17.72	23.30	28.77	34.27	39.58	44.75	49.51	54.36
RosResYel5	3.41	7.00	10.31	13.56	16.75	19.88	22.96	25.96	28.72	31.64
RosResYel6	238.04	471.47	463.41	456.96	451.55	446.71	442.22	437.50	430.25	425.18
RosResYel7	3.87	7.94	11.70	15.38	19.00	22.55	26.05	29.55	32.69	35.89
RosResYel8	4.78	9.81	14.46	19.01	23.47	27.87	32.29	36.51	40.39	44.35
RosResYel9	4.66	9.56	14.10	18.54	22.90	27.18	31.50	35.61	39.40	43.26
SpoBComYel10	185.38	370.76	557.66	741.52	926.89	1,112.27	1,301.21	1,483.03	1,668.41	1,853.79
SpoBComYel11	204.04	408.09	613.81	816.18	1,020.22	1,224.27	1,432.23	1,632.36	1,836.41	2,040.45
SpoBComYel12	89.36	178.73	268.83	357.46	446.83	536.19	627.27	714.92	804.29	893.65
SpoBoComMTA	490.66	981.32	1,476.02	1,962.64	2,453.31	2,943.97	3,444.04	3,925.29	4,415.95	4,906.61
SpoBoComMTW	1,141.97	2,274.03	3,362.04	4,439.16	5,515.12	6,591.42	7,607.99	8,614.32	9,615.38	10,624.35
SpoBoComRed1	1,679.53	3,344.50	4,944.68	6,528.84	8,111.30	9,694.25	11,189.35	12,669.40	14,141.69	15,625.63
SpoBoComRed2	130.45	260.91	392.43	521.81	652.27	782.72	915.68	1,043.63	1,174.08	1,304.54
SpoBoComYel1	12.08	24.16	36.33	48.31	60.39	72.47	84.78	96.62	108.70	120.78
SpoBoComYel2	17.69	35.38	53.22	70.76	88.45	106.14	124.17	141.52	159.21	176.90
SpoBoComYel3	376.25	752.50	1,131.84	1,504.99	1,881.24	2,257.49	2,640.95	3,009.98	3,386.23	3,762.48
SpoBoComYel4	98.82	197.64	297.27	395.28	494.10	592.92	693.64	790.56	889.38	988.20
SpoBoComYel5	40.32	80.64	121.29	161.28	201.61	241.93	283.02	322.57	362.89	403.21
SpoBoComYel6	67.29	134.00	198.11	261.58	324.99	388.41	448.31	507.61	566.60	626.05
SpoBoComYel7	54.29	108.58	163.32	217.16	271.45	325.74	381.07	434.32	488.61	542.90
SpoBoComYel8	21.58	43.17	64.93	86.34	107.93	129.51	151.51	172.68	194.26	215.85
SpoBoComYel9	147.31	294.63	443.16	589.26	736.58	883.89	1,034.03	1,178.52	1,325.83	1,473.15
SpoBoResMTA	12,623.68	25,247.35	37,974.78	50,494.70	63,118.38	75,742.05	88,607.83	100,989.41	113,613.08	126,236.76
SpoBoResMTW	110,036.98	219,120.02	323,958.02	427,746.69	531,424.08	635,133.25	733,086.99	830,055.01	926,514.23	1,023,736.61
SpoBoResRed1	37,290.62	74,257.95	109,786.68	144,959.80	180,095.20	215,241.37	248,437.08	281,298.73	313,987.96	346,935.82
SpoBoResRed2	2,758.45	5,516.89	8,298.01	11,033.78	13,792.23	16,550.68	19,362.02	22,067.57	24,826.02	27,584.46
SpoBoResYel1	122.50	243.93	360.64	476.18	591.60	707.05	816.09	924.04	1,031.42	1,139.65
SpoBoResYel2	2,023.42	4,029.31	5,957.13	7,865.66	9,772.14	11,679.20	13,480.43	15,263.54	17,037.29	18,825.07
SpoBoResYel3	35.82	71.32	105.45	139.23	172.98	172.28	170.45	168.87	167.55	166.62
SpoBoResYel4	193.42	385.15	569.43	751.86	934.10	1,116.39	1,288.57	1,459.01	1,628.56	1,799.45
SpoBoResYel5	38.68	77.03	113.89	150.37	186.82	223.28	257.71	291.80	325.71	359.89
SpoBoResYel6	193.42	385.15	569.43	751.86	934.10	1,116.39	1,288.57	1,459.01	1,628.56	1,799.45
SpoBoResYel7	38.68	77.03	113.89	150.37	186.82	223.28	257.71	291.80	325.71	359.89
SpoBoResYel8	72.31	143.99	212.88	281.08	349.21	417.35	481.72	545.44	608.83	672.71
SpoBoResYel9	73.37	146.11	216.01	285.22	354.35	423.51	488.82	553.48	617.80	682.62
SpoBResYel10	22.79	45.39	67.10	88.60	110.08	131.56	151.85	171.94	191.92	212.06
SpoBResYel11	1,598.36	3,182.86	4,705.71	6,213.31	7,719.29	9,225.73	10,648.58	12,057.10	13,458.24	14,870.46
SpoBResYel12	2,279.30	4,538.84	6,710.46	8,860.33	11,007.90	13,156.13	15,185.14	17,193.73	19,191.78	21,205.65
SpoBResYel13	14.89	29.96	44.29	58.48	72.65	86.83	100.22	113.48	126.67	139.96
SpoBResYel14	1,027.52	2,046.13	3,025.10	3,994.27	4,962.40	5,930.83	6,845.51	7,751.00	8,651.72	9,559.58
SpoBResYel15	7,407.79	14,751.36	21,809.15	28,796.30	35,775.96	42,757.76	49,352.09	55,880.07	62,373.79	68,918.89
SpoBResYel16	18.64	37.49	55.43	73.19	90.93	108.68	125.44	142.03	158.54	175.18
SpoBResYel17	1.38	2.77	4.16	5.54	6.92	8.30	9.71	11.07	12.46	13.84
SpoBResYel18	-	-	1.51	2.01	2.52	3.02	3.53	4.03	4.53	5.03
SpoBResYel19	8.87	17.65	26.36	34.81	43.25	51.68	59.66	67.55	75.40	83.31
SpoBResYel20	420.92	841.84	1,266.21	1,683.67	2,104.59	2,525.51	2,954.50	3,367.35	3,788.26	4,209.18
SpoBResYel21	5.50	11.00	16.55	22.01	27.51	33.01	38.62	44.02	49.52	55.02
SpoBResYel22	44.29	88.57	133.23	177.15	221.44	265.72	310.86	354.30	398.58	442.87
SpoBResYel23	5.50	11.00	16.55	22.01	27.51	33.01	38.62	44.02	49.52	55.02
SpoBResYel24	1,047.16	2,094.33	3,150.09	4,188.65	5,235.81	6,282.98	7,350.22	8,377.30	9,424.46	10,471.63
SpoBResYel25	178.86	356.18	526.59	695.30	863.83	1,032.40	1,191.63	1,349.25	1,506.04	1,664.08
SpoGComYel10	24.31	48.62	73.14	97.25	121.56	145.87	170.65	194.50	218.81	243.12
SpoGComYel11	26.76	53.52	80.50	107.04	133.80	160.56	187.83	214.08	240.84	267.60
SpoGComYel12	11.72	23.44	35.26	46.88	58.60	70.32	82.26	93.76	105.48	117.20
SpoGResYel10	2.82	5.89	8.71	11.50	14.29	17.08	19.91	22.55	25.17	27.81
SpoGResYel11	209.62	417.42	617.14	814.86	1,012.37	1,209.93	1,396.53	1,581.26	1,765.01	1,950.22

Appendix 4.3 - SENDOUT® Selected Measures (Low Growth High Price Case) in Dth

DSM Program	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019
SpoGResYel12	298.92	595.26	880.06	1,162.01	1,443.66	1,725.39	1,991.49	2,254.92	2,516.96	2,781.07
SpoGResYel13	1.77	3.81	5.75	7.59	9.43	11.27	13.01	14.73	16.44	18.17
SpoGResYel14	134.76	268.34	396.73	523.84	650.81	777.81	897.77	1,016.52	1,134.65	1,253.72
SpoGResYel15	971.51	1,934.60	2,860.22	3,776.56	4,691.93	5,607.57	6,472.41	7,328.53	8,180.17	9,038.54
SpoGResYel16	2.33	4.87	7.20	9.50	11.80	14.11	16.28	18.43	20.79	22.97
SpoGResYel17	-	-	-	-	-	-	1.27	1.45	1.63	1.81
SpoGResYel19	0.87	2.20	3.25	4.42	5.61	6.71	7.74	8.77	9.79	10.81
SpoGResYel20	55.20	110.40	166.06	220.81	276.01	331.21	387.48	441.62	496.82	552.02
SpoGResYel21	-	1.44	2.17	2.89	3.61	4.33	5.07	5.77	6.49	7.22
SpoGResYel22	6.13	12.27	18.45	24.53	30.67	36.80	43.05	49.07	55.20	61.34
SpoGResYel23	-	1.44	2.17	2.89	3.61	4.33	5.07	5.77	6.49	7.22
SpoGResYel24	137.33	274.67	413.13	549.33	686.66	824.00	963.96	1,098.66	1,236.00	1,373.33
SpoGResYel25	23.46	46.71	69.06	91.19	113.29	135.40	156.28	176.95	197.51	218.24
SpoGTComRed1	220.27	438.62	648.48	856.24	1,063.78	1,271.38	1,467.46	1,661.56	1,854.65	2,049.26
SpoGTComRed2	17.11	34.22	51.47	68.43	85.54	102.65	120.09	136.87	153.98	171.09
SpoGTComYel1	1.58	3.17	4.77	6.34	7.92	9.50	11.12	12.67	14.26	15.84
SpoGTComYel2	2.32	4.64	6.98	9.28	11.60	13.92	16.28	18.56	20.88	23.20
SpoGTComYel3	49.34	98.69	148.44	197.38	246.72	296.06	346.35	394.75	444.10	493.44
SpoGTComYel4	12.96	25.92	38.99	51.84	64.80	77.76	90.97	103.68	116.64	129.60
SpoGTComYel5	5.29	10.58	15.91	21.15	26.44	31.73	37.12	42.30	47.59	52.88
SpoGTComYel6	8.74	17.40	25.98	34.31	42.62	50.94	58.79	66.57	74.31	82.11
SpoGTComYel7	7.12	14.24	21.42	28.48	35.60	42.72	49.98	56.96	64.08	71.20
SpoGTComYel8	2.40	4.80	7.22	9.60	12.00	14.40	16.85	19.20	21.60	24.00
SpoGTComYel9	19.32	38.64	58.12	77.28	96.60	115.92	135.61	154.56	173.88	193.20
SpoGTNComMTA	64.35	128.70	193.58	257.40	321.75	386.09	451.68	514.79	579.14	643.49
SpoGTNComMTW	145.34	289.42	427.90	564.98	701.92	838.91	968.29	1,096.37	1,223.78	1,352.19
SpoGTNResMTA	1,655.56	3,311.13	4,980.30	6,622.26	8,277.82	9,933.38	11,620.70	13,244.51	14,900.08	16,555.64
SpoGTNResMTW	14,430.29	28,735.47	42,483.96	56,094.84	69,691.13	83,291.58	96,137.27	108,853.68	121,503.38	134,253.15
SpoGTResRed1	4,890.57	9,738.75	14,398.25	19,011.12	23,619.04	28,228.38	32,581.91	36,891.64	41,178.75	45,499.78
SpoGTResRed2	361.76	723.53	1,088.26	1,447.05	1,808.82	2,170.58	2,539.28	2,894.11	3,255.87	3,617.63
SpoGTResYel1	15.90	31.99	47.30	62.45	77.59	92.73	107.03	121.19	135.27	149.46
SpoGTResYel2	265.37	528.43	781.26	1,031.56	1,281.59	1,531.70	1,767.93	2,001.78	2,234.40	2,468.86
SpoGTResYel3	4.55	9.26	13.69	18.07	22.69	22.59	22.35	22.15	21.97	21.85
SpoGTResYel4	25.37	50.51	74.68	98.60	122.50	146.41	168.99	191.35	213.58	235.99
SpoGTResYel5	5.02	10.00	14.78	19.62	24.50	29.28	33.80	38.27	42.72	47.20
SpoGTResYel6	25.37	50.51	74.68	98.60	122.50	146.41	168.99	191.35	213.58	235.99
SpoGTResYel7	5.02	10.00	14.78	19.62	24.50	29.28	33.80	38.27	42.72	47.20
SpoGTResYel8	9.39	18.69	27.92	36.86	45.80	54.74	63.18	71.53	79.85	88.22
SpoGTResYel9	9.53	18.97	28.33	37.41	46.47	55.54	64.11	72.59	81.02	89.52
SpoNComYel10	94.21	188.42	283.40	376.84	471.05	565.25	661.27	753.67	847.88	942.09
SpoNComYel11	103.70	207.39	311.94	414.78	518.48	622.17	727.85	829.56	933.26	1,036.95
SpoNComYel12	45.42	90.83	136.62	181.66	227.08	272.49	318.78	363.32	408.73	454.15
SpoNResYel10	11.47	23.07	34.10	45.03	55.94	66.86	77.17	87.38	97.53	107.77
SpoNResYel11	812.28	1,617.52	2,391.42	3,157.58	3,922.92	4,688.49	5,411.57	6,127.38	6,839.43	7,557.12
SpoNResYel12	1,158.33	2,306.63	3,410.23	4,502.79	5,594.18	6,685.90	7,717.04	8,737.80	9,753.20	10,776.64
SpoNResYel13	7.57	15.07	22.51	29.72	36.92	44.13	50.93	57.67	64.37	71.13
SpoNResYel14	522.18	1,039.84	1,537.34	2,029.87	2,521.88	3,014.03	3,478.87	3,939.03	4,396.78	4,858.15
SpoNResYel15	3,764.62	7,496.59	11,083.34	14,634.19	18,181.23	21,729.35	25,080.57	28,398.07	31,698.16	35,024.36
SpoNResYel16	9.47	18.86	28.17	37.20	46.21	55.23	63.75	72.18	80.57	89.02
SpoNResYel17	-	1.41	2.12	2.81	3.52	4.22	4.94	5.63	6.33	7.03
SpoNResYel18	-	-	-	-	1.18	1.53	1.80	2.05	2.30	2.56
SpoNResYel19	4.41	8.97	13.26	17.51	21.98	26.27	30.32	34.33	38.32	42.34
SpoNResYel20	213.91	427.82	643.49	855.64	1,069.55	1,283.46	1,501.47	1,711.27	1,925.18	2,139.09
SpoNResYel21	2.80	5.59	8.41	11.18	13.98	16.78	19.63	22.37	25.17	27.96
SpoNResYel22	23.77	47.54	71.50	95.07	118.84	142.61	166.83	190.14	213.91	237.68
SpoNResYel23	2.80	5.59	8.41	11.18	13.98	16.78	19.63	22.37	25.17	27.96

Appendix 4.3 - SENDOUT® Selected Measures (Low Growth High Price Case) in Dth

DSM Program	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019
SpoNResYel24	532.16	1,064.33	1,600.87	2,128.66	2,660.82	3,192.99	3,735.36	4,257.32	4,789.48	5,321.65
SpoNResYel25	90.90	181.01	267.61	353.35	438.99	524.66	605.58	685.68	765.37	845.68
SpoNWComRed1	853.53	1,699.66	2,512.87	3,317.93	4,122.14	4,926.58	5,686.39	6,438.55	7,186.76	7,940.89
SpoNWComRed2	66.30	132.59	199.43	265.18	331.48	397.78	465.34	530.37	596.66	662.96
SpoNWComYel1	6.14	12.28	18.46	24.55	30.69	36.83	43.08	49.10	55.24	61.38
SpoNWComYel2	8.99	17.98	27.04	35.96	44.95	53.94	63.10	71.92	80.91	89.90
SpoNWComYel3	191.21	382.42	575.20	764.83	956.04	1,147.25	1,342.12	1,529.66	1,720.87	1,912.08
SpoNWComYel4	50.22	100.44	151.07	200.88	251.10	301.32	352.50	401.76	451.98	502.20
SpoNWComYel5	20.49	40.98	61.64	81.96	102.46	122.95	143.83	163.93	184.42	204.91
SpoNWComYel6	34.20	68.10	100.68	132.94	165.16	197.39	227.83	257.97	287.94	318.16
SpoNWComYel7	27.59	55.18	83.00	110.36	137.95	165.54	193.66	220.72	248.31	275.90
SpoNwComYel8	9.30	18.60	27.98	37.20	46.50	55.80	65.28	74.40	83.70	93.00
SpoNWComYel9	74.87	149.73	225.21	299.46	374.32	449.19	525.49	598.92	673.78	748.65
SpoNWPComMTA	249.35	498.70	750.11	997.41	1,246.76	1,496.11	1,750.25	1,994.82	2,244.17	2,493.52
SpoNWPComMTW	578.60	1,152.18	1,703.43	2,249.17	2,794.33	3,339.65	3,854.71	4,364.59	4,871.79	5,383.00
SpoNWPResMTA	6,415.31	12,830.62	19,298.66	25,661.24	32,076.55	38,491.86	45,030.21	51,322.48	57,737.80	64,153.11
SpoNWPResMTW	55,852.47	111,220.74	164,434.32	217,115.28	269,739.75	322,380.36	372,099.63	421,318.56	470,279.25	519,627.30
SpoNWResRed1	18,950.97	37,737.65	55,793.23	73,668.09	91,523.79	109,384.96	126,254.91	142,955.09	159,567.65	176,311.64
SpoNWResRed2	1,401.83	2,803.67	4,217.02	5,607.33	7,009.17	8,411.00	9,839.72	11,214.67	12,616.50	14,018.33
SpoNWResYel1	62.25	123.96	183.28	241.99	300.65	359.32	414.74	469.59	524.16	579.17
SpoNWResYel2	1,028.30	2,047.68	3,027.39	3,997.30	4,966.17	5,935.33	6,850.71	7,756.88	8,658.29	9,566.84
SpoNWResYel3	18.02	36.25	53.59	70.76	87.91	87.55	86.62	85.82	85.15	84.67
SpoNWResYel4	98.29	195.73	289.38	382.09	474.71	567.35	654.85	741.46	827.63	914.47
SpoNWResYel5	19.46	39.15	57.88	76.42	94.94	113.47	130.97	148.29	165.53	182.89
SpoNWResYel6	98.29	195.73	289.38	382.09	474.71	567.35	654.85	741.46	827.63	914.47
SpoNWResYel7	19.46	39.15	57.88	76.42	94.94	113.47	130.97	148.29	165.53	182.89
SpoNWResYel8	36.75	73.17	108.18	142.84	177.47	212.10	244.81	277.19	309.40	341.87
SpoNWResYel9	37.29	74.25	109.78	144.95	180.08	215.22	248.42	281.28	313.96	346.91
Total	335,094.09	667,509.72	988,851.57	1,303,621.65	1,618,182.17	1,932,500.04	2,233,029.26	2,529,316.73	2,824,518.92	3,121,188.13
WA/ID	302,116.96	601,889.92	891,446.95	1,177,908.61	1,464,350.59	1,750,812.98	2,023,675.73	2,292,926.83	2,561,514.54	2,831,984.15
OR	28,199.84	56,117.08	83,510.08	107,882.59	132,082.36	156,054.39	179,833.66	203,107.82	226,083.07	248,601.99

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Appendix 4.3 - SENDOUT® Selected Measures (Low Growth High Price Case) in Dth

DSM Program	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029
KlaComRed2	2,507.25	2,727.70	2,955.01	3,182.32	3,418.97	3,636.94	3,636.94	3,636.94	3,646.90	3,636.94
KlaComYel10	28.65	31.17	31.17	31.17	31.26	31.17	31.17	31.17	31.26	31.17
KlaComYel11	976.76	1,062.64	1,151.20	1,239.75	1,331.94	1,328.30	1,328.30	1,328.30	1,331.94	1,328.30
KlaComYel12	31.58	34.36	37.22	40.09	43.07	45.81	48.67	51.54	54.55	57.26
KlaComYel13	48.84	53.13	57.56	61.99	66.60	66.42	66.42	66.42	66.60	66.42
KlaComYel14	58.75	64.04	64.04	64.04	64.04	64.02	63.97	63.97	63.85	63.81
KlaComYel15	336.66	366.26	366.26	366.26	367.26	366.26	366.26	366.26	367.26	366.26
KlaComYel16	336.66	366.26	366.26	366.26	367.26	366.26	366.26	366.26	367.26	366.26
KlaComYel17	165.40	179.94	194.94	209.93	225.54	224.93	224.93	224.93	225.54	224.93
KlaComYel18	165.40	179.94	194.94	209.93	225.54	224.93	224.93	224.93	225.54	224.93
KlaComYel19	238.49	259.46	281.08	302.71	325.22	324.33	324.33	324.33	325.22	324.33
KlaComYel20	1.45	1.69	1.83	1.97	2.11	2.25	2.39	2.53	2.66	2.80
KlaComYel9	28.65	31.17	31.17	31.17	31.26	31.17	31.17	31.17	31.26	31.17
KlamComMTA	10,517.17	11,441.93	12,395.43	12,395.43	12,429.39	12,395.43	12,395.43	12,395.43	12,429.39	12,395.43
KlamComMTW	6,441.55	7,021.67	7,606.81	8,191.95	8,191.95	8,189.40	8,183.01	8,181.73	8,166.41	8,161.31
KlamComYel1	524.23	571.44	619.06	666.68	714.30	761.69	808.66	856.09	901.96	948.84
KlamComYel2	18.88	18.83	18.83	18.83	18.88	18.83	18.83	18.83	18.88	18.83
KlamComYel3	390.70	425.06	460.48	495.90	532.78	531.32	531.32	531.32	532.78	531.32
KlamComYel4	263.72	286.91	286.91	286.91	287.70	286.91	286.91	286.91	287.70	286.91
KlamComYel5	263.72	286.91	286.91	286.91	287.70	286.91	286.91	286.91	287.70	286.91
KlamComYel6	215.21	234.14	253.65	273.16	293.47	292.67	292.67	292.67	293.47	292.67
KlamComYel7	961.74	1,048.36	1,135.72	1,223.09	1,310.45	1,397.38	1,483.55	1,570.58	1,654.73	1,740.73
KlamComYel8	60.70	66.03	71.54	77.04	82.77	88.04	93.55	99.05	104.84	110.06
KlamResMTA	2,333.06	2,538.20	2,538.20	2,538.20	2,545.16	2,538.20	2,538.20	2,538.20	2,545.16	2,538.20
KlamResMTW	18,632.46	20,310.49	22,003.03	23,695.57	25,388.11	27,072.21	28,741.80	30,427.75	32,058.03	33,724.19
KlamResYel1	362.11	361.83	361.83	361.83	361.83	361.72	361.43	361.38	360.70	360.47
KlamResYel2	51.12	51.08	51.08	51.08	51.08	51.07	51.03	51.02	50.92	50.89
KlaResRed1	1,915.68	1,914.18	1,914.18	1,914.18	1,914.18	1,913.59	1,912.10	1,911.80	1,908.22	1,907.02
KlaResRed2	3,211.55	3,493.94	3,785.10	4,076.26	4,087.43	4,076.26	4,076.26	4,076.26	4,087.43	4,076.26
KlaResYel10	46.04	50.19	54.37	58.55	62.73	66.89	71.02	75.18	79.21	83.33
KlaResYel11	5,589.03	6,092.38	6,600.08	7,107.78	7,615.47	8,120.64	8,621.45	9,127.17	9,616.20	10,115.98
KlaResYel12	4,347.03	4,738.52	5,133.39	5,528.27	5,923.15	6,316.05	6,705.57	7,098.91	7,479.26	7,867.99
KlaResYel13	36.53	39.82	43.14	46.46	49.77	53.08	56.35	59.65	62.85	66.12
KlaResYel14	1.60	1.74	1.89	2.03	2.18	2.18	2.18	2.18	2.18	2.18
KlaResYel16	1,228.44	1,336.45	1,447.82	1,559.19	1,675.14	1,781.93	1,893.30	2,004.67	2,121.84	2,227.42
KlaResYel17	6.98	7.60	8.23	8.86	9.52	10.13	10.76	11.39	12.06	12.66
KlaResYel18	1,186.89	1,291.26	1,398.86	1,506.47	1,618.49	1,721.67	1,829.28	1,936.88	2,050.09	2,152.09
KlaResYel19	6.98	7.60	8.23	8.86	9.52	10.13	10.76	11.39	12.06	12.66
KlaResYel20	1,210.63	1,317.08	1,426.84	1,536.59	1,650.86	1,646.35	1,646.35	1,646.35	1,650.86	1,646.35
KlaResYel3	24.91	24.89	24.89	24.89	24.89	24.89	24.87	24.86	24.82	24.80
KlaResYel4	110.64	120.61	130.66	140.71	150.76	160.76	170.68	180.69	190.37	200.26
KlaResYel5	64.40	70.20	76.05	81.90	87.75	93.57	99.34	105.17	110.80	116.56
KlaResYel6	82.23	89.63	97.10	104.57	112.04	119.47	126.84	134.28	141.47	148.83
KlaResYel7	73.06	79.64	86.28	92.91	99.55	106.15	112.70	119.31	125.70	132.24
KlaResYel8	90.27	98.40	106.60	114.80	123.00	131.16	139.25	147.42	155.32	163.39
KlaResYel9	88.05	95.98	103.98	111.98	119.97	127.93	135.82	143.79	151.49	159.37
LaGrComMTA	5,110.96	5,560.36	6,023.72	6,023.72	6,040.23	6,023.72	6,023.72	6,023.72	6,040.23	6,023.72
LaGrComMTW	2,849.15	3,095.23	3,346.16	3,596.70	3,579.55	3,567.89	3,553.48	3,544.56	3,538.39	3,516.44
LaGrComRed2	1,218.43	1,325.56	1,436.03	1,546.49	1,661.49	1,767.42	1,767.42	1,767.42	1,772.26	1,767.42
LaGrComYel1	233.14	253.28	273.81	294.31	313.83	333.67	353.09	372.92	392.95	411.07
LaGrComYel10	15.48	16.84	16.84	16.84	16.89	16.84	16.84	16.84	16.89	16.84
LaGrComYel11	527.67	574.07	621.91	669.75	719.55	717.59	717.59	717.59	719.55	717.59
LaGrComYel12	17.06	18.56	20.11	21.66	23.27	24.75	26.30	27.84	29.47	30.94
LaGrComYel13	26.38	28.70	31.10	33.49	35.98	35.88	35.88	35.88	35.98	35.88
LaGrComYel14	26.13	28.39	28.33	28.27	28.14	28.05	27.93	27.86	27.81	27.64
LaGrComYel15	181.87	197.86	197.86	197.86	198.40	197.86	197.86	197.86	198.40	197.86

Appendix 4.3 - SENDOUT® Selected Measures (Low Growth High Price Case) in Dth

DSM Program	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029
LaGrComYel16	181.87	197.86	197.86	197.86	198.40	197.86	197.86	197.86	198.40	197.86
LaGrComYel17	89.35	97.21	105.31	113.41	121.84	121.51	121.51	121.51	121.84	121.51
LaGrComYel18	89.35	97.21	105.31	113.41	121.84	121.51	121.51	121.51	121.84	121.51
LaGrComYel19	128.84	140.17	151.85	163.53	175.69	175.21	175.21	175.21	175.69	175.21
LaGrComYel2	10.20	10.17	10.17	10.17	10.20	10.17	10.17	10.17	10.20	10.17
LaGrComYel20	0.37	0.41	0.55	0.69	0.73	0.78	0.83	0.87	0.92	1.07
LaGrComYel3	211.07	229.63	248.76	267.90	287.82	287.03	287.03	287.03	287.82	287.03
LaGrComYel4	142.47	155.00	155.00	155.00	155.42	155.00	155.00	155.00	155.42	155.00
LaGrComYel5	142.47	155.00	155.00	155.00	155.42	155.00	155.00	155.00	155.42	155.00
LaGrComYel6	116.26	126.49	137.03	147.57	158.54	158.11	158.11	158.11	158.54	158.11
LaGrComYel7	427.72	464.66	502.33	539.94	575.75	612.14	647.77	684.15	720.90	754.14
LaGrComYel8	32.79	35.67	38.65	41.62	44.71	47.56	50.54	53.51	56.64	59.46
LaGrComYel9	15.48	16.84	16.84	16.84	16.89	16.84	16.84	16.84	16.89	16.84
LaGrResMTA	972.18	1,057.66	1,057.66	1,057.66	1,060.56	1,057.66	1,057.66	1,057.66	1,060.56	1,057.66
LaGrResMTW	7,105.44	7,719.13	8,344.92	8,969.72	9,564.59	10,169.00	10,760.93	11,365.33	11,975.84	12,527.94
LaGrResRed1	730.53	727.49	725.97	724.59	721.14	718.79	715.89	714.09	712.84	708.42
LaGrResRed2	1,338.24	1,455.91	1,577.24	1,698.57	1,703.22	1,698.57	1,698.57	1,698.57	1,703.22	1,698.57
LaGrResYel1	138.09	137.51	137.23	136.97	136.31	135.87	135.32	134.98	134.75	133.91
LaGrResYel10	17.38	18.99	20.53	22.16	23.63	25.13	26.59	28.08	29.59	30.96
LaGrResYel11	2,131.35	2,315.44	2,503.15	2,690.57	2,869.00	3,050.30	3,227.86	3,409.15	3,592.28	3,757.89
LaGrResYel12	1,657.72	1,800.89	1,946.89	2,092.66	2,231.45	2,372.46	2,510.56	2,651.56	2,794.00	2,922.80
LaGrResYel13	13.79	14.98	16.19	17.50	18.67	19.85	21.00	22.18	23.48	24.56
LaGrResYel16	569.05	619.08	670.67	722.26	775.97	825.44	877.03	928.62	982.90	1,031.80
LaGrResYel17	3.23	3.52	3.81	4.10	4.41	4.69	4.98	5.28	5.59	5.86
LaGrResYel18	549.80	598.15	647.99	697.84	749.73	797.53	847.37	897.22	949.66	996.91
LaGrResYel19	3.23	3.52	3.81	4.10	4.41	4.69	4.98	5.28	5.59	5.86
LaGrResYel2	19.41	19.33	19.28	19.25	19.16	19.10	19.02	18.97	18.94	18.82
LaGrResYel20	560.80	610.11	660.95	711.79	764.72	762.64	762.64	762.64	764.72	762.64
LaGrResYel3	9.40	9.36	9.34	9.33	9.28	9.25	9.21	9.19	9.18	9.12
LaGrResYel4	42.19	45.84	49.55	53.26	56.80	60.39	63.90	67.49	71.12	74.39
LaGrResYel5	24.56	26.68	28.84	31.00	33.06	35.15	37.19	39.28	41.39	43.30
LaGrResYel6	1,647.45	1,789.73	1,934.83	2,079.69	2,217.62	2,357.75	2,495.00	2,635.13	2,776.68	2,904.69
LaGrResYel7	27.86	30.27	32.72	35.17	37.50	39.87	42.19	44.56	46.96	49.12
LaGrResYel8	34.43	37.40	40.43	43.46	46.34	49.27	52.14	55.06	58.02	60.70
LaGrResYel9	33.58	36.48	39.43	42.39	45.20	48.05	50.85	53.71	56.59	59.20
MedGComRed2	4,458.32	4,850.33	5,254.53	5,658.72	6,079.53	6,467.11	6,467.11	6,467.11	6,484.83	6,467.11
MedGComYel10	77.58	84.40	84.40	84.40	84.63	84.40	84.40	84.40	84.63	84.40
MedGComYel11	2,644.74	2,877.29	3,117.06	3,356.84	3,606.46	3,596.61	3,596.61	3,596.61	3,606.46	3,596.61
MedGComYel12	85.51	93.03	100.79	108.54	116.61	124.04	131.80	139.55	147.70	155.05
MedGComYel13	132.24	143.86	155.85	167.84	180.32	179.83	179.83	179.83	180.32	179.83
MedGComYel14	102.00	110.95	110.11	109.90	109.52	109.14	108.71	108.52	108.30	107.68
MedGComYel15	911.55	991.71	991.71	991.71	994.42	991.71	991.71	991.71	994.42	991.71
MedGComYel16	911.55	991.71	991.71	991.71	994.42	991.71	991.71	991.71	994.42	991.71
MedGComYel17	447.84	487.22	527.82	568.42	610.69	609.03	609.03	609.03	610.69	609.03
MedGComYel18	447.84	487.22	527.82	568.42	610.69	609.03	609.03	609.03	610.69	609.03
MedGComYel19	645.76	702.54	761.08	819.63	880.58	878.17	878.17	878.17	880.58	878.17
MedGComYel20	2.79	3.03	3.27	3.51	3.75	3.98	4.21	4.45	4.69	4.91
MedGComYel9	77.58	84.40	84.40	84.40	84.63	84.40	84.40	84.40	84.63	84.40
MedGResRed1	3,083.74	3,074.75	3,051.53	3,045.54	3,035.05	3,024.57	3,012.58	3,007.34	3,001.35	2,984.12
MedGResRed2	5,295.05	5,760.64	6,240.69	6,720.74	6,739.16	6,720.74	6,720.74	6,720.74	6,739.16	6,720.74
MedGResYel10	74.11	80.61	86.67	93.15	99.47	105.73	111.89	118.27	124.59	130.39
MedGResYel11	8,996.89	9,786.18	10,521.63	11,308.74	12,074.78	12,835.27	13,583.44	14,357.43	15,124.87	15,829.53
MedGResYel12	6,997.58	7,611.47	8,183.49	8,795.68	9,391.50	9,982.99	10,564.90	11,166.89	11,763.79	12,311.86
MedGResYel13	58.60	63.96	68.77	73.91	78.92	83.89	88.78	93.84	98.86	103.46
MedGResYel14	4.02	4.37	4.73	5.10	5.48	5.46	5.46	5.46	5.48	5.46
MedGResYel15	1.46	1.59	1.72	1.85	1.99	1.99	1.99	1.99	1.99	1.99

Appendix 4.3 - SENDOUT® Selected Measures (Low Growth High Price Case) in Dth

DSM Program	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029
MedGResYel16	3,084.11	3,355.29	3,634.90	3,914.50	4,205.60	4,473.72	4,753.33	5,032.93	5,327.10	5,592.15
MedGResYel17	17.53	19.07	20.66	22.25	23.90	25.43	27.02	28.60	30.28	31.78
MedGResYel18	2,979.82	3,241.83	3,511.98	3,782.13	4,063.38	4,322.43	4,592.59	4,862.74	5,146.95	5,403.04
MedGResYel19	17.53	19.07	20.66	22.25	23.90	25.43	27.02	28.60	30.28	31.78
MedGResYel20	3,039.41	3,306.66	3,582.22	3,857.77	4,144.65	4,133.33	4,133.33	4,133.33	4,144.65	4,133.33
MedGTComYel1	910.12	989.96	1,064.36	1,143.98	1,221.47	1,298.40	1,374.09	1,452.38	1,530.02	1,601.30
MedGTComYel2	51.13	50.99	50.99	50.99	51.13	50.99	50.99	50.99	51.13	50.99
MedGTComYel3	1,057.90	1,150.92	1,246.83	1,342.73	1,442.59	1,438.64	1,438.64	1,438.64	1,442.59	1,438.64
MedGTComYel4	714.08	776.87	776.87	776.87	779.00	776.87	776.87	776.87	779.00	776.87
MedGTComYel5	714.08	776.87	776.87	776.87	779.00	776.87	776.87	776.87	779.00	776.87
MedGTComYel6	582.72	633.96	686.79	739.62	794.62	792.45	792.45	792.45	794.62	792.45
MedGTComYel7	1,669.68	1,816.16	1,952.65	2,098.73	2,240.90	2,382.03	2,520.88	2,664.52	2,806.94	2,937.72
MedGTComYel8	164.35	178.80	193.70	208.60	224.11	238.40	253.30	268.20	283.87	298.00
MedGTNComMTA	18,701.37	20,345.76	22,041.24	22,041.24	22,101.62	22,041.24	22,041.24	22,041.24	22,101.62	22,041.24
MedGTNComMTW	11,185.89	12,167.22	13,081.61	14,060.23	14,011.82	13,963.40	13,908.08	13,883.87	13,856.21	13,776.67
MedGTNResMTA	3,846.64	4,184.87	4,184.87	4,184.87	4,196.33	4,184.87	4,184.87	4,184.87	4,196.33	4,184.87
MedGTNResMTW	29,979.99	32,610.12	35,060.84	37,683.69	40,236.36	42,770.50	45,263.59	47,842.74	50,400.05	52,748.16
MedGTResYel1	582.90	581.20	576.82	575.68	573.70	571.72	569.45	568.46	567.33	564.07
MedGTResYel2	82.29	82.05	81.43	81.27	80.99	80.71	80.39	80.25	80.09	79.63
MedGTResYel3	39.97	39.85	39.56	39.48	39.34	39.21	39.05	38.98	38.91	38.68
MedGTResYel4	178.11	193.73	208.29	223.88	239.04	254.10	268.91	284.23	299.42	313.37
MedGTResYel5	103.67	112.76	121.24	130.31	139.13	147.90	156.52	165.43	174.28	182.40
MedGTResYel6	6,954.21	7,564.30	8,132.78	8,741.18	9,333.30	9,921.12	10,499.42	11,097.69	11,690.89	12,235.56
MedGTResYel7	117.61	127.92	137.54	147.83	157.84	167.78	177.56	187.68	197.71	206.92
MedGTResYel8	145.32	158.06	169.94	182.66	195.03	207.31	219.40	231.90	244.29	255.68
MedGTResYel9	141.74	154.17	165.76	178.16	190.23	202.21	213.99	226.19	238.28	249.38
MedNComRed2	2,003.01	2,179.14	2,360.73	2,542.32	2,731.38	2,905.51	2,905.51	2,905.51	2,913.47	2,905.51
MedNComYel10	34.85	37.92	37.92	37.92	38.02	37.92	37.92	37.92	38.02	37.92
MedNComYel11	1,188.22	1,292.69	1,400.42	1,508.14	1,620.30	1,615.87	1,615.87	1,615.87	1,620.30	1,615.87
MedNComYel12	38.42	41.80	45.28	48.76	52.39	55.73	59.21	62.70	66.36	69.66
MedNComYel13	59.41	64.63	70.02	75.41	81.01	80.79	80.79	80.79	81.01	80.79
MedNComYel14	45.67	49.68	49.31	49.22	49.05	48.88	48.68	48.60	48.50	48.22
MedNComYel15	409.54	445.55	445.55	445.55	446.77	445.55	445.55	445.55	446.77	445.55
MedNComYel16	409.54	445.55	445.55	445.55	446.77	445.55	445.55	445.55	446.77	445.55
MedNComYel17	201.20	218.90	237.14	255.38	274.37	273.62	273.62	273.62	274.37	273.62
MedNComYel18	201.20	218.90	237.14	255.38	274.37	273.62	273.62	273.62	274.37	273.62
MedNComYel19	290.12	315.63	341.94	368.24	395.62	394.54	394.54	394.54	395.62	394.54
MedNComYel20	1.11	1.20	1.30	1.50	1.60	1.70	1.80	1.90	2.11	2.21
MedNComYel9	34.85	37.92	37.92	37.92	38.02	37.92	37.92	37.92	38.02	37.92
MedNResRed1	1,385.45	1,381.41	1,370.98	1,368.29	1,363.57	1,358.86	1,353.48	1,351.12	1,348.43	1,340.69
MedNResRed2	2,378.94	2,588.11	2,803.79	3,019.46	3,027.74	3,019.46	3,019.46	3,019.46	3,027.74	3,019.46
MedNResYel10	33.18	36.09	38.81	41.72	44.54	47.35	50.11	52.96	55.79	58.49
MedNResYel11	4,042.08	4,396.69	4,727.11	5,080.74	5,424.90	5,766.57	6,102.70	6,450.44	6,795.23	7,111.82
MedNResYel12	3,143.84	3,419.65	3,676.64	3,951.68	4,219.37	4,485.11	4,746.55	5,017.01	5,285.18	5,531.41
MedNResYel13	26.33	28.64	30.80	33.10	35.34	37.57	39.76	42.02	44.27	46.33
MedNResYel14	1.80	1.96	2.13	2.29	2.46	2.45	2.45	2.45	2.46	2.45
MedNResYel16	1,385.61	1,507.45	1,633.07	1,758.69	1,889.47	2,009.93	2,135.55	2,261.17	2,393.33	2,512.42
MedNResYel17	7.88	8.57	9.28	10.00	10.74	11.42	12.14	12.85	13.60	14.28
MedNResYel18	1,338.76	1,456.47	1,577.85	1,699.22	1,825.58	1,941.96	2,063.34	2,184.71	2,312.40	2,427.45
MedNResYel19	7.88	8.57	9.28	10.00	10.74	11.42	12.14	12.85	13.60	14.28
MedNResYel20	1,365.53	1,485.60	1,609.40	1,733.20	1,862.09	1,857.00	1,857.00	1,857.00	1,862.09	1,857.00
MedNWComYel1	408.89	444.76	478.19	513.96	548.78	583.34	617.34	652.52	687.40	719.42
MedNWComYel2	22.97	22.91	22.91	22.91	22.97	22.91	22.91	22.91	22.97	22.91
MedNWComYel3	475.29	517.08	560.17	603.26	648.12	646.35	646.35	646.35	648.12	646.35
MedNWComYel4	320.82	349.03	349.03	349.03	349.98	349.03	349.03	349.03	349.98	349.03
MedNWComYel5	320.82	349.03	349.03	349.03	349.98	349.03	349.03	349.03	349.98	349.03

Appendix 4.3 - SENDOUT® Selected Measures (Low Growth High Price Case) in Dth

DSM Program	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029
MedNWComYel6	261.80	284.82	308.56	332.29	357.01	356.03	356.03	356.03	357.01	356.03
MedNWComYel7	750.15	815.96	877.28	942.91	1,006.78	1,070.19	1,132.57	1,197.10	1,261.09	1,319.84
MedNWComYel8	73.84	80.33	87.02	93.72	100.69	107.11	113.80	120.49	127.54	133.88
MedNWPComMTA	8,402.07	9,140.85	9,902.58	9,902.58	9,929.71	9,902.58	9,902.58	9,902.58	9,929.71	9,902.58
MedNWPComMTW	5,026.86	5,467.86	5,878.78	6,318.56	6,296.81	6,275.05	6,250.19	6,239.31	6,226.88	6,191.14
MedNWPResMTA	1,728.20	1,880.16	1,880.16	1,880.16	1,885.31	1,880.16	1,880.16	1,880.16	1,885.31	1,880.16
MedNWPResMTW	13,472.88	14,654.85	15,756.20	16,934.89	18,082.05	19,220.88	20,341.27	21,500.33	22,649.57	23,704.80
MedNWResYel1	261.88	261.12	259.15	258.64	257.75	256.86	255.84	255.40	254.89	253.42
MedNWResYel2	36.85	36.74	36.47	36.40	36.27	36.15	36.00	35.94	35.87	35.66
MedNWResYel3	17.96	17.90	17.77	17.74	17.68	17.61	17.54	17.51	17.48	17.38
MedNWResYel4	80.02	87.04	93.58	100.58	107.40	114.16	120.81	127.70	134.52	140.79
MedNWResYel5	46.42	50.49	54.29	58.46	62.42	66.35	70.32	74.33	78.30	81.95
MedNWResYel6	3,124.36	3,398.45	3,653.86	3,927.19	4,193.22	4,457.32	4,717.13	4,985.92	5,252.43	5,497.13
MedNWResYel7	52.66	57.28	61.70	66.32	70.91	75.38	79.77	84.32	88.83	92.96
MedNWResYel8	65.29	71.01	76.35	82.06	87.62	93.14	98.57	104.19	109.76	114.87
MedNWResYel9	63.68	69.27	74.47	80.04	85.46	90.85	96.14	101.62	107.05	112.04
RosComMTA	8,026.91	8,732.70	9,460.43	9,460.43	9,486.35	9,460.43	9,460.43	9,460.43	9,486.35	9,460.43
RosComMTW	4,809.83	5,216.95	5,615.94	6,026.17	5,991.00	5,955.84	5,937.42	5,860.40	5,825.24	5,786.73
RosComRed2	1,913.58	2,081.84	2,255.32	2,428.81	2,609.42	2,775.78	2,775.78	2,775.78	2,783.39	2,775.78
RosComYel1	391.37	424.49	456.96	490.34	522.30	553.85	586.64	613.09	643.27	672.65
RosComYel10	37.57	40.87	40.87	40.87	40.98	40.87	40.87	40.87	40.98	40.87
RosComYel11	1,280.70	1,393.31	1,509.41	1,625.52	1,746.40	1,741.63	1,741.63	1,741.63	1,746.40	1,741.63
RosComYel12	41.41	45.05	48.80	52.56	56.47	60.07	63.82	67.58	71.52	75.08
RosComYel13	64.03	69.67	75.47	81.28	87.32	87.08	87.08	87.08	87.32	87.08
RosComYel14	43.79	47.50	47.20	47.03	46.75	46.48	46.33	45.74	45.47	45.17
RosComYel15	441.41	480.23	480.23	480.23	481.54	480.23	480.23	480.23	481.54	480.23
RosComYel16	441.41	480.23	480.23	480.23	481.54	480.23	480.23	480.23	481.54	480.23
RosComYel17	216.86	235.93	255.59	275.26	295.72	294.92	294.92	294.92	295.72	294.92
RosComYel18	216.86	235.93	255.59	275.26	295.72	294.92	294.92	294.92	295.72	294.92
RosComYel19	312.70	340.20	368.55	396.90	426.41	425.25	425.25	425.25	426.41	425.25
RosComYel2	24.76	24.69	24.69	24.69	24.76	24.69	24.69	24.69	24.76	24.69
RosComYel20	1.04	1.13	1.22	1.41	1.50	1.59	1.68	1.77	1.96	2.05
RosComYel3	512.28	557.32	603.77	650.21	698.56	696.65	696.65	696.65	698.56	696.65
RosComYel4	345.79	376.19	376.19	376.19	377.22	376.19	376.19	376.19	377.22	376.19
RosComYel5	345.79	376.19	376.19	376.19	377.22	376.19	376.19	376.19	377.22	376.19
RosComYel6	282.18	306.99	332.57	358.16	384.79	383.74	383.74	383.74	384.79	383.74
RosComYel7	718.00	778.77	838.33	899.57	958.20	1,016.08	1,076.25	1,124.77	1,180.14	1,234.04
RosComYel8	79.58	86.58	93.80	101.01	108.52	115.44	122.66	129.87	137.46	144.30
RosComYel9	37.57	40.87	40.87	40.87	40.98	40.87	40.87	40.87	40.98	40.87
RosResMTA	1,278.17	1,390.55	1,390.55	1,390.55	1,394.36	1,390.55	1,390.55	1,390.55	1,394.36	1,390.55
RosResMTW	9,985.63	10,830.85	11,659.17	12,510.84	13,326.26	14,131.25	14,968.02	15,642.90	16,412.88	17,162.50
RosResRed1	1,026.59	1,020.69	1,014.23	1,010.58	1,004.69	998.79	995.70	982.79	976.89	970.43
RosResRed2	1,759.45	1,914.15	2,073.66	2,233.18	2,239.30	2,233.18	2,233.18	2,233.18	2,239.30	2,233.18
RosResYel1	194.05	192.94	191.72	191.03	189.91	188.80	188.21	185.77	184.66	183.44
RosResYel10	24.56	26.64	28.67	30.77	32.87	34.86	36.92	38.59	40.49	42.34
RosResYel11	2,995.10	3,248.62	3,497.07	3,752.52	3,997.09	4,238.54	4,489.52	4,691.95	4,922.90	5,147.74
RosResYel12	2,329.52	2,526.70	2,719.94	2,918.62	3,108.85	3,296.64	3,491.85	3,649.29	3,828.92	4,003.80
RosResYel13	19.48	21.13	22.75	24.41	26.00	27.57	29.20	30.53	32.04	33.50
RosResYel14	1.51	1.64	1.77	1.91	2.05	2.05	2.05	2.05	2.05	2.05
RosResYel16	1,156.18	1,257.84	1,362.66	1,467.48	1,576.60	1,677.11	1,781.93	1,886.75	1,997.03	2,096.39
RosResYel17	6.57	7.15	7.74	8.34	8.96	9.53	10.13	10.72	11.35	11.91
RosResYel18	1,117.08	1,215.30	1,316.58	1,417.85	1,523.29	1,620.40	1,721.68	1,822.95	1,929.50	2,025.50
RosResYel19	6.57	7.15	7.74	8.34	8.96	9.53	10.13	10.72	11.35	11.91
RosResYel2	27.27	27.11	26.94	26.84	26.68	26.53	26.44	26.11	25.96	25.78
RosResYel20	1,139.42	1,239.61	1,342.91	1,446.21	1,553.75	1,549.51	1,549.51	1,549.51	1,553.75	1,549.51
RosResYel3	13.29	13.21	13.13	13.08	13.00	12.93	12.89	12.73	12.65	12.57

Appendix 4.3 - SENDOUT® Selected Measures (Low Growth High Price Case) in Dth

DSM Program	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029
RosResYel4	59.20	64.31	69.23	74.29	79.13	83.91	88.88	92.89	97.46	101.91
RosResYel5	34.45	37.37	40.23	43.17	45.98	48.76	51.64	53.99	56.64	59.23
RosResYel6	420.92	418.51	415.86	414.36	411.94	409.53	408.26	402.96	400.55	397.90
RosResYel7	39.09	42.40	45.64	48.97	52.16	55.31	58.59	61.25	64.26	67.19
RosResYel8	48.30	52.38	56.39	60.61	64.56	68.46	72.51	75.78	79.51	83.15
RosResYel9	47.11	51.09	55.00	59.02	62.97	66.77	70.73	73.92	77.56	81.10
SpoBComYel10	2,044.76	2,224.55	2,409.93	2,595.31	2,788.30	2,966.06	3,151.44	3,336.82	3,531.85	3,707.58
SpoBComYel11	2,250.64	2,448.54	2,652.59	2,856.63	3,069.06	3,060.68	3,060.68	3,060.68	3,069.06	3,060.68
SpoBComYel12	985.71	1,072.38	1,161.74	1,251.11	1,344.15	1,340.47	1,340.47	1,340.47	1,344.15	1,340.47
SpoBoComMTA	5,412.06	5,887.93	6,378.60	6,869.26	7,380.08	7,850.58	7,850.58	7,850.58	7,872.09	7,850.58
SpoBoComMTW	11,648.67	12,656.16	13,663.65	14,673.12	15,684.08	16,676.88	17,696.74	18,651.60	19,634.50	20,611.80
SpoBoComRed1	17,132.13	18,613.88	20,095.64	21,580.30	23,067.15	24,527.31	26,027.26	27,431.60	28,877.19	30,314.54
SpoBoComRed2	1,438.92	1,565.44	1,695.90	1,826.35	1,962.16	2,087.26	2,217.71	2,217.71	2,223.79	2,217.71
SpoBoComYel1	133.22	144.94	157.01	169.09	181.67	181.17	181.17	181.17	181.67	181.17
SpoBoComYel2	195.12	194.59	194.59	194.59	195.12	194.59	194.59	194.59	195.12	194.59
SpoBoComYel3	4,150.07	4,514.98	4,891.22	5,267.47	5,659.18	5,643.72	5,643.72	5,643.72	5,659.18	5,643.72
SpoBoComYel4	1,090.00	1,185.84	1,284.66	1,383.48	1,486.36	1,581.12	1,679.94	1,778.76	1,882.72	1,976.40
SpoBoComYel5	444.75	483.85	524.17	564.49	606.47	604.81	604.81	604.81	606.47	604.81
SpoBoComYel6	686.41	745.78	805.15	864.63	924.20	982.70	1,042.80	1,099.07	1,156.99	1,214.57
SpoBoComYel7	598.83	651.48	705.77	760.06	816.58	814.35	814.35	814.35	816.58	814.35
SpoBoComYel8	238.09	259.02	280.61	302.19	324.66	323.77	323.77	323.77	324.66	323.77
SpoBoComYel9	1,624.90	1,767.78	1,915.10	2,062.41	2,215.78	2,209.72	2,209.72	2,209.72	2,215.78	2,209.72
SpoBoResMTA	139,240.87	138,860.43	138,860.43	138,860.43	139,240.87	138,860.43	138,860.43	138,860.43	139,240.87	138,860.43
SpoBoResMTW	1,122,437.61	1,219,516.88	1,316,596.20	1,413,866.27	1,511,279.43	1,606,943.71	1,705,215.43	1,797,222.93	1,891,933.31	1,986,103.05
SpoBoResRed1	380,384.76	413,284.12	446,183.50	479,147.51	512,160.03	544,579.85	577,883.32	609,063.90	607,415.16	605,766.42
SpoBoResRed2	30,426.04	33,101.35	35,859.80	38,618.25	41,490.05	41,376.69	41,376.69	41,376.69	41,490.05	41,376.69
SpoBoResYel1	1,135.94	1,131.33	1,127.44	1,124.25	1,121.60	1,118.06	1,116.64	1,111.51	1,108.50	1,105.49
SpoBoResYel2	20,640.04	22,425.19	24,210.34	25,999.00	27,790.29	29,549.42	31,356.50	33,048.39	34,789.98	36,521.63
SpoBoResYel3	166.07	165.40	164.83	164.36	163.98	163.46	163.25	162.50	162.06	161.62
SpoBoResYel4	1,972.94	2,143.58	2,314.22	2,485.19	2,656.42	2,824.57	2,997.30	3,159.03	3,325.50	3,491.03
SpoBoResYel5	394.59	428.72	462.84	497.04	531.28	564.91	599.46	631.81	665.10	698.21
SpoBoResYel6	1,972.94	2,143.58	2,314.22	2,485.19	2,656.42	2,824.57	2,997.30	3,159.03	3,325.50	3,491.03
SpoBoResYel7	394.59	428.72	462.84	497.04	531.28	564.91	599.46	631.81	665.10	698.21
SpoBoResYel8	737.57	801.36	865.15	929.07	993.08	1,055.94	1,120.52	1,180.98	1,243.22	1,305.10
SpoBoResYel9	748.44	813.17	877.90	942.76	1,007.72	1,071.51	1,137.03	1,198.38	1,261.54	1,324.33
SpoBResYel10	232.50	252.61	272.72	292.87	313.05	332.86	353.22	372.28	391.89	411.40
SpoBResYel11	16,304.16	17,714.30	19,124.44	20,537.35	21,952.34	23,341.93	24,769.39	26,105.87	27,481.60	28,849.47
SpoBResYel12	23,250.13	25,261.03	27,271.93	29,286.78	31,304.59	33,286.18	35,321.77	37,227.62	39,189.44	41,140.07
SpoBResYel13	153.45	166.72	179.99	193.29	206.61	219.69	233.12	245.70	258.65	271.52
SpoBResYel14	10,481.24	11,387.76	12,294.28	13,202.58	14,112.22	15,005.53	15,923.18	16,782.34	17,666.74	18,546.09
SpoBResYel15	75,563.53	82,099.00	88,634.47	95,182.78	101,740.73	108,180.94	114,796.68	120,990.71	127,366.70	133,706.29
SpoBResYel16	192.06	208.68	225.29	241.93	258.60	274.97	291.79	307.53	323.74	339.85
SpoBResYel17	15.27	16.61	17.99	19.38	20.82	20.76	20.76	20.76	20.82	20.76
SpoBResYel18	5.55	6.04	6.54	7.05	7.57	7.55	7.55	7.55	7.57	7.55
SpoBResYel19	91.34	99.24	98.90	98.62	98.39	98.08	97.95	97.50	97.24	96.97
SpoBResYel20	4,642.79	5,051.02	5,471.94	5,892.86	6,331.07	6,734.69	7,155.61	7,576.53	8,019.36	8,418.37
SpoBResYel21	60.69	66.03	71.53	77.03	82.76	88.04	93.54	99.04	104.83	110.04
SpoBResYel22	488.49	531.44	575.73	620.02	666.13	708.59	752.88	797.17	843.76	885.74
SpoBResYel23	60.69	66.03	71.53	77.03	82.76	88.04	93.54	99.04	104.83	110.04
SpoBResYel24	11,550.35	12,565.95	13,613.11	14,660.28	15,750.47	15,707.44	15,707.44	15,707.44	15,750.47	15,707.44
SpoBResYel25	1,824.51	1,982.31	2,140.12	2,298.23	2,456.57	2,448.82	2,445.72	2,434.48	2,427.89	2,421.30
SpoGComYel10	268.16	291.74	316.06	340.37	365.68	388.99	413.30	437.62	463.19	486.24
SpoGComYel11	295.17	321.12	347.88	374.64	402.50	428.16	454.92	481.68	509.83	535.20
SpoGComYel12	129.27	140.64	152.36	164.08	176.28	175.80	175.80	175.80	176.28	175.80
SpoGResYel10	30.49	33.13	35.77	38.41	41.06	43.65	46.32	48.82	51.40	53.95
SpoGResYel11	2,138.25	2,323.19	2,508.12	2,693.42	2,879.00	3,061.24	3,248.45	3,423.72	3,604.14	3,783.54

DSM Program	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029
SpoGResYel12	3,049.20	3,312.92	3,576.65	3,840.89	4,105.52	4,365.40	4,632.36	4,882.31	5,139.60	5,395.42
SpoGResYel13	20.12	21.87	23.61	25.35	27.10	28.81	30.57	32.22	33.92	35.61
SpoGResYel14	1,374.59	1,493.48	1,612.36	1,731.49	1,850.78	1,967.94	2,088.29	2,200.96	2,316.95	2,432.27
SpoGResYel15	9,909.97	10,767.08	11,624.19	12,482.99	13,343.05	14,187.66	15,055.30	15,867.63	16,703.83	17,535.25
SpoGResYel16	25.19	27.37	29.55	31.73	33.91	36.06	38.27	40.33	42.46	44.57
SpoGResYel17	2.00	2.18	2.36	2.54	2.73	2.72	2.72	2.72	2.73	2.72
SpoGResYel19	11.86	12.88	12.84	12.80	12.77	12.73	12.72	12.66	12.63	12.59
SpoGResYel20	608.89	662.43	717.63	772.83	830.30	883.24	938.44	993.64	1,051.72	1,104.05
SpoGResYel21	7.96	8.66	9.38	10.10	10.85	11.55	12.27	12.99	13.75	14.43
SpoGResYel22	67.65	73.60	79.74	85.87	92.26	98.14	104.27	110.40	116.86	122.67
SpoGResYel23	7.96	8.66	9.38	10.10	10.85	11.55	12.27	12.99	13.75	14.43
SpoGResYel24	1,514.80	1,647.99	1,785.33	1,922.66	2,065.64	2,059.99	2,059.99	2,059.99	2,065.64	2,059.99
SpoGResYel25	239.28	259.98	280.67	301.41	322.17	321.16	320.75	319.28	318.41	317.55
SpoGTComRed1	2,246.84	2,441.17	2,635.49	2,830.20	3,025.20	3,216.70	3,413.41	3,597.59	3,787.17	3,975.68
SpoGTComRed2	188.71	205.30	222.41	239.52	257.33	273.74	290.85	290.85	291.64	290.85
SpoGTComYel1	17.47	19.01	20.59	22.18	23.83	23.76	23.76	23.76	23.83	23.76
SpoGTComYel2	25.59	25.52	25.52	25.52	25.59	25.52	25.52	25.52	25.59	25.52
SpoGTComYel3	544.27	592.13	641.47	690.82	742.19	740.16	740.16	740.16	742.19	740.16
SpoGTComYel4	142.95	155.52	168.48	181.44	194.93	207.36	220.32	233.28	246.91	259.20
SpoGTComYel5	58.33	63.46	68.74	74.03	79.54	79.32	79.32	79.32	79.54	79.32
SpoGTComYel6	90.02	97.81	105.59	113.39	121.21	128.88	136.76	144.14	151.74	159.29
SpoGTComYel7	78.53	85.44	92.56	99.68	107.09	106.80	106.80	106.80	107.09	106.80
SpoGTComYel8	26.47	28.80	31.20	33.60	36.10	36.00	36.00	36.00	36.10	36.00
SpoGTComYel9	213.10	231.84	251.16	270.48	290.59	289.80	289.80	289.80	290.59	289.80
SpoGTNComMTA	709.78	772.19	836.54	900.89	967.88	1,029.58	1,029.58	1,029.58	1,032.40	1,029.58
SpoGTNComMTW	1,482.56	1,610.78	1,739.01	1,867.49	1,996.15	2,122.51	2,252.31	2,373.84	2,498.94	2,623.32
SpoGTNResMTA	18,261.10	18,211.20	18,211.20	18,211.20	18,261.10	18,211.20	18,211.20	18,211.20	18,261.10	18,211.20
SpoGTNResMTW	147,196.83	159,927.84	172,658.85	185,414.88	198,189.68	210,735.12	223,622.50	235,688.40	248,108.75	260,458.21
SpoGTResRed1	49,886.53	54,201.20	58,515.87	62,839.02	67,168.53	71,420.31	75,787.98	79,877.23	79,661.00	79,444.78
SpoGTResRed2	3,990.30	4,341.16	4,702.92	5,064.69	5,441.32	5,426.45	5,426.45	5,426.45	5,441.32	5,426.45
SpoGTResYel1	148.98	148.37	147.86	147.44	147.09	146.63	146.45	145.77	145.38	144.98
SpoGTResYel2	2,706.89	2,941.01	3,175.13	3,409.71	3,644.63	3,875.33	4,112.33	4,334.21	4,562.62	4,789.72
SpoGTResYel3	21.78	21.69	21.62	21.56	21.51	21.44	21.41	21.31	21.25	21.20
SpoGTResYel4	258.75	281.13	303.50	325.93	348.38	370.44	393.09	414.30	436.13	457.84
SpoGTResYel5	51.75	56.23	60.70	65.19	69.68	74.09	78.62	82.86	87.23	91.57
SpoGTResYel6	258.75	281.13	303.50	325.93	348.38	370.44	393.09	414.30	436.13	457.84
SpoGTResYel7	51.75	56.23	60.70	65.19	69.68	74.09	78.62	82.86	87.23	91.57
SpoGTResYel8	96.73	105.10	113.46	121.85	130.24	138.48	146.95	154.88	163.04	171.16
SpoGTResYel9	98.16	106.65	115.13	123.64	132.16	140.53	149.12	157.17	165.45	173.68
SpoNComYel10	1,039.14	1,130.51	1,224.72	1,318.93	1,417.01	1,507.34	1,601.55	1,695.76	1,794.88	1,884.18
SpoNComYel11	1,143.77	1,244.34	1,348.04	1,451.73	1,559.69	1,555.43	1,555.43	1,555.43	1,559.69	1,555.43
SpoNComYel12	500.93	544.98	590.40	635.81	683.09	681.22	681.22	681.22	683.09	681.22
SpoNResYel10	118.16	128.38	138.60	148.83	159.09	169.16	179.50	189.19	199.16	209.07
SpoNResYel11	8,285.72	9,002.35	9,718.98	10,437.02	11,156.11	11,862.29	12,587.73	13,266.92	13,966.06	14,661.21
SpoNResYel12	11,815.64	12,837.57	13,859.50	14,883.44	15,908.89	16,915.93	17,950.41	18,918.95	19,915.95	20,907.25
SpoNResYel13	77.98	84.73	91.47	98.23	105.00	111.65	118.47	124.87	131.45	137.99
SpoNResYel14	5,326.53	5,787.22	6,247.91	6,709.51	7,171.78	7,625.76	8,092.11	8,528.73	8,978.18	9,425.06
SpoNResYel15	38,401.14	41,722.44	45,043.75	48,371.58	51,704.30	54,977.20	58,339.30	61,487.08	64,727.34	67,949.10
SpoNResYel16	97.61	106.05	114.49	122.95	131.42	139.74	148.28	156.29	164.52	172.71
SpoNResYel17	7.76	8.44	9.14	9.85	10.58	10.55	10.55	10.55	10.58	10.55
SpoNResYel18	2.82	3.07	3.32	3.58	3.85	3.84	3.84	3.84	3.85	3.84
SpoNResYel19	46.42	50.43	50.26	50.12	50.00	49.84	49.78	49.55	49.42	49.28
SpoNResYel20	2,359.45	2,566.91	2,780.82	2,994.73	3,217.43	3,422.55	3,636.46	3,850.37	4,075.41	4,278.19
SpoNResYel21	30.84	33.55	36.35	39.15	42.06	44.74	47.54	50.33	53.27	55.92
SpoNResYel22	262.16	285.21	308.98	332.75	357.49	380.28	404.05	427.82	452.82	475.35
SpoNResYel23	30.84	33.55	36.35	39.15	42.06	44.74	47.54	50.33	53.27	55.92

Appendix 4.3 - SENDOUT® Selected Measures (Low Growth High Price Case) in Dth

DSM Program	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029
SpoNResYel24	5,869.85	6,385.98	6,918.14	7,450.30	8,004.34	7,982.47	7,982.47	7,982.47	8,004.34	7,982.47
SpoNResYel25	927.21	1,007.41	1,087.60	1,167.95	1,248.42	1,244.48	1,242.91	1,237.19	1,233.84	1,230.49
SpoNWComRed1	8,706.49	9,459.51	10,212.54	10,967.04	11,722.65	12,464.70	13,226.97	13,940.65	14,675.30	15,405.75
SpoNWComRed2	731.25	795.55	861.85	928.14	997.17	1,060.74	1,127.03	1,127.03	1,130.12	1,127.03
SpoNWComYel1	67.70	73.66	79.79	85.93	92.32	92.07	92.07	92.07	92.32	92.07
SpoNWComYel2	99.16	98.89	98.89	98.89	99.16	98.89	98.89	98.89	99.16	98.89
SpoNWComYel3	2,109.05	2,294.50	2,485.70	2,676.91	2,875.98	2,868.12	2,868.12	2,868.12	2,875.98	2,868.12
SpoNWComYel4	553.93	602.64	652.86	703.08	755.36	803.52	853.74	903.96	956.79	1,004.40
SpoNWComYel5	226.02	245.89	266.38	286.87	308.21	307.36	307.36	307.36	308.21	307.36
SpoNWComYel6	348.83	379.00	409.17	439.40	469.68	499.41	529.95	558.54	587.98	617.24
SpoNWComYel7	304.32	331.08	358.67	386.26	414.98	413.85	413.85	413.85	414.98	413.85
SpoNwComYel8	102.58	111.60	120.90	130.20	139.88	139.50	139.50	139.50	139.88	139.50
SpoNWComYel9	825.77	898.38	973.24	1,048.11	1,126.05	1,122.98	1,122.98	1,122.98	1,126.05	1,122.98
SpoNWPComMTA	2,750.39	2,992.23	3,241.58	3,490.93	3,750.53	3,989.64	3,989.64	3,989.64	4,000.57	3,989.64
SpoNWPComMTW	5,901.99	6,412.45	6,922.92	7,434.38	7,946.60	8,449.62	8,966.35	9,450.14	9,948.15	10,443.31
SpoNWPResMTA	70,761.76	70,568.42	70,568.42	70,568.42	70,761.76	70,568.42	70,568.42	70,568.42	70,761.76	70,568.42
SpoNWPResMTW	569,725.86	619,001.29	668,276.70	717,648.96	767,093.85	815,651.02	865,531.71	912,232.80	960,305.81	1,008,104.40
SpoNWResRed1	193,310.29	210,029.64	226,748.99	243,501.19	260,278.05	276,753.70	293,678.41	309,524.28	308,686.40	307,848.51
SpoNWResRed2	15,462.41	16,822.00	18,223.83	19,625.67	21,085.11	21,027.50	21,027.50	21,027.50	21,085.11	21,027.50
SpoNWResYel1	577.28	574.94	572.96	571.34	569.99	568.19	567.47	564.87	563.34	561.81
SpoNWResYel2	10,489.20	11,396.41	12,303.62	13,212.61	14,122.94	15,016.92	15,935.27	16,795.08	17,680.15	18,560.17
SpoNWResYel3	84.40	84.06	83.77	83.53	83.33	83.07	82.96	82.58	82.36	82.14
SpoNWResYel4	1,002.64	1,089.36	1,176.08	1,262.97	1,349.98	1,435.44	1,523.22	1,605.41	1,690.01	1,774.13
SpoNWResYel5	200.53	217.87	235.22	252.59	270.00	287.09	304.64	321.08	338.00	354.83
SpoNWResYel6	1,002.64	1,089.36	1,176.08	1,262.97	1,349.98	1,435.44	1,523.22	1,605.41	1,690.01	1,774.13
SpoNWResYel7	200.53	217.87	235.22	252.59	270.00	287.09	304.64	321.08	338.00	354.83
SpoNWResYel8	374.83	407.25	439.67	472.15	504.68	536.63	569.44	600.17	631.80	663.25
SpoNWResYel9	380.35	413.25	446.15	479.11	512.12	544.54	577.84	609.01	641.11	673.02
Total	3,423,429.42	3,698,552.53	3,972,647.33	4,243,258.47	4,511,336.85	4,762,015.78	5,018,607.28	5,259,559.16	5,453,433.04	5,642,461.62
WA/ID	3,106,841.34	3,355,122.77	3,604,319.65	3,853,987.92	4,105,047.56	4,341,691.43	4,584,997.01	4,812,653.04	4,992,707.10	5,169,620.89
OR	272,273.16	295,448.80	316,929.88	335,128.43	350,000.20	362,414.83	374,107.27	386,155.35	398,439.92	409,207.47

APPENDIX 4.4

ENVIRONMENTAL EXTERNALITIES

APPENDIX 4.4 – ENVIRONMENTAL EXTERNALITIES (OREGON JURISDICTION ONLY)

OVERVIEW

The methodology for determining avoided costs from reduced incremental natural gas usage considers commodity and variable transportation costs only. These avoided cost streams do not include environmental externality costs related to the gathering, transmission, distribution or end-use of natural gas.

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

REGULATORY GUIDANCE

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

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

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

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

ANALYSIS

Unlike electric utilities, environmental cost issues rarely impact a natural gas utility's supply-side resource options. This is because the only supply-side energy resource is natural gas. The utility cannot choose between say "dirty" coal-fired generation and "clean" wind energy sources. The supply-side implication of environmental externalities generally relates to combustion of fuel to move or compress natural gas. Avista's direct gas distribution system infrastructure relies solely on the upstream line pressure of the interstate pipeline transportation network to distribute natural gas to its customers and thus does not directly combust fuels that result in any CO_2, NOx, SO2, or Hg emissions.

Upstream gas system infrastructure (pipelines, storage facilities, and gathering systems), however, do produce CO_2 emissions via compressors used to pressurize and move natural gas. Accessing CO_2 emissions data on these upstream activities to perform detailed meaningful analysis is challenging but increasingly important given building momentum around legislative developments regarding GHG legislation and the movement towards the creation of carbon cap and trade markets. Avista believes the cap and trade proposals being contemplated are the likely form of environmental externality cost capture versus a carbon tax framework. Under either structure, Avista believes the cost pass through mechanisms for upstream gas system infrastructure will not make a difference in supply-side resource selection although the amount of cost pass through could differ widely.

Table 4.2.1 summarizes a range of environmental cost adders we believe capture several compliance futures including our expected scenario and upper reaches of credible proposals. The CO2 cost adders reflect outlooks we obtained from one of our consultants, and following discussion and feedback from the TAC, have been incorporated into each of our six demand scenarios at various assumption levels.

The guidelines also call for a trigger point analysis that reflects a “turning point” at which an alternate resource portfolio would be selected at different carbon cost adders levels. Because natural gas is the only supply resource applicable to LDC’s any alternate resource portfolio selection would be a result of delivery methods of natural gas to customers. Conceptually, there could be differing levels of cost adders applicable to pipeline transported supply versus in service territory LNG storage gas. From a practical standpoint however, the differences in these relative cost adders would be very minor and would not change supply-side resource selection regardless of various carbon cost adder levels. We do acknowledge there is influence on the level of demand-side measures that could be cost effective. This alternate demand-side resource portfolio selection is captured in our overall process of comparing demand-side and supply-side resources described in Chapter 4 – Demand-Side Resources.

CONSERVATON COST ADVANTAGE

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

Environmental externalities were evaluated in the IRP by adding the cost per therm equivalent of the externality cost values to supply-side resources as described in OPUC Order No. 93-965. Avista found that the environmental cost adders had no impact on the company’s supply-side choices, although they did impact the level of demand-side measures that could be cost-effective to acquire.

REGULATORY FILING

Avista will file revised cost-effectiveness limits (CELs) based upon the updated avoided costs available from this IRP process within the prescribed regulatory timetable. We anticipate this will occur in early 2010.

Table 4.2.1 Enviornmental Externalities Cost Adder Analysis (2009$)

Expected Case - Updated June Data			2015	2020	2025	2030
	NOx	$/ton	$ 1,750	$ 1,237	$ 1,205	$ 1,119
	NOx	$/lb	$ 0.88	$ 0.62	$ 0.60	$ 0.56
	NOx	lbs/therm	0.008	0.008	0.008	0.008
	NOx	NOx Adder $/therm	$ 0.01	$ 0.00	$ 0.00	$ 0.00
	CO2	$/ton	$ 12.58	$ 16.69	$ 21.30	$ 27.19
	CO2	$/lb	$ 0.0063	$ 0.0083	$ 0.0107	$ 0.0136
	CO2	lbs/therm	11.64	11.64	11.64	11.64
	CO2	CO2 Adder $/therm	$ 0.07	$ 0.10	$ 0.12	$ 0.16
	Total	**Total Adders $/therm**	**$ 0.08**	**$ 0.10**	**$ 0.13**	**$ 0.16**

Expected Case - Updated Alt NOx			2015	2020	2025	2030
	NOx	$/ton	$ 7,001	$ 4,947	$ 4,821	$ 4,475
	NOx	$/lb	$ 3.50	$ 2.47	$ 2.41	$ 2.24
	NOx	lbs/therm	0.008	0.008	0.008	0.008
	NOx	NOx Adder $/therm	$ 0.03	$ 0.02	$ 0.02	$ 0.02
	CO2	$/ton	$ 12.58	$ 16.69	$ 21.30	$ 27.19
	CO2	$/lb	$ 0.0063	$ 0.0083	$ 0.0107	$ 0.0136
	CO2	lbs/therm	11.64	11.64	11.64	11.64
	CO2	CO2 Adder $/therm	$ 0.07	$ 0.10	$ 0.12	$ 0.16
	Total	**Total Adders $/therm**	**$ 0.10**	**$ 0.12**	**$ 0.14**	**$ 0.18**

Expected Case (Jan Data)			2015	2020	2025	2030
	NOx	$/ton	$ 1,343	$ 1,140	$ 1,137	$ 1,268
	NOx	$/lb	$ 0.67	$ 0.57	$ 0.57	$ 0.63
	NOx	lbs/therm	0.008	0.008	0.008	0.008
	NOx	NOx Adder $/therm	$ 0.01	$ 0.00	$ 0.00	$ 0.01
	CO2	$/ton	$ 21.00	$ 46.00	$ 58.00	$ 71.00
	CO2	$/lb	$ 0.0105	$ 0.0230	$ 0.0290	$ 0.0355
	CO2	lbs/therm	11.64	11.64	11.64	11.64
	CO2	CO2 Adder $/therm	$ 0.12	$ 0.27	$ 0.34	$ 0.41
	Total	**Total Adders $/therm**	**$ 0.13**	**$ 0.27**	**$ 0.34**	**$ 0.42**

Expected Case (Jan Data) Alt Nox			2015	2020	2025	2030
	NOx	$/ton	$ 5,373	$ 4,560	$ 4,547	$ 5,070
	NOx	$/lb	$ 2.69	$ 2.28	$ 2.27	$ 2.54
	NOx	lbs/therm	0.008	0.008	0.008	0.008
	NOx	NOx Adder $/therm	$ 0.02	$ 0.02	$ 0.02	$ 0.02
	CO2	$/ton	$ 21.00	$ 46.00	$ 58.00	$ 71.00
	CO2	$/lb	$ 0.0105	$ 0.0230	$ 0.0290	$ 0.0355
	CO2	lbs/therm	11.64	11.64	11.64	11.64
	CO2	CO2 Adder $/therm	$ 0.12	$ 0.27	$ 0.34	$ 0.41
	Total	**Total Adders $/therm**	**$ 0.14**	**$ 0.29**	**$ 0.36**	**$ 0.43**

Green Future			2015	2020	2025	2030
	NOx	$/ton	$ 1,343	$ 1,140	$ 1,137	$ 1,268
	NOx	$/lb	$ 0.67	$ 0.57	$ 0.57	$ 0.63
	NOx	lbs/therm	0.008	0.008	0.008	0.008
	NOx	NOx Adder $/therm	$ 0.01	$ 0.00	$ 0.00	$ 0.01
	CO2	$/ton	$ 46.45	$ 67.03	$ 96.74	$ 139.60
	CO2	$/lb	$ 0.0232	$ 0.0335	$ 0.0484	$ 0.0698
	CO2	lbs/therm	11.64	11.64	11.64	11.64
	CO2	CO2 Adder $/therm	$ 0.27	$ 0.39	$ 0.56	$ 0.81
	Total	**Total Adders $/therm**	**$ 0.28**	**$ 0.39**	**$ 0.57**	**$ 0.82**

Green Future Alt Nox			2015	2020	2025	2030
	NOx	$/ton	$ 5,373	$ 4,560	$ 4,547	$ 5,070
	NOx	$/lb	$ 2.69	$ 2.28	$ 2.27	$ 2.54
	NOx	lbs/therm	0.008	0.008	0.008	0.008
	NOx	NOx Adder $/therm	$ 0.02	$ 0.02	$ 0.02	$ 0.02
	CO2	$/ton	$ 46.45	$ 67.03	$ 96.74	$ 139.60
	CO2	$/lb	$ 0.0232	$ 0.0335	$ 0.0484	$ 0.0698
	CO2	lbs/therm	11.64	11.64	11.64	11.64
	CO2	CO2 Adder $/therm	$ 0.27	$ 0.39	$ 0.56	$ 0.81
	Total	**Total Adders $/therm**	**$ 0.29**	**$ 0.41**	**$ 0.58**	**$ 0.83**

APPENDIX 5.1

CURRENT TRANSPORTATION RATES

Appendix 5.1 - Current Transportation/Storage Rates and Assumptions
Rates in US$/Dth/Day

	Reservation	Commodity	Fuel Rate 3/	Rate Change Assumptions
TransCanada Alberta System Firm Rates -				
Postage Stamp Rates				
AECo/NIT to ABC	0.1410	-	0.00%	Changes every three years
AECo/NIT to ABC Winter Only	0.1763	-	0.00%	Changes every three years
TransCanada BC System Firm Rates -				
Postage Stamp Rates				
ABC to Kingsgate	0.0460	-	0.80%	Changes every three years
GTN FTS-1 Rates				
Mileage Based - Representative Example				
Kingsgate to Spokane	0.0885	0.0017	0.37%	Changes every five years
Kingsgate to Medford	0.3236	0.0096	2.04%	Changes every five years
Meford Lateral	0.6518	-	0.00%	Changes every five years
Spectra Energy/Westcoast System Firm Rates -				
Postage Stamp Rates				
Station 2 to Huntington/Sumas	0.3991	-	0.80%	Changes every three years
Williams NWP				
Postage Stamp Rates				
TF-1 1/	0.3798	0.03000	1.85%	Changes every five years
TF-2 1/	0.3798	0.03000	1.85%	Changes every five years
SGS-2F 2/	0.4718	0.01703	0.52%	Changes every five years

1/ TF-1 based upon annual delivery capability. TF-2 based upon approximately 32 days of delivery capability
2/ Not applicable for WA/ID Customers
3/ Fuel retained in-kind

APPENDIX 5.2

ALTERNATE SUPPLY SCENARIOS SUMMARY OF ASSUMPTIONS

Appendix 5.2 - 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

APPENDIX 6.1

MONTHLY PRICE DATA

Appendix 6.1 - Monthly Price Data by Basin

2009$

Scenario	Index	Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
Expected Case	AECo	2009-2010	$ 4.33	$ 4.85	$ 4.97	$ 5.05	$ 4.99	$ 4.75	$ 4.65	$ 4.78	$ 4.80	$ 4.89	$ 4.90	$ 5.09
Expected Case	AECo	2010-2011	$ 5.39	$ 5.62	$ 5.56	$ 5.58	$ 5.29	$ 5.03	$ 5.00	$ 5.06	$ 5.06	$ 5.10	$ 5.13	$ 5.27
Expected Case	AECo	2011-2012	$ 5.46	$ 5.63	$ 5.73	$ 5.73	$ 5.42	$ 5.17	$ 5.17	$ 5.22	$ 5.22	$ 5.24	$ 5.22	$ 5.37
Expected Case	AECo	2012-2013	$ 5.55	$ 5.66	$ 6.20	$ 6.25	$ 5.76	$ 5.50	$ 5.50	$ 5.54	$ 5.56	$ 5.59	$ 5.57	$ 5.66
Expected Case	AECo	2013-2014	$ 5.11	$ 5.19	$ 5.25	$ 5.27	$ 5.06	$ 4.94	$ 5.01	$ 5.04	$ 5.06	$ 5.07	$ 5.03	$ 5.16
Expected Case	AECo	2014-2015	$ 6.10	$ 6.22	$ 7.54	$ 7.60	$ 7.34	$ 7.16	$ 7.22	$ 7.27	$ 7.30	$ 7.34	$ 7.28	$ 7.43
Expected Case	AECo	2015-2016	$ 7.83	$ 7.97	$ 8.39	$ 8.42	$ 8.24	$ 8.13	$ 8.20	$ 8.27	$ 8.27	$ 8.29	$ 8.28	$ 8.37
Expected Case	AECo	2016-2017	$ 8.77	$ 8.86	$ 9.18	$ 9.16	$ 8.80	$ 8.69	$ 8.71	$ 8.74	$ 8.78	$ 8.81	$ 8.79	$ 8.92
Expected Case	AECo	2017-2018	$ 9.40	$ 9.47	$ 10.34	$ 10.36	$ 10.03	$ 9.83	$ 9.78	$ 9.86	$ 9.85	$ 9.91	$ 9.89	$ 10.08
Expected Case	AECo	2018-2019	$ 10.62	$ 10.71	$ 10.83	$ 10.82	$ 10.57	$ 10.31	$ 10.31	$ 10.35	$ 10.39	$ 10.43	$ 10.38	$ 10.54
Expected Case	AECo	2019-2020	$ 10.91	$ 11.06	$ 11.22	$ 11.25	$ 10.71	$ 10.58	$ 10.56	$ 10.58	$ 10.61	$ 10.65	$ 10.34	$ 10.41
Expected Case	AECo	2020-2021	$ 10.79	$ 10.92	$ 11.08	$ 11.13	$ 10.92	$ 10.59	$ 10.61	$ 10.63	$ 10.65	$ 10.67	$ 10.49	$ 10.55
Expected Case	AECo	2021-2022	$ 10.91	$ 10.98	$ 11.14	$ 11.17	$ 10.91	$ 10.60	$ 10.61	$ 10.66	$ 10.61	$ 10.66	$ 10.67	$ 10.78
Expected Case	AECo	2022-2023	$ 11.12	$ 11.26	$ 11.43	$ 11.47	$ 11.12	$ 10.87	$ 10.84	$ 10.86	$ 10.87	$ 10.79	$ 10.72	$ 10.86
Expected Case	AECo	2023-2024	$ 11.10	$ 11.18	$ 11.19	$ 11.16	$ 10.74	$ 10.61	$ 10.62	$ 10.65	$ 10.63	$ 10.68	$ 10.70	$ 10.71
Expected Case	AECo	2024-2025	$ 10.99	$ 11.11	$ 11.30	$ 11.38	$ 10.97	$ 10.77	$ 10.78	$ 10.80	$ 10.78	$ 10.82	$ 10.83	$ 10.84
Expected Case	AECo	2025-2026	$ 11.14	$ 11.29	$ 11.46	$ 11.45	$ 11.16	$ 10.97	$ 10.98	$ 10.99	$ 10.98	$ 11.02	$ 11.03	$ 11.06
Expected Case	AECo	2026-2027	$ 11.38	$ 11.52	$ 11.73	$ 11.71	$ 11.34	$ 11.18	$ 11.23	$ 11.21	$ 11.27	$ 11.31	$ 11.34	$ 11.48
Expected Case	AECo	2027-2028	$ 11.55	$ 11.66	$ 11.88	$ 11.91	$ 11.51	$ 11.37	$ 11.40	$ 11.40	$ 11.45	$ 11.50	$ 11.55	$ 11.67
Expected Case	AECo	2028-2029	$ 11.76	$ 11.85	$ 12.08	$ 12.11	$ 11.73	$ 11.55	$ 11.58	$ 11.60	$ 11.62	$ 11.66	$ 11.68	$ 11.84
Expected Case	AECo	2029-2030	$ 11.84	$ 11.84										
Expected Case	Malin	2009-2010	$ 4.67	$ 5.19	$ 5.32	$ 5.40	$ 5.26	$ 5.03	$ 4.91	$ 5.08	$ 5.13	$ 5.24	$ 5.24	$ 5.41
Expected Case	Malin	2010-2011	$ 5.74	$ 5.95	$ 5.88	$ 5.90	$ 5.57	$ 5.31	$ 5.29	$ 5.35	$ 5.36	$ 5.41	$ 5.44	$ 5.57
Expected Case	Malin	2011-2012	$ 5.74	$ 5.92	$ 6.00	$ 6.00	$ 5.65	$ 5.41	$ 5.40	$ 5.46	$ 5.48	$ 5.51	$ 5.49	$ 5.63
Expected Case	Malin	2012-2013	$ 5.80	$ 5.92	$ 6.45	$ 6.50	$ 5.95	$ 5.71	$ 5.72	$ 5.75	$ 5.81	$ 5.86	$ 5.83	$ 5.91
Expected Case	Malin	2013-2014	$ 5.36	$ 5.45	$ 5.48	$ 5.51	$ 5.22	$ 5.14	$ 5.22	$ 5.24	$ 5.28	$ 5.31	$ 5.27	$ 5.40
Expected Case	Malin	2014-2015	$ 6.33	$ 6.45	$ 7.75	$ 7.83	$ 7.49	$ 7.35	$ 7.41	$ 7.45	$ 7.52	$ 7.56	$ 7.51	$ 7.66
Expected Case	Malin	2015-2016	$ 8.04	$ 8.18	$ 8.59	$ 8.62	$ 8.37	$ 8.30	$ 8.37	$ 8.44	$ 8.49	$ 8.51	$ 8.51	$ 8.58
Expected Case	Malin	2016-2017	$ 8.99	$ 9.09	$ 9.39	$ 9.37	$ 8.95	$ 8.88	$ 8.91	$ 8.94	$ 9.01	$ 9.05	$ 9.02	$ 9.15
Expected Case	Malin	2017-2018	$ 9.61	$ 9.69	$ 10.54	$ 10.57	$ 10.17	$ 10.01	$ 9.99	$ 10.05	$ 10.08	$ 10.16	$ 10.14	$ 10.31
Expected Case	Malin	2018-2019	$ 10.85	$ 10.94	$ 11.00	$ 11.00	$ 10.71	$ 10.48	$ 10.50	$ 10.53	$ 10.63	$ 10.67	$ 10.63	$ 10.78
Expected Case	Malin	2019-2020	$ 11.14	$ 11.28	$ 11.39	$ 11.44	$ 10.87	$ 10.76	$ 10.76	$ 10.78	$ 10.86	$ 10.89	$ 10.60	$ 10.64
Expected Case	Malin	2020-2021	$ 11.02	$ 11.15	$ 11.26	$ 11.31	$ 11.06	$ 10.78	$ 10.79	$ 10.83	$ 10.88	$ 10.91	$ 10.74	$ 10.76
Expected Case	Malin	2021-2022	$ 11.12	$ 11.20	$ 11.30	$ 11.34	$ 11.04	$ 10.78	$ 10.79	$ 10.84	$ 10.84	$ 10.89	$ 10.90	$ 10.98
Expected Case	Malin	2022-2023	$ 11.32	$ 11.46	$ 11.59	$ 11.63	$ 11.26	$ 11.03	$ 11.00	$ 11.02	$ 11.07	$ 11.03	$ 10.99	$ 11.14
Expected Case	Malin	2023-2024	$ 11.42	$ 11.52	$ 11.46	$ 11.45	$ 11.00	$ 10.87	$ 10.90	$ 10.92	$ 10.98	$ 11.03	$ 11.07	$ 11.07
Expected Case	Malin	2024-2025	$ 11.33	$ 11.45	$ 11.62	$ 11.71	$ 11.25	$ 11.06	$ 11.07	$ 11.09	$ 11.14	$ 11.18	$ 11.21	$ 11.19
Expected Case	Malin	2025-2026	$ 11.49	$ 11.64	$ 11.79	$ 11.80	$ 11.44	$ 11.27	$ 11.29	$ 11.30	$ 11.34	$ 11.38	$ 11.40	$ 11.42
Expected Case	Malin	2026-2027	$ 11.74	$ 11.88	$ 12.06	$ 12.05	$ 11.63	$ 11.48	$ 11.53	$ 11.54	$ 11.62	$ 11.67	$ 11.71	$ 11.85
Expected Case	Malin	2027-2028	$ 11.91	$ 12.03	$ 12.20	$ 12.24	$ 11.79	$ 11.66	$ 11.72	$ 11.73	$ 11.80	$ 11.85	$ 11.91	$ 12.04
Expected Case	Malin	2028-2029	$ 12.13	$ 12.23	$ 12.42	$ 12.46	$ 12.01	$ 11.84	$ 11.90	$ 11.91	$ 11.96	$ 12.00	$ 12.04	$ 12.20
Expected Case	Malin	2029-2030	$ 12.20	$ 12.20										
Expected Case	Rockies	2009-2010	$ 4.42	$ 4.92	$ 5.05	$ 5.17	$ 4.99	$ 4.75	$ 4.70	$ 4.70	$ 4.78	$ 4.88	$ 4.94	$ 5.16
Expected Case	Rockies	2010-2011	$ 5.55	$ 5.75	$ 5.69	$ 5.71	$ 5.36	$ 5.07	$ 5.07	$ 4.99	$ 5.06	$ 5.10	$ 5.13	$ 5.32
Expected Case	Rockies	2011-2012	$ 5.60	$ 5.73	$ 5.84	$ 5.84	$ 5.46	$ 5.23	$ 5.25	$ 5.15	$ 5.22	$ 5.24	$ 5.21	$ 5.41
Expected Case	Rockies	2012-2013	$ 5.59	$ 5.66	$ 6.20	$ 6.25	$ 5.68	$ 5.46	$ 5.49	$ 5.39	$ 5.48	$ 5.52	$ 5.50	$ 5.62
Expected Case	Rockies	2013-2014	$ 5.06	$ 5.10	$ 5.15	$ 5.19	$ 4.89	$ 4.84	$ 4.93	$ 4.83	$ 4.91	$ 4.93	$ 4.88	$ 5.03
Expected Case	Rockies	2014-2015	$ 5.97	$ 6.05	$ 7.36	$ 7.45	$ 7.09	$ 6.96	$ 7.04	$ 6.95	$ 7.07	$ 7.09	$ 7.03	$ 7.19
Expected Case	Rockies	2015-2016	$ 7.60	$ 7.73	$ 8.13	$ 8.16	$ 7.88	$ 7.84	$ 7.93	$ 7.86	$ 7.94	$ 7.95	$ 7.95	$ 8.04
Expected Case	Rockies	2016-2017	$ 8.54	$ 8.60	$ 8.91	$ 8.90	$ 8.50	$ 8.47	$ 8.53	$ 8.43	$ 8.53	$ 8.57	$ 8.54	$ 8.69
Expected Case	Rockies	2017-2018	$ 9.13	$ 9.16	$ 10.03	$ 10.06	$ 9.68	$ 9.57	$ 9.58	$ 9.51	$ 9.58	$ 9.64	$ 9.62	$ 9.83
Expected Case	Rockies	2018-2019	$ 10.32	$ 10.38	$ 10.49	$ 10.49	$ 10.23	$ 10.04	$ 10.09	$ 10.00	$ 10.11	$ 10.14	$ 10.09	$ 10.27
Expected Case	Rockies	2019-2020	$ 10.60	$ 10.71	$ 10.87	$ 10.91	$ 10.34	$ 10.29	$ 10.30	$ 10.19	$ 10.27	$ 10.31	$ 10.01	$ 10.10
Expected Case	Rockies	2020-2021	$ 10.41	$ 10.50	$ 10.67	$ 10.70	$ 10.40	$ 10.18	$ 10.20	$ 10.09	$ 10.16	$ 10.19	$ 10.00	$ 10.08
Expected Case	Rockies	2021-2022	$ 10.41	$ 10.44	$ 10.58	$ 10.62	$ 10.33	$ 10.11	$ 10.14	$ 10.06	$ 10.08	$ 10.12	$ 10.14	$ 10.26
Expected Case	Rockies	2022-2023	$ 10.57	$ 10.68	$ 10.83	$ 10.87	$ 10.52	$ 10.35	$ 10.33	$ 10.21	$ 10.31	$ 10.27	$ 10.26	$ 10.45
Expected Case	Rockies	2023-2024	$ 10.74	$ 10.80	$ 10.91	$ 10.94	$ 10.56	$ 10.42	$ 10.47	$ 10.35	$ 10.40	$ 10.45	$ 10.49	$ 10.54
Expected Case	Rockies	2024-2025	$ 10.83	$ 10.93	$ 11.12	$ 11.20	$ 10.80	$ 10.60	$ 10.63	$ 10.52	$ 10.56	$ 10.60	$ 10.63	$ 10.67
Expected Case	Rockies	2025-2026	$ 10.98	$ 11.10	$ 11.25	$ 11.27	$ 10.97	$ 10.77	$ 10.81	$ 10.66	$ 10.72	$ 10.75	$ 10.76	$ 10.82
Expected Case	Rockies	2026-2027	$ 11.15	$ 11.27	$ 11.46	$ 11.46	$ 11.12	$ 10.93	$ 10.98	$ 10.83	$ 10.94	$ 10.98	$ 11.02	$ 11.19
Expected Case	Rockies	2027-2028	$ 11.24	$ 11.32	$ 11.52	$ 11.55	$ 11.20	$ 11.03	$ 11.09	$ 10.95	$ 11.06	$ 11.09	$ 11.15	$ 11.33
Expected Case	Rockies	2028-2029	$ 11.41	$ 11.47	$ 11.66	$ 11.70	$ 11.35	$ 11.19	$ 11.21	$ 11.09	$ 11.20	$ 11.23	$ 11.27	$ 11.48
Expected Case	Rockies	2029-2030	$ 11.48	$ 11.48										

Appendix 6.1 - Monthly Price Data by Basin

2009$

Scenario	Index	Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
Expected Case	Stanfield	2009-2010	$ 4.53	$ 5.04	$ 5.17	$ 5.25	$ 5.14	$ 4.90	$ 4.79	$ 4.94	$ 4.97	$ 5.07	$ 5.08	$ 5.26
Expected Case	Stanfield	2010-2011	$ 5.58	$ 5.80	$ 5.75	$ 5.77	$ 5.45	$ 5.18	$ 5.16	$ 5.21	$ 5.21	$ 5.26	$ 5.29	$ 5.43
Expected Case	Stanfield	2011-2012	$ 5.62	$ 5.79	$ 5.88	$ 5.88	$ 5.55	$ 5.29	$ 5.29	$ 5.35	$ 5.35	$ 5.38	$ 5.36	$ 5.51
Expected Case	Stanfield	2012-2013	$ 5.69	$ 5.81	$ 6.34	$ 6.39	$ 5.86	$ 5.62	$ 5.61	$ 5.65	$ 5.69	$ 5.73	$ 5.71	$ 5.79
Expected Case	Stanfield	2013-2014	$ 5.25	$ 5.33	$ 5.38	$ 5.41	$ 5.15	$ 5.04	$ 5.12	$ 5.14	$ 5.16	$ 5.19	$ 5.15	$ 5.28
Expected Case	Stanfield	2014-2015	$ 6.22	$ 6.35	$ 7.66	$ 7.73	$ 7.42	$ 7.25	$ 7.31	$ 7.35	$ 7.41	$ 7.44	$ 7.39	$ 7.55
Expected Case	Stanfield	2015-2016	$ 7.95	$ 8.09	$ 8.50	$ 8.53	$ 8.31	$ 8.22	$ 8.29	$ 8.35	$ 8.38	$ 8.39	$ 8.39	$ 8.48
Expected Case	Stanfield	2016-2017	$ 8.89	$ 8.99	$ 9.29	$ 9.28	$ 8.89	$ 8.78	$ 8.81	$ 8.84	$ 8.89	$ 8.93	$ 8.91	$ 9.04
Expected Case	Stanfield	2017-2018	$ 9.52	$ 9.59	$ 10.45	$ 10.48	$ 10.11	$ 9.92	$ 9.89	$ 9.95	$ 9.96	$ 10.03	$ 10.01	$ 10.20
Expected Case	Stanfield	2018-2019	$ 10.75	$ 10.84	$ 10.92	$ 10.93	$ 10.65	$ 10.40	$ 10.40	$ 10.44	$ 10.50	$ 10.54	$ 10.50	$ 10.66
Expected Case	Stanfield	2019-2020	$ 11.04	$ 11.18	$ 11.32	$ 11.36	$ 10.80	$ 10.67	$ 10.66	$ 10.68	$ 10.73	$ 10.76	$ 10.47	$ 10.53
Expected Case	Stanfield	2020-2021	$ 10.92	$ 11.05	$ 11.18	$ 11.23	$ 11.00	$ 10.69	$ 10.70	$ 10.73	$ 10.76	$ 10.79	$ 10.61	$ 10.66
Expected Case	Stanfield	2021-2022	$ 11.03	$ 11.10	$ 11.23	$ 11.27	$ 10.97	$ 10.69	$ 10.71	$ 10.75	$ 10.72	$ 10.77	$ 10.79	$ 10.88
Expected Case	Stanfield	2022-2023	$ 11.24	$ 11.37	$ 11.52	$ 11.56	$ 11.19	$ 10.95	$ 10.91	$ 10.93	$ 10.97	$ 10.91	$ 10.86	$ 11.01
Expected Case	Stanfield	2023-2024	$ 11.28	$ 11.36	$ 11.34	$ 11.32	$ 10.88	$ 10.74	$ 10.76	$ 10.79	$ 10.81	$ 10.86	$ 10.90	$ 10.90
Expected Case	Stanfield	2024-2025	$ 11.18	$ 11.30	$ 11.48	$ 11.56	$ 11.12	$ 10.92	$ 10.93	$ 10.95	$ 10.96	$ 11.00	$ 11.03	$ 11.02
Expected Case	Stanfield	2025-2026	$ 11.33	$ 11.48	$ 11.64	$ 11.64	$ 11.31	$ 11.13	$ 11.14	$ 11.15	$ 11.16	$ 11.20	$ 11.23	$ 11.25
Expected Case	Stanfield	2026-2027	$ 11.58	$ 11.72	$ 11.91	$ 11.90	$ 11.49	$ 11.34	$ 11.39	$ 11.38	$ 11.44	$ 11.49	$ 11.53	$ 11.68
Expected Case	Stanfield	2027-2028	$ 11.75	$ 11.86	$ 12.05	$ 12.09	$ 11.66	$ 11.52	$ 11.56	$ 11.57	$ 11.63	$ 11.68	$ 11.74	$ 11.87
Expected Case	Stanfield	2028-2029	$ 11.96	$ 12.06	$ 12.26	$ 12.30	$ 11.88	$ 11.71	$ 11.75	$ 11.76	$ 11.79	$ 11.83	$ 11.87	$ 12.03
Expected Case	Stanfield	2029-2030	$ 12.03	$ 12.03										
Expected Case	Sumas	2009-2010	$ 4.63	$ 5.15	$ 5.28	$ 5.36	$ 5.23	$ 4.86	$ 4.64	$ 4.75	$ 4.78	$ 4.88	$ 4.91	$ 5.19
Expected Case	Sumas	2010-2011	$ 5.70	$ 5.92	$ 5.87	$ 5.89	$ 5.54	$ 5.15	$ 5.01	$ 5.05	$ 5.05	$ 5.10	$ 5.15	$ 5.37
Expected Case	Sumas	2011-2012	$ 5.71	$ 5.88	$ 5.99	$ 6.00	$ 5.63	$ 5.30	$ 5.18	$ 5.21	$ 5.22	$ 5.25	$ 5.24	$ 5.44
Expected Case	Sumas	2012-2013	$ 5.80	$ 5.91	$ 6.45	$ 6.50	$ 5.93	$ 5.61	$ 5.51	$ 5.54	$ 5.57	$ 5.61	$ 5.61	$ 5.71
Expected Case	Sumas	2013-2014	$ 5.34	$ 5.43	$ 5.48	$ 5.51	$ 5.21	$ 5.04	$ 5.03	$ 5.05	$ 5.07	$ 5.09	$ 5.07	$ 5.22
Expected Case	Sumas	2014-2015	$ 6.31	$ 6.43	$ 7.75	$ 7.83	$ 7.48	$ 7.25	$ 7.25	$ 7.28	$ 7.33	$ 7.36	$ 7.33	$ 7.50
Expected Case	Sumas	2015-2016	$ 8.02	$ 8.17	$ 8.59	$ 8.62	$ 8.37	$ 8.22	$ 8.24	$ 8.30	$ 8.30	$ 8.32	$ 8.34	$ 8.45
Expected Case	Sumas	2016-2017	$ 8.97	$ 9.07	$ 9.39	$ 9.38	$ 8.94	$ 8.78	$ 8.76	$ 8.77	$ 8.81	$ 8.85	$ 8.84	$ 9.00
Expected Case	Sumas	2017-2018	$ 9.60	$ 9.67	$ 10.54	$ 10.58	$ 10.17	$ 9.92	$ 9.82	$ 9.88	$ 9.88	$ 9.95	$ 9.95	$ 10.16
Expected Case	Sumas	2018-2019	$ 10.83	$ 10.92	$ 11.04	$ 11.04	$ 10.71	$ 10.39	$ 10.36	$ 10.38	$ 10.43	$ 10.48	$ 10.45	$ 10.63
Expected Case	Sumas	2019-2020	$ 11.12	$ 11.27	$ 11.43	$ 11.48	$ 10.87	$ 10.67	$ 10.61	$ 10.63	$ 10.65	$ 10.70	$ 10.43	$ 10.51
Expected Case	Sumas	2020-2021	$ 11.01	$ 11.14	$ 11.30	$ 11.35	$ 11.06	$ 10.69	$ 10.67	$ 10.68	$ 10.70	$ 10.73	$ 10.58	$ 10.66
Expected Case	Sumas	2021-2022	$ 11.13	$ 11.20	$ 11.37	$ 11.42	$ 11.04	$ 10.69	$ 10.67	$ 10.71	$ 10.66	$ 10.72	$ 10.75	$ 10.88
Expected Case	Sumas	2022-2023	$ 11.32	$ 11.46	$ 11.64	$ 11.69	$ 11.25	$ 10.97	$ 10.90	$ 10.90	$ 10.92	$ 10.84	$ 10.80	$ 10.95
Expected Case	Sumas	2023-2024	$ 11.38	$ 11.48	$ 11.50	$ 11.46	$ 10.92	$ 10.68	$ 10.64	$ 10.65	$ 10.64	$ 10.70	$ 10.74	$ 10.77
Expected Case	Sumas	2024-2025	$ 11.31	$ 11.43	$ 11.62	$ 11.71	$ 11.17	$ 10.86	$ 10.80	$ 10.81	$ 10.80	$ 10.84	$ 10.88	$ 10.91
Expected Case	Sumas	2025-2026	$ 11.48	$ 11.63	$ 11.79	$ 11.80	$ 11.35	$ 11.07	$ 11.01	$ 11.01	$ 11.01	$ 11.05	$ 11.08	$ 11.14
Expected Case	Sumas	2026-2027	$ 11.71	$ 11.85	$ 12.06	$ 12.06	$ 11.48	$ 11.28	$ 11.26	$ 11.16	$ 11.22	$ 11.26	$ 11.39	$ 11.56
Expected Case	Sumas	2027-2028	$ 11.87	$ 11.99	$ 12.20	$ 12.24	$ 11.65	$ 11.48	$ 11.44	$ 11.35	$ 11.41	$ 11.46	$ 11.62	$ 11.76
Expected Case	Sumas	2028-2029	$ 12.10	$ 12.20	$ 12.42	$ 12.46	$ 11.92	$ 11.67	$ 11.62	$ 11.55	$ 11.58	$ 11.62	$ 11.74	$ 11.93
Expected Case	Sumas	2029-2030	$ 11.93	$ 11.93										

Appendix 6.1 - Monthly Price Data by Basin

2009$

Scenario	Index	Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
Updated Expected	AECo	2009-2010	$ 3.91	$ 4.43	$ 4.57	$ 4.56	$ 4.52	$ 4.33	$ 4.23	$ 4.34	$ 4.35	$ 4.41	$ 4.41	$ 4.58
Updated Expected	AECo	2010-2011	$ 4.80	$ 5.02	$ 5.18	$ 5.19	$ 4.97	$ 4.73	$ 4.74	$ 4.80	$ 4.82	$ 4.87	$ 4.83	$ 4.97
Updated Expected	AECo	2011-2012	$ 5.09	$ 5.24	$ 5.32	$ 5.32	$ 5.19	$ 4.93	$ 4.90	$ 4.95	$ 4.94	$ 4.97	$ 5.01	$ 5.14
Updated Expected	AECo	2012-2013	$ 5.26	$ 5.38	$ 5.44	$ 5.46	$ 5.29	$ 5.06	$ 5.02	$ 5.06	$ 5.04	$ 5.08	$ 5.11	$ 5.23
Updated Expected	AECo	2013-2014	$ 4.62	$ 4.69	$ 4.85	$ 4.87	$ 4.66	$ 4.55	$ 4.55	$ 4.56	$ 4.52	$ 4.54	$ 4.57	$ 4.68
Updated Expected	AECo	2014-2015	$ 5.56	$ 5.63	$ 6.57	$ 6.60	$ 6.37	$ 6.25	$ 6.26	$ 6.27	$ 6.25	$ 6.27	$ 6.30	$ 6.42
Updated Expected	AECo	2015-2016	$ 6.75	$ 6.83	$ 6.84	$ 6.86	$ 6.69	$ 6.55	$ 6.55	$ 6.58	$ 6.55	$ 6.58	$ 6.61	$ 6.73
Updated Expected	AECo	2016-2017	$ 7.05	$ 7.13	$ 7.16	$ 7.19	$ 6.70	$ 6.58	$ 6.58	$ 6.60	$ 6.57	$ 6.59	$ 6.63	$ 6.75
Updated Expected	AECo	2017-2018	$ 7.07	$ 7.15	$ 7.18	$ 7.21	$ 6.65	$ 6.51	$ 6.48	$ 6.51	$ 6.48	$ 6.52	$ 6.55	$ 6.68
Updated Expected	AECo	2018-2019	$ 7.00	$ 7.07	$ 7.06	$ 7.09	$ 6.83	$ 6.67	$ 6.66	$ 6.68	$ 6.65	$ 6.68	$ 6.71	$ 6.85
Updated Expected	AECo	2019-2020	$ 7.16	$ 7.24	$ 7.26	$ 7.28	$ 7.04	$ 6.89	$ 6.87	$ 6.89	$ 6.86	$ 6.88	$ 6.92	$ 7.04
Updated Expected	AECo	2020-2021	$ 7.36	$ 7.43	$ 7.48	$ 7.52	$ 7.36	$ 7.16	$ 7.16	$ 7.18	$ 7.15	$ 7.17	$ 7.21	$ 7.32
Updated Expected	AECo	2021-2022	$ 7.66	$ 7.74	$ 7.85	$ 7.88	$ 7.23	$ 7.03	$ 7.02	$ 7.05	$ 7.02	$ 7.05	$ 7.09	$ 7.20
Updated Expected	AECo	2022-2023	$ 7.56	$ 7.64	$ 7.60	$ 7.63	$ 7.28	$ 7.08	$ 7.05	$ 7.07	$ 7.04	$ 6.99	$ 6.94	$ 6.96
Updated Expected	AECo	2023-2024	$ 7.11	$ 7.17	$ 7.50	$ 7.45	$ 6.43	$ 6.33	$ 6.33	$ 6.36	$ 6.36	$ 6.39	$ 6.42	$ 6.53
Updated Expected	AECo	2024-2025	$ 6.84	$ 6.91	$ 6.88	$ 6.91	$ 6.66	$ 6.54	$ 6.55	$ 6.57	$ 6.56	$ 6.59	$ 6.63	$ 6.74
Updated Expected	AECo	2025-2026	$ 7.06	$ 7.14	$ 7.08	$ 7.11	$ 6.87	$ 6.75	$ 6.75	$ 6.77	$ 6.74	$ 6.77	$ 6.80	$ 6.91
Updated Expected	AECo	2026-2027	$ 7.21	$ 7.30	$ 7.54	$ 7.56	$ 6.97	$ 6.85	$ 6.87	$ 6.90	$ 6.87	$ 6.90	$ 6.93	$ 7.04
Updated Expected	AECo	2027-2028	$ 7.36	$ 7.43	$ 7.37	$ 7.41	$ 7.05	$ 6.96	$ 6.96	$ 7.00	$ 6.97	$ 7.00	$ 7.04	$ 7.14
Updated Expected	AECo	2028-2029	$ 7.47	$ 7.54	$ 7.46	$ 7.49	$ 7.22	$ 7.08	$ 7.10	$ 7.13	$ 7.04	$ 7.04	$ 7.15	$ 7.23
Updated Expected	AECo	2029-2030	$ 7.23	$ 7.23										
Updated Expected	Malin	2009-2010	$ 4.25	$ 4.77	$ 4.92	$ 4.91	$ 4.80	$ 4.60	$ 4.49	$ 4.64	$ 4.69	$ 4.75	$ 4.75	$ 4.90
Updated Expected	Malin	2010-2011	$ 5.14	$ 5.36	$ 5.50	$ 5.52	$ 5.25	$ 5.01	$ 5.03	$ 5.08	$ 5.12	$ 5.19	$ 5.15	$ 5.28
Updated Expected	Malin	2011-2012	$ 5.37	$ 5.52	$ 5.59	$ 5.59	$ 5.43	$ 5.17	$ 5.14	$ 5.19	$ 5.20	$ 5.23	$ 5.27	$ 5.40
Updated Expected	Malin	2012-2013	$ 5.52	$ 5.63	$ 5.69	$ 5.71	$ 5.48	$ 5.27	$ 5.25	$ 5.28	$ 5.29	$ 5.34	$ 5.38	$ 5.48
Updated Expected	Malin	2013-2014	$ 4.88	$ 4.95	$ 5.08	$ 5.11	$ 4.83	$ 4.75	$ 4.75	$ 4.76	$ 4.74	$ 4.78	$ 4.81	$ 4.92
Updated Expected	Malin	2014-2015	$ 5.78	$ 5.86	$ 6.79	$ 6.82	$ 6.52	$ 6.43	$ 6.44	$ 6.46	$ 6.46	$ 6.49	$ 6.53	$ 6.64
Updated Expected	Malin	2015-2016	$ 6.96	$ 7.04	$ 7.04	$ 7.06	$ 6.82	$ 6.72	$ 6.73	$ 6.75	$ 6.77	$ 6.80	$ 6.84	$ 6.94
Updated Expected	Malin	2016-2017	$ 7.27	$ 7.35	$ 7.37	$ 7.41	$ 6.85	$ 6.77	$ 6.78	$ 6.80	$ 6.80	$ 6.83	$ 6.87	$ 6.98
Updated Expected	Malin	2017-2018	$ 7.28	$ 7.36	$ 7.38	$ 7.42	$ 6.79	$ 6.69	$ 6.69	$ 6.70	$ 6.72	$ 6.76	$ 6.80	$ 6.91
Updated Expected	Malin	2018-2019	$ 7.22	$ 7.30	$ 7.23	$ 7.27	$ 6.97	$ 6.84	$ 6.85	$ 6.87	$ 6.88	$ 6.92	$ 6.96	$ 7.08
Updated Expected	Malin	2019-2020	$ 7.39	$ 7.47	$ 7.44	$ 7.48	$ 7.19	$ 7.07	$ 7.07	$ 7.09	$ 7.11	$ 7.13	$ 7.17	$ 7.27
Updated Expected	Malin	2020-2021	$ 7.59	$ 7.67	$ 7.66	$ 7.70	$ 7.51	$ 7.34	$ 7.35	$ 7.37	$ 7.38	$ 7.41	$ 7.45	$ 7.54
Updated Expected	Malin	2021-2022	$ 7.88	$ 7.96	$ 8.01	$ 8.05	$ 7.36	$ 7.21	$ 7.20	$ 7.22	$ 7.24	$ 7.28	$ 7.32	$ 7.41
Updated Expected	Malin	2022-2023	$ 7.76	$ 7.84	$ 7.75	$ 7.79	$ 7.41	$ 7.23	$ 7.21	$ 7.23	$ 7.24	$ 7.24	$ 7.21	$ 7.25
Updated Expected	Malin	2023-2024	$ 7.44	$ 7.51	$ 7.76	$ 7.75	$ 6.69	$ 6.60	$ 6.61	$ 6.64	$ 6.71	$ 6.74	$ 6.79	$ 6.89
Updated Expected	Malin	2024-2025	$ 7.18	$ 7.25	$ 7.19	$ 7.23	$ 6.93	$ 6.83	$ 6.85	$ 6.86	$ 6.92	$ 6.96	$ 7.01	$ 7.09
Updated Expected	Malin	2025-2026	$ 7.41	$ 7.49	$ 7.41	$ 7.45	$ 7.15	$ 7.05	$ 7.07	$ 7.08	$ 7.10	$ 7.13	$ 7.18	$ 7.28
Updated Expected	Malin	2026-2027	$ 7.57	$ 7.65	$ 7.86	$ 7.90	$ 7.26	$ 7.15	$ 7.18	$ 7.23	$ 7.22	$ 7.26	$ 7.30	$ 7.41
Updated Expected	Malin	2027-2028	$ 7.72	$ 7.80	$ 7.70	$ 7.73	$ 7.34	$ 7.25	$ 7.28	$ 7.33	$ 7.32	$ 7.35	$ 7.39	$ 7.51
Updated Expected	Malin	2028-2029	$ 7.84	$ 7.92	$ 7.80	$ 7.84	$ 7.50	$ 7.37	$ 7.41	$ 7.44	$ 7.38	$ 7.38	$ 7.50	$ 7.59
Updated Expected	Malin	2029-2030	$ 7.59	$ 7.59										
Updated Expected	Rockies	2009-2010	$ 4.00	$ 4.50	$ 4.65	$ 4.68	$ 4.53	$ 4.33	$ 4.27	$ 4.26	$ 4.34	$ 4.39	$ 4.44	$ 4.65
Updated Expected	Rockies	2010-2011	$ 4.95	$ 5.15	$ 5.31	$ 5.33	$ 5.04	$ 4.78	$ 4.81	$ 4.73	$ 4.82	$ 4.88	$ 4.83	$ 5.03
Updated Expected	Rockies	2011-2012	$ 5.23	$ 5.34	$ 5.42	$ 5.44	$ 5.23	$ 4.99	$ 4.98	$ 4.87	$ 4.95	$ 4.97	$ 4.99	$ 5.18
Updated Expected	Rockies	2012-2013	$ 5.30	$ 5.38	$ 5.44	$ 5.47	$ 5.21	$ 5.02	$ 5.02	$ 4.92	$ 4.96	$ 5.00	$ 5.04	$ 5.19
Updated Expected	Rockies	2013-2014	$ 4.57	$ 4.60	$ 4.75	$ 4.79	$ 4.49	$ 4.45	$ 4.47	$ 4.35	$ 4.38	$ 4.40	$ 4.42	$ 4.56
Updated Expected	Rockies	2014-2015	$ 5.42	$ 5.46	$ 6.40	$ 6.44	$ 6.12	$ 6.05	$ 6.07	$ 5.96	$ 6.01	$ 6.01	$ 6.05	$ 6.18
Updated Expected	Rockies	2015-2016	$ 6.52	$ 6.58	$ 6.57	$ 6.61	$ 6.33	$ 6.26	$ 6.28	$ 6.17	$ 6.22	$ 6.24	$ 6.28	$ 6.40
Updated Expected	Rockies	2016-2017	$ 6.83	$ 6.86	$ 6.89	$ 6.93	$ 6.40	$ 6.37	$ 6.40	$ 6.29	$ 6.32	$ 6.35	$ 6.38	$ 6.52
Updated Expected	Rockies	2017-2018	$ 6.80	$ 6.84	$ 6.87	$ 6.91	$ 6.30	$ 6.25	$ 6.28	$ 6.17	$ 6.22	$ 6.25	$ 6.28	$ 6.42
Updated Expected	Rockies	2018-2019	$ 6.69	$ 6.74	$ 6.72	$ 6.76	$ 6.48	$ 6.40	$ 6.44	$ 6.33	$ 6.37	$ 6.39	$ 6.43	$ 6.58
Updated Expected	Rockies	2019-2020	$ 6.85	$ 6.90	$ 6.91	$ 6.94	$ 6.67	$ 6.60	$ 6.61	$ 6.49	$ 6.52	$ 6.55	$ 6.58	$ 6.72
Updated Expected	Rockies	2020-2021	$ 6.97	$ 7.02	$ 7.07	$ 7.10	$ 6.85	$ 6.74	$ 6.75	$ 6.64	$ 6.66	$ 6.69	$ 6.72	$ 6.85
Updated Expected	Rockies	2021-2022	$ 7.16	$ 7.20	$ 7.29	$ 7.33	$ 6.65	$ 6.54	$ 6.55	$ 6.44	$ 6.48	$ 6.51	$ 6.56	$ 6.69
Updated Expected	Rockies	2022-2023	$ 7.01	$ 7.06	$ 6.99	$ 7.03	$ 6.68	$ 6.55	$ 6.54	$ 6.42	$ 6.47	$ 6.47	$ 6.48	$ 6.56
Updated Expected	Rockies	2023-2024	$ 6.75	$ 6.79	$ 7.22	$ 7.24	$ 6.25	$ 6.15	$ 6.18	$ 6.07	$ 6.13	$ 6.16	$ 6.21	$ 6.36
Updated Expected	Rockies	2024-2025	$ 6.68	$ 6.73	$ 6.69	$ 6.73	$ 6.49	$ 6.37	$ 6.41	$ 6.29	$ 6.35	$ 6.37	$ 6.43	$ 6.56
Updated Expected	Rockies	2025-2026	$ 6.90	$ 6.95	$ 6.88	$ 6.92	$ 6.68	$ 6.55	$ 6.59	$ 6.44	$ 6.48	$ 6.51	$ 6.54	$ 6.68
Updated Expected	Rockies	2026-2027	$ 6.99	$ 7.04	$ 7.27	$ 7.31	$ 6.75	$ 6.60	$ 6.63	$ 6.52	$ 6.54	$ 6.57	$ 6.61	$ 6.75
Updated Expected	Rockies	2027-2028	$ 7.04	$ 7.08	$ 7.01	$ 7.04	$ 6.74	$ 6.62	$ 6.66	$ 6.54	$ 6.58	$ 6.59	$ 6.63	$ 6.79
Updated Expected	Rockies	2028-2029	$ 7.12	$ 7.16	$ 7.04	$ 7.08	$ 6.84	$ 6.71	$ 6.72	$ 6.62	$ 6.62	$ 6.62	$ 6.74	$ 6.88
Updated Expected	Rockies	2029-2030	$ 6.88	$ 6.88										

Appendix 6.1 - Monthly Price Data by Basin

2009$

Scenario	Index	Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
Updated Expected	Stanfield	2009-2010	$ 4.11	$ 4.63	$ 4.77	$ 4.77	$ 4.67	$ 4.47	$ 4.36	$ 4.50	$ 4.53	$ 4.58	$ 4.59	$ 4.75
Updated Expected	Stanfield	2010-2011	$ 4.99	$ 5.21	$ 5.37	$ 5.38	$ 5.13	$ 4.88	$ 4.89	$ 4.95	$ 4.98	$ 5.03	$ 4.99	$ 5.13
Updated Expected	Stanfield	2011-2012	$ 5.25	$ 5.39	$ 5.47	$ 5.47	$ 5.32	$ 5.06	$ 5.03	$ 5.08	$ 5.07	$ 5.11	$ 5.14	$ 5.28
Updated Expected	Stanfield	2012-2013	$ 5.40	$ 5.52	$ 5.58	$ 5.60	$ 5.40	$ 5.17	$ 5.14	$ 5.18	$ 5.17	$ 5.21	$ 5.25	$ 5.36
Updated Expected	Stanfield	2013-2014	$ 4.76	$ 4.83	$ 4.97	$ 5.01	$ 4.75	$ 4.64	$ 4.65	$ 4.66	$ 4.63	$ 4.66	$ 4.69	$ 4.81
Updated Expected	Stanfield	2014-2015	$ 5.68	$ 5.76	$ 6.69	$ 6.72	$ 6.45	$ 6.34	$ 6.35	$ 6.36	$ 6.35	$ 6.37	$ 6.41	$ 6.54
Updated Expected	Stanfield	2015-2016	$ 6.87	$ 6.94	$ 6.95	$ 6.97	$ 6.76	$ 6.64	$ 6.64	$ 6.66	$ 6.65	$ 6.68	$ 6.73	$ 6.84
Updated Expected	Stanfield	2016-2017	$ 7.17	$ 7.25	$ 7.27	$ 7.31	$ 6.79	$ 6.68	$ 6.68	$ 6.70	$ 6.68	$ 6.71	$ 6.75	$ 6.87
Updated Expected	Stanfield	2017-2018	$ 7.19	$ 7.27	$ 7.29	$ 7.33	$ 6.73	$ 6.60	$ 6.59	$ 6.61	$ 6.59	$ 6.63	$ 6.67	$ 6.80
Updated Expected	Stanfield	2018-2019	$ 7.12	$ 7.20	$ 7.15	$ 7.19	$ 6.90	$ 6.76	$ 6.76	$ 6.77	$ 6.76	$ 6.79	$ 6.84	$ 6.97
Updated Expected	Stanfield	2019-2020	$ 7.29	$ 7.37	$ 7.36	$ 7.39	$ 7.13	$ 6.98	$ 6.97	$ 6.99	$ 6.98	$ 7.00	$ 7.05	$ 7.16
Updated Expected	Stanfield	2020-2021	$ 7.48	$ 7.56	$ 7.58	$ 7.62	$ 7.44	$ 7.25	$ 7.26	$ 7.27	$ 7.26	$ 7.29	$ 7.33	$ 7.44
Updated Expected	Stanfield	2021-2022	$ 7.78	$ 7.86	$ 7.94	$ 7.97	$ 7.29	$ 7.12	$ 7.12	$ 7.14	$ 7.13	$ 7.16	$ 7.21	$ 7.31
Updated Expected	Stanfield	2022-2023	$ 7.67	$ 7.75	$ 7.68	$ 7.72	$ 7.35	$ 7.16	$ 7.13	$ 7.14	$ 7.13	$ 7.11	$ 7.08	$ 7.11
Updated Expected	Stanfield	2023-2024	$ 7.29	$ 7.35	$ 7.65	$ 7.62	$ 6.57	$ 6.47	$ 6.47	$ 6.51	$ 6.54	$ 6.57	$ 6.61	$ 6.72
Updated Expected	Stanfield	2024-2025	$ 7.02	$ 7.10	$ 7.05	$ 7.08	$ 6.81	$ 6.69	$ 6.71	$ 6.72	$ 6.75	$ 6.78	$ 6.83	$ 6.92
Updated Expected	Stanfield	2025-2026	$ 7.25	$ 7.33	$ 7.26	$ 7.30	$ 7.02	$ 6.91	$ 6.92	$ 6.93	$ 6.92	$ 6.95	$ 7.01	$ 7.11
Updated Expected	Stanfield	2026-2027	$ 7.41	$ 7.49	$ 7.72	$ 7.75	$ 7.12	$ 7.01	$ 7.03	$ 7.07	$ 7.05	$ 7.08	$ 7.12	$ 7.23
Updated Expected	Stanfield	2027-2028	$ 7.55	$ 7.63	$ 7.55	$ 7.58	$ 7.21	$ 7.11	$ 7.13	$ 7.17	$ 7.14	$ 7.18	$ 7.22	$ 7.34
Updated Expected	Stanfield	2028-2029	$ 7.67	$ 7.74	$ 7.64	$ 7.68	$ 7.37	$ 7.24	$ 7.26	$ 7.29	$ 7.21	$ 7.21	$ 7.33	$ 7.42
Updated Expected	Stanfield	2029-2030	$ 7.42	$ 7.42										
Updated Expected	Sumas	2009-2010	$ 4.22	$ 4.73	$ 4.88	$ 4.88	$ 4.77	$ 4.43	$ 4.22	$ 4.31	$ 4.34	$ 4.40	$ 4.42	$ 4.68
Updated Expected	Sumas	2010-2011	$ 5.10	$ 5.33	$ 5.49	$ 5.51	$ 5.22	$ 4.86	$ 4.74	$ 4.79	$ 4.81	$ 4.87	$ 4.85	$ 5.07
Updated Expected	Sumas	2011-2012	$ 5.34	$ 5.49	$ 5.58	$ 5.59	$ 5.40	$ 5.06	$ 4.92	$ 4.94	$ 4.94	$ 4.97	$ 5.03	$ 5.21
Updated Expected	Sumas	2012-2013	$ 5.51	$ 5.62	$ 5.69	$ 5.71	$ 5.47	$ 5.17	$ 5.04	$ 5.06	$ 5.06	$ 5.09	$ 5.15	$ 5.28
Updated Expected	Sumas	2013-2014	$ 4.85	$ 4.92	$ 5.08	$ 5.11	$ 4.81	$ 4.64	$ 4.57	$ 4.57	$ 4.54	$ 4.56	$ 4.61	$ 4.74
Updated Expected	Sumas	2014-2015	$ 5.77	$ 5.84	$ 6.79	$ 6.82	$ 6.52	$ 6.34	$ 6.29	$ 6.29	$ 6.27	$ 6.29	$ 6.35	$ 6.49
Updated Expected	Sumas	2015-2016	$ 6.94	$ 7.02	$ 7.04	$ 7.07	$ 6.82	$ 6.64	$ 6.59	$ 6.60	$ 6.58	$ 6.61	$ 6.67	$ 6.81
Updated Expected	Sumas	2016-2017	$ 7.26	$ 7.34	$ 7.37	$ 7.41	$ 6.84	$ 6.67	$ 6.63	$ 6.63	$ 6.60	$ 6.63	$ 6.69	$ 6.84
Updated Expected	Sumas	2017-2018	$ 7.27	$ 7.35	$ 7.38	$ 7.42	$ 6.79	$ 6.60	$ 6.52	$ 6.54	$ 6.52	$ 6.55	$ 6.61	$ 6.76
Updated Expected	Sumas	2018-2019	$ 7.21	$ 7.29	$ 7.27	$ 7.31	$ 6.96	$ 6.75	$ 6.71	$ 6.71	$ 6.69	$ 6.72	$ 6.78	$ 6.94
Updated Expected	Sumas	2019-2020	$ 7.38	$ 7.45	$ 7.48	$ 7.52	$ 7.19	$ 6.98	$ 6.92	$ 6.93	$ 6.91	$ 6.93	$ 7.00	$ 7.14
Updated Expected	Sumas	2020-2021	$ 7.57	$ 7.65	$ 7.70	$ 7.74	$ 7.51	$ 7.25	$ 7.22	$ 7.23	$ 7.21	$ 7.23	$ 7.30	$ 7.43
Updated Expected	Sumas	2021-2022	$ 7.88	$ 7.96	$ 8.08	$ 8.13	$ 7.36	$ 7.12	$ 7.08	$ 7.09	$ 7.07	$ 7.11	$ 7.17	$ 7.30
Updated Expected	Sumas	2022-2023	$ 7.76	$ 7.84	$ 7.80	$ 7.84	$ 7.41	$ 7.17	$ 7.11	$ 7.11	$ 7.09	$ 7.05	$ 7.01	$ 7.05
Updated Expected	Sumas	2023-2024	$ 7.39	$ 7.47	$ 7.80	$ 7.75	$ 6.61	$ 6.40	$ 6.34	$ 6.36	$ 6.37	$ 6.41	$ 6.46	$ 6.59
Updated Expected	Sumas	2024-2025	$ 7.15	$ 7.23	$ 7.19	$ 7.23	$ 6.85	$ 6.63	$ 6.58	$ 6.59	$ 6.58	$ 6.61	$ 6.67	$ 6.80
Updated Expected	Sumas	2025-2026	$ 7.40	$ 7.48	$ 7.41	$ 7.45	$ 7.06	$ 6.85	$ 6.79	$ 6.79	$ 6.77	$ 6.80	$ 6.86	$ 6.99
Updated Expected	Sumas	2026-2027	$ 7.54	$ 7.62	$ 7.86	$ 7.91	$ 7.11	$ 6.95	$ 6.90	$ 6.85	$ 6.82	$ 6.85	$ 6.98	$ 7.11
Updated Expected	Sumas	2027-2028	$ 7.68	$ 7.75	$ 7.70	$ 7.73	$ 7.20	$ 7.07	$ 7.00	$ 6.95	$ 6.93	$ 6.96	$ 7.10	$ 7.23
Updated Expected	Sumas	2028-2029	$ 7.81	$ 7.88	$ 7.80	$ 7.84	$ 7.41	$ 7.20	$ 7.14	$ 7.09	$ 7.00	$ 7.01	$ 7.21	$ 7.32
Updated Expected	Sumas	2029-2030	$ 7.32	$ 7.32										

Appendix 6.1 - Monthly Price Data by Basin

2009$

Scenario	Index	Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
High Growth Low Price	AECo	2009-2010	$ 5.44	$ 5.80	$ 5.49	$ 5.53	$ 5.44	$ 4.79	$ 4.84	$ 4.92	$ 4.99	$ 5.07	$ 5.08	$ 5.13
High Growth Low Price	AECo	2010-2011	$ 5.83	$ 6.00	$ 5.94	$ 5.95	$ 5.82	$ 5.08	$ 5.09	$ 5.15	$ 5.21	$ 5.26	$ 5.29	$ 5.35
High Growth Low Price	AECo	2011-2012	$ 5.76	$ 5.89	$ 5.76	$ 5.78	$ 5.63	$ 4.92	$ 4.91	$ 4.98	$ 5.04	$ 5.09	$ 5.13	$ 5.17
High Growth Low Price	AECo	2012-2013	$ 5.68	$ 5.80	$ 6.16	$ 6.15	$ 5.99	$ 5.26	$ 5.28	$ 5.35	$ 5.37	$ 5.41	$ 5.43	$ 5.53
High Growth Low Price	AECo	2013-2014	$ 5.30	$ 5.32	$ 5.09	$ 5.12	$ 4.98	$ 4.39	$ 4.38	$ 4.44	$ 4.47	$ 4.49	$ 4.50	$ 4.53
High Growth Low Price	AECo	2014-2015	$ 5.70	$ 5.77	$ 6.82	$ 6.86	$ 6.77	$ 6.13	$ 6.14	$ 6.18	$ 6.25	$ 6.25	$ 6.26	$ 6.30
High Growth Low Price	AECo	2015-2016	$ 6.92	$ 7.07	$ 7.17	$ 7.22	$ 7.12	$ 6.44	$ 6.44	$ 6.42	$ 6.53	$ 6.51	$ 6.56	$ 6.63
High Growth Low Price	AECo	2016-2017	$ 7.26	$ 7.32	$ 7.26	$ 7.29	$ 7.06	$ 6.39	$ 6.43	$ 6.41	$ 6.42	$ 6.42	$ 6.44	$ 6.50
High Growth Low Price	AECo	2017-2018	$ 7.13	$ 7.16	$ 7.73	$ 7.76	$ 7.60	$ 7.01	$ 7.04	$ 7.05	$ 7.09	$ 7.09	$ 7.08	$ 7.11
High Growth Low Price	AECo	2018-2019	$ 7.76	$ 7.78	$ 7.69	$ 7.68	$ 7.53	$ 6.95	$ 6.96	$ 6.98	$ 6.99	$ 6.97	$ 6.99	$ 7.08
High Growth Low Price	AECo	2019-2020	$ 7.69	$ 7.73	$ 7.60	$ 7.63	$ 7.55	$ 6.87	$ 6.89	$ 6.92	$ 6.98	$ 6.96	$ 7.03	$ 7.12
High Growth Low Price	AECo	2020-2021	$ 7.74	$ 7.74	$ 7.80	$ 7.82	$ 7.54	$ 6.98	$ 6.98	$ 7.00	$ 7.03	$ 6.97	$ 6.98	$ 7.00
High Growth Low Price	AECo	2021-2022	$ 7.61	$ 7.65	$ 7.65	$ 7.67	$ 7.49	$ 6.94	$ 6.97	$ 7.00	$ 7.03	$ 7.04	$ 7.08	$ 7.12
High Growth Low Price	AECo	2022-2023	$ 7.73	$ 7.72	$ 7.75	$ 7.78	$ 7.64	$ 7.04	$ 7.08	$ 7.12	$ 7.16	$ 7.15	$ 7.20	$ 7.26
High Growth Low Price	AECo	2023-2024	$ 7.88	$ 7.90	$ 8.02	$ 8.00	$ 7.84	$ 7.24	$ 7.27	$ 7.32	$ 7.34	$ 7.35	$ 7.41	$ 7.47
High Growth Low Price	AECo	2024-2025	$ 8.07	$ 8.12	$ 8.20	$ 8.19	$ 7.98	$ 7.41	$ 7.44	$ 7.48	$ 7.51	$ 7.52	$ 7.56	$ 7.62
High Growth Low Price	AECo	2025-2026	$ 8.28	$ 8.23	$ 8.36	$ 8.35	$ 8.19	$ 7.59	$ 7.62	$ 7.66	$ 7.68	$ 7.68	$ 7.73	$ 7.79
High Growth Low Price	AECo	2026-2027	$ 8.36	$ 8.37	$ 8.52	$ 8.57	$ 8.41	$ 7.82	$ 7.84	$ 7.87	$ 7.88	$ 7.92	$ 7.92	$ 7.97
High Growth Low Price	AECo	2027-2028	$ 8.55	$ 8.56	$ 8.71	$ 8.76	$ 8.60	$ 8.01	$ 8.02	$ 8.06	$ 8.07	$ 8.11	$ 8.11	$ 8.16
High Growth Low Price	AECo	2028-2029	$ 8.74	$ 8.75	$ 8.91	$ 8.95	$ 8.79	$ 8.20	$ 8.22	$ 8.25	$ 8.26	$ 8.30	$ 8.31	$ 8.35
High Growth Low Price	AECo	2029-2030	$ 7.25	$ 7.61										
High Growth Low Price	Malin	2009-2010	$ 5.57	$ 5.93	$ 5.59	$ 5.64	$ 5.54	$ 4.86	$ 4.90	$ 4.98	$ 5.06	$ 5.16	$ 5.15	$ 5.21
High Growth Low Price	Malin	2010-2011	$ 5.96	$ 6.14	$ 6.05	$ 6.06	$ 5.93	$ 5.14	$ 5.14	$ 5.20	$ 5.27	$ 5.33	$ 5.36	$ 5.42
High Growth Low Price	Malin	2011-2012	$ 5.86	$ 5.99	$ 5.86	$ 5.88	$ 5.62	$ 4.97	$ 4.94	$ 5.01	$ 5.08	$ 5.14	$ 5.18	$ 5.23
High Growth Low Price	Malin	2012-2013	$ 5.80	$ 5.91	$ 6.18	$ 6.17	$ 5.89	$ 5.29	$ 5.30	$ 5.37	$ 5.40	$ 5.45	$ 5.47	$ 5.58
High Growth Low Price	Malin	2013-2014	$ 5.43	$ 5.45	$ 4.99	$ 5.02	$ 4.81	$ 4.38	$ 4.34	$ 4.46	$ 4.49	$ 4.52	$ 4.53	$ 4.58
High Growth Low Price	Malin	2014-2015	$ 5.85	$ 5.91	$ 6.70	$ 6.73	$ 6.50	$ 6.04	$ 6.06	$ 6.21	$ 6.29	$ 6.29	$ 6.31	$ 6.37
High Growth Low Price	Malin	2015-2016	$ 7.06	$ 7.15	$ 6.99	$ 7.42	$ 6.71	$ 6.27	$ 6.27	$ 6.45	$ 6.57	$ 6.56	$ 6.62	$ 6.72
High Growth Low Price	Malin	2016-2017	$ 7.41	$ 7.53	$ 6.93	$ 6.99	$ 6.73	$ 6.23	$ 6.31	$ 6.28	$ 6.41	$ 6.42	$ 6.46	$ 6.54
High Growth Low Price	Malin	2017-2018	$ 7.17	$ 7.17	$ 7.51	$ 7.55	$ 7.29	$ 6.90	$ 6.94	$ 6.94	$ 7.08	$ 7.09	$ 7.08	$ 7.13
High Growth Low Price	Malin	2018-2019	$ 7.83	$ 7.83	$ 7.88	$ 7.58	$ 7.41	$ 6.92	$ 6.93	$ 6.95	$ 6.96	$ 6.94	$ 6.97	$ 7.10
High Growth Low Price	Malin	2019-2020	$ 7.89	$ 7.92	$ 7.49	$ 7.52	$ 7.52	$ 6.80	$ 6.81	$ 6.86	$ 6.95	$ 6.92	$ 7.02	$ 7.15
High Growth Low Price	Malin	2020-2021	$ 7.95	$ 7.94	$ 8.01	$ 8.03	$ 7.71	$ 6.92	$ 6.89	$ 6.91	$ 6.94	$ 6.85	$ 6.91	$ 6.92
High Growth Low Price	Malin	2021-2022	$ 7.74	$ 7.82	$ 7.73	$ 7.76	$ 7.59	$ 6.79	$ 6.79	$ 6.81	$ 6.85	$ 6.87	$ 6.95	$ 7.02
High Growth Low Price	Malin	2022-2023	$ 7.88	$ 7.92	$ 7.82	$ 7.84	$ 7.73	$ 6.84	$ 6.87	$ 6.90	$ 6.96	$ 6.96	$ 7.10	$ 7.17
High Growth Low Price	Malin	2023-2024	$ 8.06	$ 8.14	$ 8.13	$ 8.10	$ 7.94	$ 7.04	$ 7.06	$ 7.12	$ 7.15	$ 7.16	$ 7.28	$ 7.42
High Growth Low Price	Malin	2024-2025	$ 8.35	$ 8.40	$ 8.33	$ 8.30	$ 8.07	$ 7.19	$ 7.21	$ 7.26	$ 7.28	$ 7.32	$ 7.44	$ 7.56
High Growth Low Price	Malin	2025-2026	$ 8.60	$ 8.49	$ 8.51	$ 8.48	$ 8.32	$ 7.35	$ 7.37	$ 7.42	$ 7.44	$ 7.45	$ 7.58	$ 7.73
High Growth Low Price	Malin	2026-2027	$ 8.65	$ 8.63	$ 8.67	$ 8.70	$ 8.58	$ 7.61	$ 7.63	$ 7.66	$ 7.67	$ 7.72	$ 7.81	$ 7.93
High Growth Low Price	Malin	2027-2028	$ 8.84	$ 8.82	$ 8.86	$ 8.89	$ 8.77	$ 7.80	$ 7.82	$ 7.85	$ 7.85	$ 7.91	$ 7.99	$ 8.12
High Growth Low Price	Malin	2028-2029	$ 9.03	$ 9.01	$ 9.06	$ 9.09	$ 8.97	$ 8.00	$ 8.01	$ 8.04	$ 8.05	$ 8.11	$ 8.19	$ 8.32
High Growth Low Price	Malin	2029-2030	$ 8.32	$ 8.32										
High Growth Low Price	Rockies	2009-2010	$ 4.21	$ 4.62	$ 4.32	$ 4.39	$ 4.19	$ 2.46	$ 2.51	$ 2.59	$ 2.68	$ 2.75	$ 2.75	$ 2.83
High Growth Low Price	Rockies	2010-2011	$ 4.80	$ 4.98	$ 4.91	$ 4.92	$ 4.67	$ 2.88	$ 2.89	$ 2.91	$ 2.96	$ 3.00	$ 3.03	$ 3.08
High Growth Low Price	Rockies	2011-2012	$ 5.77	$ 5.90	$ 5.77	$ 5.80	$ 5.55	$ 4.92	$ 4.91	$ 4.94	$ 5.00	$ 5.03	$ 5.03	$ 5.07
High Growth Low Price	Rockies	2012-2013	$ 5.57	$ 5.67	$ 6.03	$ 6.01	$ 5.72	$ 5.15	$ 5.15	$ 5.20	$ 5.22	$ 5.26	$ 5.27	$ 5.34
High Growth Low Price	Rockies	2013-2014	$ 5.04	$ 5.05	$ 4.81	$ 4.84	$ 4.57	$ 4.17	$ 4.15	$ 4.17	$ 4.16	$ 4.18	$ 4.18	$ 4.21
High Growth Low Price	Rockies	2014-2015	$ 5.45	$ 5.51	$ 6.55	$ 6.59	$ 6.31	$ 5.87	$ 5.91	$ 5.93	$ 5.97	$ 5.96	$ 5.97	$ 5.99
High Growth Low Price	Rockies	2015-2016	$ 6.60	$ 6.73	$ 6.81	$ 6.84	$ 6.55	$ 6.10	$ 6.15	$ 6.14	$ 6.18	$ 6.16	$ 6.18	$ 6.24
High Growth Low Price	Rockies	2016-2017	$ 6.79	$ 6.85	$ 6.79	$ 6.83	$ 6.56	$ 6.10	$ 6.17	$ 6.15	$ 6.16	$ 6.18	$ 6.19	$ 6.23
High Growth Low Price	Rockies	2017-2018	$ 6.79	$ 6.81	$ 7.38	$ 7.41	$ 7.17	$ 6.74	$ 6.79	$ 6.80	$ 6.83	$ 6.84	$ 6.82	$ 6.84
High Growth Low Price	Rockies	2018-2019	$ 7.41	$ 7.43	$ 7.34	$ 7.35	$ 7.15	$ 6.68	$ 6.68	$ 6.70	$ 6.69	$ 6.66	$ 6.70	$ 6.78
High Growth Low Price	Rockies	2019-2020	$ 7.30	$ 7.35	$ 7.24	$ 7.28	$ 7.18	$ 6.65	$ 6.69	$ 6.72	$ 6.75	$ 6.77	$ 6.82	$ 6.87
High Growth Low Price	Rockies	2020-2021	$ 7.43	$ 7.44	$ 7.51	$ 7.55	$ 7.34	$ 6.79	$ 6.83	$ 6.85	$ 6.87	$ 6.88	$ 6.90	$ 6.95
High Growth Low Price	Rockies	2021-2022	$ 7.49	$ 7.59	$ 7.65	$ 7.69	$ 7.45	$ 6.91	$ 6.95	$ 6.98	$ 7.02	$ 7.04	$ 7.07	$ 7.12
High Growth Low Price	Rockies	2022-2023	$ 7.74	$ 7.77	$ 7.84	$ 7.86	$ 7.72	$ 7.09	$ 7.12	$ 7.16	$ 7.20	$ 7.23	$ 7.28	$ 7.33
High Growth Low Price	Rockies	2023-2024	$ 7.98	$ 8.01	$ 8.11	$ 8.10	$ 7.92	$ 7.32	$ 7.35	$ 7.39	$ 7.42	$ 7.44	$ 7.48	$ 7.56
High Growth Low Price	Rockies	2024-2025	$ 8.16	$ 8.22	$ 8.30	$ 8.29	$ 8.06	$ 7.48	$ 7.52	$ 7.55	$ 7.59	$ 7.62	$ 7.66	$ 7.73
High Growth Low Price	Rockies	2025-2026	$ 8.38	$ 8.34	$ 8.47	$ 8.45	$ 8.26	$ 7.67	$ 7.70	$ 7.73	$ 7.76	$ 7.76	$ 7.79	$ 7.83
High Growth Low Price	Rockies	2026-2027	$ 8.47	$ 8.52	$ 8.63	$ 8.66	$ 8.47	$ 7.92	$ 7.95	$ 7.98	$ 7.99	$ 8.03	$ 8.06	$ 8.12
High Growth Low Price	Rockies	2027-2028	$ 8.66	$ 8.71	$ 8.82	$ 8.85	$ 8.66	$ 8.11	$ 8.14	$ 8.17	$ 8.18	$ 8.22	$ 8.25	$ 8.31
High Growth Low Price	Rockies	2028-2029	$ 8.85	$ 8.90	$ 9.02	$ 9.05	$ 8.86	$ 8.30	$ 8.34	$ 8.37	$ 8.38	$ 8.41	$ 8.44	$ 8.50
High Growth Low Price	Rockies	2029-2030	$ 6.78	$ 7.13										

Appendix 6.1 - Monthly Price Data by Basin

2009$

Scenario	Index	Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
High Growth Low Price	Stanfield	2009-2010	$ 5.51	$ 5.88	$ 5.54	$ 5.58	$ 5.49	$ 4.82	$ 4.86	$ 4.94	$ 5.02	$ 5.09	$ 5.10	$ 5.17
High Growth Low Price	Stanfield	2010-2011	$ 5.90	$ 6.08	$ 5.99	$ 6.00	$ 5.87	$ 5.09	$ 5.10	$ 5.16	$ 5.22	$ 5.27	$ 5.31	$ 5.37
High Growth Low Price	Stanfield	2011-2012	$ 5.80	$ 5.93	$ 5.80	$ 5.82	$ 5.68	$ 4.92	$ 4.90	$ 4.97	$ 5.03	$ 5.08	$ 5.13	$ 5.17
High Growth Low Price	Stanfield	2012-2013	$ 5.74	$ 5.85	$ 6.22	$ 6.20	$ 6.05	$ 5.25	$ 5.25	$ 5.33	$ 5.35	$ 5.39	$ 5.42	$ 5.53
High Growth Low Price	Stanfield	2013-2014	$ 5.37	$ 5.38	$ 5.15	$ 5.18	$ 5.05	$ 4.37	$ 4.30	$ 4.41	$ 4.44	$ 4.46	$ 4.48	$ 4.52
High Growth Low Price	Stanfield	2014-2015	$ 5.77	$ 5.84	$ 6.89	$ 6.93	$ 6.87	$ 6.11	$ 6.11	$ 6.15	$ 6.23	$ 6.23	$ 6.25	$ 6.30
High Growth Low Price	Stanfield	2015-2016	$ 7.01	$ 7.17	$ 7.27	$ 7.33	$ 7.25	$ 6.44	$ 6.42	$ 6.39	$ 6.51	$ 6.49	$ 6.55	$ 6.65
High Growth Low Price	Stanfield	2016-2017	$ 7.38	$ 7.44	$ 7.39	$ 7.42	$ 7.19	$ 6.35	$ 6.37	$ 6.33	$ 6.34	$ 6.35	$ 6.39	$ 6.46
High Growth Low Price	Stanfield	2017-2018	$ 7.23	$ 7.24	$ 7.82	$ 7.85	$ 7.71	$ 6.95	$ 6.96	$ 6.96	$ 7.01	$ 7.01	$ 7.00	$ 7.05
High Growth Low Price	Stanfield	2018-2019	$ 7.85	$ 7.87	$ 7.78	$ 7.77	$ 7.64	$ 6.88	$ 6.86	$ 6.88	$ 6.88	$ 6.85	$ 6.89	$ 7.01
High Growth Low Price	Stanfield	2019-2020	$ 7.78	$ 7.81	$ 7.69	$ 7.72	$ 7.67	$ 6.76	$ 6.76	$ 6.79	$ 6.87	$ 6.83	$ 6.93	$ 7.06
High Growth Low Price	Stanfield	2020-2021	$ 7.85	$ 7.84	$ 7.90	$ 7.92	$ 7.61	$ 6.84	$ 6.82	$ 6.83	$ 6.86	$ 6.76	$ 6.83	$ 6.83
High Growth Low Price	Stanfield	2021-2022	$ 7.64	$ 7.72	$ 7.63	$ 7.65	$ 7.49	$ 6.70	$ 6.71	$ 6.74	$ 6.77	$ 6.78	$ 6.86	$ 6.93
High Growth Low Price	Stanfield	2022-2023	$ 7.77	$ 7.79	$ 7.71	$ 7.73	$ 7.62	$ 6.76	$ 6.79	$ 6.82	$ 6.88	$ 6.87	$ 7.00	$ 7.07
High Growth Low Price	Stanfield	2023-2024	$ 7.95	$ 7.99	$ 8.02	$ 7.99	$ 7.83	$ 6.95	$ 6.98	$ 7.04	$ 7.06	$ 7.07	$ 7.19	$ 7.30
High Growth Low Price	Stanfield	2024-2025	$ 8.20	$ 8.25	$ 8.21	$ 8.19	$ 7.96	$ 7.09	$ 7.13	$ 7.18	$ 7.19	$ 7.23	$ 7.33	$ 7.43
High Growth Low Price	Stanfield	2025-2026	$ 8.44	$ 8.33	$ 8.39	$ 8.36	$ 8.20	$ 7.26	$ 7.29	$ 7.33	$ 7.34	$ 7.35	$ 7.47	$ 7.59
High Growth Low Price	Stanfield	2026-2027	$ 8.48	$ 8.46	$ 8.54	$ 8.58	$ 8.46	$ 7.51	$ 7.52	$ 7.55	$ 7.55	$ 7.60	$ 7.66	$ 7.76
High Growth Low Price	Stanfield	2027-2028	$ 8.67	$ 8.65	$ 8.73	$ 8.77	$ 8.65	$ 7.70	$ 7.70	$ 7.74	$ 7.74	$ 7.79	$ 7.85	$ 7.95
High Growth Low Price	Stanfield	2028-2029	$ 8.86	$ 8.84	$ 8.93	$ 8.97	$ 8.85	$ 7.90	$ 7.90	$ 7.94	$ 7.93	$ 7.98	$ 8.05	$ 8.15
High Growth Low Price	Stanfield	2029-2030	$ 8.15	$ 8.15										
High Growth Low Price	Sumas	2009-2010	$ 5.65	$ 6.01	$ 5.70	$ 5.75	$ 5.54	$ 4.88	$ 4.84	$ 4.89	$ 4.98	$ 5.06	$ 5.11	$ 5.22
High Growth Low Price	Sumas	2010-2011	$ 6.05	$ 6.23	$ 6.17	$ 6.18	$ 5.92	$ 5.13	$ 5.10	$ 5.14	$ 5.21	$ 5.26	$ 5.33	$ 5.44
High Growth Low Price	Sumas	2011-2012	$ 5.95	$ 6.08	$ 5.96	$ 5.98	$ 5.74	$ 5.01	$ 4.92	$ 4.96	$ 5.04	$ 5.09	$ 5.17	$ 5.26
High Growth Low Price	Sumas	2012-2013	$ 5.89	$ 6.00	$ 6.37	$ 6.36	$ 6.10	$ 5.33	$ 5.28	$ 5.33	$ 5.37	$ 5.42	$ 5.47	$ 5.60
High Growth Low Price	Sumas	2013-2014	$ 5.51	$ 5.53	$ 5.30	$ 5.33	$ 5.09	$ 4.46	$ 4.40	$ 4.43	$ 4.47	$ 4.50	$ 4.54	$ 4.61
High Growth Low Price	Sumas	2014-2015	$ 5.92	$ 5.98	$ 7.03	$ 7.06	$ 6.90	$ 6.21	$ 6.17	$ 6.19	$ 6.27	$ 6.28	$ 6.32	$ 6.40
High Growth Low Price	Sumas	2015-2016	$ 7.15	$ 7.29	$ 7.37	$ 7.41	$ 7.25	$ 6.54	$ 6.49	$ 6.46	$ 6.58	$ 6.57	$ 6.62	$ 6.75
High Growth Low Price	Sumas	2016-2017	$ 7.51	$ 7.57	$ 7.52	$ 7.55	$ 7.21	$ 6.51	$ 6.47	$ 6.45	$ 6.46	$ 6.48	$ 6.51	$ 6.62
High Growth Low Price	Sumas	2017-2018	$ 7.39	$ 7.41	$ 7.99	$ 8.02	$ 7.76	$ 7.13	$ 7.10	$ 7.10	$ 7.15	$ 7.16	$ 7.15	$ 7.24
High Growth Low Price	Sumas	2018-2019	$ 8.06	$ 8.05	$ 7.95	$ 7.95	$ 7.71	$ 7.08	$ 7.03	$ 7.04	$ 7.05	$ 7.04	$ 7.09	$ 7.22
High Growth Low Price	Sumas	2019-2020	$ 7.97	$ 8.00	$ 7.88	$ 7.91	$ 7.72	$ 7.00	$ 6.95	$ 6.97	$ 7.05	$ 7.03	$ 7.14	$ 7.26
High Growth Low Price	Sumas	2020-2021	$ 8.00	$ 8.01	$ 8.07	$ 8.10	$ 7.80	$ 7.10	$ 7.04	$ 7.06	$ 7.09	$ 7.03	$ 7.08	$ 7.21
High Growth Low Price	Sumas	2021-2022	$ 7.97	$ 8.02	$ 8.09	$ 8.12	$ 7.78	$ 7.07	$ 7.04	$ 7.07	$ 7.10	$ 7.11	$ 7.17	$ 7.36
High Growth Low Price	Sumas	2022-2023	$ 8.10	$ 8.10	$ 8.17	$ 8.20	$ 8.01	$ 7.32	$ 7.20	$ 7.22	$ 7.26	$ 7.24	$ 7.39	$ 7.56
High Growth Low Price	Sumas	2023-2024	$ 8.27	$ 8.29	$ 8.41	$ 8.40	$ 8.21	$ 7.51	$ 7.43	$ 7.46	$ 7.48	$ 7.50	$ 7.57	$ 7.77
High Growth Low Price	Sumas	2024-2025	$ 8.53	$ 8.58	$ 8.67	$ 8.66	$ 8.35	$ 7.68	$ 7.59	$ 7.62	$ 7.65	$ 7.68	$ 7.75	$ 7.92
High Growth Low Price	Sumas	2025-2026	$ 8.77	$ 8.71	$ 8.84	$ 8.83	$ 8.56	$ 7.88	$ 7.76	$ 7.80	$ 7.82	$ 7.83	$ 7.92	$ 8.09
High Growth Low Price	Sumas	2026-2027	$ 8.86	$ 8.86	$ 8.97	$ 9.00	$ 8.79	$ 8.11	$ 8.03	$ 8.05	$ 8.05	$ 8.10	$ 8.14	$ 8.29
High Growth Low Price	Sumas	2027-2028	$ 9.05	$ 9.05	$ 9.16	$ 9.19	$ 8.98	$ 8.30	$ 8.22	$ 8.23	$ 8.24	$ 8.29	$ 8.33	$ 8.48
High Growth Low Price	Sumas	2028-2029	$ 9.23	$ 9.24	$ 9.36	$ 9.39	$ 9.17	$ 8.50	$ 8.42	$ 8.43	$ 8.44	$ 8.48	$ 8.53	$ 8.68
High Growth Low Price	Sumas	2029-2030	$ 7.38	$ 7.76										

Appendix 6.1 - Monthly Price Data by Basin

2009$

Scenario	Index	Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
Low Growth High Price	AECo	2009-2010	$ 6.92	$ 7.30	$ 7.66	$ 7.71	$ 7.51	$ 6.87	$ 6.94	$ 7.03	$ 7.14	$ 7.22	$ 7.21	$ 7.26
Low Growth High Price	AECo	2010-2011	$ 8.45	$ 8.66	$ 8.71	$ 8.74	$ 8.47	$ 7.73	$ 7.78	$ 7.86	$ 7.95	$ 8.02	$ 8.02	$ 8.07
Low Growth High Price	AECo	2011-2012	$ 9.02	$ 9.19	$ 10.19	$ 10.24	$ 9.91	$ 9.21	$ 9.24	$ 9.33	$ 9.44	$ 9.51	$ 9.50	$ 9.53
Low Growth High Price	AECo	2012-2013	$ 10.64	$ 10.80	$ 11.31	$ 11.32	$ 10.95	$ 10.23	$ 10.29	$ 10.39	$ 10.47	$ 10.53	$ 10.50	$ 10.59
Low Growth High Price	AECo	2013-2014	$ 11.00	$ 11.07	$ 10.99	$ 11.06	$ 10.67	$ 10.08	$ 10.13	$ 10.22	$ 10.31	$ 10.37	$ 10.31	$ 10.34
Low Growth High Price	AECo	2014-2015	$ 12.19	$ 12.32	$ 13.54	$ 13.61	$ 13.24	$ 12.60	$ 12.68	$ 12.76	$ 12.90	$ 12.94	$ 12.88	$ 12.91
Low Growth High Price	AECo	2015-2016	$ 13.68	$ 13.90	$ 14.17	$ 14.27	$ 13.86	$ 13.19	$ 13.26	$ 13.29	$ 13.46	$ 13.49	$ 13.46	$ 13.52
Low Growth High Price	AECo	2016-2017	$ 14.31	$ 14.45	$ 14.55	$ 14.62	$ 14.08	$ 13.41	$ 13.52	$ 13.55	$ 13.63	$ 13.67	$ 13.62	$ 13.66
Low Growth High Price	AECo	2017-2018	$ 14.47	$ 14.57	$ 15.29	$ 15.36	$ 14.87	$ 14.28	$ 14.39	$ 14.45	$ 14.57	$ 14.62	$ 14.52	$ 14.53
Low Growth High Price	AECo	2018-2019	$ 15.37	$ 15.47	$ 15.51	$ 15.56	$ 15.06	$ 14.49	$ 14.57	$ 14.64	$ 14.73	$ 14.76	$ 14.70	$ 14.77
Low Growth High Price	AECo	2019-2020	$ 15.57	$ 15.69	$ 15.71	$ 15.79	$ 15.35	$ 14.67	$ 14.77	$ 14.86	$ 15.01	$ 15.03	$ 15.02	$ 15.09
Low Growth High Price	AECo	2020-2021	$ 15.90	$ 15.99	$ 16.00	$ 16.07	$ 15.42	$ 14.87	$ 14.95	$ 15.03	$ 15.15	$ 15.13	$ 15.06	$ 15.06
Low Growth High Price	AECo	2021-2022	$ 15.87	$ 16.00	$ 15.94	$ 16.02	$ 15.47	$ 14.92	$ 15.03	$ 15.12	$ 15.24	$ 15.30	$ 15.24	$ 15.26
Low Growth High Price	AECo	2022-2023	$ 16.07	$ 16.16	$ 16.15	$ 16.22	$ 15.71	$ 15.12	$ 15.24	$ 15.34	$ 15.47	$ 15.51	$ 15.47	$ 15.50
Low Growth High Price	AECo	2023-2024	$ 16.33	$ 16.44	$ 16.51	$ 16.55	$ 16.01	$ 15.42	$ 15.53	$ 15.64	$ 15.75	$ 15.81	$ 15.78	$ 15.82
Low Growth High Price	AECo	2024-2025	$ 16.63	$ 16.77	$ 16.81	$ 16.85	$ 16.26	$ 15.69	$ 15.80	$ 15.91	$ 16.03	$ 16.09	$ 16.04	$ 16.08
Low Growth High Price	AECo	2025-2026	$ 16.95	$ 16.99	$ 17.41	$ 17.45	$ 16.88	$ 16.29	$ 16.40	$ 16.51	$ 16.63	$ 16.68	$ 16.63	$ 16.67
Low Growth High Price	AECo	2026-2027	$ 17.47	$ 17.57	$ 18.00	$ 18.10	$ 17.51	$ 16.93	$ 17.04	$ 17.14	$ 17.25	$ 17.35	$ 17.25	$ 17.28
Low Growth High Price	AECo	2027-2028	$ 18.09	$ 18.20	$ 18.65	$ 18.76	$ 18.15	$ 17.56	$ 17.68	$ 17.78	$ 17.90	$ 18.00	$ 17.90	$ 17.92
Low Growth High Price	AECo	2028-2029	$ 18.75	$ 18.87	$ 19.34	$ 19.44	$ 18.81	$ 18.22	$ 18.35	$ 18.46	$ 18.58	$ 18.68	$ 18.57	$ 18.59
Low Growth High Price	AECo	2029-2030	$ 18.59	$ 18.59										
Low Growth High Price	Malin	2009-2010	$ 7.04	$ 7.42	$ 7.76	$ 7.82	$ 7.61	$ 6.94	$ 7.00	$ 7.10	$ 7.20	$ 7.31	$ 7.28	$ 7.34
Low Growth High Price	Malin	2010-2011	$ 8.58	$ 8.79	$ 8.83	$ 8.86	$ 8.58	$ 7.79	$ 7.83	$ 7.91	$ 8.01	$ 8.09	$ 8.09	$ 8.14
Low Growth High Price	Malin	2011-2012	$ 9.13	$ 9.29	$ 10.29	$ 10.34	$ 9.90	$ 9.25	$ 9.27	$ 9.37	$ 9.48	$ 9.55	$ 9.55	$ 9.59
Low Growth High Price	Malin	2012-2013	$ 10.76	$ 10.92	$ 11.32	$ 11.34	$ 10.85	$ 10.25	$ 10.31	$ 10.41	$ 10.49	$ 10.57	$ 10.54	$ 10.64
Low Growth High Price	Malin	2013-2014	$ 11.13	$ 11.20	$ 10.89	$ 10.96	$ 10.50	$ 10.07	$ 10.09	$ 10.24	$ 10.33	$ 10.39	$ 10.35	$ 10.39
Low Growth High Price	Malin	2014-2015	$ 12.33	$ 12.46	$ 13.41	$ 13.49	$ 12.97	$ 12.52	$ 12.59	$ 12.79	$ 12.94	$ 12.98	$ 12.93	$ 12.97
Low Growth High Price	Malin	2015-2016	$ 13.83	$ 13.98	$ 14.00	$ 14.47	$ 13.46	$ 13.02	$ 13.08	$ 13.31	$ 13.51	$ 13.53	$ 13.52	$ 13.61
Low Growth High Price	Malin	2016-2017	$ 14.47	$ 14.66	$ 14.22	$ 14.32	$ 13.74	$ 13.25	$ 13.40	$ 13.41	$ 13.62	$ 13.68	$ 13.64	$ 13.70
Low Growth High Price	Malin	2017-2018	$ 14.50	$ 14.58	$ 15.07	$ 15.15	$ 14.56	$ 14.18	$ 14.29	$ 14.34	$ 14.56	$ 14.61	$ 14.52	$ 14.56
Low Growth High Price	Malin	2018-2019	$ 15.44	$ 15.51	$ 15.71	$ 15.45	$ 14.94	$ 14.46	$ 14.55	$ 14.62	$ 14.70	$ 14.73	$ 14.68	$ 14.79
Low Growth High Price	Malin	2019-2020	$ 15.77	$ 15.88	$ 15.60	$ 15.67	$ 15.31	$ 14.60	$ 14.70	$ 14.80	$ 14.97	$ 14.99	$ 15.00	$ 15.12
Low Growth High Price	Malin	2020-2021	$ 16.12	$ 16.20	$ 16.21	$ 16.28	$ 15.60	$ 14.82	$ 14.86	$ 14.94	$ 15.05	$ 15.01	$ 14.99	$ 14.98
Low Growth High Price	Malin	2021-2022	$ 16.00	$ 16.17	$ 16.03	$ 16.10	$ 15.56	$ 14.77	$ 14.85	$ 14.93	$ 15.06	$ 15.12	$ 15.11	$ 15.17
Low Growth High Price	Malin	2022-2023	$ 16.23	$ 16.36	$ 16.21	$ 16.29	$ 15.80	$ 14.92	$ 15.03	$ 15.12	$ 15.27	$ 15.31	$ 15.37	$ 15.41
Low Growth High Price	Malin	2023-2024	$ 16.52	$ 16.68	$ 16.63	$ 16.65	$ 16.11	$ 15.22	$ 15.32	$ 15.44	$ 15.55	$ 15.62	$ 15.65	$ 15.77
Low Growth High Price	Malin	2024-2025	$ 16.90	$ 17.04	$ 16.94	$ 16.97	$ 16.35	$ 15.47	$ 15.58	$ 15.69	$ 15.80	$ 15.89	$ 15.92	$ 16.02
Low Growth High Price	Malin	2025-2026	$ 17.27	$ 17.25	$ 17.55	$ 17.57	$ 17.01	$ 16.05	$ 16.16	$ 16.27	$ 16.38	$ 16.45	$ 16.48	$ 16.61
Low Growth High Price	Malin	2026-2027	$ 17.75	$ 17.83	$ 18.15	$ 18.24	$ 17.69	$ 16.72	$ 16.83	$ 16.93	$ 17.04	$ 17.15	$ 17.13	$ 17.24
Low Growth High Price	Malin	2027-2028	$ 18.38	$ 18.46	$ 18.80	$ 18.89	$ 18.32	$ 17.36	$ 17.47	$ 17.57	$ 17.69	$ 17.80	$ 17.78	$ 17.88
Low Growth High Price	Malin	2028-2029	$ 19.04	$ 19.13	$ 19.48	$ 19.58	$ 18.98	$ 18.02	$ 18.14	$ 18.25	$ 18.36	$ 18.48	$ 18.45	$ 18.56
Low Growth High Price	Malin	2029-2030	$ 18.56	$ 18.56										
Low Growth High Price	Rockies	2009-2010	$ 5.69	$ 6.11	$ 6.49	$ 6.58	$ 6.27	$ 4.53	$ 4.61	$ 4.71	$ 4.82	$ 4.91	$ 4.88	$ 4.95
Low Growth High Price	Rockies	2010-2011	$ 7.42	$ 7.63	$ 7.69	$ 7.71	$ 7.32	$ 5.54	$ 5.57	$ 5.62	$ 5.70	$ 5.76	$ 5.75	$ 5.80
Low Growth High Price	Rockies	2011-2012	$ 9.03	$ 9.20	$ 10.21	$ 10.26	$ 9.84	$ 9.20	$ 9.24	$ 9.29	$ 9.39	$ 9.44	$ 9.40	$ 9.43
Low Growth High Price	Rockies	2012-2013	$ 10.52	$ 10.67	$ 11.17	$ 11.18	$ 10.68	$ 10.11	$ 10.16	$ 10.24	$ 10.32	$ 10.37	$ 10.34	$ 10.40
Low Growth High Price	Rockies	2013-2014	$ 10.74	$ 10.81	$ 10.72	$ 10.78	$ 10.26	$ 9.86	$ 9.89	$ 9.95	$ 10.01	$ 10.05	$ 10.00	$ 10.02
Low Growth High Price	Rockies	2014-2015	$ 11.94	$ 12.07	$ 13.27	$ 13.35	$ 12.78	$ 12.34	$ 12.45	$ 12.52	$ 12.62	$ 12.65	$ 12.59	$ 12.59
Low Growth High Price	Rockies	2015-2016	$ 13.36	$ 13.56	$ 13.82	$ 13.89	$ 13.29	$ 12.85	$ 12.96	$ 13.00	$ 13.12	$ 13.14	$ 13.08	$ 13.13
Low Growth High Price	Rockies	2016-2017	$ 13.85	$ 13.98	$ 14.08	$ 14.16	$ 13.57	$ 13.11	$ 13.26	$ 13.29	$ 13.37	$ 13.43	$ 13.37	$ 13.39
Low Growth High Price	Rockies	2017-2018	$ 14.12	$ 14.22	$ 14.94	$ 15.01	$ 14.44	$ 14.02	$ 14.14	$ 14.20	$ 14.31	$ 14.36	$ 14.26	$ 14.27
Low Growth High Price	Rockies	2018-2019	$ 15.02	$ 15.12	$ 15.17	$ 15.22	$ 14.68	$ 14.21	$ 14.29	$ 14.36	$ 14.44	$ 14.45	$ 14.41	$ 14.47
Low Growth High Price	Rockies	2019-2020	$ 15.18	$ 15.31	$ 15.35	$ 15.44	$ 14.98	$ 14.46	$ 14.57	$ 14.66	$ 14.78	$ 14.85	$ 14.80	$ 14.83
Low Growth High Price	Rockies	2020-2021	$ 15.60	$ 15.69	$ 15.71	$ 15.80	$ 15.23	$ 14.68	$ 14.80	$ 14.88	$ 14.99	$ 15.04	$ 14.97	$ 15.00
Low Growth High Price	Rockies	2021-2022	$ 15.75	$ 15.93	$ 15.95	$ 16.04	$ 15.42	$ 14.89	$ 15.01	$ 15.09	$ 15.23	$ 15.30	$ 15.23	$ 15.27
Low Growth High Price	Rockies	2022-2023	$ 16.08	$ 16.21	$ 16.24	$ 16.31	$ 15.79	$ 15.17	$ 15.28	$ 15.38	$ 15.51	$ 15.58	$ 15.54	$ 15.58
Low Growth High Price	Rockies	2023-2024	$ 16.43	$ 16.55	$ 16.61	$ 16.65	$ 16.09	$ 15.49	$ 15.61	$ 15.71	$ 15.83	$ 15.89	$ 15.85	$ 15.91
Low Growth High Price	Rockies	2024-2025	$ 16.72	$ 16.87	$ 16.91	$ 16.95	$ 16.34	$ 15.77	$ 15.89	$ 15.98	$ 16.10	$ 16.19	$ 16.14	$ 16.19
Low Growth High Price	Rockies	2025-2026	$ 17.05	$ 17.10	$ 17.51	$ 17.55	$ 16.95	$ 16.37	$ 16.48	$ 16.58	$ 16.70	$ 16.76	$ 16.69	$ 16.72
Low Growth High Price	Rockies	2026-2027	$ 17.58	$ 17.72	$ 18.11	$ 18.19	$ 17.58	$ 17.03	$ 17.16	$ 17.26	$ 17.36	$ 17.46	$ 17.38	$ 17.43
Low Growth High Price	Rockies	2027-2028	$ 18.20	$ 18.36	$ 18.76	$ 18.85	$ 18.21	$ 17.66	$ 17.80	$ 17.90	$ 18.01	$ 18.11	$ 18.03	$ 18.07
Low Growth High Price	Rockies	2028-2029	$ 18.86	$ 19.02	$ 19.44	$ 19.54	$ 18.87	$ 18.32	$ 18.47	$ 18.57	$ 18.69	$ 18.79	$ 18.70	$ 18.74
Low Growth High Price	Rockies	2029-2030	$ 18.74	$ 18.74										

Appendix 6.1 - Monthly Price Data by Basin

2009$

Scenario	Index	Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
Low Growth High Price	Stanfield	2009-2010	$ 6.99	$ 7.37	$ 7.71	$ 7.77	$ 7.56	$ 6.89	$ 6.96	$ 7.06	$ 7.16	$ 7.25	$ 7.23	$ 7.29
Low Growth High Price	Stanfield	2010-2011	$ 8.52	$ 8.73	$ 8.77	$ 8.80	$ 8.52	$ 7.75	$ 7.78	$ 7.87	$ 7.96	$ 8.03	$ 8.04	$ 8.09
Low Growth High Price	Stanfield	2011-2012	$ 9.06	$ 9.23	$ 10.23	$ 10.28	$ 9.96	$ 9.20	$ 9.22	$ 9.32	$ 9.43	$ 9.50	$ 9.50	$ 9.54
Low Growth High Price	Stanfield	2012-2013	$ 10.69	$ 10.85	$ 11.36	$ 11.37	$ 11.01	$ 10.21	$ 10.26	$ 10.37	$ 10.44	$ 10.51	$ 10.49	$ 10.59
Low Growth High Price	Stanfield	2013-2014	$ 11.06	$ 11.13	$ 11.05	$ 11.12	$ 10.73	$ 10.06	$ 10.05	$ 10.19	$ 10.28	$ 10.34	$ 10.29	$ 10.33
Low Growth High Price	Stanfield	2014-2015	$ 12.26	$ 12.39	$ 13.61	$ 13.69	$ 13.34	$ 12.58	$ 12.65	$ 12.74	$ 12.88	$ 12.92	$ 12.87	$ 12.90
Low Growth High Price	Stanfield	2015-2016	$ 13.77	$ 14.00	$ 14.28	$ 14.38	$ 14.00	$ 13.19	$ 13.23	$ 13.25	$ 13.44	$ 13.46	$ 13.45	$ 13.53
Low Growth High Price	Stanfield	2016-2017	$ 14.44	$ 14.57	$ 14.68	$ 14.75	$ 14.20	$ 13.37	$ 13.46	$ 13.47	$ 13.55	$ 13.60	$ 13.56	$ 13.63
Low Growth High Price	Stanfield	2017-2018	$ 14.56	$ 14.66	$ 15.38	$ 15.45	$ 14.98	$ 14.22	$ 14.31	$ 14.37	$ 14.49	$ 14.54	$ 14.45	$ 14.48
Low Growth High Price	Stanfield	2018-2019	$ 15.46	$ 15.56	$ 15.61	$ 15.64	$ 15.17	$ 14.41	$ 14.47	$ 14.54	$ 14.62	$ 14.64	$ 14.60	$ 14.70
Low Growth High Price	Stanfield	2019-2020	$ 15.66	$ 15.78	$ 15.80	$ 15.88	$ 15.47	$ 14.56	$ 14.64	$ 14.73	$ 14.89	$ 14.90	$ 14.92	$ 15.03
Low Growth High Price	Stanfield	2020-2021	$ 16.01	$ 16.09	$ 16.11	$ 16.17	$ 15.49	$ 14.73	$ 14.79	$ 14.86	$ 14.97	$ 14.93	$ 14.91	$ 14.89
Low Growth High Price	Stanfield	2021-2022	$ 15.90	$ 16.06	$ 15.92	$ 16.00	$ 15.46	$ 14.68	$ 14.77	$ 14.86	$ 14.98	$ 15.03	$ 15.03	$ 15.08
Low Growth High Price	Stanfield	2022-2023	$ 16.12	$ 16.23	$ 16.10	$ 16.18	$ 15.69	$ 14.83	$ 14.95	$ 15.04	$ 15.19	$ 15.23	$ 15.26	$ 15.32
Low Growth High Price	Stanfield	2023-2024	$ 16.40	$ 16.54	$ 16.51	$ 16.54	$ 16.00	$ 15.13	$ 15.24	$ 15.35	$ 15.47	$ 15.53	$ 15.56	$ 15.65
Low Growth High Price	Stanfield	2024-2025	$ 16.75	$ 16.90	$ 16.83	$ 16.85	$ 16.23	$ 15.38	$ 15.49	$ 15.61	$ 15.71	$ 15.80	$ 15.81	$ 15.89
Low Growth High Price	Stanfield	2025-2026	$ 17.11	$ 17.09	$ 17.43	$ 17.45	$ 16.89	$ 15.95	$ 16.07	$ 16.18	$ 16.29	$ 16.35	$ 16.37	$ 16.47
Low Growth High Price	Stanfield	2026-2027	$ 17.59	$ 17.66	$ 18.02	$ 18.11	$ 17.57	$ 16.62	$ 16.72	$ 16.82	$ 16.92	$ 17.03	$ 16.99	$ 17.07
Low Growth High Price	Stanfield	2027-2028	$ 18.21	$ 18.29	$ 18.67	$ 18.77	$ 18.20	$ 17.26	$ 17.36	$ 17.46	$ 17.57	$ 17.68	$ 17.63	$ 17.72
Low Growth High Price	Stanfield	2028-2029	$ 18.87	$ 18.96	$ 19.36	$ 19.46	$ 18.86	$ 17.92	$ 18.03	$ 18.14	$ 18.24	$ 18.36	$ 18.31	$ 18.39
Low Growth High Price	Stanfield	2029-2030	$ 18.39	$ 18.39										
Low Growth High Price	Sumas	2009-2010	$ 7.12	$ 7.51	$ 7.87	$ 7.93	$ 7.62	$ 6.95	$ 6.94	$ 7.01	$ 7.12	$ 7.21	$ 7.24	$ 7.34
Low Growth High Price	Sumas	2010-2011	$ 8.67	$ 8.89	$ 8.95	$ 8.97	$ 8.58	$ 7.79	$ 7.78	$ 7.85	$ 7.95	$ 8.02	$ 8.06	$ 8.16
Low Growth High Price	Sumas	2011-2012	$ 9.21	$ 9.39	$ 10.39	$ 10.44	$ 10.02	$ 9.30	$ 9.25	$ 9.31	$ 9.43	$ 9.51	$ 9.54	$ 9.63
Low Growth High Price	Sumas	2012-2013	$ 10.84	$ 11.00	$ 11.51	$ 11.53	$ 11.06	$ 10.29	$ 10.29	$ 10.37	$ 10.46	$ 10.54	$ 10.54	$ 10.66
Low Growth High Price	Sumas	2013-2014	$ 11.21	$ 11.28	$ 11.20	$ 11.27	$ 10.78	$ 10.15	$ 10.15	$ 10.21	$ 10.32	$ 10.37	$ 10.36	$ 10.42
Low Growth High Price	Sumas	2014-2015	$ 12.41	$ 12.54	$ 13.75	$ 13.82	$ 13.37	$ 12.69	$ 12.71	$ 12.77	$ 12.92	$ 12.96	$ 12.94	$ 13.00
Low Growth High Price	Sumas	2015-2016	$ 13.91	$ 14.12	$ 14.38	$ 14.45	$ 14.00	$ 13.29	$ 13.31	$ 13.32	$ 13.52	$ 13.54	$ 13.53	$ 13.64
Low Growth High Price	Sumas	2016-2017	$ 14.56	$ 14.70	$ 14.80	$ 14.88	$ 14.22	$ 13.52	$ 13.56	$ 13.59	$ 13.67	$ 13.73	$ 13.69	$ 13.78
Low Growth High Price	Sumas	2017-2018	$ 14.73	$ 14.83	$ 15.55	$ 15.62	$ 15.03	$ 14.40	$ 14.45	$ 14.50	$ 14.62	$ 14.68	$ 14.60	$ 14.67
Low Growth High Price	Sumas	2018-2019	$ 15.67	$ 15.74	$ 15.78	$ 15.83	$ 15.24	$ 14.62	$ 14.64	$ 14.71	$ 14.79	$ 14.83	$ 14.80	$ 14.91
Low Growth High Price	Sumas	2019-2020	$ 15.85	$ 15.96	$ 15.99	$ 16.07	$ 15.52	$ 14.80	$ 14.83	$ 14.91	$ 15.07	$ 15.10	$ 15.12	$ 15.23
Low Growth High Price	Sumas	2020-2021	$ 16.16	$ 16.26	$ 16.27	$ 16.35	$ 15.68	$ 15.00	$ 15.01	$ 15.09	$ 15.21	$ 15.19	$ 15.15	$ 15.26
Low Growth High Price	Sumas	2021-2022	$ 16.23	$ 16.36	$ 16.38	$ 16.46	$ 15.76	$ 15.05	$ 15.10	$ 15.19	$ 15.31	$ 15.36	$ 15.34	$ 15.51
Low Growth High Price	Sumas	2022-2023	$ 16.45	$ 16.54	$ 16.57	$ 16.64	$ 16.08	$ 15.39	$ 15.36	$ 15.44	$ 15.57	$ 15.60	$ 15.65	$ 15.80
Low Growth High Price	Sumas	2023-2024	$ 16.72	$ 16.84	$ 16.91	$ 16.95	$ 16.38	$ 15.69	$ 15.69	$ 15.78	$ 15.89	$ 15.95	$ 15.93	$ 16.12
Low Growth High Price	Sumas	2024-2025	$ 17.08	$ 17.23	$ 17.28	$ 17.32	$ 16.63	$ 15.97	$ 15.96	$ 16.05	$ 16.16	$ 16.25	$ 16.23	$ 16.38
Low Growth High Price	Sumas	2025-2026	$ 17.44	$ 17.47	$ 17.88	$ 17.93	$ 17.25	$ 16.58	$ 16.55	$ 16.65	$ 16.77	$ 16.83	$ 16.82	$ 16.98
Low Growth High Price	Sumas	2026-2027	$ 17.96	$ 18.06	$ 18.45	$ 18.53	$ 17.89	$ 17.23	$ 17.24	$ 17.32	$ 17.43	$ 17.53	$ 17.47	$ 17.60
Low Growth High Price	Sumas	2027-2028	$ 18.59	$ 18.69	$ 19.10	$ 19.19	$ 18.52	$ 17.86	$ 17.88	$ 17.96	$ 18.07	$ 18.18	$ 18.12	$ 18.24
Low Growth High Price	Sumas	2028-2029	$ 19.24	$ 19.36	$ 19.78	$ 19.88	$ 19.19	$ 18.52	$ 18.55	$ 18.63	$ 18.75	$ 18.86	$ 18.79	$ 18.92
Low Growth High Price	Sumas	2029-2030	$ 18.92	$ 18.92										

Appendix 6.1 - Monthly Price Data by Basin

2009$

Scenario	Index	Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
Green Future	AECo	2009-2010	$ 4.33	$ 4.85	$ 4.97	$ 5.05	$ 4.99	$ 4.75	$ 4.65	$ 4.78	$ 4.80	$ 4.89	$ 4.90	$ 5.09
Green Future	AECo	2010-2011	$ 5.39	$ 5.62	$ 5.56	$ 5.58	$ 5.29	$ 5.03	$ 5.00	$ 5.06	$ 5.06	$ 5.10	$ 5.13	$ 5.27
Green Future	AECo	2011-2012	$ 5.46	$ 5.63	$ 6.03	$ 6.03	$ 5.72	$ 5.47	$ 5.47	$ 5.52	$ 5.52	$ 5.54	$ 5.52	$ 5.67
Green Future	AECo	2012-2013	$ 5.85	$ 5.96	$ 6.50	$ 6.55	$ 6.06	$ 5.80	$ 5.80	$ 5.84	$ 5.86	$ 5.89	$ 5.87	$ 5.96
Green Future	AECo	2013-2014	$ 5.41	$ 5.49	$ 5.55	$ 5.57	$ 5.36	$ 5.24	$ 5.31	$ 5.34	$ 5.36	$ 5.37	$ 5.33	$ 5.46
Green Future	AECo	2014-2015	$ 6.40	$ 6.52	$ 9.46	$ 9.53	$ 9.26	$ 9.09	$ 9.14	$ 9.19	$ 9.23	$ 9.26	$ 9.21	$ 9.36
Green Future	AECo	2015-2016	$ 9.76	$ 9.90	$ 10.13	$ 10.16	$ 9.98	$ 9.87	$ 9.94	$ 10.01	$ 10.01	$ 10.03	$ 10.02	$ 10.11
Green Future	AECo	2016-2017	$ 10.51	$ 10.61	$ 11.05	$ 11.03	$ 10.67	$ 10.56	$ 10.58	$ 10.61	$ 10.65	$ 10.68	$ 10.65	$ 10.79
Green Future	AECo	2017-2018	$ 11.27	$ 11.34	$ 11.83	$ 11.85	$ 11.52	$ 11.32	$ 11.28	$ 11.35	$ 11.34	$ 11.41	$ 11.38	$ 11.57
Green Future	AECo	2018-2019	$ 12.12	$ 12.20	$ 12.47	$ 12.46	$ 12.21	$ 11.95	$ 11.95	$ 11.99	$ 12.03	$ 12.07	$ 12.02	$ 12.19
Green Future	AECo	2019-2020	$ 12.55	$ 12.70	$ 13.02	$ 13.05	$ 12.52	$ 12.38	$ 12.36	$ 12.39	$ 12.41	$ 12.45	$ 12.15	$ 12.22
Green Future	AECo	2020-2021	$ 12.59	$ 12.72	$ 13.06	$ 13.11	$ 12.90	$ 12.58	$ 12.59	$ 12.61	$ 12.63	$ 12.65	$ 12.47	$ 12.53
Green Future	AECo	2021-2022	$ 12.89	$ 12.96	$ 13.32	$ 13.35	$ 13.08	$ 12.78	$ 12.79	$ 12.84	$ 12.79	$ 12.84	$ 12.85	$ 12.95
Green Future	AECo	2022-2023	$ 13.30	$ 13.43	$ 13.82	$ 13.86	$ 13.51	$ 13.26	$ 13.23	$ 13.24	$ 13.26	$ 13.17	$ 13.11	$ 13.24
Green Future	AECo	2023-2024	$ 13.49	$ 13.56	$ 13.81	$ 13.77	$ 13.36	$ 13.23	$ 13.24	$ 13.27	$ 13.25	$ 13.30	$ 13.32	$ 13.33
Green Future	AECo	2024-2025	$ 13.61	$ 13.73	$ 14.18	$ 14.26	$ 13.85	$ 13.65	$ 13.65	$ 13.67	$ 13.65	$ 13.69	$ 13.70	$ 13.71
Green Future	AECo	2025-2026	$ 14.01	$ 14.16	$ 14.61	$ 14.60	$ 14.31	$ 14.11	$ 14.12	$ 14.13	$ 14.13	$ 14.17	$ 14.17	$ 14.21
Green Future	AECo	2026-2027	$ 14.53	$ 14.67	$ 15.18	$ 15.16	$ 14.79	$ 14.63	$ 14.68	$ 14.66	$ 14.72	$ 14.76	$ 14.79	$ 14.93
Green Future	AECo	2027-2028	$ 15.00	$ 15.11	$ 15.66	$ 15.69	$ 15.29	$ 15.15	$ 15.18	$ 15.18	$ 15.23	$ 15.28	$ 15.33	$ 15.45
Green Future	AECo	2028-2029	$ 15.54	$ 15.63	$ 16.21	$ 16.25	$ 15.87	$ 15.69	$ 15.72	$ 15.74	$ 15.76	$ 15.79	$ 15.82	$ 15.98
Green Future	AECo	2029-2030	$ 15.98	$ 15.98										
Green Future	Malin	2009-2010	$ 4.67	$ 5.19	$ 5.32	$ 5.40	$ 5.26	$ 5.03	$ 4.91	$ 5.08	$ 5.13	$ 5.24	$ 5.24	$ 5.41
Green Future	Malin	2010-2011	$ 5.74	$ 5.95	$ 5.88	$ 5.90	$ 5.57	$ 5.31	$ 5.29	$ 5.35	$ 5.36	$ 5.41	$ 5.44	$ 5.57
Green Future	Malin	2011-2012	$ 5.74	$ 5.92	$ 6.30	$ 6.30	$ 5.95	$ 5.71	$ 5.70	$ 5.76	$ 5.78	$ 5.81	$ 5.79	$ 5.93
Green Future	Malin	2012-2013	$ 6.10	$ 6.22	$ 6.75	$ 6.80	$ 6.25	$ 6.01	$ 6.02	$ 6.05	$ 6.11	$ 6.16	$ 6.13	$ 6.21
Green Future	Malin	2013-2014	$ 5.66	$ 5.75	$ 5.78	$ 5.81	$ 5.52	$ 5.44	$ 5.52	$ 5.54	$ 5.58	$ 5.61	$ 5.57	$ 5.70
Green Future	Malin	2014-2015	$ 6.63	$ 6.75	$ 9.68	$ 9.75	$ 9.41	$ 9.27	$ 9.33	$ 9.37	$ 9.45	$ 9.49	$ 9.43	$ 9.58
Green Future	Malin	2015-2016	$ 9.96	$ 10.11	$ 10.33	$ 10.36	$ 10.11	$ 10.04	$ 10.12	$ 10.19	$ 10.23	$ 10.25	$ 10.25	$ 10.32
Green Future	Malin	2016-2017	$ 10.73	$ 10.83	$ 11.26	$ 11.24	$ 10.82	$ 10.75	$ 10.78	$ 10.81	$ 10.87	$ 10.92	$ 10.89	$ 11.02
Green Future	Malin	2017-2018	$ 11.48	$ 11.55	$ 12.03	$ 12.07	$ 11.66	$ 11.50	$ 11.48	$ 11.54	$ 11.58	$ 11.65	$ 11.63	$ 11.81
Green Future	Malin	2018-2019	$ 12.34	$ 12.43	$ 12.64	$ 12.64	$ 12.35	$ 12.12	$ 12.14	$ 12.18	$ 12.27	$ 12.31	$ 12.27	$ 12.42
Green Future	Malin	2019-2020	$ 12.78	$ 12.93	$ 13.20	$ 13.25	$ 12.67	$ 12.57	$ 12.56	$ 12.59	$ 12.66	$ 12.69	$ 12.40	$ 12.45
Green Future	Malin	2020-2021	$ 12.82	$ 12.95	$ 13.24	$ 13.29	$ 13.04	$ 12.76	$ 12.77	$ 12.81	$ 12.86	$ 12.89	$ 12.72	$ 12.74
Green Future	Malin	2021-2022	$ 13.10	$ 13.18	$ 13.48	$ 13.52	$ 13.22	$ 12.95	$ 12.97	$ 13.02	$ 13.01	$ 13.06	$ 13.08	$ 13.16
Green Future	Malin	2022-2023	$ 13.50	$ 13.63	$ 13.98	$ 14.02	$ 13.65	$ 13.41	$ 13.39	$ 13.40	$ 13.46	$ 13.42	$ 13.38	$ 13.53
Green Future	Malin	2023-2024	$ 13.81	$ 13.90	$ 14.07	$ 14.07	$ 13.62	$ 13.49	$ 13.52	$ 13.54	$ 13.60	$ 13.65	$ 13.69	$ 13.69
Green Future	Malin	2024-2025	$ 13.95	$ 14.07	$ 14.49	$ 14.58	$ 14.12	$ 13.93	$ 13.94	$ 13.96	$ 14.01	$ 14.06	$ 14.08	$ 14.06
Green Future	Malin	2025-2026	$ 14.36	$ 14.52	$ 14.94	$ 14.94	$ 14.59	$ 14.42	$ 14.44	$ 14.45	$ 14.49	$ 14.53	$ 14.55	$ 14.57
Green Future	Malin	2026-2027	$ 14.89	$ 15.03	$ 15.51	$ 15.50	$ 15.08	$ 14.93	$ 14.99	$ 14.99	$ 15.07	$ 15.12	$ 15.16	$ 15.30
Green Future	Malin	2027-2028	$ 15.36	$ 15.48	$ 15.98	$ 16.01	$ 15.57	$ 15.44	$ 15.49	$ 15.51	$ 15.58	$ 15.63	$ 15.69	$ 15.82
Green Future	Malin	2028-2029	$ 15.91	$ 16.01	$ 16.55	$ 16.59	$ 16.15	$ 15.98	$ 16.03	$ 16.04	$ 16.10	$ 16.13	$ 16.17	$ 16.34
Green Future	Malin	2029-2030	$ 16.34	$ 16.34										
Green Future	Rockies	2009-2010	$ 4.42	$ 4.92	$ 5.05	$ 5.17	$ 4.99	$ 4.75	$ 4.70	$ 4.70	$ 4.78	$ 4.88	$ 4.94	$ 5.16
Green Future	Rockies	2010-2011	$ 5.55	$ 5.75	$ 5.69	$ 5.71	$ 5.36	$ 5.07	$ 5.07	$ 4.99	$ 5.06	$ 5.10	$ 5.13	$ 5.32
Green Future	Rockies	2011-2012	$ 5.60	$ 5.73	$ 6.14	$ 6.14	$ 5.76	$ 5.53	$ 5.55	$ 5.45	$ 5.52	$ 5.54	$ 5.51	$ 5.71
Green Future	Rockies	2012-2013	$ 5.89	$ 5.96	$ 6.50	$ 6.55	$ 5.98	$ 5.76	$ 5.79	$ 5.69	$ 5.78	$ 5.82	$ 5.80	$ 5.92
Green Future	Rockies	2013-2014	$ 5.36	$ 5.40	$ 5.45	$ 5.49	$ 5.19	$ 5.14	$ 5.23	$ 5.13	$ 5.21	$ 5.23	$ 5.18	$ 5.33
Green Future	Rockies	2014-2015	$ 6.27	$ 6.35	$ 9.29	$ 9.37	$ 9.01	$ 8.89	$ 8.96	$ 8.87	$ 8.99	$ 9.01	$ 8.95	$ 9.11
Green Future	Rockies	2015-2016	$ 9.52	$ 9.65	$ 9.87	$ 9.90	$ 9.63	$ 9.58	$ 9.67	$ 9.61	$ 9.68	$ 9.69	$ 9.69	$ 9.78
Green Future	Rockies	2016-2017	$ 10.28	$ 10.34	$ 10.78	$ 10.77	$ 10.37	$ 10.34	$ 10.40	$ 10.30	$ 10.39	$ 10.43	$ 10.41	$ 10.56
Green Future	Rockies	2017-2018	$ 11.00	$ 11.03	$ 11.52	$ 11.56	$ 11.17	$ 11.06	$ 11.07	$ 11.00	$ 11.08	$ 11.14	$ 11.11	$ 11.32
Green Future	Rockies	2018-2019	$ 11.81	$ 11.87	$ 12.13	$ 12.13	$ 11.87	$ 11.68	$ 11.73	$ 11.64	$ 11.75	$ 11.78	$ 11.73	$ 11.91
Green Future	Rockies	2019-2020	$ 12.24	$ 12.35	$ 12.67	$ 12.71	$ 12.15	$ 12.09	$ 12.10	$ 11.99	$ 12.07	$ 12.12	$ 11.81	$ 11.90
Green Future	Rockies	2020-2021	$ 12.21	$ 12.31	$ 12.65	$ 12.68	$ 12.38	$ 12.16	$ 12.18	$ 12.07	$ 12.14	$ 12.17	$ 11.98	$ 12.06
Green Future	Rockies	2021-2022	$ 12.39	$ 12.42	$ 12.75	$ 12.80	$ 12.51	$ 12.28	$ 12.31	$ 12.23	$ 12.25	$ 12.30	$ 12.31	$ 12.44
Green Future	Rockies	2022-2023	$ 12.75	$ 12.86	$ 13.22	$ 13.26	$ 12.91	$ 12.73	$ 12.71	$ 12.60	$ 12.70	$ 12.65	$ 12.65	$ 12.84
Green Future	Rockies	2023-2024	$ 13.12	$ 13.18	$ 13.53	$ 13.56	$ 13.18	$ 13.04	$ 13.09	$ 12.97	$ 13.02	$ 13.07	$ 13.11	$ 13.16
Green Future	Rockies	2024-2025	$ 13.45	$ 13.55	$ 13.99	$ 14.08	$ 13.67	$ 13.47	$ 13.50	$ 13.39	$ 13.44	$ 13.47	$ 13.50	$ 13.54
Green Future	Rockies	2025-2026	$ 13.85	$ 13.97	$ 14.40	$ 14.42	$ 14.12	$ 13.92	$ 13.96	$ 13.81	$ 13.87	$ 13.90	$ 13.91	$ 13.97
Green Future	Rockies	2026-2027	$ 14.30	$ 14.41	$ 14.91	$ 14.91	$ 14.57	$ 14.38	$ 14.43	$ 14.28	$ 14.39	$ 14.43	$ 14.47	$ 14.64
Green Future	Rockies	2027-2028	$ 14.69	$ 14.77	$ 15.30	$ 15.33	$ 14.97	$ 14.81	$ 14.87	$ 14.72	$ 14.84	$ 14.87	$ 14.93	$ 15.11
Green Future	Rockies	2028-2029	$ 15.19	$ 15.25	$ 15.80	$ 15.84	$ 15.49	$ 15.32	$ 15.35	$ 15.23	$ 15.34	$ 15.37	$ 15.41	$ 15.62
Green Future	Rockies	2029-2030	$ 15.62	$ 15.62										

Appendix 6.1 - Monthly Price Data by Basin

2009$

Scenario	Index	Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
Green Future	Stanfield	2009-2010	$ 4.53	$ 5.04	$ 5.17	$ 5.25	$ 5.14	$ 4.90	$ 4.79	$ 4.94	$ 4.97	$ 5.07	$ 5.08	$ 5.26
Green Future	Stanfield	2010-2011	$ 5.58	$ 5.80	$ 5.75	$ 5.77	$ 5.45	$ 5.18	$ 5.16	$ 5.21	$ 5.21	$ 5.26	$ 5.29	$ 5.43
Green Future	Stanfield	2011-2012	$ 5.62	$ 5.79	$ 6.18	$ 6.18	$ 5.85	$ 5.59	$ 5.59	$ 5.65	$ 5.65	$ 5.68	$ 5.66	$ 5.81
Green Future	Stanfield	2012-2013	$ 5.99	$ 6.11	$ 6.64	$ 6.69	$ 6.16	$ 5.92	$ 5.91	$ 5.95	$ 5.99	$ 6.03	$ 6.01	$ 6.09
Green Future	Stanfield	2013-2014	$ 5.55	$ 5.63	$ 5.68	$ 5.71	$ 5.45	$ 5.34	$ 5.42	$ 5.44	$ 5.46	$ 5.49	$ 5.45	$ 5.58
Green Future	Stanfield	2014-2015	$ 6.52	$ 6.65	$ 9.58	$ 9.65	$ 9.34	$ 9.18	$ 9.24	$ 9.28	$ 9.33	$ 9.37	$ 9.32	$ 9.47
Green Future	Stanfield	2015-2016	$ 9.87	$ 10.01	$ 10.25	$ 10.27	$ 10.05	$ 9.96	$ 10.03	$ 10.09	$ 10.12	$ 10.13	$ 10.14	$ 10.22
Green Future	Stanfield	2016-2017	$ 10.63	$ 10.73	$ 11.16	$ 11.15	$ 10.75	$ 10.65	$ 10.68	$ 10.71	$ 10.75	$ 10.79	$ 10.77	$ 10.91
Green Future	Stanfield	2017-2018	$ 11.39	$ 11.46	$ 11.94	$ 11.97	$ 11.60	$ 11.41	$ 11.38	$ 11.44	$ 11.45	$ 11.52	$ 11.51	$ 11.69
Green Future	Stanfield	2018-2019	$ 12.24	$ 12.33	$ 12.56	$ 12.57	$ 12.29	$ 12.04	$ 12.05	$ 12.08	$ 12.14	$ 12.18	$ 12.14	$ 12.31
Green Future	Stanfield	2019-2020	$ 12.68	$ 12.82	$ 13.12	$ 13.16	$ 12.61	$ 12.48	$ 12.47	$ 12.49	$ 12.53	$ 12.57	$ 12.28	$ 12.34
Green Future	Stanfield	2020-2021	$ 12.72	$ 12.85	$ 13.16	$ 13.21	$ 12.98	$ 12.67	$ 12.68	$ 12.71	$ 12.74	$ 12.77	$ 12.59	$ 12.64
Green Future	Stanfield	2021-2022	$ 13.01	$ 13.08	$ 13.41	$ 13.44	$ 13.15	$ 12.87	$ 12.88	$ 12.93	$ 12.90	$ 12.94	$ 12.97	$ 13.06
Green Future	Stanfield	2022-2023	$ 13.41	$ 13.54	$ 13.90	$ 13.95	$ 13.58	$ 13.34	$ 13.30	$ 13.32	$ 13.35	$ 13.29	$ 13.25	$ 13.40
Green Future	Stanfield	2023-2024	$ 13.66	$ 13.75	$ 13.96	$ 13.94	$ 13.50	$ 13.36	$ 13.38	$ 13.41	$ 13.43	$ 13.48	$ 13.52	$ 13.52
Green Future	Stanfield	2024-2025	$ 13.80	$ 13.92	$ 14.35	$ 14.43	$ 13.99	$ 13.79	$ 13.80	$ 13.82	$ 13.83	$ 13.88	$ 13.90	$ 13.89
Green Future	Stanfield	2025-2026	$ 14.21	$ 14.36	$ 14.79	$ 14.79	$ 14.46	$ 14.27	$ 14.29	$ 14.30	$ 14.31	$ 14.35	$ 14.37	$ 14.40
Green Future	Stanfield	2026-2027	$ 14.73	$ 14.87	$ 15.36	$ 15.35	$ 14.94	$ 14.79	$ 14.84	$ 14.83	$ 14.89	$ 14.94	$ 14.98	$ 15.13
Green Future	Stanfield	2027-2028	$ 15.20	$ 15.31	$ 15.83	$ 15.87	$ 15.44	$ 15.30	$ 15.34	$ 15.35	$ 15.40	$ 15.45	$ 15.52	$ 15.65
Green Future	Stanfield	2028-2029	$ 15.74	$ 15.84	$ 16.40	$ 16.44	$ 16.02	$ 15.84	$ 15.88	$ 15.90	$ 15.93	$ 15.96	$ 16.00	$ 16.16
Green Future	Stanfield	2029-2030	$ 16.16	$ 16.16										
Green Future	Sumas	2009-2010	$ 4.63	$ 5.15	$ 5.28	$ 5.36	$ 5.23	$ 4.86	$ 4.64	$ 4.75	$ 4.78	$ 4.88	$ 4.91	$ 5.19
Green Future	Sumas	2010-2011	$ 5.70	$ 5.92	$ 5.87	$ 5.89	$ 5.54	$ 5.15	$ 5.01	$ 5.05	$ 5.05	$ 5.10	$ 5.15	$ 5.37
Green Future	Sumas	2011-2012	$ 5.71	$ 5.88	$ 6.29	$ 6.30	$ 5.93	$ 5.60	$ 5.48	$ 5.51	$ 5.52	$ 5.55	$ 5.54	$ 5.74
Green Future	Sumas	2012-2013	$ 6.10	$ 6.21	$ 6.75	$ 6.80	$ 6.23	$ 5.91	$ 5.81	$ 5.84	$ 5.87	$ 5.91	$ 5.91	$ 6.01
Green Future	Sumas	2013-2014	$ 5.64	$ 5.73	$ 5.78	$ 5.81	$ 5.51	$ 5.34	$ 5.33	$ 5.35	$ 5.37	$ 5.39	$ 5.37	$ 5.52
Green Future	Sumas	2014-2015	$ 6.61	$ 6.73	$ 9.68	$ 9.75	$ 9.40	$ 9.18	$ 9.17	$ 9.21	$ 9.25	$ 9.29	$ 9.26	$ 9.43
Green Future	Sumas	2015-2016	$ 9.95	$ 10.09	$ 10.34	$ 10.36	$ 10.11	$ 9.96	$ 9.98	$ 10.04	$ 10.05	$ 10.06	$ 10.08	$ 10.19
Green Future	Sumas	2016-2017	$ 10.71	$ 10.81	$ 11.26	$ 11.24	$ 10.80	$ 10.65	$ 10.63	$ 10.64	$ 10.68	$ 10.71	$ 10.71	$ 10.87
Green Future	Sumas	2017-2018	$ 11.47	$ 11.54	$ 12.03	$ 12.07	$ 11.66	$ 11.41	$ 11.32	$ 11.37	$ 11.38	$ 11.45	$ 11.44	$ 11.66
Green Future	Sumas	2018-2019	$ 12.32	$ 12.42	$ 12.68	$ 12.68	$ 12.35	$ 12.03	$ 12.00	$ 12.02	$ 12.07	$ 12.12	$ 12.09	$ 12.27
Green Future	Sumas	2019-2020	$ 12.77	$ 12.91	$ 13.24	$ 13.29	$ 12.67	$ 12.47	$ 12.41	$ 12.43	$ 12.46	$ 12.50	$ 12.23	$ 12.31
Green Future	Sumas	2020-2021	$ 12.81	$ 12.94	$ 13.29	$ 13.33	$ 13.04	$ 12.67	$ 12.65	$ 12.66	$ 12.68	$ 12.71	$ 12.56	$ 12.64
Green Future	Sumas	2021-2022	$ 13.11	$ 13.18	$ 13.55	$ 13.60	$ 13.21	$ 12.87	$ 12.85	$ 12.88	$ 12.84	$ 12.89	$ 12.93	$ 13.05
Green Future	Sumas	2022-2023	$ 13.50	$ 13.63	$ 14.03	$ 14.07	$ 13.64	$ 13.35	$ 13.29	$ 13.29	$ 13.31	$ 13.23	$ 13.18	$ 13.34
Green Future	Sumas	2023-2024	$ 13.76	$ 13.87	$ 14.12	$ 14.07	$ 13.54	$ 13.30	$ 13.25	$ 13.26	$ 13.26	$ 13.31	$ 13.36	$ 13.39
Green Future	Sumas	2024-2025	$ 13.92	$ 14.05	$ 14.49	$ 14.58	$ 14.04	$ 13.73	$ 13.68	$ 13.69	$ 13.67	$ 13.71	$ 13.75	$ 13.78
Green Future	Sumas	2025-2026	$ 14.36	$ 14.50	$ 14.94	$ 14.94	$ 14.50	$ 14.22	$ 14.16	$ 14.16	$ 14.15	$ 14.20	$ 14.23	$ 14.28
Green Future	Sumas	2026-2027	$ 14.86	$ 15.00	$ 15.51	$ 15.51	$ 14.93	$ 14.73	$ 14.71	$ 14.61	$ 14.67	$ 14.71	$ 14.84	$ 15.01
Green Future	Sumas	2027-2028	$ 15.32	$ 15.44	$ 15.98	$ 16.02	$ 15.43	$ 15.26	$ 15.22	$ 15.13	$ 15.19	$ 15.24	$ 15.39	$ 15.54
Green Future	Sumas	2028-2029	$ 15.88	$ 15.98	$ 16.56	$ 16.60	$ 16.06	$ 15.80	$ 15.76	$ 15.69	$ 15.72	$ 15.76	$ 15.88	$ 16.06
Green Future	Sumas	2029-2030	$ 16.06	$ 16.06										

Appendix 6.1 - Monthly Price Data by Basin

2009$

Scenario	Index	Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
Supply Constrained	AECo	2009-2010	$ 6.60	$ 7.01	$ 7.34	$ 7.38	$ 7.16	$ 6.96	$ 6.90	$ 7.04	$ 7.09	$ 7.15	$ 7.13	$ 7.27
Supply Constrained	AECo	2010-2011	$ 8.10	$ 8.37	$ 8.40	$ 8.44	$ 8.07	$ 7.80	$ 7.80	$ 7.88	$ 7.91	$ 7.98	$ 7.96	$ 8.08
Supply Constrained	AECo	2011-2012	$ 8.80	$ 9.01	$ 9.34	$ 9.36	$ 8.93	$ 8.65	$ 8.66	$ 8.74	$ 8.81	$ 8.85	$ 8.80	$ 8.90
Supply Constrained	AECo	2012-2013	$ 9.64	$ 9.83	$ 10.29	$ 10.34	$ 9.90	$ 9.64	$ 9.67	$ 9.75	$ 9.80	$ 9.87	$ 9.77	$ 9.86
Supply Constrained	AECo	2013-2014	$ 9.92	$ 10.06	$ 9.98	$ 10.04	$ 9.59	$ 9.44	$ 9.50	$ 9.56	$ 9.60	$ 9.64	$ 9.56	$ 9.64
Supply Constrained	AECo	2014-2015	$ 11.35	$ 11.51	$ 12.71	$ 12.81	$ 12.28	$ 12.13	$ 12.19	$ 12.25	$ 12.30	$ 12.41	$ 12.27	$ 12.35
Supply Constrained	AECo	2015-2016	$ 13.02	$ 13.18	$ 13.47	$ 13.52	$ 13.00	$ 12.84	$ 12.91	$ 12.98	$ 13.03	$ 13.10	$ 13.00	$ 13.10
Supply Constrained	AECo	2016-2017	$ 13.76	$ 13.92	$ 14.07	$ 14.09	$ 13.55	$ 13.38	$ 13.46	$ 13.51	$ 13.60	$ 13.66	$ 13.54	$ 13.65
Supply Constrained	AECo	2017-2018	$ 14.32	$ 14.47	$ 15.20	$ 15.25	$ 14.73	$ 14.54	$ 14.59	$ 14.67	$ 14.71	$ 14.77	$ 14.69	$ 14.80
Supply Constrained	AECo	2018-2019	$ 15.54	$ 15.70	$ 15.66	$ 15.73	$ 15.14	$ 14.94	$ 15.00	$ 15.08	$ 15.13	$ 15.19	$ 15.10	$ 15.25
Supply Constrained	AECo	2019-2020	$ 15.94	$ 16.10	$ 16.13	$ 16.19	$ 15.61	$ 15.42	$ 15.46	$ 15.53	$ 15.61	$ 15.69	$ 15.55	$ 15.71
Supply Constrained	AECo	2020-2021	$ 16.43	$ 16.59	$ 16.59	$ 16.67	$ 16.18	$ 15.93	$ 16.01	$ 16.08	$ 16.16	$ 16.22	$ 16.12	$ 16.25
Supply Constrained	AECo	2021-2022	$ 16.95	$ 17.12	$ 17.13	$ 17.19	$ 16.66	$ 16.42	$ 16.50	$ 16.57	$ 16.61	$ 16.69	$ 16.62	$ 16.74
Supply Constrained	AECo	2022-2023	$ 17.46	$ 17.62	$ 17.65	$ 17.72	$ 17.11	$ 16.87	$ 16.91	$ 16.96	$ 17.07	$ 17.02	$ 16.92	$ 17.06
Supply Constrained	AECo	2023-2024	$ 17.68	$ 17.85	$ 17.71	$ 17.71	$ 17.06	$ 16.92	$ 17.00	$ 17.08	$ 17.13	$ 17.20	$ 17.13	$ 17.21
Supply Constrained	AECo	2024-2025	$ 17.89	$ 18.04	$ 18.08	$ 18.20	$ 17.54	$ 17.38	$ 17.47	$ 17.54	$ 17.58	$ 17.65	$ 17.58	$ 17.65
Supply Constrained	AECo	2025-2026	$ 18.37	$ 18.55	$ 18.88	$ 18.96	$ 18.32	$ 18.16	$ 18.25	$ 18.31	$ 18.36	$ 18.44	$ 18.35	$ 18.47
Supply Constrained	AECo	2026-2027	$ 19.17	$ 19.37	$ 19.75	$ 19.78	$ 19.11	$ 18.95	$ 19.06	$ 19.12	$ 19.19	$ 19.27	$ 19.19	$ 19.30
Supply Constrained	AECo	2027-2028	$ 20.01	$ 20.19	$ 20.58	$ 20.66	$ 19.94	$ 19.79	$ 19.90	$ 19.98	$ 20.05	$ 20.14	$ 20.07	$ 20.16
Supply Constrained	AECo	2028-2029	$ 20.90	$ 21.07	$ 21.48	$ 21.57	$ 20.84	$ 20.66	$ 20.77	$ 20.87	$ 20.92	$ 21.00	$ 20.90	$ 21.02
Supply Constrained	AECo	2029-2030	$ 21.02	$ 21.02										
Supply Constrained	Malin	2009-2010	$ 6.94	$ 7.35	$ 7.69	$ 7.73	$ 7.44	$ 7.24	$ 7.16	$ 7.34	$ 7.42	$ 7.50	$ 7.47	$ 7.59
Supply Constrained	Malin	2010-2011	$ 8.44	$ 8.70	$ 8.73	$ 8.77	$ 8.36	$ 8.08	$ 8.09	$ 8.16	$ 8.21	$ 8.29	$ 8.27	$ 8.38
Supply Constrained	Malin	2011-2012	$ 9.08	$ 9.30	$ 9.60	$ 9.62	$ 9.17	$ 8.89	$ 8.90	$ 8.97	$ 9.06	$ 9.11	$ 9.06	$ 9.16
Supply Constrained	Malin	2012-2013	$ 9.89	$ 10.08	$ 10.54	$ 10.60	$ 10.10	$ 9.85	$ 9.89	$ 9.96	$ 10.05	$ 10.13	$ 10.04	$ 10.11
Supply Constrained	Malin	2013-2014	$ 10.17	$ 10.32	$ 10.21	$ 10.28	$ 9.76	$ 9.64	$ 9.70	$ 9.76	$ 9.82	$ 9.88	$ 9.80	$ 9.88
Supply Constrained	Malin	2014-2015	$ 11.58	$ 11.74	$ 12.92	$ 13.03	$ 12.44	$ 12.31	$ 12.38	$ 12.44	$ 12.52	$ 12.63	$ 12.50	$ 12.57
Supply Constrained	Malin	2015-2016	$ 13.23	$ 13.39	$ 13.67	$ 13.73	$ 13.14	$ 13.01	$ 13.08	$ 13.15	$ 13.25	$ 13.32	$ 13.23	$ 13.31
Supply Constrained	Malin	2016-2017	$ 13.98	$ 14.14	$ 14.28	$ 14.30	$ 13.70	$ 13.57	$ 13.66	$ 13.71	$ 13.82	$ 13.90	$ 13.78	$ 13.88
Supply Constrained	Malin	2017-2018	$ 14.53	$ 14.69	$ 15.40	$ 15.47	$ 14.88	$ 14.73	$ 14.80	$ 14.86	$ 14.94	$ 15.01	$ 14.94	$ 15.03
Supply Constrained	Malin	2018-2019	$ 15.76	$ 15.92	$ 15.84	$ 15.91	$ 15.28	$ 15.11	$ 15.19	$ 15.27	$ 15.36	$ 15.43	$ 15.34	$ 15.48
Supply Constrained	Malin	2019-2020	$ 16.17	$ 16.33	$ 16.30	$ 16.38	$ 15.77	$ 15.60	$ 15.66	$ 15.73	$ 15.86	$ 15.93	$ 15.80	$ 15.95
Supply Constrained	Malin	2020-2021	$ 16.66	$ 16.82	$ 16.77	$ 16.85	$ 16.33	$ 16.12	$ 16.20	$ 16.27	$ 16.39	$ 16.46	$ 16.36	$ 16.47
Supply Constrained	Malin	2021-2022	$ 17.16	$ 17.34	$ 17.29	$ 17.36	$ 16.79	$ 16.60	$ 16.67	$ 16.75	$ 16.84	$ 16.91	$ 16.85	$ 16.94
Supply Constrained	Malin	2022-2023	$ 17.66	$ 17.82	$ 17.80	$ 17.88	$ 17.25	$ 17.02	$ 17.06	$ 17.12	$ 17.27	$ 17.27	$ 17.20	$ 17.35
Supply Constrained	Malin	2023-2024	$ 18.00	$ 18.19	$ 17.98	$ 18.01	$ 17.32	$ 17.19	$ 17.28	$ 17.36	$ 17.49	$ 17.55	$ 17.50	$ 17.56
Supply Constrained	Malin	2024-2025	$ 18.23	$ 18.38	$ 18.40	$ 18.52	$ 17.81	$ 17.66	$ 17.76	$ 17.83	$ 17.94	$ 18.01	$ 17.96	$ 18.00
Supply Constrained	Malin	2025-2026	$ 18.72	$ 18.90	$ 19.21	$ 19.30	$ 18.61	$ 18.47	$ 18.57	$ 18.63	$ 18.72	$ 18.80	$ 18.73	$ 18.83
Supply Constrained	Malin	2026-2027	$ 19.53	$ 19.73	$ 20.08	$ 20.12	$ 19.40	$ 19.24	$ 19.36	$ 19.45	$ 19.54	$ 19.62	$ 19.56	$ 19.67
Supply Constrained	Malin	2027-2028	$ 20.37	$ 20.55	$ 20.90	$ 20.99	$ 20.22	$ 20.09	$ 20.21	$ 20.31	$ 20.40	$ 20.49	$ 20.43	$ 20.53
Supply Constrained	Malin	2028-2029	$ 21.27	$ 21.45	$ 21.82	$ 21.92	$ 21.13	$ 20.96	$ 21.08	$ 21.18	$ 21.26	$ 21.34	$ 21.25	$ 21.38
Supply Constrained	Malin	2029-2030	$ 21.38	$ 21.38										
Supply Constrained	Rockies	2009-2010	$ 6.69	$ 7.08	$ 7.42	$ 7.50	$ 7.17	$ 6.96	$ 6.95	$ 6.96	$ 7.07	$ 7.14	$ 7.16	$ 7.33
Supply Constrained	Rockies	2010-2011	$ 8.25	$ 8.50	$ 8.54	$ 8.58	$ 8.14	$ 7.85	$ 7.87	$ 7.81	$ 7.91	$ 7.98	$ 7.95	$ 8.13
Supply Constrained	Rockies	2011-2012	$ 8.94	$ 9.12	$ 9.44	$ 9.47	$ 8.98	$ 8.72	$ 8.74	$ 8.66	$ 8.81	$ 8.85	$ 8.79	$ 8.93
Supply Constrained	Rockies	2012-2013	$ 9.68	$ 9.83	$ 10.29	$ 10.35	$ 9.83	$ 9.60	$ 9.66	$ 9.60	$ 9.72	$ 9.79	$ 9.70	$ 9.82
Supply Constrained	Rockies	2013-2014	$ 9.87	$ 9.97	$ 9.88	$ 9.96	$ 9.43	$ 9.35	$ 9.42	$ 9.35	$ 9.45	$ 9.50	$ 9.42	$ 9.52
Supply Constrained	Rockies	2014-2015	$ 11.22	$ 11.35	$ 12.53	$ 12.65	$ 12.03	$ 11.93	$ 12.01	$ 11.93	$ 12.06	$ 12.15	$ 12.02	$ 12.10
Supply Constrained	Rockies	2015-2016	$ 12.79	$ 12.93	$ 13.20	$ 13.27	$ 12.65	$ 12.54	$ 12.64	$ 12.57	$ 12.70	$ 12.76	$ 12.67	$ 12.77
Supply Constrained	Rockies	2016-2017	$ 13.54	$ 13.65	$ 13.81	$ 13.83	$ 13.25	$ 13.17	$ 13.27	$ 13.20	$ 13.34	$ 13.42	$ 13.30	$ 13.42
Supply Constrained	Rockies	2017-2018	$ 14.04	$ 14.17	$ 14.89	$ 14.96	$ 14.38	$ 14.29	$ 14.39	$ 14.32	$ 14.44	$ 14.50	$ 14.42	$ 14.55
Supply Constrained	Rockies	2018-2019	$ 15.23	$ 15.36	$ 15.33	$ 15.40	$ 14.80	$ 14.67	$ 14.78	$ 14.73	$ 14.84	$ 14.90	$ 14.81	$ 14.98
Supply Constrained	Rockies	2019-2020	$ 15.63	$ 15.76	$ 15.77	$ 15.85	$ 15.24	$ 15.13	$ 15.20	$ 15.13	$ 15.27	$ 15.36	$ 15.22	$ 15.40
Supply Constrained	Rockies	2020-2021	$ 16.05	$ 16.18	$ 16.18	$ 16.25	$ 15.67	$ 15.52	$ 15.60	$ 15.54	$ 15.67	$ 15.74	$ 15.63	$ 15.78
Supply Constrained	Rockies	2021-2022	$ 16.45	$ 16.58	$ 16.57	$ 16.64	$ 16.09	$ 15.93	$ 16.02	$ 15.97	$ 16.07	$ 16.15	$ 16.08	$ 16.22
Supply Constrained	Rockies	2022-2023	$ 16.91	$ 17.05	$ 17.04	$ 17.12	$ 16.52	$ 16.35	$ 16.39	$ 16.31	$ 16.50	$ 16.50	$ 16.47	$ 16.66
Supply Constrained	Rockies	2023-2024	$ 17.32	$ 17.47	$ 17.43	$ 17.50	$ 16.88	$ 16.74	$ 16.85	$ 16.79	$ 16.91	$ 16.97	$ 16.92	$ 17.04
Supply Constrained	Rockies	2024-2025	$ 17.73	$ 17.85	$ 17.89	$ 18.02	$ 17.36	$ 17.20	$ 17.32	$ 17.26	$ 17.36	$ 17.43	$ 17.38	$ 17.48
Supply Constrained	Rockies	2025-2026	$ 18.21	$ 18.36	$ 18.68	$ 18.77	$ 18.14	$ 17.96	$ 18.09	$ 17.99	$ 18.10	$ 18.18	$ 18.09	$ 18.23
Supply Constrained	Rockies	2026-2027	$ 18.94	$ 19.12	$ 19.48	$ 19.53	$ 18.89	$ 18.69	$ 18.81	$ 18.74	$ 18.86	$ 18.94	$ 18.86	$ 19.00
Supply Constrained	Rockies	2027-2028	$ 19.69	$ 19.84	$ 20.22	$ 20.30	$ 19.63	$ 19.46	$ 19.59	$ 19.53	$ 19.66	$ 19.73	$ 19.67	$ 19.81
Supply Constrained	Rockies	2028-2029	$ 20.55	$ 20.68	$ 21.07	$ 21.17	$ 20.47	$ 20.30	$ 20.40	$ 20.36	$ 20.50	$ 20.58	$ 20.49	$ 20.66
Supply Constrained	Rockies	2029-2030	$ 20.66	$ 20.66										

Appendix 6.1 - Monthly Price Data by Basin

2009$

Scenario	Index	Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
Supply Constrained	Stanfield	2009-2010	$ 6.79	$ 7.21	$ 7.54	$ 7.59	$ 7.32	$ 7.11	$ 7.04	$ 7.20	$ 7.26	$ 7.33	$ 7.31	$ 7.44
Supply Constrained	Stanfield	2010-2011	$ 8.29	$ 8.55	$ 8.59	$ 8.63	$ 8.23	$ 7.95	$ 7.95	$ 8.03	$ 8.07	$ 8.14	$ 8.12	$ 8.24
Supply Constrained	Stanfield	2011-2012	$ 8.96	$ 9.17	$ 9.48	$ 9.50	$ 9.06	$ 8.78	$ 8.79	$ 8.86	$ 8.94	$ 8.99	$ 8.94	$ 9.03
Supply Constrained	Stanfield	2012-2013	$ 9.78	$ 9.97	$ 10.43	$ 10.48	$ 10.01	$ 9.75	$ 9.78	$ 9.86	$ 9.93	$ 10.00	$ 9.91	$ 9.99
Supply Constrained	Stanfield	2013-2014	$ 10.06	$ 10.20	$ 10.11	$ 10.17	$ 9.68	$ 9.54	$ 9.60	$ 9.66	$ 9.70	$ 9.76	$ 9.68	$ 9.77
Supply Constrained	Stanfield	2014-2015	$ 11.48	$ 11.64	$ 12.83	$ 12.93	$ 12.36	$ 12.22	$ 12.29	$ 12.34	$ 12.40	$ 12.51	$ 12.39	$ 12.46
Supply Constrained	Stanfield	2015-2016	$ 13.13	$ 13.29	$ 13.58	$ 13.64	$ 13.07	$ 12.93	$ 13.00	$ 13.06	$ 13.13	$ 13.20	$ 13.12	$ 13.20
Supply Constrained	Stanfield	2016-2017	$ 13.88	$ 14.04	$ 14.19	$ 14.21	$ 13.63	$ 13.48	$ 13.56	$ 13.61	$ 13.70	$ 13.78	$ 13.66	$ 13.77
Supply Constrained	Stanfield	2017-2018	$ 14.43	$ 14.59	$ 15.31	$ 15.37	$ 14.81	$ 14.64	$ 14.70	$ 14.76	$ 14.81	$ 14.88	$ 14.81	$ 14.92
Supply Constrained	Stanfield	2018-2019	$ 15.66	$ 15.82	$ 15.76	$ 15.83	$ 15.22	$ 15.03	$ 15.10	$ 15.17	$ 15.24	$ 15.30	$ 15.22	$ 15.37
Supply Constrained	Stanfield	2019-2020	$ 16.07	$ 16.23	$ 16.22	$ 16.30	$ 15.70	$ 15.51	$ 15.56	$ 15.63	$ 15.73	$ 15.81	$ 15.68	$ 15.84
Supply Constrained	Stanfield	2020-2021	$ 16.56	$ 16.72	$ 16.69	$ 16.77	$ 16.26	$ 16.03	$ 16.11	$ 16.18	$ 16.27	$ 16.34	$ 16.24	$ 16.36
Supply Constrained	Stanfield	2021-2022	$ 17.07	$ 17.25	$ 17.22	$ 17.29	$ 16.73	$ 16.51	$ 16.59	$ 16.66	$ 16.72	$ 16.80	$ 16.73	$ 16.84
Supply Constrained	Stanfield	2022-2023	$ 17.57	$ 17.73	$ 17.73	$ 17.81	$ 17.18	$ 16.95	$ 16.98	$ 17.03	$ 17.16	$ 17.14	$ 17.06	$ 17.22
Supply Constrained	Stanfield	2023-2024	$ 17.86	$ 18.04	$ 17.86	$ 17.87	$ 17.20	$ 17.06	$ 17.15	$ 17.23	$ 17.31	$ 17.38	$ 17.33	$ 17.40
Supply Constrained	Stanfield	2024-2025	$ 18.08	$ 18.23	$ 18.26	$ 18.38	$ 17.68	$ 17.52	$ 17.62	$ 17.69	$ 17.76	$ 17.83	$ 17.78	$ 17.83
Supply Constrained	Stanfield	2025-2026	$ 18.57	$ 18.74	$ 19.07	$ 19.15	$ 18.48	$ 18.32	$ 18.42	$ 18.48	$ 18.54	$ 18.63	$ 18.55	$ 18.66
Supply Constrained	Stanfield	2026-2027	$ 19.36	$ 19.57	$ 19.93	$ 19.97	$ 19.26	$ 19.10	$ 19.21	$ 19.29	$ 19.36	$ 19.45	$ 19.38	$ 19.49
Supply Constrained	Stanfield	2027-2028	$ 20.20	$ 20.38	$ 20.76	$ 20.84	$ 20.09	$ 19.95	$ 20.06	$ 20.15	$ 20.22	$ 20.31	$ 20.26	$ 20.36
Supply Constrained	Stanfield	2028-2029	$ 21.10	$ 21.27	$ 21.67	$ 21.77	$ 20.99	$ 20.82	$ 20.93	$ 21.03	$ 21.09	$ 21.17	$ 21.08	$ 21.21
Supply Constrained	Stanfield	2029-2030	$ 21.21	$ 21.21										
Supply Constrained	Sumas	2009-2010	$ 6.90	$ 7.31	$ 7.65	$ 7.70	$ 7.41	$ 7.07	$ 6.89	$ 7.01	$ 7.07	$ 7.14	$ 7.13	$ 7.37
Supply Constrained	Sumas	2010-2011	$ 8.40	$ 8.67	$ 8.71	$ 8.76	$ 8.33	$ 7.93	$ 7.80	$ 7.87	$ 7.90	$ 7.98	$ 7.97	$ 8.18
Supply Constrained	Sumas	2011-2012	$ 9.05	$ 9.27	$ 9.59	$ 9.63	$ 9.14	$ 8.79	$ 8.68	$ 8.72	$ 8.81	$ 8.85	$ 8.82	$ 8.97
Supply Constrained	Sumas	2012-2013	$ 9.88	$ 10.07	$ 10.54	$ 10.60	$ 10.08	$ 9.75	$ 9.68	$ 9.75	$ 9.82	$ 9.88	$ 9.81	$ 9.91
Supply Constrained	Sumas	2013-2014	$ 10.15	$ 10.29	$ 10.22	$ 10.28	$ 9.75	$ 9.54	$ 9.52	$ 9.56	$ 9.61	$ 9.66	$ 9.60	$ 9.71
Supply Constrained	Sumas	2014-2015	$ 11.56	$ 11.72	$ 12.92	$ 13.03	$ 12.43	$ 12.22	$ 12.22	$ 12.27	$ 12.32	$ 12.43	$ 12.32	$ 12.42
Supply Constrained	Sumas	2015-2016	$ 13.21	$ 13.37	$ 13.67	$ 13.73	$ 13.13	$ 12.92	$ 12.95	$ 13.01	$ 13.06	$ 13.13	$ 13.07	$ 13.18
Supply Constrained	Sumas	2016-2017	$ 13.97	$ 14.13	$ 14.28	$ 14.30	$ 13.68	$ 13.48	$ 13.50	$ 13.54	$ 13.63	$ 13.70	$ 13.60	$ 13.74
Supply Constrained	Sumas	2017-2018	$ 14.52	$ 14.68	$ 15.40	$ 15.47	$ 14.87	$ 14.63	$ 14.63	$ 14.69	$ 14.74	$ 14.81	$ 14.75	$ 14.88
Supply Constrained	Sumas	2018-2019	$ 15.75	$ 15.91	$ 15.88	$ 15.95	$ 15.28	$ 15.03	$ 15.05	$ 15.11	$ 15.17	$ 15.23	$ 15.16	$ 15.34
Supply Constrained	Sumas	2019-2020	$ 16.16	$ 16.32	$ 16.34	$ 16.42	$ 15.76	$ 15.51	$ 15.51	$ 15.57	$ 15.66	$ 15.74	$ 15.64	$ 15.81
Supply Constrained	Sumas	2020-2021	$ 16.65	$ 16.81	$ 16.82	$ 16.90	$ 16.33	$ 16.03	$ 16.08	$ 16.13	$ 16.22	$ 16.28	$ 16.21	$ 16.36
Supply Constrained	Sumas	2021-2022	$ 17.17	$ 17.34	$ 17.36	$ 17.44	$ 16.79	$ 16.51	$ 16.55	$ 16.62	$ 16.66	$ 16.74	$ 16.70	$ 16.84
Supply Constrained	Sumas	2022-2023	$ 17.66	$ 17.82	$ 17.85	$ 17.93	$ 17.25	$ 16.96	$ 16.97	$ 17.01	$ 17.12	$ 17.07	$ 17.00	$ 17.16
Supply Constrained	Sumas	2023-2024	$ 17.96	$ 18.16	$ 18.02	$ 18.01	$ 17.24	$ 16.99	$ 17.02	$ 17.08	$ 17.14	$ 17.21	$ 17.17	$ 17.26
Supply Constrained	Sumas	2024-2025	$ 18.21	$ 18.36	$ 18.40	$ 18.52	$ 17.73	$ 17.46	$ 17.50	$ 17.56	$ 17.60	$ 17.67	$ 17.63	$ 17.72
Supply Constrained	Sumas	2025-2026	$ 18.72	$ 18.89	$ 19.22	$ 19.30	$ 18.51	$ 18.26	$ 18.29	$ 18.34	$ 18.39	$ 18.47	$ 18.41	$ 18.55
Supply Constrained	Sumas	2026-2027	$ 19.50	$ 19.70	$ 20.08	$ 20.12	$ 19.25	$ 19.04	$ 19.09	$ 19.07	$ 19.14	$ 19.22	$ 19.24	$ 19.37
Supply Constrained	Sumas	2027-2028	$ 20.33	$ 20.51	$ 20.91	$ 20.99	$ 20.08	$ 19.90	$ 19.94	$ 19.93	$ 20.01	$ 20.10	$ 20.13	$ 20.24
Supply Constrained	Sumas	2028-2029	$ 21.24	$ 21.41	$ 21.83	$ 21.92	$ 21.04	$ 20.78	$ 20.81	$ 20.83	$ 20.88	$ 20.96	$ 20.96	$ 21.11
Supply Constrained	Sumas	2029-2030	$ 21.11	$ 21.11										

APPENDIX 6.2

GENERAL ASSUMPTIONS

Appendix 6.2 - GDP Assumption

General Inflation (GDP) 1/

Year	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Inflation	0.86	0.82	1.28	1.35	1.87	2.16	2.12	2.08	2.04	2.02	1.95

Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Inflation	1.95	1.89	1.91	1.91	1.88	1.82	1.83	1.85	1.88	1.85	1.89

1/ Global Insight's Review of the U.S. Economy First Quarter 2009

Appendix 6.2 - Weighted Average Cost of Capital

OREGON
AVISTA CORPORATION
Capital Structure and Overall Rate of Return

Cost of Capital as of March 31, 2009	Amount	Percent of Total Capital	Cost	Component
L/T Debt		45.00%	6.40%	2.88%
Trust Preferred Securities		5.00%	6.57%	0.33%
Common Equity		50.00%	10.00%	5.00%
TOTAL		100.00%		8.21%

WASHINGTON
AVISTA CORPORATION
Capital Structure and Overall Rate of Return

Agreed-upon Cost of Capital	Percent of Total Capital	Cost	Component
L/T Debt	52.06%	6.84%	3.56%
Trust Preferred Securities			0.00%
Common Equity	47.94%	10.20%	4.89%
TOTAL	100.00%		8.45%

IDAHO
AVISTA CORPORATION
Capital Structure and Overall Rate of Return

Agreed-upon Cost of Capital	Amount	Percent of Total Capital	Cost	Component
L/T Debt (1)		53.70%	6.51%	3.50%
Trust Preferred Securities				0.00%
Preferred Stock				0.00%
Common Equity		46.30%	10.20%	4.72%
TOTAL		100.00%		8.22%

System Weighted Average Cost of Capital*	8.32%
GDP price deflator 2009	1.79%
Real WACC	6.42%
Tax rate	35%
Real after tax WACC	**4.17%**

*Weighting based on net rate base as of 4/30/09

Authorized Rates of Return

Washington Electric

General Case Settlement in 2008 (UE-080416)

effective 1/1/2009

Component	Capital Structure	ProForma Cost	ProForma Weighted Cost
L/T Debt [(1)]	53.70%	6.51%	3.50%
Pref Trust			0.00%
Common	46.30%	10.20%	4.72%
Total	100.00%		8.22%

(1) includes short-term debt

Washington Gas

General Case Settlement in 2008 (UG-080417)

effective 1/1/2009

Component	Capital Structure	ProForma Cost	ProForma Weighted Cost
L/T Debt [(1)]	53.70%	6.51%	3.50%
Pref Trust			0.00%
Common	46.30%	10.20%	4.72%
Total	100.00%		8.22%

(1) includes short-term debt

Idaho Electric

Case Decided in 2008-AVU-E-08-01

effective 10/1/2008

Component	Capital Structure	ProForma Cost	ProForma Weighted Cost
L/T Debt	52.06%	6.84%	3.56%
Pref Trust			0.00%
Pref Stock			0.00%
Common	47.94%	10.20%	4.89%
Total	100.00%		8.45%

(excludes short-term debt)

Idaho Gas

Case Decided in 2008-AVU-G-08-01

effective 10/1/2008

Component	Capital Structure	ProForma Cost	ProForma Weighted Cost
L/T Debt	52.06%	6.84%	3.56%
Pref Trust			0.00%
Pref Stock			0.00%
Common	47.94%	10.20%	4.89%
Total	100.00%		8.45%

(excludes short-term debt)

Oregon Gas

General Case Settlement in 2007 (UG-181)

effective 4/1/2008

Component	Capital Structure	ProForma Cost	ProForma Weighted Cost
L/T Debt	45.00%	6.40%	2.88%
Pref Trust	5.00%	6.57%	0.33%
Common	50.00%	10.00%	5.00%
Total	100.00%		8.21%

(excludes short-term debt)

ESCALATION/INFLATION FORECASTS

Implicit Price Deflators — U. S. Average 3/31/2009
Source: Randy Barcus, Finance--Analysis, Budget & Forecasting
Discount Rate: Levelizing is Not Applicable to Escalation Rates

Year	E1 Gross Domestic Product (% change)	E2 Personal Consumption Expenditures (% change)	E3 Power Equipment Investment (% change)	E4 Consumer Price Index-Urban (% change)
1996	1.9	2.2	1.6	2.9
1997	1.7	1.7	2.1	2.3
1998	1.1	0.9	1.9	1.5
1999	1.4	1.7	1.6	2.2
2000	2.2	2.5	4.1	3.4
2001	2.4	2.1	2.8	2.8
2002	1.7	1.4	2.7	1.6
2003	2.1	2.0	2.3	2.3
2004	2.9	2.6	8.4	2.7
2005	3.3	2.9	9.4	3.4
2006	3.2	2.8	6.1	3.2
2007	2.7	2.6	5.0	2.9
2008	2.2	3.3	7.7	3.8
2009	0.9	-1.0	1.6	-1.9
2010	0.8	1.4	-1.8	1.7
2011	1.3	1.8	1.6	2.2
2012	1.4	1.7	2.3	2.3
2013	1.9	2.2	3.2	2.6
2014	2.2	2.1	3.5	2.4
2015	2.1	2.1	3.2	2.4
2016	2.1	2.1	3.0	2.5
2017	2.0	2.1	3.0	2.4
2018	2.0	2.1	3.0	2.4
2019	2.0	2.0	2.8	2.3
2020	2.0	1.9	2.8	2.1
2021	1.9	1.7	2.8	1.7
2022	1.9	1.8	2.6	2.0
2023	1.9	1.9	2.7	2.2
2024	1.9	1.9	2.7	2.1
2025	1.8	1.8	2.6	2.1
2026	1.8	1.9	2.6	2.1
2027	1.8	1.9	2.7	2.1
2028	1.9	1.9	2.7	2.2
2029	1.9	1.9	2.7	2.1
2030	1.9	1.9	2.7	2.2
2031	1.9	1.9	2.8	2.2
2032	1.9	1.9	2.8	2.2
2033	1.8	1.9	2.7	2.2
2034	1.8	1.9	2.7	2.2
2035	1.8	1.9	2.7	2.2
2036	1.8	1.9	2.7	2.2
2037	1.9	1.9	2.8	2.2
2038	1.9	2.0	2.8	2.2
2008-2038 Avg.	1.8	1.9	2.7	2.1
5 Year Avg.	1.3	1.4	2.3	1.6
10 Year Avg.	1.7	1.8	2.7	2.0
20 Year Avg.	1.8	1.8	2.7	2.1
25 Year Avg.	1.8	1.9	2.7	2.1
30 Year Avg.	1.8	1.9	2.7	2.1
Std. Dev.	1.0	1.0	1.5	1.0
	0.5	0.6	1.8	0.8

E1 Applies to inflation of all good & services produced & consumed in the U.S.
E2 Applies to inflation of goods & services consumed by individuals.
E3 Applies to inflation of non-residential power equipment
E4 For all urban consumers, applies to inflation of a fixed market basket of typical goods & services.

Reference: Global Insight's Review of the U.S. Economy First Quarter 2009

COST OF CAPITAL

Source: Paul Kimball, Treasury Department 4/10/2009

Projected Long-Term Cost of Capital -- Avista Utilities
for Net Present Value Analysis

	Target Capital Structure	Component Cost	Net Present Value
Debt	50%	7.60%	3.80%
Common Equity	50%	11.25%	5.63%
Weighted Cost of Capital			9.43%

Authorized Cost of Capital -- Avista Utilities
for Revenue Requirements Analysis
Washington Elec/Gas Decided 2008

	Authorized Capital Structure	Component Cost	Component Return
Debt	53.70%	6.51%	3.50%
Common Equity	46.30%	10.20%	4.72%
Rate of Return			8.22%

Authorized Cost of Capital -- Avista Utilities
for Revenue Requirements Analysis
Idaho Elec/Gas Decided 2008 AVU-08-1

	Authorized Capital Structure	Component Cost	Component Return
Debt	52.06%	6.84%	3.56%
Common Equity	47.94%	10.20%	4.89%
Rate of Return			8.45%

APPENDIX 6.3

SUPPLY SIDE RESOURCE OPTIONS

Appendix 6.3 - Supply Side Resource Additions Available to SENDOUT®

Additional Resources	Jurisdiction	Size	Cost/Rates	Availability	Notes
Pipeline					
Capacity Release Recalls	WA/ID	20,000 Dth/d	NWPL fixed rate	2018	Recall previously released capacity
GTN Capacity	WA/ID	30,000 Dth/d	GTN rate	2010	Currently available unsubscribed capacity
GTN Capacity	OR	25,000 Dth/d	GTN rate	2010	Currently available unsubscribed capacity; requires expansion of Medford Lateral
GTN Medford Lateral Expansion	OR	25,000 Dth/d	GTN rate	2011	Additional compression to allow more gas to flow from GTN mailine to the lateral
NWP Expansion	WA/ID	50,000 Dth/d	NWPL fixed rate x 3	2013	Transport expansion from Sumas/JP to WA/ID
NWP Expansion	OR	50,000 Dth/d	NWPL fixed rate x 5	2013	Transport expansion from Sumas/JP to Oregon
Klamath Falls Lateral Capacity	OR	up to 6000 Dth/d	NWPL fixed rate	2009	Currently available unsubscribed capacity
Klamath Falls Lateral Purchase	OR	20,000 Dth/d	$2.5 million capital cost	November 2010	Agreement with NWPL to purchase the Klamath Falls lateral at net book value. Can be done with less than 1 years notice.
Statellite LNG					
WA/ID Satellite LNG	WA/ID	90,000 capacity; 30,000 delivery for 3 days	$44 million capital cost $1 million annual O&M	November 2015	
Medford/Roseburg Satellite LNG	OR	45,000 capacity; 15,000 delivery for 3 days	$22 million capital cost $850,000 annual O&M	November 2015	
Klamath Falls Satellite LNG	OR	45,000 capacity; 15,000 delivery for 3 days	$22 million capital cost $850,000 annual O&M	November 2015	
La Grande Satellite LNG	OR	45,000 capacity; 15,000 delivery for 3 days	$22 million capital cost $850,000 annual O&M	November 2015	
Company Owned Liquifaction LNG					
WA/ID	WA	600 MMcf capacity; 150,000 delivery for 4 days	$75 million capital cost, $2 million annual O&M	November 2017	
Import LNG					
Jordan Cove LNG to Medford	OR	7,500 Dth/d	Malin pricing less fuel	November 2012	
Transport from LNG Terminal	OR	7,500 Dth/d	Precedent agreement rate	November 2012	
Jordan Cove LNG to Malin	OR	7,500 Dth/d	Malin pricing less fuel	November 2012	
Transport from LNG Terminal	OR	7,500 Dth/d	Precedent agreement rate	November 2012	
Bradwood Landing LNG	OR	25,000 Dth/d	Malin pricing less fuel	November 2012	
Transport from LNG Terminal	OR	25,000 Dth/d	Precedent agreement rate	November 2012	
Other Resources Considered					
Citygate deliveries	WA/ID/OR				Represents the ability to buy a delivered product fron another utility or marketer. Limited counterparties to structure transaction
Malin Backhaul	OR		GTN rate	2010	Back haul capacity is provided by displacement and is available up to the amount of scheduled forward-haul capacity through a specific point. Also requires expansion of the Medford Lateral to facilitate delivery. Not firm especially long term
Inground Storage					
California					Dependent on GTN backhaul or convert to bidirectional pipeline
JP Expansion					Dependent on NWP Expansion or other Tport arrangements back to service territory
Mist					Dependent on NWP Expansion or other Tport arrangements back to service territory; Long term subscription may not be available

Appendix 6.3 - Supply Side Resource Additions Available to SENDOUT® by Jurisdiction
Expected Case

Additional Resources	Jurisdiction	Size	Cost/Rates	Availability	Notes
Pipeline					
Capacity Release Recalls	WA/ID	20,000 Dth/d	NWPL fixed rate	2018	Recall previously released capacity
GTN Capacity	WA/ID	40,000 Dth/d	GTN rate	2010	Currently available unsubscribed capacity
NWP Expansion	WA/ID	50,000 Dth/d	NWPL fixed rate x 3	2013	Transport expansion from Sumas/JP to WA/ID
Statellite LNG					
WA/ID Satellite LNG	WA/ID	90,000 capacity; 30,000 delivery for 3 days	$44 million capital cost $1 million	November 2015	
Company Owned Liquifaction LNG					
WA/ID	WA/ID	600 MMcf capacity; 150,000 delivery for 4 days	$75 million capital cost, $2 million	November 2017	
Other Resources Considered					
Citygate deliveries	WA/ID				Represents the ability to buy a delivered product fron another utility or marketer. Limited counterparties to structure transaction

Additional Resources	Jurisdiction	Size	Cost/Rates	Availability	Notes
Pipeline					
GTN Capacity	Medford/Roseburg	25,000 Dth/d	GTN rate	2010	Currently available unsubscribed capacity; requires expansion of Medford Lateral
GTN Medford Lateral Expansion	Medford/Roseburg	25,000 Dth/d	GTN rate	2011	Additional compression to allow more gas to flow from GTN mailine to the lateral
NWP Expansion	Medford/Roseburg	50,000 Dth/d	NWPL fixed rate x 5	2013	Transport expansion from Sumas/JP to Oregon
Statellite LNG					
Medford/Roseburg Satellite LNG	Medford/Roseburg	45,000 capacity; 15,000 delivery for 3 days	$22 million capital cost $850,000	November 2015	
Other Resources Considered					
Citygate deliveries	Medford/Roseburg				Represents the ability to buy a delivered product fron another utility or marketer. Limited counterparties to structure transaction
Malin Backhaul	Medford/Roseburg		GTN rate	2010	Back haul capacity is provided by displacement and is available up to the amount of scheduled forward-haul capacity through a specific point. Also requires expansion of the Medford Lateral to facilitate delivery. Not firm especially long term

Additional Resources	Jurisdiction	Size	Cost/Rates	Availability	Notes
Pipeline					
Klamath Falls Lateral Capacity	Klamath Falls	up to 6000 Dth/d	NWPL fixed rate	2009	Currently available unsubscribed capacity
Klamath Falls Lateral Purchase	Klamath Falls	20,000 Dth/d	$2.6 million capital cost	November 2010	Agreement with NWPL to purchase the Klamath Falls lateral at net book value. Can be done with less than 1 years notice.
Statellite LNG					
Klamath Falls Satellite LNG	Klamath Falls	45,000 capacity; 15,000 delivery for 3 days	$22 million capital cost $850,000	November 2015	
Other Resources Considered					
Citygate deliveries	Klamath Falls				Represents the ability to buy a delivered product fron another utility or marketer. Limited counterparties to structure transaction

Additional Resources	Jurisdiction	Size	Cost/Rates	Availability	Notes
Statellite LNG					
La Grande Satellite LNG	La Grande	45,000 capacity; 15,000 delivery for 3 days	$22 million capital cost $850,000	November 2015	
Other Resources Considered					
Citygate deliveries	La Grande				Represents the ability to buy a delivered product fron another utility or marketer. Limited counterparties to structure transaction

Appendix 6.3 - Supply Side Resource Additions Available to SENDOUT® by Jurisdiction
High Case

Additional Resources	Jurisdiction	Size	Cost/Rates	Availability	Notes
Pipeline					
Capacity Release Recalls	WA/ID	20,000 Dth/d	NWPL fixed rate	2018	Recall previously released capacity
GTN Capacity	WA/ID	100,000 Dth/d	GTN rate	2010	Currently available unsubscribed capacity
NWP Expansion	WA/ID	50,000 Dth/d	NWPL fixed rate x 3	2013	Transport expansion from Sumas/JP to WA/ID
Statellite LNG					
WA/ID Satellite LNG	WA/ID	90,000 capacity; 30,000 delivery for 3 days	$44 million capital cost $1 million	November 2015	
Company Owned Liquifaction LNG					
WA/ID	WA/ID	600 MMcf capacity; 150,000 delivery for 4 days	$75 million capital cost, $2 million	November 2017	
Other Resources Considered					
Citygate deliveries	WA/ID				Represents the ability to buy a delivered product fron another utility or marketer. Limited counterparties to structure transaction

Additional Resources	Jurisdiction	Size	Cost/Rates	Availability	Notes
Pipeline					
GTN Capacity	Medford/Roseburg	50,000 Dth/d	GTN rate	2010	Currently available unsubscribed capacity; requires expansion of Medford Lateral
GTN Medford Lateral Expansion	Medford/Roseburg	50,000 Dth/d	GTN rate	2011	Additional compression to allow more gas to flow from GTN mailine to the lateral
NWP Expansion	Medford/Roseburg	50,000 Dth/d	NWPL fixed rate x 5	2013	Transport expansion from Sumas/JP to Oregon
Statellite LNG					
Medford/Roseburg Satellite LNG	Medford/Roseburg	45,000 capacity; 15,000 delivery for 3 days	$22 million capital cost $850,000	November 2015	
Other Resources Considered					
Citygate deliveries	Medford/Roseburg				Represents the ability to buy a delivered product fron another utility or marketer. Limited counterparties to structure transaction
Malin Backhaul	Medford/Roseburg		GTN rate	2010	Back haul capacity is provided by displacement and is available up to the amount of scheduled forward-haul capacity through a specific point. Also requires expansion of the Medford Lateral to facilitate delivery. Not firm especially long term

Additional Resources	Jurisdiction	Size	Cost/Rates	Availability	Notes
Pipeline					
Klamath Falls Lateral Capacity	Klamath Falls	up to 6000 Dth/d	NWPL fixed rate	2009	Currently available unsubscribed capacity
Klamath Falls Lateral Purchase	Klamath Falls	20,000 Dth/d	$2.6 million capital cost	November 2010	Agreement with NWPL to purchase the Klamath Falls lateral at net book value. Can be done with less than 1 years notice.
Statellite LNG					
Klamath Falls Satellite LNG	Klamath Falls	45,000 capacity; 15,000 delivery for 3 days	$22 million capital cost $850,000	November 2015	
Other Resources Considered					
Citygate deliveries	Klamath Falls				Represents the ability to buy a delivered product fron another utility or marketer. Limited counterparties to structure transaction

Additional Resources	Jurisdiction	Size	Cost/Rates	Availability	Notes
Statellite LNG					
La Grande Satellite LNG	La Grande	45,000 capacity; 15,000 delivery for 3 days	$22 million capital cost $850,000	November 2015	
Other Resources Considered					
Citygate deliveries	La Grande				Represents the ability to buy a delivered product fron another utility or marketer. Limited counterparties to structure transaction

APPENDIX 6.4

AVOIDED COST DETAIL

Appendix 6.4

Annual Avoided Costs 1/
2009$

-1

Scenario	Gas Year	Klam Falls	La Grande	Medford GTN	Medford NWP	Roseburg	Wa/Id Both	Wa/Id GTN	Wa/Id NWP	WA/ID Annual	OR Annual
Expected	2009-2010	$ 4.98	$ 4.94	$ 5.23	$ 5.23	$ 5.23	$ 4.90	$ 4.91	$ 4.95	$ 4.92	$ 5.12
Expected	2010-2011	$ 5.42	$ 5.39	$ 5.53	$ 5.53	$ 5.53	$ 5.33	$ 5.33	$ 5.39	$ 5.35	$ 5.48
Expected	2011-2012	$ 5.54	$ 5.50	$ 5.64	$ 5.64	$ 5.64	$ 5.45	$ 5.45	$ 5.49	$ 5.46	$ 5.59
Expected	2012-2013	$ 5.85	$ 5.79	$ 5.96	$ 5.96	$ 5.96	$ 5.77	$ 5.77	$ 5.79	$ 5.78	$ 5.90
Expected	2013-2014	$ 5.25	$ 5.19	$ 5.37	$ 5.37	$ 5.37	$ 5.17	$ 5.17	$ 5.19	$ 5.18	$ 5.31
Expected	2014-2015	$ 7.32	$ 7.27	$ 7.46	$ 7.46	$ 7.46	$ 7.25	$ 7.26	$ 7.28	$ 7.26	$ 7.40
Expected	2015-2016	$ 8.40	$ 8.34	$ 8.55	$ 8.55	$ 8.55	$ 8.32	$ 8.33	$ 8.34	$ 8.33	$ 8.48
Expected	2016-2017	$ 9.05	$ 8.99	$ 9.23	$ 9.23	$ 9.23	$ 8.96	$ 8.97	$ 8.99	$ 8.97	$ 9.15
Expected	2017-2018	$ 10.11	$ 10.05	$ 10.31	$ 10.31	$ 10.31	$ 10.03	$ 10.03	$ 10.06	$ 10.04	$ 10.22
Expected	2018-2019	$ 10.72	$ 10.66	$ 10.95	$ 10.95	$ 10.95	$ 10.64	$ 10.66	$ 10.66	$ 10.66	$ 10.85
Expected	2019-2020	$ 10.95	$ 10.89	$ 11.21	$ 11.21	$ 11.21	$ 10.87	$ 10.88	$ 10.90	$ 10.88	$ 11.10
Expected	2020-2021	$ 10.96	$ 10.91	$ 11.25	$ 11.25	$ 11.25	$ 10.88	$ 10.89	$ 10.92	$ 10.90	$ 11.12
Expected	2021-2022	$ 11.01	$ 10.96	$ 11.32	$ 11.32	$ 11.32	$ 10.94	$ 10.95	$ 10.96	$ 10.95	$ 11.19
Expected	2022-2023	$ 11.21	$ 11.18	$ 11.58	$ 11.58	$ 11.58	$ 11.15	$ 11.16	$ 11.19	$ 11.17	$ 11.43
Expected	2023-2024	$ 11.11	$ 11.10	$ 11.49	$ 11.49	$ 11.49	$ 11.05	$ 11.05	$ 11.10	$ 11.06	$ 11.34
Expected	2024-2025	$ 11.23	$ 11.21	$ 11.67	$ 11.67	$ 11.67	$ 11.16	$ 11.17	$ 11.21	$ 11.18	$ 11.49
Expected	2025-2026	$ 11.42	$ 11.40	$ 11.91	$ 11.91	$ 11.91	$ 11.35	$ 11.35	$ 11.40	$ 11.37	$ 11.71
Expected	2026-2027	$ 11.69	$ 11.68	$ 12.20	$ 12.20	$ 12.20	$ 11.61	$ 11.62	$ 11.69	$ 11.64	$ 12.00
Expected	2027-2028	$ 11.87	$ 11.86	$ 12.44	$ 12.44	$ 12.44	$ 11.79	$ 11.80	$ 11.87	$ 11.82	$ 12.21
Expected	2028-2029	$ 12.08	$ 12.75	$ 12.04	$ 12.04	$ 12.04	$ 12.00	$ 12.00	$ 12.08	$ 12.02	$ 12.19

Winter Avoided Costs 1/
2009$

Scenario	Gas Year	Klam Falls	La Grande	Medford GTN	Medford NWP	Roseburg	Wa/Id Both	Wa/Id GTN	Wa/Id NWP	WA/ID Winter	OR Winter
Expected	2009-2010	$ 4.99	$ 4.97	$ 5.67	$ 5.67	$ 5.67	$ 4.92	$ 4.93	$ 4.96	$ 4.94	$ 5.39
Expected	2010-2011	$ 5.67	$ 5.65	$ 5.98	$ 5.98	$ 5.98	$ 5.58	$ 5.58	$ 5.63	$ 5.60	$ 5.85
Expected	2011-2012	$ 5.77	$ 5.74	$ 6.07	$ 6.07	$ 6.07	$ 5.67	$ 5.68	$ 5.71	$ 5.69	$ 5.94
Expected	2012-2013	$ 6.04	$ 5.98	$ 6.38	$ 6.38	$ 6.38	$ 5.96	$ 5.98	$ 5.99	$ 5.98	$ 6.23
Expected	2013-2014	$ 5.33	$ 5.27	$ 5.71	$ 5.71	$ 5.71	$ 5.25	$ 5.25	$ 5.27	$ 5.26	$ 5.55
Expected	2014-2015	$ 7.14	$ 7.11	$ 7.56	$ 7.56	$ 7.56	$ 7.08	$ 7.09	$ 7.12	$ 7.10	$ 7.38
Expected	2015-2016	$ 8.36	$ 8.31	$ 8.81	$ 8.81	$ 8.81	$ 8.29	$ 8.29	$ 8.31	$ 8.30	$ 8.62
Expected	2016-2017	$ 9.16	$ 9.09	$ 9.67	$ 9.67	$ 9.67	$ 9.08	$ 9.08	$ 9.10	$ 9.09	$ 9.45
Expected	2017-2018	$ 10.11	$ 10.07	$ 10.68	$ 10.68	$ 10.68	$ 10.06	$ 10.07	$ 10.08	$ 10.07	$ 10.44
Expected	2018-2019	$ 10.90	$ 10.85	$ 11.53	$ 11.53	$ 11.53	$ 10.84	$ 10.86	$ 10.85	$ 10.85	$ 11.27
Expected	2019-2020	$ 11.23	$ 11.18	$ 11.91	$ 11.91	$ 11.91	$ 11.17	$ 11.18	$ 11.18	$ 11.18	$ 11.62
Expected	2020-2021	$ 11.17	$ 11.13	$ 11.91	$ 11.91	$ 11.91	$ 11.10	$ 11.13	$ 11.13	$ 11.12	$ 11.61
Expected	2021-2022	$ 11.21	$ 11.18	$ 12.03	$ 12.03	$ 12.03	$ 11.16	$ 11.18	$ 11.18	$ 11.17	$ 11.69
Expected	2022-2023	$ 11.46	$ 11.44	$ 12.37	$ 12.37	$ 12.37	$ 11.42	$ 11.44	$ 11.45	$ 11.44	$ 12.00
Expected	2023-2024	$ 11.36	$ 11.47	$ 12.36	$ 12.36	$ 12.36	$ 11.41	$ 11.42	$ 11.47	$ 11.43	$ 11.98
Expected	2024-2025	$ 11.46	$ 11.55	$ 12.55	$ 12.55	$ 12.55	$ 11.49	$ 11.49	$ 11.56	$ 11.52	$ 12.14
Expected	2025-2026	$ 11.61	$ 11.72	$ 12.82	$ 12.82	$ 12.82	$ 11.64	$ 11.65	$ 11.73	$ 11.67	$ 12.36
Expected	2026-2027	$ 11.85	$ 11.96	$ 13.19	$ 13.19	$ 13.19	$ 11.88	$ 11.89	$ 11.98	$ 11.92	$ 12.68
Expected	2027-2028	$ 12.02	$ 12.13	$ 13.48	$ 13.48	$ 13.48	$ 12.05	$ 12.05	$ 12.15	$ 12.08	$ 12.92
Expected	2028-2029	$ 12.28	$ 14.02	$ 12.27	$ 12.27	$ 12.27	$ 12.29	$ 12.29	$ 12.40	$ 12.33	$ 12.62

1/ Avoided costs are before Environmental Externalities adder.

Appendix 6.4

Annual Avoided Costs 1/
2009$

Scenario	Gas Year	Klam Falls	La Grande	Medford GTN	Medford NWP	Roseburg	Wa/Id Both	Wa/Id GTN	Wa/Id NWP	WA/ID Annual	OR Annual
Low Growth	2009-2010	$ 7.25	$ 7.23	$ 7.21	$ 7.21	$ 7.21	$ 7.23	$ 7.32	$ 7.23	$ 7.26	$ 7.22
Low Growth	2010-2011	$ 8.28	$ 8.30	$ 8.26	$ 8.26	$ 8.26	$ 8.28	$ 8.30	$ 8.30	$ 8.30	$ 8.27
Low Growth	2011-2012	$ 9.59	$ 9.71	$ 9.59	$ 9.59	$ 9.59	$ 9.66	$ 9.64	$ 9.73	$ 9.68	$ 9.62
Low Growth	2012-2013	$ 10.70	$ 10.79	$ 10.70	$ 10.70	$ 10.70	$ 10.76	$ 10.80	$ 10.79	$ 10.78	$ 10.72
Low Growth	2013-2014	$ 10.55	$ 10.57	$ 10.52	$ 10.52	$ 10.52	$ 10.56	$ 10.67	$ 10.57	$ 10.60	$ 10.53
Low Growth	2014-2015	$ 12.87	$ 12.97	$ 12.86	$ 12.86	$ 12.86	$ 12.96	$ 13.04	$ 12.97	$ 12.99	$ 12.88
Low Growth	2015-2016	$ 13.62	$ 13.69	$ 13.58	$ 13.58	$ 13.58	$ 13.69	$ 13.79	$ 13.69	$ 13.72	$ 13.61
Low Growth	2016-2017	$ 13.85	$ 13.99	$ 13.85	$ 13.85	$ 13.85	$ 13.98	$ 14.09	$ 13.99	$ 14.02	$ 13.88
Low Growth	2017-2018	$ 14.59	$ 14.77	$ 14.59	$ 14.59	$ 14.59	$ 14.76	$ 14.84	$ 14.77	$ 14.79	$ 14.63
Low Growth	2018-2019	$ 14.98	$ 15.06	$ 14.98	$ 14.98	$ 14.98	$ 15.05	$ 15.15	$ 15.06	$ 15.09	$ 14.99
Low Growth	2019-2020	$ 15.21	$ 15.37	$ 15.21	$ 15.21	$ 15.21	$ 15.33	$ 15.40	$ 15.36	$ 15.36	$ 15.24
Low Growth	2020-2021	$ 15.42	$ 15.60	$ 15.42	$ 15.42	$ 15.42	$ 15.56	$ 15.57	$ 15.60	$ 15.58	$ 15.46
Low Growth	2021-2022	$ 15.41	$ 15.74	$ 15.41	$ 15.41	$ 15.41	$ 15.65	$ 15.64	$ 15.78	$ 15.69	$ 15.48
Low Growth	2022-2023	$ 15.62	$ 16.03	$ 15.62	$ 15.62	$ 15.62	$ 15.87	$ 15.85	$ 16.06	$ 15.93	$ 15.70
Low Growth	2023-2024	$ 15.94	$ 16.36	$ 15.94	$ 15.94	$ 15.94	$ 16.18	$ 16.16	$ 16.38	$ 16.24	$ 16.02
Low Growth	2024-2025	$ 16.22	$ 16.64	$ 16.22	$ 16.22	$ 16.22	$ 16.46	$ 16.44	$ 16.65	$ 16.52	$ 16.30
Low Growth	2025-2026	$ 16.76	$ 17.20	$ 16.76	$ 16.76	$ 16.76	$ 17.02	$ 16.99	$ 17.22	$ 17.08	$ 16.85
Low Growth	2026-2027	$ 17.40	$ 17.84	$ 17.40	$ 17.40	$ 17.40	$ 17.65	$ 17.62	$ 17.85	$ 17.70	$ 17.49
Low Growth	2027-2028	$ 18.04	$ 18.49	$ 18.05	$ 18.05	$ 18.05	$ 18.30	$ 18.27	$ 18.50	$ 18.35	$ 18.14
Low Growth	2028-2029	$ 18.71	$ 19.17	$ 18.72	$ 18.72	$ 18.72	$ 18.98	$ 18.95	$ 19.18	$ 19.03	$ 18.81

Winter Avoided Costs 1/
2009$

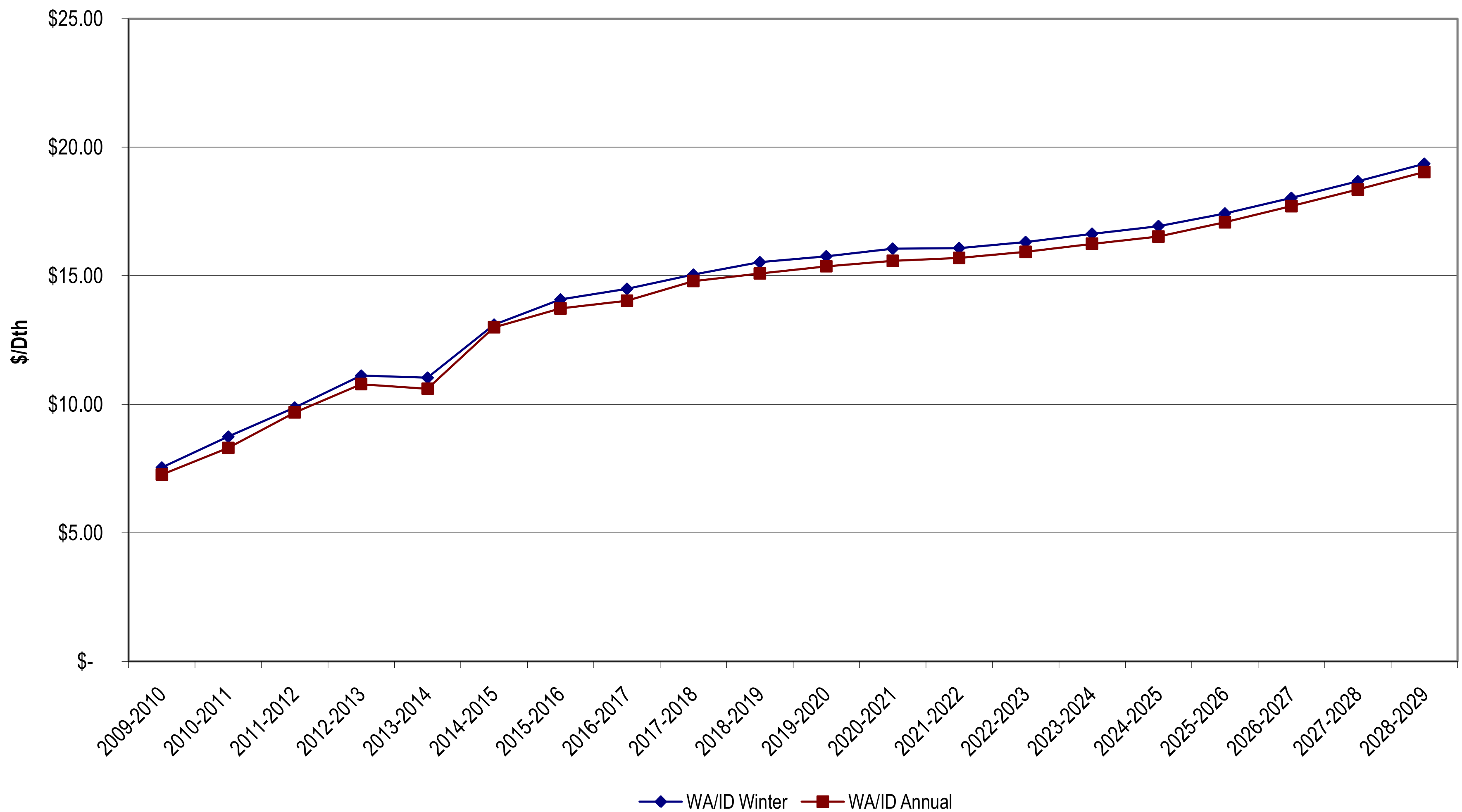
Scenario	Gas Year	Klam Falls	La Grande	Medford GTN	Medford NWP	Roseburg	Wa/Id Both	Wa/Id GTN	Wa/Id NWP	WA/ID Winter	OR Winter
Low Growth	2009-2010	$ 7.51	$ 7.55	$ 7.51	$ 7.51	$ 7.51	$ 7.55	$ 7.51	$ 7.55	$ 7.54	$ 7.52
Low Growth	2010-2011	$ 8.72	$ 8.75	$ 8.71	$ 8.71	$ 8.71	$ 8.75	$ 8.71	$ 8.75	$ 8.74	$ 8.72
Low Growth	2011-2012	$ 9.79	$ 9.93	$ 9.81	$ 9.81	$ 9.81	$ 9.87	$ 9.83	$ 9.91	$ 9.87	$ 9.83
Low Growth	2012-2013	$ 11.04	$ 11.12	$ 11.05	$ 11.05	$ 11.05	$ 11.10	$ 11.14	$ 11.10	$ 11.11	$ 11.06
Low Growth	2013-2014	$ 10.95	$ 11.00	$ 10.94	$ 10.94	$ 10.94	$ 11.00	$ 11.09	$ 11.00	$ 11.03	$ 10.96
Low Growth	2014-2015	$ 12.94	$ 13.08	$ 12.95	$ 12.95	$ 12.95	$ 13.08	$ 13.13	$ 13.08	$ 13.09	$ 12.97
Low Growth	2015-2016	$ 13.95	$ 14.04	$ 13.94	$ 13.94	$ 13.94	$ 14.04	$ 14.14	$ 14.04	$ 14.08	$ 13.96
Low Growth	2016-2017	$ 14.30	$ 14.45	$ 14.30	$ 14.30	$ 14.30	$ 14.45	$ 14.57	$ 14.45	$ 14.49	$ 14.33
Low Growth	2017-2018	$ 14.79	$ 15.02	$ 14.79	$ 14.79	$ 14.79	$ 15.02	$ 15.09	$ 15.02	$ 15.04	$ 14.84
Low Growth	2018-2019	$ 15.43	$ 15.50	$ 15.43	$ 15.43	$ 15.43	$ 15.50	$ 15.58	$ 15.50	$ 15.52	$ 15.44
Low Growth	2019-2020	$ 15.66	$ 15.73	$ 15.66	$ 15.66	$ 15.66	$ 15.73	$ 15.81	$ 15.73	$ 15.76	$ 15.67
Low Growth	2020-2021	$ 16.09	$ 16.04	$ 16.09	$ 16.09	$ 16.09	$ 16.04	$ 16.07	$ 16.04	$ 16.05	$ 16.08
Low Growth	2021-2022	$ 15.98	$ 16.10	$ 15.98	$ 15.98	$ 15.98	$ 16.08	$ 16.05	$ 16.10	$ 16.08	$ 16.01
Low Growth	2022-2023	$ 16.19	$ 16.38	$ 16.19	$ 16.19	$ 16.19	$ 16.30	$ 16.25	$ 16.37	$ 16.31	$ 16.23
Low Growth	2023-2024	$ 16.53	$ 16.72	$ 16.53	$ 16.53	$ 16.53	$ 16.62	$ 16.57	$ 16.72	$ 16.63	$ 16.57
Low Growth	2024-2025	$ 16.85	$ 17.02	$ 16.85	$ 16.85	$ 16.85	$ 16.92	$ 16.86	$ 17.01	$ 16.93	$ 16.89
Low Growth	2025-2026	$ 17.34	$ 17.51	$ 17.35	$ 17.35	$ 17.35	$ 17.41	$ 17.34	$ 17.51	$ 17.42	$ 17.38
Low Growth	2026-2027	$ 17.94	$ 18.13	$ 17.95	$ 17.95	$ 17.95	$ 18.01	$ 17.94	$ 18.12	$ 18.02	$ 17.98
Low Growth	2027-2028	$ 18.58	$ 18.78	$ 18.59	$ 18.59	$ 18.59	$ 18.66	$ 18.59	$ 18.77	$ 18.67	$ 18.63
Low Growth	2028-2029	$ 19.25	$ 19.46	$ 19.27	$ 19.27	$ 19.27	$ 19.34	$ 19.27	$ 19.46	$ 19.35	$ 19.30

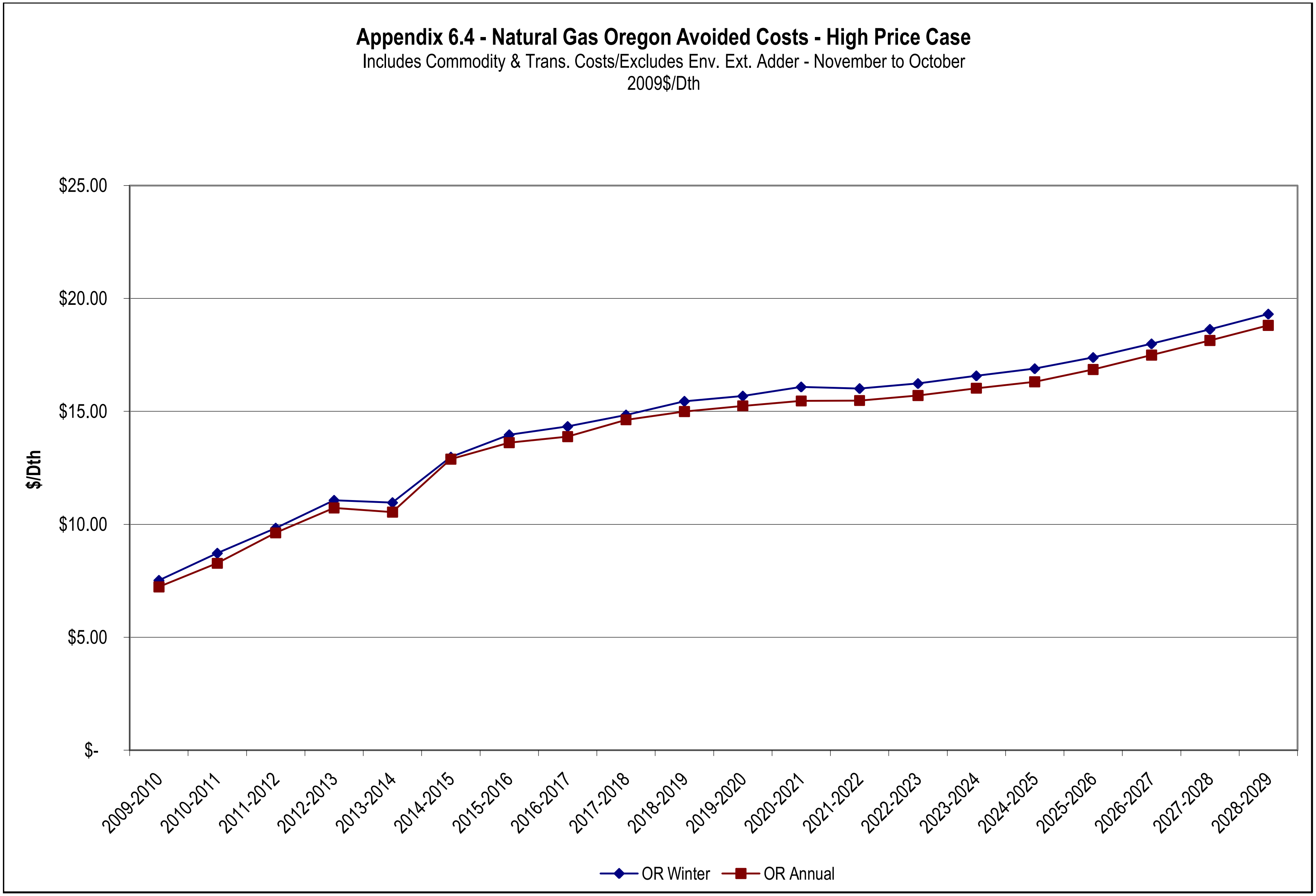
1/ Avoided costs are before Environmental Externalities adder.

Appendix 6.4 - Washington and Idaho Avoided Costs - High Price Case

Includes Commodity & Trans. Costs/Excludes Env. Ext. Adder - November to October

2009$/Dth




Appendix 6.4 - Natural Gas Oregon Avoided Costs - High Price Case
Includes Commodity & Trans. Costs/Excludes Env. Ext. Adder - November to October
2009$/Dth
$/Dth
$25.00
$20.00
$15.00
$10.00
$5.00
$-
2009-2010
2010-2011
2011-2012
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
OR Winter
OR Annual

Appendix 6.4

Annual Avoided Costs 1/

2009$

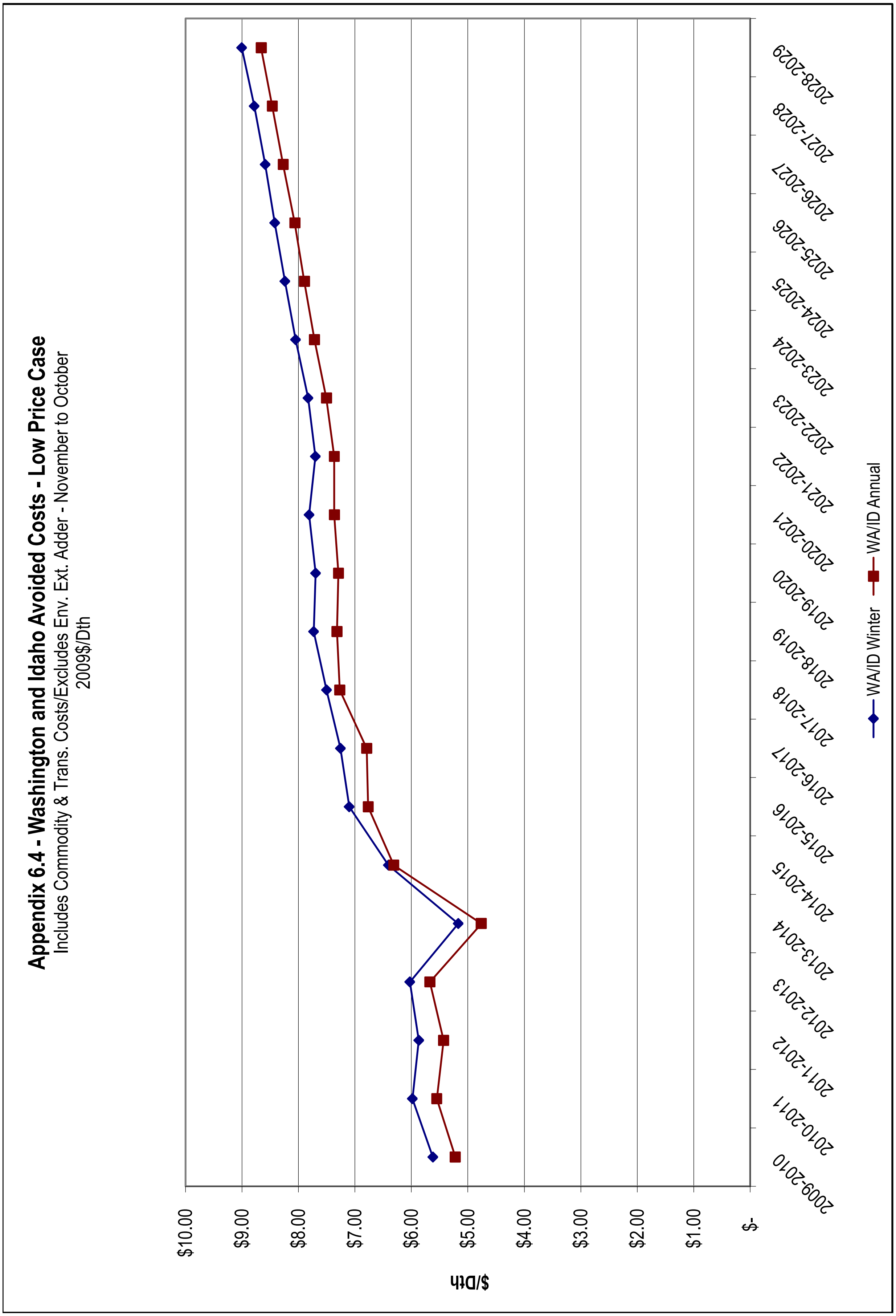
Scenario	Gas Year	Klam Falls	La Grande	Medford GTN	Medford NWP	Roseburg	Wa/Id Both	Wa/Id GTN	Wa/Id NWP	WA/ID Annual	OR Annual
High Growth	2009-2010	$ 5.23	$ 5.19	$ 5.19	$ 5.19	$ 5.19	$ 5.19	$ 5.28	$ 5.19	$ 5.22	$ 5.20
High Growth	2010-2011	$ 5.57	$ 5.55	$ 5.55	$ 5.55	$ 5.55	$ 5.53	$ 5.57	$ 5.55	$ 5.55	$ 5.55
High Growth	2011-2012	$ 5.40	$ 5.44	$ 5.40	$ 5.40	$ 5.40	$ 5.41	$ 5.41	$ 5.47	$ 5.43	$ 5.41
High Growth	2012-2013	$ 5.65	$ 5.67	$ 5.64	$ 5.64	$ 5.64	$ 5.65	$ 5.69	$ 5.67	$ 5.67	$ 5.65
High Growth	2013-2014	$ 4.75	$ 4.74	$ 4.72	$ 4.72	$ 4.72	$ 4.73	$ 4.81	$ 4.74	$ 4.76	$ 4.73
High Growth	2014-2015	$ 6.27	$ 6.30	$ 6.26	$ 6.26	$ 6.26	$ 6.26	$ 6.36	$ 6.30	$ 6.31	$ 6.27
High Growth	2015-2016	$ 6.72	$ 6.73	$ 6.70	$ 6.70	$ 6.70	$ 6.72	$ 6.84	$ 6.73	$ 6.76	$ 6.71
High Growth	2016-2017	$ 6.72	$ 6.77	$ 6.71	$ 6.71	$ 6.71	$ 6.75	$ 6.85	$ 6.77	$ 6.79	$ 6.72
High Growth	2017-2018	$ 7.17	$ 7.24	$ 7.16	$ 7.16	$ 7.16	$ 7.23	$ 7.32	$ 7.25	$ 7.27	$ 7.18
High Growth	2018-2019	$ 7.28	$ 7.30	$ 7.28	$ 7.28	$ 7.28	$ 7.28	$ 7.37	$ 7.30	$ 7.32	$ 7.29
High Growth	2019-2020	$ 7.26	$ 7.27	$ 7.25	$ 7.25	$ 7.25	$ 7.26	$ 7.34	$ 7.28	$ 7.29	$ 7.26
High Growth	2020-2021	$ 7.32	$ 7.38	$ 7.33	$ 7.33	$ 7.33	$ 7.33	$ 7.39	$ 7.38	$ 7.36	$ 7.34
High Growth	2021-2022	$ 7.26	$ 7.43	$ 7.24	$ 7.24	$ 7.24	$ 7.31	$ 7.36	$ 7.42	$ 7.36	$ 7.28
High Growth	2022-2023	$ 7.36	$ 7.60	$ 7.35	$ 7.35	$ 7.35	$ 7.42	$ 7.48	$ 7.61	$ 7.50	$ 7.40
High Growth	2023-2024	$ 7.58	$ 7.84	$ 7.57	$ 7.57	$ 7.57	$ 7.63	$ 7.68	$ 7.84	$ 7.72	$ 7.62
High Growth	2024-2025	$ 7.75	$ 8.02	$ 7.74	$ 7.74	$ 7.74	$ 7.80	$ 7.85	$ 8.03	$ 7.89	$ 7.80
High Growth	2025-2026	$ 7.92	$ 8.18	$ 7.90	$ 7.90	$ 7.90	$ 7.98	$ 8.03	$ 8.19	$ 8.06	$ 7.96
High Growth	2026-2027	$ 8.12	$ 8.41	$ 8.11	$ 8.11	$ 8.11	$ 8.17	$ 8.22	$ 8.42	$ 8.27	$ 8.17
High Growth	2027-2028	$ 8.31	$ 8.60	$ 8.30	$ 8.30	$ 8.30	$ 8.36	$ 8.41	$ 8.61	$ 8.46	$ 8.36
High Growth	2028-2029	$ 8.51	$ 8.79	$ 8.50	$ 8.50	$ 8.50	$ 8.56	$ 8.61	$ 8.81	$ 8.66	$ 8.56

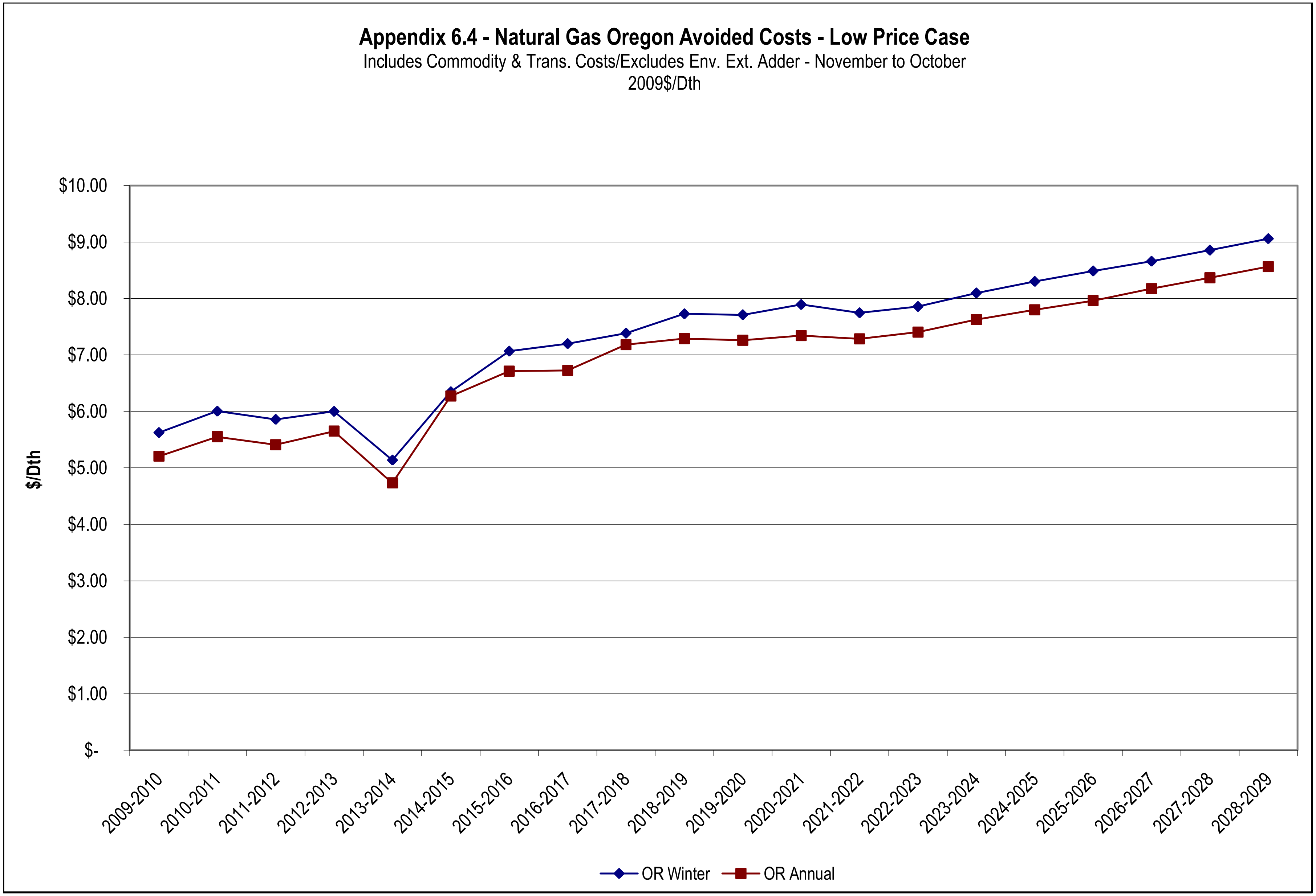
Winter Avoided Costs 1/

2009$

Scenario	Gas Year	Klam Falls	La Grande	Medford GTN	Medford NWP	Roseburg	Wa/Id Both	Wa/Id GTN	Wa/Id NWP	WA/ID Winter	OR Winter
High Growth	2009-2010	$ 5.65	$ 5.61	$ 5.62	$ 5.62	$ 5.62	$ 5.61	$ 5.63	$ 5.61	$ 5.62	$ 5.62
High Growth	2010-2011	$ 6.02	$ 5.98	$ 6.00	$ 6.00	$ 6.00	$ 5.97	$ 5.99	$ 5.98	$ 5.98	$ 6.00
High Growth	2011-2012	$ 5.84	$ 5.90	$ 5.85	$ 5.85	$ 5.85	$ 5.85	$ 5.86	$ 5.89	$ 5.87	$ 5.86
High Growth	2012-2013	$ 5.99	$ 6.01	$ 6.00	$ 6.00	$ 6.00	$ 6.01	$ 6.05	$ 6.01	$ 6.02	$ 6.00
High Growth	2013-2014	$ 5.14	$ 5.14	$ 5.13	$ 5.13	$ 5.13	$ 5.12	$ 5.23	$ 5.15	$ 5.17	$ 5.14
High Growth	2014-2015	$ 6.34	$ 6.40	$ 6.33	$ 6.33	$ 6.33	$ 6.34	$ 6.46	$ 6.41	$ 6.40	$ 6.35
High Growth	2015-2016	$ 7.07	$ 7.06	$ 7.06	$ 7.06	$ 7.06	$ 7.04	$ 7.19	$ 7.07	$ 7.10	$ 7.06
High Growth	2016-2017	$ 7.19	$ 7.23	$ 7.19	$ 7.19	$ 7.19	$ 7.20	$ 7.33	$ 7.23	$ 7.25	$ 7.20
High Growth	2017-2018	$ 7.36	$ 7.46	$ 7.36	$ 7.36	$ 7.36	$ 7.45	$ 7.56	$ 7.48	$ 7.50	$ 7.38
High Growth	2018-2019	$ 7.73	$ 7.71	$ 7.73	$ 7.73	$ 7.73	$ 7.68	$ 7.78	$ 7.72	$ 7.73	$ 7.73
High Growth	2019-2020	$ 7.72	$ 7.68	$ 7.71	$ 7.71	$ 7.71	$ 7.65	$ 7.73	$ 7.69	$ 7.69	$ 7.71
High Growth	2020-2021	$ 7.90	$ 7.84	$ 7.90	$ 7.90	$ 7.90	$ 7.76	$ 7.82	$ 7.84	$ 7.81	$ 7.89
High Growth	2021-2022	$ 7.83	$ 7.74	$ 7.72	$ 7.72	$ 7.72	$ 7.66	$ 7.71	$ 7.72	$ 7.70	$ 7.74
High Growth	2022-2023	$ 7.93	$ 7.89	$ 7.82	$ 7.82	$ 7.82	$ 7.77	$ 7.82	$ 7.89	$ 7.83	$ 7.86
High Growth	2023-2024	$ 8.17	$ 8.14	$ 8.06	$ 8.06	$ 8.06	$ 7.98	$ 8.03	$ 8.13	$ 8.05	$ 8.09
High Growth	2024-2025	$ 8.38	$ 8.32	$ 8.26	$ 8.26	$ 8.26	$ 8.17	$ 8.21	$ 8.32	$ 8.24	$ 8.30
High Growth	2025-2026	$ 8.57	$ 8.51	$ 8.45	$ 8.45	$ 8.45	$ 8.34	$ 8.39	$ 8.52	$ 8.42	$ 8.48
High Growth	2026-2027	$ 8.73	$ 8.70	$ 8.62	$ 8.62	$ 8.62	$ 8.51	$ 8.55	$ 8.69	$ 8.58	$ 8.66
High Growth	2027-2028	$ 8.93	$ 8.89	$ 8.81	$ 8.81	$ 8.81	$ 8.71	$ 8.75	$ 8.88	$ 8.78	$ 8.85
High Growth	2028-2029	$ 9.13	$ 9.10	$ 9.02	$ 9.02	$ 9.02	$ 8.91	$ 8.95	$ 9.15	$ 9.00	$ 9.06

1/ Avoided costs are before Environmental Externalities adder.


Appendix 6.4 - Washington and Idaho Avoided Costs - Low Price Case
Includes Commodity & Trans. Costs/Excludes Env. Ext. Adder - November to October
2009$/Dth
$/Dth
$10.00
$9.00
$8.00
$7.00
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$-
2009-2010
2010-2011
2011-2012
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
WA/ID Winter
WA/ID Annual


Appendix 6.4 - Natural Gas Oregon Avoided Costs - Low Price Case
Includes Commodity & Trans. Costs/Excludes Env. Ext. Adder - November to October
2009$/Dth
$/Dth
$10.00
$9.00
$8.00
$7.00
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$-
2009-2010
2010-2011
2011-2012
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
OR Winter
OR Annual

Appendix 6.4 - Monthly Avoided Cost Detail 1/
2009$

Scenario	Gas Year	Month	Klam Falls	La Grande	Medford GTN	Medford NWP	Roseburg	Wa/Id Both	Wa/Id GTN	Wa/Id NWP	WA/ID Annual	OR Annual
Low Growth & High Price	2009-2010	Nov	$ 7.04	$ 7.01	$ 7.02	$ 7.02	$ 7.02	$ 7.01	$ 7.01	$ 7.01	$ 7.01	$ 7.02
Low Growth & High Price	2009-2010	Dec	$ 7.43	$ 7.60	$ 7.47	$ 7.47	$ 7.47	$ 7.60	$ 7.39	$ 7.60	$ 7.53	$ 7.49
Low Growth & High Price	2009-2010	Jan	$ 7.76	$ 7.89	$ 7.76	$ 7.76	$ 7.76	$ 7.89	$ 7.75	$ 7.89	$ 7.85	$ 7.79
Low Growth & High Price	2009-2010	Feb	$ 7.82	$ 7.84	$ 7.82	$ 7.82	$ 7.82	$ 7.84	$ 7.81	$ 7.84	$ 7.83	$ 7.82
Low Growth & High Price	2009-2010	Mar	$ 7.52	$ 7.43	$ 7.47	$ 7.47	$ 7.47	$ 7.43	$ 7.60	$ 7.43	$ 7.49	$ 7.47
Low Growth & High Price	2009-2010	Apr	$ 6.94	$ 6.94	$ 6.94	$ 6.94	$ 6.94	$ 6.94	$ 6.95	$ 6.94	$ 6.95	$ 6.94
Low Growth & High Price	2009-2010	May	$ 7.00	$ 6.95	$ 6.95	$ 6.95	$ 6.95	$ 6.95	$ 7.03	$ 6.95	$ 6.97	$ 6.96
Low Growth & High Price	2009-2010	Jun	$ 7.03	$ 6.95	$ 6.95	$ 6.95	$ 6.95	$ 6.95	$ 7.12	$ 6.95	$ 7.00	$ 6.96
Low Growth & High Price	2009-2010	Jul	$ 7.03	$ 6.95	$ 6.95	$ 6.95	$ 6.95	$ 6.95	$ 7.23	$ 6.95	$ 7.04	$ 6.97
Low Growth & High Price	2009-2010	Aug	$ 7.03	$ 6.95	$ 6.95	$ 6.95	$ 6.95	$ 6.95	$ 7.31	$ 6.95	$ 7.07	$ 6.97
Low Growth & High Price	2009-2010	Sep	$ 7.04	$ 6.95	$ 6.95	$ 6.95	$ 6.95	$ 6.95	$ 7.30	$ 6.95	$ 7.07	$ 6.97
Low Growth & High Price	2009-2010	Oct	$ 7.34	$ 7.34	$ 7.34	$ 7.34	$ 7.34	$ 7.34	$ 7.35	$ 7.34	$ 7.35	$ 7.34
Low Growth & High Price	2010-2011	Nov	$ 8.58	$ 8.55	$ 8.57	$ 8.57	$ 8.57	$ 8.55	$ 8.55	$ 8.55	$ 8.55	$ 8.57
Low Growth & High Price	2010-2011	Dec	$ 8.80	$ 8.93	$ 8.83	$ 8.83	$ 8.83	$ 8.93	$ 8.77	$ 8.93	$ 8.87	$ 8.84
Low Growth & High Price	2010-2011	Jan	$ 8.83	$ 8.99	$ 8.83	$ 8.83	$ 8.83	$ 8.99	$ 8.82	$ 8.99	$ 8.94	$ 8.87
Low Growth & High Price	2010-2011	Feb	$ 8.87	$ 8.87	$ 8.86	$ 8.86	$ 8.86	$ 8.87	$ 8.85	$ 8.87	$ 8.87	$ 8.86
Low Growth & High Price	2010-2011	Mar	$ 8.51	$ 8.41	$ 8.46	$ 8.46	$ 8.46	$ 8.41	$ 8.57	$ 8.41	$ 8.47	$ 8.46
Low Growth & High Price	2010-2011	Apr	$ 7.79	$ 7.95	$ 7.79	$ 7.79	$ 7.79	$ 7.83	$ 7.83	$ 7.95	$ 7.87	$ 7.83
Low Growth & High Price	2010-2011	May	$ 7.83	$ 7.95	$ 7.83	$ 7.83	$ 7.83	$ 7.88	$ 7.88	$ 7.95	$ 7.90	$ 7.86
Low Growth & High Price	2010-2011	Jun	$ 7.91	$ 7.96	$ 7.91	$ 7.91	$ 7.91	$ 7.96	$ 7.96	$ 7.96	$ 7.96	$ 7.92
Low Growth & High Price	2010-2011	Jul	$ 8.01	$ 7.96	$ 7.96	$ 7.96	$ 7.96	$ 7.96	$ 8.05	$ 7.96	$ 7.99	$ 7.97
Low Growth & High Price	2010-2011	Aug	$ 8.05	$ 7.96	$ 7.96	$ 7.96	$ 7.96	$ 7.96	$ 8.12	$ 7.96	$ 8.01	$ 7.98
Low Growth & High Price	2010-2011	Sep	$ 8.06	$ 7.96	$ 7.96	$ 7.96	$ 7.96	$ 7.96	$ 8.12	$ 7.96	$ 8.02	$ 7.98
Low Growth & High Price	2010-2011	Oct	$ 8.14	$ 8.14	$ 8.14	$ 8.14	$ 8.14	$ 8.14	$ 8.17	$ 8.14	$ 8.15	$ 8.14
Low Growth & High Price	2011-2012	Nov	$ 9.13	$ 9.23	$ 9.13	$ 9.13	$ 9.13	$ 9.13	$ 9.13	$ 9.23	$ 9.16	$ 9.15
Low Growth & High Price	2011-2012	Dec	$ 9.31	$ 9.62	$ 9.37	$ 9.37	$ 9.37	$ 9.58	$ 9.30	$ 9.62	$ 9.50	$ 9.41
Low Growth & High Price	2011-2012	Jan	$ 10.29	$ 10.45	$ 10.29	$ 10.29	$ 10.29	$ 10.39	$ 10.32	$ 10.45	$ 10.39	$ 10.33
Low Growth & High Price	2011-2012	Feb	$ 10.34	$ 10.38	$ 10.34	$ 10.34	$ 10.34	$ 10.37	$ 10.37	$ 10.37	$ 10.37	$ 10.35
Low Growth & High Price	2011-2012	Mar	$ 9.90	$ 9.97	$ 9.90	$ 9.90	$ 9.90	$ 9.91	$ 10.03	$ 9.91	$ 9.95	$ 9.92
Low Growth & High Price	2011-2012	Apr	$ 9.25	$ 9.45	$ 9.25	$ 9.25	$ 9.25	$ 9.32	$ 9.32	$ 9.59	$ 9.41	$ 9.29
Low Growth & High Price	2011-2012	May	$ 9.27	$ 9.45	$ 9.27	$ 9.27	$ 9.27	$ 9.35	$ 9.35	$ 9.59	$ 9.43	$ 9.31
Low Growth & High Price	2011-2012	Jun	$ 9.37	$ 9.50	$ 9.37	$ 9.37	$ 9.37	$ 9.44	$ 9.44	$ 9.60	$ 9.49	$ 9.40
Low Growth & High Price	2011-2012	Jul	$ 9.48	$ 9.60	$ 9.48	$ 9.48	$ 9.48	$ 9.56	$ 9.56	$ 9.60	$ 9.57	$ 9.51
Low Growth & High Price	2011-2012	Aug	$ 9.55	$ 9.63	$ 9.55	$ 9.55	$ 9.55	$ 9.63	$ 9.63	$ 9.63	$ 9.63	$ 9.57
Low Growth & High Price	2011-2012	Sep	$ 9.55	$ 9.61	$ 9.55	$ 9.55	$ 9.55	$ 9.61	$ 9.62	$ 9.61	$ 9.61	$ 9.57
Low Growth & High Price	2011-2012	Oct	$ 9.59	$ 9.64	$ 9.59	$ 9.59	$ 9.59	$ 9.64	$ 9.65	$ 9.64	$ 9.64	$ 9.60
Low Growth & High Price	2012-2013	Nov	$ 10.77	$ 10.77	$ 10.77	$ 10.77	$ 10.77	$ 10.77	$ 10.77	$ 10.77	$ 10.77	$ 10.77
Low Growth & High Price	2012-2013	Dec	$ 10.93	$ 11.03	$ 10.95	$ 10.95	$ 10.95	$ 11.03	$ 10.93	$ 11.03	$ 11.00	$ 10.97
Low Growth & High Price	2012-2013	Jan	$ 11.33	$ 11.46	$ 11.33	$ 11.33	$ 11.33	$ 11.46	$ 11.45	$ 11.46	$ 11.45	$ 11.35
Low Growth & High Price	2012-2013	Feb	$ 11.35	$ 11.42	$ 11.35	$ 11.35	$ 11.35	$ 11.42	$ 11.46	$ 11.42	$ 11.44	$ 11.37
Low Growth & High Price	2012-2013	Mar	$ 10.86	$ 10.91	$ 10.86	$ 10.86	$ 10.86	$ 10.83	$ 11.08	$ 10.83	$ 10.92	$ 10.87
Low Growth & High Price	2012-2013	Apr	$ 10.25	$ 10.51	$ 10.25	$ 10.25	$ 10.25	$ 10.36	$ 10.36	$ 10.54	$ 10.42	$ 10.31
Low Growth & High Price	2012-2013	May	$ 10.31	$ 10.51	$ 10.31	$ 10.31	$ 10.31	$ 10.42	$ 10.42	$ 10.54	$ 10.46	$ 10.35
Low Growth & High Price	2012-2013	Jun	$ 10.41	$ 10.52	$ 10.41	$ 10.41	$ 10.41	$ 10.52	$ 10.52	$ 10.54	$ 10.53	$ 10.44
Low Growth & High Price	2012-2013	Jul	$ 10.49	$ 10.54	$ 10.49	$ 10.49	$ 10.49	$ 10.54	$ 10.60	$ 10.54	$ 10.56	$ 10.50
Low Growth & High Price	2012-2013	Aug	$ 10.58	$ 10.60	$ 10.58	$ 10.58	$ 10.58	$ 10.60	$ 10.66	$ 10.60	$ 10.62	$ 10.58
Low Growth & High Price	2012-2013	Sep	$ 10.55	$ 10.56	$ 10.55	$ 10.55	$ 10.55	$ 10.56	$ 10.63	$ 10.56	$ 10.59	$ 10.55
Low Growth & High Price	2012-2013	Oct	$ 10.65	$ 10.63	$ 10.63	$ 10.63	$ 10.63	$ 10.63	$ 10.72	$ 10.63	$ 10.66	$ 10.63
Low Growth & High Price	2013-2014	Nov	$ 11.14	$ 11.13	$ 11.14	$ 11.14	$ 11.14	$ 11.13	$ 11.13	$ 11.13	$ 11.13	$ 11.14
Low Growth & High Price	2013-2014	Dec	$ 11.21	$ 11.22	$ 11.21	$ 11.21	$ 11.21	$ 11.22	$ 11.21	$ 11.22	$ 11.21	$ 11.21
Low Growth & High Price	2013-2014	Jan	$ 10.90	$ 11.15	$ 10.90	$ 10.90	$ 10.90	$ 11.15	$ 11.12	$ 11.15	$ 11.14	$ 10.95
Low Growth & High Price	2013-2014	Feb	$ 10.99	$ 11.03	$ 10.99	$ 10.99	$ 10.99	$ 11.03	$ 11.20	$ 11.03	$ 11.09	$ 11.00
Low Growth & High Price	2013-2014	Mar	$ 10.51	$ 10.49	$ 10.50	$ 10.50	$ 10.50	$ 10.49	$ 10.80	$ 10.49	$ 10.59	$ 10.50
Low Growth & High Price	2013-2014	Apr	$ 10.07	$ 10.24	$ 10.07	$ 10.07	$ 10.07	$ 10.20	$ 10.20	$ 10.24	$ 10.22	$ 10.11
Low Growth & High Price	2013-2014	May	$ 10.09	$ 10.24	$ 10.09	$ 10.09	$ 10.09	$ 10.24	$ 10.25	$ 10.24	$ 10.25	$ 10.12
Low Growth & High Price	2013-2014	Jun	$ 10.24	$ 10.24	$ 10.24	$ 10.24	$ 10.24	$ 10.24	$ 10.35	$ 10.24	$ 10.28	$ 10.24
Low Growth & High Price	2013-2014	Jul	$ 10.33	$ 10.25	$ 10.25	$ 10.25	$ 10.25	$ 10.25	$ 10.44	$ 10.25	$ 10.31	$ 10.26
Low Growth & High Price	2013-2014	Aug	$ 10.39	$ 10.27	$ 10.27	$ 10.27	$ 10.27	$ 10.27	$ 10.50	$ 10.27	$ 10.35	$ 10.29
Low Growth & High Price	2013-2014	Sep	$ 10.35	$ 10.25	$ 10.25	$ 10.25	$ 10.25	$ 10.25	$ 10.44	$ 10.25	$ 10.31	$ 10.27
Low Growth & High Price	2013-2014	Oct	$ 10.39	$ 10.33	$ 10.33	$ 10.33	$ 10.33	$ 10.33	$ 10.47	$ 10.33	$ 10.38	$ 10.34
Low Growth & High Price	2014-2015	Nov	$ 12.34	$ 12.34	$ 12.34	$ 12.34	$ 12.34	$ 12.34	$ 12.34	$ 12.34	$ 12.34	$ 12.34
Low Growth & High Price	2014-2015	Dec	$ 12.48	$ 12.66	$ 12.52	$ 12.52	$ 12.52	$ 12.66	$ 12.47	$ 12.66	$ 12.60	$ 12.54
Low Growth & High Price	2014-2015	Jan	$ 13.42	$ 13.71	$ 13.42	$ 13.42	$ 13.42	$ 13.71	$ 13.71	$ 13.71	$ 13.71	$ 13.48
Low Growth & High Price	2014-2015	Feb	$ 13.52	$ 13.64	$ 13.52	$ 13.52	$ 13.52	$ 13.64	$ 13.78	$ 13.64	$ 13.69	$ 13.54
Low Growth & High Price	2014-2015	Mar	$ 12.98	$ 13.05	$ 12.98	$ 12.98	$ 12.98	$ 13.05	$ 13.40	$ 13.05	$ 13.17	$ 12.99
Low Growth & High Price	2014-2015	Apr	$ 12.53	$ 12.88	$ 12.53	$ 12.53	$ 12.53	$ 12.75	$ 12.75	$ 12.88	$ 12.80	$ 12.60
Low Growth & High Price	2014-2015	May	$ 12.60	$ 12.88	$ 12.60	$ 12.60	$ 12.60	$ 12.84	$ 12.84	$ 12.88	$ 12.85	$ 12.65
Low Growth & High Price	2014-2015	Jun	$ 12.80	$ 12.89	$ 12.80	$ 12.80	$ 12.80	$ 12.89	$ 12.92	$ 12.89	$ 12.90	$ 12.81
Low Growth & High Price	2014-2015	Jul	$ 12.95	$ 12.89	$ 12.89	$ 12.89	$ 12.89	$ 12.89	$ 13.06	$ 12.89	$ 12.94	$ 12.90
Low Growth & High Price	2014-2015	Aug	$ 12.99	$ 12.92	$ 12.92	$ 12.92	$ 12.92	$ 12.92	$ 13.10	$ 12.92	$ 12.98	$ 12.93
Low Growth & High Price	2014-2015	Sep	$ 12.94	$ 12.89	$ 12.89	$ 12.89	$ 12.89	$ 12.89	$ 13.04	$ 12.89	$ 12.94	$ 12.90
Low Growth & High Price	2014-2015	Oct	$ 12.98	$ 12.95	$ 12.95	$ 12.95	$ 12.95	$ 12.95	$ 13.07	$ 12.95	$ 12.99	$ 12.96
Low Growth & High Price	2015-2016	Nov	$ 13.84	$ 13.85	$ 13.84	$ 13.84	$ 13.84	$ 13.85	$ 13.85	$ 13.85	$ 13.85	$ 13.84
Low Growth & High Price	2015-2016	Dec	$ 14.02	$ 14.13	$ 14.02	$ 14.02	$ 14.02	$ 14.13	$ 14.07	$ 14.13	$ 14.11	$ 14.04
Low Growth & High Price	2015-2016	Jan	$ 14.01	$ 14.35	$ 14.01	$ 14.01	$ 14.01	$ 14.35	$ 14.34	$ 14.35	$ 14.35	$ 14.08
Low Growth & High Price	2015-2016	Feb	$ 14.46	$ 14.32	$ 14.38	$ 14.38	$ 14.38	$ 14.31	$ 14.44	$ 14.31	$ 14.36	$ 14.38
Low Growth & High Price	2015-2016	Mar	$ 13.47	$ 13.57	$ 13.47	$ 13.47	$ 13.47	$ 13.57	$ 14.03	$ 13.57	$ 13.72	$ 13.49
Low Growth & High Price	2015-2016	Apr	$ 13.03	$ 13.41	$ 13.03	$ 13.03	$ 13.03	$ 13.35	$ 13.35	$ 13.41	$ 13.37	$ 13.10
Low Growth & High Price	2015-2016	May	$ 13.09	$ 13.41	$ 13.09	$ 13.09	$ 13.09	$ 13.41	$ 13.42	$ 13.41	$ 13.42	$ 13.15
Low Growth & High Price	2015-2016	Jun	$ 13.32	$ 13.41	$ 13.32	$ 13.32	$ 13.32	$ 13.41	$ 13.45	$ 13.41	$ 13.43	$ 13.34
Low Growth & High Price	2015-2016	Jul	$ 13.52	$ 13.42	$ 13.42	$ 13.42	$ 13.42	$ 13.42	$ 13.62	$ 13.42	$ 13.49	$ 13.44
Low Growth & High Price	2015-2016	Aug	$ 13.54	$ 13.42	$ 13.42	$ 13.42	$ 13.42	$ 13.42	$ 13.65	$ 13.42	$ 13.50	$ 13.44
Low Growth & High Price	2015-2016	Sep	$ 13.53	$ 13.42	$ 13.42	$ 13.42	$ 13.42	$ 13.42	$ 13.62	$ 13.42	$ 13.49	$ 13.44
Low Growth & High Price	2015-2016	Oct	$ 13.62	$ 13.61	$ 13.61	$ 13.61	$ 13.61	$ 13.61	$ 13.69	$ 13.61	$ 13.64	$ 13.61
Low Growth & High Price	2016-2017	Nov	$ 14.48	$ 14.48	$ 14.48	$ 14.48	$ 14.48	$ 14.48	$ 14.48	$ 14.48	$ 14.48	$ 14.48
Low Growth & High Price	2016-2017	Dec	$ 14.68	$ 14.66	$ 14.66	$ 14.66	$ 14.66	$ 14.66	$ 14.63	$ 14.66	$ 14.65	$ 14.66
Low Growth & High Price	2016-2017	Jan	$ 14.23	$ 14.74	$ 14.23	$ 14.23	$ 14.23	$ 14.74	$ 14.73	$ 14.74	$ 14.73	$ 14.33
Low Growth & High Price	2016-2017	Feb	$ 14.39	$ 14.49	$ 14.39	$ 14.39	$ 14.39	$ 14.49	$ 14.80	$ 14.49	$ 14.60	$ 14.41
Low Growth & High Price	2016-2017	Mar	$ 13.75	$ 13.86	$ 13.75	$ 13.75	$ 13.75	$ 13.86	$ 14.25	$ 13.86	$ 13.99	$ 13.77
Low Growth & High Price	2016-2017	Apr	$ 13.26	$ 13.64	$ 13.26	$ 13.26	$ 13.26	$ 13.57	$ 13.57	$ 13.65	$ 13.60	$ 13.33
Low Growth & High Price	2016-2017	May	$ 13.41	$ 13.65	$ 13.41	$ 13.41	$ 13.41	$ 13.65	$ 13.69	$ 13.65	$ 13.66	$ 13.45
Low Growth & High Price	2016-2017	Jun	$ 13.42	$ 13.65	$ 13.42	$ 13.42	$ 13.42	$ 13.65	$ 13.72	$ 13.65	$ 13.67	$ 13.46
Low Growth & High Price	2016-2017	Jul	$ 13.63	$ 13.65	$ 13.63	$ 13.63	$ 13.63	$ 13.65	$ 13.80	$ 13.65	$ 13.70	$ 13.63
Low Growth & High Price	2016-2017	Aug	$ 13.69	$ 13.71	$ 13.69	$ 13.69	$ 13.69	$ 13.71	$ 13.84	$ 13.71	$ 13.75	$ 13.69

Appendix 6.4 - Monthly Avoided Cost Detail 1/

2009$

Scenario	Gas Year	Month	Klam Falls	La Grande	Medford GTN	Medford NWP	Roseburg	Wa/Id Both	Wa/Id GTN	Wa/Id NWP	WA/ID Annual	OR Annual
Low Growth & High Price	2016-2017	Sep	$ 13.65	$ 13.66	$ 13.65	$ 13.65	$ 13.65	$ 13.66	$ 13.79	$ 13.66	$ 13.70	$ 13.65
Low Growth & High Price	2016-2017	Oct	$ 13.71	$ 13.71	$ 13.71	$ 13.71	$ 13.71	$ 13.71	$ 13.83	$ 13.71	$ 13.75	$ 13.71
Low Growth & High Price	2017-2018	Nov	$ 14.51	$ 14.65	$ 14.51	$ 14.51	$ 14.51	$ 14.65	$ 14.65	$ 14.65	$ 14.65	$ 14.53
Low Growth & High Price	2017-2018	Dec	$ 14.64	$ 14.88	$ 14.65	$ 14.65	$ 14.65	$ 14.88	$ 14.75	$ 14.88	$ 14.83	$ 14.69
Low Growth & High Price	2017-2018	Jan	$ 15.08	$ 15.49	$ 15.08	$ 15.08	$ 15.08	$ 15.49	$ 15.48	$ 15.49	$ 15.48	$ 15.16
Low Growth & High Price	2017-2018	Feb	$ 15.20	$ 15.35	$ 15.20	$ 15.20	$ 15.20	$ 15.35	$ 15.55	$ 15.35	$ 15.41	$ 15.23
Low Growth & High Price	2017-2018	Mar	$ 14.57	$ 14.74	$ 14.57	$ 14.57	$ 14.57	$ 14.74	$ 15.05	$ 14.74	$ 14.85	$ 14.60
Low Growth & High Price	2017-2018	Apr	$ 14.19	$ 14.59	$ 14.19	$ 14.19	$ 14.19	$ 14.45	$ 14.45	$ 14.59	$ 14.50	$ 14.27
Low Growth & High Price	2017-2018	May	$ 14.30	$ 14.59	$ 14.30	$ 14.30	$ 14.30	$ 14.57	$ 14.57	$ 14.59	$ 14.57	$ 14.35
Low Growth & High Price	2017-2018	Jun	$ 14.35	$ 14.59	$ 14.35	$ 14.35	$ 14.35	$ 14.59	$ 14.63	$ 14.59	$ 14.60	$ 14.40
Low Growth & High Price	2017-2018	Jul	$ 14.57	$ 14.61	$ 14.57	$ 14.57	$ 14.57	$ 14.61	$ 14.75	$ 14.61	$ 14.66	$ 14.58
Low Growth & High Price	2017-2018	Aug	$ 14.62	$ 14.66	$ 14.62	$ 14.62	$ 14.62	$ 14.66	$ 14.80	$ 14.66	$ 14.71	$ 14.63
Low Growth & High Price	2017-2018	Sep	$ 14.53	$ 14.60	$ 14.53	$ 14.53	$ 14.53	$ 14.60	$ 14.70	$ 14.60	$ 14.63	$ 14.54
Low Growth & High Price	2017-2018	Oct	$ 14.57	$ 14.57	$ 14.57	$ 14.57	$ 14.57	$ 14.57	$ 14.71	$ 14.57	$ 14.62	$ 14.57
Low Growth & High Price	2018-2019	Nov	$ 15.45	$ 15.56	$ 15.45	$ 15.45	$ 15.45	$ 15.56	$ 15.56	$ 15.56	$ 15.56	$ 15.47
Low Growth & High Price	2018-2019	Dec	$ 15.55	$ 15.68	$ 15.55	$ 15.55	$ 15.55	$ 15.68	$ 15.66	$ 15.68	$ 15.67	$ 15.58
Low Growth & High Price	2018-2019	Jan	$ 15.72	$ 15.71	$ 15.71	$ 15.71	$ 15.71	$ 15.71	$ 15.70	$ 15.71	$ 15.71	$ 15.71
Low Growth & High Price	2018-2019	Feb	$ 15.50	$ 15.56	$ 15.50	$ 15.50	$ 15.50	$ 15.56	$ 15.75	$ 15.56	$ 15.62	$ 15.51
Low Growth & High Price	2018-2019	Mar	$ 14.95	$ 14.99	$ 14.95	$ 14.95	$ 14.95	$ 14.99	$ 15.24	$ 14.99	$ 15.07	$ 14.95
Low Growth & High Price	2018-2019	Apr	$ 14.47	$ 14.74	$ 14.47	$ 14.47	$ 14.47	$ 14.67	$ 14.67	$ 14.74	$ 14.69	$ 14.52
Low Growth & High Price	2018-2019	May	$ 14.56	$ 14.74	$ 14.56	$ 14.56	$ 14.56	$ 14.74	$ 14.75	$ 14.74	$ 14.74	$ 14.59
Low Growth & High Price	2018-2019	Jun	$ 14.63	$ 14.74	$ 14.63	$ 14.63	$ 14.63	$ 14.74	$ 14.82	$ 14.74	$ 14.77	$ 14.65
Low Growth & High Price	2018-2019	Jul	$ 14.71	$ 14.74	$ 14.71	$ 14.71	$ 14.71	$ 14.74	$ 14.91	$ 14.74	$ 14.80	$ 14.71
Low Growth & High Price	2018-2019	Aug	$ 14.74	$ 14.75	$ 14.74	$ 14.74	$ 14.74	$ 14.75	$ 14.94	$ 14.75	$ 14.82	$ 14.74
Low Growth & High Price	2018-2019	Sep	$ 14.69	$ 14.75	$ 14.69	$ 14.69	$ 14.69	$ 14.75	$ 14.88	$ 14.75	$ 14.79	$ 14.70
Low Growth & High Price	2018-2019	Oct	$ 14.80	$ 14.80	$ 14.80	$ 14.80	$ 14.80	$ 14.80	$ 14.95	$ 14.80	$ 14.85	$ 14.80
Low Growth & High Price	2019-2020	Nov	$ 15.78	$ 15.76	$ 15.78	$ 15.78	$ 15.78	$ 15.76	$ 15.76	$ 15.76	$ 15.76	$ 15.77
Low Growth & High Price	2019-2020	Dec	$ 15.90	$ 15.90	$ 15.90	$ 15.90	$ 15.90	$ 15.90	$ 15.88	$ 15.90	$ 15.89	$ 15.90
Low Growth & High Price	2019-2020	Jan	$ 15.61	$ 15.91	$ 15.61	$ 15.61	$ 15.61	$ 15.91	$ 15.90	$ 15.91	$ 15.91	$ 15.67
Low Growth & High Price	2019-2020	Feb	$ 15.71	$ 15.78	$ 15.71	$ 15.71	$ 15.71	$ 15.77	$ 15.98	$ 15.77	$ 15.84	$ 15.73
Low Growth & High Price	2019-2020	Mar	$ 15.32	$ 15.29	$ 15.32	$ 15.32	$ 15.32	$ 15.29	$ 15.54	$ 15.29	$ 15.38	$ 15.31
Low Growth & High Price	2019-2020	Apr	$ 14.61	$ 15.08	$ 14.61	$ 14.61	$ 14.61	$ 14.85	$ 14.85	$ 15.08	$ 14.93	$ 14.70
Low Growth & High Price	2019-2020	May	$ 14.71	$ 15.08	$ 14.71	$ 14.71	$ 14.71	$ 14.95	$ 14.95	$ 15.08	$ 15.00	$ 14.78
Low Growth & High Price	2019-2020	Jun	$ 14.81	$ 15.09	$ 14.81	$ 14.81	$ 14.81	$ 15.04	$ 15.04	$ 15.09	$ 15.06	$ 14.86
Low Growth & High Price	2019-2020	Jul	$ 14.98	$ 15.09	$ 14.98	$ 14.98	$ 14.98	$ 15.09	$ 15.19	$ 15.09	$ 15.12	$ 15.00
Low Growth & High Price	2019-2020	Aug	$ 15.00	$ 15.16	$ 15.00	$ 15.00	$ 15.00	$ 15.16	$ 15.21	$ 15.16	$ 15.18	$ 15.03
Low Growth & High Price	2019-2020	Sep	$ 15.01	$ 15.11	$ 15.01	$ 15.01	$ 15.01	$ 15.11	$ 15.20	$ 15.11	$ 15.14	$ 15.03
Low Growth & High Price	2019-2020	Oct	$ 15.13	$ 15.14	$ 15.13	$ 15.13	$ 15.13	$ 15.14	$ 15.27	$ 15.14	$ 15.18	$ 15.13
Low Growth & High Price	2020-2021	Nov	$ 16.13	$ 16.09	$ 16.13	$ 16.13	$ 16.13	$ 16.09	$ 16.09	$ 16.09	$ 16.09	$ 16.12
Low Growth & High Price	2020-2021	Dec	$ 16.22	$ 16.21	$ 16.21	$ 16.21	$ 16.21	$ 16.21	$ 16.19	$ 16.21	$ 16.20	$ 16.21
Low Growth & High Price	2020-2021	Jan	$ 16.22	$ 16.21	$ 16.22	$ 16.22	$ 16.22	$ 16.21	$ 16.20	$ 16.21	$ 16.20	$ 16.22
Low Growth & High Price	2020-2021	Feb	$ 16.29	$ 16.18	$ 16.29	$ 16.29	$ 16.29	$ 16.18	$ 16.27	$ 16.18	$ 16.21	$ 16.27
Low Growth & High Price	2020-2021	Mar	$ 15.61	$ 15.55	$ 15.60	$ 15.60	$ 15.60	$ 15.55	$ 15.61	$ 15.55	$ 15.57	$ 15.59
Low Growth & High Price	2020-2021	Apr	$ 14.83	$ 15.27	$ 14.83	$ 14.83	$ 14.83	$ 15.05	$ 15.05	$ 15.27	$ 15.13	$ 14.92
Low Growth & High Price	2020-2021	May	$ 14.87	$ 15.27	$ 14.87	$ 14.87	$ 14.87	$ 15.13	$ 15.13	$ 15.27	$ 15.18	$ 14.95
Low Growth & High Price	2020-2021	Jun	$ 14.95	$ 15.28	$ 14.95	$ 14.95	$ 14.95	$ 15.21	$ 15.21	$ 15.28	$ 15.23	$ 15.01
Low Growth & High Price	2020-2021	Jul	$ 15.06	$ 15.30	$ 15.06	$ 15.06	$ 15.06	$ 15.30	$ 15.34	$ 15.30	$ 15.31	$ 15.11
Low Growth & High Price	2020-2021	Aug	$ 15.02	$ 15.31	$ 15.02	$ 15.02	$ 15.02	$ 15.31	$ 15.31	$ 15.31	$ 15.31	$ 15.08
Low Growth & High Price	2020-2021	Sep	$ 15.00	$ 15.28	$ 15.00	$ 15.00	$ 15.00	$ 15.24	$ 15.24	$ 15.28	$ 15.26	$ 15.05
Low Growth & High Price	2020-2021	Oct	$ 14.99	$ 15.31	$ 14.99	$ 14.99	$ 14.99	$ 15.24	$ 15.24	$ 15.31	$ 15.27	$ 15.05
Low Growth & High Price	2021-2022	Nov	$ 16.01	$ 16.08	$ 16.01	$ 16.01	$ 16.01	$ 16.06	$ 16.06	$ 16.08	$ 16.07	$ 16.02
Low Growth & High Price	2021-2022	Dec	$ 16.19	$ 16.27	$ 16.20	$ 16.20	$ 16.20	$ 16.23	$ 16.20	$ 16.27	$ 16.23	$ 16.21
Low Growth & High Price	2021-2022	Jan	$ 16.04	$ 16.29	$ 16.04	$ 16.04	$ 16.04	$ 16.22	$ 16.13	$ 16.29	$ 16.21	$ 16.09
Low Growth & High Price	2021-2022	Feb	$ 16.12	$ 16.24	$ 16.12	$ 16.12	$ 16.12	$ 16.22	$ 16.22	$ 16.22	$ 16.22	$ 16.15
Low Growth & High Price	2021-2022	Mar	$ 15.57	$ 15.66	$ 15.57	$ 15.57	$ 15.57	$ 15.66	$ 15.66	$ 15.66	$ 15.66	$ 15.59
Low Growth & High Price	2021-2022	Apr	$ 14.78	$ 15.40	$ 14.78	$ 14.78	$ 14.78	$ 15.10	$ 15.10	$ 15.54	$ 15.25	$ 14.90
Low Growth & High Price	2021-2022	May	$ 14.86	$ 15.40	$ 14.86	$ 14.86	$ 14.86	$ 15.21	$ 15.21	$ 15.54	$ 15.32	$ 14.97
Low Growth & High Price	2021-2022	Jun	$ 14.94	$ 15.40	$ 14.94	$ 14.94	$ 14.94	$ 15.30	$ 15.30	$ 15.54	$ 15.38	$ 15.03
Low Growth & High Price	2021-2022	Jul	$ 15.07	$ 15.54	$ 15.07	$ 15.07	$ 15.07	$ 15.43	$ 15.43	$ 15.54	$ 15.47	$ 15.16
Low Growth & High Price	2021-2022	Aug	$ 15.13	$ 15.54	$ 15.13	$ 15.13	$ 15.13	$ 15.49	$ 15.49	$ 15.55	$ 15.51	$ 15.21
Low Growth & High Price	2021-2022	Sep	$ 15.12	$ 15.55	$ 15.12	$ 15.12	$ 15.12	$ 15.43	$ 15.43	$ 15.55	$ 15.47	$ 15.20
Low Growth & High Price	2021-2022	Oct	$ 15.18	$ 15.59	$ 15.18	$ 15.18	$ 15.18	$ 15.45	$ 15.45	$ 15.59	$ 15.49	$ 15.26
Low Growth & High Price	2022-2023	Nov	$ 16.24	$ 16.41	$ 16.24	$ 16.24	$ 16.24	$ 16.27	$ 16.27	$ 16.41	$ 16.32	$ 16.27
Low Growth & High Price	2022-2023	Dec	$ 16.38	$ 16.55	$ 16.39	$ 16.39	$ 16.39	$ 16.45	$ 16.36	$ 16.55	$ 16.45	$ 16.42
Low Growth & High Price	2022-2023	Jan	$ 16.22	$ 16.58	$ 16.22	$ 16.22	$ 16.22	$ 16.47	$ 16.35	$ 16.58	$ 16.47	$ 16.29
Low Growth & High Price	2022-2023	Feb	$ 16.31	$ 16.46	$ 16.32	$ 16.32	$ 16.32	$ 16.43	$ 16.42	$ 16.43	$ 16.42	$ 16.35
Low Growth & High Price	2022-2023	Mar	$ 15.81	$ 15.90	$ 15.81	$ 15.81	$ 15.81	$ 15.90	$ 15.90	$ 15.90	$ 15.90	$ 15.83
Low Growth & High Price	2022-2023	Apr	$ 14.93	$ 15.69	$ 14.93	$ 14.93	$ 14.93	$ 15.30	$ 15.30	$ 15.82	$ 15.48	$ 15.08
Low Growth & High Price	2022-2023	May	$ 15.04	$ 15.70	$ 15.04	$ 15.04	$ 15.04	$ 15.43	$ 15.43	$ 15.82	$ 15.56	$ 15.17
Low Growth & High Price	2022-2023	Jun	$ 15.13	$ 15.70	$ 15.13	$ 15.13	$ 15.13	$ 15.53	$ 15.53	$ 15.82	$ 15.63	$ 15.24
Low Growth & High Price	2022-2023	Jul	$ 15.28	$ 15.83	$ 15.28	$ 15.28	$ 15.28	$ 15.66	$ 15.66	$ 15.83	$ 15.71	$ 15.39
Low Growth & High Price	2022-2023	Aug	$ 15.32	$ 15.83	$ 15.32	$ 15.32	$ 15.32	$ 15.70	$ 15.70	$ 15.83	$ 15.74	$ 15.42
Low Growth & High Price	2022-2023	Sep	$ 15.38	$ 15.83	$ 15.38	$ 15.38	$ 15.38	$ 15.66	$ 15.66	$ 15.83	$ 15.72	$ 15.47
Low Growth & High Price	2022-2023	Oct	$ 15.42	$ 15.90	$ 15.42	$ 15.42	$ 15.42	$ 15.69	$ 15.69	$ 15.90	$ 15.76	$ 15.51
Low Growth & High Price	2023-2024	Nov	$ 16.53	$ 16.77	$ 16.53	$ 16.53	$ 16.53	$ 16.53	$ 16.53	$ 16.77	$ 16.61	$ 16.58
Low Growth & High Price	2023-2024	Dec	$ 16.69	$ 16.90	$ 16.71	$ 16.71	$ 16.71	$ 16.76	$ 16.64	$ 16.90	$ 16.77	$ 16.74
Low Growth & High Price	2023-2024	Jan	$ 16.64	$ 16.95	$ 16.64	$ 16.64	$ 16.64	$ 16.85	$ 16.71	$ 16.96	$ 16.84	$ 16.70
Low Growth & High Price	2023-2024	Feb	$ 16.67	$ 16.79	$ 16.68	$ 16.68	$ 16.68	$ 16.75	$ 16.75	$ 16.75	$ 16.75	$ 16.70
Low Growth & High Price	2023-2024	Mar	$ 16.12	$ 16.21	$ 16.12	$ 16.12	$ 16.12	$ 16.21	$ 16.21	$ 16.21	$ 16.21	$ 16.14
Low Growth & High Price	2023-2024	Apr	$ 15.23	$ 16.02	$ 15.23	$ 15.23	$ 15.23	$ 15.61	$ 15.61	$ 16.12	$ 15.78	$ 15.38
Low Growth & High Price	2023-2024	May	$ 15.33	$ 16.02	$ 15.33	$ 15.33	$ 15.33	$ 15.72	$ 15.72	$ 16.12	$ 15.85	$ 15.47
Low Growth & High Price	2023-2024	Jun	$ 15.45	$ 16.04	$ 15.45	$ 15.45	$ 15.45	$ 15.83	$ 15.83	$ 16.13	$ 15.93	$ 15.57
Low Growth & High Price	2023-2024	Jul	$ 15.56	$ 16.13	$ 15.56	$ 15.56	$ 15.56	$ 15.94	$ 15.94	$ 16.13	$ 16.00	$ 15.67
Low Growth & High Price	2023-2024	Aug	$ 15.63	$ 16.13	$ 15.63	$ 15.63	$ 15.63	$ 16.00	$ 16.00	$ 16.13	$ 16.05	$ 15.73
Low Growth & High Price	2023-2024	Sep	$ 15.66	$ 16.13	$ 15.66	$ 15.66	$ 15.66	$ 15.97	$ 15.97	$ 16.13	$ 16.03	$ 15.75
Low Growth & High Price	2023-2024	Oct	$ 15.78	$ 16.24	$ 15.78	$ 15.78	$ 15.78	$ 16.01	$ 16.01	$ 16.24	$ 16.09	$ 15.87
Low Growth & High Price	2024-2025	Nov	$ 16.91	$ 17.07	$ 16.91	$ 16.91	$ 16.91	$ 16.83	$ 16.83	$ 17.07	$ 16.91	$ 16.94
Low Growth & High Price	2024-2025	Dec	$ 17.06	$ 17.23	$ 17.07	$ 17.07	$ 17.07	$ 17.09	$ 16.97	$ 17.23	$ 17.10	$ 17.10
Low Growth & High Price	2024-2025	Jan	$ 16.95	$ 17.26	$ 16.95	$ 16.95	$ 16.95	$ 17.15	$ 17.02	$ 17.26	$ 17.14	$ 17.01
Low Growth & High Price	2024-2025	Feb	$ 16.99	$ 17.10	$ 17.00	$ 17.00	$ 17.00	$ 17.06	$ 17.06	$ 17.06	$ 17.06	$ 17.02
Low Growth & High Price	2024-2025	Mar	$ 16.36	$ 16.46	$ 16.36	$ 16.36	$ 16.36	$ 16.46	$ 16.46	$ 16.46	$ 16.46	$ 16.38
Low Growth & High Price	2024-2025	Apr	$ 15.48	$ 16.29	$ 15.48	$ 15.48	$ 15.48	$ 15.88	$ 15.88	$ 16.37	$ 16.05	$ 15.64
Low Growth & High Price	2024-2025	May	$ 15.59	$ 16.29	$ 15.59	$ 15.59	$ 15.59	$ 15.99	$ 15.99	$ 16.38	$ 16.12	$ 15.73
Low Growth & High Price	2024-2025	Jun	$ 15.70	$ 16.31	$ 15.70	$ 15.70	$ 15.70	$ 16.10	$ 16.10	$ 16.38	$ 16.20	$ 15.82

Appendix 6.4 - Monthly Avoided Cost Detail 1/
2009$

Scenario	Gas Year	Month	Klam Falls	La Grande	Medford GTN	Medford NWP	Roseburg	Wa/Id Both	Wa/Id GTN	Wa/Id NWP	WA/ID Annual	OR Annual
Low Growth & High Price	2024-2025	Jul	$ 15.81	$ 16.38	$ 15.81	$ 15.81	$ 15.81	$ 16.23	$ 16.23	$ 16.38	$ 16.28	$ 15.92
Low Growth & High Price	2024-2025	Aug	$ 15.90	$ 16.38	$ 15.90	$ 15.90	$ 15.90	$ 16.29	$ 16.29	$ 16.38	$ 16.32	$ 15.99
Low Growth & High Price	2024-2025	Sep	$ 15.93	$ 16.38	$ 15.93	$ 15.93	$ 15.93	$ 16.24	$ 16.24	$ 16.38	$ 16.29	$ 16.02
Low Growth & High Price	2024-2025	Oct	$ 16.03	$ 16.53	$ 16.03	$ 16.03	$ 16.03	$ 16.28	$ 16.28	$ 16.53	$ 16.36	$ 16.13
Low Growth & High Price	2025-2026	Nov	$ 17.28	$ 17.40	$ 17.28	$ 17.28	$ 17.28	$ 17.16	$ 17.16	$ 17.40	$ 17.24	$ 17.30
Low Growth & High Price	2025-2026	Dec	$ 17.27	$ 17.52	$ 17.33	$ 17.33	$ 17.33	$ 17.40	$ 17.20	$ 17.52	$ 17.37	$ 17.35
Low Growth & High Price	2025-2026	Jan	$ 17.56	$ 17.87	$ 17.56	$ 17.56	$ 17.56	$ 17.76	$ 17.62	$ 17.87	$ 17.75	$ 17.62
Low Growth & High Price	2025-2026	Feb	$ 17.59	$ 17.71	$ 17.59	$ 17.59	$ 17.59	$ 17.67	$ 17.66	$ 17.67	$ 17.67	$ 17.61
Low Growth & High Price	2025-2026	Mar	$ 17.02	$ 17.09	$ 17.02	$ 17.02	$ 17.02	$ 17.09	$ 17.09	$ 17.09	$ 17.09	$ 17.03
Low Growth & High Price	2025-2026	Apr	$ 16.06	$ 16.89	$ 16.06	$ 16.06	$ 16.06	$ 16.49	$ 16.49	$ 17.00	$ 16.66	$ 16.22
Low Growth & High Price	2025-2026	May	$ 16.17	$ 16.89	$ 16.17	$ 16.17	$ 16.17	$ 16.60	$ 16.60	$ 17.00	$ 16.73	$ 16.31
Low Growth & High Price	2025-2026	Jun	$ 16.28	$ 16.92	$ 16.28	$ 16.28	$ 16.28	$ 16.71	$ 16.71	$ 17.00	$ 16.81	$ 16.41
Low Growth & High Price	2025-2026	Jul	$ 16.39	$ 17.00	$ 16.39	$ 16.39	$ 16.39	$ 16.83	$ 16.83	$ 17.00	$ 16.89	$ 16.51
Low Growth & High Price	2025-2026	Aug	$ 16.46	$ 17.01	$ 16.46	$ 16.46	$ 16.46	$ 16.88	$ 16.88	$ 17.01	$ 16.92	$ 16.57
Low Growth & High Price	2025-2026	Sep	$ 16.49	$ 17.01	$ 16.49	$ 16.49	$ 16.49	$ 16.83	$ 16.83	$ 17.01	$ 16.89	$ 16.59
Low Growth & High Price	2025-2026	Oct	$ 16.62	$ 17.07	$ 16.62	$ 16.62	$ 16.62	$ 16.87	$ 16.87	$ 17.07	$ 16.94	$ 16.71
Low Growth & High Price	2026-2027	Nov	$ 17.76	$ 17.94	$ 17.76	$ 17.76	$ 17.76	$ 17.68	$ 17.68	$ 17.94	$ 17.77	$ 17.79
Low Growth & High Price	2026-2027	Dec	$ 17.85	$ 18.15	$ 17.91	$ 17.91	$ 17.91	$ 17.97	$ 17.78	$ 18.15	$ 17.97	$ 17.94
Low Growth & High Price	2026-2027	Jan	$ 18.16	$ 18.48	$ 18.16	$ 18.16	$ 18.16	$ 18.36	$ 18.22	$ 18.48	$ 18.36	$ 18.22
Low Growth & High Price	2026-2027	Feb	$ 18.26	$ 18.36	$ 18.26	$ 18.26	$ 18.26	$ 18.33	$ 18.32	$ 18.33	$ 18.33	$ 18.28
Low Growth & High Price	2026-2027	Mar	$ 17.70	$ 17.72	$ 17.70	$ 17.70	$ 17.70	$ 17.72	$ 17.72	$ 17.72	$ 17.72	$ 17.70
Low Growth & High Price	2026-2027	Apr	$ 16.73	$ 17.59	$ 16.73	$ 16.73	$ 16.73	$ 17.14	$ 17.14	$ 17.63	$ 17.30	$ 16.90
Low Growth & High Price	2026-2027	May	$ 16.84	$ 17.59	$ 16.84	$ 16.84	$ 16.84	$ 17.25	$ 17.25	$ 17.63	$ 17.38	$ 16.99
Low Growth & High Price	2026-2027	Jun	$ 16.94	$ 17.62	$ 16.94	$ 16.94	$ 16.94	$ 17.35	$ 17.35	$ 17.64	$ 17.44	$ 17.07
Low Growth & High Price	2026-2027	Jul	$ 17.05	$ 17.64	$ 17.05	$ 17.05	$ 17.05	$ 17.46	$ 17.46	$ 17.64	$ 17.52	$ 17.17
Low Growth & High Price	2026-2027	Aug	$ 17.16	$ 17.64	$ 17.16	$ 17.16	$ 17.16	$ 17.56	$ 17.56	$ 17.64	$ 17.59	$ 17.25
Low Growth & High Price	2026-2027	Sep	$ 17.14	$ 17.64	$ 17.14	$ 17.14	$ 17.14	$ 17.46	$ 17.46	$ 17.64	$ 17.52	$ 17.24
Low Growth & High Price	2026-2027	Oct	$ 17.25	$ 17.79	$ 17.25	$ 17.25	$ 17.25	$ 17.49	$ 17.49	$ 17.79	$ 17.59	$ 17.36
Low Growth & High Price	2027-2028	Nov	$ 18.39	$ 18.57	$ 18.39	$ 18.39	$ 18.39	$ 18.31	$ 18.31	$ 18.57	$ 18.40	$ 18.43
Low Growth & High Price	2027-2028	Dec	$ 18.48	$ 18.80	$ 18.54	$ 18.54	$ 18.54	$ 18.61	$ 18.42	$ 18.81	$ 18.61	$ 18.58
Low Growth & High Price	2027-2028	Jan	$ 18.81	$ 19.14	$ 18.81	$ 18.81	$ 18.81	$ 19.02	$ 18.88	$ 19.14	$ 19.01	$ 18.88
Low Growth & High Price	2027-2028	Feb	$ 18.91	$ 19.03	$ 18.91	$ 18.91	$ 18.91	$ 18.98	$ 18.99	$ 18.98	$ 18.99	$ 18.94
Low Growth & High Price	2027-2028	Mar	$ 18.33	$ 18.37	$ 18.33	$ 18.33	$ 18.33	$ 18.37	$ 18.37	$ 18.37	$ 18.37	$ 18.34
Low Growth & High Price	2027-2028	Apr	$ 17.37	$ 18.23	$ 17.37	$ 17.37	$ 17.37	$ 17.77	$ 17.77	$ 18.28	$ 17.94	$ 17.54
Low Growth & High Price	2027-2028	May	$ 17.48	$ 18.23	$ 17.48	$ 17.48	$ 17.48	$ 17.90	$ 17.90	$ 18.28	$ 18.02	$ 17.63
Low Growth & High Price	2027-2028	Jun	$ 17.58	$ 18.27	$ 17.58	$ 17.58	$ 17.58	$ 18.00	$ 18.00	$ 18.28	$ 18.09	$ 17.72
Low Growth & High Price	2027-2028	Jul	$ 17.70	$ 18.28	$ 17.70	$ 17.70	$ 17.70	$ 18.12	$ 18.12	$ 18.28	$ 18.17	$ 17.82
Low Growth & High Price	2027-2028	Aug	$ 17.81	$ 18.29	$ 17.81	$ 17.81	$ 17.81	$ 18.22	$ 18.22	$ 18.29	$ 18.24	$ 17.90
Low Growth & High Price	2027-2028	Sep	$ 17.79	$ 18.29	$ 17.79	$ 17.79	$ 17.79	$ 18.12	$ 18.12	$ 18.29	$ 18.17	$ 17.89
Low Growth & High Price	2027-2028	Oct	$ 17.89	$ 18.44	$ 17.89	$ 17.89	$ 17.89	$ 18.14	$ 18.14	$ 18.44	$ 18.24	$ 18.00
Low Growth & High Price	2028-2029	Nov	$ 19.05	$ 19.25	$ 19.05	$ 19.05	$ 19.05	$ 18.98	$ 18.98	$ 19.25	$ 19.07	$ 19.09
Low Growth & High Price	2028-2029	Dec	$ 19.15	$ 19.48	$ 19.23	$ 19.23	$ 19.23	$ 19.29	$ 19.10	$ 19.48	$ 19.29	$ 19.26
Low Growth & High Price	2028-2029	Jan	$ 19.49	$ 19.84	$ 19.49	$ 19.49	$ 19.49	$ 19.72	$ 19.58	$ 19.84	$ 19.71	$ 19.56
Low Growth & High Price	2028-2029	Feb	$ 19.61	$ 19.72	$ 19.61	$ 19.61	$ 19.61	$ 19.69	$ 19.68	$ 19.69	$ 19.68	$ 19.63
Low Growth & High Price	2028-2029	Mar	$ 18.99	$ 19.04	$ 18.99	$ 18.99	$ 18.99	$ 19.04	$ 19.04	$ 19.04	$ 19.04	$ 19.00
Low Growth & High Price	2028-2029	Apr	$ 18.03	$ 18.90	$ 18.03	$ 18.03	$ 18.03	$ 18.44	$ 18.44	$ 18.95	$ 18.61	$ 18.20
Low Growth & High Price	2028-2029	May	$ 18.15	$ 18.90	$ 18.15	$ 18.15	$ 18.15	$ 18.57	$ 18.57	$ 18.95	$ 18.70	$ 18.30
Low Growth & High Price	2028-2029	Jun	$ 18.26	$ 18.95	$ 18.26	$ 18.26	$ 18.26	$ 18.69	$ 18.69	$ 18.95	$ 18.77	$ 18.40
Low Growth & High Price	2028-2029	Jul	$ 18.37	$ 18.95	$ 18.37	$ 18.37	$ 18.37	$ 18.81	$ 18.81	$ 18.95	$ 18.86	$ 18.49
Low Growth & High Price	2028-2029	Aug	$ 18.49	$ 18.97	$ 18.49	$ 18.49	$ 18.49	$ 18.91	$ 18.91	$ 18.97	$ 18.93	$ 18.59
Low Growth & High Price	2028-2029	Sep	$ 18.46	$ 18.96	$ 18.46	$ 18.46	$ 18.46	$ 18.80	$ 18.80	$ 18.96	$ 18.85	$ 18.56
Low Growth & High Price	2028-2029	Oct	$ 18.57	$ 19.12	$ 18.57	$ 18.57	$ 18.57	$ 18.82	$ 18.82	$ 19.12	$ 18.92	$ 18.68

1/ Avoided costs shown before Environmental Externalities adder.

Appendix 6.4 - Monthly Avoided Cost Detail 1/
2009$

Scenario	Gas Year	Month	Klam Falls	La Grande	Medford GTN	Medford NWP	Roseburg	Wa/Id Both	Wa/Id GTN	Wa/Id NWP	WA/ID Annual	OR Annual
Expected	2009-2010	Nov	$ 4.03	$ 4.03	$ 4.03	$ 4.03	$ 4.03	$ 3.96	$ 3.96	$ 4.03	$ 3.98	$ 4.03
Expected	2009-2010	Dec	$ 4.60	$ 4.58	$ 9.58	$ 9.58	$ 9.58	$ 4.52	$ 4.52	$ 4.58	$ 4.54	$ 7.58
Expected	2009-2010	Jan	$ 4.71	$ 4.68	$ 4.70	$ 4.70	$ 4.70	$ 4.65	$ 4.65	$ 4.66	$ 4.65	$ 4.70
Expected	2009-2010	Feb	$ 4.70	$ 4.70	$ 4.70	$ 4.70	$ 4.70	$ 4.63	$ 4.63	$ 4.63	$ 4.63	$ 4.70
Expected	2009-2010	Mar	$ 4.63	$ 4.57	$ 4.60	$ 4.60	$ 4.60	$ 4.57	$ 4.58	$ 4.57	$ 4.57	$ 4.60
Expected	2009-2010	Apr	$ 4.46	$ 4.41	$ 4.41	$ 4.41	$ 4.41	$ 4.38	$ 4.38	$ 4.41	$ 4.39	$ 4.42
Expected	2009-2010	May	$ 4.36	$ 4.33	$ 4.33	$ 4.33	$ 4.33	$ 4.28	$ 4.28	$ 4.41	$ 4.33	$ 4.34
Expected	2009-2010	Jun	$ 4.46	$ 4.41	$ 4.41	$ 4.41	$ 4.41	$ 4.39	$ 4.39	$ 4.41	$ 4.40	$ 4.42
Expected	2009-2010	Jul	$ 4.46	$ 4.41	$ 4.41	$ 4.41	$ 4.41	$ 4.40	$ 4.40	$ 4.41	$ 4.41	$ 4.42
Expected	2009-2010	Aug	$ 4.47	$ 4.42	$ 4.42	$ 4.42	$ 4.42	$ 4.42	$ 4.47	$ 4.42	$ 4.44	$ 4.43
Expected	2009-2010	Sep	$ 4.52	$ 4.47	$ 4.47	$ 4.47	$ 4.47	$ 4.47	$ 4.47	$ 4.47	$ 4.47	$ 4.48
Expected	2009-2010	Oct	$ 4.72	$ 4.68	$ 4.68	$ 4.68	$ 4.68	$ 4.64	$ 4.64	$ 4.68	$ 4.65	$ 4.69
Expected	2010-2011	Nov	$ 4.95	$ 4.98	$ 4.95	$ 4.95	$ 4.95	$ 4.86	$ 4.86	$ 4.98	$ 4.90	$ 4.95
Expected	2010-2011	Dec	$ 5.20	$ 5.21	$ 10.17	$ 10.17	$ 10.17	$ 5.13	$ 5.13	$ 5.21	$ 5.16	$ 8.18
Expected	2010-2011	Jan	$ 5.34	$ 5.34	$ 5.34	$ 5.34	$ 5.34	$ 5.27	$ 5.27	$ 5.28	$ 5.27	$ 5.34
Expected	2010-2011	Feb	$ 5.35	$ 5.36	$ 5.36	$ 5.36	$ 5.36	$ 5.27	$ 5.28	$ 5.27	$ 5.27	$ 5.36
Expected	2010-2011	Mar	$ 5.12	$ 5.07	$ 5.10	$ 5.10	$ 5.10	$ 5.03	$ 5.03	$ 5.06	$ 5.04	$ 5.10
Expected	2010-2011	Apr	$ 4.88	$ 4.91	$ 4.88	$ 4.88	$ 4.88	$ 4.79	$ 4.79	$ 4.91	$ 4.83	$ 4.88
Expected	2010-2011	May	$ 4.89	$ 4.91	$ 4.89	$ 4.89	$ 4.89	$ 4.80	$ 4.80	$ 4.91	$ 4.84	$ 4.89
Expected	2010-2011	Jun	$ 4.95	$ 4.91	$ 4.91	$ 4.91	$ 4.91	$ 4.86	$ 4.86	$ 4.91	$ 4.88	$ 4.92
Expected	2010-2011	Jul	$ 4.97	$ 4.91	$ 4.91	$ 4.91	$ 4.91	$ 4.88	$ 4.88	$ 4.91	$ 4.89	$ 4.92
Expected	2010-2011	Aug	$ 4.97	$ 4.91	$ 4.91	$ 4.91	$ 4.91	$ 4.91	$ 4.93	$ 4.91	$ 4.92	$ 4.92
Expected	2010-2011	Sep	$ 4.97	$ 4.91	$ 4.91	$ 4.91	$ 4.91	$ 4.89	$ 4.89	$ 4.91	$ 4.90	$ 4.92
Expected	2010-2011	Oct	$ 5.12	$ 5.06	$ 5.06	$ 5.06	$ 5.06	$ 5.03	$ 5.03	$ 5.06	$ 5.04	$ 5.07
Expected	2011-2012	Nov	$ 5.25	$ 5.26	$ 5.25	$ 5.25	$ 5.25	$ 5.15	$ 5.15	$ 5.26	$ 5.19	$ 5.25
Expected	2011-2012	Dec	$ 5.41	$ 5.38	$ 10.38	$ 10.38	$ 10.38	$ 5.33	$ 5.33	$ 5.38	$ 5.35	$ 8.39
Expected	2011-2012	Jan	$ 5.48	$ 5.45	$ 5.47	$ 5.47	$ 5.47	$ 5.40	$ 5.40	$ 5.42	$ 5.41	$ 5.47
Expected	2011-2012	Feb	$ 5.48	$ 5.47	$ 5.47	$ 5.47	$ 5.47	$ 5.36	$ 5.39	$ 5.36	$ 5.37	$ 5.47
Expected	2011-2012	Mar	$ 5.32	$ 5.26	$ 5.28	$ 5.28	$ 5.28	$ 5.25	$ 5.25	$ 5.26	$ 5.25	$ 5.29
Expected	2011-2012	Apr	$ 5.08	$ 5.05	$ 5.05	$ 5.05	$ 5.05	$ 4.99	$ 4.99	$ 5.05	$ 5.01	$ 5.06
Expected	2011-2012	May	$ 5.05	$ 5.05	$ 5.05	$ 5.05	$ 5.05	$ 4.96	$ 4.96	$ 5.05	$ 4.99	$ 5.05
Expected	2011-2012	Jun	$ 5.10	$ 5.05	$ 5.05	$ 5.05	$ 5.05	$ 5.01	$ 5.01	$ 5.05	$ 5.02	$ 5.06
Expected	2011-2012	Jul	$ 5.09	$ 5.05	$ 5.05	$ 5.05	$ 5.05	$ 5.00	$ 5.00	$ 5.05	$ 5.02	$ 5.06
Expected	2011-2012	Aug	$ 5.11	$ 5.05	$ 5.05	$ 5.05	$ 5.05	$ 5.03	$ 5.03	$ 5.05	$ 5.04	$ 5.06
Expected	2011-2012	Sep	$ 5.11	$ 5.05	$ 5.05	$ 5.05	$ 5.05	$ 5.05	$ 5.07	$ 5.05	$ 5.06	$ 5.06
Expected	2011-2012	Oct	$ 5.27	$ 5.21	$ 5.21	$ 5.21	$ 5.21	$ 5.20	$ 5.20	$ 5.21	$ 5.21	$ 5.22
Expected	2012-2013	Nov	$ 5.42	$ 5.35	$ 5.39	$ 5.39	$ 5.39	$ 5.33	$ 5.33	$ 5.35	$ 5.34	$ 5.39
Expected	2012-2013	Dec	$ 5.53	$ 5.46	$ 11.02	$ 11.02	$ 11.02	$ 5.46	$ 5.46	$ 5.46	$ 5.46	$ 8.81
Expected	2012-2013	Jan	$ 5.59	$ 5.51	$ 5.57	$ 5.57	$ 5.57	$ 5.51	$ 5.51	$ 5.51	$ 5.51	$ 5.56
Expected	2012-2013	Feb	$ 5.58	$ 5.51	$ 5.56	$ 5.56	$ 5.56	$ 5.49	$ 5.53	$ 5.49	$ 5.50	$ 5.55
Expected	2012-2013	Mar	$ 5.39	$ 5.33	$ 5.35	$ 5.35	$ 5.35	$ 5.33	$ 5.36	$ 5.33	$ 5.34	$ 5.35
Expected	2012-2013	Apr	$ 5.22	$ 5.17	$ 5.17	$ 5.17	$ 5.17	$ 5.12	$ 5.12	$ 5.17	$ 5.14	$ 5.18
Expected	2012-2013	May	$ 5.17	$ 5.17	$ 5.17	$ 5.17	$ 5.17	$ 5.08	$ 5.08	$ 5.17	$ 5.11	$ 5.17
Expected	2012-2013	Jun	$ 5.22	$ 5.17	$ 5.17	$ 5.17	$ 5.17	$ 5.12	$ 5.12	$ 5.17	$ 5.14	$ 5.18
Expected	2012-2013	Jul	$ 5.20	$ 5.17	$ 5.17	$ 5.17	$ 5.17	$ 5.10	$ 5.10	$ 5.17	$ 5.13	$ 5.18
Expected	2012-2013	Aug	$ 5.24	$ 5.17	$ 5.17	$ 5.17	$ 5.17	$ 5.14	$ 5.14	$ 5.17	$ 5.15	$ 5.19
Expected	2012-2013	Sep	$ 5.24	$ 5.17	$ 5.17	$ 5.17	$ 5.17	$ 5.17	$ 5.17	$ 5.17	$ 5.17	$ 5.19
Expected	2012-2013	Oct	$ 5.36	$ 5.30	$ 5.30	$ 5.30	$ 5.30	$ 5.30	$ 5.30	$ 5.30	$ 5.30	$ 5.31
Expected	2013-2014	Nov	$ 4.76	$ 4.70	$ 4.75	$ 4.75	$ 4.75	$ 4.68	$ 4.68	$ 4.70	$ 4.69	$ 4.74
Expected	2013-2014	Dec	$ 4.84	$ 4.80	$ 10.92	$ 10.92	$ 10.92	$ 4.77	$ 4.77	$ 4.80	$ 4.78	$ 8.48
Expected	2013-2014	Jan	$ 4.98	$ 4.91	$ 4.96	$ 4.96	$ 4.96	$ 4.91	$ 4.91	$ 4.91	$ 4.91	$ 4.95
Expected	2013-2014	Feb	$ 4.91	$ 4.85	$ 4.89	$ 4.89	$ 4.89	$ 4.85	$ 4.94	$ 4.85	$ 4.88	$ 4.89
Expected	2013-2014	Mar	$ 4.77	$ 4.71	$ 4.73	$ 4.73	$ 4.73	$ 4.71	$ 4.72	$ 4.71	$ 4.71	$ 4.74
Expected	2013-2014	Apr	$ 4.69	$ 4.66	$ 4.66	$ 4.66	$ 4.66	$ 4.61	$ 4.61	$ 4.66	$ 4.62	$ 4.66
Expected	2013-2014	May	$ 4.69	$ 4.66	$ 4.66	$ 4.66	$ 4.66	$ 4.61	$ 4.61	$ 4.66	$ 4.62	$ 4.66
Expected	2013-2014	Jun	$ 4.70	$ 4.66	$ 4.66	$ 4.66	$ 4.66	$ 4.62	$ 4.62	$ 4.66	$ 4.63	$ 4.66
Expected	2013-2014	Jul	$ 4.66	$ 4.66	$ 4.66	$ 4.66	$ 4.66	$ 4.58	$ 4.58	$ 4.66	$ 4.60	$ 4.66
Expected	2013-2014	Aug	$ 4.68	$ 4.66	$ 4.66	$ 4.66	$ 4.66	$ 4.60	$ 4.60	$ 4.66	$ 4.62	$ 4.66
Expected	2013-2014	Sep	$ 4.71	$ 4.66	$ 4.66	$ 4.66	$ 4.66	$ 4.63	$ 4.63	$ 4.66	$ 4.64	$ 4.67
Expected	2013-2014	Oct	$ 4.80	$ 4.74	$ 4.74	$ 4.74	$ 4.74	$ 4.74	$ 4.74	$ 4.74	$ 4.74	$ 4.75
Expected	2014-2015	Nov	$ 5.73	$ 5.66	$ 5.72	$ 5.72	$ 5.72	$ 5.63	$ 5.63	$ 5.66	$ 5.64	$ 5.71
Expected	2014-2015	Dec	$ 5.81	$ 5.91	$ 12.52	$ 12.52	$ 12.52	$ 5.84	$ 5.84	$ 5.93	$ 5.87	$ 9.86
Expected	2014-2015	Jan	$ 6.75	$ 6.65	$ 6.72	$ 6.72	$ 6.72	$ 6.65	$ 6.65	$ 6.65	$ 6.65	$ 6.71
Expected	2014-2015	Feb	$ 6.66	$ 6.58	$ 6.64	$ 6.64	$ 6.64	$ 6.58	$ 6.69	$ 6.58	$ 6.61	$ 6.63
Expected	2014-2015	Mar	$ 6.51	$ 6.43	$ 6.46	$ 6.46	$ 6.46	$ 6.43	$ 6.45	$ 6.43	$ 6.44	$ 6.46
Expected	2014-2015	Apr	$ 6.42	$ 6.38	$ 6.38	$ 6.38	$ 6.38	$ 6.33	$ 6.33	$ 6.38	$ 6.34	$ 6.39
Expected	2014-2015	May	$ 6.43	$ 6.38	$ 6.38	$ 6.38	$ 6.38	$ 6.34	$ 6.34	$ 6.38	$ 6.35	$ 6.39
Expected	2014-2015	Jun	$ 6.44	$ 6.38	$ 6.38	$ 6.38	$ 6.38	$ 6.35	$ 6.35	$ 6.38	$ 6.36	$ 6.39
Expected	2014-2015	Jul	$ 6.43	$ 6.38	$ 6.38	$ 6.38	$ 6.38	$ 6.33	$ 6.33	$ 6.38	$ 6.34	$ 6.39
Expected	2014-2015	Aug	$ 6.45	$ 6.38	$ 6.38	$ 6.38	$ 6.38	$ 6.35	$ 6.35	$ 6.38	$ 6.36	$ 6.39
Expected	2014-2015	Sep	$ 6.45	$ 6.38	$ 6.38	$ 6.38	$ 6.38	$ 6.38	$ 6.38	$ 6.38	$ 6.38	$ 6.39
Expected	2014-2015	Oct	$ 6.58	$ 6.50	$ 6.50	$ 6.50	$ 6.50	$ 6.50	$ 6.50	$ 6.50	$ 6.50	$ 6.52
Expected	2015-2016	Nov	$ 6.95	$ 6.87	$ 6.91	$ 6.91	$ 6.91	$ 6.83	$ 6.83	$ 6.87	$ 6.84	$ 6.91
Expected	2015-2016	Dec	$ 7.01	$ 6.93	$ 14.41	$ 14.41	$ 14.41	$ 6.93	$ 6.93	$ 6.93	$ 6.93	$ 11.44
Expected	2015-2016	Jan	$ 7.02	$ 6.93	$ 7.00	$ 7.00	$ 7.00	$ 6.93	$ 6.93	$ 6.93	$ 6.93	$ 6.99
Expected	2015-2016	Feb	$ 6.98	$ 6.87	$ 6.96	$ 6.96	$ 6.96	$ 6.87	$ 6.95	$ 6.87	$ 6.90	$ 6.95
Expected	2015-2016	Mar	$ 6.81	$ 6.75	$ 6.79	$ 6.79	$ 6.79	$ 6.75	$ 6.77	$ 6.75	$ 6.76	$ 6.79
Expected	2015-2016	Apr	$ 6.72	$ 6.69	$ 6.69	$ 6.69	$ 6.69	$ 6.63	$ 6.63	$ 6.69	$ 6.65	$ 6.70
Expected	2015-2016	May	$ 6.72	$ 6.69	$ 6.69	$ 6.69	$ 6.69	$ 6.63	$ 6.63	$ 6.69	$ 6.65	$ 6.70
Expected	2015-2016	Jun	$ 6.74	$ 6.69	$ 6.69	$ 6.69	$ 6.69	$ 6.66	$ 6.66	$ 6.69	$ 6.67	$ 6.70
Expected	2015-2016	Jul	$ 6.73	$ 6.69	$ 6.69	$ 6.69	$ 6.69	$ 6.63	$ 6.63	$ 6.69	$ 6.65	$ 6.70
Expected	2015-2016	Aug	$ 6.76	$ 6.69	$ 6.69	$ 6.69	$ 6.69	$ 6.66	$ 6.66	$ 6.69	$ 6.67	$ 6.71
Expected	2015-2016	Sep	$ 6.77	$ 6.69	$ 6.69	$ 6.69	$ 6.69	$ 6.69	$ 6.69	$ 6.69	$ 6.69	$ 6.71
Expected	2015-2016	Oct	$ 6.89	$ 6.81	$ 6.81	$ 6.81	$ 6.81	$ 6.81	$ 6.81	$ 6.81	$ 6.81	$ 6.83
Expected	2016-2017	Nov	$ 7.25	$ 7.17	$ 7.22	$ 7.22	$ 7.22	$ 7.14	$ 7.14	$ 7.17	$ 7.15	$ 7.21
Expected	2016-2017	Dec	$ 7.32	$ 7.24	$ 15.50	$ 15.50	$ 15.50	$ 7.24	$ 7.24	$ 7.24	$ 7.24	$ 12.21
Expected	2016-2017	Jan	$ 7.35	$ 7.26	$ 7.33	$ 7.33	$ 7.33	$ 7.26	$ 7.26	$ 7.26	$ 7.26	$ 7.32

Appendix 6.4 - Monthly Avoided Cost Detail 1/
2009$

Scenario	Gas Year	Month	Klam Falls	La Grande	Medford GTN	Medford NWP	Roseburg	Wa/Id Both	Wa/Id GTN	Wa/Id NWP	WA/ID Annual	OR Annual
Expected	2016-2017	Feb	$ 7.33	$ 7.05	$ 7.34	$ 7.34	$ 7.34	$ 7.05	$ 7.29	$ 7.05	$ 7.13	$ 7.28
Expected	2016-2017	Mar	$ 6.85	$ 6.78	$ 6.83	$ 6.83	$ 6.83	$ 6.78	$ 6.78	$ 6.78	$ 6.78	$ 6.82
Expected	2016-2017	Apr	$ 6.76	$ 6.75	$ 6.75	$ 6.75	$ 6.75	$ 6.66	$ 6.66	$ 6.75	$ 6.69	$ 6.76
Expected	2016-2017	May	$ 6.76	$ 6.75	$ 6.75	$ 6.75	$ 6.75	$ 6.66	$ 6.66	$ 6.75	$ 6.69	$ 6.76
Expected	2016-2017	Jun	$ 6.78	$ 6.75	$ 6.75	$ 6.75	$ 6.75	$ 6.68	$ 6.68	$ 6.75	$ 6.71	$ 6.76
Expected	2016-2017	Jul	$ 6.76	$ 6.75	$ 6.75	$ 6.75	$ 6.75	$ 6.65	$ 6.65	$ 6.75	$ 6.69	$ 6.76
Expected	2016-2017	Aug	$ 6.79	$ 6.75	$ 6.75	$ 6.75	$ 6.75	$ 6.67	$ 6.67	$ 6.75	$ 6.70	$ 6.76
Expected	2016-2017	Sep	$ 6.83	$ 6.75	$ 6.75	$ 6.75	$ 6.75	$ 6.71	$ 6.71	$ 6.75	$ 6.73	$ 6.77
Expected	2016-2017	Oct	$ 6.91	$ 6.83	$ 6.83	$ 6.83	$ 6.83	$ 6.83	$ 6.83	$ 6.83	$ 6.83	$ 6.85
Expected	2017-2018	Nov	$ 7.27	$ 7.19	$ 7.24	$ 7.24	$ 7.24	$ 7.16	$ 7.16	$ 7.19	$ 7.17	$ 7.23
Expected	2017-2018	Dec	$ 7.34	$ 7.27	$ 16.32	$ 16.32	$ 16.32	$ 7.27	$ 7.27	$ 7.27	$ 7.27	$ 12.71
Expected	2017-2018	Jan	$ 7.37	$ 7.28	$ 7.35	$ 7.35	$ 7.35	$ 7.28	$ 7.28	$ 7.28	$ 7.28	$ 7.34
Expected	2017-2018	Feb	$ 7.36	$ 7.04	$ 7.36	$ 7.36	$ 7.36	$ 7.03	$ 7.31	$ 7.03	$ 7.13	$ 7.30
Expected	2017-2018	Mar	$ 6.79	$ 6.72	$ 6.77	$ 6.77	$ 6.77	$ 6.72	$ 6.73	$ 6.72	$ 6.73	$ 6.76
Expected	2017-2018	Apr	$ 6.68	$ 6.67	$ 6.67	$ 6.67	$ 6.67	$ 6.59	$ 6.59	$ 6.67	$ 6.62	$ 6.67
Expected	2017-2018	May	$ 6.67	$ 6.67	$ 6.67	$ 6.67	$ 6.67	$ 6.56	$ 6.56	$ 6.67	$ 6.60	$ 6.67
Expected	2017-2018	Jun	$ 6.69	$ 6.67	$ 6.67	$ 6.67	$ 6.67	$ 6.59	$ 6.59	$ 6.67	$ 6.62	$ 6.67
Expected	2017-2018	Jul	$ 6.67	$ 6.67	$ 6.67	$ 6.67	$ 6.67	$ 6.56	$ 6.56	$ 6.67	$ 6.60	$ 6.67
Expected	2017-2018	Aug	$ 6.71	$ 6.67	$ 6.67	$ 6.67	$ 6.67	$ 6.60	$ 6.60	$ 6.67	$ 6.62	$ 6.68
Expected	2017-2018	Sep	$ 6.75	$ 6.67	$ 6.67	$ 6.67	$ 6.67	$ 6.63	$ 6.63	$ 6.67	$ 6.64	$ 6.68
Expected	2017-2018	Oct	$ 6.84	$ 6.76	$ 6.76	$ 6.76	$ 6.76	$ 6.76	$ 6.76	$ 6.76	$ 6.76	$ 6.78
Expected	2018-2019	Nov	$ 7.20	$ 7.12	$ 7.19	$ 7.19	$ 7.19	$ 7.09	$ 7.09	$ 7.12	$ 7.10	$ 7.18
Expected	2018-2019	Dec	$ 7.27	$ 7.18	$ 17.13	$ 17.13	$ 17.13	$ 7.18	$ 7.18	$ 7.18	$ 7.18	$ 13.17
Expected	2018-2019	Jan	$ 7.23	$ 7.16	$ 7.22	$ 7.22	$ 7.22	$ 7.16	$ 7.16	$ 7.16	$ 7.16	$ 7.21
Expected	2018-2019	Feb	$ 7.22	$ 7.07	$ 7.22	$ 7.22	$ 7.22	$ 7.07	$ 7.19	$ 7.07	$ 7.11	$ 7.19
Expected	2018-2019	Mar	$ 6.97	$ 6.90	$ 6.94	$ 6.94	$ 6.94	$ 6.90	$ 6.91	$ 6.90	$ 6.90	$ 6.94
Expected	2018-2019	Apr	$ 6.84	$ 6.84	$ 6.84	$ 6.84	$ 6.84	$ 6.75	$ 6.75	$ 6.84	$ 6.78	$ 6.84
Expected	2018-2019	May	$ 6.84	$ 6.84	$ 6.84	$ 6.84	$ 6.84	$ 6.74	$ 6.74	$ 6.84	$ 6.77	$ 6.84
Expected	2018-2019	Jun	$ 6.85	$ 6.84	$ 6.84	$ 6.84	$ 6.84	$ 6.76	$ 6.76	$ 6.84	$ 6.79	$ 6.84
Expected	2018-2019	Jul	$ 6.84	$ 6.84	$ 6.84	$ 6.84	$ 6.84	$ 6.73	$ 6.73	$ 6.84	$ 6.77	$ 6.84
Expected	2018-2019	Aug	$ 6.87	$ 6.84	$ 6.84	$ 6.84	$ 6.84	$ 6.76	$ 6.76	$ 6.84	$ 6.79	$ 6.85
Expected	2018-2019	Sep	$ 6.91	$ 6.84	$ 6.84	$ 6.84	$ 6.84	$ 6.79	$ 6.79	$ 6.84	$ 6.81	$ 6.85
Expected	2018-2019	Oct	$ 7.02	$ 6.93	$ 6.94	$ 6.94	$ 6.94	$ 6.93	$ 6.93	$ 6.93	$ 6.93	$ 6.95
Expected	2019-2020	Nov	$ 7.37	$ 7.29	$ 7.36	$ 7.36	$ 7.36	$ 7.25	$ 7.25	$ 7.29	$ 7.26	$ 7.35
Expected	2019-2020	Dec	$ 7.45	$ 7.36	$ 18.27	$ 18.27	$ 18.27	$ 7.36	$ 7.36	$ 7.36	$ 7.36	$ 13.92
Expected	2019-2020	Jan	$ 7.44	$ 7.36	$ 7.43	$ 7.43	$ 7.43	$ 7.36	$ 7.36	$ 7.36	$ 7.36	$ 7.42
Expected	2019-2020	Feb	$ 7.40	$ 7.27	$ 7.41	$ 7.41	$ 7.41	$ 7.27	$ 7.38	$ 7.27	$ 7.31	$ 7.38
Expected	2019-2020	Mar	$ 7.19	$ 7.12	$ 7.16	$ 7.16	$ 7.16	$ 7.12	$ 7.13	$ 7.12	$ 7.12	$ 7.16
Expected	2019-2020	Apr	$ 7.06	$ 7.05	$ 7.05	$ 7.05	$ 7.05	$ 6.98	$ 6.98	$ 7.05	$ 7.00	$ 7.05
Expected	2019-2020	May	$ 7.05	$ 7.05	$ 7.05	$ 7.05	$ 7.05	$ 6.95	$ 6.95	$ 7.05	$ 6.99	$ 7.05
Expected	2019-2020	Jun	$ 7.07	$ 7.05	$ 7.05	$ 7.05	$ 7.05	$ 6.98	$ 6.98	$ 7.05	$ 7.00	$ 7.06
Expected	2019-2020	Jul	$ 7.06	$ 7.05	$ 7.05	$ 7.05	$ 7.05	$ 6.94	$ 6.94	$ 7.05	$ 6.98	$ 7.05
Expected	2019-2020	Aug	$ 7.08	$ 7.05	$ 7.05	$ 7.05	$ 7.05	$ 6.97	$ 6.97	$ 7.05	$ 6.99	$ 7.06
Expected	2019-2020	Sep	$ 7.13	$ 7.05	$ 7.05	$ 7.05	$ 7.05	$ 7.01	$ 7.01	$ 7.05	$ 7.02	$ 7.07
Expected	2019-2020	Oct	$ 7.21	$ 7.13	$ 7.13	$ 7.13	$ 7.13	$ 7.13	$ 7.13	$ 7.13	$ 7.13	$ 7.14
Expected	2020-2021	Nov	$ 7.56	$ 7.50	$ 7.56	$ 7.56	$ 7.56	$ 7.45	$ 7.45	$ 7.50	$ 7.47	$ 7.55
Expected	2020-2021	Dec	$ 7.65	$ 7.58	$ 19.54	$ 19.54	$ 19.54	$ 7.56	$ 7.56	$ 7.58	$ 7.56	$ 14.77
Expected	2020-2021	Jan	$ 7.66	$ 7.59	$ 7.65	$ 7.65	$ 7.65	$ 7.59	$ 7.59	$ 7.59	$ 7.59	$ 7.64
Expected	2020-2021	Feb	$ 7.66	$ 7.57	$ 7.65	$ 7.65	$ 7.65	$ 7.57	$ 7.63	$ 7.57	$ 7.59	$ 7.64
Expected	2020-2021	Mar	$ 7.51	$ 7.43	$ 7.48	$ 7.48	$ 7.48	$ 7.43	$ 7.45	$ 7.43	$ 7.44	$ 7.47
Expected	2020-2021	Apr	$ 7.34	$ 7.33	$ 7.34	$ 7.34	$ 7.34	$ 7.25	$ 7.25	$ 7.33	$ 7.28	$ 7.34
Expected	2020-2021	May	$ 7.35	$ 7.33	$ 7.34	$ 7.34	$ 7.34	$ 7.25	$ 7.25	$ 7.33	$ 7.28	$ 7.34
Expected	2020-2021	Jun	$ 7.36	$ 7.33	$ 7.34	$ 7.34	$ 7.34	$ 7.27	$ 7.27	$ 7.33	$ 7.29	$ 7.34
Expected	2020-2021	Jul	$ 7.35	$ 7.33	$ 7.34	$ 7.34	$ 7.34	$ 7.24	$ 7.24	$ 7.33	$ 7.27	$ 7.34
Expected	2020-2021	Aug	$ 7.38	$ 7.33	$ 7.34	$ 7.34	$ 7.34	$ 7.26	$ 7.26	$ 7.33	$ 7.28	$ 7.34
Expected	2020-2021	Sep	$ 7.42	$ 7.33	$ 7.34	$ 7.34	$ 7.34	$ 7.30	$ 7.30	$ 7.33	$ 7.31	$ 7.35
Expected	2020-2021	Oct	$ 7.50	$ 7.41	$ 7.41	$ 7.41	$ 7.41	$ 7.41	$ 7.41	$ 7.41	$ 7.41	$ 7.43
Expected	2021-2022	Nov	$ 7.87	$ 7.80	$ 7.86	$ 7.86	$ 7.86	$ 7.75	$ 7.75	$ 7.80	$ 7.77	$ 7.85
Expected	2021-2022	Dec	$ 7.95	$ 7.89	$ 19.30	$ 19.30	$ 19.30	$ 7.87	$ 7.87	$ 7.89	$ 7.88	$ 14.75
Expected	2021-2022	Jan	$ 8.01	$ 7.96	$ 8.01	$ 8.01	$ 8.01	$ 7.96	$ 7.96	$ 7.96	$ 7.96	$ 8.00
Expected	2021-2022	Feb	$ 8.02	$ 9.50	$ 9.92	$ 9.92	$ 9.92	$ 9.50	$ 9.88	$ 9.50	$ 9.63	$ 9.46
Expected	2021-2022	Mar	$ 7.36	$ 7.30	$ 7.34	$ 7.34	$ 7.34	$ 7.30	$ 7.32	$ 7.30	$ 7.31	$ 7.34
Expected	2021-2022	Apr	$ 7.20	$ 7.20	$ 7.20	$ 7.20	$ 7.20	$ 7.12	$ 7.12	$ 7.20	$ 7.15	$ 7.20
Expected	2021-2022	May	$ 7.20	$ 7.20	$ 7.20	$ 7.20	$ 7.20	$ 7.11	$ 7.11	$ 7.20	$ 7.14	$ 7.20
Expected	2021-2022	Jun	$ 7.22	$ 7.20	$ 7.20	$ 7.20	$ 7.20	$ 7.14	$ 7.14	$ 7.20	$ 7.16	$ 7.21
Expected	2021-2022	Jul	$ 7.21	$ 7.20	$ 7.20	$ 7.20	$ 7.20	$ 7.11	$ 7.11	$ 7.20	$ 7.14	$ 7.21
Expected	2021-2022	Aug	$ 7.24	$ 7.20	$ 7.20	$ 7.20	$ 7.20	$ 7.14	$ 7.14	$ 7.20	$ 7.16	$ 7.21
Expected	2021-2022	Sep	$ 7.29	$ 7.20	$ 7.20	$ 7.20	$ 7.20	$ 7.18	$ 7.18	$ 7.20	$ 7.19	$ 7.22
Expected	2021-2022	Oct	$ 7.37	$ 7.29	$ 7.29	$ 7.29	$ 7.29	$ 7.29	$ 7.29	$ 7.29	$ 7.29	$ 7.31
Expected	2022-2023	Nov	$ 7.76	$ 7.68	$ 7.75	$ 7.75	$ 7.75	$ 7.65	$ 7.65	$ 7.68	$ 7.66	$ 7.74
Expected	2022-2023	Dec	$ 7.84	$ 7.76	$ 19.59	$ 19.59	$ 19.59	$ 7.76	$ 7.76	$ 7.76	$ 7.76	$ 14.87
Expected	2022-2023	Jan	$ 7.75	$ 7.71	$ 7.75	$ 7.75	$ 7.75	$ 7.71	$ 7.71	$ 7.71	$ 7.71	$ 7.74
Expected	2022-2023	Feb	$ 7.77	$ 10.78	$ 10.69	$ 10.69	$ 10.69	$ 10.78	$ 10.96	$ 10.78	$ 10.84	$ 10.12
Expected	2022-2023	Mar	$ 7.41	$ 7.36	$ 7.39	$ 7.39	$ 7.39	$ 7.36	$ 7.37	$ 7.36	$ 7.36	$ 7.39
Expected	2022-2023	Apr	$ 7.23	$ 7.19	$ 7.19	$ 7.19	$ 7.19	$ 7.17	$ 7.17	$ 7.19	$ 7.18	$ 7.20
Expected	2022-2023	May	$ 7.21	$ 7.19	$ 7.19	$ 7.19	$ 7.19	$ 7.14	$ 7.14	$ 7.19	$ 7.16	$ 7.20
Expected	2022-2023	Jun	$ 7.22	$ 7.19	$ 7.19	$ 7.19	$ 7.19	$ 7.16	$ 7.16	$ 7.19	$ 7.17	$ 7.20
Expected	2022-2023	Jul	$ 7.21	$ 7.19	$ 7.19	$ 7.19	$ 7.19	$ 7.13	$ 7.13	$ 7.19	$ 7.15	$ 7.20
Expected	2022-2023	Aug	$ 7.19	$ 7.19	$ 7.19	$ 7.19	$ 7.19	$ 7.08	$ 7.08	$ 7.19	$ 7.12	$ 7.19
Expected	2022-2023	Sep	$ 7.15	$ 7.15	$ 7.15	$ 7.15	$ 7.15	$ 7.03	$ 7.03	$ 7.19	$ 7.08	$ 7.15
Expected	2022-2023	Oct	$ 7.13	$ 7.05	$ 7.05	$ 7.05	$ 7.05	$ 7.05	$ 7.05	$ 7.05	$ 7.05	$ 7.06
Expected	2023-2024	Nov	$ 7.33	$ 7.27	$ 7.32	$ 7.32	$ 7.32	$ 7.20	$ 7.20	$ 7.27	$ 7.22	$ 7.31
Expected	2023-2024	Dec	$ 7.40	$ 7.42	$ 20.55	$ 20.55	$ 20.55	$ 7.32	$ 7.32	$ 7.42	$ 7.36	$ 15.29
Expected	2023-2024	Jan	$ 7.71	$ 7.59	$ 7.70	$ 7.70	$ 7.70	$ 7.59	$ 7.59	$ 7.59	$ 7.59	$ 7.68
Expected	2023-2024	Feb	$ 7.62	$ 10.84	$ 10.50	$ 10.50	$ 10.50	$ 10.72	$ 10.97	$ 10.72	$ 10.80	$ 9.99
Expected	2023-2024	Mar	$ 6.59	$ 6.51	$ 6.58	$ 6.58	$ 6.58	$ 6.51	$ 6.51	$ 6.51	$ 6.51	$ 6.57
Expected	2023-2024	Apr	$ 6.52	$ 6.51	$ 6.51	$ 6.51	$ 6.51	$ 6.41	$ 6.41	$ 6.51	$ 6.44	$ 6.51

Appendix 6.4 - Monthly Avoided Cost Detail 1/
2009$

Scenario	Gas Year	Month	Klam Falls	La Grande	Medford GTN	Medford NWP	Roseburg	Wa/Id Both	Wa/Id GTN	Wa/Id NWP	WA/ID Annual	OR Annual
Expected	2023-2024	May	$ 6.52	$ 6.51	$ 6.51	$ 6.51	$ 6.51	$ 6.41	$ 6.41	$ 6.51	$ 6.44	$ 6.51
Expected	2023-2024	Jun	$ 6.55	$ 6.51	$ 6.51	$ 6.51	$ 6.51	$ 6.44	$ 6.44	$ 6.51	$ 6.46	$ 6.52
Expected	2023-2024	Jul	$ 6.55	$ 6.51	$ 6.51	$ 6.51	$ 6.51	$ 6.44	$ 6.44	$ 6.51	$ 6.46	$ 6.52
Expected	2023-2024	Aug	$ 6.58	$ 6.51	$ 6.51	$ 6.51	$ 6.51	$ 6.47	$ 6.47	$ 6.51	$ 6.48	$ 6.52
Expected	2023-2024	Sep	$ 6.59	$ 6.51	$ 6.51	$ 6.51	$ 6.51	$ 6.50	$ 6.50	$ 6.51	$ 6.50	$ 6.52
Expected	2023-2024	Oct	$ 6.69	$ 6.61	$ 6.61	$ 6.61	$ 6.61	$ 6.61	$ 6.61	$ 6.61	$ 6.61	$ 6.63
Expected	2024-2025	Nov	$ 7.05	$ 6.97	$ 7.04	$ 7.04	$ 7.04	$ 6.92	$ 6.92	$ 6.97	$ 6.94	$ 7.03
Expected	2024-2025	Dec	$ 7.13	$ 7.02	$ 20.26	$ 20.26	$ 20.26	$ 7.02	$ 7.02	$ 7.02	$ 7.02	$ 14.98
Expected	2024-2025	Jan	$ 7.09	$ 7.01	$ 7.09	$ 7.09	$ 7.09	$ 6.99	$ 6.99	$ 7.01	$ 7.00	$ 7.07
Expected	2024-2025	Feb	$ 7.10	$ 10.88	$ 11.88	$ 11.88	$ 11.88	$ 10.88	$ 10.93	$ 10.88	$ 10.90	$ 10.72
Expected	2024-2025	Mar	$ 6.83	$ 6.74	$ 6.82	$ 6.82	$ 6.82	$ 6.74	$ 6.74	$ 6.74	$ 6.74	$ 6.81
Expected	2024-2025	Apr	$ 6.74	$ 6.73	$ 6.74	$ 6.74	$ 6.74	$ 6.62	$ 6.62	$ 6.73	$ 6.66	$ 6.74
Expected	2024-2025	May	$ 6.75	$ 6.73	$ 6.73	$ 6.73	$ 6.73	$ 6.63	$ 6.63	$ 6.73	$ 6.67	$ 6.74
Expected	2024-2025	Jun	$ 6.77	$ 6.73	$ 6.73	$ 6.73	$ 6.73	$ 6.65	$ 6.65	$ 6.73	$ 6.68	$ 6.74
Expected	2024-2025	Jul	$ 6.76	$ 6.73	$ 6.73	$ 6.73	$ 6.73	$ 6.64	$ 6.64	$ 6.73	$ 6.67	$ 6.74
Expected	2024-2025	Aug	$ 6.79	$ 6.73	$ 6.73	$ 6.73	$ 6.73	$ 6.67	$ 6.67	$ 6.73	$ 6.69	$ 6.75
Expected	2024-2025	Sep	$ 6.81	$ 6.73	$ 6.73	$ 6.73	$ 6.73	$ 6.71	$ 6.71	$ 6.73	$ 6.72	$ 6.75
Expected	2024-2025	Oct	$ 6.90	$ 6.82	$ 6.82	$ 6.82	$ 6.82	$ 6.82	$ 6.82	$ 6.82	$ 6.82	$ 6.84
Expected	2025-2026	Nov	$ 7.27	$ 7.20	$ 7.27	$ 7.27	$ 7.27	$ 7.15	$ 7.15	$ 7.20	$ 7.16	$ 7.25
Expected	2025-2026	Dec	$ 7.36	$ 7.25	$ 20.51	$ 20.51	$ 20.51	$ 7.25	$ 7.25	$ 7.25	$ 7.25	$ 15.23
Expected	2025-2026	Jan	$ 7.30	$ 7.22	$ 7.30	$ 7.30	$ 7.30	$ 7.19	$ 7.19	$ 7.22	$ 7.20	$ 7.29
Expected	2025-2026	Feb	$ 7.32	$ 11.50	$ 14.02	$ 14.02	$ 14.02	$ 11.50	$ 11.54	$ 11.50	$ 11.51	$ 12.18
Expected	2025-2026	Mar	$ 7.05	$ 6.95	$ 7.05	$ 7.05	$ 7.05	$ 6.95	$ 6.95	$ 6.95	$ 6.95	$ 7.03
Expected	2025-2026	Apr	$ 6.95	$ 6.94	$ 6.94	$ 6.94	$ 6.94	$ 6.83	$ 6.83	$ 6.94	$ 6.87	$ 6.95
Expected	2025-2026	May	$ 6.95	$ 6.94	$ 6.94	$ 6.94	$ 6.94	$ 6.83	$ 6.83	$ 6.94	$ 6.87	$ 6.95
Expected	2025-2026	Jun	$ 6.98	$ 6.94	$ 6.94	$ 6.94	$ 6.94	$ 6.85	$ 6.85	$ 6.94	$ 6.88	$ 6.95
Expected	2025-2026	Jul	$ 6.94	$ 6.94	$ 6.94	$ 6.94	$ 6.94	$ 6.82	$ 6.82	$ 6.94	$ 6.86	$ 6.94
Expected	2025-2026	Aug	$ 6.98	$ 6.94	$ 6.94	$ 6.94	$ 6.94	$ 6.85	$ 6.85	$ 6.94	$ 6.88	$ 6.95
Expected	2025-2026	Sep	$ 7.01	$ 6.94	$ 6.94	$ 6.94	$ 6.94	$ 6.88	$ 6.88	$ 6.94	$ 6.90	$ 6.96
Expected	2025-2026	Oct	$ 7.08	$ 7.00	$ 7.00	$ 7.00	$ 7.00	$ 7.00	$ 7.00	$ 7.00	$ 7.00	$ 7.01
Expected	2026-2027	Nov	$ 7.43	$ 7.37	$ 7.42	$ 7.42	$ 7.42	$ 7.30	$ 7.30	$ 7.37	$ 7.32	$ 7.41
Expected	2026-2027	Dec	$ 7.53	$ 7.50	$ 20.69	$ 20.69	$ 20.69	$ 7.43	$ 7.43	$ 7.50	$ 7.46	$ 15.42
Expected	2026-2027	Jan	$ 7.76	$ 7.64	$ 7.76	$ 7.76	$ 7.76	$ 7.64	$ 7.64	$ 7.64	$ 7.64	$ 7.73
Expected	2026-2027	Feb	$ 7.75	$ 12.32	$ 16.59	$ 16.59	$ 16.59	$ 12.32	$ 12.44	$ 12.32	$ 12.36	$ 13.97
Expected	2026-2027	Mar	$ 7.15	$ 7.06	$ 7.14	$ 7.14	$ 7.14	$ 7.06	$ 7.06	$ 7.06	$ 7.06	$ 7.12
Expected	2026-2027	Apr	$ 7.06	$ 7.02	$ 7.02	$ 7.02	$ 7.02	$ 6.93	$ 6.93	$ 7.02	$ 6.96	$ 7.02
Expected	2026-2027	May	$ 7.08	$ 7.02	$ 7.02	$ 7.02	$ 7.02	$ 6.95	$ 6.95	$ 7.02	$ 6.98	$ 7.03
Expected	2026-2027	Jun	$ 7.10	$ 7.02	$ 7.02	$ 7.02	$ 7.02	$ 6.99	$ 6.99	$ 7.02	$ 7.00	$ 7.03
Expected	2026-2027	Jul	$ 7.08	$ 7.01	$ 7.01	$ 7.01	$ 7.01	$ 6.95	$ 6.95	$ 7.02	$ 6.98	$ 7.02
Expected	2026-2027	Aug	$ 7.09	$ 7.01	$ 7.01	$ 7.01	$ 7.01	$ 6.99	$ 6.99	$ 7.02	$ 7.00	$ 7.03
Expected	2026-2027	Sep	$ 7.10	$ 7.02	$ 7.02	$ 7.02	$ 7.02	$ 7.02	$ 7.02	$ 7.02	$ 7.02	$ 7.03
Expected	2026-2027	Oct	$ 7.21	$ 7.13	$ 7.13	$ 7.13	$ 7.13	$ 7.13	$ 7.13	$ 7.13	$ 7.13	$ 7.14
Expected	2027-2028	Nov	$ 7.58	$ 7.50	$ 7.57	$ 7.57	$ 7.57	$ 7.45	$ 7.45	$ 7.50	$ 7.47	$ 7.56
Expected	2027-2028	Dec	$ 7.67	$ 7.55	$ 20.83	$ 20.83	$ 20.83	$ 7.55	$ 7.55	$ 7.55	$ 7.55	$ 15.54
Expected	2027-2028	Jan	$ 7.60	$ 7.52	$ 7.60	$ 7.60	$ 7.60	$ 7.48	$ 7.48	$ 7.52	$ 7.50	$ 7.58
Expected	2027-2028	Feb	$ 7.61	$ 14.77	$ 18.49	$ 18.49	$ 18.49	$ 14.77	$ 14.85	$ 14.77	$ 14.80	$ 15.57
Expected	2027-2028	Mar	$ 7.24	$ 7.14	$ 7.24	$ 7.24	$ 7.24	$ 7.14	$ 7.14	$ 7.14	$ 7.14	$ 7.22
Expected	2027-2028	Apr	$ 7.17	$ 7.13	$ 7.13	$ 7.13	$ 7.13	$ 7.05	$ 7.05	$ 7.13	$ 7.07	$ 7.14
Expected	2027-2028	May	$ 7.17	$ 7.13	$ 7.13	$ 7.13	$ 7.13	$ 7.05	$ 7.05	$ 7.13	$ 7.07	$ 7.14
Expected	2027-2028	Jun	$ 7.21	$ 7.13	$ 7.13	$ 7.13	$ 7.13	$ 7.09	$ 7.09	$ 7.13	$ 7.10	$ 7.14
Expected	2027-2028	Jul	$ 7.18	$ 7.12	$ 7.12	$ 7.12	$ 7.12	$ 7.06	$ 7.06	$ 7.13	$ 7.08	$ 7.13
Expected	2027-2028	Aug	$ 7.21	$ 7.12	$ 7.12	$ 7.12	$ 7.12	$ 7.09	$ 7.09	$ 7.13	$ 7.10	$ 7.14
Expected	2027-2028	Sep	$ 7.21	$ 7.13	$ 7.13	$ 7.13	$ 7.13	$ 7.13	$ 7.13	$ 7.13	$ 7.13	$ 7.14
Expected	2027-2028	Oct	$ 7.31	$ 7.23	$ 7.23	$ 7.23	$ 7.23	$ 7.23	$ 7.23	$ 7.23	$ 7.23	$ 7.25
Expected	2028-2029	Nov	$ 7.70	$ 7.61	$ 7.69	$ 7.69	$ 7.69	$ 7.56	$ 7.56	$ 7.61	$ 7.58	$ 7.67
Expected	2028-2029	Dec	$ 7.78	$ 7.66	$ 20.96	$ 20.96	$ 20.96	$ 7.66	$ 7.66	$ 7.66	$ 7.66	$ 15.66
Expected	2028-2029	Jan	$ 7.69	$ 7.62	$ 9.76	$ 9.76	$ 9.76	$ 7.58	$ 7.58	$ 7.62	$ 7.59	$ 8.92
Expected	2028-2029	Feb	$ 7.71	$ 16.07	$ 19.39	$ 19.39	$ 19.39	$ 15.17	$ 15.21	$ 15.17	$ 15.18	$ 16.39
Expected	2028-2029	Mar	$ 7.42	$ 7.31	$ 7.41	$ 7.41	$ 7.41	$ 7.31	$ 7.31	$ 7.31	$ 7.31	$ 7.39
Expected	2028-2029	Apr	$ 7.29	$ 7.26	$ 7.26	$ 7.26	$ 7.26	$ 7.17	$ 7.17	$ 7.26	$ 7.20	$ 7.27
Expected	2028-2029	May	$ 7.31	$ 7.26	$ 7.26	$ 7.26	$ 7.26	$ 7.19	$ 7.19	$ 7.26	$ 7.21	$ 7.27
Expected	2028-2029	Jun	$ 7.35	$ 7.26	$ 7.26	$ 7.26	$ 7.26	$ 7.22	$ 7.22	$ 7.26	$ 7.23	$ 7.28
Expected	2028-2029	Jul	$ 7.25	$ 7.17	$ 7.17	$ 7.17	$ 7.17	$ 7.13	$ 7.13	$ 7.26	$ 7.17	$ 7.19
Expected	2028-2029	Aug	$ 7.25	$ 7.17	$ 7.17	$ 7.17	$ 7.17	$ 7.13	$ 7.13	$ 7.26	$ 7.17	$ 7.19
Expected	2028-2029	Sep	$ 7.35	$ 7.26	$ 7.26	$ 7.26	$ 7.26	$ 7.24	$ 7.24	$ 7.26	$ 7.25	$ 7.28
Expected	2028-2029	Oct	$ 7.41	$ 7.32	$ 7.32	$ 7.32	$ 7.32	$ 7.32	$ 7.32	$ 7.32	$ 7.32	$ 7.34

1/ Avoided costs shown before Environmental Externalities adder.

Appendix 6.4 - Monthly Avoided Cost Detail 1/
2009$

Scenario	Gas Year	Month	Klam Falls	La Grande	Medford GTN	Medford NWP	Roseburg	Wa/Id Both	Wa/Id GTN	Wa/Id NWP	WA/ID Annual	OR Annual
High Growth & Low Price	2009-2010	Nov	$ 5.57	$ 5.51	$ 5.54	$ 5.54	$ 5.54	$ 5.51	$ 5.51	$ 5.51	$ 5.51	$ 5.54
High Growth & Low Price	2009-2010	Dec	$ 5.93	$ 5.88	$ 5.87	$ 5.87	$ 5.87	$ 5.88	$ 5.88	$ 5.88	$ 5.88	$ 5.89
High Growth & Low Price	2009-2010	Jan	$ 5.59	$ 5.63	$ 5.59	$ 5.59	$ 5.59	$ 5.62	$ 5.62	$ 5.63	$ 5.63	$ 5.60
High Growth & Low Price	2009-2010	Feb	$ 5.64	$ 5.60	$ 5.62	$ 5.62	$ 5.62	$ 5.60	$ 5.61	$ 5.60	$ 5.60	$ 5.62
High Growth & Low Price	2009-2010	Mar	$ 5.50	$ 5.43	$ 5.46	$ 5.46	$ 5.46	$ 5.43	$ 5.51	$ 5.43	$ 5.46	$ 5.46
High Growth & Low Price	2009-2010	Apr	$ 4.86	$ 4.85	$ 4.85	$ 4.85	$ 4.85	$ 4.85	$ 4.85	$ 4.85	$ 4.85	$ 4.85
High Growth & Low Price	2009-2010	May	$ 4.90	$ 4.84	$ 4.84	$ 4.84	$ 4.84	$ 4.84	$ 4.90	$ 4.84	$ 4.86	$ 4.86
High Growth & Low Price	2009-2010	Jun	$ 4.90	$ 4.84	$ 4.84	$ 4.84	$ 4.84	$ 4.84	$ 4.98	$ 4.84	$ 4.89	$ 4.86
High Growth & Low Price	2009-2010	Jul	$ 4.90	$ 4.84	$ 4.84	$ 4.84	$ 4.84	$ 4.84	$ 5.05	$ 4.84	$ 4.91	$ 4.86
High Growth & Low Price	2009-2010	Aug	$ 4.90	$ 4.84	$ 4.84	$ 4.84	$ 4.84	$ 4.84	$ 5.13	$ 4.84	$ 4.94	$ 4.86
High Growth & Low Price	2009-2010	Sep	$ 4.90	$ 4.84	$ 4.84	$ 4.84	$ 4.84	$ 4.84	$ 5.14	$ 4.84	$ 4.94	$ 4.86
High Growth & Low Price	2009-2010	Oct	$ 5.21	$ 5.19	$ 5.19	$ 5.19	$ 5.19	$ 5.19	$ 5.19	$ 5.19	$ 5.19	$ 5.20
High Growth & Low Price	2010-2011	Nov	$ 5.96	$ 5.90	$ 5.93	$ 5.93	$ 5.93	$ 5.90	$ 5.90	$ 5.90	$ 5.90	$ 5.93
High Growth & Low Price	2010-2011	Dec	$ 6.14	$ 6.09	$ 6.13	$ 6.13	$ 6.13	$ 6.09	$ 6.09	$ 6.09	$ 6.09	$ 6.13
High Growth & Low Price	2010-2011	Jan	$ 6.05	$ 6.05	$ 6.05	$ 6.05	$ 6.05	$ 6.04	$ 6.04	$ 6.05	$ 6.04	$ 6.05
High Growth & Low Price	2010-2011	Feb	$ 6.06	$ 6.02	$ 6.05	$ 6.05	$ 6.05	$ 6.02	$ 6.03	$ 6.02	$ 6.03	$ 6.05
High Growth & Low Price	2010-2011	Mar	$ 5.88	$ 5.81	$ 5.85	$ 5.85	$ 5.85	$ 5.81	$ 5.89	$ 5.81	$ 5.84	$ 5.85
High Growth & Low Price	2010-2011	Apr	$ 5.14	$ 5.21	$ 5.14	$ 5.14	$ 5.14	$ 5.14	$ 5.14	$ 5.21	$ 5.17	$ 5.16
High Growth & Low Price	2010-2011	May	$ 5.14	$ 5.21	$ 5.14	$ 5.14	$ 5.14	$ 5.15	$ 5.15	$ 5.21	$ 5.17	$ 5.16
High Growth & Low Price	2010-2011	Jun	$ 5.20	$ 5.21	$ 5.20	$ 5.20	$ 5.20	$ 5.21	$ 5.21	$ 5.21	$ 5.21	$ 5.20
High Growth & Low Price	2010-2011	Jul	$ 5.27	$ 5.21	$ 5.21	$ 5.21	$ 5.21	$ 5.21	$ 5.27	$ 5.21	$ 5.23	$ 5.23
High Growth & Low Price	2010-2011	Aug	$ 5.28	$ 5.21	$ 5.21	$ 5.21	$ 5.21	$ 5.21	$ 5.33	$ 5.21	$ 5.25	$ 5.23
High Growth & Low Price	2010-2011	Sep	$ 5.28	$ 5.21	$ 5.21	$ 5.21	$ 5.21	$ 5.21	$ 5.36	$ 5.21	$ 5.26	$ 5.23
High Growth & Low Price	2010-2011	Oct	$ 5.42	$ 5.42	$ 5.42	$ 5.42	$ 5.42	$ 5.42	$ 5.42	$ 5.42	$ 5.42	$ 5.42
High Growth & Low Price	2011-2012	Nov	$ 5.86	$ 5.91	$ 5.86	$ 5.86	$ 5.86	$ 5.83	$ 5.83	$ 5.91	$ 5.86	$ 5.87
High Growth & Low Price	2011-2012	Dec	$ 5.99	$ 6.06	$ 6.01	$ 6.01	$ 6.01	$ 5.99	$ 5.99	$ 6.06	$ 6.01	$ 6.02
High Growth & Low Price	2011-2012	Jan	$ 5.86	$ 5.94	$ 5.86	$ 5.86	$ 5.86	$ 5.89	$ 5.89	$ 5.94	$ 5.91	$ 5.88
High Growth & Low Price	2011-2012	Feb	$ 5.88	$ 5.89	$ 5.88	$ 5.88	$ 5.88	$ 5.85	$ 5.86	$ 5.85	$ 5.85	$ 5.88
High Growth & Low Price	2011-2012	Mar	$ 5.62	$ 5.68	$ 5.62	$ 5.62	$ 5.62	$ 5.68	$ 5.70	$ 5.68	$ 5.69	$ 5.64
High Growth & Low Price	2011-2012	Apr	$ 4.97	$ 5.06	$ 4.97	$ 4.97	$ 4.97	$ 4.98	$ 4.98	$ 5.15	$ 5.04	$ 4.99
High Growth & Low Price	2011-2012	May	$ 4.94	$ 5.06	$ 4.94	$ 4.94	$ 4.94	$ 4.97	$ 4.97	$ 5.15	$ 5.03	$ 4.97
High Growth & Low Price	2011-2012	Jun	$ 5.01	$ 5.06	$ 5.01	$ 5.01	$ 5.01	$ 5.04	$ 5.04	$ 5.15	$ 5.08	$ 5.02
High Growth & Low Price	2011-2012	Jul	$ 5.08	$ 5.12	$ 5.08	$ 5.08	$ 5.08	$ 5.10	$ 5.10	$ 5.15	$ 5.12	$ 5.09
High Growth & Low Price	2011-2012	Aug	$ 5.14	$ 5.15	$ 5.14	$ 5.14	$ 5.14	$ 5.15	$ 5.15	$ 5.15	$ 5.15	$ 5.14
High Growth & Low Price	2011-2012	Sep	$ 5.18	$ 5.15	$ 5.15	$ 5.15	$ 5.15	$ 5.15	$ 5.19	$ 5.15	$ 5.17	$ 5.16
High Growth & Low Price	2011-2012	Oct	$ 5.23	$ 5.23	$ 5.23	$ 5.23	$ 5.23	$ 5.23	$ 5.23	$ 5.23	$ 5.23	$ 5.23
High Growth & Low Price	2012-2013	Nov	$ 5.80	$ 5.76	$ 5.78	$ 5.78	$ 5.78	$ 5.75	$ 5.75	$ 5.76	$ 5.75	$ 5.78
High Growth & Low Price	2012-2013	Dec	$ 5.91	$ 5.99	$ 5.97	$ 5.97	$ 5.97	$ 5.96	$ 5.96	$ 5.99	$ 5.97	$ 5.96
High Growth & Low Price	2012-2013	Jan	$ 6.18	$ 6.25	$ 6.18	$ 6.18	$ 6.18	$ 6.25	$ 6.25	$ 6.25	$ 6.25	$ 6.20
High Growth & Low Price	2012-2013	Feb	$ 6.18	$ 6.23	$ 6.18	$ 6.18	$ 6.18	$ 6.23	$ 6.24	$ 6.23	$ 6.23	$ 6.19
High Growth & Low Price	2012-2013	Mar	$ 5.89	$ 5.86	$ 5.87	$ 5.87	$ 5.87	$ 5.86	$ 6.06	$ 5.86	$ 5.93	$ 5.88
High Growth & Low Price	2012-2013	Apr	$ 5.29	$ 5.39	$ 5.29	$ 5.29	$ 5.29	$ 5.33	$ 5.33	$ 5.39	$ 5.35	$ 5.31
High Growth & Low Price	2012-2013	May	$ 5.30	$ 5.39	$ 5.30	$ 5.30	$ 5.30	$ 5.35	$ 5.35	$ 5.39	$ 5.36	$ 5.32
High Growth & Low Price	2012-2013	Jun	$ 5.37	$ 5.39	$ 5.37	$ 5.37	$ 5.37	$ 5.39	$ 5.42	$ 5.39	$ 5.40	$ 5.38
High Growth & Low Price	2012-2013	Jul	$ 5.40	$ 5.39	$ 5.39	$ 5.39	$ 5.39	$ 5.39	$ 5.44	$ 5.39	$ 5.41	$ 5.39
High Growth & Low Price	2012-2013	Aug	$ 5.45	$ 5.39	$ 5.39	$ 5.39	$ 5.39	$ 5.39	$ 5.48	$ 5.39	$ 5.42	$ 5.40
High Growth & Low Price	2012-2013	Sep	$ 5.46	$ 5.40	$ 5.40	$ 5.40	$ 5.40	$ 5.40	$ 5.50	$ 5.40	$ 5.43	$ 5.41
High Growth & Low Price	2012-2013	Oct	$ 5.58	$ 5.58	$ 5.58	$ 5.58	$ 5.58	$ 5.58	$ 5.60	$ 5.58	$ 5.59	$ 5.58
High Growth & Low Price	2013-2014	Nov	$ 5.43	$ 5.36	$ 5.38	$ 5.38	$ 5.38	$ 5.32	$ 5.37	$ 5.36	$ 5.35	$ 5.39
High Growth & Low Price	2013-2014	Dec	$ 5.45	$ 5.40	$ 5.43	$ 5.43	$ 5.43	$ 5.35	$ 5.39	$ 5.40	$ 5.38	$ 5.43
High Growth & Low Price	2013-2014	Jan	$ 5.02	$ 5.12	$ 5.02	$ 5.02	$ 5.02	$ 5.12	$ 5.15	$ 5.18	$ 5.15	$ 5.04
High Growth & Low Price	2013-2014	Feb	$ 5.05	$ 5.13	$ 5.05	$ 5.05	$ 5.05	$ 5.13	$ 5.18	$ 5.13	$ 5.15	$ 5.06
High Growth & Low Price	2013-2014	Mar	$ 4.79	$ 4.69	$ 4.79	$ 4.79	$ 4.79	$ 4.69	$ 5.04	$ 4.69	$ 4.81	$ 4.77
High Growth & Low Price	2013-2014	Apr	$ 4.38	$ 4.44	$ 4.38	$ 4.38	$ 4.38	$ 4.41	$ 4.44	$ 4.44	$ 4.43	$ 4.39
High Growth & Low Price	2013-2014	May	$ 4.34	$ 4.44	$ 4.34	$ 4.34	$ 4.34	$ 4.40	$ 4.43	$ 4.44	$ 4.42	$ 4.36
High Growth & Low Price	2013-2014	Jun	$ 4.46	$ 4.44	$ 4.44	$ 4.44	$ 4.44	$ 4.44	$ 4.50	$ 4.44	$ 4.46	$ 4.44
High Growth & Low Price	2013-2014	Jul	$ 4.49	$ 4.44	$ 4.44	$ 4.44	$ 4.44	$ 4.44	$ 4.53	$ 4.44	$ 4.47	$ 4.45
High Growth & Low Price	2013-2014	Aug	$ 4.49	$ 4.44	$ 4.44	$ 4.44	$ 4.44	$ 4.44	$ 4.55	$ 4.44	$ 4.48	$ 4.45
High Growth & Low Price	2013-2014	Sep	$ 4.49	$ 4.44	$ 4.44	$ 4.44	$ 4.44	$ 4.44	$ 4.56	$ 4.44	$ 4.48	$ 4.45
High Growth & Low Price	2013-2014	Oct	$ 4.58	$ 4.55	$ 4.55	$ 4.55	$ 4.55	$ 4.55	$ 4.59	$ 4.55	$ 4.56	$ 4.56
High Growth & Low Price	2014-2015	Nov	$ 5.83	$ 5.79	$ 5.83	$ 5.83	$ 5.83	$ 5.73	$ 5.77	$ 5.79	$ 5.76	$ 5.82
High Growth & Low Price	2014-2015	Dec	$ 5.91	$ 6.05	$ 5.91	$ 5.91	$ 5.91	$ 5.81	$ 5.84	$ 6.12	$ 5.92	$ 5.94
High Growth & Low Price	2014-2015	Jan	$ 6.70	$ 6.85	$ 6.70	$ 6.70	$ 6.70	$ 6.85	$ 6.90	$ 6.85	$ 6.87	$ 6.73
High Growth & Low Price	2014-2015	Feb	$ 6.76	$ 6.88	$ 6.76	$ 6.76	$ 6.76	$ 6.88	$ 6.94	$ 6.88	$ 6.90	$ 6.78
High Growth & Low Price	2014-2015	Mar	$ 6.50	$ 6.46	$ 6.50	$ 6.50	$ 6.50	$ 6.46	$ 6.85	$ 6.46	$ 6.59	$ 6.49
High Growth & Low Price	2014-2015	Apr	$ 6.04	$ 6.21	$ 6.04	$ 6.04	$ 6.04	$ 6.16	$ 6.21	$ 6.21	$ 6.19	$ 6.08
High Growth & Low Price	2014-2015	May	$ 6.06	$ 6.21	$ 6.06	$ 6.06	$ 6.06	$ 6.17	$ 6.22	$ 6.21	$ 6.20	$ 6.09
High Growth & Low Price	2014-2015	Jun	$ 6.21	$ 6.21	$ 6.21	$ 6.21	$ 6.21	$ 6.21	$ 6.26	$ 6.21	$ 6.22	$ 6.21
High Growth & Low Price	2014-2015	Jul	$ 6.28	$ 6.21	$ 6.21	$ 6.21	$ 6.21	$ 6.21	$ 6.33	$ 6.21	$ 6.25	$ 6.22
High Growth & Low Price	2014-2015	Aug	$ 6.28	$ 6.21	$ 6.21	$ 6.21	$ 6.21	$ 6.21	$ 6.33	$ 6.21	$ 6.25	$ 6.22
High Growth & Low Price	2014-2015	Sep	$ 6.28	$ 6.21	$ 6.21	$ 6.21	$ 6.21	$ 6.21	$ 6.34	$ 6.21	$ 6.25	$ 6.22
High Growth & Low Price	2014-2015	Oct	$ 6.37	$ 6.33	$ 6.33	$ 6.33	$ 6.33	$ 6.33	$ 6.38	$ 6.33	$ 6.34	$ 6.34
High Growth & Low Price	2015-2016	Nov	$ 7.06	$ 7.02	$ 7.06	$ 7.06	$ 7.06	$ 6.95	$ 7.01	$ 7.02	$ 6.99	$ 7.05
High Growth & Low Price	2015-2016	Dec	$ 7.17	$ 7.15	$ 7.17	$ 7.17	$ 7.17	$ 7.11	$ 7.16	$ 7.16	$ 7.14	$ 7.17
High Growth & Low Price	2015-2016	Jan	$ 7.04	$ 7.21	$ 7.04	$ 7.04	$ 7.04	$ 7.21	$ 7.26	$ 7.21	$ 7.22	$ 7.07
High Growth & Low Price	2015-2016	Feb	$ 7.38	$ 7.24	$ 7.36	$ 7.36	$ 7.36	$ 7.24	$ 7.31	$ 7.24	$ 7.26	$ 7.34
High Growth & Low Price	2015-2016	Mar	$ 6.71	$ 6.72	$ 6.71	$ 6.71	$ 6.71	$ 6.72	$ 7.21	$ 6.72	$ 6.88	$ 6.71
High Growth & Low Price	2015-2016	Apr	$ 6.27	$ 6.47	$ 6.27	$ 6.27	$ 6.27	$ 6.47	$ 6.52	$ 6.47	$ 6.49	$ 6.31
High Growth & Low Price	2015-2016	May	$ 6.27	$ 6.47	$ 6.27	$ 6.27	$ 6.27	$ 6.47	$ 6.52	$ 6.47	$ 6.49	$ 6.31
High Growth & Low Price	2015-2016	Jun	$ 6.45	$ 6.47	$ 6.45	$ 6.45	$ 6.45	$ 6.45	$ 6.50	$ 6.47	$ 6.47	$ 6.46
High Growth & Low Price	2015-2016	Jul	$ 6.55	$ 6.47	$ 6.47	$ 6.47	$ 6.47	$ 6.47	$ 6.61	$ 6.47	$ 6.52	$ 6.48
High Growth & Low Price	2015-2016	Aug	$ 6.55	$ 6.47	$ 6.47	$ 6.47	$ 6.47	$ 6.47	$ 6.59	$ 6.47	$ 6.51	$ 6.48
High Growth & Low Price	2015-2016	Sep	$ 6.55	$ 6.47	$ 6.47	$ 6.47	$ 6.47	$ 6.47	$ 6.64	$ 6.47	$ 6.53	$ 6.48
High Growth & Low Price	2015-2016	Oct	$ 6.72	$ 6.66	$ 6.66	$ 6.66	$ 6.66	$ 6.66	$ 6.71	$ 6.66	$ 6.68	$ 6.67
High Growth & Low Price	2016-2017	Nov	$ 7.41	$ 7.38	$ 7.41	$ 7.41	$ 7.41	$ 7.29	$ 7.35	$ 7.38	$ 7.34	$ 7.40
High Growth & Low Price	2016-2017	Dec	$ 7.52	$ 7.42	$ 7.51	$ 7.51	$ 7.51	$ 7.37	$ 7.41	$ 7.42	$ 7.40	$ 7.49
High Growth & Low Price	2016-2017	Jan	$ 7.18	$ 7.33	$ 7.18	$ 7.18	$ 7.18	$ 7.31	$ 7.35	$ 7.35	$ 7.34	$ 7.21
High Growth & Low Price	2016-2017	Feb	$ 7.12	$ 7.31	$ 7.12	$ 7.12	$ 7.12	$ 7.31	$ 7.38	$ 7.31	$ 7.33	$ 7.15
High Growth & Low Price	2016-2017	Mar	$ 6.73	$ 6.73	$ 6.73	$ 6.73	$ 6.73	$ 6.73	$ 7.15	$ 6.73	$ 6.87	$ 6.73
High Growth & Low Price	2016-2017	Apr	$ 6.23	$ 6.42	$ 6.23	$ 6.23	$ 6.23	$ 6.42	$ 6.47	$ 6.42	$ 6.44	$ 6.27
High Growth & Low Price	2016-2017	May	$ 6.31	$ 6.42	$ 6.31	$ 6.31	$ 6.31	$ 6.42	$ 6.51	$ 6.42	$ 6.45	$ 6.34
High Growth & Low Price	2016-2017	Jun	$ 6.28	$ 6.42	$ 6.28	$ 6.28	$ 6.28	$ 6.42	$ 6.49	$ 6.42	$ 6.45	$ 6.31
High Growth & Low Price	2016-2017	Jul	$ 6.41	$ 6.42	$ 6.41	$ 6.41	$ 6.41	$ 6.42	$ 6.50	$ 6.42	$ 6.45	$ 6.42
High Growth & Low Price	2016-2017	Aug	$ 6.42	$ 6.42	$ 6.42	$ 6.42	$ 6.42	$ 6.42	$ 6.50	$ 6.42	$ 6.45	$ 6.42

Appendix 6.4 - Monthly Avoided Cost Detail 1/

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Scenario	Gas Year	Month	Klam Falls	La Grande	Medford GTN	Medford NWP	Roseburg	Wa/Id Both	Wa/Id GTN	Wa/Id NWP	WA/ID Annual	OR Annual
High Growth & Low Price	2016-2017	Sep	$ 6.46	$ 6.42	$ 6.42	$ 6.42	$ 6.42	$ 6.42	$ 6.52	$ 6.42	$ 6.46	$ 6.43
High Growth & Low Price	2016-2017	Oct	$ 6.54	$ 6.53	$ 6.53	$ 6.53	$ 6.53	$ 6.53	$ 6.58	$ 6.53	$ 6.55	$ 6.53
High Growth & Low Price	2017-2018	Nov	$ 7.17	$ 7.17	$ 7.17	$ 7.17	$ 7.17	$ 7.16	$ 7.22	$ 7.17	$ 7.18	$ 7.17
High Growth & Low Price	2017-2018	Dec	$ 7.25	$ 7.25	$ 7.25	$ 7.25	$ 7.25	$ 7.20	$ 7.25	$ 7.37	$ 7.27	$ 7.25
High Growth & Low Price	2017-2018	Jan	$ 7.52	$ 7.77	$ 7.52	$ 7.52	$ 7.52	$ 7.77	$ 7.83	$ 7.77	$ 7.79	$ 7.57
High Growth & Low Price	2017-2018	Feb	$ 7.61	$ 7.78	$ 7.61	$ 7.61	$ 7.61	$ 7.78	$ 7.86	$ 7.78	$ 7.81	$ 7.64
High Growth & Low Price	2017-2018	Mar	$ 7.29	$ 7.34	$ 7.29	$ 7.29	$ 7.29	$ 7.34	$ 7.69	$ 7.34	$ 7.46	$ 7.30
High Growth & Low Price	2017-2018	Apr	$ 6.90	$ 7.07	$ 6.90	$ 6.90	$ 6.90	$ 7.04	$ 7.10	$ 7.07	$ 7.07	$ 6.94
High Growth & Low Price	2017-2018	May	$ 6.94	$ 7.07	$ 6.94	$ 6.94	$ 6.94	$ 7.07	$ 7.13	$ 7.07	$ 7.09	$ 6.97
High Growth & Low Price	2017-2018	Jun	$ 6.94	$ 7.07	$ 6.94	$ 6.94	$ 6.94	$ 7.07	$ 7.14	$ 7.07	$ 7.09	$ 6.97
High Growth & Low Price	2017-2018	Jul	$ 7.08	$ 7.07	$ 7.07	$ 7.07	$ 7.07	$ 7.07	$ 7.18	$ 7.07	$ 7.11	$ 7.07
High Growth & Low Price	2017-2018	Aug	$ 7.09	$ 7.07	$ 7.07	$ 7.07	$ 7.07	$ 7.07	$ 7.18	$ 7.07	$ 7.11	$ 7.08
High Growth & Low Price	2017-2018	Sep	$ 7.08	$ 7.07	$ 7.07	$ 7.07	$ 7.07	$ 7.07	$ 7.17	$ 7.07	$ 7.10	$ 7.07
High Growth & Low Price	2017-2018	Oct	$ 7.13	$ 7.13	$ 7.13	$ 7.13	$ 7.13	$ 7.13	$ 7.20	$ 7.13	$ 7.15	$ 7.13
High Growth & Low Price	2018-2019	Nov	$ 7.83	$ 7.83	$ 7.83	$ 7.83	$ 7.83	$ 7.79	$ 7.86	$ 7.83	$ 7.83	$ 7.83
High Growth & Low Price	2018-2019	Dec	$ 7.85	$ 7.84	$ 7.85	$ 7.85	$ 7.85	$ 7.83	$ 7.88	$ 7.86	$ 7.86	$ 7.85
High Growth & Low Price	2018-2019	Jan	$ 7.87	$ 7.86	$ 7.87	$ 7.87	$ 7.87	$ 7.75	$ 7.78	$ 7.86	$ 7.80	$ 7.87
High Growth & Low Price	2018-2019	Feb	$ 7.67	$ 7.71	$ 7.67	$ 7.67	$ 7.67	$ 7.71	$ 7.77	$ 7.71	$ 7.73	$ 7.67
High Growth & Low Price	2018-2019	Mar	$ 7.41	$ 7.33	$ 7.41	$ 7.41	$ 7.41	$ 7.33	$ 7.62	$ 7.33	$ 7.43	$ 7.40
High Growth & Low Price	2018-2019	Apr	$ 6.92	$ 6.98	$ 6.92	$ 6.92	$ 6.92	$ 6.98	$ 7.04	$ 6.98	$ 7.00	$ 6.93
High Growth & Low Price	2018-2019	May	$ 6.93	$ 6.98	$ 6.93	$ 6.93	$ 6.93	$ 6.98	$ 7.05	$ 6.98	$ 7.00	$ 6.94
High Growth & Low Price	2018-2019	Jun	$ 6.95	$ 6.98	$ 6.95	$ 6.95	$ 6.95	$ 6.98	$ 7.07	$ 6.98	$ 7.01	$ 6.96
High Growth & Low Price	2018-2019	Jul	$ 6.96	$ 6.98	$ 6.96	$ 6.96	$ 6.96	$ 6.98	$ 7.08	$ 6.98	$ 7.01	$ 6.97
High Growth & Low Price	2018-2019	Aug	$ 6.93	$ 6.98	$ 6.93	$ 6.93	$ 6.93	$ 6.98	$ 7.06	$ 6.98	$ 7.01	$ 6.94
High Growth & Low Price	2018-2019	Sep	$ 6.97	$ 6.98	$ 6.97	$ 6.97	$ 6.97	$ 6.98	$ 7.08	$ 6.98	$ 7.01	$ 6.97
High Growth & Low Price	2018-2019	Oct	$ 7.09	$ 7.11	$ 7.11	$ 7.11	$ 7.11	$ 7.11	$ 7.17	$ 7.11	$ 7.13	$ 7.11
High Growth & Low Price	2019-2020	Nov	$ 7.87	$ 7.80	$ 7.86	$ 7.86	$ 7.86	$ 7.72	$ 7.78	$ 7.80	$ 7.77	$ 7.85
High Growth & Low Price	2019-2020	Dec	$ 7.90	$ 7.82	$ 7.90	$ 7.90	$ 7.90	$ 7.78	$ 7.83	$ 7.82	$ 7.81	$ 7.88
High Growth & Low Price	2019-2020	Jan	$ 7.67	$ 7.70	$ 7.67	$ 7.67	$ 7.67	$ 7.66	$ 7.69	$ 7.74	$ 7.70	$ 7.68
High Growth & Low Price	2019-2020	Feb	$ 7.61	$ 7.65	$ 7.61	$ 7.61	$ 7.61	$ 7.65	$ 7.72	$ 7.65	$ 7.67	$ 7.62
High Growth & Low Price	2019-2020	Mar	$ 7.52	$ 7.44	$ 7.52	$ 7.52	$ 7.52	$ 7.44	$ 7.64	$ 7.44	$ 7.51	$ 7.51
High Growth & Low Price	2019-2020	Apr	$ 6.80	$ 6.95	$ 6.80	$ 6.80	$ 6.80	$ 6.90	$ 6.95	$ 6.95	$ 6.94	$ 6.83
High Growth & Low Price	2019-2020	May	$ 6.81	$ 6.95	$ 6.81	$ 6.81	$ 6.81	$ 6.92	$ 6.98	$ 6.95	$ 6.95	$ 6.84
High Growth & Low Price	2019-2020	Jun	$ 6.86	$ 6.95	$ 6.86	$ 6.86	$ 6.86	$ 6.95	$ 7.01	$ 6.95	$ 6.97	$ 6.88
High Growth & Low Price	2019-2020	Jul	$ 6.95	$ 6.95	$ 6.95	$ 6.95	$ 6.95	$ 6.95	$ 7.07	$ 6.95	$ 6.99	$ 6.95
High Growth & Low Price	2019-2020	Aug	$ 6.91	$ 6.95	$ 6.91	$ 6.91	$ 6.91	$ 6.95	$ 7.05	$ 6.95	$ 6.98	$ 6.92
High Growth & Low Price	2019-2020	Sep	$ 7.01	$ 6.98	$ 6.98	$ 6.98	$ 6.98	$ 6.98	$ 7.12	$ 6.98	$ 7.02	$ 6.99
High Growth & Low Price	2019-2020	Oct	$ 7.14	$ 7.15	$ 7.15	$ 7.15	$ 7.15	$ 7.15	$ 7.21	$ 7.15	$ 7.17	$ 7.15
High Growth & Low Price	2020-2021	Nov	$ 7.94	$ 7.92	$ 7.93	$ 7.93	$ 7.93	$ 7.78	$ 7.84	$ 7.92	$ 7.84	$ 7.93
High Growth & Low Price	2020-2021	Dec	$ 7.93	$ 7.93	$ 7.93	$ 7.93	$ 7.93	$ 7.80	$ 7.84	$ 7.93	$ 7.86	$ 7.93
High Growth & Low Price	2020-2021	Jan	$ 7.99	$ 7.94	$ 7.99	$ 7.99	$ 7.99	$ 7.87	$ 7.90	$ 7.94	$ 7.90	$ 7.98
High Growth & Low Price	2020-2021	Feb	$ 8.01	$ 7.86	$ 8.01	$ 8.01	$ 8.01	$ 7.86	$ 7.92	$ 7.86	$ 7.88	$ 7.98
High Growth & Low Price	2020-2021	Mar	$ 7.65	$ 7.53	$ 7.65	$ 7.65	$ 7.65	$ 7.53	$ 7.63	$ 7.53	$ 7.57	$ 7.63
High Growth & Low Price	2020-2021	Apr	$ 6.92	$ 7.04	$ 6.92	$ 6.92	$ 6.92	$ 7.01	$ 7.07	$ 7.04	$ 7.04	$ 6.94
High Growth & Low Price	2020-2021	May	$ 6.89	$ 7.04	$ 6.89	$ 6.89	$ 6.89	$ 7.01	$ 7.07	$ 7.04	$ 7.04	$ 6.92
High Growth & Low Price	2020-2021	Jun	$ 6.91	$ 7.04	$ 6.91	$ 6.91	$ 6.91	$ 7.03	$ 7.09	$ 7.04	$ 7.05	$ 6.94
High Growth & Low Price	2020-2021	Jul	$ 6.94	$ 7.04	$ 6.94	$ 6.94	$ 6.94	$ 7.04	$ 7.12	$ 7.04	$ 7.07	$ 6.96
High Growth & Low Price	2020-2021	Aug	$ 6.84	$ 7.04	$ 6.84	$ 6.84	$ 6.84	$ 7.00	$ 7.06	$ 7.04	$ 7.03	$ 6.88
High Growth & Low Price	2020-2021	Sep	$ 6.91	$ 7.04	$ 6.91	$ 6.91	$ 6.91	$ 7.01	$ 7.07	$ 7.04	$ 7.04	$ 6.94
High Growth & Low Price	2020-2021	Oct	$ 6.91	$ 7.11	$ 7.11	$ 7.11	$ 7.11	$ 7.03	$ 7.09	$ 7.11	$ 7.08	$ 7.07
High Growth & Low Price	2021-2022	Nov	$ 7.73	$ 7.72	$ 7.73	$ 7.73	$ 7.73	$ 7.65	$ 7.70	$ 7.72	$ 7.69	$ 7.73
High Growth & Low Price	2021-2022	Dec	$ 8.34	$ 7.81	$ 7.81	$ 7.81	$ 7.81	$ 7.71	$ 7.74	$ 7.82	$ 7.76	$ 7.92
High Growth & Low Price	2021-2022	Jan	$ 7.73	$ 7.82	$ 7.73	$ 7.73	$ 7.73	$ 7.72	$ 7.74	$ 7.82	$ 7.76	$ 7.75
High Growth & Low Price	2021-2022	Feb	$ 7.75	$ 7.77	$ 7.75	$ 7.75	$ 7.75	$ 7.72	$ 7.77	$ 7.72	$ 7.74	$ 7.75
High Growth & Low Price	2021-2022	Mar	$ 7.58	$ 7.58	$ 7.58	$ 7.58	$ 7.58	$ 7.52	$ 7.58	$ 7.52	$ 7.54	$ 7.58
High Growth & Low Price	2021-2022	Apr	$ 6.78	$ 7.20	$ 6.78	$ 6.78	$ 6.78	$ 6.97	$ 7.03	$ 7.20	$ 7.07	$ 6.86
High Growth & Low Price	2021-2022	May	$ 6.79	$ 7.20	$ 6.79	$ 6.79	$ 6.79	$ 7.00	$ 7.06	$ 7.20	$ 7.09	$ 6.87
High Growth & Low Price	2021-2022	Jun	$ 6.81	$ 7.20	$ 6.81	$ 6.81	$ 6.81	$ 7.03	$ 7.09	$ 7.20	$ 7.11	$ 6.89
High Growth & Low Price	2021-2022	Jul	$ 6.85	$ 7.20	$ 6.85	$ 6.85	$ 6.85	$ 7.06	$ 7.12	$ 7.20	$ 7.13	$ 6.92
High Growth & Low Price	2021-2022	Aug	$ 6.86	$ 7.20	$ 6.86	$ 6.86	$ 6.86	$ 7.07	$ 7.13	$ 7.20	$ 7.13	$ 6.93
High Growth & Low Price	2021-2022	Sep	$ 6.94	$ 7.20	$ 6.94	$ 6.94	$ 6.94	$ 7.11	$ 7.17	$ 7.20	$ 7.16	$ 6.99
High Growth & Low Price	2021-2022	Oct	$ 7.01	$ 7.28	$ 7.28	$ 7.28	$ 7.28	$ 7.15	$ 7.21	$ 7.28	$ 7.22	$ 7.23
High Growth & Low Price	2022-2023	Nov	$ 7.86	$ 7.92	$ 7.86	$ 7.86	$ 7.86	$ 7.77	$ 7.83	$ 7.92	$ 7.84	$ 7.87
High Growth & Low Price	2022-2023	Dec	$ 8.43	$ 7.95	$ 7.89	$ 7.89	$ 7.89	$ 7.78	$ 7.82	$ 7.99	$ 7.86	$ 8.01
High Growth & Low Price	2022-2023	Jan	$ 7.81	$ 8.02	$ 7.81	$ 7.81	$ 7.81	$ 7.82	$ 7.85	$ 8.02	$ 7.89	$ 7.85
High Growth & Low Price	2022-2023	Feb	$ 7.83	$ 7.86	$ 7.83	$ 7.83	$ 7.83	$ 7.83	$ 7.88	$ 7.83	$ 7.85	$ 7.83
High Growth & Low Price	2022-2023	Mar	$ 7.71	$ 7.71	$ 7.71	$ 7.71	$ 7.71	$ 7.68	$ 7.73	$ 7.68	$ 7.70	$ 7.71
High Growth & Low Price	2022-2023	Apr	$ 6.84	$ 7.37	$ 6.84	$ 6.84	$ 6.84	$ 7.07	$ 7.13	$ 7.40	$ 7.20	$ 6.95
High Growth & Low Price	2022-2023	May	$ 6.87	$ 7.37	$ 6.87	$ 6.87	$ 6.87	$ 7.11	$ 7.17	$ 7.40	$ 7.23	$ 6.97
High Growth & Low Price	2022-2023	Jun	$ 6.90	$ 7.37	$ 6.90	$ 6.90	$ 6.90	$ 7.15	$ 7.21	$ 7.40	$ 7.25	$ 6.99
High Growth & Low Price	2022-2023	Jul	$ 6.96	$ 7.37	$ 6.96	$ 6.96	$ 6.96	$ 7.19	$ 7.25	$ 7.40	$ 7.28	$ 7.04
High Growth & Low Price	2022-2023	Aug	$ 6.95	$ 7.40	$ 6.95	$ 6.95	$ 6.95	$ 7.18	$ 7.24	$ 7.40	$ 7.27	$ 7.04
High Growth & Low Price	2022-2023	Sep	$ 7.08	$ 7.40	$ 7.08	$ 7.08	$ 7.08	$ 7.23	$ 7.29	$ 7.40	$ 7.31	$ 7.15
High Growth & Low Price	2022-2023	Oct	$ 7.15	$ 7.50	$ 7.50	$ 7.50	$ 7.50	$ 7.29	$ 7.35	$ 7.50	$ 7.38	$ 7.43
High Growth & Low Price	2023-2024	Nov	$ 8.05	$ 8.16	$ 8.05	$ 8.05	$ 8.05	$ 7.92	$ 7.98	$ 8.16	$ 8.02	$ 8.07
High Growth & Low Price	2023-2024	Dec	$ 8.64	$ 8.19	$ 8.09	$ 8.09	$ 8.09	$ 7.96	$ 8.00	$ 8.25	$ 8.07	$ 8.22
High Growth & Low Price	2023-2024	Jan	$ 8.12	$ 8.29	$ 8.12	$ 8.12	$ 8.12	$ 8.09	$ 8.12	$ 8.29	$ 8.17	$ 8.16
High Growth & Low Price	2023-2024	Feb	$ 8.09	$ 8.13	$ 8.09	$ 8.09	$ 8.09	$ 8.07	$ 8.10	$ 8.08	$ 8.09	$ 8.10
High Growth & Low Price	2023-2024	Mar	$ 7.92	$ 7.92	$ 7.92	$ 7.92	$ 7.92	$ 7.88	$ 7.94	$ 7.88	$ 7.90	$ 7.92
High Growth & Low Price	2023-2024	Apr	$ 7.03	$ 7.60	$ 7.03	$ 7.03	$ 7.03	$ 7.27	$ 7.33	$ 7.61	$ 7.40	$ 7.15
High Growth & Low Price	2023-2024	May	$ 7.06	$ 7.60	$ 7.06	$ 7.06	$ 7.06	$ 7.31	$ 7.36	$ 7.61	$ 7.43	$ 7.17
High Growth & Low Price	2023-2024	Jun	$ 7.12	$ 7.60	$ 7.12	$ 7.12	$ 7.12	$ 7.36	$ 7.41	$ 7.61	$ 7.46	$ 7.22
High Growth & Low Price	2023-2024	Jul	$ 7.14	$ 7.60	$ 7.14	$ 7.14	$ 7.14	$ 7.38	$ 7.43	$ 7.61	$ 7.47	$ 7.23
High Growth & Low Price	2023-2024	Aug	$ 7.15	$ 7.61	$ 7.15	$ 7.15	$ 7.15	$ 7.39	$ 7.44	$ 7.61	$ 7.48	$ 7.24
High Growth & Low Price	2023-2024	Sep	$ 7.27	$ 7.61	$ 7.27	$ 7.27	$ 7.27	$ 7.45	$ 7.50	$ 7.61	$ 7.52	$ 7.34
High Growth & Low Price	2023-2024	Oct	$ 7.39	$ 7.73	$ 7.73	$ 7.73	$ 7.73	$ 7.51	$ 7.56	$ 7.73	$ 7.60	$ 7.66
High Growth & Low Price	2024-2025	Nov	$ 8.30	$ 8.34	$ 8.30	$ 8.30	$ 8.30	$ 8.11	$ 8.17	$ 8.35	$ 8.21	$ 8.31
High Growth & Low Price	2024-2025	Dec	$ 8.92	$ 8.40	$ 8.36	$ 8.36	$ 8.36	$ 8.19	$ 8.22	$ 8.46	$ 8.29	$ 8.48
High Growth & Low Price	2024-2025	Jan	$ 8.32	$ 8.49	$ 8.32	$ 8.32	$ 8.32	$ 8.27	$ 8.30	$ 8.49	$ 8.35	$ 8.35
High Growth & Low Price	2024-2025	Feb	$ 8.30	$ 8.33	$ 8.30	$ 8.30	$ 8.30	$ 8.28	$ 8.31	$ 8.29	$ 8.29	$ 8.30
High Growth & Low Price	2024-2025	Mar	$ 8.05	$ 8.05	$ 8.05	$ 8.05	$ 8.05	$ 8.02	$ 8.08	$ 8.02	$ 8.04	$ 8.05
High Growth & Low Price	2024-2025	Apr	$ 7.17	$ 7.76	$ 7.17	$ 7.17	$ 7.17	$ 7.45	$ 7.50	$ 7.79	$ 7.58	$ 7.29
High Growth & Low Price	2024-2025	May	$ 7.21	$ 7.76	$ 7.21	$ 7.21	$ 7.21	$ 7.48	$ 7.53	$ 7.79	$ 7.60	$ 7.32
High Growth & Low Price	2024-2025	Jun	$ 7.26	$ 7.76	$ 7.26	$ 7.26	$ 7.26	$ 7.52	$ 7.57	$ 7.79	$ 7.63	$ 7.36

Appendix 6.4 - Monthly Avoided Cost Detail 1/
2009$

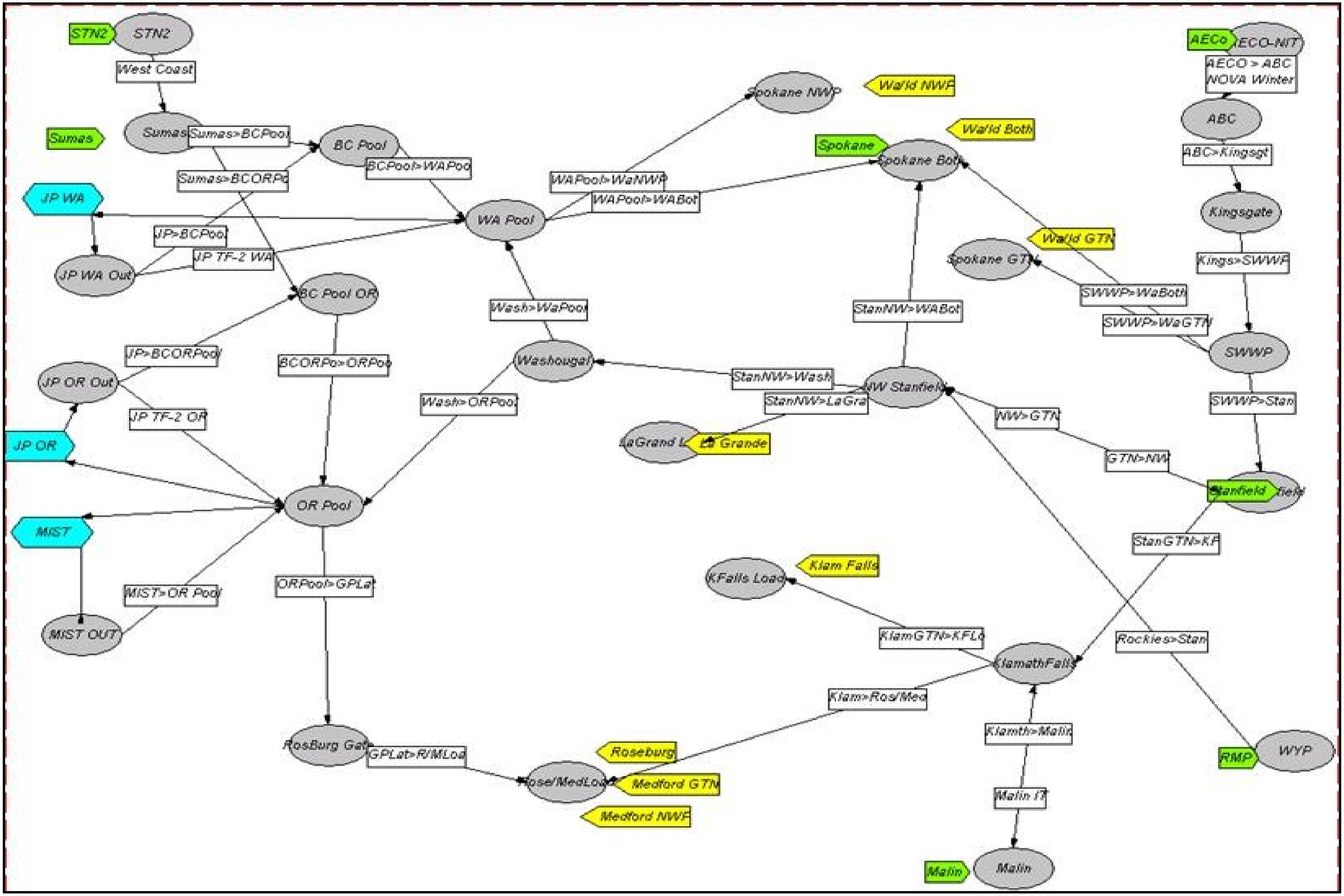
Scenario	Gas Year	Month	Klam Falls	La Grande	Medford GTN	Medford NWP	Roseburg	Wa/Id Both	Wa/Id GTN	Wa/Id NWP	WA/ID Annual	OR Annual
High Growth & Low Price	2024-2025	Jul	$ 7.27	$ 7.76	$ 7.27	$ 7.27	$ 7.27	$ 7.55	$ 7.60	$ 7.79	$ 7.65	$ 7.37
High Growth & Low Price	2024-2025	Aug	$ 7.32	$ 7.79	$ 7.32	$ 7.32	$ 7.32	$ 7.56	$ 7.61	$ 7.79	$ 7.65	$ 7.41
High Growth & Low Price	2024-2025	Sep	$ 7.42	$ 7.83	$ 7.42	$ 7.42	$ 7.42	$ 7.60	$ 7.65	$ 7.83	$ 7.69	$ 7.50
High Growth & Low Price	2024-2025	Oct	$ 7.52	$ 7.91	$ 7.91	$ 7.91	$ 7.91	$ 7.66	$ 7.71	$ 7.91	$ 7.76	$ 7.83
High Growth & Low Price	2025-2026	Nov	$ 8.53	$ 8.57	$ 8.53	$ 8.53	$ 8.53	$ 8.32	$ 8.38	$ 8.58	$ 8.43	$ 8.54
High Growth & Low Price	2025-2026	Dec	$ 9.02	$ 8.53	$ 8.45	$ 8.45	$ 8.45	$ 8.30	$ 8.33	$ 8.63	$ 8.42	$ 8.58
High Growth & Low Price	2025-2026	Jan	$ 8.50	$ 8.66	$ 8.50	$ 8.50	$ 8.50	$ 8.43	$ 8.46	$ 8.68	$ 8.53	$ 8.53
High Growth & Low Price	2025-2026	Feb	$ 8.47	$ 8.51	$ 8.47	$ 8.47	$ 8.47	$ 8.44	$ 8.47	$ 8.46	$ 8.46	$ 8.48
High Growth & Low Price	2025-2026	Mar	$ 8.30	$ 8.30	$ 8.30	$ 8.30	$ 8.30	$ 8.23	$ 8.29	$ 8.23	$ 8.25	$ 8.30
High Growth & Low Price	2025-2026	Apr	$ 7.35	$ 7.94	$ 7.35	$ 7.35	$ 7.35	$ 7.63	$ 7.68	$ 7.94	$ 7.75	$ 7.46
High Growth & Low Price	2025-2026	May	$ 7.37	$ 7.94	$ 7.37	$ 7.37	$ 7.37	$ 7.66	$ 7.71	$ 7.94	$ 7.77	$ 7.49
High Growth & Low Price	2025-2026	Jun	$ 7.42	$ 7.94	$ 7.42	$ 7.42	$ 7.42	$ 7.70	$ 7.75	$ 7.94	$ 7.80	$ 7.52
High Growth & Low Price	2025-2026	Jul	$ 7.43	$ 7.94	$ 7.43	$ 7.43	$ 7.43	$ 7.72	$ 7.77	$ 7.94	$ 7.81	$ 7.53
High Growth & Low Price	2025-2026	Aug	$ 7.44	$ 7.94	$ 7.44	$ 7.44	$ 7.44	$ 7.72	$ 7.77	$ 7.94	$ 7.81	$ 7.54
High Growth & Low Price	2025-2026	Sep	$ 7.56	$ 7.97	$ 7.56	$ 7.56	$ 7.56	$ 7.77	$ 7.83	$ 7.97	$ 7.85	$ 7.64
High Growth & Low Price	2025-2026	Oct	$ 7.68	$ 8.01	$ 8.01	$ 8.01	$ 8.01	$ 7.83	$ 7.89	$ 8.01	$ 7.91	$ 7.94
High Growth & Low Price	2026-2027	Nov	$ 8.59	$ 8.66	$ 8.59	$ 8.59	$ 8.59	$ 8.40	$ 8.46	$ 8.68	$ 8.51	$ 8.60
High Growth & Low Price	2026-2027	Dec	$ 9.17	$ 8.72	$ 8.59	$ 8.59	$ 8.59	$ 8.46	$ 8.49	$ 8.79	$ 8.58	$ 8.73
High Growth & Low Price	2026-2027	Jan	$ 8.65	$ 8.82	$ 8.65	$ 8.65	$ 8.65	$ 8.60	$ 8.62	$ 8.83	$ 8.68	$ 8.68
High Growth & Low Price	2026-2027	Feb	$ 8.69	$ 8.73	$ 8.69	$ 8.69	$ 8.69	$ 8.67	$ 8.70	$ 8.69	$ 8.68	$ 8.70
High Growth & Low Price	2026-2027	Mar	$ 8.56	$ 8.56	$ 8.56	$ 8.56	$ 8.56	$ 8.45	$ 8.51	$ 8.45	$ 8.47	$ 8.56
High Growth & Low Price	2026-2027	Apr	$ 7.60	$ 8.17	$ 7.60	$ 7.60	$ 7.60	$ 7.86	$ 7.92	$ 8.21	$ 8.00	$ 7.71
High Growth & Low Price	2026-2027	May	$ 7.61	$ 8.17	$ 7.61	$ 7.61	$ 7.61	$ 7.88	$ 7.94	$ 8.21	$ 8.01	$ 7.72
High Growth & Low Price	2026-2027	Jun	$ 7.64	$ 8.17	$ 7.64	$ 7.64	$ 7.64	$ 7.91	$ 7.97	$ 8.21	$ 8.03	$ 7.75
High Growth & Low Price	2026-2027	Jul	$ 7.64	$ 8.17	$ 7.64	$ 7.64	$ 7.64	$ 7.92	$ 7.98	$ 8.21	$ 8.04	$ 7.75
High Growth & Low Price	2026-2027	Aug	$ 7.69	$ 8.21	$ 7.69	$ 7.69	$ 7.69	$ 7.96	$ 8.02	$ 8.21	$ 8.06	$ 7.79
High Growth & Low Price	2026-2027	Sep	$ 7.75	$ 8.24	$ 7.75	$ 7.75	$ 7.75	$ 7.96	$ 8.02	$ 8.24	$ 8.07	$ 7.85
High Growth & Low Price	2026-2027	Oct	$ 7.85	$ 8.30	$ 8.30	$ 8.30	$ 8.30	$ 8.01	$ 8.07	$ 8.30	$ 8.13	$ 8.21
High Growth & Low Price	2027-2028	Nov	$ 8.78	$ 8.85	$ 8.78	$ 8.78	$ 8.78	$ 8.59	$ 8.66	$ 8.87	$ 8.71	$ 8.80
High Growth & Low Price	2027-2028	Dec	$ 9.37	$ 8.92	$ 8.80	$ 8.80	$ 8.80	$ 8.65	$ 8.68	$ 9.00	$ 8.78	$ 8.94
High Growth & Low Price	2027-2028	Jan	$ 8.84	$ 9.02	$ 8.84	$ 8.84	$ 8.84	$ 8.79	$ 8.82	$ 9.02	$ 8.88	$ 8.88
High Growth & Low Price	2027-2028	Feb	$ 8.89	$ 8.92	$ 8.89	$ 8.89	$ 8.89	$ 8.86	$ 8.89	$ 8.88	$ 8.88	$ 8.89
High Growth & Low Price	2027-2028	Mar	$ 8.76	$ 8.76	$ 8.76	$ 8.76	$ 8.76	$ 8.64	$ 8.71	$ 8.64	$ 8.66	$ 8.76
High Growth & Low Price	2027-2028	Apr	$ 7.79	$ 8.36	$ 7.79	$ 7.79	$ 7.79	$ 8.05	$ 8.11	$ 8.41	$ 8.19	$ 7.91
High Growth & Low Price	2027-2028	May	$ 7.79	$ 8.36	$ 7.79	$ 7.79	$ 7.79	$ 8.06	$ 8.12	$ 8.41	$ 8.19	$ 7.91
High Growth & Low Price	2027-2028	Jun	$ 7.83	$ 8.36	$ 7.83	$ 7.83	$ 7.83	$ 8.10	$ 8.16	$ 8.41	$ 8.22	$ 7.94
High Growth & Low Price	2027-2028	Jul	$ 7.83	$ 8.36	$ 7.83	$ 7.83	$ 7.83	$ 8.11	$ 8.17	$ 8.41	$ 8.23	$ 7.94
High Growth & Low Price	2027-2028	Aug	$ 7.88	$ 8.40	$ 7.88	$ 7.88	$ 7.88	$ 8.15	$ 8.21	$ 8.41	$ 8.26	$ 7.99
High Growth & Low Price	2027-2028	Sep	$ 7.94	$ 8.44	$ 7.94	$ 7.94	$ 7.94	$ 8.15	$ 8.21	$ 8.44	$ 8.27	$ 8.04
High Growth & Low Price	2027-2028	Oct	$ 8.04	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.20	$ 8.26	$ 8.50	$ 8.32	$ 8.41
High Growth & Low Price	2028-2029	Nov	$ 8.98	$ 9.05	$ 8.98	$ 8.98	$ 8.98	$ 8.78	$ 8.85	$ 9.07	$ 8.90	$ 8.99
High Growth & Low Price	2028-2029	Dec	$ 9.58	$ 9.13	$ 9.01	$ 9.01	$ 9.01	$ 8.86	$ 8.88	$ 9.39	$ 9.05	$ 9.15
High Growth & Low Price	2028-2029	Jan	$ 9.05	$ 9.22	$ 9.05	$ 9.05	$ 9.05	$ 8.99	$ 9.02	$ 9.35	$ 9.12	$ 9.08
High Growth & Low Price	2028-2029	Feb	$ 9.09	$ 9.13	$ 9.09	$ 9.09	$ 9.09	$ 9.07	$ 9.10	$ 9.09	$ 9.09	$ 9.10
High Growth & Low Price	2028-2029	Mar	$ 8.96	$ 8.96	$ 8.96	$ 8.96	$ 8.96	$ 8.83	$ 8.90	$ 8.83	$ 8.86	$ 8.96
High Growth & Low Price	2028-2029	Apr	$ 7.99	$ 8.53	$ 7.99	$ 7.99	$ 7.99	$ 8.24	$ 8.30	$ 8.53	$ 8.36	$ 8.10
High Growth & Low Price	2028-2029	May	$ 8.01	$ 8.53	$ 8.01	$ 8.01	$ 8.01	$ 8.26	$ 8.32	$ 8.53	$ 8.37	$ 8.12
High Growth & Low Price	2028-2029	Jun	$ 8.03	$ 8.56	$ 8.03	$ 8.03	$ 8.03	$ 8.29	$ 8.35	$ 8.56	$ 8.40	$ 8.14
High Growth & Low Price	2028-2029	Jul	$ 8.02	$ 8.53	$ 8.02	$ 8.02	$ 8.02	$ 8.30	$ 8.36	$ 8.53	$ 8.40	$ 8.12
High Growth & Low Price	2028-2029	Aug	$ 8.07	$ 8.53	$ 8.07	$ 8.07	$ 8.07	$ 8.34	$ 8.40	$ 8.53	$ 8.42	$ 8.16
High Growth & Low Price	2028-2029	Sep	$ 8.14	$ 8.63	$ 8.14	$ 8.14	$ 8.14	$ 8.35	$ 8.41	$ 8.63	$ 8.46	$ 8.24
High Growth & Low Price	2028-2029	Oct	$ 8.25	$ 8.69	$ 8.69	$ 8.69	$ 8.69	$ 8.39	$ 8.45	$ 8.69	$ 8.51	$ 8.60

1/ Avoided costs shown before Environmental Externalities adder.

APPENDIX 6.5

SENDOUT® MODEL DIAGRAM

Appendix 6.5 *SENDOUT® Model Diagram*



APPENDIX 7.1

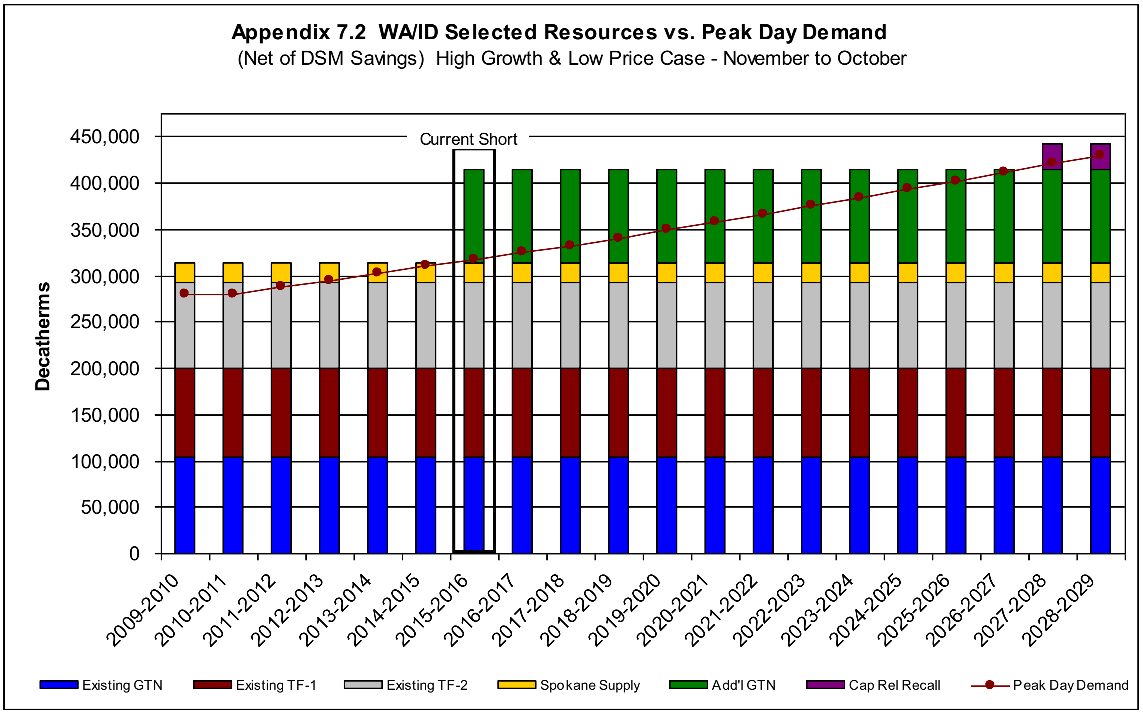
SENSITIVIES, SCNEARIOS, SIMULATIONS, AND PORTFOLIOS LIST

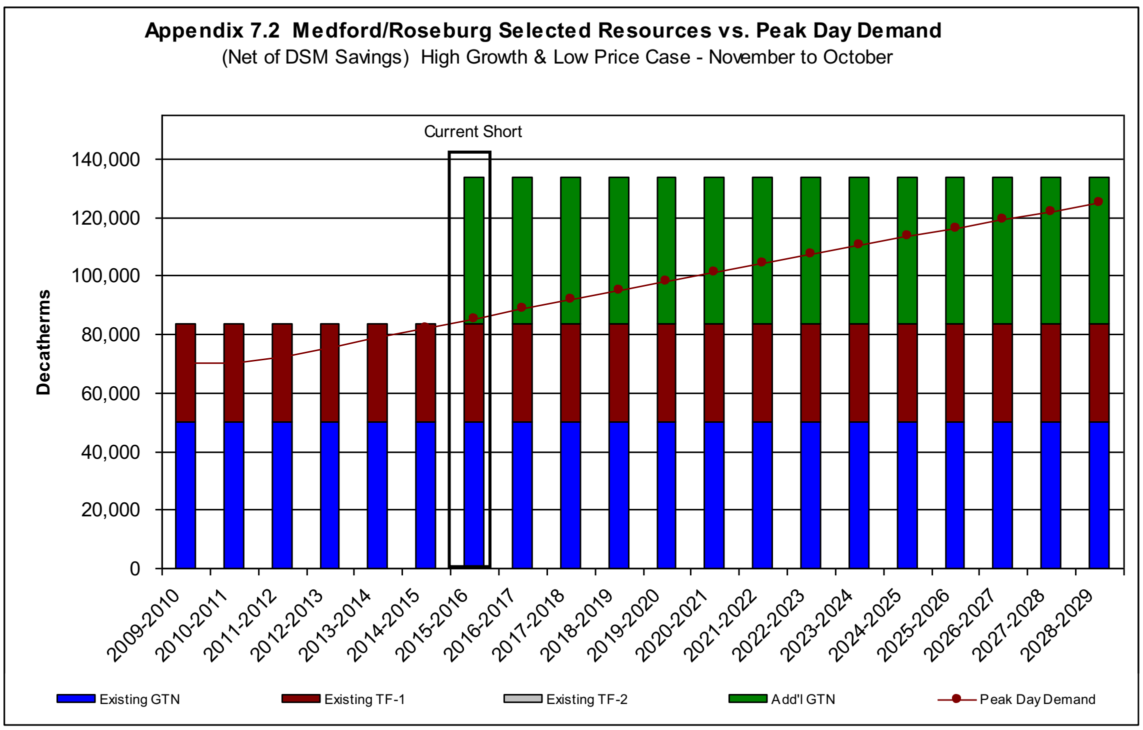
Appendix 7.1 - Avista 2009 IRP Sensitivies, Scenarios, Simulations, and Portfolios

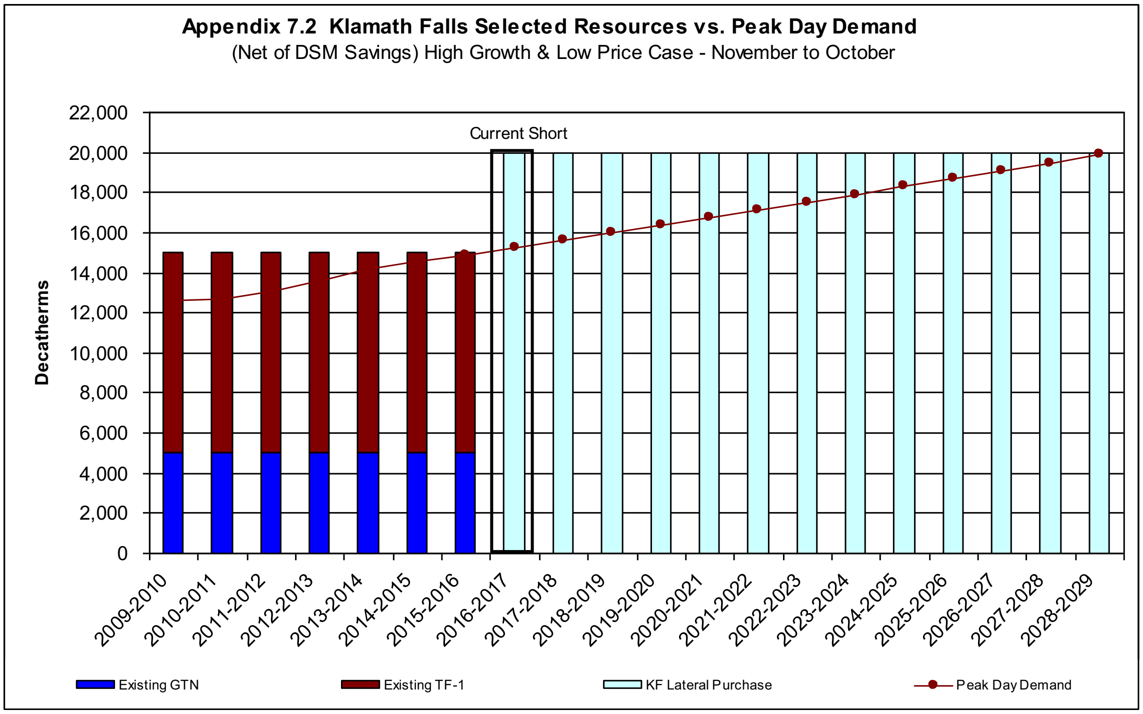
SENDOUT® #	Sensitivity, Portfolio, or Simulation	Case Name	Demand Scenario	Supply Scenario	Major Assumptions
1111	Portfolio	Expected Case	Expected Case	Current Resources	Coldest day on record, expected customer growth rates, expected price curve, low elasticity, carbon adder $5-$67
1113	Portfolio		Expected Case	Current plus currently available	Includes current transporation network, recalls of capacity releases, unsubscribed transport on existing pipelines, capacity expansions, capacity releases, and backhauls.
1120	Portfolio		Expected Case	GTN Turnback Double Cost	Expected case demand assumptions plus current supply resources and currently available resources. However, the GTN rates are doubled to incorporate the major turnback of capacity on their system.
1121	Portfolio		Expected Case	GTN Line Decomission	Expected case demand assumptions plus current supply resources and currently available resources. However, there is no more available capacity on GTN's system due to the decomissioing of one of their lines caused by capacity turnback.
1110	Portfolio	Coldest in 20 Years	Coldest in 20 Years	Current Resources	Coldest day in the last 20 years, expected customer growth rates, expected price curve, expected elasticity, carbon adder $5-$67
1114	Portfolio	Supply Constrained	Supply Constrained	Existing Resources	Coldest day on record, expected customer growth rates, high price curve, expected elasticity, carbon adder $5-$67, $.30 drilling constraints adder, and $.20 to $3.00 Canadian drilling declines.
1109	Portfolio	Green Future	Green Future	Current Resources	Coldest day on record, expected customer growth rates, high elasticity, epxected price curve, carbon adder $37-$140, drilling constraints adder $1.
1108	Portfolio	High Growth & Low Prices	High Growth & Low Prices	Current Resources	Coldest day on record, 50% increase in customer growth rates, low price curve, low elasticity, carbon adder $5-$67
1115	Portfolio		High Growth & Low Prices	Current plus currently available	Includes current transporation network, recalls of capacity releases, unsubscribed transport on existing pipelines, citygate purchases, and backhauls.
1107	Portfolio	Low Growth & High Prices	Low Growth & High Prices	Current Resources	Coldest day on record, 50% decrease in customer growth rates, high price curve, high elasticity, carbon adder $5-$67, drilling constrains adder $1.
1117	Portfolio	Expected with Medium Elasticity	Expected Case	Current Resources	Expected case demand assumptions updated with medium price elasticity and price curve plus current supply resources.
	Portfolio		Expected Case	Current Resources plus currently available	Expected case demand assumptions updated with medium price elasticity and price curve plus current supply resource and currently available supply resources.
1118	Portfolio	Expected with High Elasticity	Updated Expected with High Elasticity	Current Resouces	Expected case demand assumptions updated with high price elasticity and price curve plus current supply resources.
1022	Sensitivity	Reference Case		Current Resources	Coldest day on record, expected customer growth rates, flat use per customer, no elasticity, expected price curve, no carbon adders or drilling constraints
1011	Sensitivity	Low Elasticity		Current Resources	Reference case assumptions plus low elasticity
1009	Sensitivity	High Elasticity		Current Resources	Reference case assumptions plus high elasticity
1006	Sensitivity	Peak Day -1		Current Resources	Reference case assumptions with peak HDD's less 1
1018	Sensitivity	Low Growth		Current Resources	Reference case assumptions with low customer growth rates
1017	Sensitivity	High Growth		Current Resources	Reference case assumptions with high customer growth rates
1021	Sensitivity	Coldest in 20 Years		Current Resources	Reference case with coldest day in 20 years as the planning standard
1015	Sensitivity	Canada Dry 1		Current Resources	Reference case assumptions with $.50 adder for competition for Canadian gas
1007	Sensitivity	Peak Day -2		Current Resources	Reference case assumptions with peak day HDD's less 2
1014	Sensitivity	CNG Vehicles		Current Resources	Reference case assumptions with increasing demand due to CNG vehicle penetration.
1013	Sensitivity	Carbon Mitigation 2		Current Resources	Reference case with $5-$67/ton carbon adder
1012	Sensitivity	Carbon Mitigation 1		Current Resources	Reference case with $37-$140/ton adder
1019	Sensitivity	High Price		Current Resources	Reference case assumptions with high price curve
1020	Sensitivity	Low Price		Current Resources	Reference case assumptions with low price curve
1010	Sensitivity	Epxected Elasticity		Current Resources	Reference case assumptions plus expected elasticity
1016	Sensitivity	Drilling Constraints		Current Resources	Reference case with $.30 adder for drilling constraints
	Simulation	Weather Monte Carlo	Expected Case	Current Resources	Expected case demand assumptions with 200 draws of weather, used to determine unserved impact and fequency of peak day.
1023	Simulation	Price Monte Carlo	Expected Case	Current Resources plus currently available	Expected case demand assumptiosn with 200 draws of price, used to assess the risk to customers of price variability.

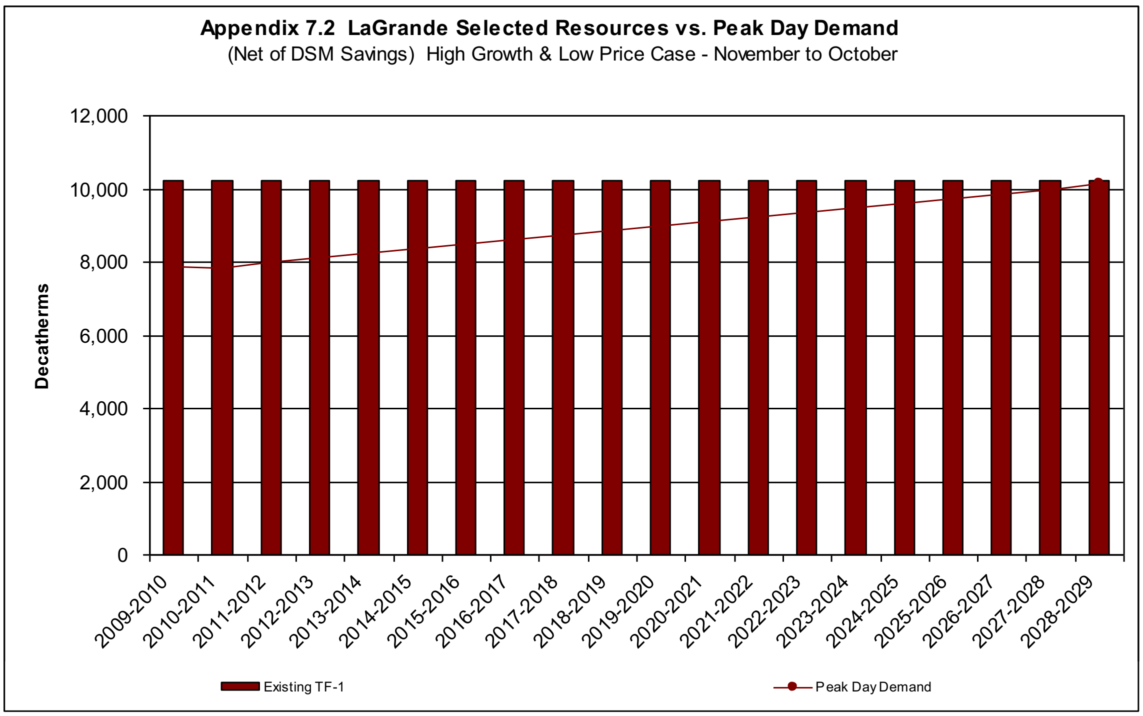
APPENDIX 7.2

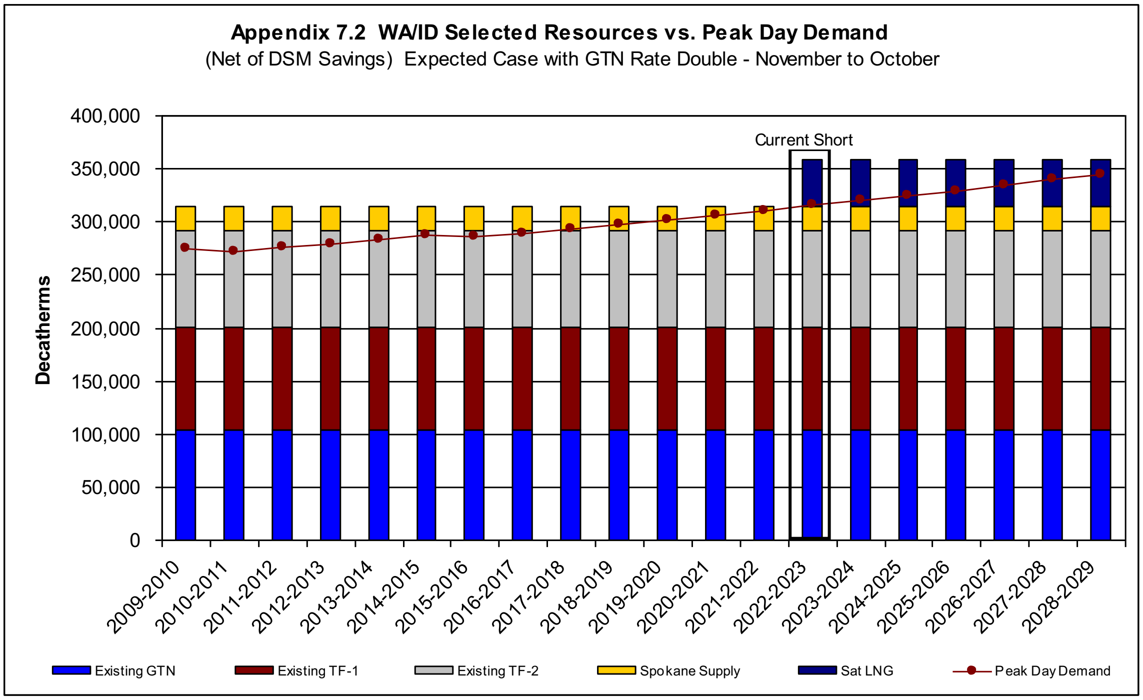
DEMAND AND EXPECTED RESOURCE GRAPHS


Appendix 7.2 WA/ID Selected Resources vs. Peak Day Demand
(Net of DSM Savings) High Growth & Low Price Case - November to October
Current Short
Decatherms
450,000
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
2009-2010
2010-2011
2011-2012
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
Existing GTN
Existing TF-1
Existing TF-2
Spokane Supply
Add'l GTN
Cap Rel Recall
Peak Day Demand

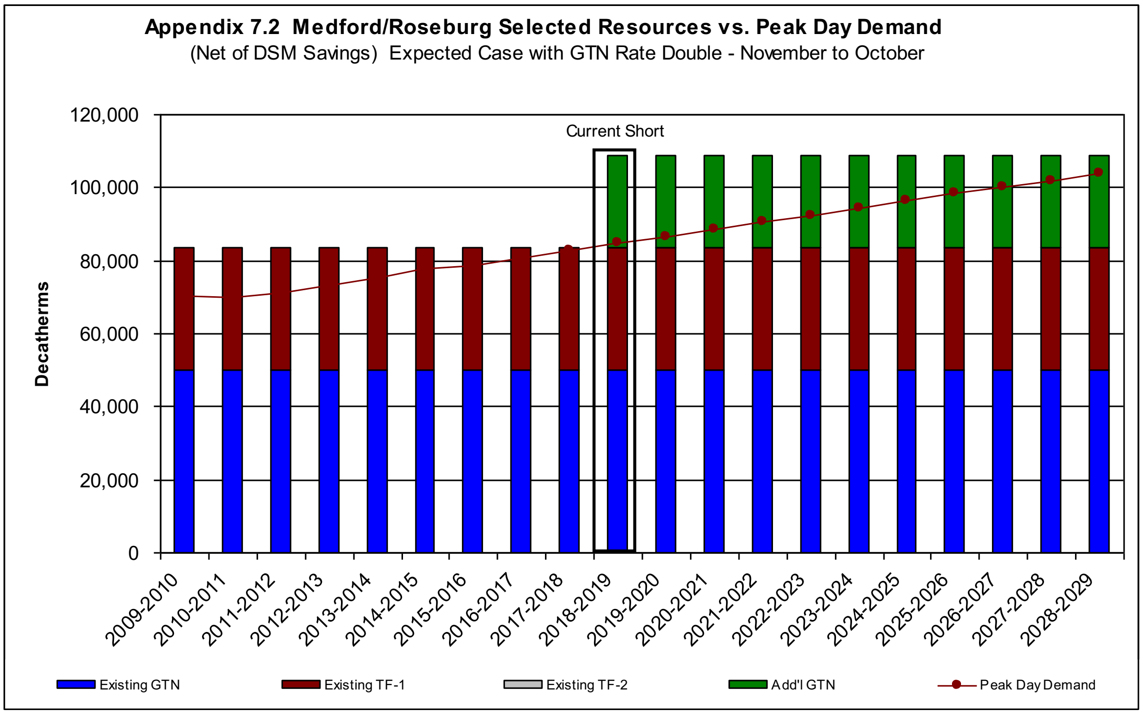

Appendix 7.2 Medford/Roseburg Selected Resources vs. Peak Day Demand
(Net of DSM Savings) High Growth & Low Price Case - November to October
Current Short
Decatherms
140,000
120,000
100,000
80,000
60,000
40,000
20,000
0
2009-2010
2010-2011
2011-2012
2012-2013
2013-2014
2014-2015
2015-2016
2016-2017
2017-2018
2018-2019
2019-2020
2020-2021
2021-2022
2022-2023
2023-2024
2024-2025
2025-2026
2026-2027
2027-2028
2028-2029
Existing GTN
Existing TF-1
Existing TF-2
Add'l GTN
Peak Day Demand


Appendix 7.2 Klamath Falls Selected Resources vs. Peak Day Demand
(Net of DSM Savings) High Growth & Low Price Case - November to October
Current Short
Decatherms
22,000
20,000
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
2009-2010
2010-2011
2011-2012
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
Existing GTN
Existing TF-1
KF Lateral Purchase
Peak Day Demand

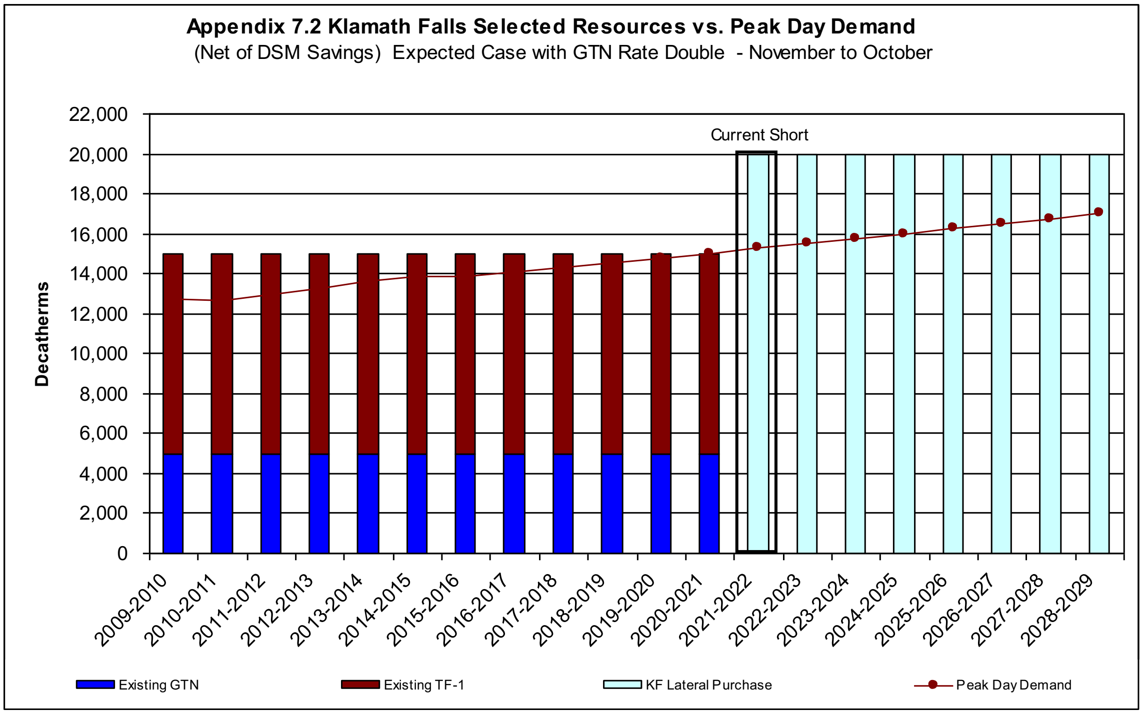

Appendix 7.2 LaGrande Selected Resources vs. Peak Day Demand
(Net of DSM Savings) High Growth & Low Price Case - November to October
Decatherms
12,000
10,000
8,000
6,000
4,000
2,000
0
2009-2010
2010-2011
2011-2012
2012-2013
2013-2014
2014-2015
2015-2016
2016-2017
2017-2018
2018-2019
2019-2020
2020-2021
2021-2022
2022-2023
2023-2024
2024-2025
2025-2026
2026-2027
2027-2028
2028-2029
Existing TF-1
Peak Day Demand



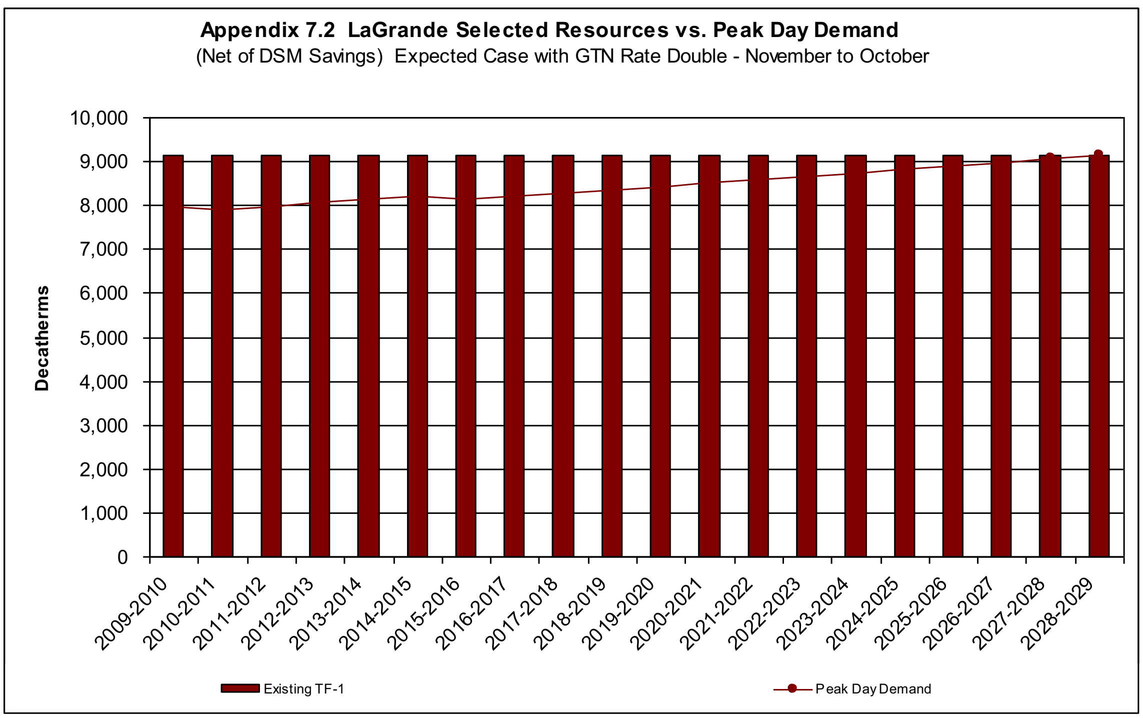
Appendix 7.2 WA/ID Selected Resources vs. Peak Day Demand
(Net of DSM Savings) Expected Case with GTN Rate Double - November to October
Decatherms
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
Current Short
2009-2010
2010-2011
2011-2012
2012-2013
2013-2014
2014-2015
2015-2016
2016-2017
2017-2018
2018-2019
2019-2020
2020-2021
2021-2022
2022-2023
2023-2024
2024-2025
2025-2026
2026-2027
2027-2028
2028-2029
Existing GTN
Existing TF-1
Existing TF-2
Spokane Supply
Sat LNG
Peak Day Demand



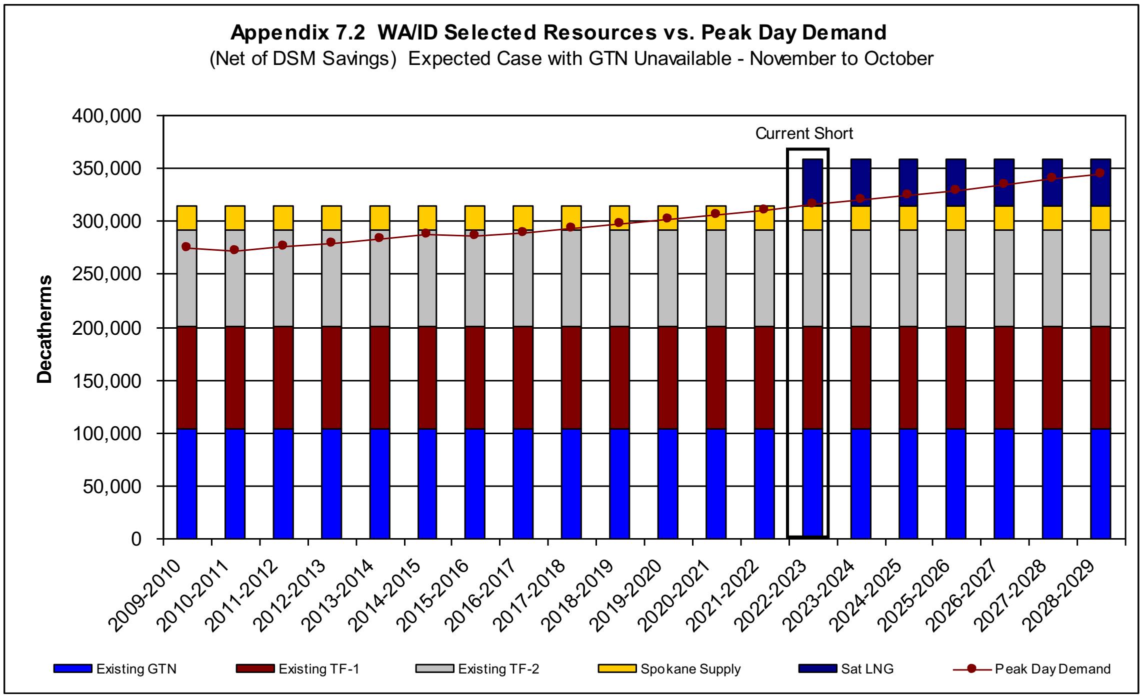
Appendix 7.2 Medford/Roseburg Selected Resources vs. Peak Day Demand
(Net of DSM Savings) Expected Case with GTN Rate Double - November to October
Decatherms
120,000
100,000
80,000
60,000
40,000
20,000
0
Current Short
2009-2010
2010-2011
2011-2012
2012-2013
2013-2014
2014-2015
2015-2016
2016-2017
2017-2018
2018-2019
2019-2020
2020-2021
2021-2022
2022-2023
2023-2024
2024-2025
2025-2026
2026-2027
2027-2028
2028-2029
Existing GTN
Existing TF-1
Existing TF-2
Add'l GTN
Peak Day Demand

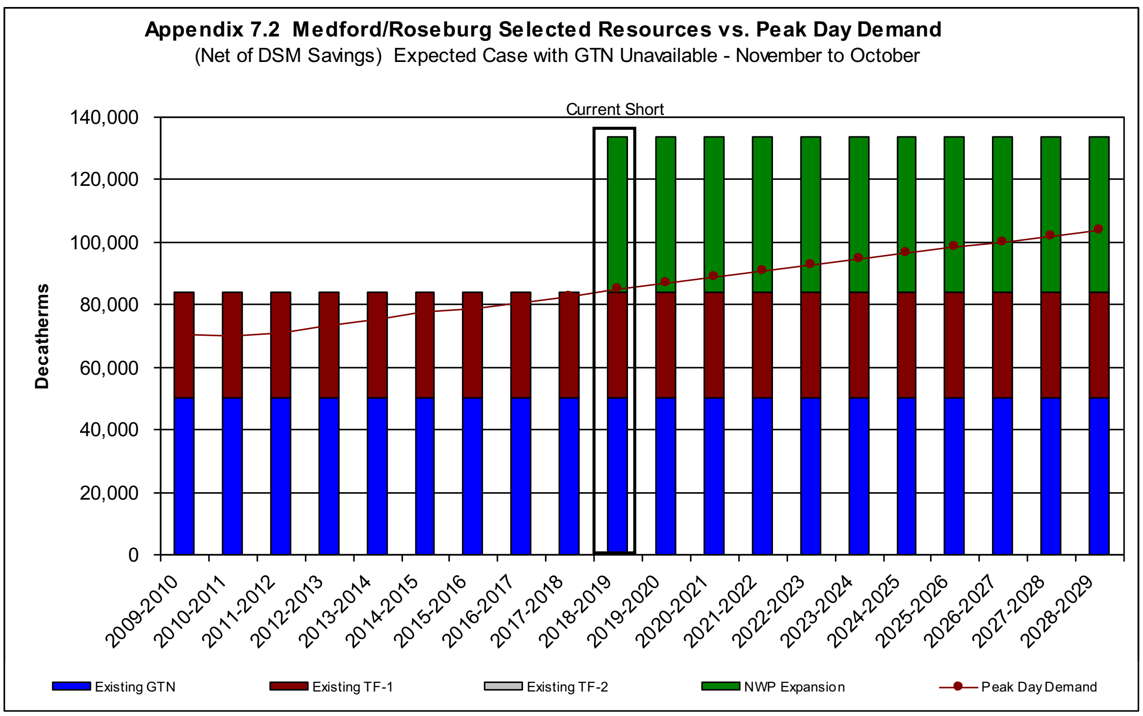


Appendix 7.2 Klamath Falls Selected Resources vs. Peak Day Demand
(Net of DSM Savings) Expected Case with GTN Rate Double - November to October
Decatherms
Current Short
22,000
20,000
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
2009-2010
2010-2011
2011-2012
2012-2013
2013-2014
2014-2015
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
Existing GTN
Existing TF-1
KF Lateral Purchase
Peak Day Demand

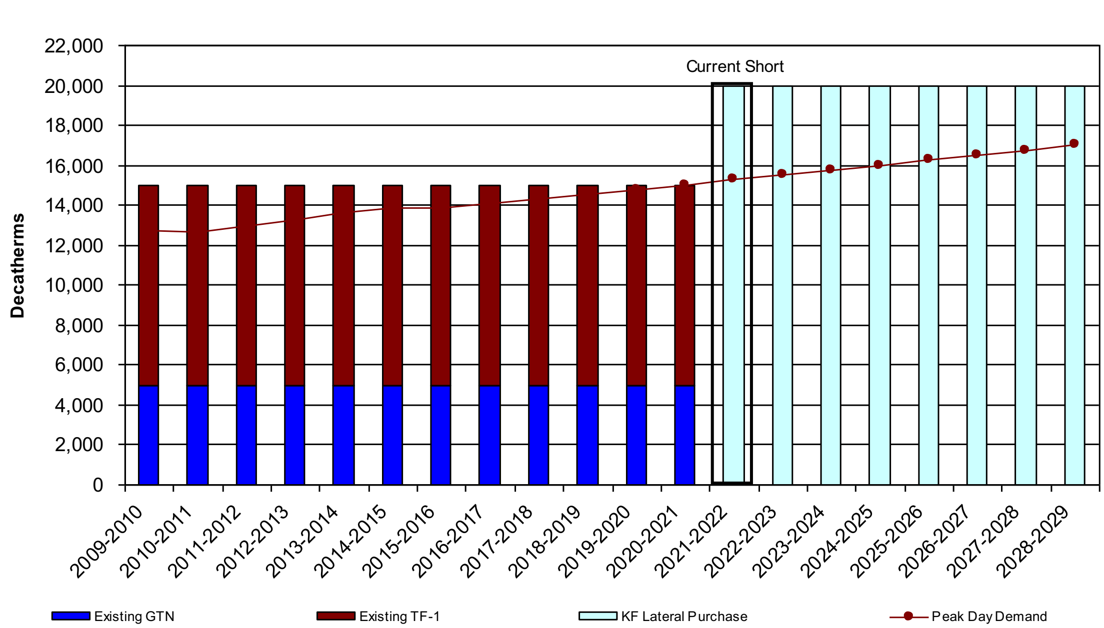


Appendix 7.2 LaGrande Selected Resources vs. Peak Day Demand
(Net of DSM Savings) Expected Case with GTN Rate Double - November to October
Decatherms
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
2009-2010
2010-2011
2011-2012
2012-2013
2013-2014
2014-2015
2015-2016
2016-2017
2017-2018
2018-2019
2019-2020
2020-2021
2021-2022
2022-2023
2023-2024
2024-2025
2025-2026
2026-2027
2027-2028
2028-2029
Existing TF-1
Peak Day Demand

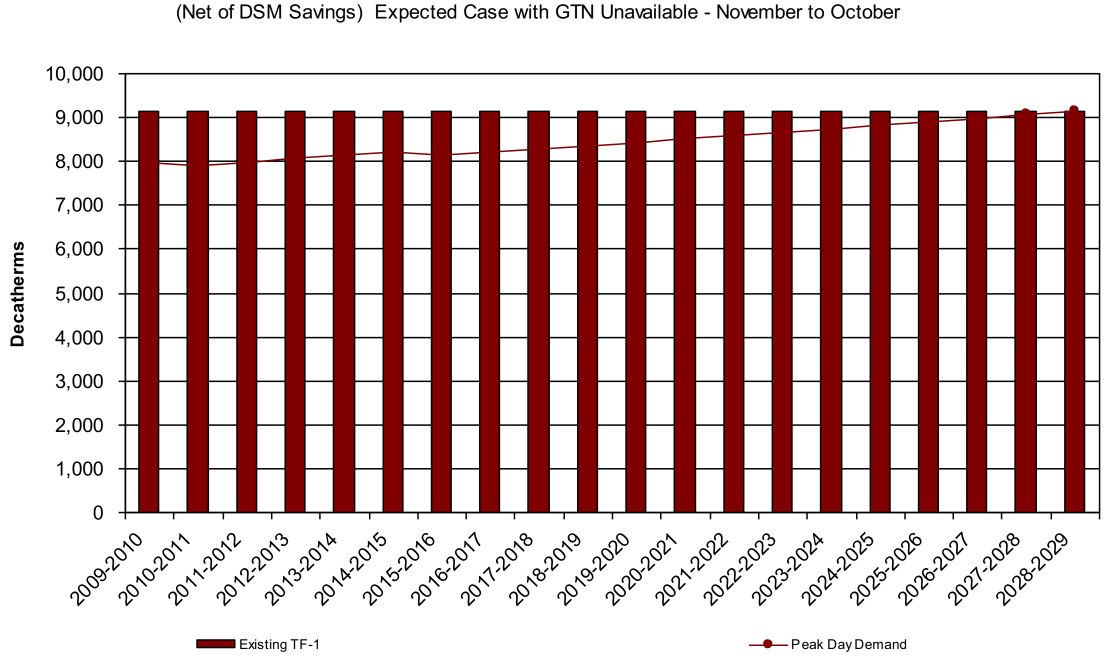

Appendix 7.2 WA/ID Selected Resources vs. Peak Day Demand
(Net of DSM Savings) Expected Case with GTN Unavailable - November to October
Current Short
Decatherms
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
2009-2010
2010-2011
2011-2012
2012-2013
2013-2014
2014-2015
2015-2016
2016-2017
2017-2018
2018-2019
2019-2020
2020-2021
2021-2022
2022-2023
2023-2024
2024-2025
2025-2026
2026-2027
2027-2028
2028-2029
Existing GTN
Existing TF-1
Existing TF-2
Spokane Supply
Sat LNG
Peak Day Demand


Appendix 7.2 Medford/Roseburg Selected Resources vs. Peak Day Demand
(Net of DSM Savings) Expected Case with GTN Unavailable - November to October
Current Short
Decatherms
140,000
120,000
100,000
80,000
60,000
40,000
20,000
0
2009-2010
2010-2011
2011-2012
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
Existing GTN
Existing TF-1
Existing TF-2
NWP Expansion
Peak Day Demand

Appendix 7.2 Klamath Falls Selected Resources vs. Peak Day Demand
(Net of DSM Savings) Expected Case with GTN Unavailable - November to October



Appendix 7.2 LaGrande Selected Resources vs. Peak Day Demand
(Net of DSM Savings) Expected Case with GTN Unavailable - November to October



APPENDIX 7.3

PEAK DAY DEMAND SERVED AND UNSERVED TABLES

Appendix 7.3 - Peak Day Demand - Served and Unserved (MDth/d)

Before Resource Additions & Net of DSM Savings

Case	Gas Year	La Grande Served	La Grande Unserved	La Grande Total	WA/ID Served	WA/ID Unserved	WA/ID Total
High Demand	2009-2010	7.88	-	7.88	279.38		279.38
High Demand	2010-2011	7.84	-	7.84	279.90		279.90
High Demand	2011-2012	7.99	-	7.99	287.30		287.30
High Demand	2012-2013	8.13	-	8.13	294.96		294.96
High Demand	2013-2014	8.26	-	8.26	302.75		302.75
High Demand	2014-2015	8.38	-	8.38	310.54		310.54
High Demand	2015-2016	8.48	-	8.48	314.67	2.17	316.84
High Demand	2016-2017	8.60	-	8.60	314.54	10.01	324.56
High Demand	2017-2018	8.73	-	8.73	314.42	18.13	332.55
High Demand	2018-2019	8.85	-	8.85	314.30	26.26	340.56
High Demand	2019-2020	8.97	-	8.97	314.17	34.79	348.96
High Demand	2020-2021	9.09	-	9.09	314.05	43.54	357.58
High Demand	2021-2022	9.14	0.08	9.22	314.04	52.27	366.31
High Demand	2022-2023	9.14	0.21	9.35	314.04	61.13	375.17
High Demand	2023-2024	9.14	0.33	9.47	314.04	69.98	384.02
High Demand	2024-2025	9.14	0.46	9.60	314.04	79.04	393.08
High Demand	2025-2026	9.14	0.59	9.73	314.04	88.09	402.13
High Demand	2026-2027	9.14	0.72	9.86	314.04	97.03	411.07
High Demand	2027-2028	9.14	0.85	9.99	314.04	106.68	420.72
High Demand	2028-2029	9.14	0.99	10.13	314.04	116.04	430.08

Case	Gas Year	Klamath Falls Served	Klamath Falls Unserved	Klamath Falls Total	Medford/ Roseburg Served	Medford/ Roseburg Unserved	Medford/ Roseburg Total
High Demand	2009-2010	12.58	-	12.58	70.11	-	70.11
High Demand	2010-2011	12.67	-	12.67	70.34	-	70.34
High Demand	2011-2012	13.10	-	13.10	72.20	-	72.20
High Demand	2012-2013	13.61	-	13.61	75.56	-	75.56
High Demand	2013-2014	14.16	-	14.16	78.80	-	78.80
High Demand	2014-2015	14.54	-	14.54	82.16	-	82.16
High Demand	2015-2016	14.85	-	14.85	84.09	1.32	85.40
High Demand	2016-2017	15.03	0.20	15.23	84.09	4.76	88.84
High Demand	2017-2018	15.03	0.58	15.61	84.09	8.06	92.14
High Demand	2018-2019	15.03	0.96	15.99	84.08	11.19	95.27
High Demand	2019-2020	15.03	1.34	16.37	84.09	14.18	98.26
High Demand	2020-2021	15.03	1.72	16.75	84.08	17.22	101.30
High Demand	2021-2022	15.03	2.10	17.13	69.30	35.02	104.32
High Demand	2022-2023	15.03	2.48	17.51	69.30	38.05	107.35
High Demand	2023-2024	15.03	2.88	17.91	69.30	41.11	110.41
High Demand	2024-2025	15.03	3.27	18.30	69.30	44.20	113.50
High Demand	2025-2026	15.03	3.66	18.69	69.30	47.13	116.43
High Demand	2026-2027	15.03	4.05	19.08	69.30	49.96	119.25
High Demand	2027-2028	15.03	4.44	19.47	69.30	52.77	122.07
High Demand	2028-2029	15.03	4.84	19.87	69.30	55.59	124.89

Appendix 7.3 - Peak Day Demand - Served and Unserved (MDth/d)

Before Resource Additions & Net of DSM Savings

Case	Gas Year	La Grande Served	La Grande Unserved	La Grande Total	WA/ID Served	WA/ID Unserved	WA/ID Total
Low Demand	2009-2010	7.86	-	7.86	274.71	-	274.71
Low Demand	2010-2011	7.87	-	7.87	274.09	-	274.09
Low Demand	2011-2012	7.57	-	7.57	262.54	-	262.54
Low Demand	2012-2013	7.24	-	7.24	249.61	-	249.61
Low Demand	2013-2014	7.23	-	7.23	248.40	-	248.40
Low Demand	2014-2015	7.25	-	7.25	248.48	-	248.48
Low Demand	2015-2016	7.20	-	7.20	245.56	-	245.56
Low Demand	2016-2017	7.21	-	7.21	244.96	-	244.96
Low Demand	2017-2018	7.23	-	7.23	244.81	-	244.81
Low Demand	2018-2019	7.23	-	7.23	244.16	-	244.16
Low Demand	2019-2020	7.25	-	7.25	244.15	-	244.15
Low Demand	2020-2021	7.26	-	7.26	244.22	-	244.22
Low Demand	2021-2022	7.28	-	7.28	244.38	-	244.38
Low Demand	2022-2023	7.30	-	7.30	244.68	-	244.68
Low Demand	2023-2024	7.32	-	7.32	244.86	-	244.86
Low Demand	2024-2025	7.35	-	7.35	245.06	-	245.06
Low Demand	2025-2026	7.37	-	7.37	245.29	-	245.29
Low Demand	2026-2027	7.39	-	7.39	245.23	-	245.23
Low Demand	2027-2028	7.40	-	7.40	245.85	-	245.85
Low Demand	2028-2029	7.42	-	7.42	246.38	-	246.38

Case	Gas Year	Klamath Falls Served	Klamath Falls Unserved	Klamath Falls Total	Medford/ Roseburg Served	Medford/ Roseburg Unserved	Medford/ Roseburg Total
Low Demand	2009-2010	12.58	-	12.58	70.10	-	70.10
Low Demand	2010-2011	12.64	-	12.64	70.38	-	70.38
Low Demand	2011-2012	12.22	-	12.22	67.93	-	67.93
Low Demand	2012-2013	11.78	-	11.78	65.62	-	65.62
Low Demand	2013-2014	11.70	-	11.70	65.29	-	65.29
Low Demand	2014-2015	11.78	-	11.78	66.17	-	66.17
Low Demand	2015-2016	11.73	-	11.73	66.53	-	66.53
Low Demand	2016-2017	11.78	-	11.78	67.31	-	67.31
Low Demand	2017-2018	11.85	-	11.85	68.13	-	68.13
Low Demand	2018-2019	11.90	-	11.90	68.79	-	68.79
Low Demand	2019-2020	11.97	-	11.97	69.51	-	69.51
Low Demand	2020-2021	12.05	-	12.05	70.24	-	70.24
Low Demand	2021-2022	12.12	-	12.12	70.98	-	70.98
Low Demand	2022-2023	12.20	-	12.20	71.75	-	71.75
Low Demand	2023-2024	12.29	-	12.29	72.53	-	72.53
Low Demand	2024-2025	12.37	-	12.37	73.30	-	73.30
Low Demand	2025-2026	12.45	-	12.45	74.04	-	74.04
Low Demand	2026-2027	12.53	-	12.53	74.70	-	74.70
Low Demand	2027-2028	12.60	-	12.60	75.34	-	75.34
Low Demand	2028-2029	12.67	-	12.67	75.98	-	75.98

Appendix 7.3 - Peak Day Demand - Served and Unserved (MDth/d)
Before Resource Additions & Net of DSM Savings

Case	Gas Year	La Grande Served	La Grande Unserved	La Grande Total	WA/ID Served	WA/ID Unserved	WA/ID Total
Green Future	2009-2010	7.98	-	7.98	274.58	-	274.58
Green Future	2010-2011	7.61	-	7.61	262.02	-	262.02
Green Future	2011-2012	7.63	-	7.63	263.10	-	263.10
Green Future	2012-2013	7.65	-	7.65	264.29	-	264.29
Green Future	2013-2014	7.68	-	7.68	266.50	-	266.50
Green Future	2014-2015	7.75	-	7.75	270.09	-	270.09
Green Future	2015-2016	7.20	-	7.20	250.52	-	250.52
Green Future	2016-2017	7.17	-	7.17	250.10	-	250.10
Green Future	2017-2018	7.16	-	7.16	250.66	-	250.66
Green Future	2018-2019	7.16	-	7.16	251.45	-	251.45
Green Future	2019-2020	7.17	-	7.17	252.68	-	252.68
Green Future	2020-2021	7.21	-	7.21	255.03	-	255.03
Green Future	2021-2022	7.25	-	7.25	257.70	-	257.70
Green Future	2022-2023	7.29	-	7.29	260.38	-	260.38
Green Future	2023-2024	7.33	-	7.33	262.62	-	262.62
Green Future	2024-2025	7.39	-	7.39	265.80	-	265.80
Green Future	2025-2026	7.43	-	7.43	268.16	-	268.16
Green Future	2026-2027	7.46	-	7.46	270.28	-	270.28
Green Future	2027-2028	7.49	-	7.49	272.85	-	272.85
Green Future	2028-2029	7.52	-	7.52	275.44	-	275.44

Case	Gas Year	Klamath Falls Served	Klamath Falls Unserved	Klamath Falls Total	Medford/ Roseburg Served	Medford/ Roseburg Unserved	Medford/ Roseburg Total
Green Future	2009-2010	12.71	-	12.71	70.44	-	70.44
Green Future	2010-2011	12.23	-	12.23	67.58	-	67.58
Green Future	2011-2012	12.38	-	12.38	68.10	-	68.10
Green Future	2012-2013	12.58	-	12.58	69.59	-	69.59
Green Future	2013-2014	12.85	-	12.85	71.22	-	71.22
Green Future	2014-2015	13.08	-	13.08	73.27	-	73.27
Green Future	2015-2016	12.26	-	12.26	69.54	-	69.54
Green Future	2016-2017	12.32	-	12.32	70.59	-	70.59
Green Future	2017-2018	12.40	-	12.40	71.75	-	71.75
Green Future	2018-2019	12.50	-	12.50	72.88	-	72.88
Green Future	2019-2020	12.61	-	12.61	73.98	-	73.98
Green Future	2020-2021	12.77	-	12.77	75.36	-	75.36
Green Future	2021-2022	12.93	-	12.93	76.79	-	76.79
Green Future	2022-2023	13.10	-	13.10	78.22	-	78.22
Green Future	2023-2024	13.25	-	13.25	79.57	-	79.57
Green Future	2024-2025	13.45	-	13.45	81.14	-	81.14
Green Future	2025-2026	13.60	-	13.60	82.42	-	82.42
Green Future	2026-2027	13.75	-	13.75	83.59	-	83.59
Green Future	2027-2028	13.89	-	13.89	84.09	0.61	84.69
Green Future	2028-2029	14.04	-	14.04	84.08	1.75	85.84

Appendix 7.3 - Peak Day Demand - Served and Unserved (MDth/d)

Before Resource Additions & Net of DSM Savings

Case	Gas Year	La Grande Served	La Grande Unserved	La Grande Total	WA/ID Served	WA/ID Unserved	WA/ID Total
Alt Weather Std	2009-2010	7.98	-	7.98	252.68	-	252.68
Alt Weather Std	2010-2011	7.86	-	7.86	249.43	-	249.43
Alt Weather Std	2011-2012	7.95	-	7.95	252.87	-	252.87
Alt Weather Std	2012-2013	8.05	-	8.05	256.46	-	256.46
Alt Weather Std	2013-2014	8.12	-	8.12	260.13	-	260.13
Alt Weather Std	2014-2015	8.20	-	8.20	263.80	-	263.80
Alt Weather Std	2015-2016	8.12	-	8.12	262.17	-	262.17
Alt Weather Std	2016-2017	8.19	-	8.19	265.71	-	265.71
Alt Weather Std	2017-2018	8.26	-	8.26	269.41	-	269.41
Alt Weather Std	2018-2019	8.34	-	8.34	273.12	-	273.12
Alt Weather Std	2019-2020	8.41	-	8.41	277.06	-	277.06
Alt Weather Std	2020-2021	8.48	-	8.48	281.15	-	281.15
Alt Weather Std	2021-2022	8.56	-	8.56	285.32	-	285.32
Alt Weather Std	2022-2023	8.63	-	8.63	289.56	-	289.56
Alt Weather Std	2023-2024	8.71	-	8.71	293.79	-	293.79
Alt Weather Std	2024-2025	8.79	-	8.79	298.16	-	298.16
Alt Weather Std	2025-2026	8.87	-	8.87	302.52	-	302.52
Alt Weather Std	2026-2027	8.95	-	8.95	306.82	-	306.82
Alt Weather Std	2027-2028	9.03	-	9.03	311.77	-	311.77
Alt Weather Std	2028-2029	9.11	-	9.11	313.86	2.69	316.55

Case	Gas Year	Klamath Falls Served	Klamath Falls Unserved	Klamath Falls Total	Medford/ Roseburg Served	Medford/ Roseburg Unserved	Medford/ Roseburg Total
Alt Weather Std	2009-2010	12.71	-	12.71	67.86	-	67.86
Alt Weather Std	2010-2011	12.63	-	12.63	67.27	-	67.27
Alt Weather Std	2011-2012	12.90	-	12.90	68.40	-	68.40
Alt Weather Std	2012-2013	13.23	-	13.23	70.51	-	70.51
Alt Weather Std	2013-2014	13.58	-	13.58	72.53	-	72.53
Alt Weather Std	2014-2015	13.82	-	13.82	74.64	-	74.64
Alt Weather Std	2015-2016	13.80	-	13.80	75.43	-	75.43
Alt Weather Std	2016-2017	14.04	-	14.04	77.55	-	77.55
Alt Weather Std	2017-2018	14.27	-	14.27	79.58	-	79.58
Alt Weather Std	2018-2019	14.51	-	14.51	81.51	-	81.51
Alt Weather Std	2019-2020	14.75	-	14.75	83.35	-	83.35
Alt Weather Std	2020-2021	14.98	-	14.98	84.09	1.13	85.22
Alt Weather Std	2021-2022	15.03	0.19	15.22	84.09	2.99	87.07
Alt Weather Std	2022-2023	15.03	0.43	15.46	84.08	4.86	88.94
Alt Weather Std	2023-2024	15.03	0.68	15.71	84.09	6.75	90.84
Alt Weather Std	2024-2025	15.03	0.92	15.95	84.09	8.67	92.76
Alt Weather Std	2025-2026	15.03	1.17	16.20	84.09	10.49	94.57
Alt Weather Std	2026-2027	15.03	1.42	16.45	84.09	12.23	96.32
Alt Weather Std	2027-2028	15.03	1.67	16.70	84.09	13.98	98.06
Alt Weather Std	2028-2029	15.03	1.92	16.95	84.09	15.72	99.81

Appendix 7.3 - Peak Day Demand - Served and Unserved (MDth/d)

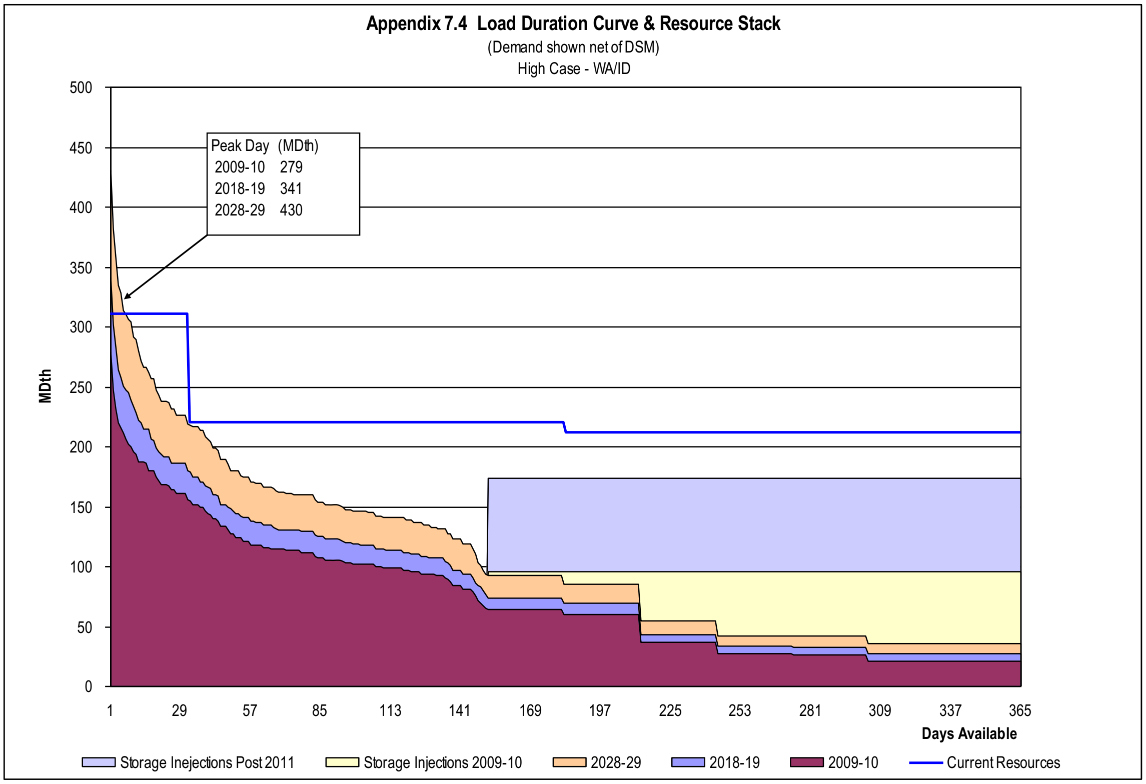
Before Resource Additions & Net of DSM Savings

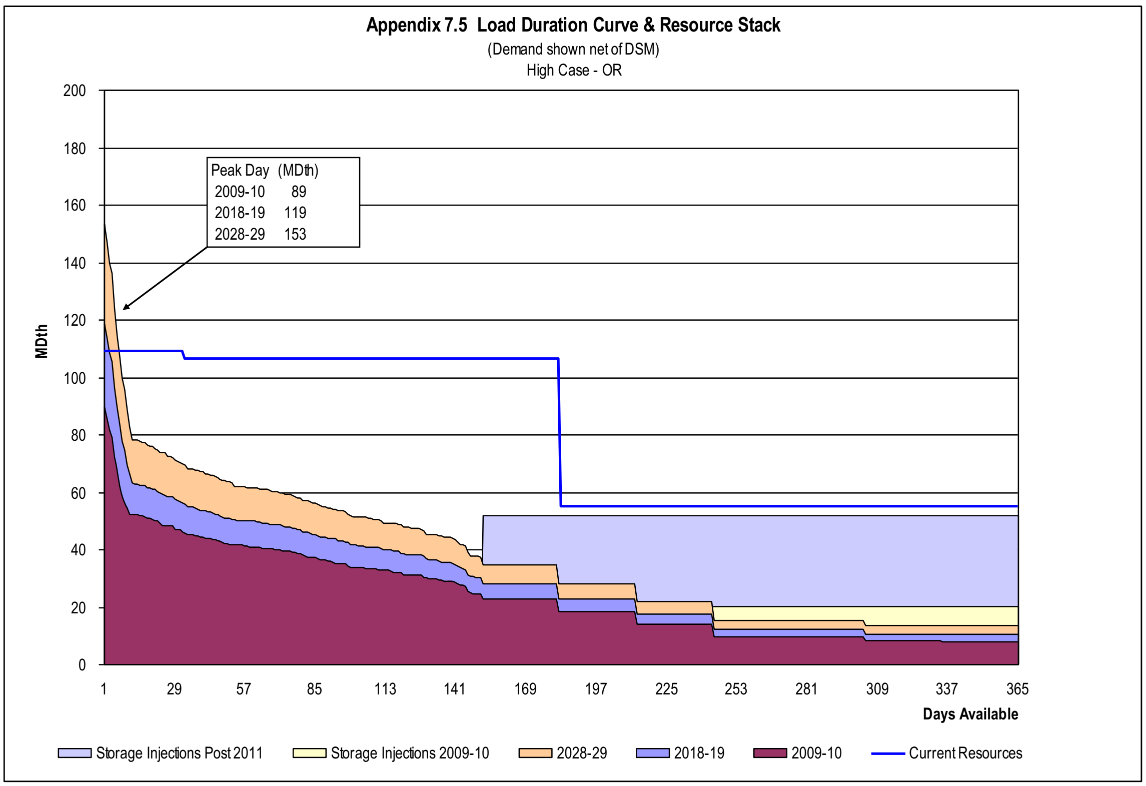
Case	Gas Year	La Grande Served	La Grande Unserved	La Grande Total	WA/ID Served	WA/ID Unserved	WA/ID Total
Supply Constrained	2009-2010	7.98	-	7.98	274.58	-	274.58
Supply Constrained	2010-2011	7.27	-	7.27	249.94	-	249.94
Supply Constrained	2011-2012	7.23	-	7.23	249.06	-	249.06
Supply Constrained	2012-2013	7.22	-	7.22	249.09	-	249.09
Supply Constrained	2013-2014	7.20	-	7.20	249.29	-	249.29
Supply Constrained	2014-2015	7.27	-	7.27	252.45	-	252.45
Supply Constrained	2015-2016	7.11	-	7.11	247.26	-	247.26
Supply Constrained	2016-2017	7.12	-	7.12	248.16	-	248.16
Supply Constrained	2017-2018	7.14	-	7.14	249.64	-	249.64
Supply Constrained	2018-2019	7.13	-	7.13	250.06	-	250.06
Supply Constrained	2019-2020	7.16	-	7.16	252.10	-	252.10
Supply Constrained	2020-2021	7.19	-	7.19	254.37	-	254.37
Supply Constrained	2021-2022	7.22	-	7.22	256.44	-	256.44
Supply Constrained	2022-2023	7.25	-	7.25	258.73	-	258.73
Supply Constrained	2023-2024	7.30	-	7.30	261.18	-	261.18
Supply Constrained	2024-2025	7.35	-	7.35	264.25	-	264.25
Supply Constrained	2025-2026	7.39	-	7.39	266.74	-	266.74
Supply Constrained	2026-2027	7.42	-	7.42	268.46	-	268.46
Supply Constrained	2027-2028	7.44	-	7.44	270.80	-	270.80
Supply Constrained	2028-2029	7.46	-	7.46	272.93	-	272.93

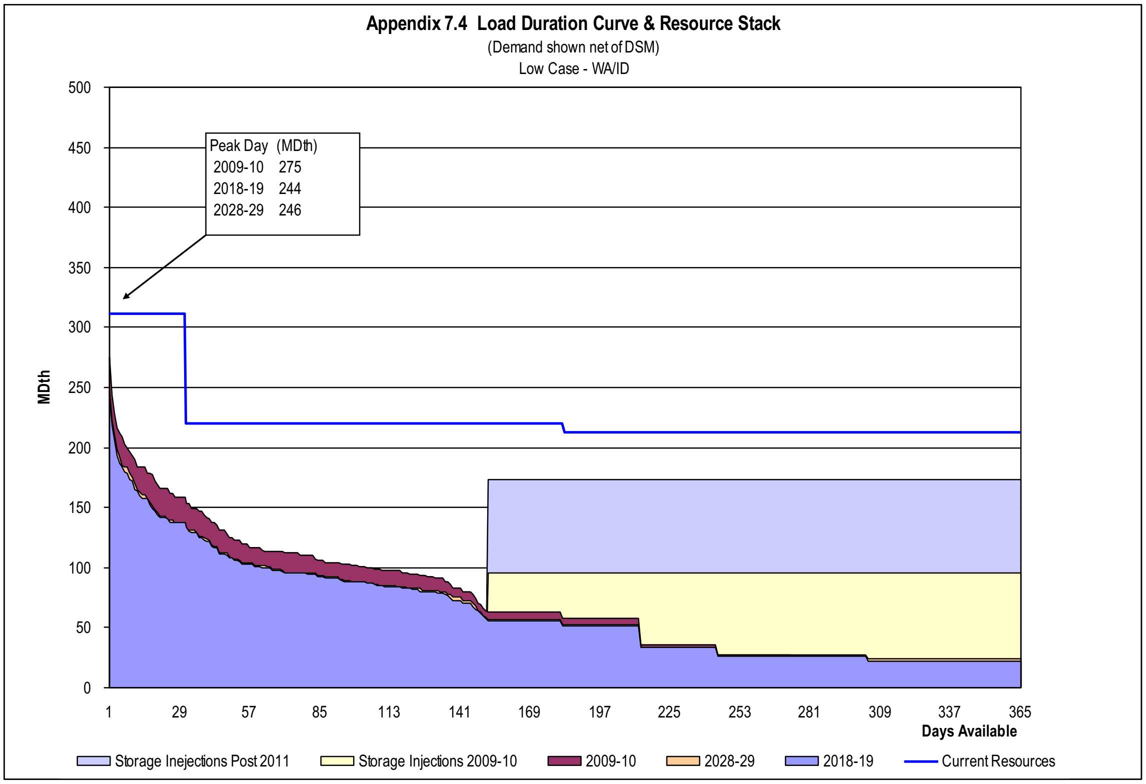
Case	Gas Year	Klamath Falls Served	Klamath Falls Unserved	Klamath Falls Total	Medford/ Roseburg Served	Medford/ Roseburg Unserved	Medford/ Roseburg Total
Supply Constrained	2009-2010	12.71	-	12.71	70.44	-	70.44
Supply Constrained	2010-2011	11.68	-	11.68	64.58	-	64.58
Supply Constrained	2011-2012	11.75	-	11.75	64.63	-	64.63
Supply Constrained	2012-2013	11.90	-	11.90	65.80	-	65.80
Supply Constrained	2013-2014	12.07	-	12.07	66.90	-	66.90
Supply Constrained	2014-2015	12.28	-	12.28	68.82	-	68.82
Supply Constrained	2015-2016	12.12	-	12.12	68.71	-	68.71
Supply Constrained	2016-2017	12.23	-	12.23	70.09	-	70.09
Supply Constrained	2017-2018	12.36	-	12.36	71.49	-	71.49
Supply Constrained	2018-2019	12.44	-	12.44	72.52	-	72.52
Supply Constrained	2019-2020	12.59	-	12.59	73.83	-	73.83
Supply Constrained	2020-2021	12.74	-	12.74	75.18	-	75.18
Supply Constrained	2021-2022	12.88	-	12.88	76.47	-	76.47
Supply Constrained	2022-2023	13.03	-	13.03	77.79	-	77.79
Supply Constrained	2023-2024	13.19	-	13.19	79.19	-	79.19
Supply Constrained	2024-2025	13.38	-	13.38	80.74	-	80.74
Supply Constrained	2025-2026	13.54	-	13.54	82.05	-	82.05
Supply Constrained	2026-2027	13.67	-	13.67	83.12	-	83.12
Supply Constrained	2027-2028	13.80	-	13.80	84.09	0.08	84.16
Supply Constrained	2028-2029	13.93	-	13.93	84.09	1.11	85.19

APPENDIX 7.4

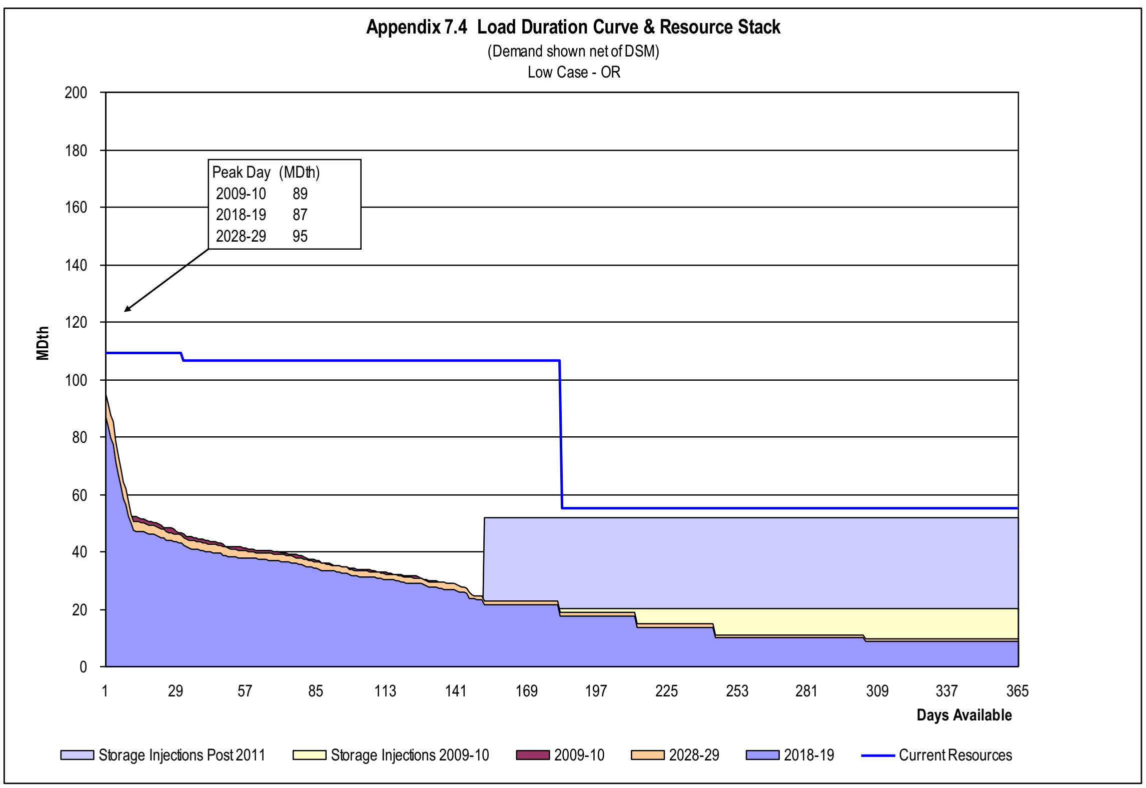
LOAD DURATION CURVE GRAPHS (HIGH AND LOW GROWTH CASES)


Appendix 7.4 Load Duration Curve & Resource Stack
(Demand shown net of DSM)
High Case - WA/ID
MDth
Peak Day (MDth)
2009-10 279
2018-19 341
2028-29 430
Days Available
Storage Inejections Post 2011
Storage Injections 2009-10
2028-29
2018-19
2009-10
Current Resources


Appendix 7.5 Load Duration Curve & Resource Stack
(Demand shown net of DSM)
High Case - OR
MDth
Peak Day (MDth)
2009-10 89
2018-19 119
2028-29 153
Days Available
Storage Injections Post 2011
Storage Injections 2009-10
2028-29
2018-19
2009-10
Current Resources



Appendix 7.4 Load Duration Curve & Resource Stack
(Demand shown net of DSM)
Low Case - WA/ID
Peak Day (MDth)
2009-10 275
2018-19 244
2028-29 246
MDth
500
450
400
350
300
250
200
150
100
50
0
1
29
57
85
113
141
169
197
225
253
281
309
337
365
Days Available
Storage Inejections Post 2011
Storage Injections 2009-10
2009-10
2028-29
2018-19
Current Resources



Appendix 7.4 Load Duration Curve & Resource Stack
(Demand shown net of DSM)
Low Case - OR
Peak Day (MDth)
2009-10 89
2018-19 87
2028-29 95
MDth
200
180
160
140
120
100
80
60
40
20
0
1
29
57
85
113
141
169
197
225
253
281
309
337
365
Days Available
Storage Injections Post 2011
Storage Injections 2009-10
2009-10
2028-29
2018-19
Current Resources

APPENDIX 7.5

TOTAL COST BY PORTFOLIO

Appendix 7.5 - Net Present Value of Revenue Requirement (NPVRR) by Portfolio

Portfolio		NPVRR in (000's)
Expected Case		
Expected Demand with Existing Resources (before resource additions)	$	(6,514,895)
Expected Demand with Existing Resources plus Expected Available	$	(6,547,705)
Expected Demand with GTN Fully Subscribed	$	(6,593,845)
Expected Demand with GTN Rate Escalation	$	(7,440,510)
Additional Demand Scenarios		
Expected Demand with High Elasticity and Existing Resources	$	(5,856,847)
Expected Demand with Expected Elasticity and Existing Resources	$	(6,249,435)
Coldest in 20 Demand with Existing Resources	$	(7,997,147)
High Growth & Low Price Demand with Existing Resources	$	(7,691,204)
High Growth & Low Price Demand with Existing Resource plus Expected Available	$	(10,704,833)
Green Future with Exisiting Resources	$	(9,277,241)
Low Growth & High Prices with Restricted Capacity	$	(10,814,967)
Supply Constrained with Existing Resources	$	(11,782,862)

Appendix 7.5 - Served Demand And Costs by Portfolio by Gas Year

Portfolio		2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020
Expected Demand with Existing Resources												
	Total Served w/o Enduser (MDth)	35,099	34,796	34,998	35,334	35,790	36,277	36,130	36,450	36,831	37,227	37,756
	Total System Cost (000's)	$ (195,180)	$ (232,351)	$ (222,775)	$ (230,341)	$ (213,825)	$ (272,971)	$ (293,852)	$ (306,592)	$ (311,644)	$ (321,129)	$ (337,014)
	Total Transport Fix Cost (000's)	$ (40,789)	$ (40,977)	$ (41,169)	$ (44,089)	$ (47,298)	$ (50,816)	$ (54,686)	$ (58,934)	$ (63,330)	$ (68,140)	$ (73,404)
	Total Transport Var Cost (000's)	$ (589)	$ (640)	$ (651)	$ (736)	$ (759)	$ (754)	$ (708)	$ (720)	$ (732)	$ (718)	$ (723)
	Total Supply Fixed Costs by Supply (000's)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Total Supply Variable Costs by Supply (000's)	$ (153,076)	$ (190,277)	$ (180,474)	$ (185,030)	$ (165,286)	$ (220,899)	$ (237,932)	$ (246,405)	$ (247,044)	$ (251,725)	$ (262,329)
	Total Storage Fix Cost (000's)	$ (348)	$ (35)	$ (35)	$ (38)	$ (42)	$ (47)	$ (51)	$ (57)	$ (62)	$ (69)	$ (75)
	Total Storage Var Cost (000's)	$ (60)	$ (94)	$ (118)	$ (119)	$ (110)	$ (127)	$ (144)	$ (147)	$ (147)	$ (149)	$ (153)
	DSM Implementation Cost (000's)	$ (319.07)	$ (329.11)	$ (329.11)	$ (329.11)	$ (329.11)	$ (329.11)	$ (329.11)	$ (329.11)	$ (329.11)	$ (329.11)	$ (329.11)
Expected Demand with Existing Resources plus Expected Available												
	Total Served w/o Enduser (MDth)	35,099	34,796	34,998	35,334	35,790	36,277	36,130	36,450	36,831	37,227	37,756
	Total System Cost (000's)	$ (195,795)	$ (233,059)	$ (223,372)	$ (230,968)	$ (214,440)	$ (273,579)	$ (294,467)	$ (307,232)	$ (312,274)	$ (321,802)	$ (337,719)
	Total Transport Fix Cost (000's)	$ (42,194)	$ (42,541)	$ (42,631)	$ (45,581)	$ (48,820)	$ (52,367)	$ (56,267)	$ (60,543)	$ (64,969)	$ (69,810)	$ (75,106)
	Total Transport Var Cost (000's)	$ (616)	$ (665)	$ (672)	$ (790)	$ (795)	$ (798)	$ (779)	$ (784)	$ (784)	$ (789)	$ (790)
	Total Supply Fixed Costs by Supply (000's)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Total Supply Variable Costs by Supply (000's)	$ (152,257)	$ (189,396)	$ (179,589)	$ (184,112)	$ (164,345)	$ (219,913)	$ (236,900)	$ (245,377)	$ (245,985)	$ (250,660)	$ (261,270)
	Total Storage Fix Cost (000's)	$ (348)	$ (35)	$ (35)	$ (38)	$ (42)	$ (47)	$ (51)	$ (57)	$ (62)	$ (69)	$ (75)
	Total Storage Var Cost (000's)	$ (60)	$ (94)	$ (115)	$ (118)	$ (109)	$ (126)	$ (141)	$ (143)	$ (144)	$ (145)	$ (150)
	DSM Implementation Cost (000's)	$ (319)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)
Expected Demand with GTN Rate Escalation												
	Total Served w/o Enduser (MDth)	35,099	34,796	34,998	35,334	35,790	36,277	36,130	36,450	36,831	37,227	37,756
	Total System Cost (000's)	$ (214,803)	$ (252,096)	$ (242,437)	$ (251,905)	$ (237,444)	$ (298,861)	$ (322,263)	$ (337,801)	$ (345,708)	$ (358,380)	$ (377,747)
	Total Transport Fix Cost (000's)	$ (61,203)	$ (61,577)	$ (61,697)	$ (66,518)	$ (71,823)	$ (77,648)	$ (84,062)	$ (91,111)	$ (98,403)	$ (106,388)	$ (115,134)
	Total Transport Var Cost (000's)	$ (616)	$ (665)	$ (672)	$ (790)	$ (795)	$ (798)	$ (779)	$ (784)	$ (784)	$ (789)	$ (790)
	Total Supply Fixed Costs by Supply (000's)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Total Supply Variable Costs by Supply (000's)	$ (152,257)	$ (189,396)	$ (179,589)	$ (184,112)	$ (164,345)	$ (219,913)	$ (236,900)	$ (245,377)	$ (245,985)	$ (250,660)	$ (261,270)
	Total Storage Fix Cost (000's)	$ (348)	$ (35)	$ (35)	$ (38)	$ (42)	$ (47)	$ (51)	$ (57)	$ (62)	$ (69)	$ (75)
	Total Storage Var Cost (000's)	$ (60)	$ (94)	$ (115)	$ (118)	$ (109)	$ (126)	$ (141)	$ (143)	$ (144)	$ (145)	$ (150)
	DSM Implementation Cost (000's)	$ (319)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)
Expected Demand with GTN Fully Subscribed												
	Total Served w/o Enduser (MDth)	35,099	34,796	34,998	35,334	35,790	36,277	36,130	36,450	36,831	37,227	37,756
	Total System Cost (000's)	$ (195,795)	$ (233,059)	$ (223,372)	$ (230,968)	$ (214,440)	$ (273,604)	$ (294,468)	$ (307,233)	$ (312,275)	$ (321,967)	$ (338,339)
	Total Transport Fix Cost (000's)	$ (42,194)	$ (42,541)	$ (42,631)	$ (45,581)	$ (48,820)	$ (52,367)	$ (56,267)	$ (60,543)	$ (64,969)	$ (69,810)	$ (75,106)
	Total Transport Var Cost (000's)	$ (616)	$ (665)	$ (672)	$ (790)	$ (795)	$ (799)	$ (780)	$ (785)	$ (785)	$ (791)	$ (791)
	Total Supply Fixed Costs by Supply (000's)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (163)	$ (610)
	Total Supply Variable Costs by Supply (000's)	$ (152,257)	$ (189,396)	$ (179,589)	$ (184,112)	$ (164,345)	$ (219,937)	$ (236,900)	$ (245,377)	$ (245,985)	$ (250,661)	$ (261,278)
	Total Storage Fix Cost (000's)	$ (348)	$ (35)	$ (35)	$ (38)	$ (42)	$ (47)	$ (51)	$ (57)	$ (62)	$ (69)	$ (75)
	Total Storage Var Cost (000's)	$ (60)	$ (94)	$ (115)	$ (118)	$ (109)	$ (126)	$ (141)	$ (143)	$ (144)	$ (145)	$ (150)
	DSM Implementation Cost (000's)	$ (319)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)
Expected Demand with Expected Elasticity and Existing Resources												
	Total Served w/o Enduser (MDth)	35,099	34,251	34,092	34,324	34,760	35,226	34,486	34,608	34,889	35,256	35,693
	Total System Cost (000's)	$ (195,167)	$ (229,524)	$ (217,925)	$ (224,798)	$ (208,810)	$ (266,222)	$ (282,394)	$ (293,366)	$ (297,709)	$ (306,975)	$ (321,789)
	Total Transport Fix Cost (000's)	$ (40,789)	$ (40,977)	$ (41,169)	$ (44,089)	$ (47,298)	$ (50,816)	$ (54,686)	$ (58,934)	$ (63,330)	$ (68,140)	$ (73,404)
	Total Transport Var Cost (000's)	$ (589)	$ (635)	$ (639)	$ (727)	$ (751)	$ (746)	$ (693)	$ (709)	$ (716)	$ (700)	$ (705)
	Total Supply Fixed Costs by Supply (000's)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Total Supply Variable Costs by Supply (000's)	$ (153,063)	$ (187,454)	$ (175,635)	$ (179,497)	$ (160,280)	$ (214,156)	$ (226,489)	$ (233,191)	$ (233,124)	$ (237,587)	$ (247,120)
	Total Storage Fix Cost (000's)	$ (348)	$ (35)	$ (35)	$ (38)	$ (42)	$ (47)	$ (51)	$ (57)	$ (62)	$ (69)	$ (75)
	Total Storage Var Cost (000's)	$ (60)	$ (94)	$ (119)	$ (119)	$ (110)	$ (128)	$ (145)	$ (147)	$ (147)	$ (150)	$ (155)
	DSM Implementation Cost (000's)	$ (319)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)
Expected Demand with High Elasticity and Existing Resources												
	Total Served w/o Enduser (MDth)	35,099	32,928	32,595	32,763	33,169	33,603	31,545	31,564	31,775	32,094	32,452
	Total System Cost (000's)	$ (195,265)	$ (222,820)	$ (210,031)	$ (216,358)	$ (201,196)	$ (256,090)	$ (262,188)	$ (271,821)	$ (275,704)	$ (284,633)	$ (298,248)
	Total Transport Fix Cost (000's)	$ (40,789)	$ (40,977)	$ (41,169)	$ (44,089)	$ (47,298)	$ (50,816)	$ (54,686)	$ (58,934)	$ (63,330)	$ (68,140)	$ (73,404)
	Total Transport Var Cost (000's)	$ (620)	$ (632)	$ (637)	$ (716)	$ (735)	$ (729)	$ (668)	$ (693)	$ (692)	$ (674)	$ (677)
	Total Supply Fixed Costs by Supply (000's)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Total Supply Variable Costs by Supply (000's)	$ (153,131)	$ (180,753)	$ (167,742)	$ (171,066)	$ (152,682)	$ (204,040)	$ (206,304)	$ (211,661)	$ (211,142)	$ (215,268)	$ (223,604)
	Total Storage Fix Cost (000's)	$ (348)	$ (35)	$ (35)	$ (38)	$ (42)	$ (47)	$ (51)	$ (57)	$ (62)	$ (69)	$ (75)
	Total Storage Var Cost (000's)	$ (59)	$ (94)	$ (120)	$ (119)	$ (111)	$ (129)	$ (149)	$ (147)	$ (148)	$ (153)	$ (158)
	DSM Implementation Cost (000's)	$ (319)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)
Coldest in 20 Demand with Existing Resources												
	Total Served w/o Enduser (MDth)	34,975	34,599	34,799	35,132	35,584	36,067	35,921	36,237	36,614	37,008	37,533
	Total System Cost (000's)	$ (197,016)	$ (234,592)	$ (225,092)	$ (245,996)	$ (230,474)	$ (298,908)	$ (334,173)	$ (357,326)	$ (387,400)	$ (409,963)	$ (432,415)
	Total Transport Fix Cost (000's)	$ (42,294)	$ (42,512)	$ (42,735)	$ (45,686)	$ (48,928)	$ (52,477)	$ (56,379)	$ (60,657)	$ (65,085)	$ (69,928)	$ (75,227)
	Total Transport Var Cost (000's)	$ (522)	$ (584)	$ (538)	$ (669)	$ (760)	$ (758)	$ (763)	$ (759)	$ (765)	$ (768)	$ (774)
	Total Supply Fixed Costs by Supply (000's)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Total Supply Variable Costs by Supply (000's)	$ (153,460)	$ (191,024)	$ (181,322)	$ (199,129)	$ (180,272)	$ (245,138)	$ (276,465)	$ (295,322)	$ (320,938)	$ (338,631)	$ (355,766)
	Total Storage Fix Cost (000's)	$ (348)	$ (35)	$ (35)	$ (38)	$ (42)	$ (47)	$ (51)	$ (57)	$ (62)	$ (69)	$ (75)
	Total Storage Var Cost (000's)	$ (73)	$ (109)	$ (134)	$ (146)	$ (144)	$ (159)	$ (186)	$ (202)	$ (220)	$ (237)	$ (245)
	DSM Implementation Cost (000's)	$ (319)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)

Appendix 7.5 - Served Demand And Costs by Portfolio by Gas Year

Portfolio	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020
High Growth & Low Price Demand with Existing Resources											
Total Served w/o Enduser (MDth)	35,508	35,593	36,231	37,036	37,961	38,921	39,762	40,520	41,341	42,171	43,150
Total System Cost (000's)	$ (195,619)	$ (229,414)	$ (241,622)	$ (255,266)	$ (231,315)	$ (294,111)	$ (324,970)	$ (336,505)	$ (364,019)	$ (380,408)	$ (391,690)
Total Transport Fix Cost (000's)	$ (42,294)	$ (42,512)	$ (42,735)	$ (45,686)	$ (48,928)	$ (52,477)	$ (56,379)	$ (60,657)	$ (65,085)	$ (69,928)	$ (75,227)
Total Transport Var Cost (000's)	$ (738)	$ (749)	$ (590)	$ (741)	$ (777)	$ (768)	$ (771)	$ (779)	$ (767)	$ (798)	$ (794)
Total Supply Fixed Costs by Supply (000's)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Supply Variable Costs by Supply (000's)	$ (151,871)	$ (185,722)	$ (197,821)	$ (208,335)	$ (181,110)	$ (240,346)	$ (267,279)	$ (274,519)	$ (297,599)	$ (309,102)	$ (315,073)
Total Storage Fix Cost (000's)	$ (348)	$ (35)	$ (35)	$ (38)	$ (42)	$ (47)	$ (51)	$ (57)	$ (62)	$ (69)	$ (75)
Total Storage Var Cost (000's)	$ (46)	$ (68)	$ (113)	$ (137)	$ (130)	$ (144)	$ (161)	$ (163)	$ (176)	$ (181)	$ (191)
DSM Implementation Cost (000's)	$ (322)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (330)	$ (330)	$ (330)	$ (330)
High Growth & Low Price Demand with Existing Resource plus Expected Available											
Total Served w/o Enduser (MDth)	35,449	35,521	36,150	36,938	37,847	38,785	39,786	40,561	41,399	42,251	43,255
Total System Cost (000's)	$ (191,492)	$ (225,178)	$ (237,400)	$ (249,797)	$ (256,337)	$ (319,762)	$ (430,384)	$ (452,595)	$ (491,499)	$ (520,573)	$ (545,603)
Total Transport Fix Cost (000's)	$ (38,449)	$ (38,674)	$ (38,903)	$ (41,425)	$ (74,131)	$ (79,492)	$ (162,237)	$ (177,081)	$ (192,879)	$ (210,204)	$ (229,207)
Total Transport Var Cost (000's)	$ (744)	$ (753)	$ (619)	$ (743)	$ (778)	$ (777)	$ (768)	$ (778)	$ (754)	$ (794)	$ (808)
Total Supply Fixed Costs by Supply (000's)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Supply Variable Costs by Supply (000's)	$ (151,576)	$ (185,320)	$ (197,401)	$ (207,126)	$ (180,927)	$ (238,972)	$ (266,834)	$ (274,184)	$ (297,291)	$ (308,995)	$ (314,992)
Total Storage Fix Cost (000's)	$ (348)	$ (35)	$ (35)	$ (38)	$ (42)	$ (47)	$ (51)	$ (57)	$ (62)	$ (69)	$ (75)
Total Storage Var Cost (000's)	$ (47)	$ (68)	$ (113)	$ (135)	$ (129)	$ (144)	$ (164)	$ (166)	$ (183)	$ (182)	$ (192)
DSM Implementation Cost (000's)	$ (328)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)
Low Growth & High Prices with Restricted Capacity											
Total Served w/o Enduser (MDth)	35,059	34,903	33,553	32,195	32,028	32,039	31,966	31,851	31,795	31,756	31,829
Total System Cost (000's)	$ (262,308)	$ (330,813)	$ (365,539)	$ (393,186)	$ (389,637)	$ (465,035)	$ (494,181)	$ (507,451)	$ (533,170)	$ (550,229)	$ (564,470)
Total Transport Fix Cost (000's)	$ (42,294)	$ (42,512)	$ (42,735)	$ (45,686)	$ (48,928)	$ (52,477)	$ (56,379)	$ (60,657)	$ (65,085)	$ (69,928)	$ (75,227)
Total Transport Var Cost (000's)	$ (735)	$ (747)	$ (542)	$ (644)	$ (683)	$ (624)	$ (648)	$ (616)	$ (585)	$ (612)	$ (589)
Total Supply Fixed Costs by Supply (000's)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Supply Variable Costs by Supply (000's)	$ (218,542)	$ (287,072)	$ (321,684)	$ (346,213)	$ (339,368)	$ (411,228)	$ (436,410)	$ (445,414)	$ (466,699)	$ (478,875)	$ (487,806)
Total Storage Fix Cost (000's)	$ (348)	$ (35)	$ (35)	$ (38)	$ (42)	$ (47)	$ (51)	$ (57)	$ (62)	$ (69)	$ (75)
Total Storage Var Cost (000's)	$ (60)	$ (119)	$ (214)	$ (275)	$ (286)	$ (330)	$ (365)	$ (377)	$ (408)	$ (415)	$ (444)
DSM Implementation Cost (000's)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (330)	$ (330)	$ (330)	$ (330)
Green Future with Exisiting Resources											
Total Served w/o Enduser (MDth)	35,098	33,855	33,819	33,910	34,207	34,662	32,893	32,851	32,947	33,079	33,351
Total System Cost (000's)	$ (212,850)	$ (244,520)	$ (237,759)	$ (252,961)	$ (235,644)	$ (349,600)	$ (385,287)	$ (414,353)	$ (444,546)	$ (474,253)	$ (495,874)
Total Transport Fix Cost (000's)	$ (42,294)	$ (42,512)	$ (42,735)	$ (45,686)	$ (48,928)	$ (52,477)	$ (56,379)	$ (60,657)	$ (65,085)	$ (69,928)	$ (75,227)
Total Transport Var Cost (000's)	$ (546)	$ (603)	$ (541)	$ (661)	$ (758)	$ (758)	$ (748)	$ (749)	$ (753)	$ (741)	$ (744)
Total Supply Fixed Costs by Supply (000's)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Supply Variable Costs by Supply (000's)	$ (169,263)	$ (200,927)	$ (193,977)	$ (206,091)	$ (185,429)	$ (295,800)	$ (327,541)	$ (352,291)	$ (378,024)	$ (402,866)	$ (419,178)
Total Storage Fix Cost (000's)	$ (348)	$ (35)	$ (35)	$ (38)	$ (42)	$ (47)	$ (51)	$ (57)	$ (62)	$ (69)	$ (75)
Total Storage Var Cost (000's)	$ (77)	$ (115)	$ (143)	$ (155)	$ (158)	$ (188)	$ (239)	$ (271)	$ (293)	$ (320)	$ (320)
DSM Implementation Cost (000's)	$ (322)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (330)	$ (330)
Supply Constrained with Existing Resources											
Total Served w/o Enduser (MDth)	35,097	32,690	32,486	32,481	32,597	33,020	32,592	32,673	32,854	32,955	33,299
Total System Cost (000's)	$ (292,218)	$ (340,956)	$ (338,468)	$ (371,515)	$ (371,164)	$ (456,869)	$ (486,335)	$ (512,956)	$ (552,310)	$ (579,609)	$ (605,036)
Total Transport Fix Cost (000's)	$ (42,294)	$ (42,512)	$ (42,735)	$ (45,686)	$ (48,928)	$ (52,477)	$ (56,379)	$ (60,657)	$ (65,085)	$ (69,928)	$ (75,227)
Total Transport Var Cost (000's)	$ (546)	$ (574)	$ (503)	$ (545)	$ (652)	$ (715)	$ (720)	$ (719)	$ (712)	$ (689)	$ (683)
Total Supply Fixed Costs by Supply (000's)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Supply Variable Costs by Supply (000's)	$ (248,606)	$ (297,328)	$ (294,624)	$ (324,645)	$ (320,924)	$ (402,991)	$ (428,511)	$ (450,819)	$ (485,715)	$ (508,171)	$ (528,276)
Total Storage Fix Cost (000's)	$ (348)	$ (35)	$ (35)	$ (38)	$ (42)	$ (47)	$ (51)	$ (57)	$ (62)	$ (69)	$ (75)
Total Storage Var Cost (000's)	$ (95)	$ (179)	$ (243)	$ (271)	$ (288)	$ (310)	$ (345)	$ (375)	$ (405)	$ (423)	$ (445)
DSM Implementation Cost (000's)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (329)	$ (330)	$ (330)	$ (330)	$ (330)

Appendix 7.5 - Served Demand And Costs by Portfolio by Gas Year

Portfolio	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	Total
Expected Demand with Existing Resources										
Total Served w/o Enduser (MDth)	38,274	38,809	39,384	40,005	40,538	41,147	41,708	42,370	42,944	761,869
Total System Cost (000's)	(354,042)	(365,279)	(373,004)	(370,477)	(381,929)	(403,330)	(424,301)	(441,877)	(462,982)	(6,514,895)
Total Transport Fix Cost (000's)	(79,167)	(85,489)	(92,623)	(100,459)	(109,066)	(118,523)	(128,915)	(140,722)	(153,754)	(1,592,348)
Total Transport Var Cost (000's)	(719)	(722)	(737)	(785)	(784)	(803)	(807)	(811)	(821)	(14,719)
Total Supply Fixed Costs by Supply (000's)	-	-	-	-	-	-	-	(80)	(573)	(653)
Total Supply Variable Costs by Supply (000's)	(273,586)	(278,491)	(279,070)	(268,634)	(271,477)	(283,393)	(293,948)	(299,700)	(307,748)	(4,896,525)
Total Storage Fix Cost (000's)	(83)	(91)	(100)	(110)	(121)	(133)	(147)	(162)	(179)	(1,984)
Total Storage Var Cost (000's)	(158)	(157)	(144)	(159)	(151)	(148)	(155)	(152)	(150)	(2,741)
DSM Implementation Cost (000's)	(329.11)	(329.92)	(329.92)	(329.92)	(329.92)	(329.92)	(329.92)	(329.92)	(329.92)	(6,579)
Expected Demand with Existing Resources plus Expected Available										
Total Served w/o Enduser (MDth)	38,274	38,809	39,384	40,005	40,538	41,147	41,708	42,370	42,944	761,869
Total System Cost (000's)	(354,803)	(366,102)	(373,946)	(371,981)	(384,151)	(406,381)	(428,291)	(447,174)	(470,168)	(6,547,705)
Total Transport Fix Cost (000's)	(80,901)	(87,258)	(94,514)	(102,867)	(112,106)	(122,308)	(133,568)	(146,510)	(160,842)	(1,641,703)
Total Transport Var Cost (000's)	(789)	(786)	(804)	(839)	(829)	(830)	(855)	(851)	(852)	(15,696)
Total Supply Fixed Costs by Supply (000's)	-	-	-	-	-	-	-	(80)	(573)	(653)
Total Supply Variable Costs by Supply (000's)	(272,545)	(277,484)	(278,054)	(267,685)	(270,622)	(282,635)	(293,240)	(299,093)	(307,244)	(4,878,406)
Total Storage Fix Cost (000's)	(83)	(91)	(100)	(110)	(121)	(133)	(147)	(162)	(179)	(1,984)
Total Storage Var Cost (000's)	(155)	(155)	(145)	(151)	(144)	(144)	(152)	(148)	(148)	(2,687)
DSM Implementation Cost (000's)	(329)	(329)	(329)	(329)	(330)	(330)	(330)	(330)	(330)	(6,576)
Expected Demand with GTN Rate Escalation										
Total Served w/o Enduser (MDth)	38,274	38,809	39,384	40,005	40,538	41,147	41,708	42,370	42,944	761,869
Total System Cost (000's)	(398,614)	(414,068)	(426,699)	(430,389)	(448,763)	(477,589)	(506,588)	(533,400)	(564,955)	(7,440,510)
Total Transport Fix Cost (000's)	(124,713)	(135,224)	(147,267)	(161,276)	(174,477)	(190,236)	(207,560)	(227,256)	(248,998)	(2,512,573)
Total Transport Var Cost (000's)	(789)	(786)	(804)	(839)	(831)	(837)	(855)	(859)	(861)	(15,722)
Total Supply Fixed Costs by Supply (000's)	-	-	-	-	(2,189)	(3,199)	(4,193)	(5,418)	(7,027)	(22,026)
Total Supply Variable Costs by Supply (000's)	(272,545)	(277,484)	(278,054)	(267,685)	(270,671)	(282,710)	(293,351)	(299,226)	(307,411)	(4,878,941)
Total Storage Fix Cost (000's)	(83)	(91)	(100)	(110)	(121)	(133)	(147)	(162)	(179)	(1,984)
Total Storage Var Cost (000's)	(155)	(155)	(145)	(151)	(144)	(144)	(152)	(148)	(149)	(2,687)
DSM Implementation Cost (000's)	(329)	(329)	(329)	(329)	(330)	(330)	(330)	(330)	(330)	(6,576)
Expected Demand with GTN Fully Subscribed										
Total Served w/o Enduser (MDth)	38,274	38,809	39,384	40,005	40,538	41,147	41,708	42,370	42,944	761,869
Total System Cost (000's)	(355,891)	(367,661)	(376,084)	(375,244)	(388,215)	(411,249)	(435,424)	(458,093)	(480,464)	(6,593,845)
Total Transport Fix Cost (000's)	(80,901)	(87,258)	(94,428)	(102,299)	(110,943)	(120,438)	(132,748)	(148,383)	(161,421)	(1,639,648)
Total Transport Var Cost (000's)	(792)	(787)	(806)	(839)	(831)	(837)	(858)	(863)	(865)	(15,748)
Total Supply Fixed Costs by Supply (000's)	(1,065)	(1,517)	(2,167)	(3,728)	(5,087)	(6,540)	(7,713)	(8,858)	(9,984)	(47,430)
Total Supply Variable Costs by Supply (000's)	(272,566)	(277,524)	(278,109)	(267,788)	(270,758)	(282,827)	(293,477)	(299,348)	(307,537)	(4,879,773)
Total Storage Fix Cost (000's)	(83)	(91)	(100)	(110)	(121)	(133)	(147)	(162)	(179)	(1,984)
Total Storage Var Cost (000's)	(154)	(155)	(145)	(151)	(144)	(144)	(152)	(148)	(149)	(2,686)
DSM Implementation Cost (000's)	(329)	(329)	(329)	(329)	(330)	(330)	(330)	(330)	(330)	(6,576)
Expected Demand with Expected Elasticity and Existing Resources										
Total Served w/o Enduser (MDth)	36,072	36,411	36,939	37,512	37,997	38,529	38,940	39,459	39,958	724,501
Total System Cost (000's)	(337,259)	(346,639)	(354,317)	(352,494)	(364,255)	(384,635)	(403,933)	(420,475)	(440,750)	(6,249,435)
Total Transport Fix Cost (000's)	(79,167)	(85,489)	(92,623)	(100,459)	(109,066)	(118,523)	(128,915)	(140,722)	(153,754)	(1,592,348)
Total Transport Var Cost (000's)	(699)	(701)	(720)	(764)	(763)	(772)	(792)	(784)	(793)	(14,398)
Total Supply Fixed Costs by Supply (000's)	-	-	-	-	-	-	-	-	-	-
Total Supply Variable Costs by Supply (000's)	(256,822)	(259,871)	(260,399)	(250,671)	(253,824)	(264,728)	(273,595)	(278,326)	(285,545)	(4,631,377)
Total Storage Fix Cost (000's)	(83)	(91)	(100)	(110)	(121)	(133)	(147)	(162)	(179)	(1,984)
Total Storage Var Cost (000's)	(159)	(158)	(146)	(160)	(151)	(149)	(155)	(152)	(149)	(2,751)
DSM Implementation Cost (000's)	(329)	(329)	(329)	(329)	(330)	(330)	(330)	(330)	(330)	(6,576)
Expected Demand with High Elasticity and Existing Resources										
Total Served w/o Enduser (MDth)	32,734	32,957	33,420	33,928	34,354	34,813	35,129	35,556	35,991	668,471
Total System Cost (000's)	(312,189)	(320,168)	(327,754)	(326,936)	(339,022)	(358,101)	(375,820)	(391,590)	(410,915)	(5,856,847)
Total Transport Fix Cost (000's)	(79,167)	(85,489)	(92,623)	(100,459)	(109,066)	(118,523)	(128,915)	(140,722)	(153,754)	(1,592,348)
Total Transport Var Cost (000's)	(676)	(674)	(697)	(731)	(736)	(736)	(768)	(756)	(760)	(14,007)
Total Supply Fixed Costs by Supply (000's)	-	-	-	-	-	-	-	-	-	-
Total Supply Variable Costs by Supply (000's)	(231,771)	(233,424)	(233,856)	(225,145)	(228,618)	(238,227)	(245,506)	(249,466)	(255,739)	(4,239,144)
Total Storage Fix Cost (000's)	(83)	(91)	(100)	(110)	(121)	(133)	(147)	(162)	(179)	(1,984)
Total Storage Var Cost (000's)	(163)	(162)	(149)	(162)	(152)	(152)	(154)	(154)	(153)	(2,787)
DSM Implementation Cost (000's)	(329)	(329)	(329)	(329)	(330)	(330)	(330)	(330)	(330)	(6,576)
Coldest in 20 Demand with Existing Resources										
Total Served w/o Enduser (MDth)	38,045	38,574	39,143	39,759	40,285	40,888	41,441	42,092	42,651	757,347
Total System Cost (000's)	(455,141)	(471,250)	(486,598)	(478,182)	(491,727)	(525,036)	(550,119)	(577,070)	(608,670)	(7,997,147)
Total Transport Fix Cost (000's)	(81,024)	(87,383)	(94,555)	(102,430)	(111,077)	(120,574)	(131,006)	(142,855)	(155,932)	(1,628,745)
Total Transport Var Cost (000's)	(771)	(777)	(781)	(772)	(780)	(776)	(787)	(786)	(788)	(14,676)
Total Supply Fixed Costs by Supply (000's)	-	-	-	-	-	-	-	-	-	-
Total Supply Variable Costs by Supply (000's)	(372,673)	(382,405)	(390,582)	(374,280)	(379,161)	(402,962)	(417,580)	(432,663)	(451,160)	(6,340,933)
Total Storage Fix Cost (000's)	(83)	(91)	(100)	(110)	(121)	(133)	(147)	(162)	(179)	(1,984)
Total Storage Var Cost (000's)	(260)	(263)	(250)	(260)	(258)	(261)	(269)	(274)	(281)	(4,230)
DSM Implementation Cost (000's)	(330)	(330)	(330)	(330)	(330)	(330)	(330)	(330)	(330)	(6,579)

Appendix 7.5 - Served Demand And Costs by Portfolio by Gas Year

Portfolio		2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	Total
High Growth & Low Price Demand with Existing Resources											
	Total Served w/o Enduser (MDth)	44,114	45,025	45,940	46,887	47,720	48,633	49,460	50,402	51,212	857,587
	Total System Cost (000's)	$ (410,141)	$ (423,014)	$ (443,146)	$ (468,605)	$ (492,550)	$ (517,678)	$ (544,457)	$ (573,948)	$ (572,727)	$ (7,691,204)
	Total Transport Fix Cost (000's)	$ (81,024)	$ (87,383)	$ (94,555)	$ (102,430)	$ (111,077)	$ (120,574)	$ (131,006)	$ (142,855)	$ (155,932)	$ (1,628,745)
	Total Transport Var Cost (000's)	$ (809)	$ (631)	$ (629)	$ (639)	$ (641)	$ (655)	$ (658)	$ (668)	$ (567)	$ (14,168)
	Total Supply Fixed Costs by Supply (000's)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Total Supply Variable Costs by Supply (000's)	$ (327,720)	$ (334,378)	$ (347,329)	$ (364,888)	$ (380,169)	$ (395,771)	$ (412,090)	$ (429,702)	$ (415,526)	$ (6,036,350)
	Total Storage Fix Cost (000's)	$ (83)	$ (91)	$ (100)	$ (110)	$ (121)	$ (133)	$ (147)	$ (162)	$ (179)	$ (1,984)
	Total Storage Var Cost (000's)	$ (174)	$ (200)	$ (203)	$ (208)	$ (213)	$ (215)	$ (226)	$ (231)	$ (192)	$ (3,371)
	DSM Implementation Cost (000's)	$ (330)	$ (330)	$ (330)	$ (330)	$ (330)	$ (330)	$ (330)	$ (330)	$ (330)	$ (6,586)
High Growth & Low Price Demand with Existing Resource plus Expected Available											
	Total Served w/o Enduser (MDth)	44,248	45,259	46,318	47,430	48,435	49,529	50,559	51,696	52,726	864,144
	Total System Cost (000's)	$ (579,111)	$ (609,025)	$ (648,913)	$ (696,324)	$ (744,437)	$ (796,100)	$ (852,189)	$ (916,538)	$ (941,575)	$ (10,704,833)
	Total Transport Fix Cost (000's)	$ (250,049)	$ (272,925)	$ (298,805)	$ (327,276)	$ (358,600)	$ (393,063)	$ (430,983)	$ (474,143)	$ (521,802)	$ (4,610,328)
	Total Transport Var Cost (000's)	$ (780)	$ (665)	$ (675)	$ (696)	$ (717)	$ (751)	$ (778)	$ (810)	$ (690)	$ (14,882)
	Total Supply Fixed Costs by Supply (000's)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Total Supply Variable Costs by Supply (000's)	$ (327,674)	$ (334,816)	$ (348,800)	$ (367,703)	$ (384,456)	$ (401,605)	$ (419,726)	$ (439,332)	$ (415,133)	$ (6,062,864)
	Total Storage Fix Cost (000's)	$ (83)	$ (91)	$ (100)	$ (110)	$ (121)	$ (133)	$ (147)	$ (162)	$ (179)	$ (1,984)
	Total Storage Var Cost (000's)	$ (197)	$ (199)	$ (203)	$ (209)	$ (213)	$ (218)	$ (226)	$ (232)	$ (168)	$ (3,388)
	DSM Implementation Cost (000's)	$ (329)	$ (329)	$ (329)	$ (330)	$ (330)	$ (330)	$ (330)	$ (330)	$ (330)	
Low Growth & High Prices with Restricted Capacity											
	Total Served w/o Enduser (MDth)	31,888	31,965	32,074	32,223	32,300	32,443	32,553	32,755	32,890	650,063
	Total System Cost (000's)	$ (579,523)	$ (589,842)	$ (606,222)	$ (626,952)	$ (646,322)	$ (675,050)	$ (707,914)	$ (744,590)	$ (782,532)	$ (10,814,967)
	Total Transport Fix Cost (000's)	$ (81,024)	$ (87,383)	$ (94,555)	$ (102,430)	$ (111,077)	$ (120,574)	$ (131,006)	$ (142,855)	$ (155,932)	$ (1,628,745)
	Total Transport Var Cost (000's)	$ (558)	$ (421)	$ (418)	$ (414)	$ (415)	$ (413)	$ (412)	$ (412)	$ (397)	$ (10,887)
	Total Supply Fixed Costs by Supply (000's)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Total Supply Variable Costs by Supply (000's)	$ (497,088)	$ (501,156)	$ (510,350)	$ (523,188)	$ (533,891)	$ (553,094)	$ (575,493)	$ (600,285)	$ (625,117)	$ (9,158,973)
	Total Storage Fix Cost (000's)	$ (83)	$ (91)	$ (100)	$ (110)	$ (121)	$ (133)	$ (147)	$ (162)	$ (179)	$ (1,984)
	Total Storage Var Cost (000's)	$ (441)	$ (461)	$ (468)	$ (480)	$ (489)	$ (506)	$ (526)	$ (545)	$ (576)	$ (7,785)
	DSM Implementation Cost (000's)	$ (330)	$ (330)	$ (330)	$ (330)	$ (330)	$ (330)	$ (330)	$ (330)	$ (330)	$ (6,593)
Green Future with Exisiting Resources											
	Total Served w/o Enduser (MDth)	33,696	34,085	34,504	34,929	35,343	35,755	36,114	36,549	36,913	688,561
	Total System Cost (000's)	$ (509,205)	$ (527,692)	$ (555,101)	$ (576,973)	$ (604,689)	$ (635,671)	$ (670,459)	$ (705,752)	$ (744,051)	$ (9,277,241)
	Total Transport Fix Cost (000's)	$ (81,024)	$ (87,383)	$ (94,555)	$ (102,430)	$ (111,077)	$ (120,574)	$ (131,006)	$ (142,855)	$ (155,932)	$ (1,628,745)
	Total Transport Var Cost (000's)	$ (744)	$ (747)	$ (753)	$ (739)	$ (741)	$ (741)	$ (740)	$ (744)	$ (753)	$ (14,306)
	Total Supply Fixed Costs by Supply (000's)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Total Supply Variable Costs by Supply (000's)	$ (426,692)	$ (438,793)	$ (459,024)	$ (472,989)	$ (492,037)	$ (513,496)	$ (537,821)	$ (561,223)	$ (586,416)	$ (7,619,876)
	Total Storage Fix Cost (000's)	$ (83)	$ (91)	$ (100)	$ (110)	$ (121)	$ (133)	$ (147)	$ (162)	$ (179)	$ (1,984)
	Total Storage Var Cost (000's)	$ (331)	$ (349)	$ (339)	$ (375)	$ (383)	$ (397)	$ (415)	$ (438)	$ (441)	$ (5,746)
	DSM Implementation Cost (000's)	$ (330)	$ (330)	$ (330)	$ (330)	$ (330)	$ (330)	$ (330)	$ (330)	$ (330)	$ (6,585)
Supply Constrained with Existing Resources											
	Total Served w/o Enduser (MDth)	33,636	33,972	34,357	34,801	35,206	35,630	35,955	36,370	36,696	679,368
	Total System Cost (000's)	$ (631,509)	$ (659,118)	$ (688,262)	$ (714,342)	$ (745,031)	$ (787,581)	$ (832,734)	$ (882,437)	$ (934,412)	$ (11,782,862)
	Total Transport Fix Cost (000's)	$ (81,024)	$ (87,383)	$ (94,555)	$ (102,430)	$ (111,077)	$ (120,574)	$ (131,006)	$ (142,855)	$ (155,932)	$ (1,628,745)
	Total Transport Var Cost (000's)	$ (694)	$ (694)	$ (706)	$ (681)	$ (686)	$ (690)	$ (705)	$ (707)	$ (692)	$ (13,311)
	Total Supply Fixed Costs by Supply (000's)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Total Supply Variable Costs by Supply (000's)	$ (548,921)	$ (570,148)	$ (592,095)	$ (610,263)	$ (632,276)	$ (665,297)	$ (699,974)	$ (737,791)	$ (776,666)	$ (10,124,043)
	Total Storage Fix Cost (000's)	$ (83)	$ (91)	$ (100)	$ (110)	$ (121)	$ (133)	$ (147)	$ (162)	$ (179)	$ (1,984)
	Total Storage Var Cost (000's)	$ (457)	$ (472)	$ (476)	$ (528)	$ (542)	$ (557)	$ (572)	$ (591)	$ (613)	$ (8,186)
	DSM Implementation Cost (000's)	$ (330)	$ (330)	$ (330)	$ (330)	$ (330)	$ (330)	$ (330)	$ (330)	$ (330)	$ (6,593)

APPENDIX 8.1

DISTRIBUTION SYSTEM MODELING

APPENDIX 8.1 – DISTRIBUTION SYSTEM MODELING

OVERVIEW

The primary goal of distribution system planning is to design for present needs and to plan for future expansion to serve demand growth. This allows Avista to satisfy current demand-serving requirements while taking steps toward meeting future needs. Distribution system planning identifies potential problems and areas of the distribution system that require reinforcement. By knowing when and where pressure problems may occur, the necessary reinforcements can be incorporated into normal maintenance. Thus, more costly reactive and emergency solutions can be avoided.

COMPUTER MODELING

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

THEORY AND APPLICATION OF STUDY

Natural gas network load studies have evolved in the last decade to become a highly technical and useful means of analyzing the operation of a distribution system. Using a pipeline fluid flow formula, a specified parameter of each pipe element can be simultaneously solved. A variety of pipeline equations exist, each tailored to a specific flow behavior. Through years of research, these equations have been refined to the point where solutions obtained closely represent actual system behavior.

Avista conducts network load studies using Advantica's SynerGEE® 4.3.0 software. This computer-based modeling tool runs on a Windows operating system and allows users to analyze and interpret solutions graphically.

CREATING A MODEL

To properly study the distribution system, all natural gas main information is entered (length, pipe roughness and ID) into the model. "Main" refers to all pipelines supplying services.

Nodes (points where natural gas enters or leaves the system) are placed at all pipe intersections, beginnings and ends of mains, changes in pipe diameter/material and to identify all large customers. A model element connects two nodes together. Therefore, a "to node" and a "from node" will represent an element between those two nodes. Almost all of the elements in a model are pipes.

Regulators are treated like adjustable valves in which the downstream pressure is set to a known value. Although specific regulator types can be entered for realistic behavior, the expected flow passing through the actual regulator is determined and the modeled regulator is forced to accommodate such flows.

FLUID MECHANICS OF THE MODEL

Pipe flow equations are used to determine the relationships between flow, pressure drop, diameter and pipe length. For all models, the Fundamental Flow equation (FM) is used due to its demonstrated reliability.

Efficiency factors are used to account for the equivalent resistance of valves, fittings and angle changes within the distribution system. Starting with a 95 percent factor, the efficiency can be changed to fine tune the model to match field results.

Pipe roughness along with flow conditions creates a friction factor for all pipes within a system. Thus, each pipe may have a unique friction factor, minimizing computational errors associated with generalized friction values.

LOAD DATA

All studies are considered steady state; all natural gas entering the distribution system must equal the natural gas exiting the distribution system at any given time.

Customer loads are obtained from Avista's customer billing system and converted to an algebraic format so loads can be generated for various conditions.

In the event of a peak day or an extremely cold weather condition, it is assumed that all curtailable loads are interrupted. Therefore, the models will be conducted with only core loads.

DETERMINING NATURAL GAS CUSTOMERS' MAXIMUM HOURLY USAGE

Determining a Base Load

Base loads are not temperature dependent; they remain relatively constant regardless of temperature. A reasonable base load can be calculated from customer billing information. The billing month, which has the lowest amount of heating degree days is usually August. Usage during this month will reflect nearly all natural gas loads exclusive of space heating.

By determining the amount of days in the billing period and applying a peaking factor, the peak hourly base load of each customer can be estimated as shown in Table 1:

Table 1 - Determining Base Load

$$\text{Customer Usage Summer Billing Period} \times \frac{1}{\text{Days in Billing Period}} \times 0.0625^{*} = \text{Peak Hourly Base Load}$$

* The average residential customer's peak usage was found to be 6.25 percent of the total daily load. This peaking factor was estimated by studying the ratio of the peak hourly flow and the total daily flow at the pipeline gate stations in past years. The peaking factor is periodically discussed with other utilities and has been consistent with other utilities of similar size.

Determining Heat Load

A heat load will be proportional to heating degree-days (HDDs); at 0 HDD, the load will be zero. A heat load can be reasonably calculated from customer billing information. The billing month with the greatest consumption is usually January. This month reflects maximum space heating as well as non-space heating loads.

Customers' usage for January (winter) billing, minus usage for August (summer) billing, leaves a reasonable estimate for heat load. This load can be divided by the amount of HDDs that occurred in January, leaving usage per HDD. Customer needs can be calculated by applying the peaking factor, resulting in a peak hourly heat load per HDD. This is shown in Table 2:

Table 2 - Determining Heat Load

$$\left\{ \text{Customer Usage Winter Billing Period} - \text{Customer Usage Summer Billing Period} \right\} \times \frac{1}{\text{Winter Billing Period Degree Days}} \times \text{Peak HDDs} \times 0.0625^{*} = \text{Peak Hourly Heat Load}$$

Determining Design Peak Hourly Load

The design peak hourly load for a customer is estimated by adding the hourly base load and the hourly heat load for a design temperature. This estimate reflects highest system hourly demands, as shown in Table 3:

Table 3 - Determining Peak Hourly Load

$$\text{Peak Hourly Base Load} + \text{Peak Hourly Heat Load} = \text{Peak Hourly Load}$$

This method differs from the approach that we use for IRP peak day load planning. The primary reason for this difference is due to the importance of responding to hourly peaking in the distribution system, while IRP resource planning focuses on peak day requirements to the city gate.

APPLYING LOADS

Having estimated the peak loads for all customers in a particular service area, the model can be loaded. The first step is to assign each load to the respective node or element.

GENERATING LOADS

Temperature-based and non-temperature-based loads are established for each node or element, thus loads can be varied based on any temperature (HDD). Such a tool is necessary to evaluate the difference in flow and pressure due to different weather conditions.

GEOGRAPHIC INFORMATION SYSTEM (GIS)

We have recently converted our natural gas facility maps to GIS. While the GIS can provide a variety of map products, its power lies in its analytical capability. A GIS consists of three components: spatial operations, data association and map representation.

A GIS allows analysts to conduct spatial operations (relating a feature or facility to another geographically). A spatial operation is possible if a facility displayed on a map maintains a relationship to other facilities. Spatial relationships allow analysts to perform a multitude of queries, including:

- identify electric customers adjacent to natural gas mains who are not currently using natural gas;
- display the ratio of customers to length of pipe in Emergency Operating Procedure zones (geographical areas defined by the number of customers and their safety in the event of an emergency); and
- classify high-pressure pipeline proximity criteria.

The second component of the GIS is data association. This allows analysts to model relationships between facilities displayed on a map to tabular information in a database. Databases store facility information such as pipe size, pipe material, pressure rating, or related information (e.g., customer databases, equipment databases and work management systems). Data association allows interactive queries within a map-like environment.

Finally, the GIS provides a means to create maps of existing facilities in different scales, projections and displays. In addition, the results of a comparative or spatial analysis can be presented pictorially. This allows users to present abstract analyses in a more intuitive context.

BUILDING SynerGEE® MODELS FROM A GIS

The GIS can provide additional benefits through the ease of creation and maintenance of load studies. Avista can create load studies from the GIS based on tabular data (attributes) installed during the mapping process.

MAINTENANCE USING A GIS

The GIS helps maintain the existing distribution facility by allowing a design to be initiated on a GIS. Currently, design jobs for the company's natural gas system are managed through Avista's Facility Management (AFM) tool. This system is being integrated with GIS, allowing jobs to be designed directly within a GIS. Once completed, the as-built information is submitted to GIS and the facility is immediately updated. This eliminates the need to convert physical maps to a GIS at a later date. Because the facility is updated on GIS, load studies can remain current by refreshing the analysis.

DEVELOPING A PRESENT CASE LOAD STUDY

In order for any model to have accuracy, a present case model has to be developed that reflects what the system was doing when downstream pressures and flows are known. To establish the present case, pressure charts located throughout the distribution system are used.

Pressure charts plot pressure (some include temperature) versus time over several days. Various locations recording simultaneously are used to validate the model. Customer loads on SynerGEE® are generated to correspond with actual temperatures recorded on the pressure charts. An accurate model's downstream pressures will match the corresponding location's field pressure chart. Efficiency factors are fine-tuned to further refine the model's pressures.

Since telemetry at the gate stations record hourly flow, temperature and pressure, these values are used to validate the model. All loads are representative of the average daily temperature and are defined as hourly flows. If the load generating method is truly accurate, all natural gas entering the actual system (physical) equals total natural gas demand solved by the simulated system (model).

DEVELOPING A PEAK CASE LOAD STUDY

Using the calculated peak loads, a model can be analyzed to identify the behavior during a peak day. The efficiency factors established in the present case are used throughout subsequent models.

ANALYZING RESULTS

After a model has been balanced, several features within the SynerGEE® model are used to translate results. Color plots are generated to depict flow direction, pressure, pipe diameter and gradient with specific break points. Reinforcements can be indentified by visual inspection. When user edits are completed and the model is re-balanced, pressure changes can be visually displayed, helping identify optimum reinforcements.

An optimum reinforcement will have the largest pressure increase per unit length. Reinforcements can also be deferred and occasionally eliminated through load mitigation of DSM efforts.

PLANNING CRITERIA

In most instances, models resulting in node pressures below 15 psig indicate a likelihood of distribution low pressure and therefore necessitate reinforcements. For most Avista distribution systems, a minimum of 15 psig will ensure deliverability as natural gas exits the distribution mains and travels through service pipelines to a customer's meter. Some Avista distribution areas operate at lower pressures and are assigned a minimum pressure of 5 psig for model results. Given a lower operating pressure, service pipelines in such areas are sized accordingly to maintain reliability.

DETERMINING MAXIMUM CAPACITY FOR A SYSTEM

Using a peak day model, loads can be prorated at intervals until area pressures drop to 15 psig. At that point, the total amount of natural gas entering the system equals the maximum capacity before new construction is necessary. The difference between natural gas entering the system in this scenario and a peak day model is the maximum additional capacity that can be added to the system.

Since the approximate natural gas usage for the average customer is known, it can be determined how many new customers can be added to the distribution system before necessitating system reinforcements. The above models and procedures are utilized with new construction proposals or pipe reinforcements to determine a potential increase in facilities.

FIVE-YEAR FORECASTING

The intent of our load study forecasting is to predict the system's behavior and reinforcements necessary within the next five years. Various Avista personnel provide information to determine where and why certain areas may experience growth.

By combining information from Avista's demand forecast, IRP planning efforts, regional growth plans and area developments, proposals for pipeline reinforcements and expansions can be evaluated with SynerGEE®.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF DAVE B. DEFELICE
REPRESENTING AVISTA CORPORATION

Capital Projects

I. INTRODUCTION

Q. Please state your name, employer and business address.

A. My name is Dave DeFelice. I am employed by Avista Corporation as a Senior Business Analyst. My business address is 1411 East Mission, Spokane, Washington.

Q. Please briefly describe your education background and professional experience.

A. I graduated from Eastern Washington University in June of 1983 with a Bachelor of Arts Degree in Business Administration majoring in Accounting. I have served in various positions within the Company, including Analyst positions in the Finance Department (Rates Section and Plant Accounting) and in the Marketing/Operations Departments, as well. In 1999, I accepted the Senior Business Analyst position that focuses on economic analysis of various project proposals as well as evaluations and recommendations pertaining to business policies and practices.

Q. As a Senior Business Analyst, what are your responsibilities?

A. As a Senior Business Analyst, I am involved in financial analysis of numerous projects within various departments such as Engineering, Operations, Marketing/Sales and Finance.

Q. What is the scope of your testimony?

A. My testimony in this proceeding will cover the Company’s proposed regulatory treatment of capital investments in utility plant through 2011.

II. CAPITAL INVESTMENT RECOVERY

Q. What does the Company's request for rate relief include regarding new

investment in utility plant to serve customers?

A. In this filing, we are proposing to include in retail rates the costs associated with utility plant that will be used to provide energy service to our customers during the 2011 forecasted test period. Including the costs associated with this investment in retail rates provides a proper "matching" of revenues from customers, with the costs associated with providing service to customers (including the cost of utility plant to serve customers).

Q. How was rate base for the forecasted test year developed for this filing?

A. Avista started with rate base using historical accounting information, which for this case is the end of period (EOP) balances for the twelve months ended December 31, 2009. Adjustments were made to plant in service, accumulated depreciation and deferred federal income taxes (DFIT) at December 31, 2009, to restate net plant to the average of monthly averages (AMA) amounts for the twelve months ended December 31, 2011. In addition, adjustments were made to reflect 2010 and 2011 plant additions and associated accumulated depreciation and DFIT through December 2011 on an AMA basis, such that the proposed rate base reflects the net plant in service that will be used to serve customers during the 2011 forecasted test year. Company witness Ms. Andrews incorporates these adjustments in her revenue requirements computation and provides the adjustment detail in her workpapers.

Q. What ratemaking objective is being served by your adjustments to rate base?

A. The objective is to include in retail rates the investment, or rate base, that is providing service to customers, and ensure that there is a proper matching of revenues and expenses during the period that rates are in effect.

In prior general rate cases we have used a rate base amount from a historical test year as the starting point for the pro forma rate year. If there were no major plant additions between the historical test year and the upcoming pro forma rate year, the historical test year rate base amount would be used for the pro forma rate year as being representative of the net plant used to serve customers.

However, if there were known major plant additions that would be in service for the pro forma rate year, such as the major reinforcement upgrades, then rate base for the pro forma rate year is adjusted for these major investments, so that rate base for the pro forma rate year is representative of the level of investment used to serve customers.

In this docket, the Company's adjustment for new investment in plant includes all forecasted capital additions in 2010 and 2011 to restate rate base from the historical test period to the forecasted test year. The end result is to reflect in retail rates the level of net plant investment that is used to serve customers during the forecasted test year, and to have a proper matching of revenues and expenses.

Q. Why did the Company use the 2011 AMA rate base in this case?

A. The 2011 AMA rate base reflects the net plant in service that will be used to serve customers during the 2011 forecasted test year, and is consistent with the use of 2011 forecasted revenues and expenses. Including the costs associated with this investment in retail rates provides a proper "matching" of revenues from customers with the costs associated with providing service to customers, including the cost of utility plant used to serve customers.

Q. Does the use of <u>average rate base</u> in a forecasted test period help ensure

that capital expenditures and customer usage are appropriately matched through the effective rate year?

A. Yes. The "test year" should reflect costs and revenues that will fairly represent the period when prices from the docket will be in effect following a general rate case proceeding. For capital expenditures, the test year rate base reflects the average effect of closing the capital expenditures to plant in service over the course of the year. Because capital expenditures are recorded as plant-in-service at a particular point in time, the component parts of rate base will change over the course of the test year as new capital expenditures close to plant-in-service throughout the year.

Because prices are set for the entire duration of the rate year, there will inevitably be certain timing differences within the year between capital expenditures and pricing to customers. Customers paying for service early in 2011 will be paying prices that include costs for some capital expenditures that do not close to plant until later that year. On the other hand, customers paying for service in December will be paying prices less than the cost for the capital expenditures that close to plant-in-service during the previous 11 months of 2011. The use of average rate base helps ensure that such timing differences throughout the year are generally balanced and do not cause undue intergenerational inequities during the test year, or result in over-recovery or under-recovery of costs.

If only capital projects that were in service at the date new rates are set are included, it would essentially require daily or monthly pricing to ensure that customers pay for capital expenditures that are used to provide service at each point in time within the test year. Of course, this would be unworkable and would be inconsistent with the use of test years to set prices.

Q. ORS 757.355 states "a public utility may not, directly or indirectly, by any device, charge, demand, collect or receive from any customer rates that include the costs of construction, building, installation of real or personal property not presently used for providing utility service to the customer." Are the capital additions included in this case consistent with ORS 757.355?

A. Yes. Ballot Measure 9, codified as ORS 757.355, applies only to new facilities and does not apply to capital improvements to existing facilities that are currently used and useful, like the capital improvements included in this docket. See UM989, Order No. 02-227 ("ORS 757.355 does not apply to routine construction work in progress (CWIP) attached to an operating plant. Ballot Measure 9, codified as ORS 757.355, was intended to apply to CWIP that reflects preconstruction commercial operating plants, not smaller projects attached to an operating plant").

Q. Are the 2011 capital projects that the Company pro formed into this case routine construction work that is attached to existing operating plant?

A. Yes, all of the 2011 projects pro formed in this case are work on existing operating plant. Avista currently has natural gas infrastructure that is being used to provide service to customers. The 2011 capital additions are either expansions or upgrades to this existing plant. None of this work represents costs on preconstruction operating plant.

Q. If rates go into effect in the first half of 2011, does including transfers to plant in service after that date in customers' rates violate the matching principle?

A. No. Since the Company is proposing rates be set according to a forecasted test-year, which includes the level of revenues expected from a population of customers in 2011 and for a level of expenses forecasted for 2011, it would require that the capital expenditures transferred to plant in service in 2011 be included. To exclude the 2011 capital expenditures would violate the matching principle in relation to the 2011 revenues and expenses filed by the Company. In addition, the exclusion of the 2011 capital expenditures would not allow the Company to earn a fair return on its investment.

Q. What is the net impact of the capital pro forma adjustments included in this filing?

A. Capital investment currently authorized (UG-186) is $135,839,000, while the forecasted level of capital investment for 2011 in this filing is $137,711,000.

Q. What are Avista's 2010 and 2011 capital expenditures that have been included in this case?

A. As shown in Table 1 below, Avista forecasts system-wide general plant capital expenditures of $44.155 million in 2010 and $32.143 million in 2011 (Oregon share totals $3.081 million and $2.202 million for 2010 and 2011, respectively.)

Table 1
General Plant Capital Expenditures in 000's

	2010		2011	
Project	System	Oregon Allocated	System	Oregon Allocated
Structures & Improvements	$ 4,400	$ 342	$ 2,300	$ 188
Tools Lab & Shop Equipment	1,700	142	1,300	109
Central Operating Facility HVAC Improvement	4,498	376	4,241	355
Transportation Equipment	13,185	300	9,718	300
Information Technology Refresh Projects-Software	5,138	430	6,295	527
Information Technology Expansion Projects-Software	1,683	141	1,180	99
Mobile Dispatch 2-Software	2,187	183	0	0
AFM.net Upgrade-Software	1,993	167	800	67
DIMP Infrastructure	993	299	130	39
Web Product Development Program-Software	890	74	960	80
WorkPlace Replatforming	300	25	1,000	84
Technology Projects Minor - Software	462	39	500	42
Small Technology Projects	4,721	395	2,539	213
Small General Projects	2,005	168	1,180	99
TOTAL	$ 44,155	$ 3,081	$ 32,143	$ 2,202

Capital Projects

As shown in Table 2 below, Avista forecasts Oregon natural gas distribution capital expenditures of $12.323 million in 2010 and $10.825 million in 2011.

Table 2
Oregon Gas Distribution Capital Expenditures in 000's

Project	2010	2011
Oregon - Gas Revenue Projects	$ 2,469	$ 2,027
Replace Deteriorating Gas System	1,145	641
Gas Replace - Street & Highway	890	821
Gas Distribution Non-Revenue Projects	1,046	989
Overbuilt Pipe Replacement Projects	365	332
Grants Pass Reinforcement	2,000	0
Winston Gate Station Rebuild	1,002	0
Relocation, N. Ross Lane	736	0
Roseburg Reinforcement	0	3,700
IMP Pipe Replacement	0	600
Small Natural Gas Distribution Projects	2,670	1,715
TOTAL	$ 12,323	$ 10,825

Q. What is driving the significant investment in new utility plant in Oregon?

A. The Company is being required to add significant new distribution facilities due to customer growth in our service area, reliability requirements, and capacity upgrades. Other issues driving the need for capital investment include an aging infrastructure, physical degradation, and municipal compliance issues (i.e., street/highway relocations), etc. Detailed explanations of the three major projects (Grants Pass Reinforcement, Roseburg Reinforcement, and the Medford Integrity Management Pipe (IMP) Replacement) that are included in this docket are described below.

III. DESCRIPTION OF CAPITAL PROJECTS

Q. For the 2010 and 2011 capital projects pro formed in this filing, please provide a description of the projects.

A. Tables 1 and 2 above detail the capital projects that will be transferred to plant in service in 2010 and 2011 and included in this filing. A short description of these projects and their costs allocated to Oregon follows:

General (Oregon):

ER 7001 - Structures and Improvements – 2010: $342,000; 2011: $188,000
This is a group of capital maintenance projects that Facilities Management coordinates at the Spokane Central Operating Facilities and Avista branch facilities - offices and service centers. For 2010, planned projects include: roof replacements, land acquisition for facility expansion, HVAC system replacement at some branch offices, energy efficiency projects, security projects, asphalt overlays and replacement, several new vehicle building additions, as well as some capital repair projects in existing buildings.

ER 7006 - Tools, Lab & Shop Equipment – 2010: $142,000; 2011: $109,000
Expenditures in this category include all large tools and instruments used throughout the company for natural gas and/or electric construction and maintenance work, distribution, transmission, or generation operations, telecommunications, and some fleet equipment (hoists, winch, etc) not permanently attached to the vehicle.

ER 7101 - HVAC Renovation Project – 2010: $376,000; 2011: $355,000
The heating, ventilating, and air conditioning systems throughout the Spokane Central Operating Facilities are approximately fifty years old and are in need of replacement. In 2007, the Company initiated a multi-year HVAC renovation project that involves replacing central air handling units and distribution systems in three buildings - the Spokane Service Center, the general office building, and the cafeteria auditorium building. The building envelope of the general office building was also renovated with high efficiency glass and insulation. The project will also achieve asbestos abatement and life safety (fire sprinkler) additions. New controls will also be installed which will enable energy conservation.

Other Small Projects – 2010: $168,000; 2011: $99,000
These projects include communication and security initiatives, radio equipment, telephone systems, office and other general facility upgrades.

Transportation (Oregon):

ER 7000 - Transportation Equipment – 2010: $300,000; 2011: $300,000
Expenditures are for the scheduled replacement of trucks, off-road construction equipment and trailers that meet the Company's guidelines for replacement including age, mileage, hours of use and overall condition. In addition, includes additions to the fleet for new positions or crews working to support the maintenance and construction of our electric and natural gas operations.

Technology (Oregon):

ER 5005 - Information Technology Refresh Projects – 2010: $430,000; 2011: $527,000
A program to replace obsolete technology according to Avista's refresh cycles that are generally driven by hardware/software manufacturer and industry trends to maintain business operations.

ER 5006 - Information Technology Expansion Projects – 2010: $141,000; 2011: $99,000
A program to deliver technology associated with expansion of existing solutions.

ER 5117 – Mobile Dispatch 2-Software – 2010: $183,000
Upgrade Mobile Dispatch Software.

ER 5129 – AFM.net Upgrade-Software– 2010: $167,000; 2011: $67,000
The AFM system has reached a point where continued or new application development and maintenance work without refreshing the application language will cause increased risk in system maintainability, reliability, and application availability. The business relies on this software for an increasing number of functions and integrations that support customer and operating transactions. With this technology refresh, the productive life of the AFM system will be extended by five to eight years.

ER 5127 – DIMP Infrastructure Software – 2010: $299,000; 2011: $39,000
This project is to comply with new federal pipeline regulations referred to as Distribution Integrity Management Program (DIMP).

ER 5009 – Web Product Development Software – 2010: $74,000; 2011: $80,000
A program to deliver enhancements to the Customer based Web technology system.

ER 5126 – WorkPlace Replatforming Software – 2010: $25,000; 2011: $84,000
A program to deliver enhancements to the WorkPlace (CSS, WMS & EGMA) technology system.

ER 5111 – Technology Projects Minor Software – 2010: $39,000; 2011: $42,000
A program to deliver new technology.

Other Small Technology Projects – 2010: $395,000; 2011: $213,000
These projects include various small technology projects including, technology to provide for field office use of Learning Management System, installing a fiber network that will replace an obsolete microwave system, an electronic records management system, upgrade of Oracle Database accounting and financial software.

Natural Gas Distribution (Oregon):

ER 1001 - Gas Revenue Projects – 2010: $2,469,000; 2011: $2,027,000
This annual project will install sections of gas piping, meters, regulators, etc. that are directly linked to new revenue.

ER 3001 - Replace Deteriorated Pipe – 2010: $1,145,000; 2011: $641,000
This annual project will replace sections of existing gas piping that are suspect for failure or have deteriorated within the gas system. This project will address the replacement of sections of gas main that no longer operate reliably and/or safely. Sections of the gas system require replacement due to many factors including material failures, environmental impact, increased leak frequency, or coating problems. This project will identify and replace sections of main to improve public safety and system reliability.

ER 3003 - Gas Replacement Street and Highways – 2010: $890,000; 2011: $821,000
This annual project will replace sections of existing gas piping that require replacement due to relocation or improvement of streets or highways in areas where gas piping is installed. Avista installs many of its facilities in public right-of-way under established franchise agreements. Avista is required under the franchise agreements, in most cases, to relocate its facilities when they are in conflict with road or highway improvements.

ER 3005 - Gas Non-Revenue Projects – 2010: $1,046,000; 2011: $989,000
This annual project will replace sections of existing gas piping that require replacement to improve the operation of the gas system but are not directly linked to new revenue. The project includes relocation of main related to overbuilds [customer constructed improvements (i.e. decks, driveways, etc.) that restricts the Company's access to pipe], improvement in equipment and/or technology to improve system operation and/or maintenance, replacement of obsolete facilities, replacement of main to improve cathodic performance, and projects to improve public safety and/or improve system reliability.

ER 3006 - Overbuild Pipe Replacement Projects – 2010: $365,000; 2011: $332,000
This annual project will replace sections of existing gas piping that have experienced encroachment or have been overbuilt. It will address the replacement of sections of gas main that no longer can be operated safely and will identify and replace sections of main to improve public safety. All types of overbuilds will be addressed with the primary focus of the project being overbuilds in manufactured home developments.

ER 3204 - Roseburg Reinforcement Project –2011: $3,700,000
This Oregon natural gas distribution project is described later in my testimony.

ER 3240 – Grants Pass Reinforcement Project – 2010: $2,000,000

This Oregon natural gas distribution project is described later in my testimony.

ER 3277 – Medford IMP Replacement Project – 2011: $600,000
This Oregon natural gas distribution project is described later in my testimony.

ER 3267 - Rebuild Winston Gate Station, Roseburg OR – 2010: $1,002,000
This project, to be completed in 2010, will increase the delivery capacity from the Winston Gate station located near Roseburg, Oregon. The gate station is a key interstate supplier receipt point with Williams Pipeline that serves the greater Winston and Roseburg area. Avista's required peak receipt volume from this location exceeds the physical capacity of the existing gate station. Rebuild of the gate station is necessary to ensure continued reliable service on a design day. The existing gate station rebuild will include the replacement and upgrade of facilities for both Williams and Avista. Rebuild of the station will ensure the continuation of reliable service and the ability to service future customer demand.

ER 3287 - Relocation, N Ross Ln. Medford, OR – 2010: $736,000
This project, completed in 2010, relocated a section of main and services located within North Ross Lane in Medford, Oregon. The existing facilities were installed under a franchise agreement within the County right-of-way. Relocation of the facilities was necessary due to a road improvement project in the area. Relocation of the facilities ensured a continuation of reliable service to existing customers.

Other Small Projects – 2010: $2,670,000; 2011: $1,715,000
Please refer to the workpapers of Ms. Andrews for detailed listing of projects.

IV. Major Natural Gas Distribution Reinforcement Capital Projects

Q. Please describe the Company's Grants Pass Reinforcement Project and the costs that are included in this filing.

A. The Grants Pass Reinforcement Project will replace the existing High Pressure (HP) source into the greater Grants Pass area. Due to growth in the area the existing HP main is capacity-constrained on a design day basis and replacement is required to ensure adequate natural gas deliveries during high system demand. This project will install a new larger HP source from the nearby Jones Creek Gate station into east central Grants Pass. The existing HP main will be converted to intermediate pressure distribution piping to provide an incremental reinforcement to the local distribution system. An additional benefit to the public is the elimination of a number of High Consequence Areas (HCA's) as defined by the recent integrity management regulation. Elimination of the HCA's will improve public safety and mitigate future costs associated with management of the HCA's. The capital cost is approximately $2.0 million, will be completed November 2010, and such costs have been pro formed into this filing. Ms. Andrews incorporates these costs in her testimony and exhibits.

Q. Please describe the Company's Roseburg Reinforcement Project and the costs that are included in this filing.

A. The Roseburg Reinforcement Project, Phase II of a two phase project, improves the delivery pressure and capacity of natural gas supplies into central and east Roseburg by extending a high pressure natural gas supply. The existing Roseburg system can no longer provide reliable service on a design day. The only natural gas supplies in the Roseburg area are received on the west side of town. Due to growth and increase in customer demand, especially on the east side of Roseburg, the system must be reinforced to meet customer loads during high system demand. This project will install a new high pressure (HP) distribution source by replacing the existing capacity constrained pipe and installation of a new regulator station.

Phase I capital cost totaled approximately $1.893 million, was completed in September 2008 and approved in Docket No. UG-181, included extending piping from a pressure-limited source that will be upgraded during this phase of the project.

Phase II will replace the existing capacity constrained source between the Jackie Street Gate station in Winston, Oregon and the south Roseburg city limits. This project was previously considered for construction in 2009 but was delayed. Incremental system capacity was achieved by utilization of an existing main, but now requires replacement in order to service system demand on a design day.

Phase II capital costs are currently estimated at approximately $3.70 million, will be completed in October 2011, and such costs have been pro formed into this filing.

Q. Please describe the Company's Medford Integrity Management Pipe (IMP) Replacement Project and the costs that are included in this filing.

A. The Integrity Management Pipe Replacement project is being completed in response to the integrity management regulation as detailed in 49 CFR 192, Subpart O – Pipeline Integrity Management. The regulation requires pipeline operators to evaluate covered segments and mitigate risk to the public by assessing the integrity of pipeline segments by direct assessment or lowering the operating stress of the pipeline which will reduce the consequences of an unforeseen event. This capital project addresses the replacement of six pipe sections that were identified as High Consequence Areas (HCA's) and require mitigation within the integrity management program (IMP). The capital cost is approximately $600,000, will be completed October 2011, and such costs have been pro formed into this filing.

V. CONCLUSION

Q. Please summarize Avista's proposal regarding the capital additions to rate base that has been included in the Company's filing.

A. Rates from this proceeding will be effective in the first half of 2011, which closely matches the forecasted test period used by the Company, and includes the forecasted revenues, costs and capital that will be in service during 2011. Including the costs associated with the Company's forecasted 2011 capital investment in retail rates provides a proper "matching" of revenues from customers with the costs associated with providing service to customers, including the cost of utility plant used to serve customers. The plant will be used and useful during the rate year. Without the forecasted capital additions, the Company would not have the opportunity to earn its allowed rate of return on investment during the rate year.

Q. Does this conclude your pre-filed direct testimony?

A. Yes, it does.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF DONALD J. CLAYTON
REPRESENTING AVISTA CORPORATION

Working Capital

I. INTRODUCTION

Q. Please state your name, employer and business address.

A. My name is Donald J. Clayton. My business address is 301 Oxford Valley Road, Suite 1604, Yardley, Pennsylvania, 19067.

Q. Please identify your current position and employer.

A. I am Vice President of Management Consulting at Tangibl, LLC.

Q. How long have you been associated with Tangibl, LLC?

A. I have been associated with Tangibl, LLC since April of 2007.

Q. Please describe Tangibl, LLC.

A. Tangibl, LLC is a professional services firm serving energy, water, wastewater and waste services utilities.

Q. What is your educational background?

A. I have Bachelor of Science and Masters of Business Administration degrees from Rensselaer Polytechnic Institute.

Q. Please summarize your professional experience.

A. Throughout my career I have served public utilities in consulting and executive capacities. Recent assignments include cost of service, cost of capital, depreciation, working capital and rate design studies for electric, natural gas and water utilities and depreciation studies for electric, natural gas, water, wastewater, thermal and railroad companies. My detailed resume is attached to my testimony as Exhibit 602.

Q. Do you hold any professional certifications?

A. Yes. I am a Registered Professional Engineer in Pennsylvania. I am also a Chartered Financial Analyst (CFA) and a Certified Depreciation Professional (CDP).

Q. Have you had any formal training related to utility accounting and ratemaking?

A. Yes. I have completed utility accounting and ratemaking seminars offered by Price Waterhouse and Salomon Brothers. I have also completed five one-week programs offered by Depreciation Programs, Inc. in the areas of actuarial and simulated life analysis, forecasting of life and net salvage, and preparing and managing depreciation studies.

Q. Have you previously testified before the Oregon Public Utility Commission?

A. No.

Q. Have you previously presented expert testimony in rate-related proceedings before other regulatory authorities?

A. Yes. I have testified before state utility regulatory authorities in Alaska, Indiana, Kentucky, Oklahoma, Pennsylvania, Texas, and West Virginia, on matters related to valuation, rate base, stranded costs, cost of service, rate design, cost of capital, working capital and depreciation. I have also testified before the Federal Energy Regulatory Commission (FERC), and presented studies that were accepted by the Surface Transportation Board and the Rural Utilities Service on matters related to depreciation. Please see page 5 of Exhibit 602 for a complete list of my testimony.

Q. What was your assignment in this case?

A. My assignment was to perform a lead/lag study for Avista Utilities in order to determine the revenue and expense lags by category for revenue and operating expenses, then to apply the leads and lags to the jurisdictional operating expenses in order to calculate appropriate daily and annual cash working capital requirements necessary to operate the

Company.

II. BASIS OF THE STUDY

Q. Please explain the basis of your study.

The calculations included in the study were based on a review of the revenue, accounts receivable and operating and maintenance expenses for the test year ended December 31, 2009. Certain pro forma adjustments were applied to the December 31, 2009 operating expenses to reflect pro forma expenses for 2011.

Q. Is it appropriate to use the leads and lags calculated at the total company level and apply them to the jurisdictional operating expenses in order to determine cash working capital requirements?

A. Yes. Avista is a multi-jurisdictional, multi-service utility that employs centralized processing of its billing, accounting and purchasing functions for both its electric and natural gas operations. Hence, the policies, procedures and timing related to revenue and expense lags are consistent from one jurisdiction to another and between electric and natural gas. The differences by jurisdiction are mostly related to the mix of operational expenses and certain tax payments that are specific to one jurisdiction or another. My study takes into account the specific expense levels and tax payments by jurisdiction, so the proper jurisdictional cash working capital requirement is computed.

III. WORKING CAPITAL METHODS

Q. Please describe cash working capital and how it impacts the company's revenue requirement.

A. Cash working capital represents the funds required to enable the Company to operate its business on a daily basis. The need for these funds results from the fact that there is a lag in time between the collection of revenues for services rendered and the necessary outlay of cash by the Company to pay the expenses of providing those services.

Cash working capital represents investor supplied funds that are properly included in the Company's rate base for ratemaking purposes. Application of the overall rate of return to this element of rate base allows the Company to service the capital costs associated with the cash working capital.

In order to determine total working capital requirement, cash working capital is typically added to either the average or ending Materials & Supplies inventory balances for the test period.

Q. What are the primary methods used in regulatory proceedings to determine cash working capital?

A. There are three primary methods used in regulatory proceedings to determine cash working capital: the FERC Formula Method (often referred to as the "FERC" method), the Balance Sheet Method, and the Lead/Lag Study Method. The Lead/Lag Method requires a lead/lag study be performed to determine the cash working capital requirement.

Q. Please describe the balance sheet method for determining cash working capital and its advantages and disadvantages.

A. The Balance Sheet Method, also known as the Investor Supplied Working Capital Method, takes current assets minus current liabilities to determine cash working capital requirement. The general formula is as follows:

Current Assets

+ Prepayments

+ Deferred Charges

- Current Liabilities

<u>- Deferred Credits</u>

= Cash Working Capital Requirements

For ratemaking purposes, this formula is modified to exclude interest-bearing income and expense-related items, regulatory assets, and other items that are handled separately in rate base and cost of capital adjustments to revenue requirements.

The advantages of the Balance Sheet Method are that it is quick and inexpensive and uses actual financial data from the Company in order to compute cash working capital requirement, without the related expense of a lead/lag study.

A disadvantage to this method is that it is based on current assets and current liabilities at a point in time. These values can vary within periods and over time, as a function of the cost of service, customer payments, financing activities, cash management policies, and various other factors. As such, this method is not a good measure of daily working capital requirements.

Additionally, this method can be very difficult to compute accurately for multi-state, multi-jurisdictional utilities, many of whom do not track all current assets and current liabilities on a jurisdictional or utility vs. non-utility basis.

Q. Please describe the FERC formula method for determining cash working capital and its advantages and disadvantages.

A. As its name implies, this approach uses a formula to calculate cash working capital requirements and has been used for many years by various regulatory bodies, including the Federal Energy Regulatory Commission ("FERC"), to calculate a cash working capital allowance.

The FERC Formula Method calculates the allowance for cash working capital by multiplying operating and maintenance expenses by 1/8th. FERC has established as a rule of thumb a 45-day working capital allowance to be included in rate base[1]. Fuel, purchased power and purchased gas are typically excluded from the calculation[2], under the assumption that the utility takes approximately as long to pay for the electricity or natural gas it purchases as its customers do. The FERC will depart from the rule when a fully developed and reliable lead/lag study shows a more appropriate working capital allowance[3].

FERC defends its rule of thumb principally on the basis that it produces reasonable results without expensive studies, prolonged litigation, or consumption of a great deal of the Commission's time.

The disadvantages are that the Formula Method does not provide evidence that the resulting allowance represents investors' supplied capital for a specific utility, nor is it based on a rigorous theoretical or conceptual foundation. It produces an allowance to be included in rate base that is unrelated to the Company’s service, billing or collection experiences, payment policies, or cash management policies.

This method, however, may actually understate cash working capital requirements for utilities that have high purchased gas and purchased power costs as a proportion of total operating and maintenance expenses, if the revenue lag associated with customer payments

[1] Carolina Power & Light Company, Opinion No. 19-A, 17 Fed. Power Serv, 5-141, 5-142 (1979).
[2] The FERC Formula Method excludes fuel, purchased gas and purchased power under a simplifying assumption that payment lag for the purchased gas or power is exactly equal to the revenue lag related to the sale of the purchased gas or power to end customers. The lead/lag method includes fuel, purchased gas and purchased power and takes the actual payment lag and revenue lag into consideration, producing a result that reflects what the Company actually experiences.
[3] Id. At 5-142-143

exceeds the expense lag experienced by the Company for purchased power and purchased gas.

Q. Please describe the lead/lag study method for determining cash working capital and the advantages and disadvantages of that method.

A. A lead/lag study measures the differences between (1) the time services are rendered until the revenues for that service are received, and (2) the time that expenses are incurred until those expenses are paid. The difference between these periods is expressed in terms of days. The number of days so calculated times the average daily operating expenses produces the cash working capital required for operations.

The primary advantage of the lead/lag study methodology is that it produces a more accurate estimate of cash working capital because it is based on the individual utility's actual operating conditions and experience coupled with its billing, collecting and cash disbursement practices.

This method produces a cash working capital that fairly and accurately represents the amount of investor-supplied working capital that is likely to be experienced during the period for which rates will be in effect. Additionally, since the "leads" and "lags" are applied to specific jurisdictional expenses, no jurisdictional allocation issues arise from the use of this method.

The disadvantage is that performing a lead/lag study tends to be much more time consuming and costly than either of the other methods.

Q. In your opinion, what is the best way of determining the appropriate level of cash working capital?

A. The best method of determining cash working capital is the lead/lag study. It is the only method that is based on a detailed analysis of cash working capital requirements, and is more likely to produce consistent and accurate calculations of cash working capital requirements over time. Also, the methodology is well established and accepted by numerous State regulatory authorities and FERC.

IV. CALCULATIONS OF LEAD/LAG DAYS

Q. Please explain how you developed the cash working capital requirement for this case.

A. I have performed what is commonly known as a lead/lag study to determine the Company's cash working capital requirement. I analyzed the Company's meter reading, billing and collection procedures and experience, reviewed payment practices, service dates and payment dates by expense category, and performed an analysis of the accounts payable for the Company's major operating expense components. I then applied the leads and lags to the revenue and expense accounts to determine the daily cash working capital requirement and the overall cash working capital requirements.

Q. Please explain in further detail Exhibit 601, Schedules DJC-001 to DJC-010, which present the results of your lead/lag study.

A. Exhibit 601, Schedule DJC-001, Summary of Lead/Lag Calculations, Oregon-Gas Operations shows the final results of applying the leads and lags developed in the study to the Company's expenses related to natural gas service in Oregon, and the associated cash working capital requirement.

Exhibit 601, Schedule DJC-002, Operating Revenue Lag Days, shows the calculation of total revenue lag days based on the sum of the service, billing and collection lags.

Exhibit 601, Schedule DJC-003, Payroll and Benefits Lag, lists the service periods and payment days related to payroll and benefits and calculates the average lag for each.

Exhibit 601, Schedule DJC-004, Insurance Lag, calculates the average lag for insurance premiums.

Exhibit 601, Schedule DJC-005, Interest Expense Lag, calculates the average lag for interest payments on long term debt.

Exhibit 601, Schedule DJC-006, Tax Lag, calculates the average lag for the federal and state income tax, along with non-payroll state and local taxes.

Exhibit 601, Schedule DJC-007, Service Lag, calculates the average lag between the date service was delivered to the customer and the meter reading date.

Exhibit 601, Schedule DJC-008, Billing Lag, calculates the average lag between the meter reading date and the date the bill was mailed to the customer.

Exhibit 601, Schedule DJC-009, Payables Lag, calculates the average amount of time that the Company's bills are outstanding prior to being paid, using Accounts Payable data.

Exhibit 601, Schedule DJC-010, Collection Lag, calculates the average amount of time that it takes to collect billed revenue, using accounts receivable turnover.

Q. Does the lead/lag study prepared by you include any accruals for future cash expenditures, amortizations of previous costs or claims for bad debt expense?

A. No. By their nature, such costs do not require a daily cash outlay for the Company and have not been included in our analysis.

Q. Please explain how the revenue lag for the company was developed.

A. The revenue lag represents the period of time from when the Company rendered service to its customers to the time it received payment for that service. To determine this lag, one must look at three components. They are the service lag, billing lag, and the collection lag. Revenue lag was calculated separately for operating revenues and other operating revenues.

The service lag for metered customers represents the time from the midpoint of service to the meter read date. Since all of the customers are billed on a monthly basis, the service lag equates to approximately 1/2 of a month. Exhibit 601, Schedule DJC-007 shows the service periods related to every meter reading date during the test year period, and calculates the average number of service days per meter reading period. The Company's average service lag, as shown on Exhibit 601, Schedule DJC-002, was determined to be **15.2** days.

The billing lag represents the time from the meter reading date to the billing date. Exhibit 601, Schedule DJC-008 shows the associated billing date related to every meter reading date during the test year period, and calculates the average billing lag. The Company's average billing lag was determined to be **2.8** days, as shown on Exhibit 601, Schedule DJC-002.

The collection lag represents the time from the billing date to the date that payment is received. To determine this lag the average accounts receivable balance was calculated using a 12 month average of accounts receivable, and divided by the average daily sales to determine the average number of days it takes to turn over the accounts receivable balance. This methodology is used to estimate the number of days that it takes to collect billed revenue. As shown on Exhibit 601, Schedule DJC-010, the average accounts receivable turnover lag was **41.2** days.

The total operating revenue lag is the sum of the service lag, billing lag and collection lag. As shown on Exhibit 601, Schedule DJC-002, the Company has an average operating revenue lag of **59.2** days.

For other operating revenue, the lag was calculated based on a 30 days service period, no billing lag and payment terms of net 30 days. Average lag for this revenue category was calculated as 30 days/2 + 30 days or **45** days. This is consistent with company policy and experience for other operating revenues.

After weighting the operating revenue lag and the other revenue lag, the net average revenue lag is **58.5** days.

Q. Please explain how you determined the leads and lags for operating expenses.

A. The major areas of operating expenses were segregated and are detailed on Exhibit 601, Schedule DJC-001.

There are two types of lags utilized in expense analysis. They are either for materials received or for service rendered. For materials, the lag represents the time from receipt of the material to the time the Company makes payment for the material. When the delivery date was not known the invoice date was used.

Generally, there are two types of services, periodic and continuous. The periodic service would utilize the same lag day methodology as was used for materials. For continuing service, the lag represents the time from the midpoint of service to the time the Company pays for that service.

The following items were broken out and calculated independently in order to accurately analyze and reflect the appropriate lag for each of these items: Payroll and Benefits, Insurance, Interest Expense, and Taxes. Each of these categories was analyzed independently, based on the service periods and historic payment practices of the Company.

The lag for the remaining operating expenses was developed based on analyzing the Company's Accounts Payables, computing the associated leads and lags on an individual item basis and comparing the result with the Company's internal payment practices. In total, over 83,000 items were analyzed. A summary of this analysis is shown in Exhibit 601, Schedule DJC-009. Confidential detailed supporting workpapers have been provided with the Company's filing. Intercompany payables and payments related to the excluded items, such as bank transfers related to bond interest payment, payroll, etc., were excluded from the analysis of payables. The excluded items have been included in supporting confidential workpapers filed with the Company's filing.

Q. Please explain how you calculated the lag days for payroll and benefits.

A. Payroll and benefits represent a continuing service and the Company pays for the service on a periodic basis. For payroll and benefits, the lag represents the time from the midpoint of service period to the time the Company pays its employees. See Exhibit 601, Schedule DJC-003 for the calculations of payroll and benefits lags.

All employees are paid every two weeks with a one week lag. Specifically, payroll is paid on the Friday following the two week service period ending on the prior Friday, unless it is a holiday. In that case, payroll is paid on the first, non-holiday day immediately preceding the holiday.

In order to calculate the total payroll lag, we must take the lag from the mid-point of the service period and add the lag between the end of the service period and the payment date. In this case, the average service lag is 7.0 days (14 days divided by 2) plus seven days to the payment date, for a total average lag of **14.0** days.

Benefits (401k, Federal withholding, Social Security, Medicare, etc.) related to the same service period are paid the first business day following payday. Average service lag is 7.0 days, just as with payroll, but the payment lag is 10 days. The total lag for benefits is equal to 7.0 days service lag plus 10 days payment lag, or **17.0** days.

State income tax withholding payments related to the same service period are paid variously on the first to the third business day following payday. Average service lag is 7.0 days, just as with payroll, but the payment lag is 10 days for payments made on the first business day and 12 days for payments made on the third business day, for an average payment lag of 11 days (10 days plus 12 days divided by 2). The total lag for state income tax withholding lag is equal to 7.0 days service lag plus 11 days payment lag, or **18.0** days.

Q. Please explain how you calculated the lag days for insurance.

A. Insurance premiums are typically required to be prepaid, and thus create a negative expense lag, since the Company must outlay the funds prior to the applicable service period. This results in an increase in the cash working capital requirement, since such prepaid funds will not be available to the Company. See Exhibit 601, Schedule DJC-004 for the Insurance Lag calculation.

The Company's insurance policies cover the annual period of December 31 to December 31 each year, and are paid in advance. Service lag is equal to 365 days divided by 2, or **182.5** days. Since the payments are made in advance, the value is expressed as a negative lag (or lead).

Q. Please explain how you calculated the lag days for interest expense.

A. Interest payments on bonds are made semi-annually, for the interest accrued during the 6 prior month period. Service lag is thus 182.5 days (half a calendar year) divided by 2, or **91.25** days. See Exhibit 601, Schedule DJC-005 for the Interest Expense Lag calculation.

Q. Please explain how you calculated the lag days for federal and state income tax.

A. The lag days for income taxes were calculated based on the lag between the midpoint of service and the payment date, as shown in Exhibit 601, Schedule DJC-006. Federal and State taxes are paid quarterly, at dates prescribed by the IRS. Average service lag for each quarter was calculated. In the event that the payment date was after the end of the quarter, the payment lag days were added to the average service lag in order to calculate the total lag of **41.5** days.

Q. How were the lag days determined for taxes other than income taxes and interest expense?

A. The lag days for taxes other than income taxes and interest expense were calculated based on the lag between the midpoint of service and the payment date, as shown in Exhibit 601, Schedule DJC-006. Each type of tax paid by the Company was listed, including the accrual period, payment period and payment date. Lags were calculated by taking the average service lag and adding the payment lag to it.

Oregon Property Taxes accrue monthly and are paid annually on November 15th of the current year. Average service lag is (320.0 days/2) or 160.0 days. Average payment lag is 0 days. Net lag for this item is 160.0 days + 0 days or **160.0** days.

Municipal / Franchise – Annual Taxes are paid on the 30th of the month following the end of the year. Average service lag is 365/2 or 182.5 days. Payment lag is 30.0 days. Net lag for this item is 182.5 days + 30.0 days or **212.5** days.

Municipal / Franchise – Semi-annual Taxes are paid on the 30th of the month following each semi-annual period. Average service lag is 182.5 days/2 or 91.3 days. Average payment lag is 30 days. Net lag for this item is 91.3 days + 30 days or **121.3** days.

Municipal / Franchise – Quarterly Taxes are paid quarterly on the 15th of the month following the end of the quarter. Average service lag is 90.0 days/2 or 45.0 days. Average payment lag is 15.0 days. Net lag for this item is 45.0 days + 15.0 days or **60.0** days.

Municipal / Franchise – Monthly Taxes are paid monthly on the 30th of the month following the end of the month. Average service lag is 30.0 days/2 or 15.0 days. Average payment lag is 30.0 days. Net lag for this item is 15.0 days + 30.0 days or **45.0** days.

Q. Is it appropriate for the Company to include expenses related to purchased gas and purchased power in its calculation of cash working capital?

A. It is only appropriate to exclude purchased gas and purchased power costs from cash working capital claims if the Company's purchased gas and purchased power adjustments include a recovery mechanism for the lag between the time the company receives and pays for its purchased gas or power, and the date the funds are recovered by the company through payments from customers.

Purchased gas and purchased power adjustment mechanisms usually recover only the cost of the natural gas or power and the time value of money on over/under collections. Such agreements do not normally consider the lag from the date of the expenditure of funds to purchase of natural gas or power by the utility until the date utility is able to recover the revenue through payments from customers. Unless there is a separate cost adjustment in the purchased gas and purchased power adjustment mechanisms to cover these lags, it is appropriate to include these expenses in the calculation of cash working capital.

The Company recovers and/or pays interest on over and under collections in rates, but does not recover for the lag when funds must be expended to purchase gas or power and the related collection of revenue from customers. The funding of these expenses during this period represents investor supplied working capital, therefore, purchased gas and purchased power expenditures should be included in the calculation of the Company's cash working capital claim.

Q. Is it "double counting" when natural gas inventories are included in the Company's rate base, and natural gas expense is included in the lead lag study supporting the calculation of cash working capital?

A. No, there is no double counting. The Company calculates the rate base adjustment for natural gas inventories using an average inventory balance based on the expected injection and withdrawal schedule. Some natural gas is purchased and sold immediately, other natural gas remains in inventory for an extended period of time. This calculation is independent of the cash working capital calculations. The natural gas expense included in the lead-lag study does not reflect the amount of time that purchased gas remains in inventory, but only the difference between when the natural gas was received by the company, and when it was paid for by the Company.

The following simplified example illustrates this point:

The Company obtains a quantity of natural gas on June 1, 2010. The vendor sends the Company an invoice, which the Company pays on June 20, 2010. The expense lead on that item is 19 days, that is, the Company receives the benefit of possessing the natural gas for 19 days before having to pay for it. Regardless of how long the Company holds the natural gas in inventory, only the 19 day expense lead is included in the calculation of cash working capital, so there is no double counting.

V. RESULTS OF THE STUDY

Q. What are the final results of your study?

A. The results of my study can be found on Exhibit 601, Schedule DJC-001, which shows the cash working capital requirement for Avista's natural gas operations in Oregon.

The natural gas operations have a cash working capital requirement of $7,485,894. This is based upon the daily cash requirement calculated using the expenses associated with the Oregon natural gas operations multiplied by the net lag of **34.0** days.

The net lag of 34.0 days was derived by subtracting the expense lead of 24.5 days from the revenue lag of 58.5 days. This represents the number of days on average that the Company must fund operating expenses prior to receiving the corresponding revenue related to those expenses.

The daily cash requirement of $220,165 was determined by dividing the total annual cash requirement of $80,360,036 by 365 days. Total cash requirement is the sum of the operating expenses, insurance, interest, taxes other than income and income taxes from the test year ended December 31, 2009, including material pro forma adjustments to operating expenses for 2011. The daily cash requirement multiplied by the net lag is the total cash working capital requirement.

In order to calculate total working capital adjustment to rate base, the cash working capital requirement for the natural gas operations should be added to the Company's associated materials and supplies inventory balances.

Q. Does this conclude your pre-filed direct testimony?

A. Yes, it does.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DONALD J. CLAYTON
Exhibit No. 601

Working Capital

AVISTA UTILITIES

CALCULATION OF ESTIMATED LEAD/LAG DAYS FOR CASH WORKING CAPITAL
FOR THE TEST YEAR ENDED DECEMBER 31, 2009

Summary of Lead/Lag Calculations
Oregon - Gas Operations

Description (1)		Amount (2)	Lead/Lag Days (3)		Weighted Amount (4)
Revenue Lag					
Operating Revenues			58.5	(1)	
Operating Expense Lag					
Operating Expenses					
O&M Other than Payroll and Insurance	PF	62,265,096	16.7	(2)	1,039,718,072
Payroll	PF	5,843,704	14.0	(3)	81,811,856
Benefits	PF	3,389,348	17.0	(3)	57,618,921
State Payroll Taxes	PF	511,324	18.0	(3)	9,203,834
Insurance		390,298	(182.5)	(4)	(71,229,385)
Interest		4,145,128	91.3	(5)	378,242,930
Taxes Other Than Income					
Property - Oregon		1,755,338	160.0	(6)	280,854,080
Municipal / Franchise Annual		201,414	212.5	(6)	42,800,520
Municipal / Franchise Semi-annual		28,333	121.3	(6)	3,435,417
Municipal / Franchise Quarterly		3,746,401	60.0	(6)	224,784,079
Municipal / Franchise Monthly		285,683	45.0	(6)	12,855,754
Income Taxes		(2,201,983)	41.5	(7)	(91,382,295)
Total Requirements		80,360,086	24.5		1,968,713,784
Revenue Lag Days			58.5		
Requirement Lag Days			24.5		
Net Lag			**34.0**		
Daily Requirements (Total Requirements / 365 days)		220,165			
Net Cash Working Capital Requirements		**7,485,894**			

Notes:
(1) See Schedule DJC-002 for Revenue Lag Calculation
(2) See Schedule DJC-009 for O&M Other than Payroll and Insurance Lag Calculation
(3) See Schedule DJC-003 for Payroll and Benefits Lag Calculation
(4) See Schedule DJC-004 for Insurance Lag Calculation
(5) See Schedule DJC-005 for Interest Lag Calculation
(6) See Schedule DJC-006 for Taxes other than Income Tax Lag Calculation
(7) See Schedule DJC-006 for Income Tax Lag Calculation
(PF) Amounts were updated to reflect Forecasted 2011 expenses per the Company's filed general rate case amounts. All other amounts were based on 2009 historical expense balances (i.e. insurance, taxes, etc.) These amounts were not considered material, nor would they have a material impact on the calculation of the working capital requirement.

AVISTA UTILITIES

CALCULATION OF ESTIMATED LEAD/LAG DAYS FOR CASH WORKING CAPITAL
FOR THE TEST YEAR ENDED DECEMBER 31, 2009

Operating Revenue Lag Days

Desc.	Days	Avg. Lag	
Service Lag: Usage to Meter Reading	30.3	15.2	(1)
Billing Lag: Meter Reading to Billing	2.8	2.8	(2)
Collection Lag: Accounts Receivable Turnover	41.2	41.2	(3)
Total Operating Revenue Lag		**59.2**	

Other Operating Revenue Lag Days

Desc.	Days	Avg. Lag	
Service Lag: Usage to Billing	30.0	15.0	(4)
Collection Lag: Net 30 Days	30.0	30.0	(5)
Total Other Operating Revenue Lag		**45.0**	

Description		Amount	Average Lag Days	Weighted Amount
Operating Revenues	(6)	$ 903,542,878	59.2	$ 53,489,738,378
Total Other Operating Revenues	(6)	$ 47,486,381	45.0	$ 2,136,887,145
Net Revenue Lag Days		$ 951,029,259	**58.5**	$ 55,626,625,523

Notes:
(1) Average Service Days per Meter Reading Cycle / 2. See Service Lag schedule DJC-007
(2) See Billing Lag schedule DJC-008
(3) See Collection Lag schedule DJC-010
(4) Based on a 30 day service period, with bills sent at the end of each service period
(5) Based on an average of 30 days from billing to payment.
(6) Net change in total Company revenues for the historical 2009 versus the forcasted 2011 total company balance is not expected to be material, thus these balances have not been updated.

AVISTA UTILITIES

CALCULATION OF ESTIMATED LEAD/LAG DAYS FOR CASH WORKING CAPITAL
FOR THE TEST YEAR ENDED DECEMBER 31, 2009

<u>Payroll and Benefits Lag</u>

Payroll Lag

All employees are paid every two weeks with a one week lag.
Specifically, payroll is paid on the Friday following the two week service period ending on the prior Friday, unless it is a holiday. In that case, payroll is paid on the first, non-holiday day immediately preceding the holiday.

Average lag days = 14/2 + 7 = **14**

Benefits Lag

Federal withholding, Social Security, Medicare and 401k are paid the first business day following each payday.

Average lag days = 14/2 + 10 = **17**

State income tax withholding payments vary from the first to third business day following each payday.

Average lag days = 14/2 + (10+12)/2 = **18**

AVISTA UTILITIES

**CALCULATION OF ESTIMATED LEAD/LAG DAYS FOR CASH WORKING CAPITAL
FOR THE TEST YEAR ENDED DECEMBER 31, 2009**

Insurance Lag

Policies cover the annual period of December 31 through December 31, and are paid, in full, a few days prior to the start of the coverage period.

Average lag days = (-365 days / 2) = **(182.5)**

AVISTA UTILITIES

CALCULATION OF ESTIMATED LEAD/LAG DAYS FOR CASH WORKING CAPITAL
FOR THE TEST YEAR ENDED DECEMBER 31, 2009

Interest Expense Lag

Interest payments on bonds are made semi-annually.
Average lag days = (365 days / 2 payments) / 2 = **91.25**

AVISTA UTILITIES

CALCULATION OF ESTIMATED LEAD/LAG DAYS FOR CASH WORKING CAPITAL
FOR THE TEST YEAR ENDED DECEMBER 31, 2009

Tax Lag

Taxes Other Than Income		**Return Frequency**	**Accrued**	**Taxes Paid**	**Date Paid**	**Avg Lag**	**Average Lag Days**
Property - Oregon		Annual	Monthly	Annually	11/15 of current year	320/2 =	160
** Municipal / Franchise Annual		Annual	Monthly	Annual	30th of month following end of year	365/2 + 30 =	212.5
** Municipal / Franchise Semi-annual		Semi-annual	Monthly	Semi-annual	30th of month following mid year and year end	182.5/2 + 30 =	121.25
** Municipal / Franchise Quarterly	Oregon	Quarterly	Monthly	Quarterly	15th of month following end of each quarter	90/2 + 15 =	60
** Municipal / Franchise Monthly		Monthly	Monthly	Monthly	30th of following month	30/2 + 30 =	45
***** (Multiple cities in each category)***							

Income Taxes	**Return Frequency**	**Accrued**	**Taxes Paid**	**Date Paid**	**Days**	**Average Lag Days**
Federal & State	Annual	Monthly	Quarterly	15-Apr	106	53
	Annual	Monthly	Quarterly	15-Jun	75	37.5
	Annual	Monthly	Quarterly	15-Sep	76	38
	Annual	Monthly	Quarterly	15-Dec	75	37.5
					Average	**41.5**

AVISTA UTILITIES

CALCULATION OF ESTIMATED LEAD/LAG DAYS FOR CASH WORKING CAPITAL
FOR THE TEST YEAR ENDED DECEMBER 31, 2009

Service Lag (Usage to Meter Reading)
Meter Reading Schedule Jan 2009 - December 2009

READ DAY	Jan	SVC Days	Feb	SVC Days	Mar	SVC Days	Apr	SVC Days	May	SVC Days	Jun	SVC Days	Jul	SVC Days	Aug	SVC Days	Sep	SVC Days	Oct	SVC Days	Nov	SVC Days	Dec	SVC Days
1	Dec-31	30	Jan-30	30	**Mar-2**	31	Mar-31	29	Apr-30	30	**Jun-1**	32	Jun-30	29	Jul-30	30	Aug-28	29	Sep-29	32	Oct-28	29	Nov-30	33
2	**Jan-2**	31	**Feb-2**	31	Mar-3	29	**Apr-1**	29	**May-1**	30	Jun-2	32	**Jul-1**	29	Jul-31	30	Aug-31	31	Sep-30	30	Oct-29	29	**Dec-1**	33
3	Jan-5	33	Feb-3	29	Mar-4	29	Apr-2	29	May-4	32	Jun-3	30	Jul-2	29	**Aug-3**	32	**Sep-1**	29	**Oct-1**	30	Oct-30	29	Dec-2	33
4	Jan-6	33	Feb-4	29	Mar-5	29	Apr-3	29	May-5	32	Jun-4	30	Jul-6	32	Aug-4	29	Sep-2	29	Oct-2	30	**Nov-2**	31	Dec-3	31
5	Jan-7	33	Feb-5	29	Mar-6	29	Apr-6	31	May-6	30	Jun-5	30	Jul-7	32	Aug-5	29	Sep-3	29	Oct-5	32	Nov-3	29	Dec-4	31
6	Jan-8	31	Feb-6	29	Mar-9	31	Apr-7	29	May-7	30	Jun-8	32	Jul-8	30	Aug-6	29	Sep-4	29	Oct-6	32	Nov-4	29	Dec-7	33
7	Jan-9	31	Feb-9	31	Mar-10	29	Apr-8	29	May-8	30	Jun-9	32	Jul-9	30	Aug-7	29	Sep-8	32	Oct-7	29	Nov-5	29	Dec-8	33
8	Jan-12	33	Feb-10	29	Mar-11	29	Apr-9	29	May-11	32	Jun-10	30	Jul-10	30	Aug-10	31	Sep-9	30	Oct-8	29	Nov-6	29	Dec-9	33
9	Jan-13	33	Feb-11	29	Mar-12	29	Apr-10	29	May-12	32	Jun-11	30	Jul-13	32	Aug-11	29	Sep-10	30	Oct-9	29	Nov-9	31	Dec-10	31
10	Jan-14	33	Feb-12	29	Mar-13	29	Apr-13	31	May-13	30	Jun-12	30	Jul-14	32	Aug-12	29	Sep-11	30	Oct-12	31	Nov-10	29	Dec-11	31
11	Jan-15	31	Feb-13	29	Mar-16	31	Apr-14	29	May-14	30	Jun-15	32	Jul-15	30	Aug-13	29	Sep-14	32	Oct-13	29	Nov-11	29	Dec-14	33
12	Jan-16	31	Feb-16	31	Mar-17	29	Apr-15	29	May-15	30	Jun-16	32	Jul-16	30	Aug-14	29	Sep-15	32	Oct-14	29	Nov-12	29	Dec-15	33
13	Jan-19	33	Feb-17	29	Mar-18	29	Apr-16	29	May-18	32	Jun-17	30	Jul-17	30	Aug-17	31	Sep-16	30	Oct-15	29	Nov-13	29	Dec-16	33
14	Jan-20	33	Feb-18	29	Mar-19	29	Apr-20	32	May-19	29	Jun-18	30	Jul-20	32	Aug-18	29	Sep-17	30	Oct-16	29	Nov-16	31	Dec-17	31
15	Jan-21	33	Feb-19	29	Mar-20	29	Apr-21	32	May-20	29	Jun-19	30	Jul-21	32	Aug-19	29	Sep-18	30	Oct-19	31	Nov-17	29	Dec-18	31
16	Jan-22	31	Feb-20	29	Mar-23	31	Apr-22	30	May-21	29	Jun-22	32	Jul-22	30	Aug-20	29	Sep-21	32	Oct-20	29	Nov-18	29	Dec-21	33
17	Jan-23	31	Feb-23	31	Mar-24	29	Apr-23	30	May-22	29	Jun-23	32	Jul-23	30	Aug-21	29	Sep-22	32	Oct-21	29	Nov-19	29	Dec-22	33
18	Jan-26	33	Feb-24	29	Mar-25	29	Apr-24	30	May-26	32	Jun-24	29	Jul-24	30	Aug-24	31	Sep-23	30	Oct-22	29	Nov-20	29	Dec-23	33
19	Jan-27	32	Feb-25	29	Mar-26	29	Apr-27	32	May-27	30	Jun-25	29	Jul-27	32	Aug-25	29	Sep-24	30	Oct-23	29	Nov-23	31	Dec-24	31
20	Jan-28	30	Feb-26	29	Mar-27	29	Apr-28	32	May-28	30	Jun-26	29	Jul-28	32	Aug-26	29	Sep-25	30	Oct-26	31	Nov-24	29	Dec-28	34
21	Jan-29	30	Feb-27	29	Mar-30	31	Apr-29	30	May-29	30	Jun-29	31	Jul-29	30	Aug-27	29	Sep-28	32	Oct-27	29	Nov-25	29	Dec-29	34

Total Meter Reading Cycles **252**
Average Service Days per Meter Reading Cycle **30.33**

AVISTA UTILITIES

CALCULATION OF ESTIMATED LEAD/LAG DAYS FOR CASH WORKING CAPITAL
FOR THE TEST YEAR ENDED DECEMBER 31, 2009

Billing Lag (Meter Reading to Billing)
Customer Bill Date Schedule Jan 2009 - December 2009

READ DAY	Jan		Feb		Mar		Apr		May		Jun		Jul		Aug		Sep		Oct		Nov		Dec	Lag
1	**Jan- 4**	4	Feb-3	4	Mar - 4	2	Apr - 2	2	May- 4	4	Jun - 3	2	Jul- 2	2	**Aug-3**	4	**Sep-1**	4	**Oct-1**	2	Oct-30	2	Dec-2	2
2	Jan - 5	3	Feb - 4	2	Mar - 5	2	Apr - 3	2	May - 5	4	Jun - 4	2	Jul - 6	5	Aug- 4	4	Sep- 2	2	Oct- 2	2	**Nov-2**	4	Dec - 3	2
3	Jan - 6	1	Feb - 5	2	Mar - 6	2	Apr - 6	4	May - 6	2	Jun - 5	2	Jul - 7	5	Aug - 5	2	Sep - 3	2	Oct - 5	4	Nov- 3	4	Dec - 4	2
4	Jan - 7	1	Feb - 6	2	Mar - 9	4	Apr - 7	4	May - 7	2	Jun - 8	4	Jul - 8	2	Aug - 6	2	Sep - 4	2	Oct - 6	4	Nov - 4	2	Dec - 7	4
5	Jan - 8	1	Feb - 9	4	Mar-10	4	Apr-8	2	May - 8	2	Jun - 9	4	Jul - 9	2	Aug - 7	2	Sep - 8	5	Oct - 7	2	Nov - 5	2	Dec - 8	4
6	Jan-11	3	Feb-10	4	Mar-11	2	Apr-9	2	May - 11	4	Jun - 10	2	Jul-10	2	Aug - 10	4	Sep - 9	5	Oct - 8	2	Nov - 6	2	Dec - 9	2
7	Jan-12	3	Feb-11	2	Mar-12	2	Apr-10	2	May-12	4	Jun-11	2	Jul-13	4	Aug-11	4	Sep - 10	2	Oct - 9	2	Nov - 9	4	Dec-10	2
8	Jan-13	1	Feb-12	2	Mar-13	2	Apr-13	4	May-13	2	Jun-12	2	Jul-14	4	Aug-12	2	Sep-11	2	Oct - 12	4	Nov - 10	4	Dec-11	2
9	Jan-14	1	Feb-13	2	Mar-16	4	Apr-14	4	May-14	2	Jun-15	4	Jul-15	2	Aug-13	2	Sep-14	4	Oct-13	4	Nov-11	2	Dec-14	4
10	Jan-15	1	Feb-16	4	Mar-17	4	Apr-15	2	May-15	2	Jun-16	4	Jul-16	2	Aug-14	2	Sep-15	4	Oct-14	2	Nov-12	2	Dec-15	4
11	Jan-18	3	Feb-17	4	Mar-18	2	Apr-16	2	May-18	4	Jun-17	2	Jul-17	2	Aug-17	4	Sep-16	2	Oct-15	2	Nov-13	2	Dec-16	2
12	Jan-19	3	Feb-18	2	Mar-19	2	Apr-20	5	May-19	4	Jun-18	2	Jul-20	4	Aug-18	4	Sep-17	2	Oct-16	2	Nov-16	4	Dec-17	2
13	Jan-20	1	Feb-19	2	Mar-20	2	Apr-21	5	May-20	2	Jun-19	2	Jul-21	4	Aug-19	2	Sep-18	2	Oct-19	4	Nov-17	4	Dec-18	2
14	Jan-21	1	Feb-20	2	Mar-23	4	Apr-22	2	May-21	2	Jun-22	4	Jul-22	2	Aug-20	2	Sep-21	4	Oct-20	4	Nov-18	2	Dec-21	4
15	Jan-22	1	Feb-23	4	Mar-24	4	Apr-23	2	May-22	2	Jun-23	4	Jul-23	2	Aug-21	2	Sep-22	4	Oct-21	2	Nov-19	2	Dec-22	4
16	Jan-25	3	Feb-24	4	Mar-25	2	Apr-24	2	May-26	5	Jun-24	2	Jul-24	2	Aug-24	4	Sep-23	2	Oct-22	2	Nov-20	2	Dec-23	2
17	Jan-26	3	Feb-25	2	Mar-26	2	Apr-27	4	May-27	5	Jun-25	2	Jul-27	4	Aug-25	4	Sep-24	2	Oct-23	2	Nov-23	4	Dec-24	2
18	Jan-27	1	Feb-26	2	Mar-27	2	Apr-28	4	May-28	2	Jun-26	2	Jul-28	4	Aug-26	2	Sep-25	2	Oct-26	4	Nov-24	4	Dec-28	5
19	Jan-28	1	Feb-27	2	Mar-30	4	Apr-29	2	May-29	2	Jun-29	4	Jul-29	2	Aug-27	2	Sep-28	4	Oct-27	4	Nov-25	2	Dec-29	5
20	Jan-29	1	**Mar-2**	4	Mar-31	4	Apr-30	2	**Jun-1**	4	Jun-30	4	Jul-30	2	Aug-28	2	Sep-29	4	Oct-28	2	Nov-30	6	Dec-30	2
21	**Feb-1**	3	Mar - 3	4	**Apr- 1**	2	**May-1**	2	Jun- 2	4	**Jul-1**	2	Jul-31	2	Aug-31	4	Sep-30	2	Oct-29	2	**Dec- 1**	8	Dec-31	2

Total Billing Cycles	**252**
Average Service Days per Meter Reading Cycle	**2.80**

AVISTA UTILITIES

CALCULATION OF ESTIMATED LEAD/LAG DAYS FOR CASH WORKING CAPITAL
FOR THE TEST YEAR ENDED DECEMBER 31, 2009

Accounts Payable Lag
Accounts Payable Jan 2009 - Dec 2009

For the detail related to the Accounts Payable Lag calculation, please see Confidential Clayton Workpapers provided with the Company's filing.

	Distributed Amount	Weighted Amount
Totals	**980,653,765.59**	**16,375,200,673.48**
Average Lag Days	**16.70**	

AVISTA UTILITIES

CALCULATION OF ESTIMATED LEAD/LAG DAYS FOR CASH WORKING CAPITAL
FOR THE TEST YEAR ENDED DECEMBER 31, 2009

Collection Lag (Accounts Receivable Turnover)
Jan 2009 - Dec 2009

Average Accounts Receivable

January (1)	February (2)	March (3)	April (4)	May (5)	June (6)	July (7)	August (8)	September (9)	October (10)	November (11)	December (12)
220,665,212	211,075,814	204,456,560	171,034,814	138,029,086	113,993,285	128,608,755	125,154,495	125,136,265	119,329,342	144,460,597	186,054,433

Average Accounts Receivable **157,333,221.43**

Total Sales

Electric Operating Revenues (000's)

Category	2009
Residential	315,649
Commercial	273,954
Industrial	107,741
Public street and highway lighting	6,607
Total Retail	703,951
Wholesale	88,414
Sales of Fuel	32,992
Other	15,426
Total	840,783

Natural Gas Operating Revenues (000's)

Category	2009
Residential	251,022
Commercial	135,236
Interruptible	4,709
Industrial	5,236
Total Retail	396,203
Wholesale	143,524
Transportation	6,067
Other	8,624
Total	554,418

Total Sales **1,395,201,000**

Account Receivable Turnover

(Average Account Receivable / (Total Sales / 365))

Lag Days **41.16**

AVISTA UTILITIES

CALCULATION OF ESTIMATED LEAD/LAG DAYS FOR CASH WORKING CAPITAL
FOR THE TEST YEAR ENDED DECEMBER 31, 2009

Summary of Lead/Lag Calculations
Oregon - Gas Operations

Description (1)		Amount (2)	Lead/Lag Days (3)		Weighted Amount (4)
Revenue Lag					
Operating Revenues			58.5	(1)	
Operating Expense Lag					
Operating Expenses					
O&M Other than Payroll and Insurance	PF	62,265,096	16.7	(2)	1,039,718,072
Payroll	PF	5,843,704	14.0	(3)	81,811,856
Benefits	PF	3,389,348	17.0	(3)	57,618,921
State Payroll Taxes	PF	511,324	18.0	(3)	9,203,834
Insurance		390,298	(182.5)	(4)	(71,229,385)
Interest		4,145,128	91.3	(5)	378,242,930
Taxes Other Than Income					
Property - Oregon		1,755,338	160.0	(6)	280,854,080
Municipal / Franchise Annual		201,414	212.5	(6)	42,800,520
Municipal / Franchise Semi-annual		28,333	121.3	(6)	3,435,417
Municipal / Franchise Quarterly		3,746,401	60.0	(6)	224,784,079
Municipal / Franchise Monthly		285,683	45.0	(6)	12,855,754
Income Taxes		(2,201,983)	41.5	(7)	(91,382,295)
Total Requirements		80,360,086	24.5		1,968,713,784
Revenue Lag Days			58.5		
Requirement Lag Days			24.5		
Net Lag			**34.0**		
Daily Requirements (Total Requirements / 365 days)		220,165			
Net Cash Working Capital Requirements		**7,485,894**			

Notes:
(1) See Schedule DJC-002 for Revenue Lag Calculation
(2) See Schedule DJC-009 for O&M Other than Payroll and Insurance Lag Calculation
(3) See Schedule DJC-003 for Payroll and Benefits Lag Calculation
(4) See Schedule DJC-004 for Insurance Lag Calculation
(5) See Schedule DJC-005 for Interest Lag Calculation
(6) See Schedule DJC-006 for Taxes other than Income Tax Lag Calculation
(7) See Schedule DJC-006 for Income Tax Lag Calculation
(PF) Amounts were updated to reflect Forecasted 2011 expenses per the Company's filed general rate case amounts. All other amounts were based on 2009 historical expense balances (i.e. insurance, taxes, etc.) These amounts were not considered material, nor would they have a material impact on the calculation of the working capital requirement.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DONALD J. CLAYTON
Exhibit No. 601

Working Capital

Tangibl LLC
301 Oxford Valley Rd / Suite 1604 / Yardley, Pennsylvania 19067-7706
TEL 215.369.9345 / FAX 215.369.9344 / www.tangibl.com

DONALD J. CLAYTON / *Vice President*

Mr. Clayton has over 30 years' experience in the energy utility industry and management consulting profession. His experience includes financial and treasury management, including his role as Vice President and Treasurer at DQE, at that time the parent company of Duquesne Light Company. Mr. Clayton also has extensive experience in new venture creation, as President of the AquaSource venture at DQE and President and Chief Operating Officer of Conjunction LLC in New York State. In his management consulting roles, Mr. Clayton's technical specialties include public utility valuation, depreciation, plant, rate base, cost of service and rate design as well as economic analysis and financial modeling.

Mr. Clayton holds a Bachelors of Science in Civil Engineering and a Master of Business Administration from Rensselaer Polytechnic Institute. He is a registered Professional Engineer in the Commonwealth of Pennsylvania, a Chartered Financial Analyst, as well as a Certified Depreciation Professional.

Professional Experience

2007 – PRESENT .... TANGIBL, LLC
VICE PRESIDENT – MANAGEMENT CONSULTING

As Vice President of Management Consulting at Tangibl, LLC, Mr. Clayton is responsible for a wide range of assignments including depreciation studies for electric, gas, water, wastewater, thermal and railroad companies and rate case preparation and management, including cost of service, cost of capital, working capital and rate design studies for electric, gas, water and wastewater utilities.

Current and recent assignments include:

- *American Electric Power, Columbus, Ohio* – Depreciation Study of Transmission Plant. Recommended annual depreciation accrual rates and prepared direct testimony for FERC filings related to the PATH, Prairie Wind, Tall Grass and Pioneer transmission projects. Also, prepared testimony related to net salvage and depreciation for Public Service of Oklahoma.

- *Allegheny Energy, Inc., Greensburg, Pennsylvania* – Depreciation Study for the Black Oak SVC. The study involved establishing initial depreciation rates for this new facility near Cumberland, Maryland. The study was prepared to support the cost of service for FERC ratemaking purposes.

- *East Resources, Inc., Pittsburgh, Pennsylvania* – Natural Gas Base Rate Case. The assignment was to prepare a complete base rate case filing for a test year ended June 30, 2007 for East Resources natural gas utility.

- *Megan Oil & Gas Company Inc., Spencer, West Virginia* – Natural Gas Base Rate Case. Complete base rate case preparation for a test year ended June 30, 2009 Megan's natural gas utility. Depreciation study for natural gas plant.

- *National Passenger Railroad Corporation (Amtrak), Philadelphia, Pennsylvania* – The assignments for Amtrak involved consulting on units of property, updating depreciation calculations for the 2007 and 2008 fiscal years, projecting retirements and preparing a complete depreciation study using data through September 30, 2008. The depreciation study is currently underway and involves updating service life and net salvage estimates and making depreciation calculations for all of Amtrak's road and equipment property.

- *Ni America, Houston, Texas* – Various valuation and rate consulting services, including rate case preparation, related to small water and wastewater companies in Texas, Florida, Mississippi and South Carolina.

- *West Virginia Utility Company, Charleston, West Virginia* – Electric Base Rate Case and Merger filing. Complete base rate case preparation, including all minimum filing requirements, revenue requirements, cost of capital, cost of service, working capital and Rule 42 exhibits supporting a rate increase and merger of three subsidiary electric utilities.

2005 – 2007 .... GANNETT FLEMING, INC.
DIRECTOR, REGULATORY ECONOMICS

Representative assignments include d:

- *Allegheny Energy, Inc., Greensburg, Pennsylvania* – Depreciation Studies of Regulated Electric Companies in West Virginia and Unregulated Generation Plant. The studies included development of annual depreciation rates for regulated electric plant in service in West Virginia and the unregulated generating plant throughout the system. Elements of the study included a field inspection of power plants, major substations, operations centers and office buildings; discussions with management regarding outlook; statistical analyses of service life and net salvage, and calculation of annual and accrued depreciation using several alternative bases and procedures. The depreciation study for the regulated West Virginia Utilities was filed with the West Virginia Public Service Commission in September 2006.

- *Citizens Gas and Coke Utility, Indianapolis, Indiana* – Depreciation Studies of Gas and Thermal Plant. The studies involved development of annual depreciation rates for gas and thermal plant. Field inspections of the facilities were performed, discussions with management regarding outlook were held, statistical analyses of service life and salvage data were conducted and annual and accrued depreciation were calculated.

- *East Kentucky Power Cooperative, Winchester, Kentucky* – Depreciation Studies of Electric Plant. The study involved development of annual depreciation rates for the company's electric plant including generation, transmission and general plant. The study included a field inspection of power plants, major substations, operations centers and office buildings; discussions with management regarding outlook; statistical analyses of service life and net salvage, and calculation of annual and accrued depreciation. The depreciation study filed with the Kentucky Public Service Commission in May of 2006 and the Rural Utilities Service in June of 2006.

- *Anchorage Water and Wastewater Utility (AWWU), Anchorage, Alaska* – Testimony on Contributed Plant and Depreciation Studies for Water and Wastewater Plant. The first assignment included rebuttal testimony on behalf of the company related to its accounting treatment of contributed plant. The depreciation studies included field inspections of the treatment plants, major pumping stations, and offices; discussions with management regarding outlook; data assembly; statistical analysis of service life and net salvage; and calculation of annual and accrued depreciation related to pant in service as of December 31, 2005.

- *Kansas City Southern Railroad (KCS), Kansas City, Missouri* – Capitalization Policy and Depreciation Studies for Kansas City Southern, Kansas City Southern de Mexico, and Texas Mexican Railway. The first assignment involved development of a revised capitalization policy. The Company's existing capitalization policy and retirement units catalogue were compared with those of other class I and passenger railroad companies and revisions were suggested and subsequently adopted by the company. The depreciation studies involved discussions with management regarding outlook, statistical aging of the subsidiary company property, service life and net salvage analysis and calculating of annual and accrued depreciation.

- *East Resources, Inc., Pittsburgh, Pennsylvania* – Base Rate Case Filing. The assignment involved preparation of a complete base rate case filing for the Company's West Virginia gas utility division. Exhibits were prepared in conformance with the West Virginia Commission's filing requirements under Rule 42. Direct testimony was prepared and responses to numerous data requests were completed. The case was filed in April 2006 and was settled in September 2006.

2002 – 2005 ....CONJUNCTION, LLC
PRESIDENT AND CHIEF OPERATING OFFICER

Conjunction LLC was formed to develop a high voltage direct current transmission line from upstate New York to New York City.

- Responsible for day-to-day activities of the firm, raising equity capital to fund the project and negotiation of numerous contracts and agreements between the Company and its consultants, lawyers, landowners and investors.
- Responsible for preparation of the Company's transmission siting filing under Article VII before the New York Public Service Commission and the FERC filing for merchant transmission line status.

2000 – 2002 .... ENERGY LEADER CONSULTING, LLC
PARTNER

Energy Leader Consulting provided strategic consulting to energy companies concerning opportunities related to electric generating stations.

- Performed acquisition analysis for generating stations, identification of power plant development opportunities throughout the U.S. market and diagnostic studies for electric generators.
- Led multi-million dollar study for Amtrak to determine the feasibility of using their railroad rights-of-way for electric transmission.

1985 – 2000 ....DQE
VICE PRESIDENT AND TREASURER
PRESIDENT – AQUASOURCE
MANAGER – VALUATION AND PROPERTY RECORDS DEPARTMENT

- Mr. Clayton developed and directed the AquaSource subsidiary where he managed all aspects of a rapidly-growing business, including development of the initial business plan, integration of acquisition targets, recruitment of executive staff, and political and regulatory relations. He also headed the rate case filed in Texas for a statewide tariff related to the small water and wastewater companies acquired by AquaSource.

- As Vice President and Treasurer, Mr. Clayton was responsible for corporate finance, financial planning, corporate budgeting, cash management and investor and shareholder relations during a period of unprecedented organizational and marketplace changes. While he was Vice President and Treasurer, he was the stranded cost witness for Duquesne Light Company in their restructuring proceeding before the Pennsylvania Public Utility Commission.

- Mr. Clayton's first position with DQE was as Manager of the Valuation and Property Records (Fixed Assets) department, where he was responsible for the Company's $5+ billion of fixed assets and the construction cost accounting system, at a time when two nuclear electrical generation plants were being built and added to rate base. While in this position, he was the company's rate base and depreciation witness in its two largest rate cases.

1980 – 1985 .... PRICE WATERHOUSE
MANAGER, PUBLIC UTILITY INDUSTRY SPECIALTY GROUP

- Performed numerous cost-of-service, rate design, depreciation and other valuation and rate related assignments for electric, gas, water and sewer clients in the public and private sectors.
- Developed a PC-based cost of service program and completed a program for evaluating street lighting.

1977 – 1980 ....GANNETT FLEMING, INC.

- Performed numerous studies in the areas of depreciation and cost of service for electric, gas, telephone, water, wastewater and railroad companies.
- Presented expert testimony before the Pennsylvania Public Utility Commission, the Alaska Public Utilities Commission and Monmouth County Court in New Jersey.
- Completed assignments for more than 50 companies, including electric, gas, water, and telephone and railroad clients.
- Participated in the valuation related to the $2.1 Billion conveyance of the former Penn Central Railroad to Conrail and provided the analytics for three successful tax cases involving more than $300 million in tax depreciation for the Union Pacific, the Burlington Northern and the Chesapeake & Ohio Railroads.

Continuing Education

- All programs offered by Depreciation Programs, Inc.
- Management training courses offered by the Edison Electric Institute.
- Utility accounting seminars offered by Salomon Brothers.

Professional Societies

Mr. Clayton is an active member of the Society of Depreciation Professional where he is an instructor at their annul depreciation training sessions. He has taught the basic life analysis course and the advanced course on preparing and defending a depreciation study. He is also a member of the Society of Utility and Regulatory Financial Analysts.

AVISTA UTILITIES

Testimonial History of Donald J. Clayton

Regulatory Cases

State	Agency	Docket Number	Company	Utility Type	Primary Issue
AK	RCA	U-04-22	Anchorage Water and Wastewater Utility	Water/Wastewater	Contributed water/wastewater plant and depreciation
AK	RCA	U-04-23	Anchorage Water and Wastewater Utility	Water/Wastewater	Contributed water/wastewater plant and depreciation
IN	IURC	Cause No. 43201	Citizens Thermal	Steam, Thermal	Depreciation
IN	IURC	Cause No. 43463	Citizens Gas & Coke Utility	Gas	Depreciation
IN	IURC	Cause No. 43624	Citizens Gas of Westfield	Gas	Depreciation
KY	KYPSC	2006-00236	East Kentucky Power Cooperative	Electric	Depreciation
N/A	FERC	ER-07-562-004	Trans-Allegheny Interstate Line Company (Allegheny)	Electric	Depreciation and Net Salvage for Static Var Compensator
N/A	FERC	ER-08-386-000	Potomac-Appalachian Transmission Highline, LLC (AEP/Allegheny Energy)	Electric	Depreciation and Net Salvage of Transmission Plant
N/A	FERC	ER-09-35-000	Tallgrass Transmission, LLC (AEP/MidAmerican/OGE)	Electric	Depreciation and Net Salvage of Transmission Plant
N/A	FERC	ER-09-36-000	Prairie Wind Transmission, LLC (AEP/MidAmerican/Westar)	Electric	Depreciation and Net Salvage of Transmission Plant
N/A	FERC	ER-09-75-000	Pioneer Transmission, LLC (AEP/Duke Energy)	Electric	Depreciation and Net Salvage of Transmission Plant
OK	OCC	Cause Nos. PUD 200800144	Public Service Company of Oklahoma (AEP)	Electric	Net salvage
PA	PAPUC	R-860378	Duquesne Light Company	Electric	Rate base and depreciation
PA	PAPUC	R-870651	Duquesne Light Company	Electric	Rate base and depreciation
PA	PAPUC	R-00974041	Duquesne Light Company	Electric	Stranded cost and electric industry restructuring
TX	TCEQ	(SOAH) 582-09-4290	Country Vista	Water	Revenue requirements, cost of service, cost of capital, rate design
TX	TCEQ	(SOAH) 582-08-0702	Shaded Lane	Water	Revenue requirements, cost of service, cost of capital, rate design
WV	WVPSC	06-0445-G-42T	East Resources	Gas	Rate base, cost of service, cost of capital, working capital and revenue requirements
WV	WVPSC	08-0275-G-42T	East Resources	Gas	Rate base, cost of service, cost of capital, working capital and revenue requirements
WV	WVPSC	09-2069-G-42T	Megan Oil & Gas Company	Gas	Rate base, cost of service, cost of capital, working capital and revenue requirements
WV	WVPSC	05-0420-E-CN	Monongahela Power Company and The Potomac Edison Company (Allegheny Energy)	Electric	Depreciation, cost of removal, net salvage

Other Cases

State	Agency	Docket Number	Company	Utility Type	Primary Issue
NJ	N/A	N/A	International Flavors and Fragrances	Wastewater	Cost of service, rate design
N/A	RUS	N/A	East Kentucky Power Co-op	Electric	Depreciation
N/A	STB	N/A	Kansas City Southern Railroad	Railroad	Depreciation

Case Support (No testimony filed)

State	Agency	Docket Number	Company	Utility Type	Primary Issue
FL	FLPSC	090182	Ni Florida (Hudson)	Wastewater	Complete rate case preparation
ID	IDPUC	AVU-E-10-01	Avista Corporation		Cash working capital study
ID	IDPUC	AVU-G-10-01	Avista Corporation		Cash working capital study
WA	WUTC	UE-100467	Avista Corporation		Cash working capital study
WA	WUTC	UG-100468	Avista Corporation		Cash working capital study
WV	WVPSC	08-2030-E-PC	Black Diamond Power Company, Elk Power Company, Union Power Company, West Virginia Utility Company	Electric	Merger justification and support
WV	WVPSC	09-1985-E-42T	Black Diamond Power Company	Electric	Complete Rule 42 Exhibit preparation, including rate base, cost of service, cost of capital, working capital and revenue requirements
WV	WVPSC	09-1986-E-42T	Elk Power Company	Electric	Complete Rule 42 Exhibit preparation, including rate base, cost of service, cost of capital, working capital and revenue requirements
WV	WVPSC	09-1987-E-42T	Union Power Company	Electric	Complete Rule 42 Exhibit preparation, including rate base, cost of service, cost of capital, working capital and revenue requirements
WV	WVPSC	10-0757-G-PC	Megan Oil & Gas Company	Gas	Rate base and depreciation

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF ELIZABETH M. ANDREWS
REPRESENTING AVISTA CORPORATION

Revenue Requirement and Allocations

I. INTRODUCTION

Q. Please state your name, business address, and present position with Avista Corp.

A. My name is Elizabeth M. Andrews. I am employed by Avista Corporation as Manager of Revenue Requirements in the State and Federal Regulation Department. My business address is 1411 East Mission, Spokane, Washington.

Q. Would you please describe your education and business experience?

A. I am a 1990 graduate of Eastern Washington University with a Bachelor of Arts Degree in Business Administration, majoring in Accounting. That same year, I passed the November Certified Public Accountant exam, earning my CPA License in August 1991[1]. I worked for Lemaster & Daniels, CPAs from 1990 to 1993, before joining the Company in August 1993. I served in various positions within the sections of the Finance Department, including General Ledger Accountant and Systems Support Analyst until 2000. In 2000, I was hired into the State and Federal Regulation Department as a Regulatory Analyst until my promotion to Manager of Revenue Requirements in early 2007. I have also attended several utility accounting, ratemaking and leadership courses.

Q. As the Manager of Revenue Requirements, what are your responsibilities?

A. As Manager of Revenue Requirements, aside from special projects, I am responsible for the preparation of normalized revenue requirement, pro forma studies, and forecasted studies for the various jurisdictions in which the Company provides utility services. During the last ten years I have assisted or led the Company's electric and/or natural gas

[1] Currently I keep a CPA-Inactive status with regard to my CPA license.

general rate filings in Washington, Idaho and Oregon.

Q. What is the scope of your testimony in this proceeding?

A. My testimony and exhibits in this proceeding will generally cover accounting and financial data in support of the Company's need for the proposed increase in rates. I will explain forecasted operating results including expense and rate base adjustments made to actual operating results and rate base.

The forecasted net operating income and rate base that serve as the basis for the overall revenue requirement in this filing incorporate not only those adjustments prepared by myself, but also by Company witnesses Mr. DeFelice, Mr. Ehrbar and Mr. Clayton. I will cover the revenue adjustment briefly, while Mr. Ehrbar provides a more in-depth discussion. I will provide a summary of the Company's forecasted 2010 and 2011 capital additions, while Mr. DeFelice will present more detail in his testimony. In addition, I also incorporate the working capital adjustment in my calculation of the Company's revenue requirement and exhibits, however, Mr. Clayton discusses the details of this adjustment within his direct testimony. Finally, I will provide an overview of the Company's system and jurisdictional allocation methodologies that have been in place for several years.

Q. Are you sponsoring any exhibits to be introduced in this proceeding?

A. Yes. I am sponsoring Exhibit No. 701, which was prepared under my direction. Exhibit 701 consists of worksheets, which show historical actual 2009 operating results, forecasted results for 2011, proposed natural gas operating results and rate base for the Company's Oregon jurisdiction, the Company's calculation of the general revenue requirement, the derivation of the net operating income to gross revenue conversion factor, and the forecasted adjustments proposed in this filing.

II. REVENUE REQUIREMENT AND RATE REQUEST PROPOSAL

Q. Would you please summarize the results of the Company's forecasted study for its natural gas operating system for the Oregon jurisdiction?

A. Yes. After taking into account all standard earnings test adjustments, as well as additional forecast adjustments, the forecasted natural gas rate of return ("ROR") for the Company's Oregon jurisdictional operations is 6.47%, as shown on Exhibit No. 701, page 1. This return level is below the Company's requested rate of return of 8.61%. The incremental revenue requirement for base retail rates, necessary to give the Company an opportunity to earn its requested ROR is $5,446,000. The overall base natural gas revenue increase associated with the Company's request is 5.6%.

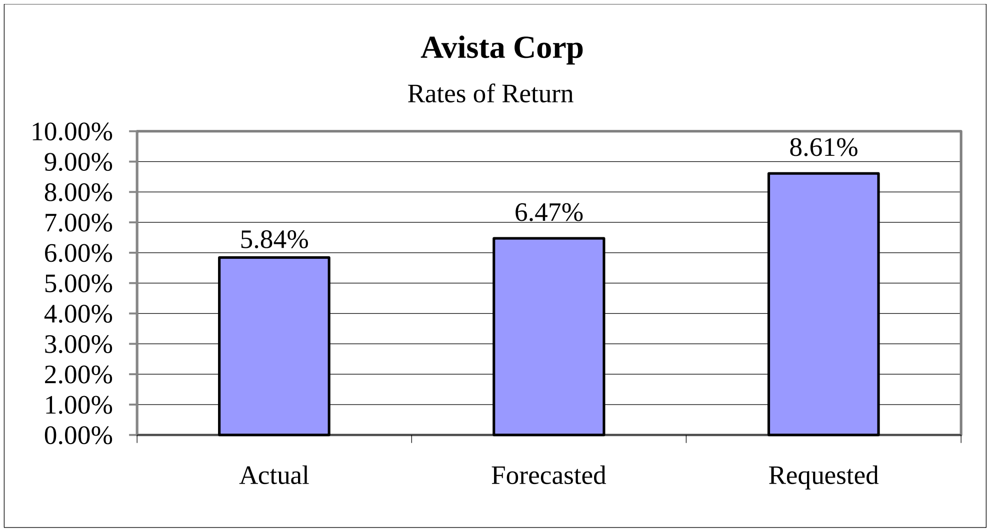
Q. What was the Company's rate of return that was last authorized by this Commission for its natural gas operations in Oregon?

A. The Company's currently authorized rate of return for its Oregon operations is 8.19%, effective November 1, 2009.

Q. By way of summary, could you please explain the different rates of return that you will be presenting in your testimony?

A. Yes. As shown in Illustration No.1 below, there are three different rates of return that will be discussed. The actual ROR earned by the Company during the twelve months ended December 31, 2009, the forecasted ROR determined in my Exhibit No. 701, page 1, and the requested ROR.

Illustration No. 1:



Q. What is the test year the Company is utilizing for this general rate request?

A. The forecasted test period being used by the Company is the twelve months ended December 31, 2011, presented on a forecasted basis. Currently authorized rates are based upon the 2010 forecasted test year utilized in Docket No. UG-186 adjusted on a pro forma basis.

Q. Why did the Company use the year ending December 31, 2011 as the test period?

A. The forecasted test period in this case was selected to best reflect the conditions during which time the new rates will be in effect. Rates from this proceeding will be effective in the first half of 2011, which closely matches the forecasted test period used by the Company in the calculation of the revenue requirement.

Q. Please explain how the Company developed the revenue requirement for the test period.

A. Revenue requirement preparation began with the historical accounting information for the twelve months ended December 31, 2009. Each of the revenue requirement components in the historical period was analyzed to determine if a normalizing adjustment was warranted to reflect normal operating conditions. The historical information was then adjusted to include previous Commission–ordered adjustments; next these results were adjusted to recognize known, measurable and anticipated events to determine a forecasted 2011 test period.

Q. Why did the Company begin with historical information?

A. The Company began with historical information and made adjustments to arrive at the forecasted test period revenue requirement because starting with historical information provides a solid foundation and paper trail that is easily auditable.

Q. Please summarize the process used to adjust the historical information to reflect the forecasted test period revenues and costs.

A. Revenues are adjusted for the effect of applying the current Commission approved tariff rates to the forecasted test period customer usage. Historical operations and maintenance ("O&M") expenses were separated into labor and non-labor components. Non-labor costs were adjusted using the consumer price index (CPI). Historical labor costs were also adjusted for increases through the end of the forecasted test period. Specific adjustments are described in further detail later in my testimony and shown in Exhibit 701.

III. NEED FOR ADDITIONAL RATE RELIEF

Q. Please describe the Company's need for additional natural gas rate relief.

A. The Company's need for additional rate relief is due in part to an increase in overall net rate base, including an adjustment for working capital and additional plant in service, such as the Company's Roseburg reinforcement project and other 2011 required projects, as described by Company witness Mr. DeFelice. In addition, as described by Company witness Mr. Ehrbar, the Company forecasts a drop in revenues necessary to cover its costs associated with providing safe and reliable service, due to a reduction in the number of customers and declining therm usage by our customers on a weather-adjusted basis, versus what was approved in the Company's last general rate case (UG-186).

The Company is also requesting additional rate relief for a slight increase in Operating and Maintenance (O&M) and Administrative and General (A&G) expenditures, as well as the inclusion of pro forma expenses, capital investment and inventory for the increased storage capacity and deliverability associated with the transfer on May 1, 2011 of a portion of the Jackson Prairie storage facility to the utility.

IV. GENERAL REVENUE REQUIREMENT

Q. Would you please explain what is shown in Exhibit 701?

A. Yes. Exhibit 701 shows 2009 actual results and forecasted natural gas operating results and rate base for the 2011 test period for the Company's Oregon jurisdiction. Column (b) of page 1 of Exhibit 701 shows the twelve months ended December 31, 2009 operating results and components of the end-of-period rate base as recorded; column (c) is the total of all adjustments to net operating income and rate base; and column (d) is forecasted results of operations, all under existing rates. Column (e) shows the revenue increase required which would allow the Company an opportunity to earn its requested 8.61% rate of return. Column (f) reflects forecasted natural gas operating results with the requested general increase of $5,446,000.

Q. Would you please explain page 2 of Exhibit No. 701?

A. Yes. As discussed earlier in my testimony, page 2 shows the calculation of the $5,446,000 revenue requirement using the requested 8.61% rate of return.

Q. Would you now please explain page 3 of Exhibit 701?

A. Yes. Page 3 shows the derivation of the net operating income to gross revenue conversion factor. The conversion factor takes into account uncollectible accounts receivable, Oregon Commission fees, Oregon Energy Resource Supplier Assessment Fees, Franchise Taxes and Oregon Excise Tax, which is the Oregon state income tax. Federal income taxes are reflected at 35%.

Q. Now turning to pages 4 through 6 of your Exhibit 701, would you please explain what those pages show?

A. Yes. Page 4 begins with actual operating results and rate base for the twelve months ended December 31, 2009 in column (b). Individual earnings test adjustments that are standard components of our annual earnings reporting to the Commission, and other restating adjustments begin in column (c) on page 4 and continue through column (j) on page 5. Column (Ttl) on page 5, entitled Restated Total, is the subtotal of all preceding columns. The individual forecast adjustments are presented in column (F1) through column (F10) on pages 5 and 6.

V. RESTATING ADJUSTMENTS

Q. Would you please explain each of these adjustments, the reason for the adjustment and its effect on test period State of Oregon net operating income and/or rate base?

A. Yes. The first adjustment, column (c) on page 4, entitled **Uncollectible Expense**, revises the 2009 historical period level of accrued expense to the three-year average percentage of actual net customer accounts receivable write-offs. The effect on State of Oregon net operating income is an increase of $64,000.

The adjustment in column (d), **Incentive Pay**, adjusts incentive expense by removing 100% of the executive incentive, removing 50% of the non-executive incentive, and removing 50% of merit-based incentives. This is the same method as agreed to in UG 186, Order No. 09-422, dated October 26, 2009. The result of this adjustment is an increase in net operating income of $153,000.

Column (e), **Memberships and Dues**, classifies expenses by category and specific percentages are applied to determine the recoverable amounts. This calculation is consistent with what was recommended to the Company during Staff review of the December 31, 1994 Earnings Report. The effect of this adjustment on State of Oregon net operating income is an increase of $14,000.

Column (f), **Miscellaneous Restating,** restates actual test period results for miscellaneous restating items such as atmospheric testing, advertising and insurance. The adjustment for atmospheric testing reflects one-third of the cost expected to be incurred associated with testing that occurs every three years. This is the same method as agreed to in UG 186, Order No. 09-422, dated October 26, 2009. The result of this adjustment is a decrease in net operating income of $97,500. The adjustment for advertising is comprised of two components: 1) Restates the 2009 test period advertising expense for corrected jurisdictional allocation of expenses, and 2) removes costs reflecting the application of 1/8 of 1% of proposed retail revenues, pursuant to OAR 860-026-0022.

Finally, 2009 actual insurance expense was adjusted to reflect the expected 2011 insurance level of expense resulting in an increase in expense of $32,500. The net total of all restating adjustments decreases net operating income by $109,000.

The adjustment in column (g), **Franchise Tax Pass-Through Elimination**, has no impact on the Company's revenue requirement. This adjustment removes the impact of the collection through revenues of franchise taxes that exceed the general level of 3% from results of operations. The revenue and expense impact of the adjustment nets to zero and facilitates analysis of cost of service and rate design.

Column (h), **Remove Senate Bill 408 Accrual**, removes all accounting transactions recorded in 2009 related to the provisions of Oregon Senate Bill 408. This includes the removal of the revenue reduction and associated amortization for the amounts refunded in 2009 related to the 2007 tax report. In addition, this adjustment removes the accrual entries recorded in 2009. The adjustment increases net operating income by $1,064,000.

The adjustment in column (i), **SIT-FIT**, adjusts Oregon state income tax expense and federal income tax expense applicable to Oregon gas utility operations. Avista Corporation files a consolidated federal income tax return for an affiliated group that includes electric utility operations in Washington and Idaho, gas utility operations in Oregon, Washington, and Idaho, and non-utility subsidiary operations.

Federal income tax expense is determined for Oregon gas utility operations on a stand-alone basis, or, in other words, based on the income generated by Oregon gas operations. The $450,000 adjustment to current federal income tax expense relates to the federal income tax impact of the adjustment to Oregon state income tax and to a correction related to a Schedule M addition that was not properly assigned to Oregon gas operations. The $47,000 adjustment to deferred federal income tax relates to a reclassification of deferred tax items recorded during the 2009 calendar year.

The level of Oregon state income tax was also calculated on a stand-alone basis, since this is the method used to determine taxes paid in Senate Bill 408 filings. The first $250,000 of Oregon stand-alone taxable income before state income tax was multiplied by the state statutory rate of 6.6%, and the amount over $250,000 was multiplied by the marginal tax rate for 2011-2012 of 7.6% to determine the amount of Oregon state income tax. The adjustment to Oregon state income tax amounts to a decrease of $355,000.

The net impact to Oregon net operating income for federal and state income taxes is a reduction of $142,000.

Column (j), entitled **Restate Debt Interest**, restates debt interest using the Company's forecasted weighted average cost of debt, as outlined in the testimony and exhibits of Company witness Mr. Thies and applied to Oregon's forecasted level of rate base to produce a forecasted level of tax deductible interest expense. The federal income tax effect of the restated level of interest for the test period increases Oregon net operating income by $170,000.

Column (Ttl) entitled **Restated Total**, provides a subtotal of the preceding columns (b) through column (j) and represents actual operating results and rate base, plus the restating adjustments that have been previously discussed.

VI. FORECASTED ADJUSTMENTS

Q. Please explain the significance of the eight columns that begin on page 5 and continue on page 6, in your Exhibit 701.

A. The ten adjustments subsequent to the Restated Total column represent forecasted adjustments that recognize the jurisdictional impacts of items that will affect the forecasted operating period levels. They encompass revenue and expense items as well as additional capital projects and inventory items. These adjustments bring the 2009 operating results and rate base to the final forecasted level for the 2011 forecasted test period.

Q. Why did the Company use a forecasted test period?

A. The Company chose to use a forecasted test period to best reflect the conditions during which new rates will be in effect. Rates as a result of this case will match revenues and expenses for the 2011 forecasted test period.

Q. Please continue with your explanation of the forecasted adjustments on page 5.

A. Column (F1), **Forecast Expense Adjustment**, increases non-labor O&M and A&G expenses based on forecasts through 2011 for the various FERC accounts. Workpapers accompanying my testimony and Exhibit in this case provide summary adjustments by FERC account and provide the Company's analysis of each FERC account balance and shows the use of CPI for 2010 and 2011 to make the adjustment. This adjustment decreases Oregon net operating income by $184,000.

Column (F2), **Forecast Revenue Adjustment**, takes into account forecasted normalized usage and customers during 2011. It calculates revenues and purchased gas expense based on rates and associated gas costs approved in the Company's most recent Purchased Gas Adjustment filing, filed November 1, 2009. This adjustment was made under the direction of Mr. Ehrbar and is described further in his testimony. The effect of this adjustment is to increase Oregon net operating income by $2,161,000, caused primarily by the rate increase approved in November 2009, offset by the reduction in usage and customers discussed by Mr. Ehrbar.

Q. Is the Company's request for rate relief and its proposed revenue requirement impacted by changes in customer usage and the number of forecasted customers.

A. Yes it is. As further explained by Mr. Ehrbar the Company's request for rate relief is partially necessary due to a reduction in the number of customers expected during 2011 and a reduction in overall therm usage. This overall reduction in customers and usage totals approximately $2.3 million of the Company's request for rate relief to cover the costs of providing safe, reliable service to our customers.

Q. Please continue with your explanation of the adjustments included on page 5 of Exhibit 701.

A. Column (F3), **Forecast Labor and Benefits Adjustment**, reflects changes to the historical period labor and benefits for union, non-union and executives forward to 2011 levels. Historical period labor and benefits for 2009 were restated to annualize the March 1, 2009 increase, include the 2010 increase, and to include the 2011 increase as of March 1, 2011. This adjustment also includes changes in both the Company's pension and medical insurance expense planned for 2011, for a total decrease in Oregon net operating income of $374,000.

Column (F4), **Forecast Property Tax Adjustment**, adjusts the property tax accrual to the most current information available and eliminates any adjustments related to the prior year. The effect of this adjustment is to decrease Oregon net operating income by $122,000.

Q. Please turn to page 6 and continue with your explanation of the forecast

adjustments.

A. Column (F5), **Forecast Depreciation Adjustment**, adjusts 2009 vintage plant depreciation expense to the 2011 expense level on all plant in service at December 31, 2009. In addition, the associated accumulated depreciation and DFIT were adjusted to reflect the expected 2011 balances on an AMA basis for all 2009 vintage plant in service at December 31, 2009. This net effect of the adjustment decreases Oregon net operating income by $15,000 and decreases rate base by $10,285,000.

Column (F6), **Forecast 2010 Capital Additions Adjustment**, adjusts for all Oregon capital projects that will become operational and will transfer to plant in service in 2010, and the associated accumulated depreciation and DFIT to December 31, 2010 on an EOP basis. This adjustment also adjusts depreciation expense and property taxes on the 2010 capital projects to the 2011 forecasted test year level. This adjustment was made under the direction of Mr. DeFelice and is described further in his testimony. This adjustment decreases Oregon net operating income by $370,000 and increases rate base by $14,919,000.

Column (F7), **Forecast 2011 Capital Additions Adjustment**, adjusts for all Oregon capital projects that will become operational and will transfer to plant in service in 2011, and the associated accumulated depreciation and DFIT to December 31, 2011 on an AMA basis. This adjustment also includes depreciation expense and property taxes on the 2011 capital projects to the 2011 forecasted test year level. In addition, this adjustment adjusts the 2010 capital projects [included in adjustment (F6)] associated accumulated depreciation and DFIT to December 31, 2011, on an AMA basis. This adjustment was also made under the direction of Mr. DeFelice and is described further in his testimony. This adjustment decreases Oregon net operating income by $279,000 and increases rate base by $4,742,000.

Column (F8), **Forecast JP Capital/Inventory Adjustment**, pro forms expenses, capital investment and inventory for the increased storage capacity and deliverability associated with the transfer on May 1, 2011 of a portion of the Jackson Prairie (JP) Storage facility to the Utility that was previously utilized by Avista Energy. Assets with a net book value of approximately $11.6 million will transfer from Avista Energy to Avista Utilities, which is comprised of approximately $5.9 million of cushion gas and approximately $5.7 million of fixed assets. Company witness Mr. Christie discusses the details of this transfer.

Additionally, the adjustment incorporates the impact of revised accounting treatment for existing cushion gas using the net book value of the utility assets at February 2010 to record the transfer of the cushion gas from non-recoverable (FERC Account No. 352.3), which is a depreciable asset, to recoverable (FERC Account No. 117.1), which is a non-depreciable asset. The Jackson Prairie assets that will be added on May 1, 2011 will include plant assets as well as cushion gas that will be recorded in both recoverable and non-recoverable FERC accounts using a similar allocation method.[2] The details of the proposed accounting treatment of this adjustment are provided with my workpapers.

Oregon's share of the Jackson Prairie assets on a 2011 average-of-monthly-average basis increases net rate base by $1,246,000. The reclassification of existing cushion gas increases net rate base by $11,000. The adjustment also includes a net rate base increase of $176,000 for the working gas associated with the additional storage. The total of these net rate base adjustments increases net rate base by $1,433,000.

Underground storage expense increased for the additional operating, depreciation and

[2] This allocation methodology was proposed as part of its general rate requests in Docket UG-100468 (Washington) and Case AVU-G-10-01 (Idaho). Both Commission staffs have accepted this proposed allocation methodology as a part of an all party settlement in both cases. The Idaho Public Utilities Commission approved the settlement on September 21, 2010.

property taxes expense by approximately $89,000 which was offset by a reduction of $24,000 in depreciation and property taxes expense due to the reclassification of existing cushion gas. The overall impact of these adjustments decreases Oregon net operating income by $39,000.

Column (F9), **Restated Salaries and Wages**, adjusts the 2011 forecasted labor expense to be consistent with the method agreed to by the parties in the previous rate proceeding UG-186. This method utilized Staff's approach that adjusts for 1/2 the difference between actual payroll and the annual percent based on the Consumer Price Index for non-union employees. The Union portion of this adjustment annualizes the effect on union labor expense of the union wage adjustments implemented in April of each year. In order to simplify the matters in this case, the Company has applied this approach to its 2011 salary expense. The result of this adjustment on net operating income is an increase of $19,000, and a decrease in rate base of $19,000.

Column (F10), entitled **Forecast Working Capital**, increases total rate base for the Company's working capital adjustment. The Company has calculated cash working capital in this proceeding on the basis of a lead lag study. The lead lag study was performed by Mr. Clayton, President of Management Consulting of Tangible LLC, and determines the revenue and expense lags by category for revenue and operating expenses, then applies the leads and lags to the jurisdictional operating expenses in order to calculate appropriate daily and annual cash working capital requirements necessary to operate the Company. Please refer to Mr. Clayton's testimony and exhibits, Exhibit 600 and 601, for further detail regarding the lead lag study. The effect on Oregon rate base is an increase of $7,486,000.

Workpapers for each of the restating and forecasted adjustments, described above, accompany the Company's filed case.

Q. Referring back to page 1, line 24, of Exhibit 701, what was the actual and forecasted gas rate of return realized by the Company during the test period?

A. For the State of Oregon, the actual test period rate of return was 5.84%. The forecasted rate of return is 6.47% under present rates. Thus, the Company does not, on a forecasted basis, realize the 8.61% rate of return requested by the Company in this case.

Q. How much additional net operating income would be required for the State of Oregon gas operations to allow the Company an opportunity to earn its proposed 8.61% rate of return on a forecasted basis?

A. The net operating income deficiency amounts to $3,174,000, as shown on line 5, page 2 of Exhibit 701. The resulting revenue requirement is shown on line 7 and amounts to $5,446,000, or an increase of 5.6% over forecasted revenues.

VII. ALLOCATION PROCEDURES

Q. Have there been any changes to the Company's system and jurisdictional procedures since the Company's last general natural gas case, Docket No. UG-186?

A. No. For ratemaking purposes, the Company directly assigns or allocates revenues, expenses and rate base between electric and gas services and between Oregon, Washington, and Idaho jurisdictions where electric and/or gas service is provided. The current methodology is based on previously-approved methodology that has been in place for several years. The allocation factors and procedures used in this case have been provided with my workpapers.

Q. Does that conclude your pre-filed, direct testimony?

A. Yes, it does.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

ELIZABETH M. ANDREWS
Exhibit No. 701

Revenue Requirement and Allocations

AVISTA UTILITIES
NATURAL GAS RESULTS OF OPERATION
OREGON JURISDICTION FORECASTED RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 2011
(000'S OF DOLLARS)

		WITH PRESENT RATES			WITH PROPOSED RATES	
Line No.	DESCRIPTION	Actual Per Results Report (EOP)	Total Adjustments	Forecasted Total	Proposed Revenues & Related Exp	Forecasted Proposed Total (AMA)
	a	*b*	*c*	*d*	*e*	*f*
	OPERATING REVENUES					
1	Total General Business	$113,472	$ (18,332)	$95,140	$5,446	$100,586
2	Total Transportation	2,198	325	2,523		2,523
3	Other Revenues	40,811	(40,659)	152		152
4	Total Operating Revenues	156,481	(58,666)	97,815	5,446	103,261
	OPERATING EXPENSES					
5	Gas Purchased	118,258	(61,231)	57,027		57,027
6	Operation and Maintenance	12,721	(322)	12,399	30	12,429
7	Administration & General	7,193	(27)	7,166	18	7,184
8	Taxes Other than Income	6,017	(1,633)	4,384	114	4,498
9	Depreciation & Amortization	4,078	1,381	5,459		5,459
10	Total Operating Expenses	148,267	(61,832)	86,435	162	86,597
11	OPERATING INCOME BEFORE FIT	8,214	3,166	11,380	5,284	16,664
	INCOME TAXES					
12	Current Federal Income Taxes	(2,680)	1,611	(1,069)	1,709	640
13	Deferred Federal Income Taxes	2,877	(185)	2,692		2,692
14	State Income Taxes	423	(271)	152	402	554
15	Total Income Taxes	620	1,155	1,775	2,111	3,886
16	NET OPERATING INCOME	$7,594	$2,011	$9,605	$3,173	$12,778
	RATE BASE					
17	Utility Plant in Service	242,885	20,906	263,791		263,791
18	Less: Accum Depr and Amort	(89,352)	(7,523)	(96,875)	0	(96,875)
19	Net Utility Plant	153,533	13,383	166,916	0	166,916
20	Accumulated Deferred FIT	(25,385)	(3,820)	(29,205)		(29,205)
21	Inventory and Other	1,997	1,227	3,224	0	3,224
22	Working Capital	0	7,486	7,486	0	7,486
23	TOTAL RATE BASE	$130,145	$18,276	$148,421	$0	$148,421
24	RATE OF RETURN	5.84%		6.47%		8.61%

AVISTA UTILITIES
Calculation of General Revenue Requirement
Oregon Natural Gas Jurisdiction
TWELVE MONTHS ENDED DECEMBER 31, 2011

Line No.	Description	(000's of Dollars)
1	Forecasted Rate Base	$148,421
2	Proposed Rate of Return	8.610%
3	Net Operating Income Requirement	$12,779
4	Forecasted Net Operating Income	$9,605
5	Net Operating Income Deficiency	$3,174
6	Conversion Factor	0.58285
7	Revenue Requirement	$5,446
8	Total General Business Revenues	$97,663
9	Percentage Revenue Increase	5.6%

	12/31/2011 Forecasted		
	Capital	Cost	Weighted
Long Term Debt	49.24%	6.25%	3.08%
Common Equity	50.76%	10.90%	5.53%
Total	100.00%		8.61%

AVISTA UTILITIES
Calculation of Conversion Factor
Oregon Natural Gas Jurisdiction
TWELVE MONTHS ENDED DECEMBER 31, 2011

Line No.	Description		Factor
1	Revenues		1.000000
	Expense:		
2	Uncollectibles		0.005419
3	Commission Fees		0.002500
4	Energy Resource Supplier Assessment		0.000780
5	Franchise Fees		0.020856
6	Oregon Excise Tax		0.073754
6	Total Expense		0.103309
7	Net Operating Income Before FIT		0.896691
8	Federal Income Tax @	35.00%	0.313842
9	REVENUE CONVERSION FACTOR		0.582849

AVISTA UTILITIES
NATURAL GAS RESULTS OF OPERATION
OREGON FORECASTED RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 2011
(000'S OF DOLLARS)

Blue = Done
Red = Not Done

Line No.	DESCRIPTION	Per Results of Operations Report	Uncollectible Expense Adj.	Incentive Pay Adj.	Memberships and Dues Adjustment	Miscellaneous Restating Adj	Franchise Tax Pass Through Elimination
	a	b	c	d	e	f	g
	REVENUES						
1	Total General Business	$113,472					$ (1,823)
2	Total Transportation	2,198					(22)
3	Other Revenues	40,811					
4	Total Gas Revenues	156,481	0	0	0	0	(1,845)
	EXPENSES						
5	Exploration and Development	0					
	Production						
6	City Gate Purchases	118,258					
7	Purchased Gas Expense	0					
8	Other Gas Expenses	541					
9	Depreciation	0					
10	Taxes	0					
11	Total Production	118,799	0	0	0	0	0
	Underground Storage						
12	Operating Expenses	37					
13	Depreciation	90					
14	Taxes	0					0
15	Total Underground Storage	127	0	0	0	0	0
	Distribution						
16	Operating Expenses	5,830				150	
17	Depreciation	3,352					
18	Taxes	6,017					$ (1,845)
19	Total Distribution	15,199	0	0	0	150	(1,845)
20	Customer Accounting	3,406	(107)	0	0	0	
21	Customer Service & Information	2,799					
22	Sales Expenses	108					
	Administrative & General						
23	Operating Expenses	7,193		(254)	(23)	32	
24	Depreciation & Amortization	636					
25	Taxes	0					
26	Total Admin. & General	7,829	0	(254)	(23)	32	0
27	Total Gas Expense	148,267	(107)	(254)	(23)	182	(1,845)
28	OPERATING INCOME BEFORE FIT	8,214	107	254	23	(182)	0
	FEDERAL INCOME TAX						
29	Current Accrual	(2,680)	35	82	7	(59)	
30	Deferred FIT	2,877					
31	State Income Tax	423	8	19	2	(14)	
32	NET OPERATING INCOME	$7,594	$64	$153	$14	($109)	$0
	RATE BASE: PLANT IN SERVICE						
33	Production Plant	$8					
34	Underground Storage Plant	4,843					
35	Transmission Plant	0					
36	Distribution Plant	218,233					
37	General Plant	19,801					
38	Total Plant in Service	242,885	0	0	0	0	0
	ACCUMULATED DEPRECIATION						
39	Production Plant	0					
40	Underground Storage Plant	119					
41	Transmission Plant	0					
42	Distribution Plant	83,082					
43	General Plant	6,151					
44	Total Accum. Depreciation	89,352	0	0	0	0	0
45	DEFERRED FIT	(25,385)					
46	GAS INVENTORY	1,997					
47	WORKING CAPITAL	0					
48	TOTAL RATE BASE	$130,145	$0	$0	$0	$0	$0
49	RATE OF RETURN	5.84%					

AVISTA UTILITIES
NATURAL GAS RESULTS OF OPERATION
OREGON FORECASTED RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 2011
(000'S OF DOLLARS)

Line No.	DESCRIPTION	Remove SB 408 Accrual	SIT - FIT Adjustment	Restate Debt Interest	Restated Total	Forecast Expense Adjustment	Forecast Revenue Adjustment	Forecast Labor & Benefits Adjustment	Forecast Property Tax Adjustment
	a	h	i	j	Ttl	F1	F2	F3	F4
	REVENUES								
1	Total General Business	$2,165			$113,814		$ (18,674)		
2	Total Transportation	134	0		2,310		213		
3	Other Revenues				40,811		(40,659)		
4	Total Gas Revenues	2,299	0	0	156,935	0	(59,120)	0	0
	EXPENSES								
5	Exploration and Development				0				
	Production								
6	City Gate Purchases				118,258		(61,231)		
7	Purchased Gas Expense				0				
8	Other Gas Expenses				541	3		25	
9	Depreciation				0				
10	Taxes				0				
11	Total Production	0	0	0	118,799	3	(61,231)	25	0
	Underground Storage								
12	Operating Expenses				37	2			
13	Depreciation				90				
14	Taxes				0				
15	Total Underground Storage	0	0	0	127	2	0	0	0
	Distribution								
16	Operating Expenses				5,980	84		320	
17	Depreciation				3,352				
18	Taxes				4,172		(385)		190
19	Total Distribution	0	0	0	13,504	84	(385)	320	190
20	Customer Accounting	0	0	0	3,299	59	(100)	115	0
21	Customer Service & Information				2,799	1	(941)	4	0
22	Sales Expenses				108				0
	Administrative & General								
23	Operating Expenses				6,948	157	(61)	159	0
24	Depreciation & Amortization	662	-		1,298				0
25	Taxes				0				14
26	Total Admin. & General	662	0	0	8,246	157	(61)	159	14
27	Total Gas Expense	662	0	0	146,882	306	(62,718)	623	204
28	OPERATING INCOME BEFORE FIT	1,637	0	0	10,053	(306)	3,598	(623)	(204)
	FEDERAL INCOME TAX								
29	Current Accrual	$805	$450	(138)	(1,498)	(99)	1,164	(202)	(66)
30	Deferred FIT	(232)	47		2,692				
31	State Income Tax		$ (355)	(32)	51	(23)	273	(47)	(16)
32	NET OPERATING INCOME	$1,064	($142)	$170	$8,808	($184)	$2,161	($374)	($122)
	RATE BASE: PLANT IN SERVICE								
33	Production Plant				$8				
34	Underground Storage Plant				4,843				
35	Transmission Plant				0				
36	Distribution Plant				218,233				
37	General Plant				19,801				
38	Total Plant in Service	0	0	0	242,885	0	0	0	0
	ACCUMULATED DEPRECIATION								
39	Production Plant				0				
40	Underground Storage Plant				119				
41	Transmission Plant				0				
42	Distribution Plant				83,082				
43	General Plant				6,151				
44	Total Accum. Depreciation	0	0	0	89,352	0	0	0	0
45	DEFERRED FIT				(25,385)				
46	GAS INVENTORY				1,997				
47	WORKING CAPITAL				0				
48	TOTAL RATE BASE	$0	$0	$0	$130,145	$0	$0	$0	$0
49	RATE OF RETURN				6.77%				

AVISTA UTILITIES
NATURAL GAS RESULTS OF OPERATION
OREGON FORECASTED RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 2011
(000'S OF DOLLARS)

Line No.	DESCRIPTION	Forecast Depreciation Adjustment	Forecast Capital Additions 2010 Adjustment	Forecast Capital Additions 2011 Adjustment	Forecast JP Capital / Inventory Adj.	Restated Salaries and Wages	Forecast Working Capital	Forecasted Total
	a	F5	F6	F7	F8	F9	F10	-
	REVENUES							
1	Total General Business							$95,140
2	Total Transportation							2,523
3	Other Revenues							152
4	Total Gas Revenues	0	0	0	0	0	0	97,815
	EXPENSES							
5	Exploration and Development							0
	Production							
6	City Gate Purchases							57,027
7	Purchased Gas Expense							0
8	Other Gas Expenses							569
9	Depreciation							0
10	Taxes							0
11	Total Production	0	0	0	0	0	0	57,596
	Underground Storage							
12	Operating Expenses				59			98
13	Depreciation				3			93
14	Taxes				3			3
15	Total Underground Storage	0	0	0	65	0	0	194
	Distribution							
16	Operating Expenses					4		6,388
17	Depreciation	96	171	153				3,772
18	Taxes		185	123				4,285
19	Total Distribution	96	356	276	0	4	0	14,445
20	Customer Accounting	0	0	0	0			3,373
21	Customer Service & Information				0			1,863
22	Sales Expenses				0			108
	Administrative & General							
23	Operating Expenses				0	(37)		7,166
24	Depreciation & Amortization	(71)	214	153	0			1,594
25	Taxes		46	36	0			96
26	Total Admin. & General	(71)	260	189	0	(37)	0	8,856
27	Total Gas Expense	25	616	465	65	(33)	0	86,435
28	OPERATING INCOME BEFORE FIT	(25)	(616)	(465)	(65)	33	0	11,380
	FEDERAL INCOME TAX							
29	Current Accrual	(8)	(199)	(151)	(21)	11		(1,069)
30	Deferred FIT							2,692
31	State Income Tax	(2)	(47)	(35)	(5)	3		152
32	NET OPERATING INCOME	($15)	($370)	($279)	($39)	$19	$0	$9,605
	RATE BASE: PLANT IN SERVICE							
33	Production Plant							$8
34	Underground Storage Plant				$207			5,050
35	Transmission Plant							0
36	Distribution Plant		$12,323	$4,129		(19)		234,666
37	General Plant		$3,081	$1,185				24,067
38	Total Plant in Service	0	15,404	5,314	207	(19)	0	263,791
	ACCUMULATED DEPRECIATION							
39	Production Plant							0
40	Underground Storage Plant				(11)			108
41	Transmission Plant							0
42	Distribution Plant	5,308	73	90				88,553
43	General Plant	1,840	110	113				8,214
44	Total Accum. Depreciation	7,148	183	203	(11)	0	0	96,875
45	DEFERRED FIT	(3,137)	(302)	(369)	(12)			(29,205)
46	GAS INVENTORY				1,227			3,224
47	WORKING CAPITAL						$7,486	7,486
48	TOTAL RATE BASE	($10,285)	$14,919	$4,742	$1,433	($19)	$7,486	$148,421
49	RATE OF RETURN							6.47%

AVISTA/800
Miller

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF JOSEPH D. MILLER
REPRESENTING AVISTA CORPORATION

Long-Run Incremental Cost

I. INTRODUCTION

Q. Would you please state your name, business address and present position with Avista Corporation?

A. My name is Joseph D. Miller. My business address is East 1411 Mission Avenue, Spokane, Washington. I am employed as a Regulatory Analyst in the State and Federal Regulation department.

Q. Would you briefly describe your responsibilities?

A. I am responsible for preparing data for and maintaining the regulatory natural gas cost of service models for the Company as well as providing support in the preparation of revenue analysis, rate spread and rate design, and miscellaneous other duties as required.

Q. Would you please describe your educational background and professional experience?

A. I am a 1999 graduate of Portland State University with a Bachelors degree in Business Administration, majoring in Accounting. In 2005 I graduated from Gonzaga University with a Masters degree in Business Administration. I joined the Company in March 2008 after spending eight years in both the public and private accounting sector. I started with Avista as a Natural Gas Accounting Analyst in the Company's Resource Accounting department. In January 2009 I joined the State and Federal Regulation Department as a Regulatory Analyst.

Q. Would you please briefly summarize your testimony?

A. My testimony presents the natural gas cost of service study prepared for this filing. The results of the long-run incremental cost study indicate that at current rates, on a relative margin to cost basis, residential customers are generally in line with relative cost of service, small commercial and seasonal customers are paying less than their relative cost of service, while large general, interruptible, and transportation customer groups exceed their relative cost of service to varying degrees.

Q. Are you sponsoring any exhibits to be introduced in this proceeding?

A. Yes. I am sponsoring Exhibit No. 801, which is the Company's long-run incremental cost (LRIC) study and Exhibit No. 802, which shows the functional component classification of the Company's proposed revenue requirement in this case.

Q. Were these exhibits prepared by you?

A. Yes.

II. LONG-RUN INCREMENTAL COST STUDY

Q. What is a long-run incremental cost study and what is its purpose?

A. A long-run incremental cost study is an engineering-economic study which estimates the incremental annual cost of providing natural gas service to customers segregated into groups according to their usage characteristics. In the Company's study customers are grouped by rate schedule. When applied to current results of operations, the study indicates the adequacy of current rates compared to costs. The study results are used as one of the guidelines in determining the appropriate rate spread among rate schedules.

Q. What are the elements of the LRIC study?

A. The elements of the cost study include incremental plant investment, incremental operating and maintenance expenses, and the cost of gas supplied to a customer. All of the information is accumulated in terms of cost per customer for an average or typical customer on each rate schedule and then summarized to represent the long-run incremental cost of the 2011 total pro forma customers and therms.

<u>Incremental Investment Costs</u>

Q. What is included in incremental plant investment?

A. Plant investment required for a new customer includes a gas main extension to reach the customer, a service line to connect the customer to the main, and metering equipment at the customer's premises. The distribution system must be capable of meeting the combined peak needs of all customers at reliable pressure, so capacity reinforcement investment is required for new customer loads over the long term. Mandated safety and reliability requirements cause incremental costs to the distribution system for the benefit of all customers. Additionally, over the long run, all distribution facilities ultimately require replacement. These facilities provide both capacity and commodity for the benefit of all customers. The appropriate allocation of the Company's investment in underground storage has also been included in the incremental investment cost analysis.

Q. Are these items identified in the cost study presented in this case?

A. Yes. Exhibit 801 page 2 shows the calculation of the 2011 cost per customer of the various investment costs included in this study. System core main investments have been categorized into capacity or commodity unit costs.

Q. How are new customer investment costs quantified in this study?

A. Typical main extensions are quantified in terms of the size and length of pipe recently provided for customers, multiplied by recent costs for each pipe size. A summary of the last four years of Oregon project work orders were used to identify the average length and typical size of pipe to serve different residential and small commercial customers. Interruptible and transportation customers, that have not had recent installations, were individually examined to determine average current cost of pipe that is dedicated to them.

Special contract transportation customers, who have a feasible option to direct-connect to the interstate pipeline, were assigned the estimated bypass cost. For large general service customers on Schedule 424, a random sample comprising approximately 25% of the population was selected. Using the facilities mapping system and the in-service date of the mains, the length and size of apparent line extensions associated with the randomly selected customers were identified and current costs applied to determine the sample line extension cost per customer for this group, and the resulting values were also used for the seasonal customers on Schedule 444.

Services were quantified by the size of pipe typically needed for the type of customer. For large general service, interruptible and transportation customers, the sample analysis and identified dedicated pipe were used to determine average current cost, similar to the main extension cost assignment.

Metering equipment was quantified by a weighted average current meter cost per customer. The weighted average captures the actual equipment types in service on each rate schedule priced at the 2009 average installed cost. For transportation customers, $1,000 was added to approximate the additional cost of telemetering equipment required for transportation service.

Q. You stated that system core main costs were simplified into capacity-related and commodity-related investments. Would you please explain what is included in these categories?

A. Yes. First, the Company's Oregon (non-revenue producing) distribution system investment projects were segregated into reinforcement projects versus safety and reliability projects based on the capital project categories described in Company witness

DeFelice's testimony. A four-year average (2 years actual and 2 years budget) annual investment total was determined for the two types of projects. The reinforcement projects are considered capacity-related and therefore were divided by estimated Oregon total design day usage in therms. The safety and reliability projects are considered commodity-related and therefore were divided by annual therms. Long-run replacement cost was estimated by computing the current cost of all Oregon mains in service at December 31, 2009 by size and type. The current cost already accounted for by customer main extensions, reinforcement projects, and safety/reliability projects were deducted to determine remaining system replacement investment. The remaining value was segregated into capacity versus commodity by the 2009 peak and average ratio. The capacity portion was then divided by estimated Oregon total design day usage and the commodity portion was divided by annual therms.

Q. How was 2011 incremental capacity-related investment per customer quantified?

A. The sum of the investment per design day therm for reinforcement projects and the capacity-related portion of system replacement was divided by days in the year to arrive at a 100% load factor cost per therm shown on line 13 of page 2 of Exhibit 801. This cost per therm has been adjusted for each rate schedule, based on the average estimated design day load factor for customers served under the schedule. Customers' design day load characteristics are the primary criteria associated with system capacity planning. The rate schedule cost per therm is then applied to average annual consumption per customer to get capacity main investment per customer for each schedule.

Q. How was 2011 incremental commodity-related main investment per customer quantified?

A. The investment per therm for safety and reliability projects and the commodity-related portion of system replacement are added together to determine the incremental commodity main investment per therm. This per therm cost is then multiplied by the average annual consumption per customer to get the capacity-related main investment per customer for each schedule.

Q. How was investment in underground storage facilities quantified?

A. The Oregon jurisdictional underground storage plant balance at December 31, 2009 was used to represent investment in underground storage facilities. The assignment of costs associated with Oregon's share of the Jackson Prairie Storage facility recognizes that storage provides benefits to customers both through the mitigation of gas commodity costs and pipeline balancing. The assignment related to the Jackson Prairie Storage facility was split based on an 87% sales commodity and 13% throughput (balancing) basis. This relationship has been utilized in this cost study by determining the cost per therm based on throughput of 13% of the investment, and the cost per therm based on sales volumes of the remaining 87% of the investment. These unit costs are then multiplied by the average use per customer to determine the investment per customer for each schedule.

Q. Does the methodology related to the assignment of costs related to underground storage differ from prior cases?

A. Yes, with the additional Jackson Prairie storage that the utility will receive to serve customers beginning May 1, 2011, the Company believed it was necessary to reassess the proper relationship that the additional storage provides between sales commodity and throughput (balancing).

Q. Please discuss your rationale for moving to a cost assignment based on an 87% sales commodity and 13% throughput (balancing) basis.

A. Through discussions with our Energy Resources personnel it was concluded that approximately 20% (1,099,422 Dth) of the current Jackson Prairie capacity (5,497,112 Dth) is utilized for balancing and the remaining 80% is utilized for the benefit of sales customers. The Company believes that the additional capacity coming back to the utility in 2011 will have no further benefit to balancing the system. Based on this information, the relationship between sales commodity and throughput (balancing) was derived by dividing the current estimated capacity utilized for balancing of 1,099,422 Dth by the future total capacity of 8,527,999 Dth, resulting in a 13% allocation for throughput (balancing).

Q. Exhibit 801 page 3 shows a "levelized plant cost factor" for each investment. What is the purpose of this factor?

A. The levelized plant cost factor is an annual carrying charge applied to plant investments. There is a different factor for services, meters, mains and underground storage based on different estimated lives.

Q. How are the levelized plant cost factors determined?

A. A "Revenue Requirement Model" is used to determine the levelized revenue requirement (annual cost) associated with incremental plant over the estimated life of the asset. The model accounts for all costs and expenses associated with owning and maintaining the asset.

<u>Operating Expenses</u>

Q. What is included in gas supply and customer service related incremental operating and maintenance expenses?

A. This category captures the current costs associated with gas scheduling and planning, meter reading, and billing customers.

Q. Are these items identified in the cost study presented in this case?

A. Yes. Exhibit 801 page 3 itemizes the various operating and maintenance expenses included in this study.

Q. Please explain the items shown on Exhibit 801 page 3.

A. Gas supply schedulers schedule and track all the natural gas being delivered at all delivery points on the system, including the gas owned by transportation customers. The majority of their time is spent for the benefit of core customers, however, transportation customers require individual attention. A proportion of their time devoted to providing services for transportation versus core customers was applied to the scheduler's hours charged to FERC Account 813 "Other Gas Expenses" during 2009, resulting in an estimate of the annual hours necessary for these services. The annual hours were then divided by the number of customers served to arrive at the hours per customer shown on page 3, line 1.

The long run cost of gas management planning was estimated by dividing the hours charged by gas planning staff to FERC Account 813 "Other Gas Expenses" during the test year by the number of gas customers served to arrive at the annual hours per customer shown on page 3, line 4.

Similarly, the hours dedicated to manually billing interruptible and transportation customers were divided by the number of customers billed to get the annual hours per customer for that function. The total hours charged to meter reading in 2009 were divided by the number of customers to determine the annual hours per customer spent on meter reading.

All of these labor hour estimates are then priced at the average direct labor charges per hour during 2009 to estimate the incremental cost per customer.

Finally, billing cost per customer has been estimated from the average annual cost per customer the Company has experienced in the Oregon service territory over the last five years.

<u>Cost of Gas Commodity</u>

Q. What is included in the cost of gas?

A. The cost of gas includes all of the items included in the gas cost deferral process. These include the entire commodity, demand, amortization and upstream transportation charges (including the benefits of storage) the Company passes through to customers. The gas commodity costs shown on Exhibit 801, page 1, line 4, reflect the rates approved as a result of the most recent purchased gas adjustment (PGA) filing that went into effect November 1, 2009 and the LIRAP cost proposed to be removed from base rates in this case, grossed up for the revenue related expenses shown in Company witness Andrews revenue conversion factor.

<u>Results Analysis</u>

Q. What is shown on Exhibit No. 801, Page 1 entitled "Result Summary"?

A. The first three lines present the pro forma rate year usage and customer statistics relevant to the study. The next section, beginning on line 5 and ending on line 16, shows the pro forma rate year incremental costs for each component in the study. All items include revenue related expenses either through an after the fact gross up or embedded in the carrying charge on investment costs. The Long Run Incremental Distribution Cost on Line 17 is the sum of all the components (except gas commodity costs). Beginning on line 20 the study brings in the Company revenue requirement segregated into components comparable with the LRIC components shown above. Each component cost is then assigned to the rate schedules based on the LRIC results for the equivalent component. Once all of the components have been assigned, the results for each schedule are summed to produce the LRIC Based Target Margin on line 27. Following this are the resulting Current Margin to Target Margin ratios stated both in the absolute (Line 29) and on a relative basis (Line 29A). LRIC Based Target Margin results in an Oregon Total margin to cost ratio (shown on line 29) of 0.87. On line 28, I also included a comparison of Total Current Revenue to Total Proposed Cost, which includes the cost of gas in both the numerator and denominator. The Component LRIC Target Increase by Schedule, on line 30, represents the margin revenue (including the proposed increase) required from each schedule that would be perfectly aligned with the cost study. Company witness Ehrbar uses the Relative Margin to Cost at Present Rates, on line 29A, as a guide to spread the proposed increase by service schedule.

Q. Where did the revenue requirement components come from?

A. Exhibit No. 802 shows how the pro forma results of operations, including the requested revenue increase from Ms. Andrews Exhibit No. 501, have been assigned to the functional component classifications used in the cost of service.

Q. What are the results of the Company's LRIC study?

A. The following table shows the relative margin-to-cost ratio at present rates for each rate schedule:

Table 1 Long Run Incremental Cost Study

Customer Class	**LRIC Summary Component Allocation Relative Margin-to-Cost**
	Present Rates
Residential Service Schedule 410	0.99
General Service Schedule 420	0.89
Large General Service Schedule 424	1.49
Interruptible Sales Service Schedule 440	1.41
Seasonal Sales Service 444	0.78
Special Contracts Schedule 447	1.40
Transportation Service Schedule 456	1.62
Total Oregon Gas	1.00

The present relative margin-to-cost ratios indicate that general service (primarily commercial) customers on Schedule 420 and seasonal service customers on Schedule 444 are paying somewhat less than their relative cost of service, while large general (Schedule 424), interruptible (Schedule 440), and transportation (Schedule 456) service customers are paying somewhat more than their relative cost of service. Residential service customers on Schedule 410 are not far from parity, but are slightly under relative cost of service. The summary results of this study were provided to Mr. Ehrbar as an input into development of the proposed rates.

Q. Please summarize your testimony regarding cost of service.

A. I have provided a long-run incremental cost study by service schedule for the Company's Oregon jurisdiction. The study incorporates the essential elements of providing service to customers over the long term. As a guideline for the proposed rate spread, the study indicates that it would be reasonable for small general service customers on Schedule

420 and seasonal customers on Schedule 444 to receive a somewhat larger percentage increase than other customer groups, and large general service, interruptible service, and transportation customers on Schedules 424, 440 and 456 to receive a smaller percentage increase than other customer groups.

Q. Does this conclude your pre-filed, direct testimony?

A. Yes, it does.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

AVISTA CORP

JOSEPH D. MILLER
Exhibit No. 801

Long-Run Incremental Cost

AVISTA UTILITIES
OREGON JURISDICTION
LONG-RUN INCREMENTAL COST STUDY
TWELVE MONTHS ENDED DECEMBER 2011

RESULT SUMMARY *(Component Allocation)*

Line No.		OREGON TOTAL	Residential Service SCH 410	General Service SCH 420	Large General Service SCH 424	Interruptible Service SCH 440	Seasonal Service SCH 444	Special Contract Service SCH 447	Transportation Service SCH 456
	STATISTICS								
1	2011 ANNUAL THERM DELIVERIES	107,555,045	46,808,685	24,945,857	3,429,042	4,393,867	140,144	2,839,561	24,997,889
2	2011 AVERAGE CUSTOMERS	96,010	84,714	11,132	80	36	8	4	36
3	AVERAGE ANNUAL THERM DELIVERIES PER CUSTOMER		553	2,241	42,863	122,052	17,518	709,890	694,386
4	Gas Commodity Costs	$ 60,518,000	36,360,000	19,247,000	2,646,000	2,152,000	108,000	-	5,000
5	Gas Scheduling 1.03046	$ 76,009	43,579	5,727	41	1,379	4	2,528	22,752
6	Gas Planning	$ 187,965	165,850	21,794	157	70	16	8	70
7	Meter Reading	$ 99,315	87,394	11,484	83	164	8	18	164
8	Billing	$ 2,065,403	1,819,215	239,057	1,718	2,483	172	276	2,483
	Customer Installation Investment Cost								
9	Meters	$ 4,017,046	2,723,550	1,119,614	45,763	25,874	5,404	21,725	75,117
10	Services	$ 8,528,435	7,216,860	992,639	48,472	80,169	4,847	18,927	166,521
11	Main Extensions	$ 62,675,892	37,906,769	23,696,323	371,158	78,991	37,116	254,910	330,625
12	Total Customer Installation Investment Cost	$ 75,221,373	47,847,178	25,808,576	465,393	185,034	47,367	295,562	572,263
	System Core Main Cost								
13	Capacity	$ 9,623,029	4,620,902	2,296,161	195,944	180,231	-	83,629	2,246,163
14	Commodity	$ 7,225,009	3,145,792	1,675,193	230,262	295,051	9,411	190,678	1,678,623
15	Total Core Main Cost	$ 16,848,038	7,766,694	3,971,353	426,206	475,282	9,411	274,307	3,924,786
16	Underground Storage Cost	$ 932,789	529,468	281,952	38,755	49,660	1,584	3,200	28,170
17	Long Run Incremental Distribution Cost	$ 95,430,892	58,259,378	30,339,943	932,353	714,071	58,562	575,898	4,550,687
18	Revenue at Present Rates	$ 97,663,000	61,282,000	27,973,000	3,162,000	2,596,000	127,000	257,000	2,266,000
19	**Margin Revenue at Present Rates**	**$ 37,145,000**	**24,922,000**	**8,726,000**	**516,000**	**444,000**	**19,000**	**257,000**	**2,261,000**
	Proposed Cost by Functional Classification Assigned to Schedule by LRIC components								
20	Cost of Gas Commodity	$ 60,518,000	36,360,000	19,247,000	2,646,000	2,152,000	108,000	-	5,000
21	Scheduling and Planning Costs	$ 586,000	464,914	61,093	439	3,218	44	5,629	50,663
22	Meter Reading, Billing, Etc. Costs	$ 3,208,000	2,825,496	371,290	2,668	3,922	267	436	3,922
23	Meters & Services Costs	$ 14,563,000	11,538,991	2,451,937	109,389	123,096	11,900	47,189	280,497
24	System Core Main Costs	$ 22,916,000	13,161,486	7,972,851	229,772	159,722	13,407	152,502	1,226,260
25	Underground Storage Costs	$ 1,318,000	748,121	398,388	54,760	70,168	2,238	4,521	39,804
26	Proposed Cost	$ 103,109,000	65,099,007	30,502,559	3,043,029	2,512,126	135,856	210,277	1,606,145
27	**LRIC Based Target Margin**	**$ 42,591,000**	**28,739,007**	**11,255,559**	**397,029**	**360,126**	**27,856**	**210,277**	**1,601,145**
28	Current Revenue to Proposed Cost (Includes Cost of Gas)	**0.95**	**0.94**	**0.92**	**1.04**	**1.03**	**0.93**	**1.22**	**1.41**
29	Current Margin Revenue to LRIC Based Target Margin	**0.87**	**0.87**	**0.78**	**1.30**	**1.23**	**0.68**	**1.22**	**1.41**
	29A **Relative Margin to Cost at Present Rates**	**1.00**	**0.99**	**0.89**	**1.49**	**1.41**	**0.78**	**1.40**	**1.62**
30	Component LRIC Target Increase by Schedule	$ 5,446,000	$ 3,817,007	$ 2,529,559	$ (118,971)	$ (83,874)	$ 8,856	$ (46,723)	$ (659,855)
31	Target Increase as Percent of Total Present Revenue	5.58%	6.23%	9.04%	-3.76%	-3.23%	6.97%	-18.18%	-29.12%
	31A Target Increase as Percent of Present Margin Revenue	14.66%	15.32%	28.99%	-23.06%	-18.89%	46.61%	-18.18%	-29.18%

Exhibit No. 801
Miller / Avista
Page 1 of 3

AVISTA UTILITIES
OREGON JURISDICTION
LONG-RUN INCREMENTAL COST STUDY
TWELVE MONTHS ENDED DECEMBER 2011

INCREMENTAL INVESTMENT COSTS

Line No.			Residential Service SCH 410	General Service SCH 420	Large General Service SCH 424	Interruptible Service SCH 440	Seasonal Service SCH 444	Special Contract Service SCH 447	Transportation Service SCH 456
	SERVICE INSTALLATIONS	50 yr life							
1	TYPICAL SERVICE PIPE SIZE		3/4"	1"	1 1/4" - 2"	1/2" - 1.25"	1 1/4" - 2"	1/2" - 1.25"	1/2" - 1.25"
2	AVERAGE SERVICE COST		$ 442.55	$ 463.22	$ 3,147.54	$ 11,568.39	$ 3,147.54	$ 24,580.31	$ 24,029.04
3	LEVELIZED PLANT COST FACTOR		0.1925	0.1925	0.1925	0.1925	0.1925	0.1925	0.1925
4	ANNUAL REVENUE REQUIREMENT		$ 85.19	$ 89.17	$ 605.90	$ 2,226.92	$ 605.90	$ 4,731.71	$ 4,625.59
	METERS & REGULATORS	45 yr life							
5	METERS & REGULATORS		$ 166.58	$ 521.12	$ 2,963.90	$ 3,723.90	$ 3,500.18	$ 28,140.95	$ 10,811.27
6	LEVELIZED PLANT COST FACTOR		0.1930	0.1930	0.1930	0.1930	0.1930	0.1930	0.1930
7	ANNUAL REVENUE REQUIREMENT		$ 32.15	$ 100.58	$ 572.03	$ 718.71	$ 675.53	$ 5,431.20	$ 2,086.58
	MAIN INVESTMENT	70 yr life							
8	AVERAGE MAIN EXTENSION PER CUSTOMER		70	333	924	412	924	Estimated	1025
9	TYPICAL PIPE SIZE REQUIRED		2 "	2 "	sample	dedicated plt	same as 424	Bypass Cost	dedicated plt
10	AVERAGE COST PER FOOT 2008		33.19	33.19	26.07	$ 27.65	26.07		$ 46.52
11	MAIN EXTENSION INVESTMENT		$ 2,323.30	$ 11,052.27	$ 24,088.68	$ 11,392.49	$ 24,088.68	$ 330,880.00	$ 47,684.42
12	ESTIMATED DESIGN DAY LOAD FACTOR	100%	24.14%	25.87%	41.67%	58.05%	0.00%	80.85%	26.50%
13	INCR CAPACITY MAIN INVESTMENT PER THERM	0.123631	$ 0.512142	$ 0.477893	$ 0.296691	$ 0.212973	$ -	$ 0.152914	$ 0.466532
14	2011 AVERAGE THERMS PER CUSTOMER		553	2,241	42,863	122,052	17,518	709,890	694,386
15	CAPACITY MAIN INVESTMENT		$ 283.21	$ 1,070.96	$ 12,717.05	$ 25,993.82	$ -	$ 108,552.15	$ 323,953.34
16	INCR COMMODITY MAIN INVESTMENT PER THERM		0.348653	$ 0.348653	$ 0.348653	$ 0.348653	$ 0.348653	$ 0.348653	$ 0.348653
17	2011 AVERAGE THERMS PER CUSTOMER		553	2,241	42,863	122,052	17,518	709,890	694,386
18	SAFETY MAIN INVESTMENT		$ 192.81	$ 781.33	$ 14,944.31	$ 42,553.80	$ 6,107.70	$ 247,505.28	$ 242,099.76
19	TOTAL MAIN INVESTMENT PER CUSTOMER		$ 2,799.32	$ 12,904.56	$ 51,750.05	$ 79,940.10	$ 30,196.38	$ 686,937.42	$ 613,737.52
20	LEVELIZED PLANT COST FACTOR		0.1926	0.1926	0.1926	0.1926	0.1926	0.1926	0.1926
21	ANNUAL REVENUE REQUIREMENT		$ 539.15	$ 2,485.42	$ 9,967.06	$ 15,396.46	$ 5,815.82	$ 132,304.15	$ 118,205.85
	UNDERGROUND STORAGE INVESTMENT								
22	BALANCING INVESTMENT PER THROUGPUT THERM		$ 0.005854	$ 0.005854	$ 0.005854	$ 0.005854	$ 0.005854	$ 0.005854	$ 0.005854
23	STORAGE INVESTMENT PER SALES THERM		$ 0.052858	$ 0.052858	$ 0.052858	$ 0.052858	$ 0.052858		
24	2011 AVERAGE THERMS PER CUSTOMER		553	2,241	42,863	122,052	17,518	709,890	694,386
25	UNDERGROUND STORAGE INVESTMENT		$ 32.47	$ 131.57	$ 2,516.58	$ 7,165.95	$ 1,028.52	$ 4,155.76	$ 4,065.00
26	LEVELIZED PLANT COST FACTOR	50 yr life	0.1925	0.1925	0.1925	0.1925	0.1925	0.1925	0.1925
27	ANNUAL REVENUE REQUIREMENT		$ 6.25	$ 25.33	$ 484.44	$ 1,379.45	$ 197.99	$ 799.98	$ 782.51
28	**TOTAL INCREMENTAL INVESTMENT COST PER CUSTOMER**		**$ 662.74**	**$ 2,700.49**	**$ 11,629.44**	**$ 19,721.54**	**$ 7,295.25**	**$ 143,267.05**	**$ 125,700.52**

AVISTA UTILITIES
OREGON JURISDICTION
LONG-RUN INCREMENTAL COST STUDY
TWELVE MONTHS ENDED DECEMBER 2011

INCREMENTAL OPERATING AND MAINTENANCE COSTS

Line No.		Residential Service SCH 410	General Service SCH 420	Large General Service SCH 424	Interruptible Service SCH 440	Seasonal Service SCH 444	Special Contract Service SCH 447	Transportation Service SCH 456
	GAS MANAGEMENT (SCHEDULING)							
1	ANNUAL HOURS	0.01361	0.01361	0.01361	1.01361	0.01361	16.72043	16.72043
2	AVERAGE RATE PER HOUR	$ 36.68	$ 36.68	$ 36.68	$ 36.68	$ 36.68	$ 36.68	$ 36.68
3	LABOR COST	$ 0.49921	$ 0.49921	$ 0.49921	$ 37.17921	$ 0.49921	$ 613.30537	$ 613.30537
	GAS MANAGEMENT (PLANNING)							
4	ANNUAL HOURS	0.032802	0.032802	0.032802	0.032802	0.032802	0.032802	0.032802
5	AVERAGE RATE PER HOUR	$ 57.92	$ 57.92	$ 57.92	$ 57.92	$ 57.92	$ 57.92	$ 57.92
6	LABOR COST	$ 1.89989	$ 1.89989	$ 1.89989	$ 1.89989	$ 1.89989	$ 1.89989	$ 1.89989
7	**TOTAL GAS SUPPLY O&M**	**$ 2.40**	**$ 2.40**	**$ 2.40**	**$ 39.08**	**$ 2.40**	**$ 615.21**	**$ 615.21**
	METER READING							
8	ANNUAL HOURS	0.04319	0.04319	0.04319	0.14815	0.04319	0.14815	0.14815
9	AVERAGE RATE PER HOUR	$ 23.18	$ 23.18	$ 23.18	$ 29.78	$ 23.18	$ 29.78	$ 29.78
10	LABOR COST	$ 1.00114	$ 1.00114	$ 1.00114	$ 4.41191	$ 1.00114	$ 4.41191	$ 4.41191
	CUSTOMER HANDBILLS							
11	ANNUAL HOURS	0.00000	0.00000	0.00000	1.71309	0.00000	1.71309	1.71309
12	AVERAGE RATE PER HOUR	$ -	$ -	$ -	$ 26.90	$ -	$ 26.90	$ 26.90
13	LABOR COST	$ -	$ -	$ -	$ 46.08	$ -	$ 46.08	$ 46.08
	BILLING							
14	ANNUAL POSTAGE PER CUST	$ 3.61	$ 3.61	$ 3.61	$ 3.61	$ 3.61	$ 3.61	$ 3.61
15	5 YR AVERAGE PER CUST	$ 17.23	$ 17.23	$ 17.23	$ 17.23	$ 17.23	$ 17.23	$ 17.23
16	BILLING COST	$ 20.84	$ 20.84	$ 20.84	$ 20.84	$ 20.84	$ 20.84	$ 20.84
17	**TOTAL CUSTOMER O&M**	**$ 21.84**	**$ 21.84**	**$ 21.84**	**$ 71.33**	**$ 21.84**	**$ 71.33**	**$ 71.33**

AVISTA UTILITIES
OREGON JURISDICTION
LONG-RUN INCREMENTAL COST STUDY
TWELVE MONTHS ENDED DECEMBER 2011

RESULT SUMMARY *(Component Allocation)*

Line No.		OREGON TOTAL	Residential Service SCH 410	General Service SCH 420	Large General Service SCH 424	Interruptible Service SCH 440	Seasonal Service SCH 444	Special Contract Service SCH 447	Transportation Service SCH 456
	STATISTICS								
1	2011 ANNUAL THERM DELIVERIES	107,555,045	46,808,685	24,945,857	3,429,042	4,393,867	140,144	2,839,561	24,997,889
2	2011 AVERAGE CUSTOMERS	96,010	84,714	11,132	80	36	8	4	36
3	AVERAGE ANNUAL THERM DELIVERIES PER CUSTOMER		553	2,241	42,863	122,052	17,518	709,890	694,386
4	Gas Commodity Costs	$ 60,518,000	36,360,000	19,247,000	2,646,000	2,152,000	108,000	-	5,000
5	Gas Scheduling 1.03046	$ 76,009	43,579	5,727	41	1,379	4	2,528	22,752
6	Gas Planning	$ 187,965	165,850	21,794	157	70	16	8	70
7	Meter Reading	$ 99,315	87,394	11,484	83	164	8	18	164
8	Billing	$ 2,065,403	1,819,215	239,057	1,718	2,483	172	276	2,483
	Customer Installation Investment Cost								
9	Meters	$ 4,017,046	2,723,550	1,119,614	45,763	25,874	5,404	21,725	75,117
10	Services	$ 8,528,435	7,216,860	992,639	48,472	80,169	4,847	18,927	166,521
11	Main Extensions	$ 62,675,892	37,906,769	23,696,323	371,158	78,991	37,116	254,910	330,625
12	Total Customer Installation Investment Cost	$ 75,221,373	47,847,178	25,808,576	465,393	185,034	47,367	295,562	572,263
	System Core Main Cost								
13	Capacity	$ 9,623,029	4,620,902	2,296,161	195,944	180,231	-	83,629	2,246,163
14	Commodity	$ 7,225,009	3,145,792	1,675,193	230,262	295,051	9,411	190,678	1,678,623
15	Total Core Main Cost	$ 16,848,038	7,766,694	3,971,353	426,206	475,282	9,411	274,307	3,924,786
16	Underground Storage Cost	$ 932,789	529,468	281,952	38,755	49,660	1,584	3,200	28,170
17	Long Run Incremental Distribution Cost	$ 95,430,892	58,259,378	30,339,943	932,353	714,071	58,562	575,898	4,550,687
18	Revenue at Present Rates	$ 97,663,000	61,282,000	27,973,000	3,162,000	2,596,000	127,000	257,000	2,266,000
19	**Margin Revenue at Present Rates**	**$ 37,145,000**	**24,922,000**	**8,726,000**	**516,000**	**444,000**	**19,000**	**257,000**	**2,261,000**
	Proposed Cost by Functional Classification Assigned to Schedule by LRIC components								
20	Cost of Gas Commodity	$ 60,518,000	36,360,000	19,247,000	2,646,000	2,152,000	108,000	-	5,000
21	Scheduling and Planning Costs	$ 586,000	464,914	61,093	439	3,218	44	5,629	50,663
22	Meter Reading, Billing, Etc. Costs	$ 3,208,000	2,825,496	371,290	2,668	3,922	267	436	3,922
23	Meters & Services Costs	$ 14,563,000	11,538,991	2,451,937	109,389	123,096	11,900	47,189	280,497
24	System Core Main Costs	$ 22,916,000	13,161,486	7,972,851	229,772	159,722	13,407	152,502	1,226,260
25	Underground Storage Costs	$ 1,318,000	748,121	398,388	54,760	70,168	2,238	4,521	39,804
26	Proposed Cost	$ 103,109,000	65,099,007	30,502,559	3,043,029	2,512,126	135,856	210,277	1,606,145
27	**LRIC Based Target Margin**	**$ 42,591,000**	**28,739,007**	**11,255,559**	**397,029**	**360,126**	**27,856**	**210,277**	**1,601,145**
28	Current Revenue to Proposed Cost (Includes Cost of Gas)	**0.95**	**0.94**	**0.92**	**1.04**	**1.03**	**0.93**	**1.22**	**1.41**
29	Current Margin Revenue to LRIC Based Target Margin	**0.87**	**0.87**	**0.78**	**1.30**	**1.23**	**0.68**	**1.22**	**1.41**
	29A **Relative Margin to Cost at Present Rates**	**1.00**	**0.99**	**0.89**	**1.49**	**1.41**	**0.78**	**1.40**	**1.62**
30	Component LRIC Target Increase by Schedule	$ 5,446,000	$ 3,817,007	$ 2,529,559	$ (118,971)	$ (83,874)	$ 8,856	$ (46,723)	$ (659,855)
31	Target Increase as Percent of Total Present Revenue	5.58%	6.23%	9.04%	-3.76%	-3.23%	6.97%	-18.18%	-29.12%
	31A Target Increase as Percent of Present Margin Revenue	14.66%	15.32%	28.99%	-23.06%	-18.89%	46.61%	-18.18%	-29.18%

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

AVISTA CORP

JOSEPH D. MILLER
Exhibit No. 802

Long-Run Incremental Cost

AVISTA UTILITIES
NATURAL GAS RESULTS OF OPERATION
OREGON FORECASTED RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 2011
(000'S OF DOLLARS)

Compute Functional Revenue Requirement

FUNCTIONAL CLASSIFICATION

Line No.	DESCRIPTION		Forecasted Total	Cost of Gas Commodity & Amortizations	Scheduling and Planning Costs	Meter Reading Billing, Etc Costs	Meters & Services Costs	System Core Main Costs	Underground Storage Costs
	a		-						
	REVENUES								
1	Revenue From Rates		$97,663	60,518	586	3,208	14,563	22,916	1,318
2	Proposed Increase		5,446						
3	Other Revenues		152				152		
4	Total Gas Revenues		103,261	60,518	586	3,208	14,715	22,916	1,318
	EXPENSES								
5	Exploration and Development		0						
	Production								
6	City Gate Purchases		57,027	57,027					
7	Purchased Gas Expense		0						
8	Other Gas Expenses		569		569				
9	Depreciation		0						0
10	Taxes		3						3
11	Total Production		57,599	57,027	569	0	0	0	3
	Underground Storage								
12	Operating Expenses		98						98
13	Depreciation		93						93
14	Taxes		3						3
15	Total Underground Storage		194	0	0	0	0	0	194
	Distribution								
16	Operating Expenses		6,388				2,498	3,890	
17	Depreciation		3,772				1,475	2,297	
18	Taxes		2,248				879	1,369	
19	Total Distribution		12,408	0	0	0	4,853	7,555	0
20	Customer Accounting		2,844			2,844			
21	Customer Service & Information		1,863	1702		161			
22	Sales Expenses		108			108			
	Administrative & General								
23	Operating Expenses		6,846				2,621	4,081	144
24	Depreciation & Amortization		1,594				610	950	34
25	Taxes		96				37	57	2
26	Total Admin. & General		8,536	0	0	0	3,268	5,088	180
	Reveue Related Expenses								
	20 Uncollectibles	0.005419	559	328	3	17	79	124	6
	23 Commission Fees	0.002500	258	152	1	8	36	57	3
	23 ERSA	0.000780	80	47	0	3	11	18	1
	18 Franchise Fees	0.020856	2,151	1,262	12	67	304	478	27
27	Total Gas Expense	0.029555	86,600	60,518	586	3,208	8,551	13,321	415
28	OPERATING INCOME BEFORE FIT		16,661	(0)	0	0	6,164	9,595	903
	FEDERAL INCOME TAX								
29	Current and Deferred FIT		1,623	-	-	-	600	935	88
30	FIT on Revenue Increase	0.313842	1,709	-	-	-	632	984	93
31	State Income Tax		152	-	-	-	56	88	8
	SIT on Revenue Increase	0.073754	402	-	-	-	149	231	22
32	NET OPERATING INCOME		$12,775	($0)	$0	$0	$4,727	$7,357	$692
	Interest Expense	3.08%	4,571	0	0	0	1,691	2,633	248
	RATE BASE: PLANT IN SERVICE								
33	Production Plant		8						8
34	Underground Storage Plant		5,050						5,050
35	Transmission Plant		0						
36	Distribution Plant		234,666				91,775	142,891	
37	General Plant		24,067				9,214	14,344	508
38	Total Plant in Service		263,791	0	0	0	100,989	157,235	5,566
	ACCUMULATED DEPRECIATION								
39	Production Plant		0						0
40	Underground Storage Plant		108						108
41	Transmission Plant		0						
42	Distribution Plant		88,553				34,632	53,921	
43	General Plant		8,214				3,145	4,896	173
44	Total Accum. Depreciation		96,875	0	0	0	37,777	58,817	281
45	DEFERRED FIT		(29,205)				(11,181)	(17,408)	(616)
46	GAS INVENTORY		3,224						3,224
47	WORKING CAPITAL		7,486				2,866	4,462	158
48	TOTAL RATE BASE		$148,421	$0	$0	$0	$54,897	$85,472	$8,051
49	RATE OF RETURN		8.61%	#DIV/0!	#DIV/0!	#DIV/0!	8.61%	8.61%	8.61%

AVISTA UTILITIES
NATURAL GAS RESULTS OF OPERATION
OREGON FORECASTED RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 2011
(000'S OF DOLLARS)

Compute Functional Revenue Requirement

FUNCTIONAL CLASSIFICATION

Exhibit No. 802
Miller / Avista
Page 1 of 1

Line No.	DESCRIPTION		Forecasted Total	Cost of Gas Commodity & Amortizations	Scheduling and Planning Costs	Meter Reading Billing, Etc Costs	Meters & Services Costs	System Core Main Costs	Underground Storage Costs
	a		-						
	REVENUES								
1	Revenue From Rates		$97,663	60,518	586	3,208	14,563	22,916	1,318
2	Proposed Increase		5,446						
3	Other Revenues		152				152		
4	Total Gas Revenues		103,261	60,518	586	3,208	14,715	22,916	1,318
	EXPENSES								
5	Exploration and Development		0						
	Production								
6	City Gate Purchases		57,027	57,027					
7	Purchased Gas Expense		0						
8	Other Gas Expenses		569		569				
9	Depreciation		0						0
10	Taxes		3						3
11	Total Production		57,599	57,027	569	0	0	0	3
	Underground Storage								
12	Operating Expenses		98						98
13	Depreciation		93						93
14	Taxes		3						3
15	Total Underground Storage		194	0	0	0	0	0	194
	Distribution								
16	Operating Expenses		6,388				2,498	3,890	
17	Depreciation		3,772				1,475	2,297	
18	Taxes		2,248				879	1,369	
19	Total Distribution		12,408	0	0	0	4,853	7,555	0
20	Customer Accounting		2,844			2,844			
21	Customer Service & Information		1,863	1702		161			
22	Sales Expenses		108			108			
	Administrative & General								
23	Operating Expenses		6,846				2,621	4,081	144
24	Depreciation & Amortization		1,594				610	950	34
25	Taxes		96				37	57	2
26	Total Admin. & General		8,536	0	0	0	3,268	5,088	180
	Reveue Related Expenses								
	20 Uncollectibles	0.005419	559	328	3	17	79	124	6
	23 Commission Fees	0.002500	258	152	1	8	36	57	3
	23 ERSA	0.000780	80	47	0	3	11	18	1
	18 Franchise Fees	0.020856	2,151	1,262	12	67	304	478	27
27	Total Gas Expense	0.029555	86,600	60,518	586	3,208	8,551	13,321	415
28	OPERATING INCOME BEFORE FIT		16,661	(0)	0	0	6,164	9,595	903
	FEDERAL INCOME TAX								
29	Current and Deferred FIT		1,623	-	-	-	600	935	88
30	FIT on Revenue Increase	0.313842	1,709	-	-	-	632	984	93
31	State Income Tax		152	-	-	-	56	88	8
	SIT on Revenue Increase	0.073754	402	-	-	-	149	231	22
32	NET OPERATING INCOME		$12,775	($0)	$0	$0	$4,727	$7,357	$692
	Interest Expense	3.08%	4,571	0	0	0	1,691	2,633	248
	RATE BASE: PLANT IN SERVICE								
33	Production Plant		8						8
34	Underground Storage Plant		5,050						5,050
35	Transmission Plant		0						
36	Distribution Plant		234,666				91,775	142,891	
37	General Plant		24,067				9,214	14,344	508
38	Total Plant in Service		263,791	0	0	0	100,989	157,235	5,566
	ACCUMULATED DEPRECIATION								
39	Production Plant		0						0
40	Underground Storage Plant		108						108
41	Transmission Plant		0						
42	Distribution Plant		88,553				34,632	53,921	
43	General Plant		8,214				3,145	4,896	173
44	Total Accum. Depreciation		96,875	0	0	0	37,777	58,817	281
45	DEFERRED FIT		(29,205)				(11,181)	(17,408)	(616)
46	GAS INVENTORY		3,224						3,224
47	WORKING CAPITAL		7,486				2,866	4,462	158
48	TOTAL RATE BASE		$148,421	$0	$0	$0	$54,897	$85,472	$8,051
49	RATE OF RETURN		8.61%	#DIV/0!	#DIV/0!	#DIV/0!	8.61%	8.61%	8.61%

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF PATRICK D. EHRBAR
REPRESENTING AVISTA CORPORATION

Revenue Adjustment, Rate Spread, and Rate Design

I. INTRODUCTION

Q. Please state your name, business address and present position with Avista Corporation?

A. My name is Patrick D. Ehrbar and my business address is 1411 East Mission Avenue, Spokane, Washington. My present position is Manager of Rates and Tariffs.

Q. Would you briefly describe your duties?

A. Yes. My primary areas of responsibility include electric and natural gas rate design, customer usage and revenue analysis, and tariff administration.

Q. Please briefly describe your educational background and professional experiences.

A. I am a 1995 graduate of Gonzaga University with a Bachelors degree in Business Administration. In 1997 I graduated from Gonzaga University with a Masters degree in Business Administration. I started with Avista in April 1997 as a Resource Management Analyst in the Company's DSM department. Later, I became a Program Manager, responsible for energy efficiency program offerings for the Company's educational and governmental customers. In 2000, I was selected to be one of the Company's key Account Executives. In this role I was responsible for, among other things, being the primary point of contact for numerous commercial and industrial customers, including delivery of the Company's site specific energy efficiency programs.

I joined the State and Federal Regulation Department as a Senior Regulatory Analyst in 2007. Responsibilities in this role included being the discovery coordinator for the Company's rate cases and lead coordinator for the Natural Gas Decoupling Mechanism pilot program in Washington and resulting reporting and analysis. In November 2009, I was promoted to my current role.

Q. Have you previously provided testimony in other regulatory jurisdictions?

A. Yes. I have submitted pre-filed testimony before the Washington Utilities and Transportation Commission and Idaho Public Utilities Commission as a revenue and rate design witness.

Q. What is the scope of your testimony in this proceeding?

A. In addition to discussing the Company's Revenue Adjustment, my testimony in this proceeding will cover the spread of the proposed annual margin/revenue increase among the Company's gas service schedules as well as the application of the increase to the rates within each of the schedules.

Q. Are you sponsoring any exhibits to be introduced in this proceeding?

A. Yes. I am sponsoring Exhibit Nos. 901, 902 and 903, which were prepared under my direction.

Q. Would you please explain what is contained in Exhibit No. 901 and 902?

A. Yes. Exhibit No. 901 contains the present natural gas rates and schedules which are on file with the Commission as a part of our present tariff, PUC OR. No. 5. Exhibit No. 902 contains the proposed natural gas rates and schedules which reflect the proposed annual revenue increase of $5,446,000.

Q. What is contained in Exhibit No. 903?

A. Exhibit No. 903 contains information regarding the proposed rate spread and rate design of the proposed annual revenue increase of $5,446,000. Page 1 shows customer usage information by service schedule for 2009, 2010, and forecast for 2011. Page 2 shows the application of the overall revenue/margin increase by service schedule and the cost of service results before and after application of the proposed increase. Page 3 shows the proposed revenue and percentage increase by service schedule. Page 4 shows the present billing rates under each of the schedules, the proposed changes to those rates, and the rates after application of the proposed changes. Page 5 of Exhibit No. 903 shows the impact on the Company's margins resulting from the billing determinants approved in the Company's last general rate case, which were higher than what the Company is forecasting for 2011. The information contained in these pages will be referred to and discussed later in my testimony.

II. REVENUE ADJUSTMENT AND CUSTOMER USAGE

Q. Would you please describe the Revenue Adjustment?

A. Yes. The Revenue Adjustment represents the difference between the Company's actual recorded retail revenues during 2009 and forecasted revenue for 2011. Forecasted revenue for 2011 is based on projected customer usage and number of customers from the Company's most recent forecast applied to the present natural gas rates in effect. The Revenue Adjustment also contains an adjustment for purchased gas costs, which represents the difference between actual recorded gas costs during 2009 and "pro forma" gas costs for 2011. Pro forma gas costs for 2011 were determined using forecasted 2011 customer usage applied to the gas costs reflected in present rates, as approved by the Commission in UG 188 (the Company's 2009 Purchased Gas Adjustment (PGA) filing).

Q. You mentioned that projected customer usage for 2011 was taken from

the Company's most recent forecast. Could you please explain?

A. Yes. The Company's forecast is updated periodically to include the most recent actual results and for significant changes in the assumptions included in the forecast. The most recent forecast update was in September 2010 which included actual customer usage through July 2010 and the forecasted number of customers and total therm usage for future periods.

Q. Did the Company utilize projected usage from this forecast for all schedules/customer classes?

A. Projected customer usage from the forecast was used for all schedules with the exception of 447 and 456. Actual 2009 usage, adjusted for known and measurable changes, were used for those schedules.

Q. How does projected 2011 customer usage compare to (weather-normalized) usage since the Company's last general filing?

A. Page 1 of Exhibit 903 shows actual and weather normalized usage by rate schedule for 2009, the actual/forecasted usage for 2010, and the forecasted usage for 2011 used in this filing. As shown on lines 16 and 18, total throughput (sales and transportation volumes) is projected to decrease by approximately 1.1% over that two year period. Nearly all of this decrease in throughput is due to a decrease in usage by sales customers (non-transportation).

Q. How does the 2011 usage for residential customers compare to 2009 usage for these customer classes?

A. As shown in Exhibit 903, page 1 lines 1 and 3, total forecasted 2011 usage for residential customers is 0.5% less than total (weather-corrected) residential usage in 2009. In evaluating residential monthly use per customer, forecasted 2011 use per customer is 1.7% lower than monthly use per customer (weather-corrected) in 2009.

Q. How does projected 2011 usage for commercial and industrial customers compare to 2009 usage for these customer classes?

A. As shown in Exhibit 903, page 1 lines 4 and 6, total forecasted 2011 usage for commercial customers is 1.6% less than total (weather-corrected) commercial usage in 2009. As shown on lines 7 and 9, industrial usage shows a more significant drop (7.7%) from 2009 to forecasted 2011. This drop in overall usage is primarily due to a reduction in the average number of customers (from 142 in 2009 to 119 in 2011).

Q. How is the Company's forecasted usage for 2011 different from the billing determinants agreed upon in the Company's last general rate case?

A. In the Company's last general rate case, Docket UG-186, as part of the settlement approved by the Commission, the Parties agreed to a certain level of billing determinants which included the number of customers and average use per customer. Those billing determinants, specifically in Schedule 410, were considerably higher than what the Company is observing in 2010 and what it forecasts for 2011. For example, the average use per customer agreed upon in UG-186 for 2010 was approximately 48 therms per customer per month. As shown in Exhibit 903, Page 1, actual use per customer in 2009 was 46.8 therms per month, and for 2010 is projected to be 45.7 therms per month based on eight months actual and four months forecast. This is approximately <u>4.8% lower</u> than what was agreed upon in that case.

In addition, as it relates to number of customers, the Company is forecasting 84,714 average customers in 2011 for Schedule 410. In the billing determinants agreed upon in UG-186, the average customers agreed upon for 2010 was 86,421 which is 2% higher than currently forecasted by the Company for 2011 and 2.7% higher than 2010.

Q. What are the implications of the lower overall billing determinants?

A. The result of having both a lower number of customers, and lower use per customer, upon which to recover the Company's revenue requirement results in lower Company revenues and increased rates as there are simply fewer therms upon which to spread the Company's approved fixed costs. Page 5 of Exhibit 903 demonstrates the impact of the agreed upon billing determinants in UG-186 versus what the Company is forecasting for 2011. For all rate schedules, the total estimated lost margin from reduced loads is approximately $2.3 million.

Q. Is the Company proposing any changes to the present allocation of gas costs by rate schedule used in its PGA filings?

A. No.

III. PROPOSED RATE DESIGN AND RATE SPREAD

Q. Would you please describe the Company's present rate schedules and the types of gas service offered under each?

A. Yes. Table 1 below shows the type of customer and the average number of customers served during 2009 under each of the Company's Oregon natural gas schedules:

Table 1 – Customers by Rate Schedule

Schedule	Type of Customer	No. of Customers
Residential Sch. 410	Residential	84,373
General Sch. 420	Commercial	11,048
Lge. General Sch. 424	Large Comm. & Industrial	101
Interruptible Sch. 440	Large Comm. & Industrial	36
Seasonal Sch. 444	Non-winter Use	1
Transportation Sch. 456	Large Industrial	39
Sp. Contract Sch. 447	Large Industrial Transportation	5

Q. How does the Company propose to spread the proposed revenue increase of $5,446,000, or 5.6%, among its various service schedules?

A. The Company utilized the cost of service results sponsored by Company witness Mr. Miller as a guide to spread the proposed margin/revenue increase by service schedule. The spread of the proposed increase generally results in the margin-to-cost ratios for the various service schedules moving approximately 30% closer to 1.00 (unity). Table 2 below shows the margin-to-cost ratio under present rates and proposed rates.

Table 2 – Margin to Cost Ratios

Schedule	Margin to Cost at Present Rates	Margin to Cost at Proposed Rates
Residential Schedule 410	0.99	1.00
General Schedule 420	0.89	0.92
Large General Schedule 424	1.49	1.32
Interruptible Schedule 440	1.41	1.27
Seasonal Schedule 444	0.78	0.86
Transportation Schedule 456	1.62	1.44

This information is also shown in more detail on page 2 of Exhibit 903.

Q. What is the proposed percentage increase in revenue for each schedule?

A. Table 3 below shows the proposed percentage increase in revenue (including gas costs) for each service schedule:

<u>Table 3 – Proposed Increase in Revenue by Rate Schedule</u>

Schedule	Increase in Present Revenue
Residential Schedule 410	6.2%
General Schedule 420	5.7%
Large General Schedule 424	0.2%
Interruptible Schedule 440	0.5%
Seasonal Schedule 444	3.5%
Transportation Schedule 456	2.2%

More detailed information related to the revenue increase by schedule is shown on Page 3 of Exhibit 903.

Q. Is the Company projecting a PGA rate increase or decrease for customers this fall?

A. The Company recently filed for a PGA decrease. In the Company's initial filing on August 31, 2010, the Company proposed an overall 2.4% reduction in customers rates. That proposed reduction would help offset the requested general increase. As of the date of this filing, the Company has hedged (fixed) the price on a significant portion of forecasted customer gas requirements for the 2010-11 PGA year. The level of the decrease is dependent to some degree upon the Company's updated PGA filing due in mid-October 2010. Economic conditions continue to support lower overall wholesale gas prices in the near-term.

Q. Turning now to the proposed changes to the rates <u>within</u> the various service schedules, could you please describe what is shown on Page 4 of Exhibit No. 903?

A. Yes. Page 4 of Exhibit No. 903 shows the present rates for each of the various schedules, the proposed increases to those rates, and the resulting proposed rates.

Q. Please describe the proposed changes in the rates for Residential Schedule 410 that result in the overall revenue increase of 6.2% for that Schedule.

A. As shown on Page 4 of Exhibit No. 903, the Company is proposing an increase in the present monthly customer charge of $0.50 per month, from $6.50 to $7.00. The present charge per therm would be increased by $0.06971 per therm, from $1.16353 to $1.23324 per therm.

Q. Why is the Company proposing to increase the basic charge for Schedule 410?

A. A significant portion of the Company's costs are fixed and do not vary with customer usage. These costs include distribution plant and operating costs to provide reliable service to customers. As shown in Company witness Mr. Miller's Exhibit 801, the costs associated with billing, meter reading, meters and services are $14.13 per month for Schedule 410[1]. The Company believes that it is appropriate to recover a more reasonable level of these fixed customer costs through the basic charge.

Q. What is the change in the average bill for a residential customer as a result of these proposed changes?

A. Based on an average usage level of 46 therms per month, the average bill for a residential customer, which includes both base and adder schedules, would increase $3.71 per month, or 6.2%, from $59.77 to $63.48.

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[1] See Exhibit 901, Page 1 lines 22 & 23

Q. Could you please describe the changes you propose to the rates of General Service Schedule 420?

A. Yes. As shown on Page 2 of Exhibit No. 903, the present rates for service under Schedule 420 consist of an $8.50 per month customer charge and a usage charge of $1.07584 per therm. The Company is proposing an increase in the customer charge of $0.50 per month, from $8.50 to $9.00, and an increase of $0.06142 per therm in the usage charge. These changes result in the overall proposed increase of 5.7% in the revenue for the Schedule.

Q. Could you please describe the service provided and the proposed rate changes under Large General Service Schedule 424 and Seasonal Service 444?

A. Yes. Large General Service Schedule 424 provides service to customers whose usage is at least 75% for uses other than space-heating, i.e., who have a relatively high load-factor compared to other firm service customers. The Company is proposing an increase of $0.00165 per therm to the present usage rate under the Schedule and an increase of $2.00 per month in the present monthly customer charge, from $48.00 to $50.00 per month, resulting in an overall increase of 0.2% in revenue under the Schedule.

Seasonal Service Schedule 444 is for customers who use no natural gas during December, January and February. There are only eight customers served under the Schedule, most of whom are mint farmers. Customers served under this Schedule are not assessed a monthly customer charge. The Company is proposing an increase in the per therm charge under the Schedule of $0.03223 per therm, resulting in an overall increase of 3.5% in revenue under the Schedule.

Q. Could you please describe the service provided and the proposed rate changes under Interruptible Schedule 440?

A. Interruptible Service Schedule 440 serves customers that are able to curtail their natural gas usage or switch to an alternate fuel upon relatively short notice by the Company. These customers are not assigned firm pipeline transportation costs through their rates, as they do not create peak service requirements. The Company is proposing that the rate for service under Schedule 440 be increased by $0.00309 per therm, resulting in the proposed revenue increase of 0.5% for the Schedule. There is also an annual minimum charge under the Schedule associated with usage of 50,000 therms per year multiplied by the margin rate; correspondingly, the annual minimum margin rate is proposed to increase by $0.00249 per therm.

Q. Could you please describe the proposed changes to the present rates for Transportation Service Schedule 456?

A. Yes. Transportation Schedule 456 provides Company distribution service for large customers who use over 225,000 therms per year. These customers purchase natural gas and pipeline transportation from a third party. As shown on Page 4 of Exhibit No. 903, the present rates under the Schedule consist of a monthly customer charge of $250.00 and a five-block rate structure with declining rates for higher usage. The Company is proposing an increase of $25.00 per month to $275.00 for the monthly customer charge, and a uniform percentage increase of 1.82% to all rate blocks under the Schedule.

Q. Is the Company proposing any other changes to its natural gas service tariffs in this filing?

A. Yes. The Company is requesting that the incremental monthly rate detailed in tariff Schedule 493, "Residential Low Income Rate Assistance Program (LIRAP) – Oregon", be removed from base rates (Schedule 410), and be administered as a stand-alone tariff. This action would remove the current funding level of $0.00438 per therm (grossed up for revenue related costs to $0.00451 per therm) from Schedule 410 base rates, and is reflected on Page 4 of Exhibit 903.

Q. Why is the Company proposing to make this change?

A. The Company believes that the base tariff schedules should reflect distribution margin only, with all other costs tracked in separate stand-alone schedules. Currently, several rate schedules administered by the Company provide for recovery of certain costs in base tariffs. This includes such items as natural gas commodity and demand costs, intervenor funding, and DSM cost recovery. Other rate schedules are stand-alone tariffs and are not embedded in base rates. Schedule 408 (Income Tax Adjustment), and Schedule 496 (Margin Reduction Surcharge) are administered in a similar fashion to the Company's proposed treatment of Schedule 493 in that the rates approved under these schedules are not embedded in base rates. The Company believes that using a consistent methodology (i.e. stand-alone tariffs) provides for greater transparency for our customer's understanding of the individual components of their billing rate.

Q. Is the Company proposing other changes similar to that for Schedule 493?

A. The Company is not requesting other similar changes in this docket, however the Company, on August 31, 2010, filed with the Commission two new tariff schedules that would start the process for the removal of "DSM Cost Recovery" and "Intervenor Funding" from base rates[2]. In those filings, the Company has requested that the incremental change in funding for those two items be tracked in new rate schedules (Schedule 478 for DSM and Schedule 476 for Intervenor Funding), while the existing funding levels remain in base rates. Given that these filings are pending with the Commission, the Company did not believe that it was appropriate to request additional changes to these items until after those matters are resolved.

As it relates to natural gas costs and demand/transportation costs, those costs are currently broken out in sufficient detail Schedule 461 (Purchase Gas Cost Adjustment), although those costs are embedded in base rates. Changes to this tariff schedule though are also pending with the Commission as a part of the Company's 2010 PGA filing and therefore did not request any changes to this schedule at this time. The Company may, at the conclusion of this general rate case, file with the Commission a request to move the remaining costs embedded in base rates to appropriate stand-alone rate schedules.

Q. Does that conclude your pre-filed, direct testimony?

A. Yes, it does.

[2] See Avista Advice No. 10-2-G, 10-3-G and 10-4-G.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

AVISTA CORP

PATRICK D EHRBAR
Exhibit No. 901

Present Natural Gas Service Tariffs

AVISTA CORPORATION
dba Avista Utilities

SCHEDULE 410

GENERAL RESIDENTIAL NATURAL GAS SERVICE - OREGON

APPLICABILITY:

Applicable to residential natural gas service for all purposes.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:	Per Meter Per Month	
Customer Charge:	$6.50	(I)
Commodity Charge Per Therm:	$1.16804	(R)

Minimum Charge:

The Customer Charge constitutes the Minimum Charge.

SPECIAL CONDITIONS:

1. The above Commodity Charge Per Therm is subject to the provisions of Income Tax Adjustment Schedule 408 and Margin Reduction Surcharge Schedule 496.
2. A reconnection charge shall be made for restoration of service where service has been turned off for seasonal turnoff, or for other reasons arising through the action or for the convenience of the customer. (See Rule No. 20)
3. Service under this schedule is subject to adjustments as specified under Schedule 451 as well as any other applicable adjustments approved by the Public Utility Commission.
4. The above Commodity Charge includes a $.00438 per therm for the Residential Low Income Rate Assistance Program, as set forth under Schedule 493.
5. When service has been discontinued at the Customer's request and then reestablished within a twelve-month period, the Customer shall be required to pay the monthly minimum charges that would have been billed had service not been discontinued.

AVISTA CORPORATION
dba Avista Utilities

SCHEDULE 420
GENERAL NATURAL GAS SERVICE - OREGON

APPLICABILITY:
Applicable to commercial and small industrial natural gas service for all purposes.

TERRITORY:
This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:
The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:	Per Meter Per Month	
Customer Charge:	$8.50	(I)
Commodity Charge Per Therm:	$1.07584	(R)

Minimum Charge:
The Customer Charge constitutes the Minimum Charge.

SPECIAL CONDITIONS:

1. The above Commodity Charge Per Therm is subject to the provisions of Income Tax Adjustment Schedule 408 and Margin Reduction Surcharge Schedule 496.

2. A reconnection charge shall be made for restoration of service when service has been turned off for reasons arising through action of or for the convenience of the customer. (See Rule No. 20)

3. Service for the sole purpose of supplying a fireplace, log lighter, gas log, barbecue or any multiple or combination thereof, will be rendered only under this schedule. Where service for such purpose is requested, an advance-in-aid of construction in the amount of the Company's estimated total additional investment in the facilities required to provide such service shall be made prior to the commencement of construction. If the advance is for facilities to serve more than one customer location, an appropriate portion thereof will be assigned to each customer location. The advance will be refunded by the Company to the person or entity who made the

(continued)

AVISTA CORPORATION
dba Avista Utilities

SCHEDULE 424

LARGE GENERAL AND INDUSTRIAL NATURAL GAS SERVICE - OREGON

APPLICABILITY:

Applicable to large commercial and industrial use customers where at least 75% of the natural gas requirements are for uses other than space heating and where adequate capacity exists in the Company's system. Customers served under this schedule must use a minimum of 29,000 therms annually.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month	
Customer Charge:	$48.00	(I)
Commodity Charge Per Therm:	$.90868	(R)

Minimum Charge:

The minimum monthly charge shall consist of the Monthly Customer Charge.

SPECIAL CONDITIONS:

1. The above Commodity Charge Per Therm is subject to the provisions of Income Tax Adjustment Schedule 408.
2. This service is available only where adequate capacity exists in the Company's system.
3. As a condition precedent to service under this schedule an executed Agreement with the Company is required specifying quantity requirements and other terms and conditions as hereinafter provided.

(continued)

SCHEDULE 440

INTERRUPTIBLE NATURAL GAS SERVICE FOR LARGE COMMERCIAL AND INDUSTRIAL - OREGON

APPLICABILITY:

Applicable, subject to interruptions in capacity and supply, for large commercial and industrial use where capacity in excess of the existing requirements of firm sales and transportation customers exists in the Company's system. Customers served under this schedule must use a minimum of 50,000 therms annually.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month	
Commodity Charge Per Therm:	$.59070	(R)

Annual Minimum Charge:

Each Customer shall be subject to an Annual Minimum Charge if their gas usage during the prior year does not equal or exceed 50,000 therms. Such Annual Minimum Charge shall be determined by subtracting their actual usage for a twelve-month period from 50,000 therms multiplied by 10.152 cents per therm. (R)

SPECIAL CONDITIONS:

1. The above Commodity Charge Per Therm is subject to the provisions of Income Tax Adjustment Schedule 408.

2. This service is available only where capacity in excess of firm sales and firm transportation requirements exists in the Company's system.

3. Service under this schedule is not available to any "essential agricultural user" or "high priority user" (as defined in Section 281.203(a), Title 18, Code of Federal Regulations), who has requested protection from curtailment, as contemplated by Section 401 of the NGPA (Public Law 95-

(continued)

AVISTA CORPORATION
Dba Avista Utilities

SCHEDULE 444

SEASONAL NATURAL GAS SERVICE - OREGON

APPLICABILITY:

Applicable for natural gas service to customers whose entire natural gas requirements for any calendar year are supplied during the period from and after March 1, and continuing through November 30, of each year.

Service under this schedule is not available to any "essential agricultural user" or "high priority user" (as defined in section 281.203(a), Title 18, Code of Federal Regulations), who has requested protection from curtailment, as contemplated by Section 401 of the NGPA (Public Law 95-261). An "essential agricultural" or "high-priority" user receiving service under this schedule can obtain protection from curtailment by requesting transfer to the appropriate firm rate schedule of the Company.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month	
Commodity Charge Per Therm:	$.90877	(R)
Minimum Charge: $5,810.92 per season.		(R)

SPECIAL CONDITIONS:

1. The above Commodity Charge Per Therm is subject to the provisions of Income Tax Adjustment Schedule 408.

2. A contract will be required for a period of one (1) year when service is first rendered and year by year thereafter. Service will be subject to termination at the end of any contract year in the event the supply of gas may become limited to other firm gas customers.

3. The Company, when operating its propane-air peak shaving facilities, falls under the jurisdiction of the Federal Energy Agency with respect to the Company's

(continued)

SCHEDULE 456

INTERRUPTIBLE TRANSPORTATION OF CUSTOMER-OWNED NATURAL GAS FOR LARGE COMMERCIAL AND INDUSTRIAL SERVICE - OREGON

APPLICABILITY:

Applicable, subject to interruptions in capacity and supply, for the transportation of customer-owned natural gas for large commercial and industrial use where capacity in excess of the existing requirements of firm sales and transportation customers exists in the Company's system. Customers served under this schedule must transport over the Company's system a minimum of 225,000 therms annually.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:	Per Meter Per Month	
Customer Charge:	$250.00	(I)
Volumetric Charge Per Therm:		
First 10,000	$.15487	(I)
Next 20,000	$.09321	(I)
Next 20,000	$.07662	(I)
Next 200,000	$.05997	(I)
All Additional	$.03042	(I)

Minimum Charge:

The minimum monthly charge shall be $1,354.30 per month, accumulative annually.

Gross Revenue Fee Reimbursement:

The total of all charges invoiced by the Company shall be subject to a Gross Revenue Fee reimbursement charge of 2.6371 percent to cover governmental fees and levies imposed upon the Company, as those fees and levies may be in effect from time to time.

(continued)

SCHEDULE 493

RESIDENTIAL LOW INCOME RATE ASSISTANCE PROGRAM (LIRAP)-OREGON

PURPOSE:

The purpose of this schedule is to adjust rates in Schedule 410 – General Residential Natural Gas Service – Oregon, to generate funds to be used for bill payment assistance for Avista's qualifying low-income residential customers, in accordance with ORS 757.315.

APPLICABLE:

To all residential Customers in the State of Oregon where the Company has natural gas service available. This Residential Low Income Rate Assistance Program (LIRAP) Adjustment shall be applicable to all residential customers taking service under Schedule 410. This Rate Adjustment, set below is approximately 0.5% of retail rates.

MONTHLY RATE:

The energy charge of the residential rate Schedule 410 has been increased by $0.00438 per therm. This rate adjustment is reflected in the present rate set forth under Schedule 410.

SPECIAL CONDITIONS:

1. Each month, the Company will bill and collect low-income bill payment assistance funds from all Residential Customers. By the 10th of the month following the billing month, using the Company's internal cashless voucher system, the Company will determine and send the monthly voucher amount showing the Program Payment funds available to each participating Community Action Agency. By the 20th of the month following the billing month, the Company will remit payment to each Agency for allowed administrative and program delivery costs. Each agency will process client intake, authorize payments, and provide the Company with a client voucher list. Based on this client voucher list, the Company will transfer the authorized payments to the individual customer's utility account.

(continued)

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

AVISTA CORP

PATRICK D. EHRBAR
Exhibit No. 902

Proposed Natural Gas Service Tariffs

AVISTA CORPORATION
dba Avista Utilities

SCHEDULE 410

GENERAL RESIDENTIAL NATURAL GAS SERVICE - OREGON

APPLICABILITY:
Applicable to residential natural gas service for all purposes.

TERRITORY:
This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:
The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:	Per Meter Per Month	
Customer Charge:	$7.00	(I)
Commodity Charge Per Therm:	$1.23324	(I)

Minimum Charge:
The Customer Charge constitutes the Minimum Charge.

SPECIAL CONDITIONS:

1. The above Commodity Charge Per Therm is subject to the provisions of Income Tax Adjustment Schedule 408, Residential Low Income Rate Assistance Program (LIRAP) Schedule 493 and Margin Reduction Surcharge Schedule 496. (C)
2. A reconnection charge shall be made for restoration of service where service has been turned off for seasonal turnoff, or for other reasons arising through the action or for the convenience of the customer. (See Rule No. 20)
3. Service under this schedule is subject to adjustments as specified under Schedule 451 as well as any other applicable adjustments approved by the Public Utility Commission.
4. When service has been discontinued at the Customer's request and then reestablished within a twelve-month period, the Customer shall be required to pay the monthly minimum charges that would have been billed had service not been discontinued.

Advice No. 10-06-G
Issued September 29, 2010

Effective For Service On & After
November 1, 2010

Issued by Avista Utilities
By Kelly O. Norwood, V.P. State & Federal Regulation

Kelly Norwood

SCHEDULE 420
GENERAL NATURAL GAS SERVICE - OREGON

APPLICABILITY:
Applicable to commercial and small industrial natural gas service for all purposes.

TERRITORY:
This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:
The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month	
Customer Charge:	$9.00	(I)
Commodity Charge Per Therm:	$1.13726	(I)

Minimum Charge:
The Customer Charge constitutes the Minimum Charge.

SPECIAL CONDITIONS:

1. The above Commodity Charge Per Therm is subject to the provisions of Income Tax Adjustment Schedule 408 and Margin Reduction Surcharge Schedule 496.

2. A reconnection charge shall be made for restoration of service when service has been turned off for reasons arising through action of or for the convenience of the customer. (See Rule No. 20)

3. Service for the sole purpose of supplying a fireplace, log lighter, gas log, barbecue or any multiple or combination thereof, will be rendered only under this schedule. Where service for such purpose is requested, an advance-in-aid of construction in the amount of the Company's estimated total additional investment in the facilities required to provide such service shall be made prior to the commencement of construction. If the advance is for facilities to serve more than one customer location, an appropriate portion thereof will be assigned to each customer location. The advance will be refunded by the Company to the person or entity who made the

(continued)

AVISTA CORPORATION
dba Avista Utilities

SCHEDULE 424

LARGE GENERAL AND INDUSTRIAL NATURAL GAS SERVICE - OREGON

APPLICABILITY:

Applicable to large commercial and industrial use customers where at least 75% of the natural gas requirements are for uses other than space heating and where adequate capacity exists in the Company's system. Customers served under this schedule must use a minimum of 29,000 therms annually.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month	
Customer Charge:	\$50.00	(I)
Commodity Charge Per Therm:	\$0.91033	(I)

Minimum Charge:

The minimum monthly charge shall consist of the Monthly Customer Charge.

SPECIAL CONDITIONS:

1. The above Commodity Charge Per Therm is subject to the provisions of Income Tax Adjustment Schedule 408.
2. This service is available only where adequate capacity exists in the Company's system.
3. As a condition precedent to service under this schedule an executed Agreement with the Company is required specifying quantity requirements and other terms and conditions as hereinafter provided.

(continued)

SCHEDULE 440

INTERRUPTIBLE NATURAL GAS SERVICE FOR LARGE COMMERCIAL AND INDUSTRIAL - OREGON

APPLICABILITY:

Applicable, subject to interruptions in capacity and supply, for large commercial and industrial use where capacity in excess of the existing requirements of firm sales and transportation customers exists in the Company's system. Customers served under this schedule must use a minimum of 50,000 therms annually.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month	
Commodity Charge Per Therm:	$.59379	(I)

Annual Minimum Charge:

Each Customer shall be subject to an Annual Minimum Charge if their gas usage during the prior year does not equal or exceed 50,000 therms. Such Annual Minimum Charge shall be determined by subtracting their actual usage for a twelve-month period from 50,000 therms multiplied by 10.401 cents per therm. (I)

SPECIAL CONDITIONS:

1. The above Commodity Charge Per Therm is subject to the provisions of Income Tax Adjustment Schedule 408.

2. This service is available only where capacity in excess of firm sales and firm transportation requirements exists in the Company's system.

3. Service under this schedule is not available to any "essential agricultural user" or "high priority user" (as defined in Section 281.203(a), Title 18, Code of Federal Regulations), who has requested protection from curtailment, as contemplated by Section 401 of the NGPA (Public Law 95-

(continued)

SCHEDULE 444

SEASONAL NATURAL GAS SERVICE - OREGON

APPLICABILITY:

Applicable for natural gas service to customers whose entire natural gas requirements for any calendar year are supplied during the period from and after March 1, and continuing through November 30, of each year.

Service under this schedule is not available to any "essential agricultural user" or "high priority user" (as defined in section 281.203(a), Title 18, Code of Federal Regulations), who has requested protection from curtailment, as contemplated by Section 401 of the NGPA (Public Law 95-261). An "essential agricultural" or "high-priority" user receiving service under this schedule can obtain protection from curtailment by requesting transfer to the appropriate firm rate schedule of the Company.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month	
Commodity Charge Per Therm:	$0.94100	(I)

Minimum Charge:
$5,810.92 per season.

SPECIAL CONDITIONS:

1. The above Commodity Charge Per Therm is subject to the provisions of Income Tax Adjustment Schedule 408.

2. A contract will be required for a period of one (1) year when service is first rendered and year by year thereafter. Service will be subject to termination at the end of any contract year in the event the supply of gas may become limited to other firm gas customers.

3. The Company, when operating its propane-air peak shaving facilities, falls under the jurisdiction of the Federal Energy Agency with respect to the Company's

(continued)

Kelly Norwood

AVISTA CORPORATION
dba Avista Utilities

SCHEDULE 456

INTERRUPTIBLE TRANSPORTATION OF CUSTOMER-OWNED NATURAL GAS FOR LARGE COMMERCIAL AND INDUSTRIAL SERVICE - OREGON

APPLICABILITY:

Applicable, subject to interruptions in capacity and supply, for the transportation of customer-owned natural gas for large commercial and industrial use where capacity in excess of the existing requirements of firm sales and transportation customers exists in the Company's system. Customers served under this schedule must transport over the Company's system a minimum of 225,000 therms annually.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month	
Customer Charge:	$275.00	(I)
Volumetric Charge Per Therm:		
First 10,000	$.15768	(I)
Next 20,000	$.09490	(I)
Next 20,000	$.07801	(I)
Next 200,000	$.06106	(I)
All Additional	$.03097	(I)

Minimum Charge:
The minimum monthly charge shall be $1,354.30 per month, accumulative annually.

Gross Revenue Fee Reimbursement:
The total of all charges invoiced by the Company shall be subject to a Gross Revenue Fee reimbursement charge of 2.6371 percent to cover governmental fees and levies imposed upon the Company, as those fees and levies may be in effect from time to time.

(continued)

AVISTA CORPORATION
dba Avista Utilities

SCHEDULE 493

RESIDENTIAL LOW INCOME RATE ASSISTANCE PROGRAM (LIRAP)-OREGON

PURPOSE:

The purpose of this schedule is to generate funds to be used for bill payment assistance for Avista's qualifying low-income residential customers, in accordance with ORS 757.315. (C)

APPLICABLE:

To all residential Customers in the State of Oregon where the Company has natural gas service available. This Residential Low Income Rate Assistance Program (LIRAP) Adjustment shall be applicable to all residential customers taking service under Schedule 410. This Rate Adjustment, set below is approximately 0.5% of retail rates.

MONTHLY RATE:

With Gross Revenue Factor:	$0.00451 per therm	(C)
Without Gross Revenue Factor:	$0.00438 per therm	(C)

SPECIAL CONDITIONS:

1. Each month, the Company will bill and collect low-income bill payment assistance funds from all Residential Customers. By the 10th of the month following the billing month, using the Company's internal cashless voucher system, the Company will determine and send the monthly voucher amount showing the Program Payment funds available to each participating Community Action Agency. By the 20th of the month following the billing month, the Company will remit payment to each Agency for allowed administrative and program delivery costs. Each agency will process client intake, authorize payments, and provide the Company with a client voucher list. Based on this client voucher list, the Company will transfer the authorized payments to the individual customer's utility account.

(continued)

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

AVISTA CORP

PATRICK D. EHRBAR
Exhibit No. 903

Rate Design & Rate Spread

Avista Utilities
State of Oregon
Comparison of Natural Gas Usage
2009 Weather-Normalized, 2010 Actual & Forecast *, and 2011 Forecast

Line No.		Actual Usage	Weather Adj.	Normalized Usage	Avg. Customers	Annual Use/ Customer	Monthly Use/ Customer
	Residential Sch 410						
1	2009	49,979,769	(2,947,495)	47,032,274	83,719	561.8	46.8
2	2010	46,525,476	(417,484)	46,107,992	84,125	548.1	45.7
3	2011			46,808,685	84,714	552.5	46.0
	Commercial Sch 420						
4	2009	26,908,990	(1,542,926)	25,366,064	11,017	2,302	192
5	2010	25,283,919	(191,276)	25,092,643	11,060	2,269	189
6	2011			24,945,857	11,132	2,241	187
	Industrial Sales Schs. 424, 440 & 444						
7	2009			8,618,099	142	60,549	5,046
8	2010			7,734,443	124	62,375	5,198
9	2011			7,963,053	119	66,916	5,576
	Total Sales Volumes						
10	2009			81,016,437	94,878		
11	2010			78,935,078	95,309		
12	2011			79,717,595	95,965		
	Transport Schs. 447 & 456						
13	2009			27,683,978	41	668,426	55,702
14	2010			31,297,946	43	727,859	60,655
15	2011			27,837,450	40	695,936	57,995
	Total Throughput						
16	2009			108,700,415			
17	2010			110,233,024			
18	2011			107,555,045			

* The 2010 numbers include January through August actual booked usage and September through December forecasted usage.

Avista Utilities
Oregon - Gas
Pro Forma 12 Months Ended December 31, 2011

Line No.		OREGON TOTAL	Residential Service SCH 410	General Service SCH 420	Large General Service SCH 424	Interruptible Service SCH 440	Seasonal Service SCH 444	Special Contract Service SCH 447	Transportation Service SCH 456
1	CURRENT REVENUE (Less Schedule 493 - LIRAP)	$ 97,451,893	$ 61,070,893	$ 27,973,000	$ 3,162,000	$ 2,596,000	$ 127,000	$ 257,000	$ 2,266,000
2	COST OF GAS (Less Schedule 493 - LIRAP)	$ 60,306,893	$ 36,148,893	$ 19,247,000	$ 2,646,000	$ 2,152,000	$ 108,000	$ -	$ 5,000
3	CURRENT MARGIN	$ 37,145,000	$ 24,922,000	$ 8,726,000	$ 516,000	$ 444,000	$ 19,000	$ 257,000	$ 2,261,000
4	% of Current Margin excl Sch 447	100.00%	67.56%	23.66%	1.40%	1.20%	0.05%		6.13%
5	Total Revenue Requirement	$ 5,446,000							
6	Revenue Requirement as a Percent of Margin Revenue	14.66%							
7	Percentage Applied to Overall Margin Increase		103.22%	125.00%	10.00%	20.00%	175.00%		15.00%
8	Increase as a Percent of Total Current Margin		15.13%	18.33%	1.47%	2.93%	25.66%		2.20%
9	**PROPOSED MARGIN REVENUE INCREASE**	**$ 5,446,000**	**$ 3,771,617**	**$ 1,599,199**	**$ 7,565**	**$ 13,019**	**$ 4,875**		**$ 49,724**
10	**Percentage Revenue Increase**	**5.59%**	**6.18%**	**5.72%**	**0.24%**	**0.50%**	**3.84%**		**2.19%**
	Cost of Service								
11	Proposed Margin	$ 42,591,000	$ 28,693,617	$ 10,325,199	$ 523,565	$ 457,019	$ 23,875	$ 257,000	$ 2,310,724
12	LRIDC Based Target Margin (Line 27 of Miller Exhibit 801 Page 1 of 3)	42,591,000	28,739,007	11,255,559	397,029	360,126	27,856	210,277	1,601,145
13	**Relative Margin to Cost at Present Rates (Line 29A of Miller Exhibit 801 Page 1 of 3)**	**1.00**	**0.99**	**0.89**	**1.49**	**1.41**	**0.78**		**1.62**
14	**Relative Margin to Cost at Proposed Rates**	**1.00**	**1.00**	**0.92**	**1.32**	**1.27**	**0.86**		**1.44**

Avista Utilities
Proposed Revenue Increase by Schedule
Oregon - Gas
Pro Forma 12 Months Ended December 31, 2011
(000s of Dollars)

Line No.	Type of Service	Schedule Number	Revenue Under Present Rates	Increase/ (Decrease)	Revenue Under Proposed Rates	Therms (000s)	Increase/ (Decrease) Per Therm	**Revenue Percentage Increase**
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Residential	410	$61,071	$3,771	$64,842	46,809	8.06¢	**6.2%**
2	General Service	420	27,973	1,599	29,572	24,946	6.41¢	**5.7%**
3	Large General Service	424	3,162	8	3,170	3,429	0.22¢	**0.2%**
4	Interruptible Service	440	2,596	13	2,609	4,394	0.29¢	**0.5%**
5	Seasonal Service	444	127	5	132	140	3.22¢	**3.5%**
6	Transportation Service	456	2,266	50	2,316	24,998	0.20¢	**2.2%**
7	Special Contract	447	257	0	257	2,840	0.00¢	**0.0%**
8	Total		$97,452 0	$5,446	$102,898 0	107,555 0	5.06¢	**5.6%**

Avista Utilities
Comparison of Present & Proposed Gas Rates
Oregon - Gas

Present Base Rates	Proposed Schedule 493 Adjustment	New Present Base Rates	Change	Proposed Base Rates
		Residential Service Schedule 410		
$6.50 Customer Charge		$6.50 Customer Charge	$0.50/month	$7.00 Customer Charge
All Therms - $1.16804/Therm	All Therms - -$0.00451/Therm	All Therms - $1.16353/Therm	$0.06971/therm	All Therms - $1.23324/Therm
		General Service Schedule 420		
$8.50 Customer Charge		$8.50 Customer Charge	$0.50/month	$9.00 Customer Charge
All Therms - $1.07584/Therm		All Therms - $1.07584/Therm	$0.06142/therm	All Therms - $1.13726/Therm
		Large General Service Schedule 424		
$48.00 Customer Charge		$48.00 Customer Charge	$2.00/month	$50.00 Customer Charge
All Therms - $0.90868/Therm		All Therms - $0.90868/Therm	$0.00165/therm	All Therms - $0.91033/Therm
		Interruptible Service Schedule 440		
All Therms - $0.59070/Therm		All Therms - $0.59070/Therm	$0.00309/therm	All Therms - $0.59379/Therm
		Seasonal Service Schedule 444		
All Therms - $0.90877/Therm		All Therms - $0.90877/Therm	$0.03223/therm	All Therms - $0.94100/Therm
		Transportation Service Schedule 456		
$250.00 Customer Charge		$250.00 Customer Charge	$25.00/month	$275.00 Customer Charge
1st 10,000 Therms - $0.15487/Therm		1st 10,000 Therms - $0.15487/Therm	$0.00281/therm	1st 10,000 Therms - $0.15768/Therm
Next 20,000 Therms - $0.09321/Therm		Next 20,000 Therms - $0.09321/Therm	$0.00169/therm	Next 20,000 Therms - $0.09490/Therm
Next 20,000 Therms - $0.07662/Therm		Next 20,000 Therms - $0.07662/Therm	$0.00139/therm	Next 20,000 Therms - $0.07801/Therm
Next 200,000 Therms - $0.05997/Therm		Next 200,000 Therms - $0.05997/Therm	$0.00109/therm	Next 200,000 Therms - $0.06106/Therm
Over 250,000 Therms - $0.03042/Therm		Over 250,000 Therms - $0.03042/Therm	$0.00055/therm	Over 250,000 Therms - $0.03097/Therm
Annual Minimum: $1,354.30 per Month		Annual Minimum: $1,354.30 per Month		

Avista Utilities
State of Oregon
Margin Loss Analysis

		Schedule 410	Schedule 420	Schedule 424	Schedule 440	Schedule 444	Schedule 456	Total
	Impact of Use per Customer							
A	Use Per Customer - Forecast 2011 (S)	46.05	186.74	3,571.92	10,170.99	3,892.89	57,865.48	
B	Use Per Customer - UG-186 (V)	48.03	202.84	3,489.05	12,084.32	4,989.32	65,198.44	
C	Use per Customer Difference per Month (A - B)	(1.98)	(16.10)	82.87	(1,913.33)	(1,096.43)	(7,332.96)	
D	Number of Customer Bills per Year (R)	1,016,568	133,584	960	432	36	432	
E	Reduction in Therms (C * D)	(2,012,805)	(2,150,702)	79,555	(826,559)	(39,471)	(3,167,839)	
F	Margin Rate Per Therm	$ 0.39095	$ 0.30399	$ 0.13683	$ 0.10068	$ 0.13692	$ 0.05045	
G	Margin Lost (E * F)	$ (786,905.97)	$ (653,792.02)	$ 10,885.54	$ (83,217.92)	$ (5,404.44)	$ (159,830.03)	$ (1,678,264.84)
	Impact of Number of Customers							
H	Number of Customer Bills (Forecast 2011) (R)	1,016,568	133,584	960	432	36	432	
I	Number of Customer Bills (UG-186) (U)	1,037,046	134,496	1,170	478	36	408	
J	Difference (H - I)	(20,478)	(912)	(210)	(46)	-	24	
K	Customer Charge	$ 6.50	$ 8.50	$ 48.00	$ -	$ -	$ 250.00	
L	Reduction in Monthly Basic Charge (J * K)	$ (133,107.00)	$ (7,752.00)	$ (10,080.00)	$ -	$ -	$ 6,000.00	
M	Reduction in Use Per Customer - Therms (A * J)	(943,012)	(170,307)	(750,103)	(467,866)	-	1,388,772	
N	Reduction in Use Per Customer - Margin (F * M)	$ (368,670.50)	$ (51,771.59)	$ (102,636.62)	$ (47,104.70)	$ -	$ 70,069.03	
O	Margin Lost (L + N)	$ (501,777.50)	$ (59,523.59)	$ (112,716.62)	$ (47,104.70)	$ -	$ 76,069.03	$ (645,053.38)
P	Total Lost Margin Due to Use/# of Customers (G + O)	**$ (1,288,683.48)**	**$ (713,315.61)**	**$ (101,831.08)**	**$ (130,322.62)**	**$ (5,404.44)**	**$ (83,761.00)**	**$ (2,323,318.22)**

Calculate Use per Customer

		Schedule 410	Schedule 420	Schedule 424	Schedule 440	Schedule 444	Schedule 456
Q	Usage - Forecast 2011	46,808,685	24,945,857	3,429,042	4,393,867	140,144	24,997,889
R	Customer Bills - Forecast 2011	1,016,568	133,584	960	432	36	432
S	Average Monthly Usage per Customer - Forecast 2011 (Q / R)	46.05	186.74	3,571.92	10,170.99	3,892.89	57,865.48
T	Usage - UG-186	49,810,674	27,280,991	4,082,190	5,776,303	184,605	26,600,962
U	Customer Bills - UG-186	1,037,046	134,496	1,170	478	37	408
V	Average Monthly Usage per Customer - UG-186 (T / U)	48.03	202.84	3,489.05	12,084.32	4,989.32	65,198.44

Avista Utilities
Oregon - Gas
Revenue Under Present and Proposed Base Tariff Rates
Pro Forma Year Ended 12/31/10

WORK PAPER REFERENCE		TOTAL	RESIDENTIAL SCHED. 410	GEN SVC SCHED. 420	LG GEN SVC SCHED. 424	INTERRUPT SCHED. 440	SEASONAL SCHED. 444	TRANSPORT SCHED. 456	SP CONTRACT SCHED. 447
	PRESENT BILL DETERMINANTS								
	THERMS								
PDE-5	BLOCK 1		46,808,685	24,945,857	3,429,042	4,393,867	140,144	4,019,793	
PDE-5	BLOCK 2							6,433,815	935,868
PDE-5	BLOCK 3							4,132,889	
PDE-5	BLOCK 4							10,223,303	1,575,921
PDE-5	BLOCK 5							188,089	327,772
	SUBTOTAL	107,555,045	46,808,685	24,945,857	3,429,042	4,393,867	140,144	24,997,889	2,839,561
	NET SHIFTING ADJUSTMENT								
	SUBTOTAL	107,555,045	46,808,685	24,945,857	3,429,042	4,393,867	140,144	24,997,889	2,839,561
	ADJUSTMENT TO ACTUAL								
	TOTAL BEFORE ADJUSTMENT	107,555,045	46,808,685	24,945,857	3,429,042	4,393,867	140,144	24,997,889	2,839,561
	WEATHER & UNBILLED REV. ADJ.								
	TOTAL PROFORMA THERMS	107,555,045	46,808,685	24,945,857	3,429,042	4,393,867	140,144	24,997,889	2,839,561
PDE-5	TOTAL BILLS		1,016,568	133,584	960	432	36	432	48
	TOTAL MINIMUM BILLS								
	PROPOSED BILL DETERMINANTS								
	THERMS								
	BLOCK 1		46,808,685	24,945,857	3,429,042	4,393,867	140,144	4,019,793	
	BLOCK 2							6,433,815	935,868
	BLOCK 3							4,132,889	
	BLOCK 4							10,223,303	1,575,921
	BLOCK 5							188,089	327,772
	SUBTOTAL	107,555,045	46,808,685	24,945,857	3,429,042	4,393,867	140,144	24,997,889	2,839,561
	NET SHIFTING ADJUSTMENT								
	SUBTOTAL	107,555,045	46,808,685	24,945,857	3,429,042	4,393,867	140,144	24,997,889	2,839,561
	ADJUSTMENT TO ACTUAL								
	TOTAL BEFORE ADJUSTMENT	107,555,045	46,808,685	24,945,857	3,429,042	4,393,867	140,144	24,997,889	2,839,561
	WEATHER & UNBILLED REV. ADJ.								
	TOTAL PROFORMA THERMS	107,555,045	46,808,685	24,945,857	3,429,042	4,393,867	140,144	24,997,889	2,839,561
	TOTAL BILLS		1,016,568	133,584	960	432	36	432	48
	TOTAL MINIMUM BILLS								

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WORK PAPER REFERENCE		TOTAL	RESIDENTIAL SCHED. 410	GEN SVC SCHED. 420	LG GEN SVC SCHED. 424	INTERRUPT SCHED. 440	SEASONAL SCHED. 444	TRANSPORT SCHED. 456	SP CONTRACT SCHED. 447
	PRESENT RATES								(1)
Exh 701	BASIC CHARGE		$6.50	$8.50	$48.00			$250.00	
PDE-7	ANNUAL MINIMUM								$161,468
Exh 701	BLOCK 1 PER THERM		$1.16353	$1.07584	$0.90868	$0.59070	$0.90877	$0.15487	$0.02700
Exh 701	BLOCK 2 PER THERM							$0.09321	$0.04694
Exh 701	BLOCK 3 PER THERM							$0.07662	
Exh 701	BLOCK 4 PER THERM							$0.05997	$0.02750
Exh 701	BLOCK 5 PER THERM							$0.03042	$0.02500
	PROPOSED RATES								
	BASIC CHARGE		$7.00	$9.00	$50.00			$275.00	
	ANNUAL MINIMUM								$161,468
	BLOCK 1 PER THERM		$1.23324	$1.13726	$0.91033	$0.59379	$0.94100	$0.15768	$0.02700
	BLOCK 2 PER THERM							$0.09490	$0.04694
	BLOCK 3 PER THERM							$0.07801	
	BLOCK 4 PER THERM							$0.06106	$0.02750
	BLOCK 5 PER THERM							$0.03097	$0.02500

(1) Block 1 - Bio Mass One; Annual Min. Charge = $38,000
Block 2 - Collins Products; no annual minimum
Block 4 - Murphy Plywood; Annual Min. Charge = $75,000
Block 5 - Roseburg Forest Products; Annual Min. Charge = $100,000

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WORK PAPER REFERENCE		TOTAL	RESIDENTIAL SCHED. 410	GEN SVC SCHED. 420	LG GEN SVC SCHED. 424	INTERRUPT SCHED. 440	SEASONAL SCHED. 444	TRANSPORT SCHED. 456	SP CONTRACT SCHED. 447
	PRESENT REVENUE								
	BASE TARIFF REVENUE								
	BASIC CHARGE	$7,897,236	$6,607,692	$1,135,464	$46,080			$108,000	
	ANNUAL MINIMUM	$161,468							$161,468
	BLOCK 1	$87,762,323	$54,463,309	$26,837,751	$3,115,902	$2,595,457	$127,359	$622,545	
	BLOCK 2	$643,626						$599,696	$43,930
	BLOCK 3	$316,662						$316,662	
	BLOCK 4	$656,429						$613,091	$43,338
	BLOCK 5	$13,916						$5,722	$8,194
	ANNUAL MINIMUM	$0							
	SUBTOTAL	$97,451,660	$61,071,001	$27,973,215	$3,161,982	$2,595,457	$127,359	$2,265,716	$256,930
	NET SHIFTING ADJUSTMENT								
	SUBTOTAL	$97,451,660	$61,071,001	$27,973,215	$3,161,982	$2,595,457	$127,359	$2,265,716	$256,930
	ADJUST TO ACTUAL	$0							
	TOTAL BASE TARIFF REVENUE	$97,451,660	$61,071,001	$27,973,215	$3,161,982	$2,595,457	$127,359	$2,265,716	$256,930
	ADJUSTMENT REVENUE								
	UNBILLED REVENUE ADJUSTMENT								
	UNBILLED THERMS	0							
Exh 701	UNBILLED RATE		$1.16353	$1.07584	$0.90868		$0.90877		
	UNBILLED REVENUE	$0	$0	$0	$0		$0		
	WEATHER NORMALIZATION ADJ								
	WEATHER-SENSITIVE THERMS	0	0	0					
Exh 701	WEATHER-SENSITIVE RATE		$1.16353	$1.07584					
	WEATHER-SENSITIVE REVENUE	$0	$0	$0					
	OTHER ADJUSTMENTS								
	TOTAL ADJUSTMENT REVENUE	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL BASE TARIFF REVENUE	$97,451,660	$61,071,001	$27,973,215	$3,161,982	$2,595,457	$127,359	$2,265,716	$256,930
	TOTAL PRESENT REVENUE	$97,451,660	$61,071,001	$27,973,215	$3,161,982	$2,595,457	$127,359	$2,265,716	$256,930

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Revenue Under Present and Proposed Base Tariff Rates
Pro Forma Year Ended 12/31/10

WORK PAPER REFERENCE		TOTAL	RESIDENTIAL SCHED. 410	GEN SVC SCHED. 420	LG GEN SVC SCHED. 424	INTERRUPT SCHED. 440	SEASONAL SCHED. 444	TRANSPORT SCHED. 456	SP CONTRACT SCHED. 447
	PROPOSED REVENUE								
	BASE TARIFF REVENUE								
	BASIC CHARGE	$8,485,032	$7,115,976	$1,202,256	$48,000			$118,800	
	ANNUAL MINIMUM	$161,468							$161,468
	BLOCK 1	$92,592,595	$57,726,343	$28,369,925	$3,121,560	$2,609,034	$131,876	$633,858	
	BLOCK 2	$654,523						$610,593	$43,930
	BLOCK 3	$322,416						$322,416	
	BLOCK 4	$667,570						$624,232	$43,338
	BLOCK 5	$14,020						$5,826	$8,194
	ANNUAL MINIMUM	$0							
	SUBTOTAL	$102,897,624	$64,842,319	$29,572,181	$3,169,560	$2,609,034	$131,876	$2,315,724	$256,930
	NET SHIFTING ADJUSTMENT								
	SUBTOTAL	$102,897,624	$64,842,319	$29,572,181	$3,169,560	$2,609,034	$131,876	$2,315,724	$256,930
	ADJUST TO ACTUAL	$0							
	TOTAL BASE TARIFF REVENUE	$102,897,624	$64,842,319	$29,572,181	$3,169,560	$2,609,034	$131,876	$2,315,724	$256,930
	ADJUSTMENT REVENUE								
	UNBILLED REVENUE ADJUSTMENT								
	UNBILLED THERMS	0	0	0	0		0		
PDE-2	UNBILLED RATE		$1.23324	$1.13726	$0.91033		$0.94100		
	UNBILLED REVENUE	$0	$0	$0	$0		$0		
	WEATHER NORMALIZATION ADJ								
	WEATHER-SENSITIVE THERMS	0	0	0					
PDE-2	WEATHER-SENSITIVE RATE		$1.23324	$1.13726					
	WEATHER-SENSITIVE REVENUE	$0	$0	$0					
	OTHER ADJUSTMENTS								
	TOTAL ADJUSTMENT REVENUE	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL BASE TARIFF REVENUE	$102,897,624	$64,842,319	$29,572,181	$3,169,560	$2,609,034	$131,876	$2,315,724	$256,930
	TOTAL PROPOSED REVENUE	$102,897,624	$64,842,319	$29,572,181	$3,169,560	$2,609,034	$131,876	$2,315,724	$256,930
	TOTAL PRESENT REVENUE	$97,451,660	$61,071,001	$27,973,215	$3,161,982	$2,595,457	$127,359	$2,265,716	$256,930
	TOTAL INCREASED REVENUE	**$5,445,964**	**$3,771,317**	**$1,598,967**	**$7,578**	**$13,577**	**$4,517**	**$50,008**	**$0**
	PERCENT REVENUE INCREASE	**5.59%**	**6.18%**	**5.72%**	**0.24%**	**0.52%**	**3.55%**	**2.21%**	**0.00%**