AVISTA/100
Morris

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, and board director of the Washington Roundtable. On January 1, 2011, I was appointed to the Federal Reserve Bank of San Francisco, Seattle Branch board of directors and in January 2012 I was appointed as Chairman of the Board to Innovate Washington by Governor Christine Gregoire. 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. A large part of our need for a rate increase is driven by the costs associated with continuing to expand and replace the facilities we use every day to serve our customers. When we replace old equipment with new, it results in higher overall costs to serve customers.

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 increase.

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 includes a map of the Company's service territories, and page 2 includes a map of our natural gas trading hubs, interstate pipelines, and natural gas storage facilities. This exhibit was prepared under my direction.

II. OVERVIEW OF AVISTA

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.[1] Of the Company's 366,305 electric and 325,919 natural gas customers (as of December 31, 2013), approximately 97,486 were Oregon customers. A map showing Avista's electric and natural gas service areas is provided in Exhibit No. 101.

As of December 31, 2013, Avista Utilities had total assets (electric and natural gas) of approximately $3.9 billion (on a system basis), with electric retail revenues of $743 million (system) and natural gas retail revenues of $315 million (system). As of December 2013, the Utility had 1,520 full-time employees.

[1] Avista also serves approximately 28 retail electric customers in western Montana.

The Company acquired its Oregon natural gas operations from CP National in 1991. Avista serves four counties in southwest Oregon and one county in northeast Oregon, which include Medford, Klamath Falls, Roseburg, Ashland, Grants Pass and LaGrande as shown on page 1 of Exhibit No. 101.

The Company's Oregon service area includes approximately 82 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 approximately 97,000 residential, commercial and industrial customers.

Avista purchases natural gas for its distribution customers in wholesale markets at multiple supply basins in the western United States and western Canada. Purchased natural gas can be transported through six connected pipelines on which Avista holds firm contractual transportation rights. These contracts provide access to both US and Canadian-sourced supply. The US-sourced gas represents 20% of the contractual rights, with transportation from the Rocky Mountains. The remaining 80% comes from Alberta and British Columbia supply basins.

Avista has a long history of innovation and environmental stewardship. At the turn of the 19^{th} 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. A portion of this natural gas storage facility is used to serve our Oregon customers.

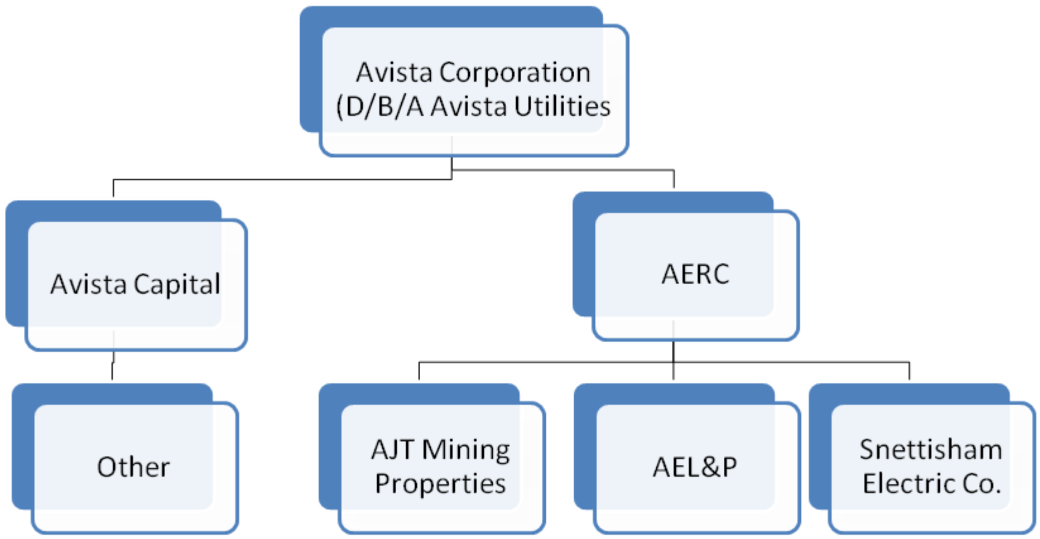
Q. Please describe Avista's current business focus for its utility operations.

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.

Q. Please briefly describe Avista's subsidiary businesses.

A. Mr. Thies provides an overview of our recent transactions involving the sale of our Ecova subsidiary, and our purchase of Alaska Energy and Resources Company (AERC), effective July 1, 2014. With the sale of Ecova, Avista Corp.'s primary subsidiary is now AERC, which includes the utility operations of Alaska Electric Light and Power (AEL&P).

AEL&P is operated by the same employees operating the utility prior to being acquired by the Company, including the existing management team of AEL&P. AEL&P has 60 full-time employees. AEL&P serves approximately 15,900 retail electric customers under the authority of the Regulatory Commission of Alaska, and is the sole electric utility serving the City and Borough of Juneau, Alaska. The following is a diagram of Avista's corporate structure[2]:



III. AVISTA'S RATE INCREASE REQUEST

Q. Would you please summarize Avista Utilities' request in this filing?

A. Yes. A combination of increasing rate base and increases in general business expenses requires the Company to request an overall increase in billing rates of $9.140 million or 9.8%. This request is based on a proposed rate of return of 7.77%, with a capital structure common equity component of 51%, and a 9.9% return on equity. The Company is utilizing a forecasted test period for the calendar year 2015. 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.

[2] Reflects the primary subsidiaries of Avista. Other subsidiaries that have limited or no operations, or were formed for a limited purpose, are excluded.

Ehrbar testify to these rate spread issues.

Based on an average usage level of 47 therms per month, the average residential bill would increase $5.78 per month, or 10.3%, from $55.97 to $61.75.

Q. What are the primary factors causing the Company's request for a natural gas rate increase in this filing?

A. Over 74% (or approximately $6.7 million) of the Company's need for additional rate relief relates to the increase in rate base. As will be described in more detail by Company witness Mr. DeFelice, these investments reflect replacement and maintenance of Avista's aging system and technology to sustain reliability and safety. Major projects include the Company's Customer Information System (Project Compass), continuing replacement of Aldyl-A natural gas pipe, compliance with municipal requirements (i.e., street/highway relocations), and the systematic replacement of aging infrastructure, among others.

The remaining 26% (or approximately $2.4 million) of the Company's requested revenue requirement relates to an increase in operating and maintenance (O&M) and administrative and general (A&G) expenditures, and the net change in retail revenues since our last rate case filed in 2013.

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. Changes in natural gas costs are addressed in the annual Purchased Gas Cost Adjustment ("PGA") filing.

IV. COST MANAGEMENT AND EFFICIENCIES

Q. What is Avista doing to manage its costs to mitigate rate increases for customers?

A. Over the last several years we have renewed our efforts to control our costs and improve efficiency. We are focused on long-term sustainable savings to continuously improve our service to customers and manage costs into the future.

As an example, in October 2012 the Company's Board of Directors approved a Voluntary Severance Incentive Plan (VSIP) that resulted in a reduction to the total utility workforce of 55 positions effective January 1, 2013. The Company continues to operate under a hiring restriction which requires approval by myself, the President of the Utility, the CFO, and the Sr. VP for Human Resources for all replacement or new hire positions.

In 2013 we made changes to the retirement income (pension) and post-retirement medical plans offered to non-union employees, effective January 1, 2014. Changes to plans offered to the bargaining unit employees will be subject to future negotiations.

For non-union employees, with regard to retirement income, Avista no longer offers a pension plan for new hires beginning January 1, 2014. Avista will make a contribution to a 401(K) fund established for the employee, but will no longer offer a defined benefit pension plan that provides an annual annuity upon retirement.

For post-retirement medical, again for non-union employees only, beginning January 1, 2014, Avista no longer provides funding for post-retirement medical for new hires. Following retirement, new hires would be permitted to participate in Avista's retiree medical plan, but would be required to pay the full premium associated with the plan. In addition, for both existing employees and new hires, when the retiree reaches age 65, Avista will no longer provide an Avista-sponsored medical plan. At age 65, retirees may choose from a variety of plans offered by the healthcare exchange company Extend Health. For existing retirees, Avista will continue to provide a monthly contribution to the employee for healthcare, but will no longer offer a Company-sponsored healthcare plan for retirees age 65 and older. Through these changes, Avista is transitioning out of funding medical coverage for retirees. These changes result in a reduction to Avista's future funding obligation related to pensions and post-retirement medical costs, as well as a reduction in the annual expense associated with these plans. These reductions in costs are reflected in Ms. Andrews revenue requirement calculations.

Employee teams from across the Company continue to focus on contact points or "touch points" a customer has with Avista. The objective of the initiative is to improve our customers' overall experience when doing business with us, as well as improve responsiveness in a respectful and least cost manner. This team identified a "touch point map" of 172 different customer interactions or touch points. Designing improvements to these touch points requires that we take an outside-in view of the customer interaction. To date, the touch point teams have made improvements to 54 distinct touch points. As examples, two recent teams have focused on customer awareness of natural gas safety, and accuracy of outage estimated restoration times.

V. COMMUNICATIONS WITH CUSTOMERS

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

A. The Company proactively communicates with its customers in a number of ways: customer forums, one-on-one customer interactions through field personnel and account representatives, bill inserts, social media, media contacts, group presentations, 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 we serve to better understand the issues faced by the Company, such as increased infrastructure investment, environmental mitigation and security, all of which have led to higher costs for our customers.

We have listened to our customers and learned that they want information and conversations with Avista employees to better understand the choices they have to manage how they use energy and the forces that are impacting their energy prices.

One of the important principles in our intensified outreach is to meet customers where they gather. Our conversations with customers use traditional and non-traditional communication channels, including one-on-one and group presentations, print, radio, website, newsletters, videos, social media and direct emails.

Another important customer segment that we seek to reach are those customers who gather online. We have a solid foundation on social media and use Twitter© and Facebook© to communicate with customers, as well as communicating through a blog on our www.avistautilities.com website. For customers who want a more private online conversation, we offer customers a conversation email account to make sure they are comfortable communicating with us. The website also includes a section focusing on rates and provides a video for customers on how rates are set, including the regulatory process. General rates information, as well as information on active rate filings are also included on the website.

Our employees provide excellent customer service, and this focus on communicating with our customers includes providing our employees messaging and new tools and training to make it 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 have the opportunity to voice their concerns and receive answers to their questions, their satisfaction level increases. We're listening to our customers' point-of-view and sharing ours about energy issues that directly affect us all.

We are continuing our focus on informing 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.

VI. 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 Washington customers, such as the Low-Income Rate Assistance Program (LIRAP), energy efficiency programs, Project Share for emergency assistance to customers, a Customer Assistance Referral and Evaluation Service (CARES) program, senior programs, level pay plans, and payment arrangements. Through these programs, the Company works to build lasting ways to ease the burden of energy costs for customers that have the greatest need.

To assist our customers in their ability to pay, the Company focuses on actions and programs in four primary areas: 1) advocacy for, and support of, bill payment assistance programs providing direct financial assistance; 2) low income and senior outreach programs;

3) energy efficiency and energy conservation education; and 4) support of community programs that increase customers' ability to pay basic costs of living.

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. Avista Utilities' Low-Income Rate Assistance Program (LIRAP) approved by the Commission in 2002 collects revenue under Schedule 410, "General Residential Natural Gas Service–Oregon." The current rate for LIRAP is approximately 0.4% of the current volumetric billing rate. The purpose of LIRAP is to reduce the energy cost burden among those customers least able to pay energy bills. 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. LIRAP provided 749 grants and distributed a total of $220,013 during the past heating season in its Oregon service territory.

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.

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. A total of 9,252 (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 2013, 14,213 Oregon customers were provided with over 23,302 such payment arrangements.

Q. Please summarize Avista's CARES program.

A. In Oregon, Avista is currently working with over 228 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 last heating season, 4,349 Oregon customers received $863,244 in various forms of energy assistance (Avista LIRAP, Federal LIHEAP program, Project Share, and local community funds) to date. This program and the partnerships we have formed have been invaluable to customers who often have nowhere else to go for help.

VII. 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. Adrien M. McKenzie, as Vice 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 9.9% return on equity.

Mr. Jason Thackston, Sr. Vice President, Energy Resources, will describe Avista's natural gas resource planning process, and provide an update on the Company's 2014 Natural Gas Integrated Resource Plan.

Mr. Jim Kensok, Vice President and Chief Information and Security Officer, will describe the costs associated with Avista's information technology programs. These costs include the capital investments for a range of systems implemented by the Company, including the ongoing replacement of the its legacy Customer Information and Work and Asset Management System ("Project Compass"). He will also describe the additional expenses required to support applications and systems for cyber security, the Next Generation Radio System, operation of the new Customer Information and Work and Asset Management

System, and increases in application license fees and software maintenance costs.

Ms. Elizabeth Andrews, Manager, Revenue Requirements, will discuss the Company's overall revenue requirement proposal. She will also explain forecasted operating results including expense and rate base adjustments made to actual operating results and rate base.

Mr. Dave DeFelice, Senior Business Analyst, will describe the Company's proposed regulatory treatment of capital investments in utility plant through March 31, 2015.

Mr. Joseph Miller, Senior 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 2015 Test Period Revenue Load Adjustment.

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

A. Yes.

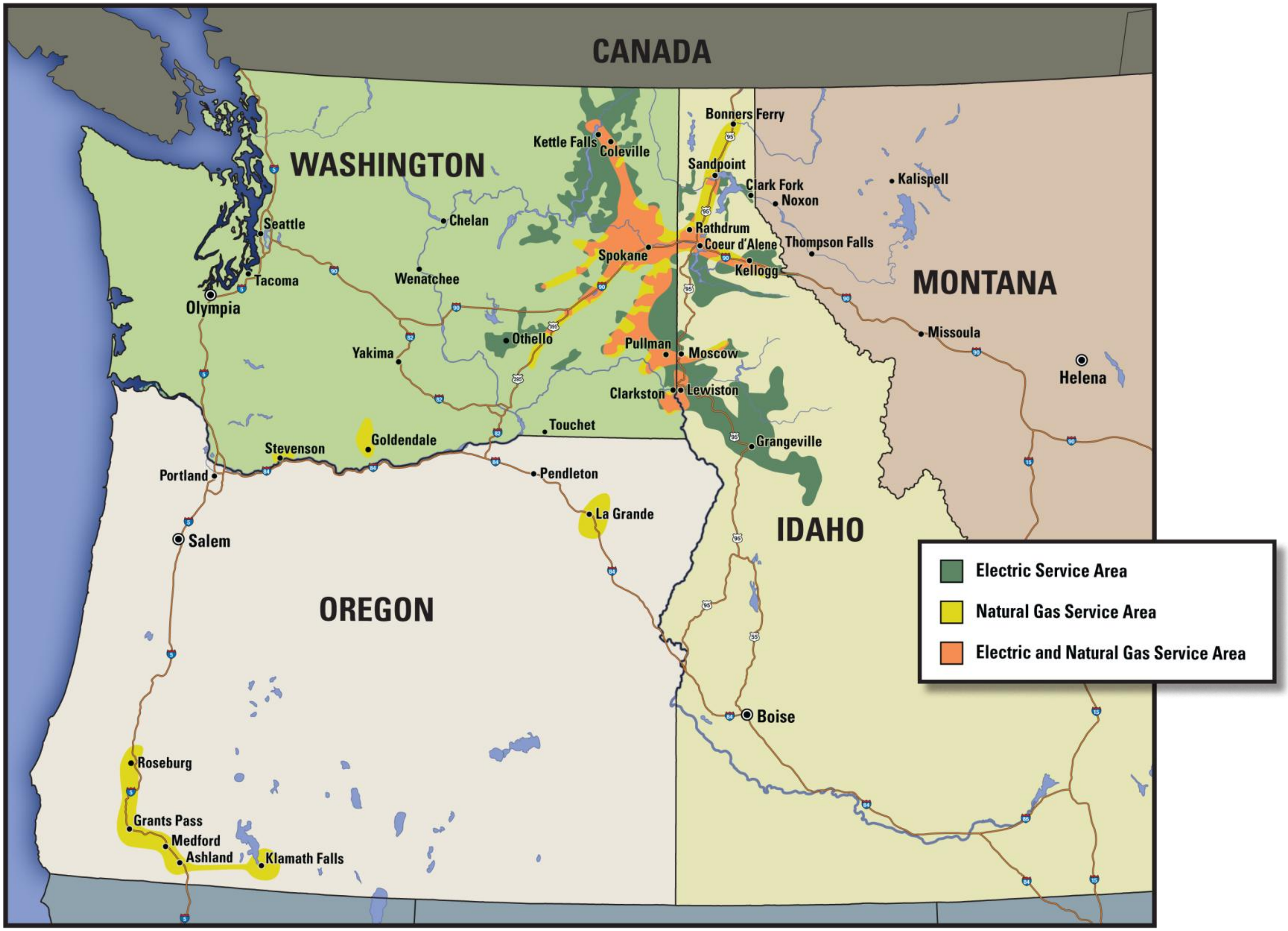
BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

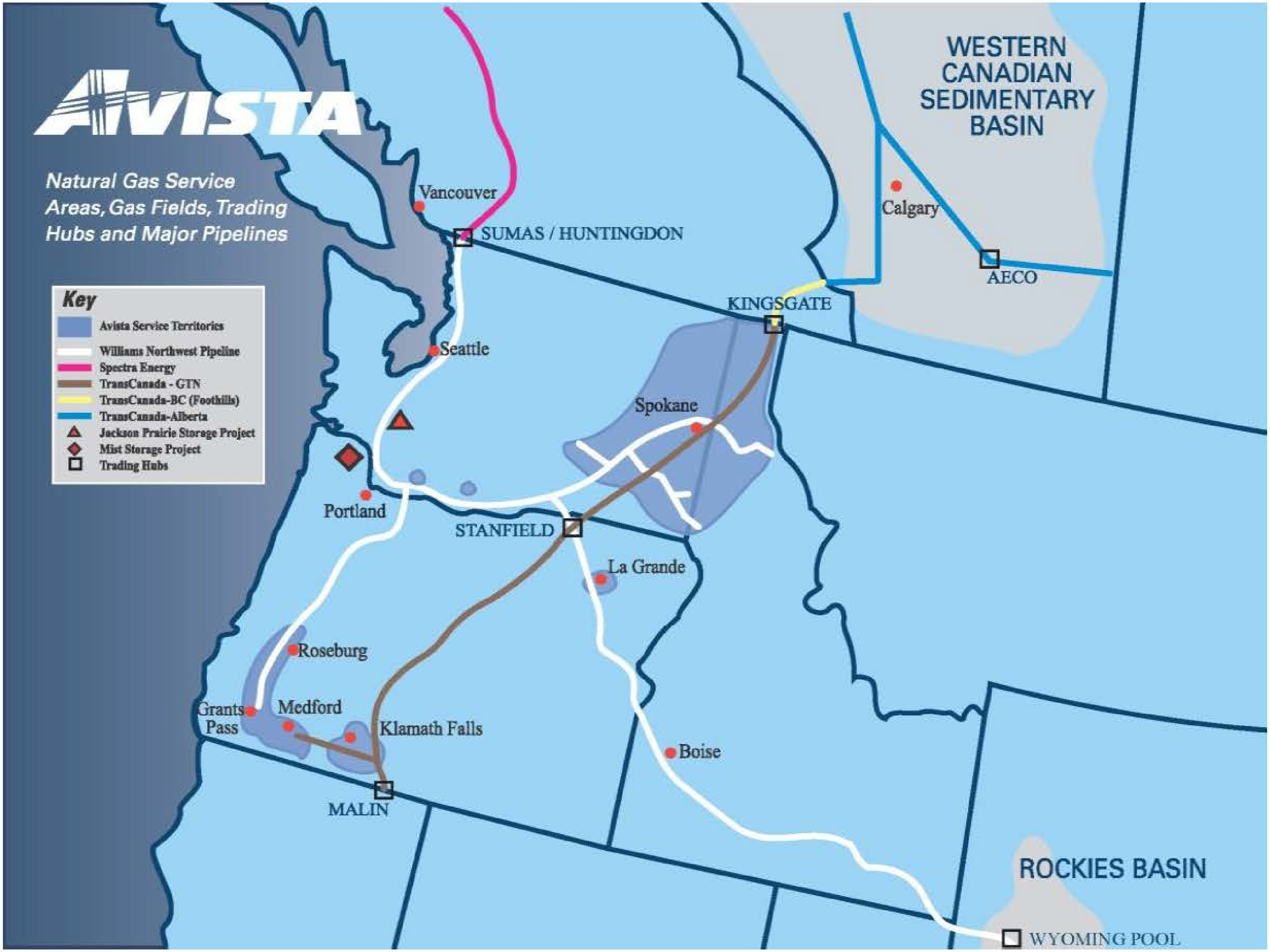
DOCKET NO. UG-___

SCOTT L. MORRIS
Exhibit No. 101

Policy and Operations

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
Vancouver
SUMAS / HUNTINGDON
Calgary
AECO
KINGSGATE
Seattle
Spokane
Portland
STANFIELD
La Grande
Roseburg
Grants Pass
Medford
Klamath Falls
Boise
MALIN
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

I. INTRODUCTION

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

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

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

A. I received a Bachelor of Arts degree in 1986, 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.

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 Avista Corporation as well as explain the proposed capital structure, overall rate of return, our credit ratings, and summarize our capital expenditures program. Additionally, I will discuss recent business transactions of Avista Corp. including the sale of Ecova, Inc. to Cofely USA Inc. and the acquisition of Alaska Energy and Resources Company.

Mr. Adrien McKenzie, on behalf of Avista, will provide additional testimony related to the appropriate return on equity for Avista, based on our specific circumstances, together with the current state of the financial markets.

In brief, I will provide information that shows:

- Avista's plans call for making significant utility capital investments to preserve and enhance service reliability for our customers, replace aging infrastructure, and meeting customer growth. Capital expenditures of $710 million are planned for 2014-2015. Capital expenditures of approximately $1.8 billion are planned for the five-year period ending December 31, 2018. Avista needs adequate cash flow from operations to fund these requirements, together with access to capital from external sources under reasonable terms, on a sustainable basis.

- We are proposing an overall rate of return of 7.77 percent, which includes a 51.0 percent common equity ratio, a 9.9 percent return on equity, and a cost of debt of 5.56 percent. We believe our proposed overall rate of return of 7.77 percent and proposed capital structure provide a reasonable balance between safety and economy.

- Avista's corporate credit rating from Standard & Poor's (S&P) is currently BBB and from Moody's Investors Service (Moody's) it is Baa1. Avista must operate at a level that will support a solid investment grade corporate credit rating in order to access capital markets at reasonable rates. A supportive regulatory environment is an important consideration by the rating agencies when reviewing Avista. Maintaining solid credit metrics and credit ratings will also help support a stock price necessary to issue equity under reasonable terms to fund capital requirements.

A table of contents for my testimony is as follows:

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

A. Yes. I am sponsoring Exhibit No. 201, pages 1 through 4 which were prepared under my direction. Avista's credit ratings by S&P and Moody's are summarized on page 1, and Avista's actual capital structure at June 30, 2014, and the forecasted capital structure at December 31, 2015, are included on page 2, with supporting information on pages 3 through 4. Confidential Exhibit No. 202 includes our Interest Rate Risk Management Plan, and Exhibit No. 203 includes the equity ratios and returns on equity approved by various state regulatory commissions from January 1, 2014 to August 6, 2014. Confidential Exhibit 204 includes the Company's planned capital expenditures and long-term debt issuances by year.

II. FINANCIAL OVERVIEW

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

A. 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. What additional steps are the Company taking to improve its financial health?

A. We are working to assure there are adequate funds for operations, capital expenditures and debt maturities. We obtain a portion of these funds through the issuance of long-term debt and common equity. We actively manage risks related to the issuance of both long-term debt and equity. These efforts include, but are not limited to, interest rate risk mitigation efforts and issuing common stock on a regular basis.

III. BUSINESS TRANSACTIONS

Q. On June 30, 2014, the Company closed a transaction with Cofely USA for the sale of its subsidiary, Ecova. What was the sale price and net proceeds of this transaction?

A. The sale price of Ecova was $335 million in cash, less the payment of debt and other customary closing adjustments. When all escrow amounts are released, the sales transaction is expected to provide net cash proceeds to Avista Corp. of approximately $133 million, and result in a net gain of about $68 million.

Q. How will the proceeds from the Ecova transaction be used?

A. We expect to use a majority of the proceeds of the sale to buy back up to four million shares of Avista Corp. outstanding common stock. Our common stock repurchase program began on July 7, 2014 and will continue until we repurchase four million shares or December 31, 2014; however we can also choose to terminate the repurchase program before the expiration date or share limit is reached. As of August 21, 2014 we have repurchased 1,143,172 shares of Avista Corp. common stock.

Q. On July 1, 2014, the Company closed a transaction to acquire Alaska Energy and Resources Company (AERC). How did the Company fund this transaction?

A. The Company funded this acquisition primarily with the issuance of common stock. At the closing of the acquisition of AERC by Avista, the issued and outstanding shares of AERC common stock were exchanged for shares of Avista common stock. The purchase price for AERC at closing was $170 million, less the assumption of outstanding debt and other closing adjustments per the Merger Agreement. The value of Avista common stock issued in exchange for AERC common stock was approximately $150 million.

AERC is a wholly-owned subsidiary of Avista. Alaska Electric Light and Power Company (AEL&P), a vertically integrated electric utility providing electric service to the City and Borough of Juneau, continues to be a wholly-owned subsidiary of AERC.

Q. Are there plans to rebalance the capital structure at AERC following the acquisition with 100% common stock?

A. Yes. New debt issuances at AEL&P and AERC will rebalance the capital structure in alignment with our targeted capital structure. The first new debt issue for AEL&P consists of $75 million of 30-year first mortgage bonds that were committed through a private placement in July 2014, with funding on those bonds set for September 2014 and maturity in 2044. The new AEL&P debt proceeds will allow early repayment of approximately $38 million of existing AEL&P debt and will result in an AEL&P utility capital structure aligned with what was approved by the Regulatory Commission of Alaska in AEL&P's most recent general rate case.

New debt will also be issued at AERC to achieve the overall targeted capital structure for AERC. Rebalancing the capital structure at AEL&P and AERC by issuing new debt allows the capital structure of these subsidiaries to be more comparable to Avista and its utility operations in Washington, Idaho and Oregon. Avista does not provide collateral or guarantees related to AERC or AEL&P debt. The debt and equity of AERC are excluded from the capital structure proposed in rate filings in Avista's Washington, Idaho and Oregon jurisdictions.

Further, the recapitalization provides funds that plan to transfer from AERC to Avista, which will be used to fund the utility capital budget and utility operating costs at Avista. Therefore, a portion of the proceeds from the initial common equity issuance to acquire AERC will ultimately be used to fund the utility capital budget and utility operating costs at Avista and obtain our targeted capital structure.

IV. CAPITAL EXPENDITURES

Q. What has been the recent history of the Company's capital investment program?

A. We are making significant capital investments in electric generation, transmission and distribution facilities, and in our natural gas distribution system to better serve the needs of our customers. These investments preserve and enhance safety and utility service reliability and replace aging infrastructure. For the period 2010 through 2013, our capital expenditures totaled $1.012 billion, for an average annual investment of $253 million. While there is variation among the functional areas we invest in each year, the predominant areas have included electric generation and transmission and distribution facilities, natural gas distribution plant, new customer connects, environmental and regulatory requirements, information technology and other supporting functions, such as fleet services and facilities.

Q. In general, has the overall level of capital investment during these years (2010 – 2013) matched the annual capital <u>requests</u> submitted by the Company's various departments?

A. No. In recent years Avista has chosen to not fund all of the capital investment projects proposed by the various departments in the Company; driven primarily by the Company's desire to mitigate the retail rate impacts to customers. The decision to delay funding certain projects was made only in cases where the Company believed the amount of risk associated with the delay was reasonable and prudent.

Q. What are the Company's current and future plans related to its capital expenditure program?

A. We made the decision in 2013 to increase our overall level of capital investment. Going forward, our five-year capital plan includes $355 million for 2014, $355 million for 2015, and $350 million for each of the years 2016 through 2018.

Q. Why is the Company increasing the level of its capital expenditures?

A. There are three primary drivers Avista's decision to increase the level of capital investment, including: 1) the business need to fund a greater portion of the departmental requests for new capital investments that in the past have not been funded; 2) the need for life cycle investments that support benefits identified by our asset management processes, and 3) a continued focus on controlling the increase in operation and maintenance (O&M) spending through prudent capital investment.

Q. Can you provide some examples that illustrate the key drivers?

A. Yes. An example includes Avista's natural gas Aldyl A pipe replacement program and the replacement of Avista's Customer Information and Work and Asset Management System ("Project Compass"), as described by Company witness Mr. Kensok. Our continuing asset management discipline helps maintain or increase levels of service reliability, improve the safety of our facilities, and reduce the life-cycle costs paid by our customers. A principal goal of asset management is to optimally manage risk and asset performance relative to capital investment and maintenance costs. Benefits of asset management include improved safety and reliability, improved life-cycle costs, and controlling the increase in O&M spending.

In addition, this is an opportune time for higher investments in our utility system. Interest rates remain near all-time lows, and funding capital investments now will result in a lower long-term cost to customers, versus waiting until interest rates rise. Furthermore, electric and natural gas commodity costs continue to be relatively stable as compared to past years, and are expected to remain relatively stable for the near future.

Funding the additional needed capital investment projects now will result in lower overall bill impacts to customers rather than waiting until a time when retail rates are being driven higher by increasing commodity costs and/or higher interest rates.

V. CAPITAL STRUCTURE

Q. What is the capital structure and rate of return the Company is requesting in this proceeding?

A. Our requested capital structure is 49.0 percent total debt and 51.0 percent equity with a requested overall rate of return in this proceeding of 7.77 percent, as shown in Illustration No. 1 below. The requested capital structure is based on our forecasted capital structure at December 31, 2015.

Illustration No. 1

	Amount	Percent of Total Capital	Cost	Component
AVISTA CORPORATION Proposed Cost of Capital December 31, 2015				
Total Debt	$1,483,000,000	49%	5.56%	2.72%
Common Equity	1,546,414,823	51%	9.90%	5.05%
Total	$3,029,414,823	100.00%		**7.77%**

Q. Is the capital structure reflected in Illustration No. 1 above, calculated in a manner similar to the capital structure calculated in Avista's recent rate proceedings?

A. Yes. This methodology removes investments at our subsidiary business as well as the impact of costs related to the issuance of equity.

Q. How does the Company determine the amount of long-term debt and common equity to be included in its capital structure?

A. As a regulated utility, Avista has a continuing obligation to provide safe and reliable service to customers while balancing safety and economy, including long-term cost stability for financing utility investments and operations. Lower leverage implies lower financial risk for a company's debt obligations. Through our planning process, we determine the amount and types of new financing needed to support our capital expenditure programs for current and future years.

Q. What are the Company's expected long-term debt issuances through 2018?

A. To support the significant capital expenditures noted in Section IV above and to replace maturing long-term debt, we are forecasting the issuance of long-term debt in each year through 2018. We plan to issue $50 million in 2014. Issuances planned for 2015 through 2018 are provided in confidential Exhibit No. 204.

Q. Why is the Company proposing a 51.0 percent equity ratio?

A. Avista's financing plans include a 51.0 percent equity ratio during the 2015 rate year. Maintaining a 51.0 percent common equity ratio has several benefits for customers. We are dependent on raising funds in capital markets throughout all business cycles. These cycles include times of contraction and expansion. An adequate level of equity will assist us in accessing debt capital markets on reasonable terms in both favorable financial markets and when there are disruptions in the financial markets.

Additionally, a 51.0 percent common equity ratio solidifies our current credit ratings and moves us closer to our long-term goal of having a corporate credit rating of BBB+. A rating of BBB+ would be consistent with the natural gas and electric industry average, which I will further explain later in my testimony. We rely on credit ratings in order to access capital markets on reasonable terms. Moving further away from non-investment grade (BB+) provides more stability for the Company, which is also beneficial for customers. We believe our requested 51.0 percent equity appropriately balances safety and economy for customers.

In addition, because there is a relationship between the equity ratio and the return on equity (ROE), later in my testimony I will also address the reasonableness of the proposed 51.0 percent equity ratio in combination with the proposed 9.9 percent ROE.

Q. In attracting capital under reasonable terms, is it necessary to attract capital from both debt and equity investors?

A. Yes, it is absolutely essential. As a publicly traded company we have two primary sources of external capital: debt and equity investors. As of June 30, 2014, we had approximately $2.7 billion of debt and equity. Approximately half of our capital structure is funded by debt holders, and the other half is funded by equity investors and retained earnings. There tends to be significant emphasis on maintaining credit metrics and credit ratings that will provide access to debt capital markets under reasonable terms, however, access to equity capital markets is equally important. In fact, equity investors also focus on cash flows, capital structure and liquidity, much like debt investors. The level of common equity in our capital structure can have a direct impact on investors' decisions. A balanced capital structure allows us access to both debt and equity markets under reasonable terms, on a sustainable basis.

Q. Are the debt and equity markets competitive markets?

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 equal to or better than the equity investors' other alternatives. We are competing not only with other utilities, but also with businesses in other sectors of the economy. Demand for our stock supports our stock price, which provides us the opportunity to issue additional shares under reasonable terms to fund capital investment requirements.

Q. What is Avista doing to attract equity investment?

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

We have steadily increased our dividend for common shareholders over the past several years, to work 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.

Tracking mechanisms, such as the Purchased Gas Adjustment approved by the regulatory commissions, help 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 have been seeking timely general rate changes that reflect the company's capital investments on behalf of customers and changes in operating costs to serve customers. When approved by the regulatory commissions, the revenues from timely rate changes allow investors a reasonable opportunity for a fair return.

VI. PROPOSED RATE OF RETURN

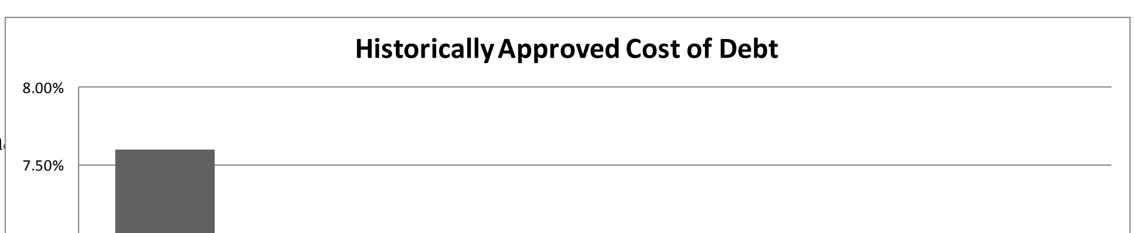
Q. Has Avista prepared an exhibit that includes the components of Avista's requested rate of return of 7.77 percent?

A. Yes. Exhibit No. 201 shows the components of Avista's requested rate of return of 7.77 percent.

Q. What is the Company's overall cost of debt, and how does the Company's requested overall cost of debt compare to its historically-approved cost?

A. Our requested overall cost of debt is 5.56 percent. This cost of debt is lower than the Commission's historically approved cost of debt for Avista from 2003 to 2011, and only slightly above the level approved by the Commission in 2014. Illustration No. 2 contains the Commission's approved cost of debt for Avista since 2003.

Illustration No. 2



Fin

Q. Please explain why Avista's cost of long-term debt has continued to decrease.

A. The market rates for creditworthy long-term debt issuances dropped significantly in late 2011 and, though rates fluctuate constantly, they have been within a historically low range since 2011. In addition to the overall decline in interest rates, we have been prudently managing our interest rate risk, which has involved fixed rate long-term debt with varying maturities, and executing forward starting interest rate swaps to mitigate interest rate risk. We also evaluate opportunities presented when rates for differing maturities are attractive.

Since December 2010 we have issued $392 million in long-term debt. The weighted average rate of these issuances is 3.25 percent. These issuances have varying maturities, which ranged from 3 years to 35 years and resulted in a weighted average maturity of approximately 19 years. Through these programs we have been able to lower the cost of debt while extending our weighted average maturity.

Our most recent issuance (in 2013) was $90 million of first mortgage bonds with a three year maturity at a rate of 0.84 percent. This new debt, which matures in 2016, refinanced $50 million of three year debt that matured in 2013, with an interest rate of 1.68 percent. We have continued to issue debt with varying maturities to balance the cost of debt and the weighted average maturity. This has provided us with the ability to take advantage of historically low rates on both the short end and long end of the yield curve.

We plan on continuing to issue long-term debt with various maturities for the foreseeable future in order to fund our capital expenditure program and long-term debt maturities.

Q. What is the Company doing to mitigate interest rate risk related to future long-term debt issuances?

A. Our future borrowing requirements are primarily driven by our significant capital expenditure program and maturing debt, which creates exposure to interest rate risk. As mentioned earlier, we have $1.8 billion in forecasted capital expenditures over the next five years. Additionally, we have $362.5 million of debt maturing during the same period. We are forecasting the issuance of $765 million in long-term debt from 2014 through 2018 to fund these capital expenditures and maturing debt as well as to maintain an appropriate capital structure.

We manage this interest rate risk exposure by limiting outstanding debt with variable interest rates, issuing fixed rate long-term debt with varying maturities to manage the amount of debt that is required to be refinanced in any period, and executing forward starting interest rate swaps.

Q. Does the Company have guidelines regarding its interest rate risk management?

A. Yes. The Company's Interest Rate Risk Management Plan is attached as Confidential Exhibit No. 202. The goal of this plan is to maintain a competitive cost of capital, while reducing cash flow volatility and the associated retail rate impacts related to future interest rate variability.

The Interest Rate Risk Management Plan addresses:

- Limiting variable rate exposures to a percentage of total capitalization;
- Issuing fixed rate long-term debt with varying maturities;
- Hedging a portion of interest rate risk with financial derivative instruments which we execute based on our guidelines that include hedge ratios, hedge windows, rate triggers, and rate monitoring;
- Forecasting, counterparty, credit, basis and termination risks;
- Authorized interest rate derivatives utilized to hedge interest rate risk; and
- The oversight provided by the Finance Committee of the Board, Risk Management Committee, and Treasury Management.

The plan provides that interest rate risk management transactions occur solely in the context of hedging underlying financial exposures associated with interest rate uncertainty on our anticipated long-term debt requirements.

Q. Were there any forward-starting interest rate swap agreements settled related to the long-term debt issued in 2013?

A. Yes. We cash settled two interest rate swap contracts (notional amount of $85.0 million) in conjunction with the pricing and issuance of a $90.0 million term loan agreement that was completed in August 2013 and received a total of $2.9 million. This amount has been included in the yield to maturity calculation for the $90 million debt resulting in an effective yield, or interest rate, of negative 44 thousandths percent (-.044 percent).

Q. The Company is requesting a 9.9 percent return on equity. Please explain why the Company believes this is reasonable?

A. We agree with the analyses presented by Company witness Mr. McKenzie which demonstrates that the proposed 9.9 percent ROE, when combined with a 51 percent equity layer, would properly balance safety and economy for customers, provide Avista with an opportunity to earn a fair and reasonable return, and provide access to capital markets under reasonable terms on a sustainable basis.

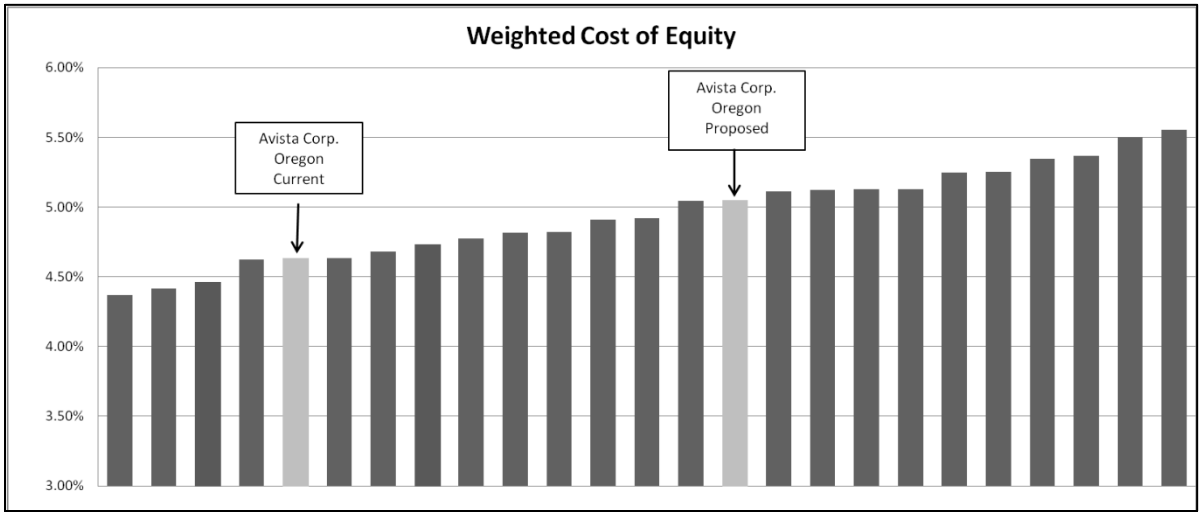
Q. How does Avista's requested 5.05 percent weighted cost of equity (9.9 percent ROE x 51 percent equity layer) compare with the weighted cost of equity recently approved for electric and natural gas utilities in other jurisdictions?

A. The bar charts in Illustration Nos. 3 and No. 4 below show the weighted cost of equity approved by state regulators for investor-owned utilities across the country for the period from January 1, 2014 through August 6, 2014. Illustration No. 3 includes electric and natural gas utilities, whereas Illustration No. 4 includes natural gas utilities only. These data in the bar chart represent all of the commission decisions that specify an ROE and equity ratio for utilities in the most recent approximate seven-month period.

Avista's proposed weighted cost of equity of 5.05 percent, which is also shown in the charts, is in the middle of the range of these weighted cost of equity numbers. Avista's current authorized weighted cost of equity of 4.63 percent is also shown on the charts, which is based on a 48 percent equity ratio and a 9.65 percent ROE. Additional details related to these charts, including the names of the utilities, are provided in Exhibit No. 203.

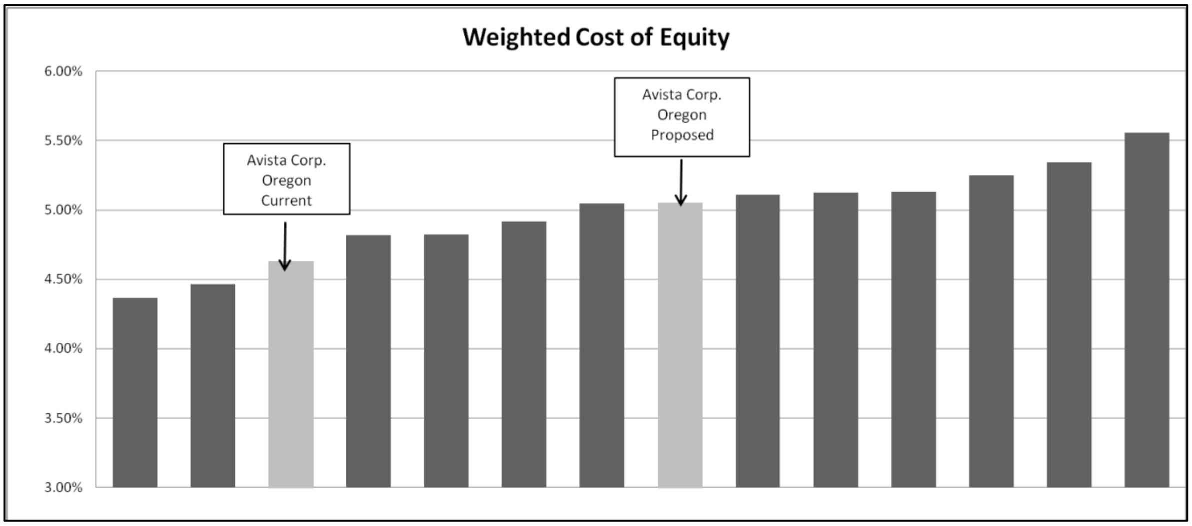
Because Avista competes with other utilities for equity investor dollars, it is important for Avista to have an earnings opportunity that is competitive with other utilities.

Illustration No. 3[1]



[1] Source – SNL Financial, Rate Cases finalized January 1, 2014 through August 6, 2014.

Illustration No. 4[2]



VII. CREDIT RATINGS

Q. How important are credit ratings for Avista?

A. Utilities require 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 significant volatility in commodity costs, necessitates the need to have the ability to go to the financial markets under reasonable terms on a regular basis and under a broad range of circumstances. In order to have this ability, investors need to understand the risks related to any of their investments. To help investors assess the creditworthiness of a company, nationally recognized statistical rating organizations (rating agencies) developed their own standardized ratings scale, otherwise known as credit ratings. These credit ratings indicate the creditworthiness of a company and assist investors in determining if they want to invest in a Company.

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

[2] Source – SNL Financial, Natural Gas Rate Cases finalized January 1, 2014 through August 6, 2014.

A. Avista' credit ratings, assigned by Standard & Poor's (S&P) and Moody's are as follows:

	S&P	Moody's
Senior Secured Debt	A-	A2
Senior Unsecured Debt	BBB	Baa1
Outlook	Stable	Stable

Additional information on our credit ratings has been provided on page 1 of Exhibit No. 201.

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

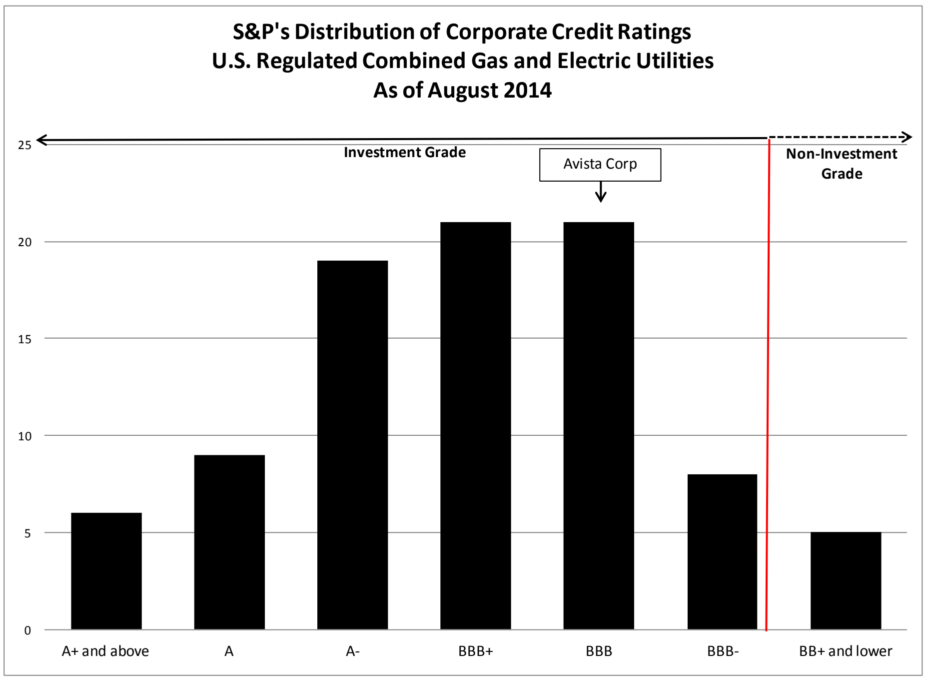
A. Credit ratings impact investor demand and expected returns. More specifically, when the Company issues debt, the credit rating can affect the determination of the interest rate at which the debt will be issued. The credit rating can affect the type of investor who will be interested in purchasing 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 for payment of principal and interest in the event that the organization experiences severe financial stress. Investment risks include, but are not limited to, liquidity risk, market risk, operational risk, and credit risk. These risks are considered by S&P, Moody's and investors in assessing our creditworthiness.

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, weaker credit ratings may result in a company having more difficulty accessing capital markets and/or incur significantly higher costs when accessing capital.

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

A. Avista believes operating at a corporate credit rating level of BBB+ is comparable with other US utilities providing both electricity and natural gas. As shown in Illustration No. 5, the average credit rating for U.S. Regulated Combined Gas and Electric Utilities is BBB+.

Illustration No. 5



We expect that a continued focus on the regulated utility, conservative financing strategies and a supportive regulatory environment will contribute toward an upgrade to a BBB+ credit rating. Operating at a BBB+ would likely attract additional investors, lower our debt pricing, and make us more competitive with other utilities. In addition, financially healthy utilities are better able to invest in the required infrastructure over time to serve their customers, and to withstand the challenges facing the industry and disruptions in the financial market.

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

A. The regulatory environment in which a company operates is a major qualitative factor in determining a company's creditworthiness.

Moody's rating methodology is based on four primary factors. Two of those factors: a utility's "regulatory framework" and its "ability to recover costs and earn returns," make up 50 percent of Moody's rating methodology.

S&P states 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"[3].

> "The regulatory framework/regime's influence is of critical importance when assessing regulated utilities' credit risk because it defines the environment in which a utility operates and has a significant bearing on a utility's financial performance. We base our assessment of the regulatory framework's relative credit supportiveness on our view of how regulatory stability, efficiency of tariff setting procedures, financial stability, and regulatory independence protect a utility's credit quality and its ability to recover its costs and earn a timely return. Our view of these four pillars is the foundation of a utility's regulatory support"[4].

Due to the major capital expenditures planned by Avista and future maturities of long-term debt, a supportive regulatory environment is essential in maintaining our current credit rating.

Q. Do you have any closing observations?

A. Yes, our initiatives to carefully manage our operating costs and capital expenditures are an important part of our performance, but are not sufficient without revenues from this general rate request for our natural gas business. Sufficient cash flows from

---

[3] Standard and Poor's, Key Credit Factors: Business and Financial Risks in the Investor-owned Utility Industry, March 2010.
[4] Standard and Poor's, Key Credit Factors For the Regulated Utilities Industry, November 19, 2013.

operations can only be achieved with the support of regulators in allowing the timely recovery of costs and the ability to earn a reasonable return.

Q. Does this 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	March/August 2011[1]			January 2014
Credit Outlook	Stable			Stable
	AAA		**Aaa**	
	AA+		**Aa1**	
	AA		**Aa2**	
	AA-		**Aa3**	
	A+		**A1**	
	A		**A2**	First Mortgage Bonds Secured Medium-Term Notes
	A-	First Mortgage Bonds Secured Medium-Term Notes	**A3**	
	BBB+		**Baa1**	Avista Corp./Issuer rating
	BBB	Avista Corp./Corporate credit rating	**Baa2**	Trust-Originated Preferred Securities
	BBB-		**Baa3**	
		INVESTMENT GRADE		
	BB+	Trust-Originated Preferred Securities	**Ba1**	
	BB		**Ba2**	
	BB-		**Ba3**	

(1) The Company received an upgrade to its Corporate credit rating in March 2011 and to its First Mortgage Bonds in August 2011

AVISTA CORPORATION
Proposed Cost of Capital
December 31, 2015

	Amount	Percent of Total Capital	Cost	Component
Total Debt	$1,483,000,000	48.95%	5.56%	2.72%
Common Equity	1,546,414,823	51.05%	9.90% [1]	5.05%
Total	$3,029,414,823	100.00%		**7.77%**

AVISTA CORPORATION
Cost of Capital as of
June 30, 2014

	Amount	Percent of Total Capital	Cost	Component
Total Debt	$1,333,000,000	48.28%	5.63%	2.72%
Common Equity	1,428,149,238	51.72%	9.65%	4.99%
Total	$2,761,149,238	100.00%		**7.71%**

[1] Proposed Return on Common Equity

AVISTA CORPORATION
Cost of Long-Term Debt Detail - Oregon
December 31, 2015

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	Outstanding 12-31-2015	Effective Cost	Years to Maturity	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(g)	(h)	(i)	(j)	(k)	(l)		
1	FMBS - SERIES A	7.530%	05-05-2023	05-06-1993	5,500,000	42,712	-	-	963,011	4,494,277	9.359%	5,500,000	514,744	7.4 years	1
2	FMBS - SERIES A	7.540%	05-05-2023	05-07-1993	1,000,000	7,766	-	-	175,412	816,822	9.375%	1,000,000	93,747	7.4 years	2
3	FMBS - SERIES A	7.390%	05-11-2018	05-11-1993	7,000,000	54,364	-	-	1,227,883	5,717,753	9.287%	7,000,000	650,114	2.4 years	3
4	FMBS - SERIES A	7.450%	06-11-2018	06-09-1993	15,500,000	120,377	-	50,220	2,140,440	13,188,963	8.953%	15,500,000	1,387,715	2.5 years	4
5	FMBS - SERIES A	7.180%	08-11-2023	08-12-1993	7,000,000	54,364	-	-	-	6,945,636	7.244%	7,000,000	507,064	7.7 years	5
6	TRUST PREFERRED*	1.980% [1]	06-01-2037	06-03-1997	40,000,000	1,296,086	-	-	(1,769,125)	40,473,039	1.938%	40,000,000	775,104	21.5 years	6
7	FMBS - SERIES	6.370%	06-19-2028	06-19-1998	25,000,000	158,304	-	-	188,649	24,653,047	6.475%	25,000,000	1,618,863	12.5 years	7
8	5.45% SERIES	5.450%	12-01-2019	11-18-2004	90,000,000	1,192,681	-	239,400	-	88,567,919	5.608%	90,000,000	5,047,001	4 years	8
9	FMBS - 6.25%	6.250%	12-01-2035	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	20 years	9
10	FMBS - 5.70%	5.700%	07-01-2037	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	21.6 years	10
11	5.95% SERIES	5.950%	06-01-2018	04-03-2008	250,000,000	2,246,419	16,395,000	835,000	-	230,523,581	7.034%	250,000,000	17,585,926	2.5 years	11
12	5.125% SERIES	5.125%	04-01-2022	09-22-2009	250,000,000	2,284,788	(10,776,222)	575,000	2,875,817	255,040,618	4.907%	250,000,000	12,268,615	6.3 years	12
13	3.89% SERIES	3.890%	12-20-2020	12-20-2010	52,000,000	383,338	-	-	6,273,664	45,342,997	5.578%	52,000,000	2,900,325	5 years	13
14	5.55% SERIES	5.550%	12-20-2040	12-20-2010	35,000,000	258,834	-	-	5,263,822	29,477,345	6.788%	35,000,000	2,375,887	25 years	14
15	4.45% SERIES	4.450%	12-14-2041	12-14-2011	85,000,000	692,833	10,557,000	-	-	73,750,167	5.340%	85,000,000	4,538,871	26 years	15
16	4.23% SERIES	4.230%	11-29-2047	11-30-2012	80,000,000	730,833	18,546,870	-	105,020	60,617,277	5.868%	80,000,000	4,694,533	31.9 years	16
17	0.84% SERIES	0.840%	08-14-2016	08-14-2013	90,000,000	512,223	(2,900,680)			92,388,457	-0.044%	90,000,000	(39,540)	0.7 years	17
18	Forecasted Issuance [3]	5.500% [4]	12-15-2044	12-15-2014	50,000,000	500,000 [2]				49,499,998	5.569%	50,000,000	2,784,481	29 years	18
19	Forecasted Issuance [3]	5.750% [4]	09-15-2045	09-15-2015	100,000,000	1,000,000 [2]				98,999,998	5.821%	100,000,000	5,820,885	29.8 years	19
20												1,483,000,000	81,912,617		20
21															21
22	Repurchase	[5] 7.74%	12-31-2017	06-30-2006	6,875,000				483,582	6,391,418	8.721%	[6]	70,127	2 years	22
23	Repurchase	[5] 5.72%	03-01-2034	12-30-2009	17,000,000				1,916,297	15,083,703	6.661%	[6]	159,446	18.3 years	23
24	Repurchase	[5] 6.55%	10-01-2032	12-31-2008	66,700,000				3,709,174	62,990,826	7.034%	[6]	324,360	16.8 years	24
25	**OREGON TOTAL DEBT OUTSTANDING AND COST OF DEBT AT December 31, 2015**											1,483,000,000	82,466,550		25
26															26
27								**Adjusted Weighted Average Cost of Debt**			**5.56%**				27
28															28
29															29
30	[1] Average Monthly Average Rate over a thirteen month period (see page four of this Exhibit)														30
31	[2] The issuance costs are estimated														31
32	[3] Forecasted issuance pursuant to the Company's internal forecast														32
33	[4] Forecasted Rates are based on forward rates from Thomson Reuters analysis tools plus an estimated credit spread														33
34	[5] Coupon Rate at the time of repurchase														
35	[6] Calculated using the Internal Rate of Return method														

AVISTA CORPORATION
Cost of Long-Term Variable Rate
December 31, 2015

	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Avg of
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
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**
Number of Days in Month	31	31	28	31	30	31	30	31	31	30	31	30	31	
Monthly Borrowing Rate**	1.3976%**	1.5333%**	1.5333%**	1.5333%**	1.7059%**	1.7059%**	1.7059%**	1.9175%**	1.9175%**	1.9175%**	2.1736%**	2.1736%**	2.1736%**	
Interest Expense	$ 48,140	$ 52,814	$ 47,703	$ 52,814	$ 56,863	$ 58,759	$ 56,863	$ 66,047	$ 66,047	$ 63,917	$ 74,868	$ 72,453	$ 74,868	**$ 792,156**

*Original issue principal amount was $50 million. The Company repurchased $10 million of the securities outstanding.

**Forecasted Rates are based on forward rates from Thomson Reuters analysis tools plus the 87.5 basis points pursuant to the debt agreement.

Average borrowing rate 1.980%

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

MARK T. THIES
Exhibit No. 202

Financial Overview, Capital Structure and Overall Rate of Return

CONFIDENTIAL

Interest Rate Risk Management Plan

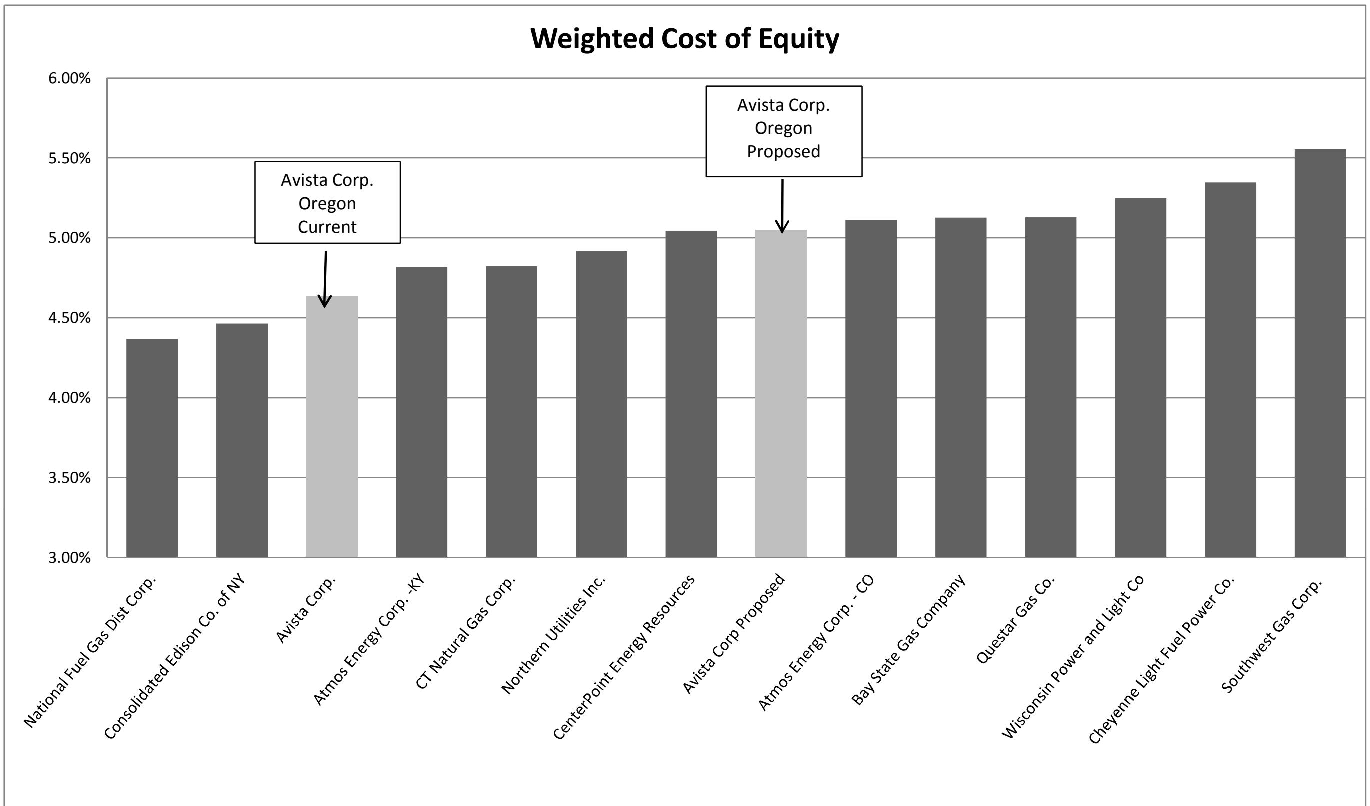
Pages 1 through 8

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

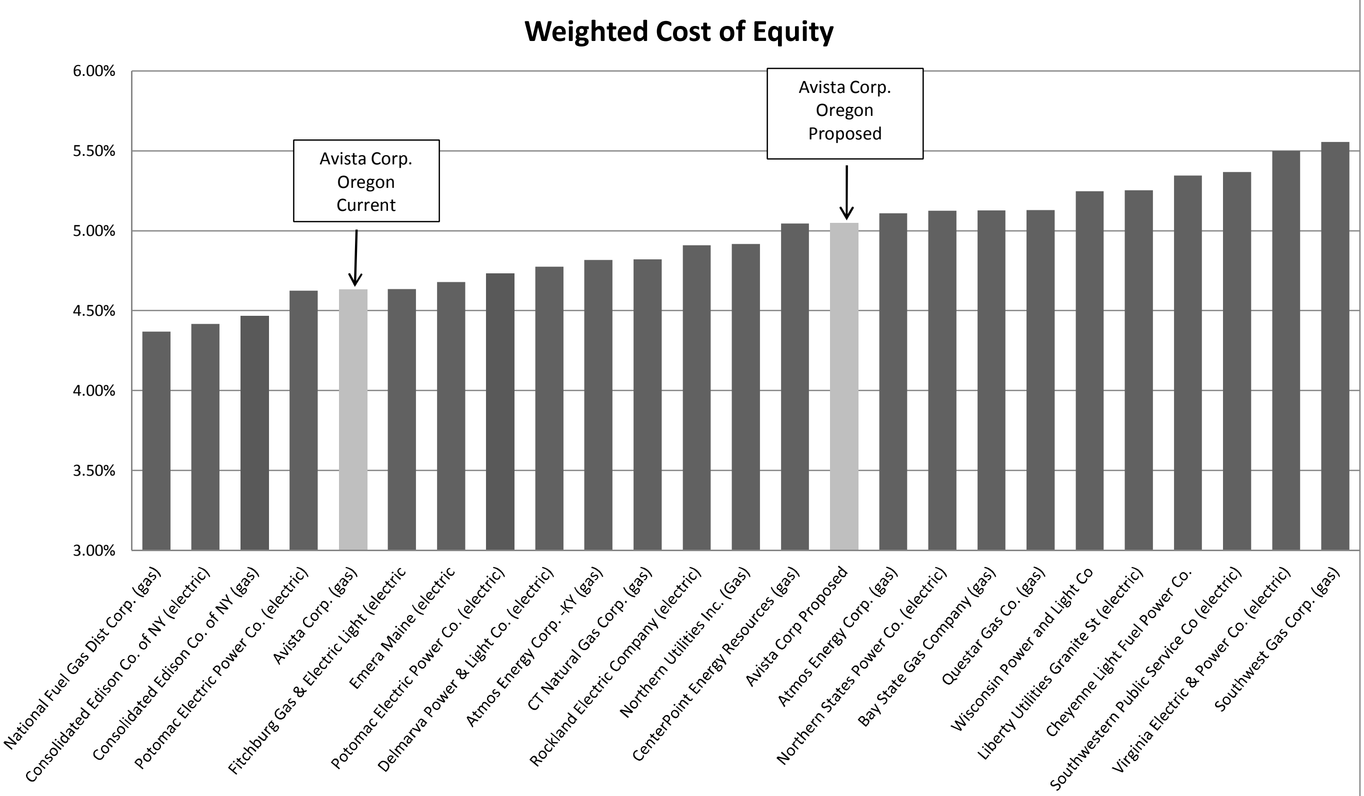
DOCKET NO. UG-___

MARK T. THIES
Exhibit No. 203

Financial Overview, Capital Structure and Overall Rate of Return



(1) Source - SNL Financial, Natural Gas Rate Cases finalized January 1, 2014 through August 6, 2014.
(Authorized Return on Equity- times -Authorized Common Equity)



(1) Source - SNL Financial, Rate Cases finalized January 1, 2014 through August 6, 2014.
(Authorized Return on Equity- times -Authorized Common Equity)

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

MARK T. THIES
Exhibit No. 204

Financial Overview, Capital Structure and Overall Rate of Return

CONFIDENTIAL

Planned capital expenditures and long-term debt issuances

Pages 1 through 2

Exhibit No. 300
McKenzie

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF ADRIEN M. MCKENZIE

REPRESENTING AVISTA CORPORATION

Return on Equity

DIRECT TESTIMONY OF ADRIEN M. MCKENZIE

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. Adrien M. McKenzie, 3907 Red River, Austin, Texas, 78751.

Q. In what capacity are you employed?

A. I am a Vice 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 No. 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 9.9% fair rate of return on equity ("ROE") that Avista Corp. ("Avista" or "the Company") is requesting for its jurisdictional gas utility operations. 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. How is your testimony organized?

A. After first summarizing my conclusions and recommendations, I review current conditions in the capital markets and their implications in evaluating a fair ROE for Avista. With this as a background, I conducted well-accepted quantitative analyses to estimate the current cost of equity for separate reference groups of gas and combination utilities. These included the discounted cash flow ("DCF") model, the empirical form of Capital Asset Pricing Model ("ECAPM"), and an equity risk premium approach based on allowed ROEs for gas utilities. Based on the cost of equity estimates indicated by my analyses, the reasonableness of Avista's requested 9.9% ROE was evaluated taking into account the specific risks for its jurisdictional utility operations in Oregon, Avista's requirements for financial strength that provides benefits to customers, as well as flotation costs, which are properly considered in setting a fair ROE.

Finally, I tested my conclusions based on the results of alternative ROE benchmarks for my proxy groups, including applications of the traditional Capital Asset Pricing Model

("CAPM"), reference to expected rates of return and allowed ROEs, and application of the DCF model to a select group of low risk non-utility firms.

Q. What is the role of the ROE in setting utility 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 commensurate with other investments of comparable risk, (2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and (3) maintain the utility's financial integrity.

II. RETURN ON EQUITY FOR AVISTA

Q. What is the purpose of this section?

A. This section presents my conclusions regarding the reasonableness of the 9.9% ROE requested by Avista for its jurisdictional gas utility operations. This section also discusses the relationship between ROE and preservation of a utility's financial integrity and the ability to attract capital.

---

[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).

B. Importance of Financial Strength

Q. What role does OPUC regulation play in supporting investor confidence?

A. Regulatory signals are a major driver of investors' risk assessment for utilities. Security analysts study commission orders and regulatory policy statements to advise investors where to put their money. If OPUC actions instill confidence that the regulatory environment is supportive, investors make capital available to Oregon's utilities on more reasonable terms. When investors are confident that a utility has supportive regulation, they will make funds available even in times of turmoil in the financial markets.

Q. Does Avista anticipate the need for capital going forward?

A. Yes. Avista will require capital investment to meet customer growth, provide for necessary maintenance and replacements of its natural gas utility systems, as well as fund new investment in electric generation, transmission and distribution facilities. Utility capital additions are expected to total approximately $1.8 billion through 2018. This represents a substantial investment given Avista's current rate base of $2.4 billion. Significant increases in capital investment continue to be the driving force behind Avista's need for additional rate relief in each of its jurisdictions. Continued support for Avista's financial integrity and flexibility will be instrumental in attracting the capital necessary to fund these projects in an effective manner.

Q. What other considerations are relevant in determining a reasonable ROE for Avista's jurisdictional gas utility operations?

A. Unlike many gas utilities, Avista does not have a weather normalization adjustment ("WNA") 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 of the nine 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.[3]

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. Are there other factors that distinguish the risks of Avista's gas utility operations from other gas utilities in Oregon?

A. Yes. 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. Avista's jurisdictional gas utility operations have experienced declines in customer usage that have translated into reduced margins. Moreover, customer load growth in Avista's Oregon jurisdictional gas utility operations continues to be weak and is not expected to strengthen in the near future.

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

Q. What does this imply with respect to Avista's risks relative to other gas utilities in general?

A. In contrast to Avista's situation in Oregon, adjustment mechanisms and trackers, including decoupling, have been increasingly prevalent in the utility industry in recent years. Reflective of this industry trend, the companies included in the proxy groups referenced in my analyses operate under a variety of cost adjustment and decoupling mechanisms. For example, Regulatory Research Associates recently reported that Atmos Energy Corporation, New Jersey Resources, Northwest Natural Gas, Piedmont Natural Gas, South Jersey Industries, and Southwest Gas Corporation all have utilities that operate under some form of decoupling mechanism that accounts for the impact of various factors affecting sales volumes and revenues.[4] In addition, AGL Resources and NiSource, Inc. have utilities that operate under Straight-Fixed-Variable rate design, which has a similar impact.

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 other utilities operating in Oregon and the firms in my proxy groups.

C. Recommended ROE

Q. What are your findings regarding the fair ROE for Avista's gas utility operations?

A. Based on the adjusted cost of equity estimates presented on Exhibit No. 301, Schedule AMM-1, page 1, I conclude that an appropriate ROE for Avista falls in the range of 9.90% to 10.80%, or 10.03% to 10.93% after considering an adjustment for flotation costs.

[4] Regulatory Research Associates, "Adjustment Clauses and Rate Riders," *Regulatory Focus* (March 21, 2012).

Q. Please summarize the results of the quantitative analyses on which your recommended ROE range was based.

A. In order to reflect the risks and prospects associated with Avista's jurisdictional utility operations, my analyses focused on two proxy groups of firms with gas utility operations. The cost of common equity estimates produced by the DCF, ECAPM, and risk premium analyses described subsequently are presented on Exhibit No. 301, Schedule AMM-1, page 2, and summarized below:

- Taken together, I concluded that the DCF, ECAPM, and risk premium results suggested an overall cost of equity range of 9.9% to 10.9%;
  - Considering the relative merits of the alternative growth rates, I determined that the DCF results implied an ROE range on the order of 9.2% to 10.2%;
  - The forward-looking ECAPM estimates suggested an ROE on the order of 10.4% to 11.6%;
  - The utility risk premium approach implies an ROE estimate of 10.1% to 11.0% for gas utilities;
- Adding a minimal flotation cost adjustment of 13 basis points resulted in an adjusted ROE range of 10.03% to 11.03%.

Q. What did the results of alternative ROE benchmarks indicate with respect to your recommended ROEs?

A. The results of the traditional CAPM analyses, a review of expected earned rates of return and authorized returns for gas utilities, as well as DCF results for a select, low risk group of non-utility firms,[5] are shown on Exhibit No. 301, Schedule AMM-1, page 3, and summarized in Exhibit No. 302, Table AMM-7, which is reproduced below:

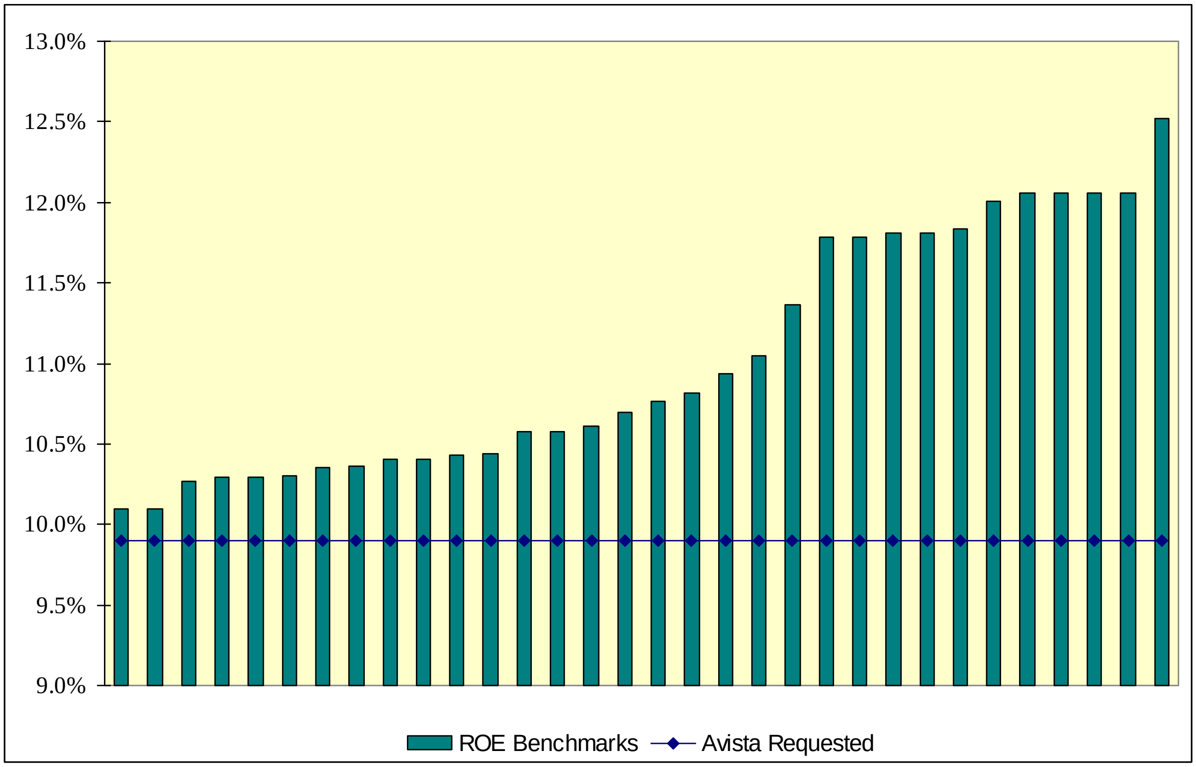
[5] As discussed subsequently, the average risk measures for the group of non-utility firms suggest that they have less investment risk than Avista or the proxy groups of utilities.

TABLE AMM-7
SUMMARY OF ALTERNATIVE ROE BENCHMARKS

	Gas Group		Combination Group	
	Average	Midpoint	Average	Midpoint
CAPM - Historical Yield				
Unadjusted	10.3%	10.1%	10.3%	10.1%
Size Adjusted	11.8%	11.8%	11.8%	11.8%
CAPM - Projected Yield				
Unadjusted	10.6%	10.4%	10.6%	10.4%
Size Adjusted	12.1%	12.1%	12.1%	12.1%
Expected Earnings	11.4%	12.5%	10.9%	11.8%
Allowed ROE	10.3%	10.6%	10.4%	10.4%
Non-Utility DCF				
Value Line	11.0%	12.0%		
IBES	10.4%	10.8%		
Zacks	10.7%	10.8%		
Reuters	10.3%	10.4%		

Figure AMM-1, below, presents these 32 alternative benchmark results presented in Table AMM7 in rank order, and compares them with Avista's 9.9% ROE request:

FIGURE AMM-1
ALTERNATIVE ROE BENCHMARKS VS. AVISTA ROE REQUEST



As illustrated in Figure AMM-1, Avista's 9.9% requested ROE falls below all the tests of reasonableness presented in my testimony.

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 9.9% percent is reasonable and, if anything, understated. Based on my evaluation, I determined that:

- Because Avista's requested ROE of 9.9% falls at the bottom end of my recommended cost of equity range, it represents a conservative estimate of investors' required rate of return;
- The reasonableness of a 9.9% minimum ROE for Avista is also reinforced by the lack of a WNA in Oregon for Avista, the fact that, unlike many gas utilities, Avista does

not benefit from a decoupling mechanism that provides recovery of fixed costs as customer usage changes, and the need to consider flotation costs.

Q. Does this 9.9% ROE represent a reasonable cost for Avista's customers to pay?

A. Yes. Investors have many options vying for their money. They make investment capital available to Avista only if the expected returns justify the risk. Customers will enjoy reliable and efficient utility service so long as investors are willing to make the capital investments necessary to maintain and improve Avista's utility system. Providing an adequate return to investors is necessary to ensure that capital is available to Avista now and in the future. If regulatory decisions increase risk or limit returns to levels that are insufficient to justify the risk, investors will look elsewhere to invest capital.

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 51.0% 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 2013 and near-term expectations;
- Avista's 51.0% common equity ratio falls below the 52.6% average for the proxy group of gas utilities at year-end 2013. Similarly, Avista's requested equity ratio falls short of the 55.8% 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.

III. OUTLOOK FOR CAPITAL COSTS

Q. Do current capital market conditions provide a representative basis on which to evaluate a fair ROE?

A. No. Current capital market conditions reflect the legacy of the Great Recession, and are not representative of what investors expect in the future. Investors have had to contend with a level of economic uncertainty and capital market volatility that has been unprecedented in recent history. The ongoing potential for renewed turmoil in the capital markets has been seen repeatedly, with common stock prices exhibiting the dramatic volatility that is indicative of heightened sensitivity to risk. In response to heightened uncertainties, investors have repeatedly sought a safe haven in U.S. government bonds. As a result of this "flight to safety," Treasury bond yields have been pushed significantly lower in the face of political, economic, and capital market risks. In addition, the Federal Reserve has implemented measures designed to push interest rates to historically low levels in an effort to stimulate the economy and bolster employment.

Q. How do current yields on public utility bonds compare with what investors have experienced in the past?

A. Despite recent increases, the yields on utility bonds remain near their lowest levels in modern history. Figure AMM-1, below, compares the July 2014 yield on long-term, triple-B rated utility bonds with those prevailing since 1968:

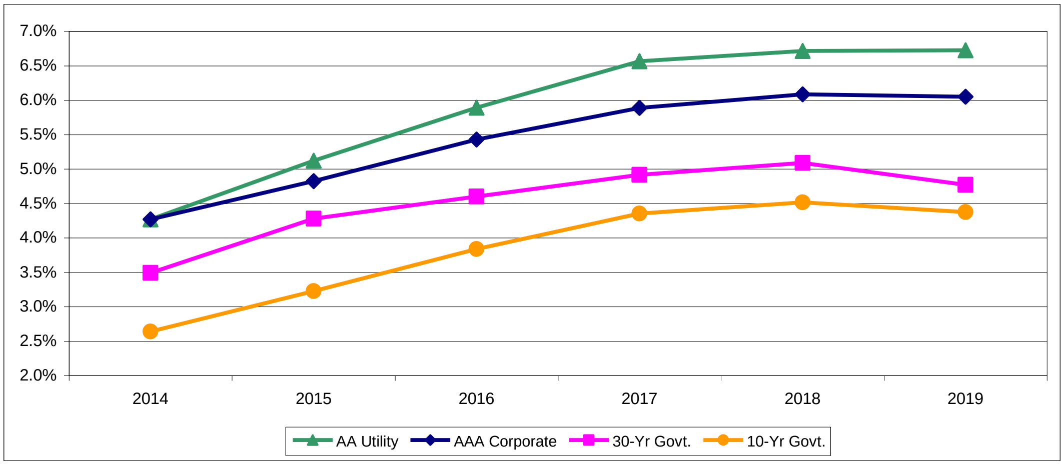
FIGURE AMM-1
BBB UTILITY BOND YIELDS – CURRENT VS. HISTORICAL

As illustrated above, prevailing capital market conditions, as reflected in the yields on triple-B utility bonds, are an anomaly when compared with historical experience.

Q. Are these very low interest rates expected to continue?

A. No. Investors do not anticipate that these low interest rates will continue. It is widely anticipated that as the economy continues to stabilize and resumes a more robust pattern of growth, long-term capital costs will increase from present levels. Figure AMM-2 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, Blue Chip Financial Forecasts ("Blue Chip"), and the Energy Information Administration ("EIA"):

FIGURE AMM-2
INTEREST RATE TRENDS



Source:
Value Line Investment Survey, Forecast for the U.S. Economy (May 23, 2014)
IHS Global Insight, U.S. Economic Outlook at 79 (May 2014)
Energy Information Administration, Annual Energy Outlook 2014 (May 7, 2014)
Blue Chip Financial Forecasts, Vol. 32, No. 12 (Dec. 1, 2013)

These forecasting services are highly regarded and widely referenced, with the Commission incorporating forecasts from IHS Global Insight and the EIA in its two-step DCF model. As evidenced above, there is a clear consensus in the investment community that the cost of long-term capital will be significantly higher over the 2015-2018 period than it is currently.

Q. Do recent actions of the Federal Reserve support the contention that current low interest rates will continue indefinitely?

A. No. While the Federal Reserve continues to express support for maintaining a highly accommodative monetary policy and an exceptionally low target range for the federal funds rate, it has also acted to steadily pare back its monthly bond-buying program. More recently, the Federal Reserve announced that it expects to continue steady reductions in bond-buying, and anticipates an end to new asset purchases after its October 2014 meeting.[6]

[6] *Minutes of the Federal Open Market Committee* (June 17-18, 2014).

Elimination of the Federal Reserve's bond buying program should exert upward pressure on long-term interest rates, with The Wall Street Journal observing that:

> The Fed's decision to begin trimming its $85 billion monthly bond-buying program is widely expected to result in higher medium-term and long-term market interest rates. That means many borrowers, from home buyers to businesses, will be paying higher rates in the near future.[7]

The Federal Reserve's tapering announcements have moderated uncertainties over just when, and to what degree, the stimulus program would be altered, but investors continue to face ongoing uncertainties over future moves that could ultimately affect how quickly and how much interest rates are affected. The Federal Reserve's holdings of Treasuries and mortgage-backed securities amount to more than $4 trillion.[8] For now, the Federal Reserve is maintaining its policy of reinvesting principal payments from these securities – about $16 billion a month – and rolling over maturing Treasuries at auction. As the Federal Reserve recently noted:

> The Committee is maintaining its existing policy of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities and of rolling over maturing Treasury securities at auction. The Committee's sizable and still-increasing holdings of longer-term securities should maintain downward pressure on longer-term interest rates, support mortgage markets, and help to make broader financial conditions more accommodative, which in turn should promote a stronger economic recovery and help to ensure that inflation, over time, is at the rate most consistent with the Committee's dual mandate.[9]

Of course, the corollary to these observations is that ending this policy of reinvestment could place significant upward pressure on bond yields, especially considering the enormous

[7] Hilsenrath, Jon, "Fed Dials Back Bond Buying, Keeps a Wary Eye on Growth," *The Wall Street Journal* at A1 (Dec. 19, 2013).
[8] Appelbaum, Binyamin, "Federal Reserve's Bond-Buying Fades, but Stimulus Doesn't End There," *The New York Times* (Jun. 19, 2014).
[9] Federal Open Market Committee, *Press Release* (Jun. 18, 2014).

magnitude of the Federal Reserve's holdings of Treasury bonds and mortgage-backed securities. The International Monetary Fund noted that, "A lack of Fed clarity could cause a major spike in borrowing costs that could cause severe damage to the U.S. recovery and send destructive shockwaves around the global economy," adding that, "A smooth and gradual upward shift in the yield curve might be difficult to engineer, and there could be periods of higher volatility when longer yields jump sharply—as recent events suggest."[10] Similarly, the Wall Street Journal noted investors' "hypersensitivity to Fed interest rate decisions," and expectations that higher interest rates "may come a bit sooner and be a touch more aggressive than expected."[11]

These developments highlight concerns for investors and support expectations for higher interest rates as the economy and labor markets continue to recover. With the Federal Reserve curtailing the expansion of its enormous portfolio of Treasuries and mortgage bonds, ongoing concerns over political stalemate in Washington, continued economic weakness in the Eurozone, and political and economic unrest in Ukraine, the Middle East, and emerging markets, the potential for significant volatility and higher capital costs is clearly evident to investors.

Q. Have other regulators recognized the importance of considering the implications of current capital market conditions when evaluating a fair ROE for a utility?

A. Yes. In its June 19, 2014 order in Docket No. EL11-66-001, FERC explicitly noted the need to "consider the extent to which economic anomalies may have affected the

[10] Talley, Ian, "IMF Urges 'Improved' U.S. Fed Policy Transparency as It Mulls Easy Money Exit," *The Wall Street Journal* (July 26, 2013).
[11] Jon Hilsenrath and Victoria McGrane, "Yellen Debut Rattles Markets," Wall Street Journal (Mar. 19, 2014).

reliability of DCF analyses in determining where to set a public utility's ROE within the range of reasonable returns."[12] FERC ultimately determined that due to unrepresentative capital market conditions, an upward adjustment to the 9.39% midpoint of its DCF range was required in order to meet the regulatory standards established by *Hope* and *Bluefield*. Based on its examination of alternatives to the DCF approach, FERC authorized an ROE from the upper end of its DCF range, or 10.57%.[13]

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

A. Current capital market conditions continue to reflect the impact of unprecedented policy measures taken in response to recent dislocations in the economy and financial markets. As a result, current capital costs are not representative of what is likely to prevail over the near-term future, with this conclusion being demonstrated by comparisons to the historical record and independent forecasts. Near-term projections from recognized economic forecasting services indicate that long-term capital costs will increase from present levels. To address the reality of current capital markets, the OPUC should consider this expected upward trend in capital costs in evaluating the reasonableness of individual cost of equity estimates and in selecting a reasonable ROE for Avista from within the zone of reasonableness.

---

[12] *Martha Coakley et al., v. Bangor Hydro-Electric Company, et al.*, Opinion No. 531, 147 FERC ¶ 61,234 at P 41 (2014) ("Opinion No. 531").
[13] *Id.* at PP 145, 146, 148, & 152.

IV. COMPARABLE RISK PROXY GROUPS

Q. How did you implement quantitative methods to estimate the cost of common equity for Avista?

A. Application of 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 quantitative methods such as the DCF and ECAPM to a proxy group of publicly traded companies that investors regard as risk-comparable.

Q. What specific proxy groups 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, I examined quantitative estimates of investors' required ROE for a group of natural gas utilities, consisting of nine publicly traded firms included in Value Line's Natural Gas Utility industry.[14] I refer to these utilities as the "Gas Group."

Q. What other proxy group of utilities did you consider in your analyses?

A. My analyses also considered those utilities followed by Value Line with both electric and gas utility operations. In addition, I excluded seven firms that otherwise would have been in the proxy group, but are not appropriate for inclusion because of current

[14] I excluded one firm (UGI Corporation) that was included in Value Line's Natural Gas Utility Industry because it is primarily engaged in propane sales and marketing, and another firm (Laclede Group, Inc.) due to its pending $1.6 billion acquisition of Alegasco.

involvement in a major merger or acquisition.[15] These criteria resulted in a proxy group composed of twenty-one companies, which I will refer to as the "Combination Group."

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

A. Table AMM-1 compares the average corporate credit rating for Gas and Combination Groups with Avista, as well as three key quality rankings published by Value Line, which are also widely referenced by investors:

TABLE AMM-1
COMPARISON OF RISK INDICATORS

	S&P	Value Line		
Proxy Group	**Credit Rating**	**Safety Rank**	**Financial Strength**	**Beta**
Gas Utility	A-	2	A	0.77
Combination Utility	BBB+	2	A	0.72
Avista	BBB	2	A	0.75

Q. Do these indicators 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. Investment restrictions tied to

[15] Exelon Corporation, NorthWestern Corporation, Pepco Holdings, Inc., PPL Corporation, TECO Energy, Inc., UIL Holdings Corporation, and UNS Energy Corporation.

credit ratings continue to influence capital flows, and credit ratings are widely cited in the investment community and referenced by investors, and also frequently used as a primary risk indicator in establishing proxy groups to estimate the cost of common equity.

While credit ratings provide the most widely referenced benchmark for investment risks, other quality rankings published by investment advisory services also provide relative assessments of risks that are considered by investors in forming their expectations for common stocks. Value Line's primary risk indicator is its Safety Rank, which ranges from "1" (Safest) to "5" (Riskiest). This overall risk measure is intended to capture the total risk of a stock, and incorporates elements of stock price stability and financial strength. Given that Value Line is perhaps the most widely available source of investment advisory information, its Safety Rank provides useful guidance regarding the risk perceptions of investors.

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. These objective, published indicators incorporate consideration of a broad spectrum of risks, including financial and business position, relative size, and exposure to firm-specific factors.

Finally, beta measures a utility's stock price volatility relative to the market as a whole, and reflects the tendency of a stock's price to follow changes in the market. 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. Beta is the only relevant measure of investment risk under modern capital market theory, and is widely cited in academics and in the investment industry as a guide to investors' risk perceptions. Moreover, in my experience Value Line is the most widely referenced source for beta in regulatory proceedings.

Q. What does this comparison indicate regarding investors' assessment of the equity risks associated with your utility proxy groups?

A. As displayed in Table AMM-1, Avista is assigned a corporate credit rating of "BBB" by S&P, with the average corporate credit ratings for the Gas and Combination Groups indicating less risk. The average Safety Rank and Financial Strength values for the two utility groups are identical to Avista, while the Company's beta indicates slightly greater risk than for the Combination Group and slightly less risk than the Gas Group.

Considered together, a comparison of these objective measures, which consider a broad spectrum of risks, including financial and business position, and exposure to firm-specific factors, indicates that investors would likely conclude that the overall investment risks for Avista are generally comparable to those of the two proxy groups of utilities. As a result there is certainly no justification that would support a lower ROE for the Company than what is indicated based on my analyses for the proxy groups, and Avista's lower credit rating would suggest a higher cost of equity than for the groups of gas and combination utilities.

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 investors ahead of them, thereby increasing the uncertainty as to the amount of cash flow, if any, that will remain.

Q. What common equity ratio is implicit in Avista's capital structure?

A. The capital structure used to compute the overall rate of return for Avista includes 51.0% common equity.

Q. How can the Company's requested 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 average capitalizations are maintained by the Combination and Gas Groups?

A. As shown on page 1 of Exhibit No. 301, Schedule AMM-2, for the firms in the Gas Group, common equity ratios at December 31, 2013 averaged 52.6% of long-term capital, with Value Line expecting an average common equity ratio of 55.8% for its three-to-five year forecast horizon. Meanwhile, for the firms in the Combination Group, common equity ratios ranged from 31.35 to 58.0% and averaged 48.1% in 2013, while Value Line's near-term projected common equity ratios fell in a range of 37.0& to 55.5% and averaged 48.3% (page 2 of Exhibit No. 301, Schedule AMM-2). Thus, Avista's common equity ratio is within the range maintained by the Combination Group, while indicating somewhat greater financial risk than investors would associate with the Gas Group.

Based on my evaluation, I concluded that Avista's requested capital structure represents a reasonable mix of capital sources from which to calculate the Company's overall rate of return.

V. CAPITAL MARKET ESTIMATES

Q. What is the purpose of this section?

A. This section presents capital market estimates of the cost of 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, ECAPM, and risk premium analyses conducted to estimate the cost of common equity for benchmark groups of comparable risk firms. 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 rate of return on common equity play in a utility's rates?

A. The return on common equity is the cost of inducing and retaining 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. Investors 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.

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

A. The fundamental economic principle underlying the cost of equity concept is the notion that investors are risk averse. In capital markets where relatively risk-free assets are available (*e.g.*, U.S. Treasury securities), investors can be induced to hold riskier assets only if they are offered a premium, or additional return, above the rate of return on a risk-free asset. Because all assets compete with each other for investor funds, riskier assets must yield a higher expected rate of return than safer assets to induce investors to invest and hold them.

Given this risk-return tradeoff, the required rate of return (k) from an asset (i) can generally be expressed as:

$$k_i = R_f + RP_i$$

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

Thus, the required rate of return for a particular asset at any time is a function of: (1) the yield on risk-free assets, and (2) the asset's relative risk, with investors demanding correspondingly larger risk premiums for bearing greater risk.

Q. Is there evidence that the risk-return tradeoff principle actually operates in the capital markets?

A. Yes. The risk-return tradeoff can be readily documented in segments of the capital markets where required rates of return can be directly inferred from market data and where generally accepted measures of risk exist. Bond yields, for example, reflect investors' expected rates of return, and bond ratings measure the risk of individual bond issues. Comparing the observed yields on government securities, which are considered free of default risk, to the yields on bonds of various rating categories demonstrates that the risk-return tradeoff does, in fact, exist.

Q. Does the risk-return tradeoff observed with fixed income securities extend to common stocks and other assets?

A. It is widely accepted that the risk-return tradeoff evidenced with long-term debt extends to all assets. Documenting the risk-return tradeoff for assets other than fixed income securities, however, is complicated by two factors. First, there is no standard measure of risk applicable to all assets. Second, for most assets – including common stock – required rates of return cannot be directly observed. Yet there is every reason to believe that investors exhibit risk aversion in deciding whether or not to hold common stocks and other assets, just as when choosing among fixed-income securities.

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. 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. What does the above discussion imply with respect to estimating the cost of common equity for a utility?

A. Although the cost of common equity cannot be observed directly, it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed. Because it is not readily observable, the cost of common 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' 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.

D. Discounted Cash Flow Analyses

Q. What market valuation process underlies DCF models?

A. DCF models assume 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. Thus, the cost of equity is the discount rate that equates the current price of a share of stock with the present value of all expected cash flows from the stock. The formula for the general form of the DCF model is as follows:

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

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 common equity.

That is, the cost of common equity is the discount rate that will equate the current price of a share of stock with the present value of all expected cash flows from the stock.

Q. What form of the DCF model is customarily used to estimate the cost of common equity in rate cases?

A. Rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form:[16]

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

where: g = Investors' long-term growth expectations.

The cost of common equity (k_e) can be isolated by rearranging terms within the equation:

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

This constant growth form of the 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 the capital gains associated with price appreciation over the investors' holding period.

Q. What form of the DCF model did you use?

A. I applied the constant growth DCF model to estimate the cost of common equity for Avista, which is the form of the model most commonly relied on to establish the

[16] The constant growth DCF model is dependent on a number of strict assumptions, which in practice are never 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.

cost of common equity for traditional regulated utilities and the method most often referenced by regulators.

Q. How is the constant growth form of the DCF model typically used to estimate the cost of common 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 step is to estimate investors' long-term growth 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 common equity.

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

A. For D_1, I used estimates of dividends to be paid by each of these utilities over the next 12 months, obtained from Value Line. This annual dividend was then divided by a 30-day average 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 Group are presented on Exhibit No. 301, Schedule AMM-3. As shown on page 1, dividend yields for the firms in the Gas Group ranged from 2.8% to 4.4%.

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

A. Given that 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 ratios falling significantly. 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.

A measure that plays a pivotal role in determining investors' long-term growth expectations are future trends in earnings per share ("EPS"), which provide the source for future dividends and ultimately support share prices. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community, and surveys of analytical techniques relied on by professional analysts indicate that growth in earnings is far more influential than trends in dividends per share ("DPS").

The availability of projected EPS growth rates also is key to investors relying on this measure as compared to future trends in DPS. Apart from Value Line, investment advisory services do not generally publish comprehensive DPS growth projections, and this scarcity of dividend growth rates relative to the abundance of earnings forecasts attests to their relative influence. The fact that securities analysts focus on EPS growth, and that DPS growth rates are not routinely published, indicates that projected EPS growth rates are likely to provide a superior indicator of the future long-term growth expected by investors.

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. Did Professor Myron J. Gordon, who originated the DCF approach, recognize the pivotal role that earnings play in forming investors' expectations?

A. Yes. Dr. Gordon specifically recognized that "it is the growth that investors expect that should be used" in applying the DCF model and he concluded:

> A number of considerations suggest that investors may, in fact, use earnings growth as a measure of expected future growth."[17]

Q. Are analysts' assessments of growth rates appropriate for estimating investors' required return using the DCF model?

A. Yes. 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-

[17] Gordon, Myron J., "The Cost of Capital to a Public Utility," *MSU Public Utilities Studies* at 89 (1974).

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, then it is 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, as well as the continued success of services such as Thomson Reuters and Value Line, implies that investors use them as a basis for their expectations.

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.[18]

Q. Have other regulators also recognized that analysts' growth rate estimates are an important and meaningful guide to investors' expectations?

A. Yes. FERC has expressed a clear preference for projected EPS growth rates from IBES in applying the DCF model to estimate the cost of equity for both electric and natural gas pipeline utilities, and has expressly rejected reliance on other sources.[19] As FERC concluded:

> Opinion No. 414-A held that the IBES five-year growth forecasts for each company in the proxy group are the best available evidence of the short-term growth rates expected by the investment community. It cited evidence that (1) those forecasts are provided to IBES by professional security analysts, (2) IBES reports the forecast for each firm as a service to investors, and (3) the IBES reports are well known in the investment community and used by investors. The Commission has also rejected the suggestion that the IBES analysts are biased and stated that "in fact the analysts have a significant incentive to make their analyses as accurate as possible to meet the needs of their clients since those investors will not utilize brokerage firms whose analysts repeatedly overstate the growth potential of companies."[20]

Similarly, the Kentucky Public Service Commission has also indicated its preference for relying on analysts' projections in establishing investors' expectations:

> KU's argument concerning the appropriateness of using investors' expectations in performing a DCF analysis is more persuasive than the AG's argument that analysts' projections should be rejected in favor of historical results. The Commission agrees that analysts' projections of growth will be relatively more compelling in forming investors' forward-

[18] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 298 (2006) (emphasis added).
[19] *See, e.g., Midwest Independent Transmission System Operator, Inc.*, 99 FERC ¶ 63,011 at P 53 (2002); *Golden Spread Elec. Coop. Inc.*, 123 FERC ¶ 61,047 (2008).
[20] *Kern River Gas Transmission Co.*, 126 FERC ¶ 61,034at P 121 (2009) ((footnote omitted).

> looking expectations than relying on historical performance, especially given the current state of the economy. [21]

More recently, the Public Utility Regulatory Authority of Connecticut noted that:

> The Authority used growth in earnings exclusively based on the record of this docket showing that financial literature supports security analysts' EPS growth rate projections as superior for use in a DCF analysis. Response to Interrogatory FI-106. The Authority takes note that long-term, there is not growth in DPS without growth in EPS. Market prices are more highly influenced by security analyst's earnings expectations then expectations in dividends. The Authority agrees with Ms. Ahern that "the use of earnings growth rates in a DCF analysis provides a better matching between investors' market price appreciation expectations and the growth rate component of the DCF."[22]

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

A. The earnings growth projections for each of the firms in the Gas Group reported by Value Line, IBES, Zacks Investment Research ("Zacks"), and Reuters are displayed on page 2 of Exhibit No. 301, Schedule AMM-3.[23]

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 never met in practice, this "sustainable growth"

[21] *Order*, Case No. 2009-00548 at 30-31 (Jul. 30, 2010).
[22] *Decision*, Docket No. 13-02-20 (Sep. 24, 2013).
[23] Formerly I/B/E/S International, Inc., IBES growth rates are now compiled and published by Thomson Reuters.

approach may provide a rough guide for evaluating a firm's growth prospects and is frequently proposed in regulatory proceedings.

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. 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. Because Value Line reports end-of-year book values, an adjustment factor was incorporated to compute an average rate of return over the year, consistent with the theory underlying this approach to estimating investors' growth expectations.

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

A. The sustainable, "br+sv" growth rates for each firm in the Gas Group are summarized on page 2 of Exhibit No. 301, Schedule AMM-3, with the underlying details being presented on Exhibit No. 301, Schedule AMM-4.

Q. What cost of common equity estimates were implied for the Gas 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 page 3 of Exhibit No. 301, Schedule AMM-3.

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. I based my evaluation of DCF estimates at the low end of the range on the fundamental risk-return tradeoff, which holds that investors will only take on more risk if they expect to earn a higher rate of return to compensate them for the greater uncertainly. Because common stocks lack the protections associated with an investment in long-term bonds, a utility's common stock imposes far greater risks on investors. As a result, the rate of return that investors require from a utility's common stock is considerably higher than the yield offered by senior, long-term debt. Consistent with this principle, DCF results that are not sufficiently higher than the yield available on less risky utility bonds must be eliminated.

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. The practice of eliminating low-end outliers has been affirmed in numerous proceedings,[24] and in its June 16, 2014 decision in Opinion No. 531, FERC concluded that, "The purpose of the low-end outlier test is to exclude

[24] *See, e.g., Virginia Electric Power Co.*, 123 FERC ¶ 61,098 at P 64 (2008).

from the proxy group those companies whose ROE estimates are below the average bond yield or are above the average bond yield but are sufficiently low that an investor would consider the stock to yield essentially the same return as debt."[25] FERC has used 100 basis points above the six-month average public utility bond yield as an approximation of this threshold, but has also recognized that this is a flexible test.[26]

Q. What interest rate benchmark did you consider in evaluating the DCF results for Avista?

A. As noted earlier, S&P has assigned a corporate credit rating of BBB to Avista. 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 4.8% over the six-months ending July 2014.[27]

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 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 AMM-2 below, forecasts of IHS Global Insight and the EIA imply an average triple-B bond yield of 6.62% over the period 2015-2018:

[25] Opinion No. 531 at P 122.
[26] *Id.*
[27] Moody's Investors Service, http://credittrends.moodys.com/chartroom.asp?c=3.

TABLE AMM-2
IMPLIED BBB BOND YIELD

	2015-18
Projected AA Utility Yield	
IHS Global Insight (a)	6.19%
EIA (b)	5.96%
Average	6.07%
Current BBB - AA Yield Spread (c)	0.55%
Implied Triple-B Utility Yield	**6.62%**

(a) IHS Global Insight, U.S. Economic Outlook at 79 (May 2014)
(b) Energy Information Administration, Annual Energy Outlook 2014 (May 7, 2014)
(c) Based on monthly average bond yields from Moody's Investors Service for the six-month period Feb. 2014 - Jul. 2014

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 over 160 basis points through 2018.[28]

Q. What does this evaluation imply with respect to low-end DCF estimates for the Gas Group?

A. As highlighted on page 3 of Exhibit No. 301, Schedule AMM-3, low-end DCF estimates ranged from 5.1% to 7.3%. In light of the risk-return tradeoff principle and the test of economic logic applied by FERC, 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 upward trend expected for utility bond yields, these low-end values provide little guidance as to the returns investors require from utility common stocks and should be excluded.

[28] *Blue Chip Financial Forecasts*, Vol. 32, No. 12 (Dec. 1, 2013).

Q. Is there a basis to exclude DCF estimates at the high end of the range?

A. No. The upper end of the DCF range for the Gas Group was set by a cost of equity estimate of 14.2%. While this cost of equity estimate may exceed the majority of the remaining values, remaining low-end estimates in the 7.5% range are assuredly far below investors' required rate of return. Taken together and considered along with the balance of the DCF estimates, these values provide a reasonable basis on which to evaluate investors' required rate of return.

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

A. As shown on page 3 of Exhibit No. 301, Schedule AMM-3 and summarized in Table AMM-3, below, after eliminating illogical values, application of the constant growth DCF model resulted in the following cost of equity estimates:

TABLE AMM-3
DCF RESULTS – GAS GROUP

	Cost of Equity	
Growth Rate	**Average**	**Midpoint**
Value Line	10.4%	10.9%
IBES	9.9%	10.4%
Zacks	9.1%	9.5%
Reuters	9.6%	10.4%
br + sv	9.5%	10.2%

Q. What were the results of your DCF analysis for the Combination Group?

A. I applied the DCF model to the Combination Group in exactly the same manner described earlier for the Gas Group. The results of my DCF analysis for the Combination Group are presented in Exhibit No. 301, Schedule AMM-5, with the sustainable, "br+sv" growth rates being developed on Exhibit No. 301, Schedule AMM-6.

As shown on page 3 of Exhibit No. 301, Schedule AMM-5 and summarized in Table AMM-4, below, after eliminating illogical values, application of the constant growth DCF model to the Combination Group resulted in the following cost of equity estimates:

TABLE AMM-4
DCF RESULTS – COMBINATION GROUP

	Cost of Equity	
Growth Rate	**Average**	**Midpoint**
Value Line	9.6%	10.0%
IBES	9.0%	8.9%
Zacks	9.2%	10.0%
Reuters	9.0%	8.9%
br + sv	8.7%	9.4%

E. Empirical Capital Asset Pricing Model

Q. Please describe the ECAPM.

A. The ECAPM is a variant of the traditional CAPM, which is generally considered to be the most widely referenced method for estimating the cost of equity among academicians and professional practitioners, with the pioneering researchers of this method receiving the Nobel Prize in 1990. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. Assuming investors are 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. 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.

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 ECAPM 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 ECAPM must be applied using estimates that reflect the expectations of actual investors in the market, not with backward-looking, historical data.

Q. How does the ECAPM approach differ from traditional applications of the CAPM?

A. The ECAPM is a variant of the traditional CAPM approach that is designed to correct for an observed bias in the CAPM results. Specifically, empirical tests of the CAPM have shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. In other words, the CAPM tends to overstate the actual sensitivity of the cost of capital to beta, with low-beta stocks tending to have higher returns and high-beta stocks tending to have lower risk returns than predicted by the CAPM. This empirical finding is widely reported in the finance literature, as summarized in *New Regulatory Finance*:

> As discussed in the previous section, several finance scholars have developed refined and expanded versions of the standard CAPM by relaxing the constraints imposed on the CAPM, such as dividend yield, size, and skewness effects. These enhanced CAPMs typically produce a risk-return relationship that is flatter than the CAPM prediction in keeping with the actual observed risk-return relationship. The ECAPM makes use of these empirical relationships.[29]

[29] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports* at 189 (2006).

As discussed in *New Regulatory Finance*, empirical evidence suggests that the expected return on a security is related to its risk by the ECAPM, which is represented by the following formula:

$$Rj = Rf + 0.25(Rm - Rf) + 0.75[\beta j(Rm - Rf)]$$

This ECAPM equation, and the associated weighting factors, recognize the observed relationship between standard CAPM estimates and the cost of capital documented in the financial research, and correct for the understated returns that would otherwise be produced for low beta stocks.

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

A. Application of the ECAPM to the Gas Group based on a forward-looking estimate for investors' required rate of return from common stocks is presented on Exhibit No. 301, Schedule AMM-7. 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 dividend yield for each firm was obtained from Value Line, and the growth rate was equal to the average of the EPS growth projections for each firm published by IBES, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. Based on the weighted average of the projections for the 410 individual firms, current estimates imply an average growth rate over the next five years of 10.0%. Combining this average growth rate with a year-ahead dividend yield of 2.3% results in a current cost of common equity estimate for the market as a whole (R_m) of approximately 12.3%. Subtracting a 3.5% risk-free rate based on the average yield on 30-year Treasury bonds for the six-months ended July 2014 produced a market equity risk premium of 8.8%.

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

A. As indicated earlier, 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.

Q. What else should be considered in applying the ECAPM?

A. As explained by *Morningstar*:

> One of the most remarkable discoveries of modern finance is that of a relationship between firm size and return. The relationship cuts across the entire size spectrum but is most evident among smaller companies, which have higher returns on average than larger ones.[30]

Because financial research indicates that the CAPM does not fully account for observed differences in rates of return attributable to firm size, a modification is required to account for this size effect.

According to the ECAPM, the expected return on a security should consist of the riskless rate, plus a premium to compensate for the systematic risk of the particular security. The degree of systematic risk is represented by the beta coefficient. The need for the size adjustment arises because differences in investors' required rates of return that are related to firm size are not fully captured by beta. To account for this, Morningstar has developed size premiums that need to be added to the theoretical ECAPM cost of equity estimates to account for the level of a firm's market capitalization in determining the ECAPM cost of equity.[31] These premiums correspond to the size deciles of publicly traded common stocks, and range from a premium of approximately 6.0% for a company in the first decile (market capitalization less than $338.8 million), to a reduction of 33 basis points for firms in the tenth decile (market capitalization between $21.8 billion and $428.7 billion). Accordingly, my

[30] *Morningstar*, "Ibbotson SBBI 2013 Valuation Yearbook," at p. 85.
[31] *Morningstar*, "2014 Ibbotson SBBI Market Report," at Table 10 (2014).

ECAPM analyses also incorporated an adjustment to recognize the impact of size distinctions, as measured by the average market capitalization for the Gas Group.

Q. What is the implied ROE for the Gas Group using the ECAPM approach?

A. As shown on page 1 of Exhibit No. 301, Schedule AMM-7, a forward-looking application of the ECAPM approach resulted in an average unadjusted ROE estimate of 10.8%.[32] After adjusting for the impact of firm size, the ECAPM approach implied an average cost of equity of 11.4% for the Gas Group, with a midpoint cost of equity estimate of 12.3%.

Q. Did you also apply the ECAPM using forecasted bond yields?

A. Yes. As discussed earlier, there is widespread consensus that interest rates will increase materially as the economy continues to strengthen. Accordingly, in addition to the use of historical bond yields, I also applied the CAPM based on the forecasted long-term Treasury bond yields developed based on projections published by Value Line, IHS Global Insight and Blue Chip. As shown on page 2 of Exhibit No. 301, Schedule AMM-7, incorporating a forecasted Treasury bond yield for 2015-2018 implied a cost of equity of approximately 11.0% for the Gas Group, or 12.5% after adjusting for the impact of relative size. The midpoints of the unadjusted and size adjusted cost of equity ranges were 10.9% and 12.4%, respectively.

Q. What implied ROEs were indicated for the Combination Group using the ECAPM approach?

A. An identical application of the ECAPM to the firms in the Combination Group is presented on Exhibit No. 301, Schedule AMM-8. As shown on page 1, the forward-looking

[32] The midpoint of the unadjusted ECAPM range was 10.6%.

ECAPM analysis resulted in an average unadjusted ROE estimate of 10.4% for the Combination group, or 11.3% after adjusting for the impact of firm size. The midpoints of the unadjusted and size adjusted cost of equity ranges were 10.5% and 11.2%, respectively. Incorporating a projected Treasury bond yield for 2015-2018 (Exhibit No. 301, Schedule AMM-8, p. 2) implied a cost of equity of approximately 10.7% for the Combination Group, or 11.6% after adjusting for the impact of relative size.[33]

F. Utility Risk Premium

Q. Briefly describe the risk premium method.

A. The risk premium method extends the risk-return tradeoff observed with bonds to estimate investors' required rate of return on common stocks. The cost of equity is estimated by first determining the additional return investors require to forgo the relative safety of bonds and to bear the greater risks associated with common stock, and by then adding this equity risk premium to the current yield on bonds. Like the DCF model, the risk premium method is capital market oriented. However, unlike DCF models, which indirectly impute the cost of equity, risk premium methods directly estimate investors' required rate of return by adding an equity risk premium to observable bond yields.

Q. Is the risk premium approach a widely accepted method for estimating the cost of equity?

A. Yes. The risk premium approach is based on the fundamental risk-return principle that is central to finance, which holds that investors will require a premium in the form of a higher return in order to assume additional risk. This method is routinely referenced

[33] The midpoint of the unadjusted ECAPM range was 10.7%, or 11.5% after adjusting for relative size.

by the investment community and in academia and regulatory proceedings, and provides an important tool in estimating a fair ROE for Avista.

Q. How did you implement the risk premium method?

A. I based my estimates of equity risk premiums for utilities on surveys of previously authorized ROEs. Authorized ROEs presumably reflect regulatory commissions' best estimates of the cost of equity, however determined, at the time they issued their final order. Such ROEs should represent a balanced and impartial outcome that considers the need to maintain a utility's financial integrity and ability to attract capital. Moreover, allowed returns are an important consideration for investors and have the potential to influence other observable investment parameters, including credit ratings and borrowing costs. Thus, these data provide a logical and frequently referenced basis for estimating equity risk premiums for regulated utilities.

Q. Is it circular to consider risk premiums based on authorized returns in assessing a fair ROE for Avista?

A. No. In establishing authorized ROEs, regulators typically consider the results of alternative market-based approaches, including the DCF model. Because allowed risk premiums consider objective market data (*e.g.*, stock prices, dividends, beta, and interest rates), and are not based strictly on past actions of other regulators, this mitigates concerns over any potential for circularity.

Q. How did you calculate the equity risk premiums based on allowed ROEs?

A. The ROEs authorized for electric utilities by regulatory commissions across the U.S. are compiled by Regulatory Research Associates and published in its *Regulatory Focus* report. In Exhibit No. 301, Schedule AMM-9, the average yield on public utility bonds is subtracted from the average allowed ROE for gas utilities to calculate equity risk premiums for each quarter between 1980 and the second quarter of 2014.[34] As shown on page 3 of Exhibit No. 301, Schedule AMM-9, over this period, these equity risk premiums for electric utilities averaged 3.31%, and the yield on public utility bonds averaged 8.57%.

Q. Is there any capital market relationship that must be considered when implementing the risk premium method?

A. Yes. There is considerable evidence that the magnitude of equity risk premiums is not constant and that equity risk premiums tend to move inversely with interest rates.[35] In other words, when interest rate levels are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums widen. The implication of this inverse relationship is that the cost of equity does not move as much as, or in lockstep with, interest rates. Accordingly, for a 1% increase or decrease in interest rates, the cost of equity may only rise or fall, say, 50 basis points. Therefore, when implementing the risk premium method, adjustments may be required to incorporate this inverse relationship if current interest rate levels have diverged from the average interest rate level represented in the data set.

Q. What cost of equity is implied by the risk premium method using surveys of allowed ROEs?

A. Based on the regression output between the interest rates and equity risk premiums displayed on page 4 of Exhibit No. 301, Schedule AMM-9, the equity risk premium

[34] My analysis encompasses the entire period for which published data is available.

[35] *See, e.g.,* Brigham, E.F., Shome, D.K., and Vinson, S.R., "The Risk Premium Approach to Measuring a Utility's Cost of Equity," *Financial Management* (Spring 1985); Harris, R.S., and Marston, F.C., "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts," *Financial Management* (Summer 1992).

for gas utilities increased approximately 46 basis points for each percentage point drop in the yield on average public utility bonds. As illustrated on page 1 of Exhibit No. 301, Schedule AMM-9, with an average yield on single-A public utility bonds for the six-months ending July 2014 of 4.37%, this implied a current equity risk premium of 5.23% for gas utilities. Adding this equity risk premium to the average yield on triple-B utility bonds for the six-months ended July 2014 of 4.82% implies a current cost of equity of approximately 10.1%.

Q. What risk premium cost of equity estimates were produced for Avista's gas utility operations after incorporating forecasted bond yields?

A. As shown on page 2 of Exhibit No. 301, Schedule AMM-9, incorporating a forecasted yield for 2015-2018 and adjusting for changes in interest rates since the study period implied an equity risk premium of 4.41% for gas utilities. Adding this equity risk premium to the implied average yield on triple-B public utility bonds for 2015-2018 of 6.62% resulted in an implied cost of equity of approximately 11.0%.

G. Flotation Costs

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

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. 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 equity being the most appropriate mechanism.

Q. Is there a theoretical and practical basis to include a flotation cost adjustment in this case?

A. Yes. First, an adjustment for flotation costs associated with past equity issues is appropriate, even when the utility is not contemplating any new sales of common stock. The need for a flotation cost adjustment to compensate for past equity issues been recognized in the financial literature. In a *Public Utilities Fortnightly* article, for example, Brigham, Aberwald, and Gapenski demonstrated that even if no further stock issues are contemplated, a flotation cost adjustment in all future years is required to keep shareholders whole, and that the flotation cost adjustment must consider total equity, including retained earnings.[36] Similarly, *New Regulatory Finance* contains the following discussion:

> Another controversy is whether the flotation cost allowance should still be applied when the utility is not contemplating an imminent common stock issue. Some argue that flotation costs are real and should be recognized in calculating the fair rate of return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument implies that the company has already been compensated for these costs and/or the initial contributed capital was obtained freely, devoid of any flotation costs, which is an unlikely assumption, and certainly not applicable to most utilities. … The flotation cost adjustment cannot be strictly forward-looking unless all past flotation costs associated with past issues have been recovered.[37]

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

A. There are a number of ways in which a flotation cost adjustment can be calculated, but 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, *Regulatory Finance: Utilities' Cost of Capital* 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.[38]

---

[36] Brigham, E.F., Aberwald, D.A., and Gapenski, L.C., "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly,* May, 2, 1985.
[37] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 335 (2006).
[38] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 323 (2006).

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%.[39]

Issuance costs are a legitimate consideration in setting the return on equity for a utility, and applying these expense percentages to an average dividend yield of 3.5% implies a flotation cost adjustment on the order of 13 to 35 basis points.

Q. Did you include a flotation cost adjustment in arriving at your recommended ROE range?

A. Yes. I included a minimum adjustment for flotation costs of 13 basis points in evaluating a fair ROE range for Avista.

VI. OTHER ROE BENCHMARKS

Q. What is the purpose of this section of your testimony?

A. This section presents alternative tests to demonstrate that the end-results of the ROE analyses discussed earlier are reasonable and do not exceed a fair ROE given the facts and circumstances of Avista. These tests include applications of the traditional CAPM analysis using historical and projected interest rates, as well as a review of expected earned returns and allowed rates of return for the utility proxy groups. Finally, I present a DCF analysis for a select, low risk group of non-utility firms, with which Avista must compete for investors' money.

[39] *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%.

A. Capital Asset Pricing Model

Q. What cost of equity estimates were indicated by the traditional CAPM?

A. My applications of the traditional CAPM were based on the same forward-looking market rate of return, risk-free rates, and beta values discussed earlier in connections with the ECAPM. As shown on page 1 of Exhibit No. 301, Schedule AMM-10, applying the forward-looking CAPM approach to the firms in the Gas Group results in an average theoretical cost of equity estimate of 10.3%, or 11.8% after incorporating the size adjustment corresponding to the market capitalization of the individual utilities. As shown on page 1 of Exhibit No. 301, Schedule AMM-11, adjusting the 9.8% theoretical CAPM result for the Combination Group to incorporate the size adjustment results in an average indicated cost of common equity of 10.7%.

As shown on page 2 of Exhibit No. 301, Schedule AMM-10, incorporating a forecasted Treasury bond yield for 2015-2018 implied a cost of equity of approximately 10.6% for the Gas Group, or 12.1% after adjusting for the impact of relative size. For the Combination Group (page 2 of Exhibit No. 301, Schedule AMM-11), projected bond yields implied a theoretical CAPM estimate of 10.1%, or 11.0% after incorporating the size adjustment.

B. Expected Earnings Approach

Q. What other analyses did you conduct to estimate the cost of common 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 expected earnings approach is consistent with the economic underpinnings for a fair rate of return established by the U.S. Supreme Court in *Bluefield* and *Hope*. 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 economic premise underlies the expected earnings approach?

A. The simple, but powerful concept underlying the expected earnings approach is that investors compare each investment alternative with the next best opportunity. If the utility is unable to offer a return similar to that available from other opportunities of comparable risk, investors will become unwilling to supply the capital on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their opportunity cost of capital. In this situation the government is effectively taking the value of investors' capital without adequate compensation. The expected earnings approach is consistent with the economic rationale underpinning established regulatory standards, which specifies a methodology to determine an ROE benchmark based on earned rates of return for a peer group of other regional utilities.

Q. How is the expected earnings approach typically implemented?

A. The traditional comparable earnings test identifies a group of companies that are believed to be comparable in risk to the utility. The actual earnings of those companies on the book value of their investment are then compared to the allowed return of the utility. While the traditional comparable earnings test is implemented using historical data taken from the accounting records, it is also common to use projections of returns on book investment, such as those published by recognized investment advisory publications (*e.g.*, Value Line).

Because these returns on book value equity are analogous to the allowed return on a utility's rate base, this measure of opportunity costs results in a direct, "apples to apples" comparison.

Moreover, regulators do not set the returns that investors earn in the capital markets, which are a function of dividend payments and fluctuations in common stock prices- both of which are outside their control. Regulators can only establish the allowed ROE, which is applied to the book value of a utility's investment in rate base, as determined from its accounting records. Moreover, regulators do not set the returns that investors earn in the capital markets – they can only establish the allowed return on the value of a utility's investment, as reflected on its accounting records. This is directly analogous to the expected earnings approach, which measures the return that investors expect the utility to earn on book value. As a result, the expected earnings approach provides a meaningful guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. This expected earnings test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

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

A. Value Line's projected year-end returns on common equity for the firms in the Gas Group are shown on page 1 of Exhibit No. 301, Schedule AMM-12. 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 Exhibit No. 301, Schedule AMM-4. As shown on page 1 of Exhibit No. 301, Schedule AMM-12, Value Line's projections for the Gas Group suggest an average ROE of approximately 11.4%. As shown on page 2 of Exhibit No. 301, Schedule AMM-12, Value Line's projections for the Combination Group suggested an average ROE of 10.9%.[40]

C. Allowed ROEs

Q. Can allowed ROEs also be used to evaluate the reasonableness of Avista's requested ROE?

A. Yes. Reference to allowed rates of return for other utilities provides another useful guideline that can be used to assess the extent to which Avista's requested 9.9% ROE is reasonable. As shown on page 1 of Exhibit No. 301, Schedule AMM-13, data from the May 2014 *AUS Monthly Utility Report* indicates that the average authorized ROE for the firms in the Gas Group is approximately 10.3%, with a midpoint of 10.6%. With respect to the group of combination utilities, as shown on page 2 of Exhibit No. 301, Schedule AMM-13, these firms are also presently authorized an average ROE of approximately 10.4%, with the midpoint also being 10.4%.[41]

[40] The midpoint values for the Gas and Electric Groups were 12.5% and 11.8%, respectively.
[41] As reflected on page 2 of Exhibit No. 301, Schedule AMM-13, solely for the purposes of comparing allowed ROEs, I excluded Avista Corp. from the Combination Group.

D. Low Risk Non-Utility DCF

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

A. Consistent with underlying economic and regulatory standards, I also applied the DCF model to a reference group of low-risk companies in the non-utility sectors of the economy. I refer to this group as the "Non-Utility 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. Indeed, modern portfolio theory is built on the assumption that rational investors will hold a diverse portfolio of stocks, not just companies in a single industry.

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

A. Yes. The cost of equity capital 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.[42]

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

Q. Does consideration of the results for the Non-Utility Group make the estimation of the cost of equity using the DCF model more reliable?

A. Yes. The estimates of growth from the DCF model depend on analysts' forecasts. It is possible for utility growth rates to be distorted by short-term trends in the industry, or by the industry falling into favor or disfavor by analysts. The result of such distortions would be to bias the DCF estimates for utilities. Because the Non-Utility Group includes low risk companies from many industries, it diversifies away any distortion that may be caused by the ebb and flow of enthusiasm for a particular sector.

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

A. My comparable risk proxy group was composed of those United States 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 0.70 or less; and
5) have investment grade credit ratings from S&P.

[42] *Federal Power Comm'n v. Hope Natural Gas Co.* 320 U.S. 391, (1944).

Q. How do the overall risks of this Non-Utility Group compare with the Gas and Combination Groups?

A. Table AMM-5 compares the Non-Utility Group with the Gas and Combination Groups across the four measures of investment risk discussed earlier:

TABLE AMM-5
COMPARISON OF RISK INDICATORS

	S&P	Value Line		
Proxy Group	**Credit Rating**	**Safety Rank**	**Financial Strength**	**Beta**
Non-Utility	A	1	A+	0.64
Gas Utility	A-	2	A	0.77
Combination Utility	BBB+	2	A	0.72
Avista	BBB	2	A	0.75

As shown above, the average credit rating, Safety Rank, Financial Strength Rating, and beta for the Non-Utility Group suggest less risk than for Avista and the proxy groups of utilities. These measures incorporate a broad spectrum of risks, including financial and business position, the impact of regulation, relative size, and exposure to company specific factors, and they apply equally to regulated and unregulated firms. Indeed, the core idea of modern portfolio theory is that investors will diversify their holdings across multiple firms and industry groups, so that the risk of a stock is directly proportional to its beta, not the extent of competition or the freedom to set prices.

The 16 companies that make up the Non-Utility Group are representative of the pinnacle of corporate America. These firms, which include household names such as Coca-Cola, Colgate-Palmolive, McDonalds, and Wal-Mart, have long corporate histories, well-established track records, and exceedingly conservative risk profiles. Many of these companies pay dividends on a par with utilities, with the average dividend yield for the group approaching 3%. Moreover, because of their significance and name recognition, these companies receive intense scrutiny by the investment community, which increases confidence that published growth estimates are representative of the consensus expectations reflected in common stock prices.

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

A. I applied the DCF model to the Non-Utility Group using the same analysts' EPS growth projections described earlier for the Gas and Combination Groups, The results of my DCF analysis for the Non-Utility Group are presented in Exhibit No. 301, Schedule AMM-14. As summarized in Table AMM-6, below, after eliminating illogical low- and high-end values, application of the constant growth DCF model resulted in the following cost of equity estimates:

TABLE AMM-6
DCF RESULTS – NON-UTILITY GROUP

	Cost of Equity	
Growth Rate	**Average**	**Midpoint**
Value Line	11.0%	12.0%
IBES	10.4%	10.8%
Zacks	10.7%	10.8%
Reuters	10.3%	10.4%

As discussed earlier, reference to the Non-Utility 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. How can you reconcile these DCF results for the Non-Utility Group against the significantly lower estimates produced for your groups of utilities?

A. First, it is important to be clear that the higher DCF results for the Non-Utility Group cannot be attributed to risk differences. As I documented earlier, the risks that investors associate with the group of non-utility firms - as measured by S&P's credit ratings and Value Line's Safety Rank, Financial Strength, beta – are lower than the risks investors associate with Avista and the Gas and Combination Groups. The objective evidence provided by these observable risk measures rules out a conclusion that the higher non-utility DCF estimates are associated with higher investment risk.

Rather, the divergence between the DCF results for these groups of utility and non-utility firms can be attributed to the fact that DCF estimates invariably depart from the returns that investors actually require because their expectations may not be captured by the inputs to the model, particularly the assumed growth rate. Because the actual cost of equity is unobservable, and DCF results inherently incorporate a degree of error, the cost of equity estimates for the Non-Utility Group provide an important benchmark in evaluating a fair ROE for Avista. There is no basis to conclude that DCF results for a group of utilities would be inherently more reliable than those for firms in the competitive sector, and the divergence between the DCF estimates for the groups of utilities and the Non-Utility Group suggests that both should be considered to ensure a balanced end-result. The results of the Non-Utility Group DCF suggests that the 9.9% requested ROE for Avista's gas operations is a conservative estimate of a fair return.

Q. Please summarize the results of your alternative ROE benchmarks.

A. The cost of common equity estimates produced by the various tests of reasonableness discussed above are shown on page 3 of Exhibit No. 301, Schedule AMM-1, and summarized in Table AMM-7, below:

TABLE AMM-7
SUMMARY OF ALTERNATIVE ROE BENCHMARKS

	Gas Group		Combination Group	
	Average	**Midpoint**	**Average**	**Midpoint**
CAPM - Historical Yield				
Unadjusted	10.3%	10.1%	10.3%	10.1%
Size Adjusted	11.8%	11.8%	11.8%	11.8%
CAPM - Projected Yield				
Unadjusted	10.6%	10.4%	10.6%	10.4%
Size Adjusted	12.1%	12.1%	12.1%	12.1%
Expected Earnings	11.4%	12.5%	10.9%	11.8%
Allowed ROE	10.3%	10.6%	10.4%	10.4%
Non-Utility DCF				
Value Line	11.0%	12.0%		
IBES	10.4%	10.8%		
Zacks	10.7%	10.8%		
Reuters	10.3%	10.4%		

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

A. Yes, it does.

RECOMMENDED ROE RANGE

	Range		
DCF	9.2%	--	10.2%
ECAPM	10.4%	--	11.6%
Utility Risk Premium	10.1%	--	11.0%
Recommended ROE Range	**9.9%**	--	**10.9%**
Flotation Cost Adjustment			
Dividend Yield	3.50%		3.50%
Flotation Cost Percentage	3.60%		3.60%
Adjustment	0.13%		0.13%
Adjusted Cost of Equity Range	**10.03%**	--	**11.03%**

PRIMARY METHODS

	Gas Group		Combination Group	
DCF	**Average**	**Midpoint**	**Average**	**Midpoint**
Value Line	10.4%	10.9%	9.6%	10.0%
IBES	9.9%	10.4%	9.0%	8.9%
Zacks	9.1%	9.5%	9.2%	10.0%
Reuters	9.6%	10.4%	9.0%	8.9%
br + sv	9.5%	10.2%	8.7%	9.4%
Empirical CAPM - Historical Yield				
Unadjusted	10.8%	10.6%	10.4%	10.5%
Size Adjusted	12.3%	12.3%	11.3%	11.2%
Empirical CAPM - Projected Yield				
Unadjusted	11.0%	10.9%	10.7%	10.7%
Size Adjusted	12.5%	12.4%	11.6%	11.5%
Utility Risk Premium				
Historical Bond Yields	10.1%		--	
Projected Bond Yields	11.0%		--	

CHECKS OF REASONABLENESS

	Gas Group		Combination Group	
	Average	Midpoint	Average	Midpoint
CAPM - Historical Yield				
Unadjusted	10.3%	10.1%	10.3%	10.1%
Size Adjusted	11.8%	11.8%	11.8%	11.8%
CAPM - Projected Yield				
Unadjusted	10.6%	10.4%	10.6%	10.4%
Size Adjusted	12.1%	12.1%	12.1%	12.1%
Expected Earnings	11.4%	12.5%	10.9%	11.8%
Allowed ROE	10.3%	10.6%	10.4%	10.4%
Non-Utility DCF				
Value Line	11.0%	12.0%		
IBES	10.4%	10.8%		
Zacks	10.7%	10.8%		
Reuters	10.3%	10.4%		

GAS GROUP

		At Fiscal Year-End 2013 (a)			Value Line Projected (b)		
	Company	Debt	Preferred	Common Equity	Debt	Other	Common Equity
1	AGL Resources	50.9%	0.0%	49.1%	50.5%	0.0%	49.5%
2	Atmos Energy Corp.	48.8%	0.0%	51.2%	45.0%	0.0%	55.0%
3	New Jersey Resources	39.6%	0.0%	60.4%	30.0%	0.0%	70.0%
4	NiSource, Inc.	58.0%	0.0%	42.0%	60.5%	0.0%	39.5%
5	Northwest Natural Gas	49.7%	0.0%	50.3%	45.5%	0.0%	54.5%
6	Piedmont Natural Gas	51.8%	0.0%	48.2%	46.0%	0.0%	54.0%
7	South Jersey Industries	45.9%	0.0%	54.1%	42.0%	0.0%	58.0%
8	Southwest Gas Corp.	49.6%	0.0%	50.4%	49.5%	0.0%	50.5%
9	WGL Holdings, Inc.	31.2%	1.5%	67.3%	27.5%	1.5%	71.0%
	Average	**47.3%**	**0.2%**	**52.6%**	**44.1%**	**0.2%**	**55.8%**

(a) Company Form 10-K and Annual Reports.
(b) The Value Line Investment Survey (Jun. 6, 2014).

COMBINATION GROUP

		At Fiscal Year-End 2013 (a)			Value Line Projected (b)		
	Company	**Debt**	**Preferred**	**Common Equity**	**Debt**	**Other**	**Common Equity**
1	Alliant Energy	48.9%	2.9%	48.1%	46.0%	2.5%	51.5%
2	Ameren Corp.	47.5%	0.0%	52.5%	45.5%	1.0%	53.5%
3	Avista Corp.	49.0%	0.0%	51.0%	53.5%	0.0%	46.5%
4	Black Hills Corp.	51.6%	0.0%	48.4%	53.5%	0.0%	46.5%
5	CenterPoint Energy	52.4%	0.0%	47.6%	59.5%	0.0%	40.5%
6	CMS Energy Corp.	68.7%	0.0%	31.3%	63.0%	0.0%	37.0%
7	Consolidated Edison	47.3%	0.0%	52.7%	49.0%	0.0%	51.0%
8	Dominion Resources	63.7%	0.8%	35.6%	58.0%	0.5%	41.5%
9	DTE Energy Co.	50.2%	0.0%	49.8%	49.5%	0.0%	50.5%
10	Duke Energy Corp.	49.3%	0.0%	50.7%	52.5%	0.0%	47.5%
11	Empire District Elec	49.8%	0.0%	50.2%	50.0%	0.0%	50.0%
12	Entergy Corp.	54.1%	1.4%	44.5%	54.5%	1.0%	44.5%
13	Integrys Energy Group	48.0%	0.8%	51.2%	46.5%	0.5%	53.0%
14	Northeast Utilities	46.4%	0.0%	53.6%	45.5%	1.0%	53.5%
15	PG&E Corp.	48.2%	0.9%	50.9%	48.5%	0.5%	51.0%
16	Pub Sv Enterprise Grp	42.0%	0.0%	58.0%	44.5%	0.0%	55.5%
17	SCANA Corp.	53.9%	0.0%	46.1%	52.5%	0.0%	47.5%
18	Sempra Energy	51.1%	0.1%	48.8%	52.0%	0.0%	48.0%
19	Vectren Corp.	53.8%	0.0%	46.2%	53.0%	0.0%	47.0%
20	Wisconsin Energy	52.5%	0.3%	47.2%	50.5%	0.5%	49.0%
21	Xcel Energy, Inc.	53.9%	0.0%	46.1%	50.5%	0.0%	49.5%
	Average	**51.5%**	**0.3%**	**48.1%**	**51.3%**	**0.4%**	**48.3%**

(a) Company Form 10-K and Annual Reports.
(b) The Value Line Investment Survey (May 23, Jun. 20, & Aug. 1, 2014).

DIVIDEND YIELD

		(a)	(b)	
	Company	**Price**	**Dividends**	**Yield**
1	AGL Resources	$ 53.02	$ 1.96	3.7%
2	Atmos Energy Corp.	$ 50.67	$ 1.51	3.0%
3	New Jersey Resources	$ 51.70	$ 1.68	3.2%
4	NiSource, Inc.	$ 36.81	$ 1.04	2.8%
5	Northwest Natural Gas	$ 44.46	$ 1.84	4.1%
6	Piedmont Natural Gas	$ 35.29	$ 1.28	3.6%
7	South Jersey Industries	$ 56.81	$ 2.00	3.5%
8	Southwest Gas Corp.	$ 53.13	$ 1.48	2.8%
9	WGL Holdings, Inc.	$ 39.74	$ 1.76	4.4%
	Average			**3.5%**

(a) Average of closing prices for 30 trading days ended Jun. 6, 2014.
(b) The Value Line Investment Survey, *Summary & Index* (Jun. 6, 2014).

GROWTH RATES

		(a)	(b)	(c)	(d)	(e)
		Earnings Growth				**br+sv**
	Company	**V Line**	**IBES**	**Zacks**	**Reuters**	**Growth**
1	AGL Resources	10.5%	NA	2.0%	4.0%	6.2%
2	Atmos Energy Corp.	7.5%	7.1%	6.7%	7.1%	6.4%
3	New Jersey Resources	5.5%	3.6%	4.0%	3.6%	6.2%
4	NiSource, Inc.	10.5%	10.4%	8.7%	10.4%	6.9%
5	Northwest Natural Gas	6.5%	3.5%	3.7%	3.5%	4.0%
6	Piedmont Natural Gas	4.0%	3.7%	4.0%	3.7%	3.8%
7	South Jersey Industries	8.0%	6.0%	6.0%	NA	9.5%
8	Southwest Gas Corp.	6.0%	2.4%	4.7%	2.4%	7.1%
9	WGL Holdings, Inc.	4.0%	4.9%	5.4%	4.9%	4.3%

(a) The Value Line Investment Survey (Jun. 6, 2014).
(b) www.finance.yahoo.com (retrieved Jun. 16, 2014).
(c) www.zacks.com (retrieved Jun. 16, 2014).
(d) www.reuters.com (retrieved June. 16, 2014).
(e) See Avista/301, Schedule AMM-4.

DCF COST OF EQUITY ESTIMATES

		(a)	(a)	(a)	(a)	(a)
		Earnings Growth				br+sv
	Company	**V Line**	**IBES**	**Zacks**	**Reuters**	**Growth**
1	AGL Resources	14.2%	NA	5.7%	7.7%	9.9%
2	Atmos Energy Corp.	10.5%	10.0%	9.7%	10.0%	9.3%
3	New Jersey Resources	8.7%	6.8%	7.2%	6.8%	9.4%
4	NiSource, Inc.	13.3%	13.2%	11.5%	13.2%	9.8%
5	Northwest Natural Gas	10.6%	7.6%	7.8%	7.6%	8.1%
6	Piedmont Natural Gas	7.6%	7.3%	7.6%	7.3%	7.4%
7	South Jersey Industries	11.5%	9.5%	9.5%	NA	13.0%
8	Southwest Gas Corp.	8.8%	5.1%	7.5%	5.1%	9.8%
9	WGL Holdings, Inc.	8.4%	9.3%	9.8%	9.3%	8.7%
	Average (b)	**10.4%**	**9.9%**	**9.1%**	**9.6%**	**9.5%**
	Midpoint (c)	**10.9%**	**10.4%**	**9.5%**	**10.4%**	**10.2%**

(a) Sum of dividend yield (Avista/301, Schedule AMM-3, p. 1) and respective growth rate
(b) Excludes highlighted figures.
(c) Average of low and high values.

SUSTAINABLE GROWTH RATE

		(a)	(a)	(a)			(b)	(c)		(d)	(e)		
		2018					Adjustment			"sv" Factor			
	Company	**EPS**	**DPS**	**BVPS**	**b**	**r**	**Factor**	**Adjusted r**	**br**	**s**	**v**	**sv**	**br + sv**
1	AGL Resources	$4.30	$2.40	$36.25	44.2%	11.9%	1.0225	12.1%	5.4%	0.0181	0.4423	0.80%	**6.2%**
2	Atmos Energy Corp.	$3.50	$1.70	$38.90	51.4%	9.0%	1.0470	9.4%	4.8%	0.0470	0.3235	1.52%	**6.4%**
3	New Jersey Resources	$3.75	$1.76	$30.10	53.1%	12.5%	1.0266	12.8%	6.8%	(0.0141)	0.4267	-0.60%	**6.2%**
4	NiSource, Inc.	$2.40	$1.20	$19.30	50.0%	12.4%	1.0068	12.5%	6.3%	0.0138	0.4853	0.67%	**6.9%**
5	Northwest Natural Gas	$3.30	$2.10	$34.20	36.4%	9.6%	1.0250	9.9%	3.6%	0.0108	0.3782	0.41%	**4.0%**
6	Piedmont Natural Gas	$2.10	$1.43	$19.45	31.9%	10.8%	1.0217	11.0%	3.5%	0.0057	0.4813	0.28%	**3.8%**
7	South Jersey Industries	$4.80	$2.60	$33.35	45.8%	14.4%	1.0410	15.0%	6.9%	0.0539	0.4869	2.62%	**9.5%**
8	Southwest Gas Corp.	$4.00	$1.80	$37.00	55.0%	10.8%	1.0265	11.1%	6.1%	0.0247	0.3833	0.95%	**7.1%**
9	WGL Holdings, Inc.	$3.10	$1.87	$29.90	39.7%	10.4%	1.0194	10.6%	4.2%	0.0017	0.3356	0.06%	**4.3%**

SUSTAINABLE GROWTH RATE

		(a)	(a)	(f)	(a)	(a)	(f)	(g)	(a)	(a)		(h)	(a)	(a)	(g)
		2013			2018			Chg	2018 Price				Common Shares		
	Company	Eq Ratio	Tot Cap	Com Eq	Eq Ratio	Tot Cap	Com Eq	Equity	High	Low	Avg.	M/B	2013	2018	Growth
1	AGL Resources	48.8%	$7,444	$3,633	49.5%	$9,195	$4,552	4.6%	$70.00	$60.00	$65.00	1.793	118.89	125.00	1.01%
2	Atmos Energy Corp.	51.2%	$5,036	$2,578	55.0%	$7,500	$4,125	9.9%	$65.00	$50.00	$57.50	1.478	90.64	106.00	3.18%
3	New Jersey Resources	63.4%	$1,400	$888	70.0%	$1,655	$1,159	5.5%	$60.00	$45.00	$52.50	1.744	41.66	40.00	-0.81%
4	NiSource, Inc.	43.7%	$13,480	$5,891	39.5%	$15,965	$6,306	1.4%	$45.00	$30.00	$37.50	1.943	313.68	325.00	0.71%
5	Northwest Natural Gas	52.4%	$1,434	$751	54.5%	$1,770	$965	5.1%	$60.00	$50.00	$55.00	1.608	27.08	28.00	0.67%
6	Piedmont Natural Gas	50.3%	$2,364	$1,189	54.0%	$2,735	$1,477	4.4%	$45.00	$30.00	$37.50	1.928	74.88	76.00	0.30%
7	South Jersey Industries	54.9%	$1,507	$828	58.0%	$2,150	$1,247	8.5%	$75.00	$55.00	$65.00	1.949	32.72	37.50	2.76%
8	Southwest Gas Corp.	50.6%	$2,794	$1,414	50.5%	$3,650	$1,843	5.5%	$70.00	$50.00	$60.00	1.622	46.36	50.00	1.52%
9	WGL Holdings, Inc.	69.8%	$1,827	$1,275	71.0%	$2,180	$1,548	4.0%	$50.00	$40.00	$45.00	1.505	51.70	52.00	0.12%

(a) The Value Line Investment Survey (Jun. 6, 2014).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) Product of average year-end "r" for 2018 and Adjustment Factor.
(d) Product of change in common shares outstanding and M/B Ratio.
(e) Computed as 1 - B/M Ratio.
(f) Product of total capital and equity ratio.
(g) Five-year rate of change.
(h) Average of High and Low expected market prices divided by 2018 BVPS.

DIVIDEND YIELD

	Company	(a) Price	(b) Dividends	Yield
1	Alliant Energy	$ 59.01	$ 2.04	3.5%
2	Ameren Corp.	$ 39.85	$ 1.62	4.1%
3	Avista Corp.	$ 32.43	$ 1.30	4.0%
4	Black Hills Corp.	$ 57.76	$ 1.60	2.8%
5	CenterPoint Energy	$ 24.93	$ 0.98	3.9%
6	CMS Energy Corp.	$ 30.27	$ 1.11	3.7%
7	Consolidated Edison	$ 56.79	$ 2.55	4.5%
8	Dominion Resources	$ 69.77	$ 2.45	3.5%
9	DTE Energy Co.	$ 76.34	$ 2.76	3.6%
10	Duke Energy Corp.	$ 72.81	$ 3.18	4.4%
11	Empire District Elec	$ 25.17	$ 1.04	4.1%
12	Entergy Corp.	$ 77.80	$ 3.32	4.3%
13	Integrys Energy Group	$ 68.77	$ 2.72	4.0%
14	Northeast Utilities	$ 45.76	$ 1.63	3.6%
15	PG&E Corp.	$ 46.97	$ 1.82	3.9%
16	Pub Sv Enterprise Grp	$ 38.12	$ 1.49	3.9%
17	SCANA Corp.	$ 52.84	$ 2.12	4.0%
18	Sempra Energy	$102.43	$ 2.72	2.7%
19	Vectren Corp.	$ 40.46	$ 1.46	3.6%
20	Wisconsin Energy	$ 45.45	$ 1.62	3.6%
21	Xcel Energy, Inc.	$ 31.60	$ 1.23	3.9%
	Average			**3.8%**

(a) Average of closing prices for 30 trading days ended Aug. 1, 2014.
(b) The Value Line Investment Survey, Summary & Index (Aug. 1, 2014).

GROWTH RATES

		(a)	(b)	(c)	(d)	(e)
		Earnings Growth				br+sv
	Company	V Line	IBES	Zacks	Reuters	Growth
1	Alliant Energy	6.0%	5.0%	5.5%	5.5%	5.3%
2	Ameren Corp.	4.5%	2.0%	7.8%	NA	4.0%
3	Avista Corp.	5.5%	5.0%	NA	NA	3.1%
4	Black Hills Corp.	9.5%	7.0%	NA	NA	4.1%
5	CenterPoint Energy	2.0%	3.5%	4.2%	3.5%	3.0%
6	CMS Energy Corp.	6.5%	6.8%	6.1%	6.8%	6.0%
7	Consolidated Edison	1.0%	2.5%	2.8%	2.5%	2.6%
8	Dominion Resources	5.5%	6.0%	5.6%	6.0%	6.7%
9	DTE Energy Co.	6.5%	5.9%	6.2%	5.9%	4.3%
10	Duke Energy Corp.	5.0%	4.2%	4.2%	4.4%	2.9%
11	Empire District Elec	4.0%	3.0%	3.0%	3.0%	3.3%
12	Entergy Corp.	1.0%	1.3%	-5.1%	2.7%	4.2%
13	Integrys Energy Group	3.5%	3.5%	5.0%	3.5%	3.4%
14	Northeast Utilities	8.0%	6.3%	6.9%	6.1%	4.3%
15	PG&E Corp.	5.0%	6.4%	5.2%	6.4%	3.0%
16	Pub Sv Enterprise Grp	2.0%	2.0%	2.1%	5.5%	4.8%
17	SCANA Corp.	5.0%	4.6%	4.4%	4.6%	5.0%
18	Sempra Energy	6.0%	7.0%	6.9%	7.0%	5.7%
19	Vectren Corp.	9.0%	4.0%	4.7%	4.0%	7.8%
20	Wisconsin Energy	5.5%	5.2%	5.5%	5.2%	4.6%
21	Xcel Energy, Inc.	5.5%	4.5%	4.2%	5.1%	4.8%

(a) The Value Line Investment Survey (May 23, Jun. 20, & Aug. 1, 2014).
(b) www.finance.yahoo.com (retrieved Aug. 5, 2014).
(c) www.zacks.com (retrieved Aug. 5, 2014).
(d) www.reuters.com/finance/stocks (retrieved Aug 5, 2014).
(e) See Avista/301, Schedule AMM-6.

DCF COST OF EQUITY ESTIMATES

		(a)	(a)	(a)	(a)	(a)
		Earnings Growth				br+sv
	Company	V Line	IBES	Zacks	Reuters	Growth
1	Alliant Energy	9.5%	8.5%	9.0%	9.0%	8.7%
2	Ameren Corp.	8.6%	6.1%	11.9%	NA	8.1%
3	Avista Corp.	9.5%	9.0%	NA	NA	7.1%
4	Black Hills Corp.	12.3%	9.8%	NA	NA	6.9%
5	CenterPoint Energy	5.9%	7.4%	8.1%	7.4%	7.0%
6	CMS Energy Corp.	10.2%	10.5%	9.8%	10.5%	9.7%
7	Consolidated Edison	5.5%	7.0%	7.2%	7.0%	7.1%
8	Dominion Resources	9.0%	9.5%	9.1%	9.5%	10.2%
9	DTE Energy Co.	10.1%	9.5%	9.8%	9.5%	7.9%
10	Duke Energy Corp.	9.4%	8.6%	8.6%	8.8%	7.2%
11	Empire District Elec	8.1%	7.1%	7.1%	7.1%	7.4%
12	Entergy Corp.	5.3%	5.6%	-0.8%	7.0%	8.4%
13	Integrys Energy Group	7.5%	7.5%	9.0%	7.5%	7.4%
14	Northeast Utilities	11.6%	9.9%	10.4%	9.6%	7.9%
15	PG&E Corp.	8.9%	10.3%	9.1%	10.3%	6.8%
16	Pub Sv Enterprise Grp	5.9%	5.9%	6.0%	9.4%	8.7%
17	SCANA Corp.	9.0%	8.6%	8.4%	8.6%	9.0%
18	Sempra Energy	8.7%	9.6%	9.6%	9.6%	8.4%
19	Vectren Corp.	12.6%	7.6%	8.3%	7.6%	11.4%
20	Wisconsin Energy	9.1%	8.8%	9.1%	8.8%	8.2%
21	Xcel Energy, Inc.	9.4%	8.4%	8.1%	9.0%	8.7%
	Average (b)	**9.6%**	**9.0%**	**9.2%**	**9.0%**	**8.7%**
	Midpoint (c)	**10.0%**	**8.9%**	**10.0%**	**8.9%**	**9.4%**

(a) Sum of dividend yield (Avista/301, Schedule AMM-5, p. 1) and respective growth rate
(b) Excludes highlighted figures.
(c) Average of low and high values.

DCF MODEL - COMBINATON GROUP

BR+SV GROWTH RATE

		(a)	(a)	(a)			(b)	(c)		(d)	(e)		
		2018					Adjustment			"sv" Factor			
	Company	EPS	DPS	BVPS	b	r	Factor	Adjusted r	br	s	v	sv	br + sv
1	Alliant Energy	$4.05	$2.40	$34.80	40.7%	11.6%	1.0269	12.0%	4.9%	0.0113	0.3673	0.41%	**5.3%**
2	Ameren Corp.	$3.00	$1.80	$32.25	40.0%	9.3%	1.0217	9.5%	3.8%	0.0094	0.1938	0.18%	**4.0%**
3	Avista Corp.	$2.25	$1.50	$25.75	33.3%	8.7%	1.0219	8.9%	3.0%	0.0111	0.1417	0.16%	**3.1%**
4	Black Hills Corp.	$3.25	$1.90	$35.50	41.5%	9.2%	1.0218	9.4%	3.9%	0.0078	0.2900	0.23%	**4.1%**
5	CenterPoint Energy	$1.45	$1.15	$11.25	20.7%	12.9%	1.0117	13.0%	2.7%	0.0057	0.5909	0.34%	**3.0%**
6	CMS Energy Corp.	$2.25	$1.35	$17.00	40.0%	13.2%	1.0331	13.7%	5.5%	0.0129	0.4333	0.56%	**6.0%**
7	Consolidated Edison	$4.00	$2.75	$48.50	31.3%	8.2%	1.0142	8.4%	2.6%	0.0001	0.1917	0.00%	**2.6%**
8	Dominion Resources	$4.00	$2.80	$27.00	30.0%	14.8%	1.0366	15.4%	4.6%	0.0350	0.5846	2.05%	**6.7%**
9	DTE Energy Co.	$5.50	$3.30	$56.25	40.0%	9.8%	1.0278	10.0%	4.0%	0.0127	0.2241	0.29%	**4.3%**
10	Duke Energy Corp.	$5.25	$3.40	$65.00	35.2%	8.1%	1.0108	8.2%	2.9%	0.0014	-	0.00%	**2.9%**
11	Empire District Elec	$1.75	$1.15	$20.00	34.3%	8.8%	1.0237	9.0%	3.1%	0.0200	0.1111	0.22%	**3.3%**
12	Entergy Corp.	$6.50	$3.80	$66.75	41.5%	9.7%	1.0220	10.0%	4.1%	0.0016	0.2147	0.03%	**4.2%**
13	Integrys Energy Group	$4.50	$3.00	$47.50	33.3%	9.5%	1.0198	9.7%	3.2%	0.0128	0.1739	0.22%	**3.4%**
14	Northeast Utilities	$3.50	$2.00	$36.50	42.9%	9.6%	1.0193	9.8%	4.2%	0.0043	0.3048	0.13%	**4.3%**
15	PG&E Corp.	$3.00	$2.10	$36.50	30.0%	8.2%	1.0242	8.4%	2.5%	0.0226	0.1889	0.43%	**3.0%**
16	Pub Sv Enterprise Grp	$3.00	$1.65	$29.00	45.0%	10.3%	1.0241	10.6%	4.8%	0.0001	0.2267	0.00%	**4.8%**
17	SCANA Corp.	$4.25	$2.35	$43.30	44.7%	9.8%	1.0377	10.2%	4.6%	0.0271	0.1752	0.48%	**5.0%**
18	Sempra Energy	$6.25	$3.40	$55.50	45.6%	11.3%	1.0242	11.5%	5.3%	0.0107	0.4308	0.46%	**5.7%**
19	Vectren Corp.	$3.00	$1.55	$21.50	48.3%	14.0%	1.0177	14.2%	6.9%	0.0180	0.5222	0.94%	**7.8%**
20	Wisconsin Energy	$3.25	$2.10	$20.75	35.4%	15.7%	1.0057	15.8%	5.6%	(0.0175)	0.5389	-0.94%	**4.6%**
21	Xcel Energy, Inc.	$2.50	$1.45	$24.25	42.0%	10.3%	1.0305	10.6%	4.5%	0.0169	0.1917	0.32%	**4.8%**

DCF MODEL - COMBINATON GROUP

BR+SV GROWTH RATE

		(a)	(a)	(f)	(a)	(a)	(f)	(g)	(a)	(a)		(h)	(a)	(a)	(g)
		2013			2018			Chg	2018 Price				Common Shares		
	Company	**Eq Ratio**	**Tot Cap**	**Com Eq**	**Eq Ratio**	**Tot Cap**	**Com Eq**	**Equity**	**High**	**Low**	**Avg.**	**M/B**	**2013**	**2018**	**Growth**
1	Alliant Energy	47.0%	$6,530	$3,069	51.5%	$7,800	$4,017	5.5%	$65.00	$45.00	$55.00	1.580	110.98	115.00	0.71%
2	Ameren Corp.	53.7%	$12,190	$6,546	53.5%	$15,200	$8,132	4.4%	$45.00	$35.00	$40.00	1.240	242.63	252.00	0.76%
3	Avista Corp.	48.6%	$2,670	$1,297	46.5%	$3,475	$1,616	4.5%	$35.00	$25.00	$30.00	1.165	60.08	63.00	0.95%
4	Black Hills Corp.	48.4%	$2,705	$1,309	46.5%	$3,500	$1,628	4.5%	$60.00	$40.00	$50.00	1.408	44.50	45.75	0.56%
5	CenterPoint Energy	35.6%	$12,146	$4,324	40.5%	$12,000	$4,860	2.4%	$30.00	$25.00	$27.50	2.444	429.00	434.00	0.23%
6	CMS Energy Corp.	32.2%	$10,730	$3,455	37.0%	$13,000	$4,810	6.8%	$35.00	$25.00	$30.00	1.765	266.10	276.00	0.73%
7	Consolidated Edison	53.9%	$22,735	$12,254	51.0%	$27,700	$14,127	2.9%	$65.00	$55.00	$60.00	1.237	292.87	293.00	0.01%
8	Dominion Resources	37.3%	$31,229	$11,648	41.5%	$40,500	$16,808	7.6%	$75.00	$55.00	$65.00	2.407	581.50	625.00	1.45%
9	DTE Energy Co.	52.3%	$15,135	$7,916	50.5%	$20,700	$10,454	5.7%	$85.00	$60.00	$72.50	1.289	177.09	186.00	0.99%
10	Duke Energy Corp.	52.0%	$79,482	$41,331	47.5%	$96,900	$46,028	2.2%	$75.00	$55.00	$65.00	1.000	706.00	711.00	0.14%
11	Empire District Elec	50.2%	$1,494	$750	50.0%	$1,900	$950	4.8%	$25.00	$20.00	$22.50	1.125	43.04	47.00	1.78%
12	Entergy Corp.	43.6%	$22,109	$9,640	44.5%	$27,000	$12,015	4.5%	$100.00	$70.00	$85.00	1.273	178.37	179.50	0.13%
13	Integrys Energy Group	52.0%	$6,269	$3,260	53.0%	$7,500	$3,975	4.0%	$65.00	$50.00	$57.50	1.211	79.45	83.75	1.06%
14	Northeast Utilities	54.8%	$17,544	$9,614	53.5%	$21,800	$11,663	3.9%	$60.00	$45.00	$52.50	1.438	315.27	320.00	0.30%
15	PG&E Corp.	52.5%	$27,311	$14,338	51.0%	$35,800	$18,258	5.0%	$55.00	$35.00	$45.00	1.233	456.67	500.00	1.83%
16	Pub Sv Enterprise Grp	59.6%	$19,470	$11,604	55.5%	$26,600	$14,763	4.9%	$40.00	$35.00	$37.50	1.293	505.86	506.00	0.01%
17	SCANA Corp.	46.4%	$10,059	$4,667	47.5%	$14,325	$6,804	7.8%	$60.00	$45.00	$52.50	1.212	141.00	157.50	2.24%
18	Sempra Energy	49.4%	$22,281	$11,007	48.0%	$29,200	$14,016	5.0%	$110.00	$85.00	$97.50	1.757	244.46	252.00	0.61%
19	Vectren Corp.	46.7%	$3,331	$1,556	47.0%	$3,950	$1,857	3.6%	$50.00	$40.00	$45.00	2.093	82.40	86.00	0.86%
20	Wisconsin Energy	49.1%	$8,627	$4,236	49.0%	$9,150	$4,484	1.1%	$50.00	$40.00	$45.00	2.169	225.96	217.00	-0.81%
21	Xcel Energy, Inc.	46.7%	$20,477	$9,563	49.5%	$26,200	$12,969	6.3%	$35.00	$25.00	$30.00	1.237	497.97	533.00	1.37%

(a) The Value Line Investment Survey (May 23, Jun. 20, & Aug. 1, 2014).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) Product of average year-end "r" for 2018 and Adjustment Factor.
(d) Product of change in common shares outstanding and M/B Ratio.
(e) Computed as 1 - B/M Ratio.
(f) Product of total capital and equity ratio.
(g) Five-year rate of change.
(h) Average of High and Low expected market prices divided by 2018 BVPS.

HISTORICAL BOND YIELD

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(f)	(i)		(j)	(k)	(l)	(m)
		Market Return (R_m)				Market										Size
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP				Unadjusted	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Weight	*RP*[1]	Beta	Weight	*RP*[2]	Total RP	K_e	Cap	Adjustment	K_e
1	AGL Resources	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.80	75%	5.3%	7.5%	11.0%	$6,282	0.93%	11.9%
2	Atmos Energy Corp.	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.80	75%	5.3%	7.5%	11.0%	$5,069	1.19%	12.2%
3	New Jersey Resources	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.75	75%	5.0%	7.2%	10.6%	$2,301	1.75%	12.4%
4	NiSource, Inc.	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.80	75%	5.3%	7.5%	11.0%	$11,644	0.80%	11.8%
5	Northwest Natural Gas	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.70	75%	4.6%	6.8%	10.3%	$1,219	1.75%	12.1%
6	Piedmont Natural Gas	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.75	75%	5.0%	7.2%	10.6%	$2,829	1.72%	12.4%
7	South Jersey Industries	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.80	75%	5.3%	7.5%	11.0%	$1,858	1.75%	12.7%
8	Southwest Gas Corp.	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.80	75%	5.3%	7.5%	11.0%	$2,405	1.75%	12.7%
9	WGL Holdings, Inc.	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.75	75%	5.0%	7.2%	10.6%	$2,129	1.75%	12.4%
	Average												**10.8%**			**12.3%**
	Midpoint (n)												**10.6%**			**12.3%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Jul. 8, 2014).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Jul. 10, 2014).
(c) (a) + (b).
(d) Average yield on 30-year Treasury bonds for the six-months ending Jul. 2014 based on data from the Federal Reserve at http://www.federalreserve.gov/releases/h15/data.ht
(e) (c) - (d).
(f) Morin, Roger A., "New Regulatory Finance,"*Public Utilities Reports, Inc.* at 190 (2006).
(g) (e) x weighting factor.
(h) The Value Line Investment Survey (Jun. 6, 2014)
(i) (e) x (h) x weighting factor.
(j) (d) + (g) + (i).
(k) www.valueline.com (retrieved Jun. 16, 2014)
(l) *Morningstar* , "2014 Ibbotson SBBI Market Report," at Table 10 (2014).
(m) (g) + (h).
(n) Average of low and high values.

PROJECTED BOND YIELD

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(f)	(i)		(j)	(k)	(l)	(m)
		Market Return (R_m)				Market										Size
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP				Unadjusted	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Weight	RP[1]	Beta	Weight	RP[2]	Total RP	K_e	Cap	Adjustment	K_e
1	AGL Resources	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.80	75%	4.5%	6.4%	11.2%	$6,282	0.93%	12.1%
2	Atmos Energy Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.80	75%	4.5%	6.4%	11.2%	$5,069	1.19%	12.4%
3	New Jersey Resources	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.75	75%	4.3%	6.2%	10.9%	$2,301	1.75%	12.6%
4	NiSource, Inc.	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.80	75%	4.5%	6.4%	11.2%	$11,644	0.80%	12.0%
5	Northwest Natural Gas	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.70	75%	4.0%	5.9%	10.6%	$1,219	1.75%	12.3%
6	Piedmont Natural Gas	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.75	75%	4.3%	6.2%	10.9%	$2,829	1.72%	12.6%
7	South Jersey Industries	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.80	75%	4.5%	6.4%	11.2%	$1,858	1.75%	12.9%
8	Southwest Gas Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.80	75%	4.5%	6.4%	11.2%	$2,405	1.75%	12.9%
9	WGL Holdings, Inc.	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.75	75%	4.3%	6.2%	10.9%	$2,129	1.75%	12.6%
	Average												**11.0%**			**12.5%**
	Midpoint (n)												**10.9%**			**12.4%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Jul. 8, 201

(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Jul. 10, 201

(c) (a) + (b).

(d) Average projected 30-year Treasury bond yield for 2015-2018 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (May 23, 2014); IHS Global Insight, U.S. Economic Outlook at 79 (May 2014); & Blue Chip Financial Forecasts, Vol. 32, No. 12 (Dec. 1, 2013).

(e) (c) - (d).

(f) Morin, Roger A., "New Regulatory Finance,"*Public Utilities Reports, Inc.* at 190 (2006).

(g) (e) x weighting factor.

(h) The Value Line Investment Survey (Jun. 6, 2014)

(i) (e) x (h) x weighting factor.

(j) (d) + (g) + (i).

(k) www.valueline.com (retrieved Jun. 16, 2014)

(l) *Morningstar* , "2014 Ibbotson SBBI Market Report," at Table 10 (2014).

(m) (g) + (h).

(n) Average of low and high values

COMBINATION GROUP

		(a)	(b)		(c)		(d)		(e)	(d)				(f)	(g)	
		Market Return (R_m)				Market										Size
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP			Total	Unadjusted	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Weight	RP^1	Beta	Weight	RP^2	RP	K_e	Cap	Adjustment	K_e
1	Alliant Energy	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.75	75%	5.0%	7.2%	10.7%	$ 6,406.6	0.93%	11.6%
2	Ameren Corp.	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.75	75%	5.0%	7.2%	10.7%	$ 9,439.6	0.80%	11.5%
3	Avista Corp.	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.75	75%	5.0%	7.2%	10.7%	$ 1,934.2	1.75%	12.4%
4	Black Hills Corp.	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.85	75%	5.6%	7.8%	11.3%	$ 2,552.8	1.72%	13.0%
5	CenterPoint Energy	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.75	75%	5.0%	7.2%	10.7%	$10,316.9	0.80%	11.5%
6	CMS Energy Corp.	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.75	75%	5.0%	7.2%	10.7%	$ 7,907.1	0.93%	11.6%
7	Consolidated Edison	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.60	75%	4.0%	6.2%	9.7%	$16,006.7	0.80%	10.5%
8	Dominion Resources	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.70	75%	4.6%	6.8%	10.3%	$39,851.8	-0.33%	10.0%
9	DTE Energy Co.	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.75	75%	5.0%	7.2%	10.7%	$13,341.7	0.80%	11.5%
10	Duke Energy Corp.	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.60	75%	4.0%	6.2%	9.7%	$50,147.5	-0.33%	9.3%
11	Empire District Elec	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.65	75%	4.3%	6.5%	10.0%	$ 1,032.0	2.48%	12.5%
12	Entergy Corp.	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.70	75%	4.6%	6.8%	10.3%	$13,530.8	0.80%	11.1%
13	Integrys Energy Group	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.80	75%	5.3%	7.5%	11.0%	$ 4,555.4	1.19%	12.2%
14	Northeast Utilities	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.75	75%	5.0%	7.2%	10.7%	$14,221.2	0.80%	11.5%
15	PG&E Corp.	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.65	75%	4.3%	6.5%	10.0%	$21,207.5	0.80%	10.8%
16	Pub Sv Enterprise Grp	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.75	75%	5.0%	7.2%	10.7%	$19,476.2	0.80%	11.5%
17	SCANA Corp.	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.70	75%	4.6%	6.8%	10.3%	$ 7,264.3	0.93%	11.3%
18	Sempra Energy	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.75	75%	5.0%	7.2%	10.7%	$24,540.0	-0.33%	10.3%
19	Vectren Corp.	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.75	75%	5.0%	7.2%	10.7%	$ 3,261.2	1.72%	12.4%
20	Wisconsin Energy	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.65	75%	4.3%	6.5%	10.0%	$10,170.9	0.80%	10.8%
21	Xcel Energy, Inc.	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.65	75%	4.3%	6.5%	10.0%	$15,320.2	0.80%	10.8%
	Average												**10.4%**			**11.3%**
	Midpoint (h)												**10.5%**			**11.2%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Jul. 8, 201
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Jul. 10, 2014).
(c) Average yield on 30-year Treasury bonds for the six-months ending Jul. 2014 based on data from the http://www.federalreserve.gov/releases/h15/data.ht
(d) Morin, Roger A., "New Regulatory Finance,"*Public Utilities Reports, Inc.* at 190 (2006).
(e) The Value Line Investment Survey (May 23, Jun. 20, & Aug. 1, 2014)
(f) www.valueline.com (retrieved Jun. 8, 2014)
(g) Morningstar, "2014 Ibbotson SBBI Market Report," at Table 10 (2014).
(h) Average of low and high values

COMBINATION GROUP

		(a)	(b)		(c)		(d)		(e)	(d)				(f)	(g)	
		Market Return (R_m)				Market										Size
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP			Total	Unadjusted	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Weight	RP[1]	Beta	Weight	RP[2]	RP	K_e	Cap	Adjustment	K_e
1	Alliant Energy	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.75	75%	4.3%	6.2%	10.9%	$ 6,406.6	0.93%	11.8%
2	Ameren Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.75	75%	4.3%	6.2%	10.9%	$ 9,439.6	0.80%	11.7%
3	Avista Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.75	75%	4.3%	6.2%	10.9%	$ 1,934.2	1.75%	12.6%
4	Black Hills Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.85	75%	4.8%	6.7%	11.4%	$ 2,552.8	1.72%	13.2%
5	CenterPoint Energy	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.75	75%	4.3%	6.2%	10.9%	$10,316.9	0.80%	11.7%
6	CMS Energy Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.75	75%	4.3%	6.2%	10.9%	$ 7,907.1	0.93%	11.8%
7	Consolidated Edison	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.60	75%	3.4%	5.3%	10.0%	$16,006.7	0.80%	10.8%
8	Dominion Resources	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.70	75%	4.0%	5.9%	10.6%	$39,851.8	-0.33%	10.3%
9	DTE Energy Co.	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.75	75%	4.3%	6.2%	10.9%	$13,341.7	0.80%	11.7%
10	Duke Energy Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.60	75%	3.4%	5.3%	10.0%	$50,147.5	-0.33%	9.7%
11	Empire District Elec	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.65	75%	3.7%	5.6%	10.3%	$ 1,032.0	2.48%	12.8%
12	Entergy Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.70	75%	4.0%	5.9%	10.6%	$13,530.8	0.80%	11.4%
13	Integrys Energy Group	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.80	75%	4.6%	6.5%	11.2%	$ 4,555.4	1.19%	12.4%
14	Northeast Utilities	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.75	75%	4.3%	6.2%	10.9%	$14,221.2	0.80%	11.7%
15	PG&E Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.65	75%	3.7%	5.6%	10.3%	$21,207.5	0.80%	11.1%
16	Pub Sv Enterprise Grp	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.75	75%	4.3%	6.2%	10.9%	$19,476.2	0.80%	11.7%
17	SCANA Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.70	75%	4.0%	5.9%	10.6%	$ 7,264.3	0.93%	11.5%
18	Sempra Energy	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.75	75%	4.3%	6.2%	10.9%	$24,540.0	-0.33%	10.5%
19	Vectren Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.75	75%	4.3%	6.2%	10.9%	$ 3,261.2	1.72%	12.6%
20	Wisconsin Energy	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.65	75%	3.7%	5.6%	10.3%	$10,170.9	0.80%	11.1%
21	Xcel Energy, Inc.	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.65	75%	3.7%	5.6%	10.3%	$15,320.2	0.80%	11.1%
	Average												**10.7%**			**11.6%**
	Midpoint (h)												**10.7%**			**11.5%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Jul. 8, 201

(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Jul. 10, 2014).

(c) Average yield on 30-year Treasury bonds for 2015-2018 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (May 23, 2014); IHS Global Insight, U.S. Econom Outlook at 79 (May 2014); & Blue Chip Financial Forecasts, Vol. 32, No. 12 (Dec. 1, 2013).

(d) Morin, Roger A., "New Regulatory Finance,"*Public Utilities Reports, Inc.* at 190 (2006).

(e) The Value Line Investment Survey (May 23, Jun. 20, & Aug. 1, 2014)

(f) www.valueline.com (retrieved Jun. 8, 2014)

(g) Morningstar, "2014 Ibbotson SBBI Market Report," at Table 10 (2014).

(h) Average of low and high values

HISTORICAL BOND YIELDS

Current Equity Risk Premium

(a)	Avg. Yield over Study Period	8.57%
(b)	Historical Single-A Utility Bond Yield	4.37%
	Change in Bond Yield	-4.20%
(c)	Risk Premium/Interest Rate Relationship	-0.4589
	Adjustment to Average Risk Premium	1.93%
(a)	Average Risk Premium over Study Period	3.31%
	Adjusted Risk Premium	**5.23%**

Implied Cost of Equity

(b)	Historical Triple-B Utility Bond Yield	4.82%
	Adjusted Equity Risk Premium	5.23%
	Risk Premium Cost of Equity	**10.05%**

(a) Avista/301, Schedule AMM-9, page 3.
(b) Based on monthly average bond yields from Moody's Investors Service for the six-month period Feb. 2014 - Jul. 2014
(c) Avista/301, Schedule AMM-9, page 4.

PROJECTED BOND YIELDS

	Current Equity Risk Premium	
(a)	Avg. Yield over Study Period	8.57%
(b)	2015-18 Single-A Utility Bond Yield	6.17%
	Change in Bond Yield	-2.39%
(c)	Risk Premium/Interest Rate Relationship	-0.4589
	Adjustment to Average Risk Premium	1.10%
(a)	Average Risk Premium over Study Period	3.31%
	Adjusted Risk Premium	**4.41%**
	Implied Cost of Equity	
(b)	2015-18 Triple-B Utility Bond Yield	6.62%
	Adjusted Equity Risk Premium	4.41%
	Risk Premium Cost of Equity	**11.03%**

(a) Avista/301, Schedule AMM-9, page 3.
(b) Based on data from IHS Global Insight, U.S. Economic Outlook at 79 (May 2014); Energy Information Administration, Annual Energy Outlook 2014 (May 7, 2014); & Moody's Investors Service at www.credittrends.com.
(c) Avista/301, Schedule AMM-9, page 4.

AUTHORIZED RETURNS

Year	Qtr.		(a) Allowed ROE	(b) Single-A Utility Bond Yield	Risk Premium
1980	1		13.45%	13.49%	-0.04%
	2		14.38%	12.87%	1.51%
	3		13.87%	12.88%	0.99%
	4		14.35%	14.11%	0.24%
1981	1		14.69%	14.77%	-0.08%
	2		14.61%	15.82%	-1.21%
	3		14.86%	16.65%	-1.79%
	4		15.70%	16.57%	-0.87%
1982	1		15.55%	16.72%	-1.17%
	2		15.62%	16.26%	-0.64%
	3		15.72%	15.88%	-0.16%
	4		15.62%	14.56%	1.06%
1983	1		15.41%	14.15%	1.26%
	2		14.84%	13.58%	1.26%
	3		15.24%	13.52%	1.72%
	4		15.41%	13.38%	2.03%
1984	1		15.39%	13.56%	1.83%
	2		15.07%	14.72%	0.35%
	3		15.37%	14.47%	0.90%
	4		15.33%	13.38%	1.95%
1985	1		15.03%	13.31%	1.72%
	2		15.44%	12.95%	2.49%
	3		14.64%	12.11%	2.53%
	4		14.44%	11.49%	2.95%
1986	1		14.05%	10.18%	3.87%
	2		13.28%	9.41%	3.87%
	3		13.09%	9.39%	3.70%
	4		13.62%	9.31%	4.31%
1987	1		12.61%	8.96%	3.65%
	2		13.13%	9.77%	3.36%
	3		12.56%	10.61%	1.95%
	4		12.73%	11.05%	1.68%
1988	1		12.94%	10.32%	2.62%
	2		12.48%	10.71%	1.77%
	3		12.79%	10.94%	1.85%
	4		12.98%	9.98%	3.00%
1989	1		12.99%	10.13%	2.86%
	2		13.25%	9.94%	3.31%
	3		12.56%	9.53%	3.03%
	4		12.94%	9.50%	3.44%
1990	1		12.60%	9.72%	2.88%
	2		12.81%	9.91%	2.90%
	3		12.34%	9.93%	2.41%
	4		12.77%	9.89%	2.88%
1991	1		12.69%	9.58%	3.11%
	2		12.53%	9.50%	3.03%
	3		12.43%	9.33%	3.10%
	4		12.38%	9.02%	3.36%
1992	1		12.42%	8.91%	3.51%
	2		11.98%	8.86%	3.12%
	3		11.87%	8.47%	3.40%
	4		11.94%	8.53%	3.41%
1993	1		11.75%	8.07%	3.68%
	2		11.71%	7.81%	3.90%
	3		11.39%	7.28%	4.11%
	4		11.15%	7.22%	3.93%
1994	1		11.12%	7.55%	3.57%
	2		10.81%	8.29%	2.52%
	3		10.95%	8.51%	2.44%
	4	(c)	11.64%	8.87%	2.77%
1995	2		11.00%	7.93%	3.07%
	3		11.07%	7.72%	3.35%
	4		11.56%	7.37%	4.19%
1996	1		11.45%	7.44%	4.01%
	2		10.88%	7.98%	2.90%
	3		11.25%	7.96%	3.29%
	4		11.32%	7.62%	3.70%
1997	1		11.31%	7.76%	3.55%
	2		11.70%	7.88%	3.82%
	3		12.00%	7.49%	4.51%
	4	(c)	11.01%	7.25%	3.76%
1998	2		11.37%	7.12%	4.25%
	3		11.41%	6.99%	4.42%
	4		11.69%	6.97%	4.72%
1999	1		10.82%	7.11%	3.71%
	2	(c)	10.82%	7.48%	3.34%
	4		10.33%	8.05%	2.28%
2000	1		10.71%	8.29%	2.42%
	2		11.08%	8.45%	2.63%
	3		11.33%	8.25%	3.08%
	4		12.50%	8.03%	4.47%
2001	1		11.16%	7.74%	3.42%
	2	(c)	10.75%	7.93%	2.82%
	4		10.65%	7.68%	2.97%
2002	1		10.67%	7.65%	3.02%
	2		11.64%	7.50%	4.14%
	3		11.50%	7.19%	4.31%
	4		10.78%	7.15%	3.63%
2003	1		11.38%	6.93%	4.45%
	2		11.36%	6.40%	4.96%
	3		10.61%	6.64%	3.97%
	4		10.84%	6.35%	4.49%
2004	1		11.10%	6.09%	5.01%
	2		10.25%	6.48%	3.77%
	3		10.37%	6.13%	4.24%
	4		10.66%	5.94%	4.72%
2005	1		10.65%	5.74%	4.91%
	2		10.52%	5.52%	5.00%
	3		10.47%	5.51%	4.96%
	4		10.40%	5.82%	4.58%
2006	1		10.63%	5.85%	4.78%
	2		10.50%	6.37%	4.13%
	3		10.45%	6.19%	4.26%
	4		10.14%	5.86%	4.28%
2007	1		10.44%	5.90%	4.54%
	2		10.12%	6.09%	4.03%
	3		10.03%	6.22%	3.81%
	4		10.27%	6.08%	4.19%
2008	1		10.38%	6.15%	4.23%
	2		10.17%	6.32%	3.85%
	3		10.49%	6.42%	4.07%
	4		10.34%	7.23%	3.11%
2009	1		10.24%	6.37%	3.87%
	2		10.11%	6.39%	3.72%
	3		9.88%	5.74%	4.14%
	4		10.27%	5.66%	4.61%
2010	1		10.24%	5.83%	4.41%
	2		9.99%	5.61%	4.38%
	3		9.93%	5.09%	4.84%
	4		10.09%	5.34%	4.75%
2011	1		10.10%	5.60%	4.50%
	2		9.85%	5.38%	4.47%
	3		9.65%	4.81%	4.84%
	4		9.88%	4.37%	5.51%
2012	1		9.63%	4.39%	5.24%
	2		9.83%	4.23%	5.60%
	3		9.75%	3.98%	5.77%
	4		10.07%	3.93%	6.14%
2013	1		9.57%	4.18%	5.39%
	2		9.47%	4.23%	5.24%
	3		9.60%	4.74%	4.86%
	4		9.83%	4.76%	5.07%
2014	1		9.54%	4.56%	4.98%
	2		9.84%	4.32%	5.52%
Average			**11.89%**	**8.57%**	**3.31%**

(a) Regulatory Research Associates, Inc., Major Rate Case Decisions, (Jul. 10, 2014, Jan. 24, 2002, Jan. 18, 1995, and Jan. 16, 1990).

(b) Moody's Investors Service.

(c) No decisions reported for following quarter.

REGRESSION RESULTS

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.9398234
R Square	0.8832681
Adjusted R Square	0.8823838
Standard Error	0.0053022
Observations	134

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.028079089	0.028079	998.7963	2.00386E-63
Residual	132	0.003710907	2.81E-05		
Total	133	0.031789996			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0723827	0.001325659	54.6013	1.8E-92	0.069760403	0.07500496	0.069760403	0.075004964
X Variable 1	-0.4589493	0.014521995	-31.6037	2E-63	-0.487675253	-0.43022344	-0.48767525	-0.43022344

GAS GROUP

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
		Market Return (R_m)									Size
	Company	Div Yield	Proj. Growth	Cost of Equity	Risk-Free Rate	Risk Premium	Beta	Unadjusted K_e	Market Cap	Size Adjustment	Adjusted K_e
1	AGL Resources	2.3%	10.0%	12.3%	3.5%	8.8%	0.80	10.5%	$6,282	0.93%	11.5%
2	Atmos Energy Corp.	2.3%	10.0%	12.3%	3.5%	8.8%	0.80	10.5%	$5,069	1.19%	11.7%
3	New Jersey Resources	2.3%	10.0%	12.3%	3.5%	8.8%	0.75	10.1%	$2,301	1.75%	11.8%
4	NiSource, Inc.	2.3%	10.0%	12.3%	3.5%	8.8%	0.80	10.5%	$11,644	0.80%	11.3%
5	Northwest Natural Gas	2.3%	10.0%	12.3%	3.5%	8.8%	0.70	9.7%	$1,219	1.75%	11.4%
6	Piedmont Natural Gas	2.3%	10.0%	12.3%	3.5%	8.8%	0.75	10.1%	$2,829	1.72%	11.8%
7	South Jersey Industries	2.3%	10.0%	12.3%	3.5%	8.8%	0.80	10.5%	$1,858	1.75%	12.3%
8	Southwest Gas Corp.	2.3%	10.0%	12.3%	3.5%	8.8%	0.80	10.5%	$2,405	1.75%	12.3%
9	WGL Holdings, Inc.	2.3%	10.0%	12.3%	3.5%	8.8%	0.75	10.1%	$2,129	1.75%	11.8%
	Average							**10.3%**			**11.8%**
	Midpoint (k)							**10.1%**			**11.8%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Jul. 8, 2014).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Jul. 10, 2014).
(c) (a) + (b).
(d) Average yield on 30-year Treasury bonds for the six-months ending Jul. 2014 based on data from the Federal Reserve at http://www.federalreserve.gov/releases/h15/data.htm.
(e) (c) - (d).
(f) The Value Line Investment Survey (Jun. 6, 2014).
(g) (d) + (e) x (f).
(h) www.valueline.com (retrieved Jun. 16, 2014).
(i) *Morningstar* , "2014 Ibbotson SBBI Market Report," at Table 10 (2014).
(j) (g) + (h).
(k) Average of low and high values.

CAPM - PROJECTED BOND YIELD

GAS GROUP

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
		Market Return (R_m)									**Size**
		Div	**Proj.**	**Cost of**	**Risk-Free**	**Risk**		**Unadjusted**	**Market**	**Size**	**Adjusted**
	Company	**Yield**	**Growth**	**Equity**	**Rate**	**Premium**	**Beta**	**K_e**	**Cap**	**Adjustment**	**K_e**
1	AGL Resources	2.3%	10.0%	12.3%	4.7%	7.6%	0.80	10.8%	$6,282	0.93%	11.7%
2	Atmos Energy Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	0.80	10.8%	$5,069	1.19%	12.0%
3	New Jersey Resources	2.3%	10.0%	12.3%	4.7%	7.6%	0.75	10.4%	$2,301	1.75%	12.2%
4	NiSource, Inc.	2.3%	10.0%	12.3%	4.7%	7.6%	0.80	10.8%	$11,644	0.80%	11.6%
5	Northwest Natural Gas	2.3%	10.0%	12.3%	4.7%	7.6%	0.70	10.0%	$1,219	1.75%	11.8%
6	Piedmont Natural Gas	2.3%	10.0%	12.3%	4.7%	7.6%	0.75	10.4%	$2,829	1.72%	12.1%
7	South Jersey Industries	2.3%	10.0%	12.3%	4.7%	7.6%	0.80	10.8%	$1,858	1.75%	12.5%
8	Southwest Gas Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	0.80	10.8%	$2,405	1.75%	12.5%
9	WGL Holdings, Inc.	2.3%	10.0%	12.3%	4.7%	7.6%	0.75	10.4%	$2,129	1.75%	12.2%
	Average							**10.6%**			**12.1%**
	Midpoint (k)							**10.4%**			**12.1%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Jul. 8, 2014).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Jul. 10, 2014).
(c) (a) + (b).
(d) Average projected 30-year Treasury bond yield for 2015-2018 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (May 23, 2014); IHS Global Insight, U.S. Economic Outlook at 79 (May 2014); & Blue Chip Financial Forecasts, Vol. 32, No. 12 (Dec. 1, 2013).
(e) (c) - (d).
(f) The Value Line Investment Survey (Jun. 6, 2014).
(g) (d) + (e) x (f).
(h) www.valueline.com (retrieved Jun. 27, 2013).
(i) *Morningstar* , "2014 Ibbotson SBBI Market Report," at Table 10 (2014).
(j) (g) + (h).
(k) Average of low and high values.

CAPM - CURRENT BOND YIELD

COMBINATION GROUP

		(a)	(b)		(c)		(d)		(e)	(f)	
		Market Return (R_m)									Size
		Div	Proj.	Cost of	Risk-Free	Risk		Unadjusted	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Beta	K_e	Cap	Adjustment	K_e
1	Alliant Energy	2.3%	10.0%	12.3%	3.5%	8.8%	0.75	10.1%	$ 6,406.6	0.93%	11.0%
2	Ameren Corp.	2.3%	10.0%	12.3%	3.5%	8.8%	0.75	10.1%	$ 9,439.6	0.80%	10.9%
3	Avista Corp.	2.3%	10.0%	12.3%	3.5%	8.8%	0.75	10.1%	$ 1,934.2	1.75%	11.9%
4	Black Hills Corp.	2.3%	10.0%	12.3%	3.5%	8.8%	0.85	11.0%	$ 2,552.8	1.72%	12.7%
5	CenterPoint Energy	2.3%	10.0%	12.3%	3.5%	8.8%	0.75	10.1%	$ 10,316.9	0.80%	10.9%
6	CMS Energy Corp.	2.3%	10.0%	12.3%	3.5%	8.8%	0.75	10.1%	$ 7,907.1	0.93%	11.0%
7	Consolidated Edison	2.3%	10.0%	12.3%	3.5%	8.8%	0.60	8.8%	$ 16,006.7	0.80%	9.6%
8	Dominion Resources	2.3%	10.0%	12.3%	3.5%	8.8%	0.70	9.7%	$ 39,851.8	-0.33%	9.3%
9	DTE Energy Co.	2.3%	10.0%	12.3%	3.5%	8.8%	0.75	10.1%	$ 13,341.7	0.80%	10.9%
10	Duke Energy Corp.	2.3%	10.0%	12.3%	3.5%	8.8%	0.60	8.8%	$ 50,147.5	-0.33%	8.5%
11	Empire District Elec	2.3%	10.0%	12.3%	3.5%	8.8%	0.65	9.2%	$ 1,032.0	2.48%	11.7%
12	Entergy Corp.	2.3%	10.0%	12.3%	3.5%	8.8%	0.70	9.7%	$ 13,530.8	0.80%	10.5%
13	Integrys Energy Group	2.3%	10.0%	12.3%	3.5%	8.8%	0.80	10.5%	$ 4,555.4	1.19%	11.7%
14	Northeast Utilities	2.3%	10.0%	12.3%	3.5%	8.8%	0.75	10.1%	$ 14,221.2	0.80%	10.9%
15	PG&E Corp.	2.3%	10.0%	12.3%	3.5%	8.8%	0.65	9.2%	$ 21,207.5	0.80%	10.0%
16	Pub Sv Enterprise Grp	2.3%	10.0%	12.3%	3.5%	8.8%	0.75	10.1%	$ 19,476.2	0.80%	10.9%
17	SCANA Corp.	2.3%	10.0%	12.3%	3.5%	8.8%	0.70	9.7%	$ 7,264.3	0.93%	10.6%
18	Sempra Energy	2.3%	10.0%	12.3%	3.5%	8.8%	0.75	10.1%	$ 24,540.0	-0.33%	9.8%
19	Vectren Corp.	2.3%	10.0%	12.3%	3.5%	8.8%	0.75	10.1%	$ 3,261.2	1.72%	11.8%
20	Wisconsin Energy	2.3%	10.0%	12.3%	3.5%	8.8%	0.65	9.2%	$ 10,170.9	0.80%	10.0%
21	Xcel Energy, Inc.	2.3%	10.0%	12.3%	3.5%	8.8%	0.65	9.2%	$ 15,320.2	0.80%	10.0%
	Average							**9.8%**			**10.7%**
	Midpoint (g)							**9.9%**			**10.6%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Jul. 8, 2014).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Jul. 10, 2014).
(c) Average yield on 30-year Treasury bonds for the six-months ending Jul. 2014 based on data from the http://www.federalreserve.gov/releases/h15/data.htm.
(d) The Value Line Investment Survey (May 23, Jun. 20, & Aug. 1, 2014).
(e) www.valueline.com (retrieved Jun. 8, 2014).
(f) Morningstar, "2014 Ibbotson SBBI Market Report," at Table 10 (2014).
(g) Average of low and high values.

COMBINATION GROUP

		(a)	(b)		(c)		(d)		(e)	(f)	
		Market Return (R_m)									Size
		Div	Proj.	Cost of	Risk-Free	Risk		Unadjusted	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Beta	K_e	Cap	Adjustment	K_e
1	Alliant Energy	2.3%	10.0%	12.3%	4.7%	7.6%	0.75	10.4%	$ 6,406.6	0.93%	11.3%
2	Ameren Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	0.75	10.4%	$ 9,439.6	0.80%	11.2%
3	Avista Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	0.75	10.4%	$ 1,934.2	1.75%	12.2%
4	Black Hills Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	0.85	11.2%	$ 2,552.8	1.72%	12.9%
5	CenterPoint Energy	2.3%	10.0%	12.3%	4.7%	7.6%	0.75	10.4%	$10,316.9	0.80%	11.2%
6	CMS Energy Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	0.75	10.4%	$ 7,907.1	0.93%	11.3%
7	Consolidated Edison	2.3%	10.0%	12.3%	4.7%	7.6%	0.60	9.3%	$16,006.7	0.80%	10.1%
8	Dominion Resources	2.3%	10.0%	12.3%	4.7%	7.6%	0.70	10.0%	$39,851.8	-0.33%	9.7%
9	DTE Energy Co.	2.3%	10.0%	12.3%	4.7%	7.6%	0.75	10.4%	$13,341.7	0.80%	11.2%
10	Duke Energy Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	0.60	9.3%	$50,147.5	-0.33%	8.9%
11	Empire District Elec	2.3%	10.0%	12.3%	4.7%	7.6%	0.65	9.6%	$ 1,032.0	2.48%	12.1%
12	Entergy Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	0.70	10.0%	$13,530.8	0.80%	10.8%
13	Integrys Energy Group	2.3%	10.0%	12.3%	4.7%	7.6%	0.80	10.8%	$ 4,555.4	1.19%	12.0%
14	Northeast Utilities	2.3%	10.0%	12.3%	4.7%	7.6%	0.75	10.4%	$14,221.2	0.80%	11.2%
15	PG&E Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	0.65	9.6%	$21,207.5	0.80%	10.4%
16	Pub Sv Enterprise Grp	2.3%	10.0%	12.3%	4.7%	7.6%	0.75	10.4%	$19,476.2	0.80%	11.2%
17	SCANA Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	0.70	10.0%	$ 7,264.3	0.93%	11.0%
18	Sempra Energy	2.3%	10.0%	12.3%	4.7%	7.6%	0.75	10.4%	$24,540.0	-0.33%	10.1%
19	Vectren Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	0.75	10.4%	$ 3,261.2	1.72%	12.1%
20	Wisconsin Energy	2.3%	10.0%	12.3%	4.7%	7.6%	0.65	9.6%	$10,170.9	0.80%	10.4%
21	Xcel Energy, Inc.	2.3%	10.0%	12.3%	4.7%	7.6%	0.65	9.6%	$15,320.2	0.80%	10.4%
	Average							**10.1%**			**11.0%**
	Midpoint (g)							**10.2%**			**10.9%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Jul. 8, 2014
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Jul. 10, 2014).
(c) Average yield on 30-year Treasury bonds for 2015-2018 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (May 23, 2014); IHS Global Insight, U.S. Economic Outlook at 79 (May 2014); & Blue Chip Financial Forecasts, Vol. 32, No. 12 (Dec. 1, 2013).
(d) The Value Line Investment Survey (May 23, Jun. 20, & Aug. 1, 2014).
(e) www.valueline.com (retrieved Jun. 8, 2014)
(f) Morningstar, "2014 Ibbotson SBBI Market Report," at Table 10 (2014).
(g) Average of low and high values.

GAS GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	AGL Resources	6.0%	1.022546	6.1%
2	Atmos Energy Corp.	8.5%	1.046952	8.9%
3	New Jersey Resources	12.5%	1.026608	12.8%
4	NiSource, Inc.	10.0%	1.006814	10.1%
5	Northwest Natural Gas	10.5%	1.025003	10.8%
6	Piedmont Natural Gas	11.0%	1.021693	11.2%
7	South Jersey Industries	15.5%	1.040978	16.1%
8	Southwest Gas Corp.	10.5%	1.026532	10.8%
9	WGL Holdings, Inc.	10.0%	1.019378	10.2%
	Average (d)			**11.4%**
	Midpoint (e)			**12.5%**

(a) The Value Line Investment Survey (Jun. 6, 2014).

(b) Adjustment to convert year-end return to an average rate of return from Avista/301, Schedule AMM-4.

(c) (a) x (b).

(d) Excludes highlighted figures.

(e) Average of low and high values.

COMBINATION GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	Alliant Energy	11.5%	1.0269	11.8%
2	Ameren Corp.	9.5%	1.0217	9.7%
3	Avista Corp.	8.5%	1.0219	8.7%
4	Black Hills Corp.	9.0%	1.0218	9.2%
5	CenterPoint Energy	13.0%	1.0117	13.2%
6	CMS Energy Corp.	13.5%	1.0331	13.9%
7	Consolidated Edison	8.5%	1.0142	8.6%
8	Dominion Resources	15.0%	1.0366	15.5%
9	DTE Energy Co.	10.0%	1.0278	10.3%
10	Duke Energy Corp.	8.0%	1.0108	8.1%
11	Empire District Elec	8.5%	1.0237	8.7%
12	Entergy Corp.	10.0%	1.0220	10.2%
13	Integrys Energy Group	9.5%	1.0198	9.7%
14	Northeast Utilities	9.5%	1.0193	9.7%
15	PG&E Corp.	8.5%	1.0242	8.7%
16	Pub Sv Enterprise Grp	10.5%	1.0241	10.8%
17	SCANA Corp.	10.0%	1.0377	10.4%
18	Sempra Energy	11.5%	1.0242	11.8%
19	Vectren Corp.	14.0%	1.0177	14.2%
20	Wisconsin Energy	15.5%	1.0057	15.6%
21	Xcel Energy, Inc.	10.5%	1.0305	10.8%
	Average (d)			**10.9%**
	Midpoint (e)			**11.8%**

(a) The Value Line Investment Survey (May 23, Jun. 20, & Aug. 1, 2014).

(b) Adjustment to convert year-end return to an average rate of return from Avista/301, Schedule AMM-6.

(c) (a) x (b).

(d) Excludes highlighted figures.

(e) Average of low and high values.

GAS GROUP

	Company	(a) Allowed ROE
1	AGL Resources	10.17%
2	Atmos Energy Corp.	11.72%
3	New Jersey Resources	10.30%
4	NiSource, Inc.	10.34%
5	Northwest Natural Gas	9.50%
6	Piedmont Natural Gas	10.40%
7	South Jersey Industries	10.30%
8	Southwest Gas Corp.	10.12%
9	WGL Holdings, Inc.	9.58%
	Average	**10.27%**
	Midpoint (b)	**10.61%**

(a) AUS Monthly Utility Report (May 2014).
(b) Average of low and high values.

COMBINATION GROUP (a)

	Company	(b) Allowed ROE
1	Alliant Energy	10.34%
2	Ameren Corp.	9.49%
3	Black Hills Corp.	10.72%
4	CenterPoint Energy	10.05%
5	CMS Energy Corp.	10.30%
6	Consolidated Edison	9.93%
7	Dominion Resources	10.52%
8	DTE Energy Co.	10.75%
9	Duke Energy Corp.	10.46%
10	Empire District Elec	NA
11	Entergy Corp.	10.50%
12	Integrys Energy Group	10.03%
13	Northeast Utilities	9.38%
14	PG&E Corp.	10.40%
15	Pub Sv Enterprise Grp	10.30%
16	SCANA Corp.	10.72%
17	Sempra Energy	11.48%
18	Vectren Corp.	10.43%
19	Wisconsin Energy	10.43%
20	Xcel Energy, Inc.	10.48%
	Average	**10.35%**
	Midpoint (c)	**10.43%**

(a) Excludes Avista Corp.
(b) AUS Monthly Utility Report (Jul. 2013).
(c) Average of low and high values.

DIVIDEND YIELD

		(a)	(b)	
	Company	**Price**	**Dividends**	**Yield**
1	Church & Dwight	$ 69.07	$ 1.24	1.8%
2	Coca-Cola	$ 41.05	$ 1.50	3.7%
3	Colgate-Palmolive	$ 67.72	$ 1.47	2.2%
4	ConAgra Foods	$ 31.31	$ 1.00	3.2%
5	Gen'l Mills	$ 54.22	$ 1.64	3.0%
6	Hormel Foods	$ 48.69	$ 0.84	1.7%
7	Johnson & Johnson	$ 102.64	$ 2.80	2.7%
8	Kellogg	$ 67.51	$ 1.86	2.8%
9	Kimberly-Clark	$ 111.19	$ 3.36	3.0%
10	McCormick & Co.	$ 71.75	$ 1.54	2.1%
11	McDonald's Corp.	$ 101.63	$ 3.24	3.2%
12	PepsiCo, Inc.	$ 87.62	$ 2.62	3.0%
13	Procter & Gamble	$ 79.94	$ 2.58	3.2%
14	Smucker (J.M.)	$ 103.48	$ 2.38	2.3%
15	Verizon Communic.	$ 49.40	$ 2.12	4.3%
16	Wal-Mart Stores	$ 76.03	$ 1.92	2.5%
	Average			**2.8%**

(a) Average of closing prices for 30 trading days ended Jun. 27, 2014.
(b) The Value Line Investment Survey, Summary & Index (Jun. 27, 2014).

GROWTH RATES

		(a)	(b)	(c)	(d)
		Earnings Growth Rates			
	Company	**V Line**	**IBES**	**Zacks**	**Reuters**
1	Church & Dwight	9.5%	10.0%	9.9%	10.0%
2	Coca-Cola	6.5%	6.7%	7.2%	6.7%
3	Colgate-Palmolive	10.5%	8.9%	8.9%	8.9%
4	ConAgra Foods	10.0%	6.5%	7.0%	6.5%
5	Gen'l Mills	6.5%	6.9%	7.7%	6.9%
6	Hormel Foods	11.0%	11.0%	8.0%	NA
7	Johnson & Johnson	6.5%	7.0%	6.6%	7.0%
8	Kellogg	6.5%	6.0%	6.7%	6.0%
9	Kimberly-Clark	9.0%	6.9%	7.3%	6.9%
10	McCormick & Co.	7.5%	7.6%	7.5%	7.6%
11	McDonald's Corp.	7.0%	7.6%	8.6%	7.6%
12	PepsiCo, Inc.	8.5%	7.2%	7.9%	7.2%
13	Procter & Gamble	7.5%	8.4%	8.6%	8.7%
14	Smucker (J.M.)	7.5%	7.3%	7.8%	7.3%
15	Verizon Communic.	10.5%	6.1%	8.0%	6.1%
16	Wal-Mart Stores	7.5%	8.1%	8.7%	8.1%

(a) www.valueline.com (retrieved Jul. 9, 2014).
(b) www.finance.yahoo.com (retreived Jul. 9, 2014).
(c) www.zacks.com (Retreived Jul. 9, 2014).
(d) www.reuters.com (retreived Jul. 9, 2014).

DCF COST OF EQUITY ESTIMATES

			(a)	(a)	(a)	(a)
			Cost of Equity Estimates			
	Company	Industry Group	V Line	IBES	Zacks	Reuters
1	Church & Dwight	Household Products	11.3%	11.8%	11.7%	11.8%
2	Coca-Cola	Beverage	10.2%	10.4%	10.9%	10.4%
3	Colgate-Palmolive	Household Products	12.7%	11.1%	11.1%	11.1%
4	ConAgra Foods	Food Processing	13.2%	9.7%	10.2%	9.7%
5	Gen'l Mills	Food Processing	9.5%	9.9%	10.7%	9.9%
6	Hormel Foods	Food Processing	12.7%	12.7%	9.7%	NA
7	Johnson & Johnson	Medical Supply	9.2%	9.8%	9.3%	9.8%
8	Kellogg	Food Processing	9.3%	8.8%	9.4%	8.8%
9	Kimberly-Clark	Household Products	12.0%	9.9%	10.3%	9.9%
10	McCormick & Co.	Food Processing	9.6%	9.8%	9.7%	9.8%
11	McDonald's Corp.	Restaurant	10.2%	10.8%	11.8%	10.8%
12	PepsiCo, Inc.	Beverage	11.5%	10.2%	10.9%	10.2%
13	Procter & Gamble	Household Products	10.7%	11.6%	11.8%	11.9%
14	Smucker (J.M.)	Food Processing	9.8%	9.6%	10.1%	9.6%
15	Verizon Communic.	Telecommunications	14.8%	10.4%	12.3%	10.4%
16	Wal-Mart Stores	Retail Store	10.0%	10.6%	11.2%	10.6%
	Average		**11.0%**	**10.4%**	**10.7%**	**10.3%**
	Midpoint (b)		**12.0%**	**10.8%**	**10.8%**	**10.4%**

(a) Sum of dividend yield (Avista/301, Schedule AMM-14, p. 1) and respective growth rate (Avista/301, Schedule AMM-14, p. 2).

(b) Average of low and high values.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

ADREIN M. MCKENZIE
Exhibit No. 302

Return on Equity

EXHIBIT NO. 302

QUALIFICATIONS OF ADRIEN M. MCKENZIE

Q. What is the purpose of this exhibit to your testimony?

A. This exhibit describes my background and experience and contains the details of my qualifications.

Q. Please describe your qualifications and experience.

A. I received B.A. and M.B.A. degrees with a major in finance from The University of Texas at Austin, and hold the Chartered Financial Analyst (CFA®) designation. In 1984, I joined FINCAP, Inc. as an Associate. Since that time, I have participated in consulting assignments involving a broad range of economic and financial issues, including cost of capital, cost of service, rate design, economic damages, and business valuation. I have extensive experience in economic and financial analysis for regulated industries, and in preparing and supporting expert witness testimony before courts, regulatory agencies, and legislative committees throughout the U.S. and Canada.

Over the past year, I have personally sponsored direct and rebuttal testimony concerning the rate of return on equity ("ROE") in eleven proceedings filed with the Federal Energy Regulatory Commission ("FERC"), the Kansas State Corporation Commission, the Montana Public Service Commission, the Washington Utilities and Transportation Commission, and the Wyoming Public Service Commission. My testimony addressed the establishment of risk-comparable proxy groups, the application of alternative quantitative methods, and the consideration of regulatory standards and policy objectives in establishing a fair ROE for regulated electric and gas utility operations. In addition, over the course of my career I have prepared prefiled testimony in over 250 regulatory proceedings before FERC (including Docket No. EL11-66-001, which established FERC's current policies with respect to ROE for electric utilities), the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies in over 30 states that was ultimately sponsored by Dr. William E. Avera, who is President of FINCAP, Inc. In connection with these assignments, my responsibilities have included performing analyses to estimate investors' required rate of return, critically evaluating the results of alternative approaches, evaluating the positions of other parties, representing clients in settlement negotiations and hearings, and assisting in the preparation of legal briefs. Prior to joining FINCAP, I was employed by an oil and gas firm and was responsible for operations and accounting. A resume containing the details of my experience and qualifications is attached.

ADRIEN M. McKENZIE

Vice President
FINCAP, INC.
Financial Concepts and Applications
Economic and Financial Counsel

3907 Red River
Austin, Texas 78751
(512) 458–4644
FAX (512) 458–4768
fincap3@texas.net

Summary of Qualifications

Adrien McKenzie has an MBA in finance from the University of Texas at Austin and holds the Chartered Financial Analyst (CFA) designation. He has over 25 years of experience in economic and financial analysis for regulated industries, and in preparing and supporting expert witness testimony before courts, regulatory agencies, and legislative committees throughout the U.S. and Canada. Assignments have included a broad range of economic and financial issues, including cost of capital, cost of service, rate design, economic damages, and business valuation.

Employment

Consultant, FINCAP, Inc. (June 1984 to June 1987) (April 1988 to present)	Economic consulting firm specializing in regulated industries and valuation of closely-held businesses. Assignments have involved electric, gas, telecommunication, and water/sewer utilities, with clients including utilities, consumer groups, municipalities, regulatory agencies, and cogenerators. Areas of participation have included rate of return, revenue requirements, rate design, tariff analysis, avoided cost, forecasting, and negotiations. Develop cost of capital analyses using alternative market models for electric, gas, and telephone utilities. Prepare pre-filed direct and rebuttal testimony, participate in settlement negotiations, respond to interrogatories, evaluate opposition testimony, and assist in the areas of cross-examination and the preparations of legal briefs. Other assignments have involved preparation of technical reports, valuations, estimation of damages, industry studies, and various economic analyses in support of litigation.
Manager, McKenzie Energy Company (Jan. 1981 to May. 1984)	Responsible for operations and accounting for firm engaged in the management of working interests in oil and gas properties.

Education

M.B.A., Finance, University of Texas at Austin (Sep. 1982 to May. 1984)	Program included coursework in corporate finance, accounting, financial modeling, and statistics. Received Dean's Award for Academic Excellence and Good Neighbor Scholarship. Professional Report: *The Impact of Construction Expenditures on Investor-Owned Electric Utilities*
B.B.A., Finance, University of Texas at Austin (Jan. 1981 to May 1982)	Electives included capital market theory, portfolio management, and international economics and finance. Elected to Beta Gamma Sigma business honor society. Dean's List 1981-1982.
Simon Fraser University, Vancouver, Canada and University of Hawaii at Manoa, Honolulu, Hawaii (Jan. 1979 to Dec 1980)	Coursework in accounting, finance, economics, and liberal arts.

Professional Associations

Received Chartered Financial Analyst (CFA) designation in 1990.

Member – CFA Institute.

Bibliography

"A Profile of State Regulatory Commissions," A Special Report by the Electricity Consumers Resource Council (ELCON), Summer 1991.

"The Impact of Regulatory Climate on Utility Capital Costs: An Alternative Test," with Bruce H. Fairchild, *Public Utilities Fortnightly* (May 25, 1989).

Presentations

"ROE at FERC: Issues and Methods," *Expert Briefing on Parallels in ROE Issues between AER, ERA, and FERC*, Jones Day (Sydney, Melbourne, and Perth, Australia) (April 15, 2014)

Cost of Capital Working Group eforum, Edison Electric Institute (April 24, 2012)

"Cost-of-Service Studies and Rate Design," General Management of Electric Utilities (A Training Program for Electric Utility Managers from Developing Countries), Austin, Texas (October 1989 and November 1990 and 1991).

Representative Assignments

Mr. McKenzie has prepared and supported prefiled testimony submitted in over 250 regulatory proceedings. In addition to filings before regulators in 33 states, Mr. McKenzie has considerable expertise in preparing expert analyses and testimony before the Federal Energy Regulatory Commission ("FERC") on the issue of ROE. Many of these proceedings have been influential in addressing key aspects of FERC's policies with respect to ROE determinations. Broad experience in applying and evaluating the results of quantitative methods to estimate a fair ROE, including discounted cash flow approaches, the Capital Asset Pricing Model, risk premium methods, and other quantitative benchmarks. Other representative assignments have included the application of econometric models to analyze the impact of anti-competitive behavior and estimate lost profits; development of explanatory models for nuclear plant capital costs in connection with prudency reviews; and the analysis of avoided cost pricing for cogenerated power. Mr. McKenzie has represented clients at settlement negotiations and hearings.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF JASON THACKSTON
REPRESENTING AVISTA CORPORATION

Natural Gas Supply

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

A. My name is Jason Thackston and I am employed as Senior Vice President of Energy Resources for Avista Utilities (Avista or Company). In my current role I am responsible for Avista's power and natural gas resources. My business address is at 1411 East Mission Avenue, Spokane, Washington.

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

A. Yes. I graduated from Whitworth University with a Bachelor of Arts Degree in International Studies and an emphasis in Business Management. I also earned a Master of Business Administration at Gonzaga University. I joined the Company in 1996 and have held staff and management positions in our finance, internal audit, power supply, and gas supply departments. In 2009, I was appointed Vice President, Finance, and I held the positions of Vice President, Energy Delivery and Vice President, Customer Solutions prior to my current role.

Q. Mr. Thackston, what is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to describe Avista's natural gas resource planning process, and provide an update on the Company's 2014 Natural Gas Integrated Resource Plan.

Q. Are you sponsoring exhibits in this proceeding?

A. Yes. I am sponsoring Exhibit No. 401 which is a copy of the Company's 2014 Natural Gas Integrated Resource Plan which was filed with this Commission on August 29, 2014. I am also sponsoring Exhibit No. 402 which is a copy of the Company's 2012 Natural Gas Integrated Resource Plan which was acknowledged by this Commission on August 31, 2012.

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. Changes in the cost of natural gas included in customers' rates are addressed in the Company's annual PGA filing. The Company filed its annual PGA filing on July 31, 2014, and will update that filing on or before September 15, 2014 as required.

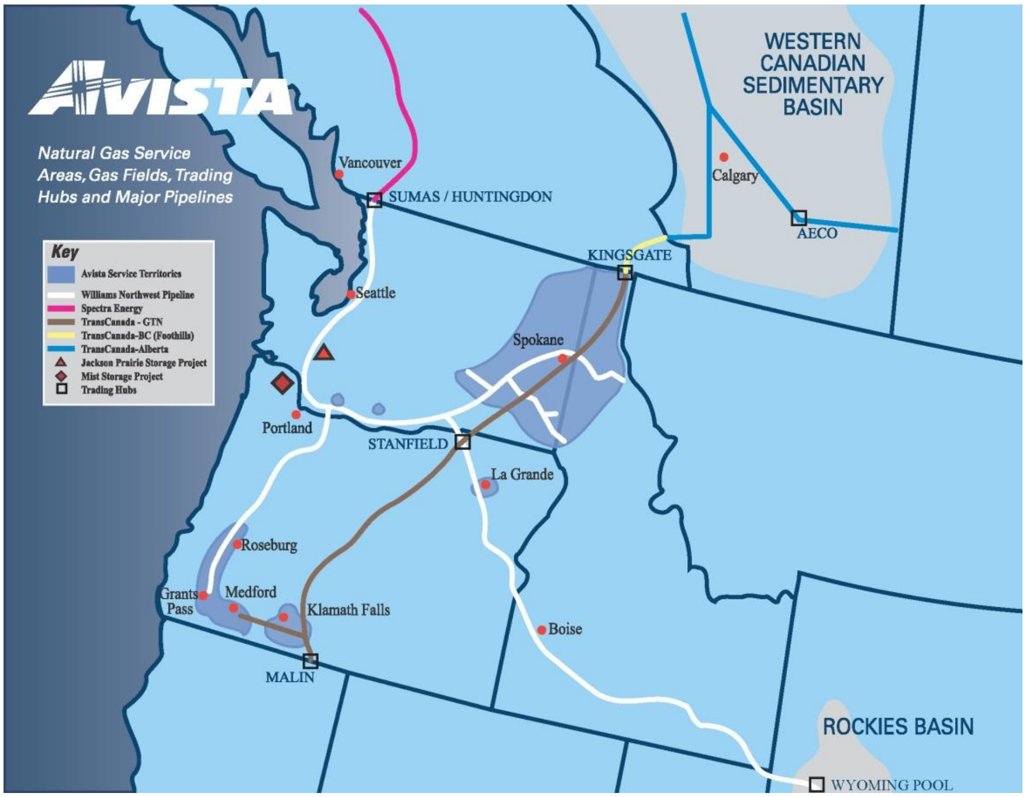
Procurement Planning

Q. Please describe Avista's natural gas portfolio as it relates to the procurement of natural gas for its local distribution company ("LDC") customers?

A. Avista purchases natural gas for its distribution customers in wholesale markets at multiple supply basins in the western United States and western Canada. Purchased natural gas can be transported through six connected pipelines on which Avista holds firm contractual transportation rights. These contracts provide access to both US and Canadian-sourced supply. The US-sourced gas represents 20% of the contractual rights, with transportation from the Rocky Mountains. The remaining 80% is sourced from Alberta and British Columbia supply basins. This diverse portfolio of natural gas resources allows the Company to make natural gas procurement decisions based on the reliability and economics that provide the most benefit to our customers. As natural gas prices in the Pacific Northwest can be affected by global energy markets, as well as supply and demand factors in other regions of the United States and Canada, future prices and delivery constraints may cause the source mix to vary.

Illustration No. 1 below is a map showing our service territory, natural gas trading hubs, interstate pipelines, and natural gas storage facilities:

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



Future natural gas prices cannot be accurately predicted; however, market conditions, information, analysis, and experience shape our overall procurement approach. The Company's goal is to provide reliable supply at competitive prices, with a certain level of stability, in a volatile commodity market. To that end, the Company utilizes a Procurement Plan which includes hedging (on both a short-term and long-term basis), storage utilization, and index purchases. This approach is diversified by transaction time, term, counterparty, and supply basin. The Procurement Plan is disciplined, yet flexible, and layers in fixed-price purchases over time and term to reduce price volatility to customers. The Company provides in its annual PGA filing a copy of its Natural Gas Procurement Plan.

The Procurement Plan provides a process that fixes prices for a pre-designated portion of the portfolio through the use of hedge windows. The hedge windows are "open" for a predetermined time period and have upper and lower pricing levels which are set by the market at the time the window becomes effective. In a rising market, this reduces exposure to extreme price spikes. In a declining market, it can facilitate locking in lower prices. These windows can be executed, or "closed" if certain pricing levels are met, or upon time expiration if no pricing events occur. The Company always maintains some level of discretion and may choose not to execute within a window or to change some aspect of a window given market conditions.

In addition, a portion of the portfolio that is separate from the defined hedge windows is designated as discretionary. This opportunistic portion of the portfolio allows the Company to hedge additional volumes in gas years beyond the prompt year at potentially favorable pricing levels. In the event those pricing levels are not reached, the unexecuted volumes designated as discretionary hedges will become a part of the prompt year hedging program.

Gas Supply continuously monitors the results of the Procurement Plan, evolving market conditions, variation in demand profiles, new supply opportunities, and regulatory conditions. Although various windows and targets are established in the initial design phase of the portfolio, the plan provides flexibility to exercise judgment to revise and/or adjust the Procurement Plan in response to changing conditions. Material changes to the Procurement Plan are communicated to Avista's Senior Management and Commission Staff.

Q. What delivery period does the natural gas Procurement Plan include?

A. The Procurement Plan includes four complete natural gas operating years (November through October) and whole months remaining from the current month until the next October 31 period (the current natural gas operating year). The four complete upcoming natural gas operating years are designated "Prompt", "Second", "Third", and "Fourth" years.

Q. Please describe the components of the natural gas Procurement Plan.

A. Each year a comprehensive review of the previous year's plan is performed. The review includes analysis of historical and forecasted market trends, fundamental market analysis, demand forecasting, and transportation, storage and other resource considerations. The plan includes the following components:

1. **<u>Previous Year(s) Hedges</u>** – longer-term fixed-price purchases executed as a part of a previous year's Procurement Plan.
2. **<u>Prompt Year Hedges</u>** – the portion of the portfolio addressed through the utilization of hedge windows. In each window, fixed price purchases are made for various prompt year delivery periods. Prior to the execution of each window, market conditions, fundamental market knowledge, and other information are considered to determine if execution will occur.
3. **<u>Storage Withdrawals</u>** – utilizing the capacity and deliverability from the Jackson Prairie storage facility, Avista is able to inject natural gas during the summer months and withdraw it to serve customers during the higher demand winter months. I will provide an overview of Jackson Prairie later in my testimony.
4. **<u>Discretionary Long-term Hedges</u>** – opportunistic purchases based on a set of price levels, or targets, which trigger possible execution. At the time the triggers are reached, evaluation of market conditions, fundamental market

knowledge, and other information are considered. These hedges will generally be executed when they can be done at or below the established targets.

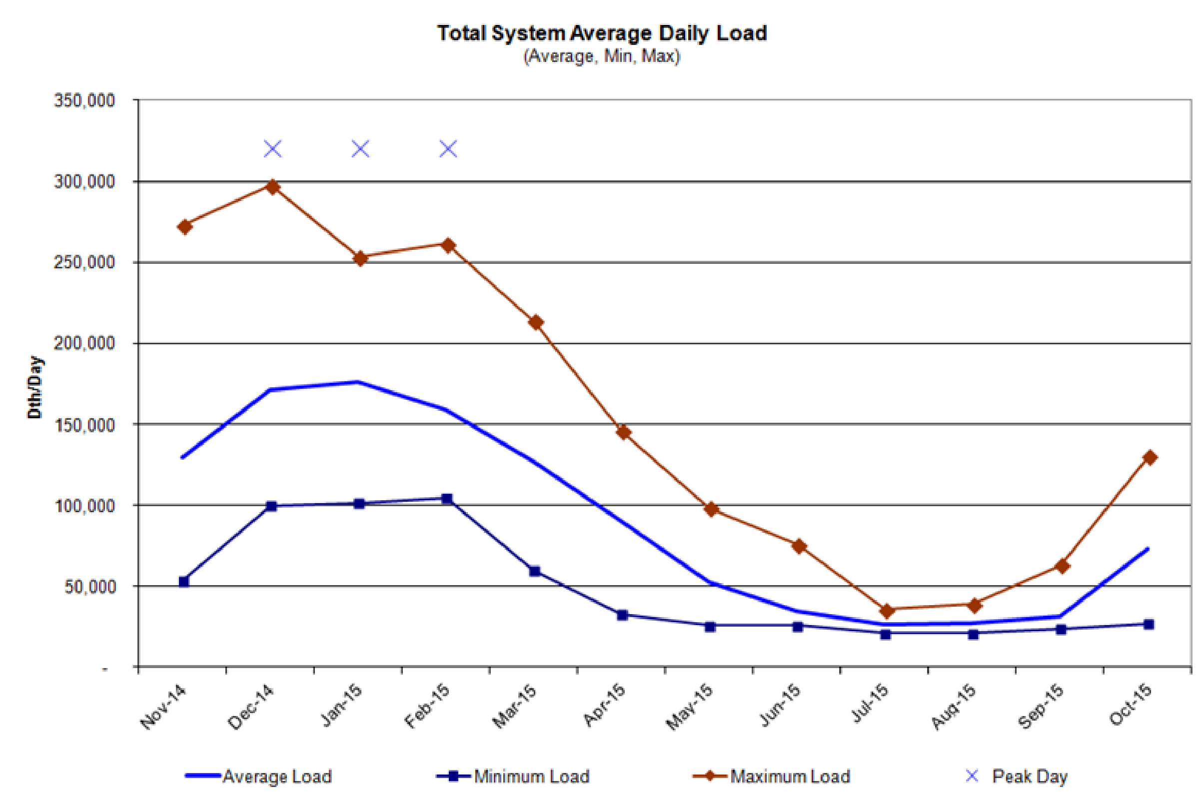
5. **Index Purchases** – physical index-based natural gas purchases are procured prior to or throughout the delivery month. These purchases are usually associated with daily pricing. The amount of index purchases planned is the difference between the forecasted demand less the sum of the previous year hedges, prompt year hedges, and storage withdrawals.

Q. Please describe how the Procurement Plan manages volatility.

A. The Procurement Plan focuses on managing demand and price volatility. Natural gas demand is volatile and will vary day to day. For example, system-wide *average* daily demand can fluctuate between 27,000 dekatherms (Dth) per day during a summer month and 180,000 Dth/day during a winter month. Further, December's system-wide daily demand volatility has ranged from a low of 124,000 Dth/day to a high of 300,000 Dth/Day. Finally, from Avista's 2014 IRP, system-wide peak day demand for 2014-2015 heating season is forecasted to be approximately 336,000 Dth per day.

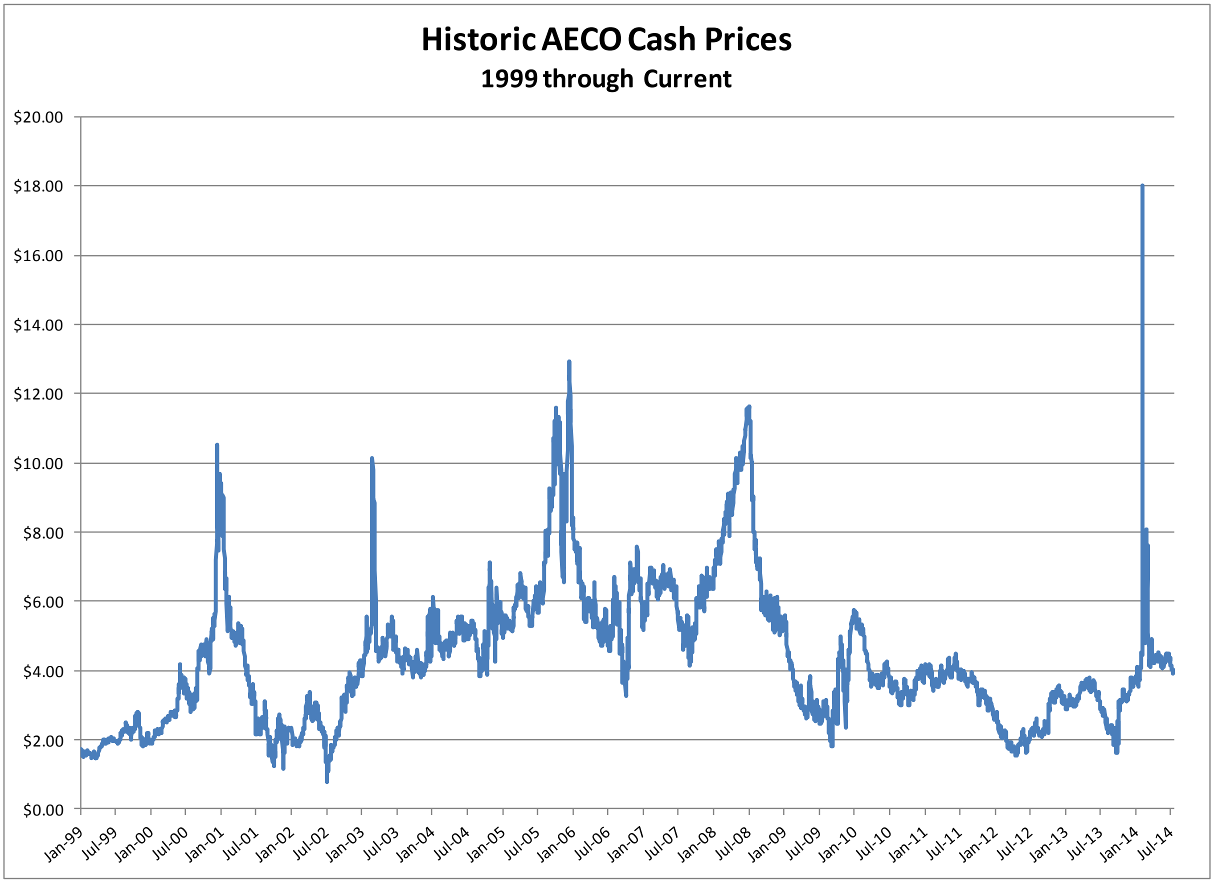
In order to manage these seasonal, monthly and daily volume swings, Avista shapes the components of the Procurement Plan by month (i.e. more natural gas is hedged for the winter months than for the summer). Illustration No. 2 below shows the demand volatility:

<u>Illustration No. 2</u>:



Price volatility can also vary widely by season, month and day. Illustration No. 3 below depicts natural gas price volatility over time. Avista cannot predict with accuracy where natural gas prices may go, however, our experience and fundamentally based market intelligence guide our procurement decisions. By layering in fixed price purchases over time, setting upper and lower pricing levels on the hedge windows, opportunistically hedging at favorable pricing levels through the discretionary hedge program, and actively managing storage resources, Avista is able to meet our goal of providing a meaningful measure of price stability, together with competitive prices, for our customers.

Illustration No. 3:



Q. Could you please describe Avista's involvement with the Jackson Prairie natural 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. This year marks the 50th anniversary of the operation of the facility. 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 <u>owns</u> a total of 8,528,013 dekatherms (Dth) of capacity. This capacity comes with a withdrawal capability of 398,667 Dth per day (deliverability). Oregon's current share of that capacity is 823,337 Dth and 52,000 Dth of deliverability. Additionally, the Company has <u>leased</u> 95,565 Dth of capacity (2,623 Dth of deliverability) for the benefit of Oregon customers. The <u>combined</u> leased and owned storage provides Oregon Customers storage capacity of 918,902 Dth and deliverability of 54,623 Dth per day.

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, among other things, capture seasonal price spreads (differentials), improve reliability of supply, increase operational flexibility, and mitigate peak demand price spikes.

<u>2014 Natural Gas Integrated Resource Plan</u>

Q. Would you please provide an overview of the Company's development of its 2014 Natural Gas Integrated Resource Plan?

A. Yes. On August 29, 2014, Avista filed with the Commission its Natural Gas Integrated Resource Plan ("IRP"). The IRP includes forecasts of natural gas demand and any supply-side and demand-side resources projected for the coming 20 years, which will help Avista continue to reliably provide natural gas to our customers. A copy of the Company's 2014 Natural Gas Integrated Resource Plan is included as Exhibit No. 401.

Q. What are the summary highlights from the 2014 IRP?

A. The 2014 Plan highlights the following:

- The Company has sufficient natural gas pipeline resources well into the future with resource needs not occurring during the 20 year planning horizon in Oregon, Idaho or Washington;
- A sustained trend in the 2014 IRP was that customer growth has continued to slow and it is not anticipated to rebound in the near term;
- Prices of natural gas have continued to stabilize due to robust North American supplies led by shale gas developments; and
- As forecasted demand is relatively flat, the Company will monitor actual demand for signs of increased growth which could accelerate resource needs.

Q. Has the Company's 2014 IRP been acknowledged by the Commission?

A. No, the Company filed its 2014 IRP around the same time as this general rate case. The Company's last IRP, filed in August 2012, was acknowledged by the Commission on April 30, 2013. The 2012 IRP has been included as Exhibit No. 402.

Q. When will the Company file its next IRP?

A. The Company will file its next IRP on or before August 31, 2016. A courtesy work plan will be filed August 31, 2015 detailing Avista's IRP planning process as well as tentative dates and content for meetings with the Technical Advisory Group, which includes Commission Staff. Technical Advisory Group meetings will begin in the first quarter of

2016.

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

A. Yes, it does.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

AVISTA CORPORATION
JASON THACKSTON
Exhibit No. 401

2014 Natural Gas Integrated Resource Plan

2014 Natural Gas Integrated Resource Plan (IRP)

Compact Disc Exhibit

Also Available At:

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

AVISTA/402
Thackston

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

AVISTA CORPORATION

JASON THACKSTON
Exhibit No. 402

2012 Natural Gas Integrated Resource Plan

2012 Natural Gas Integrated Resource Plan (IRP)

Compact Disc Exhibit

Also Available At:

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

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF JAMES M. KENSOK
REPRESENTING AVISTA CORPORATION

Information Technology Programs

I. INTRODUCTION

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

A. My name is James M. Kensok. I am employed by Avista Corporation as the Vice-President and Chief Information and Security Officer (CISO). My business address is 1411 E. Mission Avenue, Spokane, Washington.

Q. Mr. Kensok, please provide information pertaining to your educational background and professional experience.

A. I am a graduate of Eastern Washington University with a Bachelor of Arts Degree in Business Administration, majoring in Management Information Systems and from Washington State University with an Executive MBA. I have experience through direct application and management of Information Services over the course of my 32-year information technology career. I joined the Company in June of 1996. Over the past 19 plus years, I have spent approximately one year in Avista's Internal Audit Department as an Information Systems Auditor with involvement in performing internal information systems compliance and technology audits. I have been in the Information Services Department for approximately 16 years in a variety of management roles directing and leading information technology and systems; planning, operations, system analysis, complex communication networks, cyber security, applications development, outsourcing agreements, contract negotiations, technical support, cost management, data management and strategic development. I was appointed Vice-President and CIO in January of 2007 and Chief Security Officer in January of 2013.

Q. What is the scope of your testimony?

A. My testimony describes the costs associated with Avista's information technology programs. These costs include the capital investments for a range of systems implemented by the Company, including the ongoing replacement of the its legacy Customer Information and Work and Asset Management System ("Project Compass"). These Enterprise Technology capital expenditures are part of the capital additions testimony provided by Company witness Mr. DeFelice. I also describe the additional expenses required to support applications and systems for cyber security, the Next Generation Radio System, operation of the new Customer Information and Work and Asset Management System, and increases in application license fees and software maintenance costs. These costs are included in Company witness Ms. Andrews' 2015 test period operating results used to determine the revenue requirement in this filing.

A table of contents for my testimony is as follows:

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring Exhibits Nos. 501 and 502. Exhibit No. 501 is a report providing an overview of Avista's Project Compass, the Company's ongoing project to replace its legacy Customer Information and Work and Asset Management System. Exhibit

No. 502 is a report describing recent revisions to the initial timeline and budget for Project Compass.

II. ENTERPRISE TECHNOLOGY CAPITAL PROJECTS

Q. Please describe each of the Enterprise Technology projects for 2014 and 2015.

A. The enterprise technology capital costs for projects to be completed during 2014 and the first three months of 2015 are identified by project in Table No. 1, below, and each project is briefly described in the testimony following.

Table 1
Technology Capital Projects - Transferred to Plant
($000's)

	2014		Q1 2015	
Project	System	Oregon Allocated	System	Oregon Allocated
Technology Refresh to Sustain Business Process	$17,059	$1,524	$4,114	$366
Technology Expansion to Enable Business Process	5,403	480	1,450	129
Enterprise Security Systems	3,221	286	546	49
Next Generation Radio System	13,246	1,177	27	2
Microwave Replacement with Fiber	2,114	188	-	-
Customer Information and Asset System Replacement	139	12	87,608	7,787
Small Technology Projects	4,039	359	2,305	205
Total	$45,221	$4,026	$96,050	$8,538

Technology Refresh to Sustain Business Process – 2014: $1,524,000; 2015: $366,000

The Company manages an ongoing program to systematically replace aging and obsolete technology under "refresh cycles" that are timed to optimize hardware/software system changes or industry trends. An example of technology managed under this program is the fleet of personal computers and other computing devices used by field operations, power plant operators, call centers, and our general office employees.

Technology Expansion to Enable Business Process – 2014: $480,000; 2015: $129,000

This program facilitates technology growth throughout the Company, including technology expansion for the entire workforce, business process automation and increased technology to support efficient business processes. For example; when trucks are added to the fleet, communication equipment needs to be added to the truck; as the Company hosts more customer data, disk storage needs to be expanded, as customers expand their use of the website, additional computing capacity is needed to support that functionality.

Enterprise Security – 2014: $286,000; 2015: $49,000

There are three primary drivers of the increasing costs for Enterprise Security: cyber security, physical security and regulatory requirements. Each plays a critical role in supporting our delivery of safe and reliable energy to our customers.

<u>Cyber Security</u>

The security of our electric and natural gas infrastructure is a significant priority at a national and state level, and is of critical importance to Avista. Threats from cyber space, including viruses, phishing, and spyware, continue to test our industry's capabilities. And while the sources of these malicious intentions are often unknown, it is clear the methods are becoming more advanced and the attacks more persistent. In addition to these threats, the vulnerabilities of hardware and software systems continues to increase, especially with industrial control systems such as those supporting the delivery of energy. For these reasons, Avista must continue to advance its cyber security strategy and invest in security controls to prevent, detect, and respond to these increasingly frequent and sophisticated attacks.

<u>Physical Security</u>

While considerable attention is focused on cyber security, physical security also remains a concern for our industry. Physical security encompasses the aspects of employee safety and the protective security of our facilities. Acts of theft, vandalism, and sabotage of critical infrastructure not only results in property losses, but can also directly impact our ability to serve customers. Securing remote unmanned or unmonitored critical infrastructure is difficult, especially when traditional tools such as perimeter fencing are not adequate. In response to these challenges, the Company has focused its resources on remote detection and response, which is creating the need for additional expertise and technology.

<u>Regulatory Requirements</u>

Advancing cyber threats continue to drive change in the regulatory landscape faced by the Company. Early in 2013, President Obama issued the Executive Order

"Improving Critical Infrastructure Cybersecurity." The Order directed the National Institute of Standards and Technology to work with stakeholders in developing a voluntary framework for reducing cyber risks to critical infrastructure. The Framework consists of standards, guidelines, and best practices to promote the protection of critical infrastructure. The Federal Energy Regulatory Commission also issued Order 791 on November 22, 2013, approving the North American Electric Reliability Corporation Critical Infrastructure Protection Standards, Version 5. Both of these activities will increase our security-related operating costs because they require the Company's security controls and processes to conform to new standards, guidelines, and best practices.

Next Generation Radio – 2014: $1,177,000; 2015: $2,000

This project is refreshing Avista's 20-year-old Land Mobile Radio system and it fulfills a mandate from the Federal Communications Commission that all licensees in the Industrial/Business Radio Pool migrate to spectrum efficient narrowband technology by January 1, 2013. The Company maintains this private radio system because no public provider is capable of supporting communications throughout our rural service territory. And, since our gas and electric systems comprise a portion of our nation's critical infrastructure, Avista is required to have a communication network that will operate in the event of a disaster. Avista requested an extension in time until September 30, 2014 for compliance with the narrowband deadline that was granted by the Federal Communication Commission.

Microwave Replacement with Fiber – 2014: $188,000; 2015 $0

Avista utilizes analog microwave technology for the transport of many communication circuits. These include communications critical to mobile workforce management and transmission, substation and distribution system controls. Most of the Company's microwave technology is obsolete and is at risk from an operations and manufacturer support network. This project is to replace our aging analog technology with modern digital communications, and to replace microwave communication spans with fiber infrastructure.

Customer Information and Work and Asset Management System Replacement – 2014: $12,000; 2015 $7,787,000

The Company's legacy Customer Information and Work and Asset Management System has been in service for twenty years and is currently being replaced in a multi-year effort named "Project Compass." The major applications being replaced include the Company's Customer Service System, Work Management System, and the Electric and Gas Meter Application. The primary replacement systems are Oracle's Customer Care & Billing application and International Business Machine's ("IBM") Maximo work and asset management application. A portion of the Maximo system was enabled in the fall of 2013, and the full System is planned to be in service in Q1 2015. I describe recent revisions in the implementation timeline and cost of this significant technology project later in my testimony.

Small Technology Projects – 2014: $359,000; 2015: $205,000

The Company has grouped the capital costs for a number of smaller information technology projects, each of which are briefly described below:

Enterprise Business Continuity Plan

Avista has developed and maintains an Enterprise Business Continuity Plan to support the Company's emergency response, and to ensure the continuity of its critical business systems under crisis conditions. The framework includes the key areas of technology recovery, alternate facilities, and overall business processes.

Radio Telephone Communications Console System Refresh

This project supports the refresh of the Company's Radio Telephone Communications Console System. The "console system" is the hardware and software that provides the communication interface with Avista's Land Mobile Radio system. The new console system is integrated with the Company's Next Generation Radio project, described above, which is refreshing Avista's 20-year-old Land Mobile Radio network.

High Voltage Protection Upgrade

Telecommunication facilities, including Phone, Modem, SCADA, and Metering & Monitoring systems, are commonly co-located inside the Company's high voltage substations. This requires communications technicians to work in close association with our high-voltage electrical equipment. This work supports the Company's implementation of new high-voltage protection & isolation standards that are designed to lower potential risks to our personnel and equipment.

AvistaUtilities.com and AvaNet Upgrade

Like many businesses today, the Company is experiencing continued growth in the use of its customer website, Avistautilities.com. The website was built in 2006-2007, but because the technology landscape has advanced so quickly, the site does not meet current web best practices for customer usability. This project will update and improve the technology, overall web usability, and customer satisfaction. The website is part of the Company's strategy to provide customers a more effective channel to meet their expectations for self-service options, including mobile, energy efficiency education, and to drive self-service as a means to lower transaction costs.

Mobility in the Field

This program is designed to increase the Company's use of field mobile dispatch for service employees equipped with mobile devices. Avista has documented 30 field opportunities to apply mobile technology, and has selected those with the greatest benefit and savings for implementation in a five-year program, named "Visibility in the Field." This effort primarily supports the functions of Leak Survey and Gas Service Dispatch by enabling the use of facility maps on a mobile device.

Asset Facilities Management Application Migration

The project replaces the Company's obsolete, custom Facilities Management system with a commercial, off-the-shelf application. The project includes replacement of the natural gas and electric Construction Design Tool, Edit Tool, and the Company's proprietary Outage Management Tool. These applications aid in the engineering and design of Avista's electric and gas infrastructure, which costs would increase without the aid of this technology. In addition to supporting design, the Outage Management Tool allows the Company to quickly isolate the likely cause of system outages, to communicate proactively with customers, and to quickly and accurately dispatch Avista crews for service restoration.

III. CUSTOMER INFORMATION AND WORK AND ASSET MANAGEMENT SYSTEM REPLACEMENT – PROJECT COMPASS

Q. Please summarize the replacement project for Avista's Customer Information and Work and Asset Management System.

A. In 2010, Avista began the research and planning for replacing its legacy Customer Information and Work Management System. Named "Project Compass," the program is replacing the Company's legacy applications with Oracle's 'Customer Care & Billing' solution, and IBM's 'Maximo' work and asset management application. Exhibit No. 501 provides a comprehensive overview of Project Compass, including the initial timeline and budget. In the Company's last general rate filing, the parties agreed that Project Compass costs were prudently incurred, up to the amount of the initial budget ($79 million System, and $6.520 million Oregon), and that any additional Project costs would be subject to prudence review before they could be recovered in rates.

Q. Under Avista's initial Project Plan, completed in 2012, when did it expect to place these new Systems into service?

A. The process of placing new Systems into service is known as the "Go-Live." A portion of the Maximo asset management application was placed into service in the fall of 2013, and Avista was initially targeting the third quarter of 2014 for the Go Live of the remainder of the Maximo application and the Customer Care & Billing System.

Q. Has Avista revised the Go Live to a later effective time frame?

A. Yes, it has. The Company is now planning for a Go Live of the new System in the first quarter of 2015.

Q. Has the Company also revised the Project budget in conjunction with the re-forecasted timeline?

A. Yes it has. At this point, the Company is expecting the Project capital costs to equal approximately $100 million.

Q. Has Avista described the factors responsible for adjustments to the Go Live date and Project budget?

A. Yes. The discussion is contained in a report attached to this testimony as Exhibit No. 502. As explained in the report, the process of coding extensions for the applications was more complex than initially expected. In addition, the ongoing process to remediate defects in the code is taking more time than was allotted in the initial Project plan.

Q. Is it possible that Avista could further revise the Go Live date?

A. Yes. The Go Live target date is an important project planning and management tool that represents a point in time in which every major project activity reaches a critical and timely state of completion. As described in Exhibit No. 502, the currently-ongoing process of code defect management is associated with inherent uncertainty, and until the point that the number of defects declines in a measured and predictable way, it's difficult to estimate the amount of effort (and cost) remaining in the project. In establishing a revised Go Live timeframe of early 2015, Avista is cognizant that as it makes more progress in code defect management it may need to once again revise the expected Go Live date and project budget in order to ensure a successful launch of the new System.

Q. Does Avista consider the revision of the Go Live date and Project budget, to be a failure in the delivery of the new System?

A. No, it does not. As described in Exhibit No. 501, the Company made a considerable effort to research and understand the root causes of the failed projects of other utilities. It systematically applied those learnings to the design of Project Compass in order to avoid some of the major pitfalls experienced by others. And, it has worked diligently to prudently manage the project scope, timeline and budget.

Q. Are there any capital costs associated with Project Compass that will continue after the new Systems are in place serving Avista's customers?

A. Yes. Even after rigorous System and User testing, comprehensive employee training on the new applications and work processes, and timely customer communications highlighting service changes, industry experience demonstrates the value of having key technical support teams available to users for a period after the Go Live of the new systems. Accordingly, the Company will keep contract technical teams in place for a period up to six months after the Go Live date, in the phase referred to as "project stabilization." This work focuses on the post Go Live technical support of the new applications, information technology staff, and customer service and other Avista employees.

Q. Are there any Project development costs that will continue after the new Systems are in service?

A. Yes. Although Avista cannot point to any specific development activities at present, the Company's experience with large information-technology projects is that often, even before the System is placed in service, opportunities will be identified for adding functionality to serve the evolving needs of customers, to improve the efficiency or effectiveness of the new System for employees, or to integrate new or modified applications and systems. As was the case with the Company's Legacy System, there was essentially a continuous development effort required to support the System from its inception, to accommodate changing technology, the growing needs of our customers, new regulatory requirements, and the perpetual effort to optimize the value of the investment.

IV. INFORMATION SYSTEM OPERATING EXPENSES

Q. What are the primary business needs supported by Avista's Information Services Department?

A. With advancements in the utility industry, the use of operating, information, and customer-application technologies is increasingly prevalent in day-to-day business operations. The Information Services department provides the technology support required by all Company operations, both internal as well as customer facing. Examples include field operations, engineering, transmission & distribution operations, power supply, finance, treasury, legal, human resources, customer solutions, customer services, and regulatory functions. Types of support include the design, engineering, implementation, and support of Cyber security, computer hardware, application software, data and voice systems and networks, application integration, business continuity and disaster recovery, and data management and mobility. Our customers expect mobile solutions for transacting business with Avista that are available 24 hours per day, in addition to having more data and information about their energy use and tools to manage their consumption of energy.

Records management is increasing for both gas and electric infrastructure, and Avista is experiencing continued growth in the use of its networks by customers and our employees who are increasingly using mobile, real-time systems to transact business and deliver safe and reliable energy services. These technologies are foundational to Avista's efforts to keep pace with the service expectations of our customers, to fulfill our regulatory requirements, and to achieve cost savings through prudent technology deployments.

Q. What are the primary drivers increasing Information Systems expenses?

A. There are four key areas, the first of which is the expense associated with the replacement of obsolete systems, such as the Company's legacy Customer Information and Work Management systems, described above.

The second area is the increasing cyber and physical security requirements to protect Company infrastructure. Our industry is increasingly a target for malicious entities, and in order to protect Avista and its customers, we have been required to increase staffing, deploy new security systems, improve employee training, and deploy more sophisticated business-continuity recovery programs. Meeting expanding regulatory requirements is also driving cost increases in security compliance.

A third focus is the sensor technology and the associated data networks required by the industry's modernization of the electric grid and the improved reliability of our natural gas distribution system. Though there are many advantages for customers and the Company associated with the deployment of these new systems, the expenses to support them are an increasing portion of the costs of providing efficient, safe and reliable energy services.

The fourth driver of Avista's costs is related to the growth in usage of applications, data, and our data networks. As customer expectations and business and compliance requirements continue to grow, they drive the need for new and expanded technology solutions. Although these new solutions provide the most cost-effective way to meet these growing needs, they also increase costs for application licensing, maintenance and support, and for the computer hardware and networks required to enable them.

Q. As Information Services requirements have increased, has Avista focused on managing its overall technology expenses for the benefit of its customers?

A. Yes. Over the past several years, Avista has focused on reducing customer transaction costs through the prudent deployment of technology. Along with meeting customer needs, Avista works continuously to minimize its costs and to maximize employee efficiency through the use of appropriate technology.

During the period 2010 through 2013, the Information Services expense budget at Avista remained flat to slightly declining. Over the same period, however, the Company completed and supported many new Information Services projects. Examples that benefit customers today include the implementation of advanced cyber-security protection (protecting power plant operations, the electric transmission and distribution system, natural gas delivery, financial data, and customer and employee data), a new tax application, and a financial system upgrade.

Q. Please summarize the increases in expenses for the 2015 rate year.

A. Table 2 below summarizes the net increase in Information System expenses for year 2014, and which continue through the 2015 rate year. A brief description of each program is provided following Table 2.

TABLE NO. 2
Information Services Incremental Expense Increases (2015 vs. 2013)

Description	System Expense	OR Allocated Share
New Expense From Projects:		
Compass (net increase over current customer & work management system)	$ 475,869	$ 42,257
Radio Telephone Communications Console System Refresh	136,962	12,162
Next Generation Radio	126,941	11,272
Enterprise Security - Non Labor Additions	105,000	9,324
Mobile Gas Compliance and Efficiency	34,400	3,055
Enterprise Document Management	40,000	3,552
Enterprise Voice Portal Application Upgrade	105,000	9,324
Total New Expense from Projects	**$1,024,172**	**$ 90,946**
Other Expenses: (incremental expenses for existing systems)		
Network Services (hardware, networks)	$ 336,000	$ 29,837
Incremental maintenance cost increase for existing software applications		
Oracle Database and Software Maintenance	172,001	15,274
Microsoft Software Maintenance	87,094	7,734
IntelliResponse Software Maintenance	179,939	15,979
Total Other Expenses	**$ 775,034**	**$ 68,823**
TOTAL (New Expenses from Projects and Other Expenses)	**$1,799,206**	**$ 159,769**

Project Compass - There will be a net increase of $475,869 ($42,257 – Oregon) in the expenses associated with the deployment of the Company's new Customer Service and Work and Asset Management Systems implemented as part of Project Compass. The total for new operating expenses required to support these new Systems is $2,764,869, however, there is a corresponding offset in the approximate amount of $2,289,000, which reflects the annual expense reduction in contract services and mainframe computer costs associated with the retirement of the Company's Legacy Customer Service System. The new costs support the annual license and maintenance fees for the new primary applications (Maximo and Customer Care & Billing) and supporting applications. Costs also include the labor and professional services associated with the realtime operation and maintenance of the applications, and the labor expense supporting management reporting for the new Systems. A brief description of each of these costs is provided below:

IBM Maximo Application

- Application Maintenance Fee paid to IBM. This fee, which is shared among the Maximo user/clients, supports ongoing application maintenance, enhancements and updates.

Oracle Customer Care & Billing Application

- Application Maintenance Fee paid to Oracle for system maintenance, enhancements and updates.
- Application Maintenance Fee for IBM's Tivoli batch scheduling software, which automates, aggregates and executes batch system functions each day (e.g. customer billing, credit and collections, letters and notices).
- License and Maintenance Fee for the Oracle Database System.
- License and Maintenance Fee for the Oracle Data Integrator Application, which performs the extraction, transfer and loading of data for management reporting.

Shared Support

- Labor associated with the operation and maintenance of the Maximo and Customer Care & Billing integrations with Avista's Enterprise Service Bus application architecture.
- License and Maintenance Fee for Hewlett Packard's ("HP") Quality Center Application, which is used to automate the routine user testing of the integrated software systems.
- HP services (labor) supporting management reporting for the Maximo and Customer Care & Billing Applications.
- IBM Application Management Services, providing technical resource support for maintaining and managing the realtime availability and performance of the Customer Care & Billing and Maximo application systems for Avista.

Radio Telephone Communications Console System Refresh ($12,162) - Deployment of this refreshed console equipment is a prerequisite for the successful implementation of the Next Generation Radio project, described above in my testimony. The integrated console system provides access to the narrowband communication network being deployed in the Next Generation Radio project. These costs are for maintenance fees required to assure the system meets our availability and security requirements for service. In particular, the maintenance fees also provide the Company access to software patches that address security vulnerabilities, and enable features and enhancements that extend the functionality of the deployed console system.

Next Generation Radio Hardware and Software Maintenance ($11,272) Similar to the costs for the console system as described above, these costs support the maintenance contracts for the hardware and software infrastructure required to effectively own and operate the Next Generation Radio system.

Enterprise Security – Non Labor Additions ($9,324) **-** This incremental expense is for software maintenance for new application services that monitor high-risk utility targets (including both physical and cyber), third party independent penetration testing, data breach response programs, and business continuity recovery programs.

Mobile Gas Compliance and Efficiency ($3,055) **-** This cost supports software maintenance for a new mobile application used to provide our employees near-real-time gas facility information in the field. The collection of near-real-time information on a mobile platform improves productivity and safety for our employees and customer satisfaction through improved response time.

Enterprise Document Management ($3,552) **-** This incremental cost is for software maintenance for a new application used in managing invoice processing and archiving. Currently, documents (i.e., invoices) in various departments are maintained on paper, and are processed manually. The new application allows Avista to scan invoices for electronic storage, processing, and approval, providing for more efficient and timely processing and access to stored documents.

Enterprise Voice Portal Application Upgrade ($9,324) **–** Avista's current automated telephone system will no longer be supported after 2014. The system manages all customer calls for reporting outages, automated bill pay and billing inquiries, and other types of self-service options for our customers. These expenses support the services agreement, providing for software maintenance and management for the replacement voice portal system.

Network Services (hardware, networks, etc.) ($29,837) **-** This cost is for service and maintenance fees paid to network providers such as AT&T and Verizon for increased network capacity and system support. As network capacity is increased, the electronics that move data/voice traffic over the networks must be upgraded. The upgraded electronics require maintenance and service contracts to keep them current on security patches, firmware upgrades and general performance tuning and support.

Increases in Existing Application Maintenance Fees ($439,034) - Avista licenses all commercial software it employs in the conduct of its business. The Company experiences periodic increases in the application licensing and maintenance fees for existing applications, such as those described below. The Company also faces incremental cost increases associated with licenses for new applications supporting new technology such as virtual desktops and application and data servers. Avista works to minimize the need for additional licenses by maintaining stringent controls over existing licenses and through a systematic assessment of existing licenses that can be discontinued.

Oracle Database Maintenance ($15,274) - Avista uses Oracle products to provide, and maintain and manage its primary business databases, supporting financial, supply chain, operations, customer service, and realtime infrastructure data. This cost covers increases in recurring maintenance fees as well as incremental costs associated with new Oracle databases that are being licensed.

Microsoft Software Maintenance ($7,734) - The incremental increase in maintenance fees reflects vendor price increases for existing systems, as well as costs associated with the deployment of new systems. One such new system is "desktop virtualization," which provides a highly flexible and much-more secure desktop computer environment. In addition, this approach supports a more complete desktop disaster recovery strategy, as all components are essentially saved in the data center and backed up through traditional redundant maintenance systems. In addition, because no data is saved to the user's device there is much less chance that any critical data can be retrieved and compromised in the event a device is lost.

IntelliResponse Software Maintenance ($15,979) **–** This cost is for maintenance fees for a new technology that will improve the effectiveness of customer self-service on Avista's web portal. When a customer using the web has a question, they can select the IntelliResponse application, which employs a Question and Answer directory to quickly answer the customer's question. In addition to providing a better customer experience, the application will also reduce operating expenses by reducing calls to the Contact Center. Over 18,000 customer questions were handled by this application between April and November 2013, and over 90% of the questions were answered accurately according to a post-question survey.

Q. In Table No. 2 above, do any of these items have related offsetting reduction in expenses?

A. No. The majority of costs included above support new applications being deployed by the Company, and increases in maintenance costs for existing applications (i.e. increased non-labor expense for software maintenance and licensing fees and software and hardware costs). Certain offsets, such as those described above for Project Compass, have already been reflected in the operating areas where these applications are deployed, and do not provide additional offsets within the Information Services Department.

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

A. Yes.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

JAMES M. KENSOK
Exhibit No. 501

Information Technology Programs

Overview of

Avista's Project Compass

Avista Utilities

August 2013

Table of Contents

VI. List of Attachments

Attachment 1 Depiction of major systems interconnected with Avista's legacy Customer Information System.

Attachment 2 Request for Information for potential reinvestment in Avista's legacy Customer Information System.

Attachment 3 Project charter document for initial work to evaluate options for replacing Avista's legacy Customer Information System.

Attachment 4 Project update presented to Avista's executive steering Committee.

Attachment 5 Request for Information for services in support of the evaluation of options for replacing Avista's legacy Customer Information System.

Attachment 6	List of vendors who received the Request for Information document for supporting System evaluation options.
Attachment 7	CONFIDENTIAL – Scoring results from assessment of vendor proposals, per Attachment 5 & 6.
Attachment 8	Overview document of Avista's Request for Proposals for vendor application solutions and services.
Attachment 9	List of vendors who received Avista Request for Proposals, per Attachment 8.
Attachment 10	Avista Project Compass Guidebook.
Attachment 11	CONFIDENTIAL – Scoring results of the assessments of vendor's solution and services proposals, per Attachment 8.
Attachment 12	CONFIDENTIAL – Final solution evaluation workbook, per Attachment 8.
Attachment 13	CONFIDENTIAL – Voting tallies for final vendor Selections.
Attachment 14	CONFIDENTIAL – Price comparison of final solutions packages.
Attachment 15	CONFIDENTIAL – Final capital budget approved for Project Compass.
Attachment 16	CONFIDENTIAL – Project update for Avista's Board of Directors, February 2012.
Attachment 17	CONFIDENTIAL – Project update for Avista's Board of Directors, September 2012.
Attachment 18	CONFIDENTIAL – Project update for Avista's Board of Directors, February 2013.

I. Summary

Avista Utilities (Avista or Company) is engaged in a multi-year effort to replace its legacy Customer Information System (or System). Research and planning for this effort began in 2010, and the actual work of replacement, which was named Project Compass (or Compass) was begun in May of 2012. The Company's Customer Information System has been in service since 1994, and has been fortified over time by linking it with nearly 100 other software applications and systems to keep pace with evolving information technologies and expanding customer preferences. While this strategy has provided our customers value, the Company has also been mindful that its ability to continue supporting this aging technology is finite. Between 2003 and 2010, Avista and its technology support partner Hewlett-Packard, assessed options for modernizing the legacy system in order to reduce business risks and operating costs while delaying its ultimate replacement. The Company decided in 2010 to commence with the research and planning needed to support the current replacement initiative. During 2011, Avista selected a technology partner to assist in documenting technology needs, and in assessing commercial business applications from leading vendors. Project Compass was formally launched in 2012, and proceeded with Avista's purchase of Oracle's Customer Care & Billing application, IBM's Maximo asset management application, and implementation support from EP2M. A final capital budget was approved for the Project in 2012. The Company and its support contractors are currently engaged in the implementation of these new systems, which involves the complex process of enabling them to support over 3,500 business requirements associated with 200 business processes, and to connect seamlessly with 100 other software systems and applications. In addition, the training programs needed to support these new systems and work processes, are also being developed and tested. Portions of the Maximo application will be enabled in the fall of 2013, and all other asset management and Customer Care & Billing systems will enter service in July of 2014. A final Phase of Project Compass will span a period of 6 to 12 months after the systems are fully in service, to ensure that all technical, training, and process issues that arise are identified, assessed and timely solved.

II. Avista's Legacy Customer Information System

A utility's Customer Information System is one of the most essential business systems enabling the organization's daily operations. For Avista, it supports functions that range from customer calls, to automated service on the phone system or web, access to electric and gas meter information, customer billing, outage management, customer work scheduling and status reporting, ordering construction materials, and managing customer account information. Each of these activities, and many more, is supported by our highly-integrated Customer Information System. Developed in the early 1990's, it's considered a "legacy" System because it relies on key technologies that are no longer manufactured, commercially available, or supported. Like the systems implemented by many utilities of that era, our software applications were designed and developed by Avista staff, and are often referred to as "homegrown." The decisions of companies to 'self build' resulted in part from the then-high cost of commercially available software products, and the desire to tailor systems to their own unique business processes. In 1992, Avista contracted with Electronic Data Services (EDS) to provide enterprise-wide information technology support, including the ongoing development of the Customer Information System, which was placed in service in August 1994.

Architecture of the System

Avista's legacy System is composed of three highly-integrated applications, also known as the Avista "Workplace." As a unified platform, these applications draw information from a common set of master data tables, and form the technology foundation for a network of complex business processes and transactions. A brief description of the applications is provided below.

1. <u>Customer Service</u> – application supports the traditional utility business functions of meter reading, customer billing, payment processing, credit, collections, field requests and customer service orders. In addition, it hosts the single source of customer-related data that is used widely throughout Avista for various other business processes.
2. <u>Work Management</u> – this application supports gas 'trouble' reporting and the electric Outage Management System, and is used to create orders for location services, permitting, and construction jobs, including those requested by our customers and those arising

through the normal course of construction scheduling and operations. In addition, the Work Management system is linked with the Company's Enterprise Procurement System, part of Avista's Oracle e-Business Suite, for the automated ordering and proper accounting of construction materials.

3. Electric and Gas Meter Application – module used to inventory and manage the Company's fleet of in-service electric and gas meters. In addition to hosting the meter data associated with each customer and premise, the system is also used to track each meter and manage the periodic requirements for meter maintenance and testing.

Avista's Customer Information System was developed around then state-of-the-art concepts including 'single source data,' 'subject area databases,' and 'relational databases.' These innovative and powerful tools, based on the 'relational model', organized very large sets of data into a series of normalized tables (or *relations*). Each table represented a certain type of data, such as the street addresses where the Company provided service. Data in these tables could be freely inserted, deleted and edited, and stored much more efficiently than 'linked' databases. In this model, each individual record in every data table was associated with a unique identifier or 'key'. This unique key might represent a single service address contained in the table of address data. But the unique key for this address was also shared by all of the data related to that address that was contained in all of the other data tables. In this way, a service address was linked with all other related data for that address, including such information as the date of meter installation, the meter manufacturer, meter serial number and usage data for that meter, etc.

The System also employed the now ubiquitous 'client-server' architecture. But when implemented in 1994, it was the first utility system in North America to deploy this design. Databases were built and managed for the mainframe platform using IBM's DB2 product, and the application program code was written in the then-mainstream programming language COBOL v2. The COBOL application routines or programs were developed using the CASE tool "ADW", created by Sterling, performed on desktop computers running the IBM OS/2 operating system. The application was designed for the mainframe operating system known as CICS. Another language, Smalltalk, was used to create visual interface for computer screens, and employed the innovative object-oriented programming methodology. Queries of the data tables were enabled by routines written in the language known as SQL. This advanced System allowed the Company's customer service representatives to efficiently access the mainframe applications, and to query, display, edit and manage data in object form on their desktop computer screens.

Keeping Pace with Change

The Customer Service and Electric & Gas Meter Applications were enabled in 1994, and development of the Work Management System application quickly followed. Avista's Workplace was initially integrated with three other business systems, as depicted below in Figure 1.

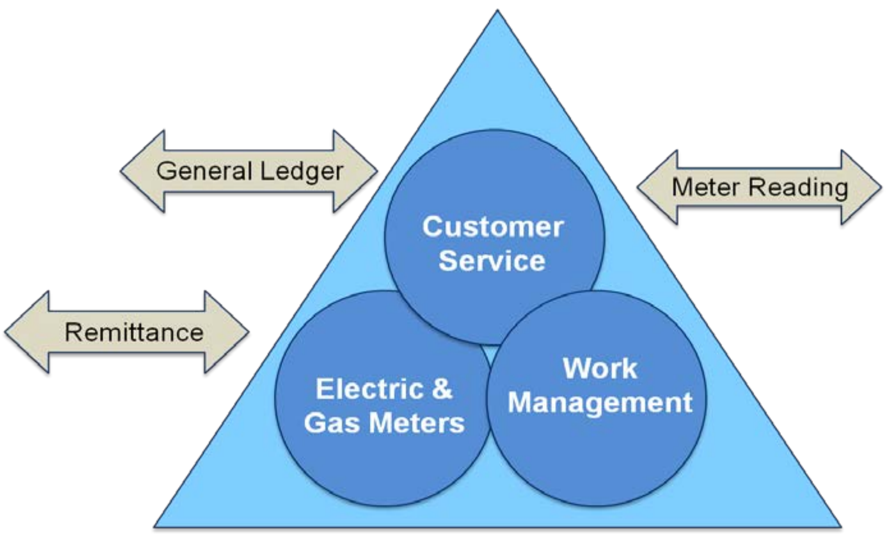


Figure 1. A simplified graphic representing the initial configuration of Avista's legacy Customer Information System, showing the three primary applications and integrated systems.

Change to the System came quickly, however, as wave after wave of new information technologies (such as automated phone systems, powerful mid-range computing platforms, and customer web portals) enabled an evolving stream of new customer service functionalities, embedded as standard features in each new generation of applications developed by leading global vendors. As consumers grew accustomed to these service options in their interaction with a wide range of other companies, they began to expect these types of services from their utilities. Avista worked to accommodate these developments, and in addition, added many features to its System to reduce internal costs by automating paper functions, redesigning work-processes, and providing self-service options for customers. This expanded functionality (such as payment by phone) was accomplished by ‘integrating’ the legacy System with the emerging applications and systems that enabled these new capabilities.

An ‘integration’ refers to the sharing of data between computer applications when more than one is required to complete a process. In early integrations, data from one application was sent directly to another application in a direct link known as a ‘point to point’ integration. The integration relied on a custom computer program to translate the data format and computer language of one application into a form that could be input into the other application for processing, and vice versa. This function allowed the two applications to communicate and work in concert to perform a joint function. Many businesses shared this need to extend the capabilities of the limited architecture of their information systems, and this demand gave rise to an entirely new software product family known as “Middleware.” These applications provide communication and management of data for distributed software applications beyond those available from the computer operating system itself. Using a Middleware product known as ‘Biz Talk’, the Company was able to cost-effectively expand the efficiency, capability and functionality of its legacy System, by integrating new commercial off-the-shelf software, internally developed custom applications, and the application systems of third-party service providers. For both customers and employees, this approach seamlessly integrated technologies far beyond the boundaries of the System’s original design limitations. When the System architecture was designed, home computers were uncommon, the internet was in its infancy, there were no e-mail services, no automated phone system, few cell phones, no text or SMS messaging, and no mobile computing, as supported by today’s smart phones and tablets. Some of the major applications and systems now integrated with Avista’s Workplace include the following:

- Enterprise Voice Portal – this automated telephone system supports a range of self service options for customers, as well as voicemail and other functions used by those contacting the Company and for internal Company operations.
- Mobile Dispatch System – this application supports the call out and scheduling of Avista’s gas and electric servicemen, and other field staff required to support Company operations.

- Avista Facilities Management – this application houses the Company's Geographic Information System. In addition to map data, it includes all the Company's electric and gas facility maps and other geographic data.
- Automatic Meter Reading – this system gathers meter-reading data from the Company's fleet of AMR-equipped meters in Avista's service territories in Oregon, Idaho and portions of Washington.
- Construction Design Tool – this application supports the Company's computer-based design tool for gas and electric construction projects, the automated input of component assemblies, materials ordering, and cost accounting.
- Outage Management Tool – this application uses Avista's electric Facility Management and mapping data, in conjunction with electric system device and circuit intelligence, to determine the likely source of a reported outage, to display the likely size of the outage, and to automatically dial affected customers as well as automatically posting outage information on our customer web portal.
- Mobile Web Application – this application hosts our customer's access of Avista's web portal using smart phones and tablets.
- Electronic Check Payment – this family of applications belongs to banks and third-party service vendors used by the Company to support payment options for customers.
- Contract Billing – this family of applications supports services such as customer account management, bill printing, mailing and remittance processing.
- Customer e-mail Support – applications that host e-mail services for our customers, and provide support applications and services.
- Meter Data Management – this recently integrated system provides the data-storage and management capability to enable 'smart metering' capabilities such as customers' real-time use of energy.
- Smart Grid Pilot – this portal provides access for Avista customers participating in the Company's Smart Grid Demonstration Project.
- Avista Web Applications – this system of applications supports the Company's internet website, Avistautilities.com, and enables customers to access and manage their account information held in the Customer Information System.

- Avista's Oracle Financial and Enterprise Procurement Systems – these enterprise applications support the breadth of the Company's financial and reporting systems, as well as a host of enterprise supply-chain functions.

Prudent investments in our legacy system over the past 20 years have allowed us to deliver consistently-high levels of customer service across an expanding range of service channels and self-service options. In place of its initial three modules and three system integrations, the current System supports nearly 200 business processes, and includes approximately 100 integrations with other specific applications and systems, as depicted in simplified form in Figure 2, below. A more complete depiction of the interconnection of major systems is provided as Attachment 1.

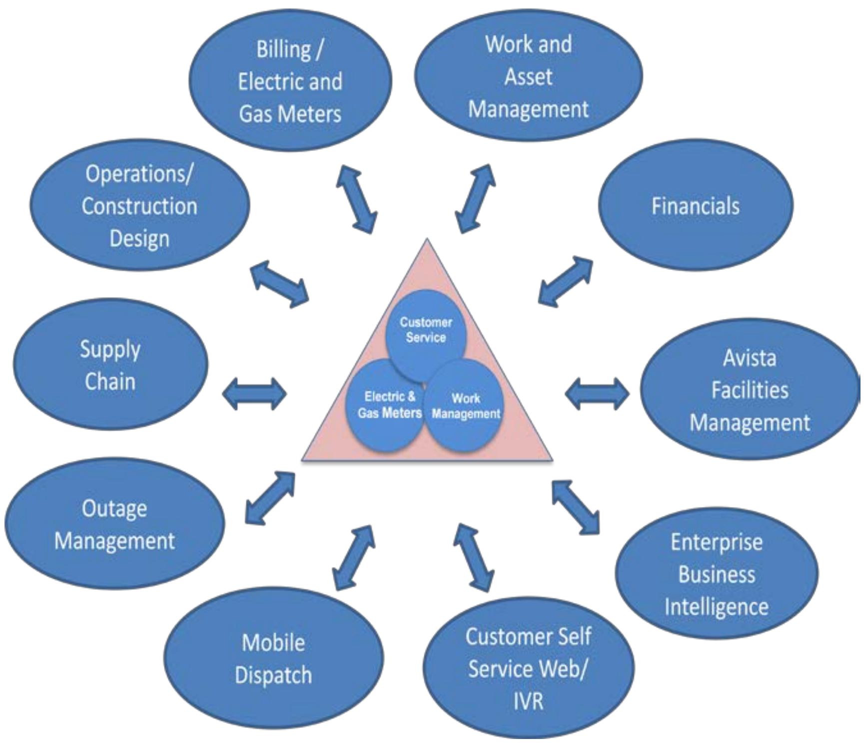


Figure 2. A simplified graphic representing the integration of Avista's legacy Customer Information System with other major applications and systems.

Additional Benefit of Extending the Life of the Legacy System

Avista has invested in its Customer Information System, principally because we could add functionality and value to better serve customers for relatively small incremental investments. But, importantly, this approach also allowed the Company to 'skip over' successive generations of technology platforms, many of which are being replaced by our peer utilities today as they install new contemporary systems. In addition, the Company was able to evaluate the experiences of other utilities engaged in replacing their systems, as one way to support the design of a best practices project. Extending the life of its legacy System has allowed the Company to avoid the significant investment of replacement, and to acquire replacement systems later in the evolutionary trajectory of the technology, giving it broader and more standardized capabilities, and a likely longer future service life.

III. Drivers of the Need for Replacement

As described above, our legacy System meets the basic needs of our stakeholders today because we've made managed investments to extend its value, cost effectiveness and service life. But while there has been incremental and long-term benefits associated with this strategy, there have also been less-obvious but important costs and business risks accumulating with time as the technology platform ages. These latter costs and risks can compete with the benefits of extending the service life, and the Company has remained aware of the inevitability that our core legacy System and the very-complex "patchwork" of integration programs supporting other applications, would have to be replaced.

The Role of Technology Evolution

Over the past twenty years, the rapid evolution of information science technologies has impacted the life-cycle availability of aging software and hardware products and services, and it has enabled significant improvements in consumer service capabilities in each new generation of commercial applications. This rapid cycling of product and service innovation has eroded the foundational integrity of Avista's legacy technology. And at the same time, it has pressured us to continue adding on functionality well beyond the design capabilities of our legacy System.

A Familiar Example

As a way to illustrate the impact of these technology forces, consider a parallel evolution in personal music players. In 1980, Sony introduced the revolutionary and highly-successful Walkman cassette player. Cassette tapes were then dominant, but by the mid-1980s, the Walkman was redesigned for the new format of compact discs (CD). By 1990, cassette players began to disappear from store shelves as personal CD players were continually improved. But, like the cassette tape before, the CD personal music player was doomed when Apple introduced the iPod in 2001. And for some time now, the supremacy of the iPod has been undermined by the iPhone and other smart devices that can store and play music files, but in addition, can access music via web streaming or files stored in the computing cloud.

Today, a person might still use a Walkman to listen to music on existing cassette tapes. But to maintain and expand a cassette music library, requires several electronic components forming a ‘chain of technology’ that’s no longer mainstream. Though cumbersome (by today’s standards), it’s still possible to perform the steps required to record a new tape, so long as each piece of equipment in the technology chain is working. And the incremental cost is small, compared with the alternative of replacing the tape library with digital files purchased from iTunes. At some point, however, the old equipment will fail. And, because it’s no longer mainstream, it will be progressively more difficult and expensive to repair. Even the most ardent cassette person will probably reach the point, where the cost, complexity and limitations are enough to overcome the inertia of reinvesting in a new music platform.

Avista’s Chain of Legacy Technologies

The complexity of the technology chain supporting the Company’s legacy System is similar in many ways. The key areas of vulnerability and challenge have to do with older computer hardware and operating systems, computer applications and programming languages, and the availability of qualified technical and development support, as briefly described below:

Hardware – As mentioned, our System is based on a mainframe computing platform. This is because when the system was designed and launched, only mainframe machines had the computing horsepower required for its operation. Even though smaller computers have the necessary capabilities today, the legacy System databases and program applications are entirely mainframe dependent. In addition, the development application used for making programming changes to the Company's System, runs on IBM's OS/2 operating system that has not been sold or supported for many years. And the computers that were matched to the OS/2 operating system haven't been manufactured for a similar time. For several years after the hardware and operating system were discontinued, Avista bought used computer components (some from e-Bay auctions) that were matched with OS/2. More recently, however, the Company uses specialized software that runs on contemporary desktop computers to "emulate" the OS/2 operating system. This workaround allows the Company to execute its OS/2-dependent software applications in a "virtual" OS/2 environment.

<u>Applications and Computer Languages</u> – The legacy software application is the 'computer program' that runs and maintains our legacy system databases, and enables all the features required to support our business processes. These applications are written in the computer language, COBOL v2, which for many years has not been sold, supported, or used in programming applications. This version of COBOL, which we refer to as 'native' COBOL, is also no longer compatible with contemporary mainframe operating systems. To work around this, the Company has for many years used another specialized application, Micro Focus COBOL, to compile the native COBOL language into machine language that is a virtual replication of a more contemporary version of COBOL, which is then able to run on the mainframe operating system. While the virtual COBOL replication has a very high degree of fidelity with the native COBOL, it relies on a visual replication that sometimes results in transcription errors. While the error rate is low, there are millions of lines of computer code that are re-created during the compiling process. The system must be tested to detect these errors, which then requires additional programming time to locate and repair them. More recently, there is a concern that the machine language created by Micro Focus COBOL may not be able to run on newer mainframe operating systems, which now run COBOL v390.

Avista's legacy software applications are almost constantly being repaired, modified (to comply with new requirements), or upgraded with new functionality or capabilities. To accomplish these operations requires use of a CASE tool application known as Application Development Workbench, or ADW. CASE tool applications, whose use peaked in the early 1990s, are tightly coupled with mainframe programming languages; they enable and help-automate the process of generating (writing) code in the native COBOL language. The company that produced ADW is no longer in business, and Avista's application is neither produced nor supported. In addition, ADW can only run on the desktop machines using the emulation software to create a compatible OS/2 operating system. Once the coding changes are made in native COBOL using ADW, they are then compiled using the Micro Focus COBOL application.

Another computer language that's key to sustaining Avista's legacy system is known as Smalltalk. The language is used to create routines or programs that enable many key functionalities of Avista's system, including 'rendering' the display screens customer service representatives use to view and manage customer and system data. Rendering is the conversion of lines of computer code into a visual screen display, which not only allows the user to see account information, for example, but to also make changes to the data or information contained on the rendered screen. This functionality is utterly everywhere today, such as the displays on your smart phone, but it was a very innovative application when designed into Avista's system the early 1990s. And, Smalltalk was the leading programming language of its type in that day. Although this language is a very flexible and powerful tool, it is no longer mainstream, and is no longer sold or supported. Many versions of Smalltalk are still in use among small communities of users in the computer industry, but the language is no longer taught in computer curricula and there is no formal training for new programmers.

Finally, the Company's customer service and system data residing on the mainframe platform must be updated every night in what is known as a 'batch' program. The batch updates the data tables to reflect changes in account status made during the day, and to perform other functions using the data, such as producing customer bills. Like the COBOL routines that enable the interactive use of the Customer Service application (described above), separate COBOL routines are required to perform these batch functions. There are approximately 3,000 individual COBOL programs and millions of individual lines of code in the legacy System. The management, repair and modification of these native COBOL programs can only be performed using the ADW and Micro Focus COBOL applications to both modify and compile them.

People – Maintaining our legacy System requires us to train and maintain technical staff competent in these older programming languages and computer operating systems. This is becoming more difficult as the availability of business analysts and application developers who are familiar with these languages and technology becomes more limited each year. This attrition of skilled developers makes it very difficult to replace members of Avista's support team, many of whom grew up with this technology when it was new, and who either have retired, or are anticipated to do so in the next few years. Since there is no longer technical training or schooling available for these old languages and systems, the Company must train developers in house, which requires a considerable investment to achieve proficiency. It's also difficult to channel younger employees into career tracks that have very-limited and diminishing future application. As a consequence, the need to find, train, and maintain capable technical staff adds another layer of complexity, cost and risk to the maintenance of these legacy Systems.

Other Legacy Considerations

Each of the elements above focuses on an aspect of the Company's System that poses a level of risk greater than that associated with contemporary hardware, operating systems, technical support, and business applications. Avista's situation is not unique, however, and illustrates the general technology principle shared by many legacy systems: that even though they may require complex workarounds to perform their intended functions, which many can do adequately, they are subject to elevated levels of risk that only compound with time. In addition to increasing business and customer service risk, there are other considerations associated with the maintenance of legacy systems like Avista's.

Cost of Modifications – In addition to the risks associated with outdated technology, the System is difficult to modify to add new functionality. This arises because the linkages connecting the applications of Avista's Workplace, along with the Middleware that connects Workplace with the other applications and systems, are 'hardwired' together. Unlike contemporary enterprise applications, when a programming change is made to one of Avista's applications it requires complimentary programming changes to both the connecting Middleware and the other applications themselves. Because the system has been stretched over time so far beyond its original design considerations, these layers of changes have geometrically increased the complexity of the entire system. Each new modification must be adapted to this complexity, and at the same time, it adds to the complexity. Additionally, because the legacy System is used only by Avista, the ongoing application development costs must be borne entirely by our customers.

Ultimate Cost of Replacement – As Avista added new capability to its legacy System, as described above, this required 'programming' to modify the software applications to enable the business processes supporting this new capability. When the legacy System is replaced, the new applications must be 'programmed' to support the same integrated systems and business processes. Generally, then, as the number of integrations in the legacy System increases, so does the cost, complexity and the degree of sophistication required to install the replacement system.

Platform for the Future – In addition to the costs and risks of extending the service life of Avista's legacy system, and the complexity and cost of adding functionality, its ultimate capability has been largely exhausted. The System was designed as a meter-based billing system that provided the Company an efficient and cost-effective platform for managing a customer's basic transactions. In this respect, the system is more 'business centric' because it was designed around the transactional needs of the business. This is not surprising, though, since at the time the System was developed, the transactional convention consisted of customers receiving a paper bill, which they paid with a personal check sent by mail, or in person at one of Avista's offices. Utility customers, generally, had no expectation of being involved in energy choices or service options, which likewise, were rare. Today's information technologies and the market demands for service differentiation have swept aside the business-centric service model and placed the 'customer centric' model front and center. Consumers today have an ever-increasing expectation of being able to conduct business with all manner of companies in ways they, the customer, prefer (e-mail, text, chat, phone), at the time they determine to be convenient (24 x 7 x 365), and to have one point of contact to seamlessly, quickly and efficiently meet all their needs. As capably as Avista's System has performed in the past, it simply does not have the fundamental capabilities required to provide customers the service options they have come to expect in the customer-centric marketplace. In addition, the legacy system cannot support the newer utility product offerings becoming more familiar to customers, such as real-time information management, pre-pay options and time-of-use metering and billing. Some enhancements viewed by customers today as “basic service” (e.g. text messaging or selecting their preferred mode of contact – phone, text, SMS or e-mail), simply cannot be accommodated.

Summary of the Limitations of Avista’s Legacy System

The Company’s legacy System is dependent on expensive mainframe computing platforms, even though today’s mid-range computers have the capability needed to support the applications. It also depends on many obsolete technologies that require complex workarounds to function properly. And the workarounds themselves depend on obsolete systems and applications working properly in concert to enable them. As a consequence, maintaining the system involves risk that grows as the technology ages, and requires expert staff and trained contractors who remain competent in these archaic technologies. Making changes to the System is complex, burdensome, and expensive. But unlike the inconvenience of having to repair a broken cassette player , Avista’s system is the hub of business operations for over 600,000 customers, and it must operate flawlessly on a continuous basis. Finally, though the System still operates adequately, there are finite and insurmountable limits to its ultimate ability to provide the technology platform that’s needed to serve our customers today and into the future.

Options to Extend the Service Life of the System

Periodically, Avista and its support partner, EDS/Hewlett-Packard, have evaluated the System’s capabilities as well as options for its possible modernization. The potential scalability of the Customer Information System was assessed in 1999 to determine the feasibility of expanding the number of customers that could be served with then-current applications, processes and technical infrastructure. The results of this work titled “Avista Workplace Application Scalability Assessment,” indicated that with certain investments, the system would be able to support up to 1.5 million customers. As the number of customers served by Avista continued to grow at generally-historic rates, the system investments needed to support greater scalability were neither needed nor made. In 2002, as some of the technologies supporting Avista’s System, such as ADW, were becoming unsupported, an assessment was made, titled “Avista Application Migration

Review", of the feasibility of moving the Company's system from the mainframe platform to a contemporary mid-range platform and operating system. The benefits of such a process, commonly known as 'replatforming', were forecast over time and were compared with the estimated costs for completing the work. Results of this work indicated that replatforming the System at that time was not cost effective, and as a result, this work did not proceed. The next assessment was made in 2003 and focused on ways to reduce the risk associated with the ADW application then running on aging desktop computers using the IBM OS/2 operating system. The project report, titled "ADW Conversion", recommended Avista purchase the specialized software to emulate the OS/2 system on contemporary computers and operating systems. This recommendation was implemented. The legacy System was reviewed again in 2006 as part of a larger information technology review conducted for the entire Company. The report, titled "Preliminary Applications Rationalization Assessment", addressed the overall rationalization potential across the Company, and identified any 'modernization' opportunities for specific applications. The term "rationalization" refers to an information technology discipline that's aimed at reducing the ongoing costs of maintaining overlapping or redundant software systems across the whole of the business. The report noted the Company's Customer Information System as a 'high risk' application that was a candidate for either replacement or "refactoring." The latter refers to a process of changing the internal structure of the existing application code to reduce its complexity and improve its readability. While this process helps reduce the risk associated with legacy software, it does not fundamentally change its basic properties or architecture. Refactoring the Customer Service System was assessed as not having sufficient benefit, and the Company was not ready to replace the System. Most recently, in 2010, the Company again reconsidered reinvesting in its legacy System as means to delay its ultimate replacement. As a prelude to requesting vendor proposals to support such an effort, the Company sent a Request for Information to several major information technology vendors to describe the legacy System, and to gauge their interest in participating in possible next steps. A copy of the document, titled: "Request for Information for Avista Workplace Revitalization Project" is attached to this report as Attachment 2. As Avista continued to weigh the possible feasibility of this approach, it ultimately determined that commencing with the research and planning for the current replacement project was the prudent course of action.

Timing of the Replacement

Avista's decision to replace its legacy System involved a number of considerations, many of which have been described above. Considered in concert, these helped shape the decision to commence with the research and planning necessary to support this effort:

- Confidence that Avista could operate the legacy system without fail through at least 2014, without any significant upgrades to older technology. This timeframe would accommodate the period of research, planning, design and implementation of a replacement project;
- Avista expected to have a limited window of availability for the employee and contract technical resources necessary ensure the proper functioning, maintenance, repair, and upgrades of the legacy system expected through 2014;
- The pending need to determine whether or not to renew the long-term (ten years) services contract with Hewlett – Packard for the ongoing mainframe capability, and the maintenance and operations support for the legacy system. The end of the then-current contract presented a window of opportunity for replacing the legacy system;
- The experience that the Company had practically tapped the capabilities of its legacy system, whether or not it was operating on contemporary computer hardware and software;
- The concern that business and service risks associated with the legacy system were continuing to accumulate with time;
- The continuing assessment that as new functionality was added to the legacy system, it was driving geometrically-increasing complexity, and likely greater ultimate replacement costs, and
- The knowledge that the legacy system would not have the capability to deliver some of the service and billing options our customers desired, or service and work-process options.

IV. Planning for Replacement of the Legacy System

Replacements of Customer Information Systems are Common

Nationwide, many utilities have undertaken the same journey in replacing their own legacy

Customer Information Systems, and many are replacing systems installed around the year 2000, a 'generation' newer than Avista's System. Several utilities in the Northwest are among those engaged in some phase of a major replacement project. Avista's understanding of the status of these efforts is summarized below:

Company	State(s)	Status
Cascade Natural Gas & Intermountain Gas	OR/WA/ID	Currently using Oracle's Customer Care & Billing application in Oregon and Washington, which replaced their prior system installed in 1999. Planning to install this system in their Idaho service area in late 2014-2015.
Northwest Natural Gas	OR/WA	Currently using commercial system installed around year 2000. Now in the process of evaluating potential for upgrades and/or system replacement in near future.
Puget Sound Energy	WA	Recently placed in service new SAP and Outage Management applications in April 2013. Now engaged in system stabilization.
Portland General Electric	OR	Beginning evaluation phase for the replacement of their customer information and meter data management applications, expected to be completed in next 5 years.
Idaho Power	ID	Planning to place in service a new SAP customer information system in September 2013.
PacifiCorp	ID/OR/WA	Currently evaluating systems for possible installation over the coming five years.
Seattle City Light	WA	Engaged in the early installation work of their recently selected Oracle Customer Care & Billing system.

These Projects also Present a Significant Challenge

Replacing a customer information system is a major undertaking for any corporation. And, it's particularly complex for an integrated business, such as a utility, that manufactures it own products, constructs and maintains its own distribution and delivery infrastructure, and that often sells more than one energy product in the highly regulated markets of sometimes multiple state jurisdictions. The degree of interconnectedness of the customer information system with the many other business systems and applications supporting the enterprise, is a key driver of the challenge. In addition to the complexity of these systems, there's significant workload associated with the steps of planning, evaluating, selecting, implementing and testing the new systems, as well as training employees and informing customers in time for a smooth transition. In addition, successful projects have a high degree of executive engagement and commitment, superb information technology competence, a deep knowledge of the company's work processes – both current and potential future states, and proven experience with the implementation of enterprise information technology projects. The confirmation of these challenges lies in the failure rates reported for these projects, in the range of 40% to 60% over the past five years. In these cases, "failure" was judged as a project that was either abandoned, or that failed to substantially meet its project goals – in terms of cost, solution expectations, implementation timeline or operational readiness.

Identifying Common Challenges

As part of its initial project research, Avista contacted several utility peers who were in various stages of the process of implementing new customer information systems. In an effort to evaluate their preparation, approaches and performances, Avista conducted in-depth interviews to gather lessons learned from these utilities, which included El Paso Electric, San Jose Water, Green Mountain Power and Los Angeles Department of Water and Power.

In addition, the Company took advantage of shared industry knowledge related to the changing demands being placed on utility customer information systems, the maturation of technology solutions, and project audits[1] that assessed root causes of the failure to successfully implement new systems. What emerged from that collective work was a pattern of challenges that had caused many projects to be less than successful. Taking advantage of the opportunity to learn from the experience of others helped Avista prepare, with eyes wide open, for the challenges of replacing its Customer Information System. Some of the central issues the Company and others identified as problematic are included in the list below.

1. Executive involvement that was either distant or faded over the term of the project.
2. Sponsorship of the project that was weak or diffused because there were necessarily so many departments involved in the project.

[1] Focused Management and Operations Audit of Kentucky Utilities Company and Louisville Gas and Electric Company. Final Report presented to The Kentucky Public Service Commission. Liberty Consulting Group, September 12, 2011.

Performance Audit of the Customer Care and Billing System: Testing Prior to Go-Live. Office of the Auditor, Austin, Texas. September 21, 2011.

3. Project management that lacked the applicable experience and strong skills needed to establish a realistic, comprehensive and sustainable plan for the administration of such a large and complex information technology project.
4. Expectations established too early in the project for the ultimate project cost, scope and timeframe, which rendered them unachievable.
5. In spite of the involvement of many departments, project leadership that was often ‘tilted’ toward either the information technology aspect or the business processes.
6. Research to identify best practices and peer-lessons learned that was either inadequate or ineffectively built into the project.
7. Inventory of business requirements that was not complete or that lacked sufficient detail.
8. Business requirements that were not effectively translated into a complete understanding of the application capabilities required to support them.
9. The expertise and effort needed to perform comprehensive evaluations of vendors and their proposals, related to due diligence, project scope and confirmation, was insufficient.
10. Selected vendor solutions often were not complete without additional customized development, which drove added complexity and costs.
11. Implementation support from third-party contractors that had little familiarity with the systems being purchased from the software vendors.
12. Inadequate code testing by the vendor prior to installation in the utility environment.
13. Test environments that did not fully replicate production.
14. The tendency to customize the product solution to better match the existing business processes of the organization, rather than working to implement the solution as designed.
15. An organizations’ resistance to re-design work processes to comport with the architecture of the new solution.
16. Inadequate test team involvement.
17. Inadequate training, education and organizational change management programs to help employees accept and perform competently in new work processes and systems.
18. Going Live with the new systems before the business was fully prepared and production ready.

Designing the Project Around Best Practices

While alarming in some respects, the challenge experienced by many utilities is also not entirely surprising. The process of selecting and implementing a new customer information solution is complex enough by itself, but it is also commonly joined, like Avista's, with the implementation of new asset management or other software systems, and many other work processes. It's also outside a utility's core competency, and it can occur only once in a generation. The degree of challenge and failure has, not surprisingly, given rise to a range of business services whose purpose is to reinforce the capabilities of companies like Avista in the technical and project management skills identified as areas of potential weakness. Avista selected several of these specialized vendors as part of its application selection and implementation processes. Some of the key project-design decisions made by the Company are listed below.

- Established a steering committee of senior executives, meeting monthly with the project directors, to provide executive oversight on all aspects of the design and implementation of the replacement project.
- Made the executive decision to implement what is referred to as "off the shelf" vendor applications, with a commitment to minimize the number of Avista-specific customizations. This approach, while it demands that significant changes be made to the Company's existing business processes during the replacement, helps ensure our customers benefit from the periodic application updates to be provided by the vendor without bearing the cost of the additional software programming that would otherwise be required to accommodate the volume of customized computer code. This approach, which is more mainstream today, is diametric to the approach common when the Company's legacy System was designed and built in house and was carefully tailored over the years to match our existing business practices.
- Created an Avista project leadership structure with two co-directors serving as executive leaders of the effort: the director of customer service, representing the Company's business processes, and the director of application systems programming, responsible for the information technology aspects. The intent of this structure, although potentially ungainly, was to overcome a common failing of projects to 'overweight' one aspect of the project to

the detriment of the other. In addition, both project managers are dedicated full time to Project Compass.

- Hired an outside expert in change management as a Company employee to work full time developing and implementing a communications and change management plan for the project. Avista learned this function was critical to successful companies' efforts to substantially change work processes that accompanied the adoption of off the shelf applications.
- Hired an outside firm to assist the Company in developing a solutions Request for Proposals, in soliciting, comparing, and evaluating proposals from an array of options and potential vendors, and in selecting and purchasing the vendor applications. In Avista's research, this was an area of key challenge for utilities because even the process of understanding the totality of its 'business requirements' was a barrier, let alone the challenge of assessing whether a vendor's application had the full capability to support these requirements.
- Ensuring the vendor selected for supporting the implementation of the customer service and asset management applications, and in seamlessly linking them together, had direct experience and extensive familiarity with the applications selected.
- Retaining an outside project manager with significant expertise and experience implementing enterprise-wide utility software applications – being assigned the broad responsibility for the overall implementation process, including the coordination of project leaders representing the vendor applications selected and those who would be selected for quality assurance monitoring and system testing.
- Identifying and securing the full-time participation of key employees who would be needed full time for the project.
- Securing dedicated office space located away from the distractions of Avista's day-to-day operations, and having ample office and meeting space for all project leaders, employees and contractors associated with the project.
- Retaining the services of an outside firm specialized in creating training programs for new systems, development of the curricula, training the trainers, and evaluating the effectiveness of the training effort.

- Planning for an employee communication program that would be part of the foundation of the Company's change management effort for Project Compass.
- Anticipating the service changes that would arise for customers associated with the new System, and planning for the communications effort that would accompany the Go-Live.
- Waited to establish a final project budget until the planning, preparation and scope had been well enough defined to successfully manage the project.

The Initial Project Plan

The Project was envisioned to be completed over a four-year time horizon, with a substantial effort dedicated to pre-project research and planning. Figure 3, below, depicts the high-level activity phases of this initial plan.

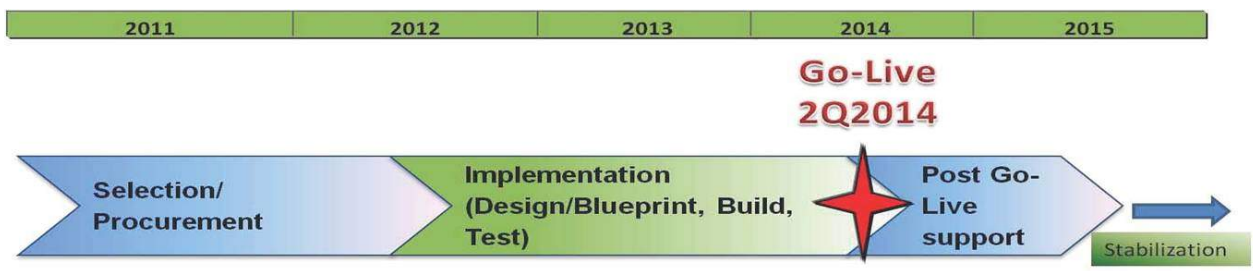


Figure 3. Depiction of the high-level phases of activity envisioned for the Project to replace Avista's legacy Customer Information System.

The first Phase of the Project, known as "Selection/Procurement," encompassed the activities of mapping Avista's business process needs and developing the detailed business requirements for requesting and evaluating alternative sets of software and system solutions that would best meet those needs. This Phase would conclude with the Company selecting the optimized solution set, negotiating final pricing, and signing the purchase agreements with vendors.

Known broadly as "Implementation," Phase 2 encompasses the complex activities of installing and configuring the new vendor software, testing the new systems, and developing and delivering the specialized training modules for the new Systems. 'Configuring' a software application involves the programming required to code its generic capabilities to execute the steps needed to match each of the Company's work processes. In addition, there are many Avista process steps that cannot be executed within the generic capability of the new applications, without customization. This involves the addition of customized programming that is outside the bounds of the 'off the shelf' capability of the application. Significant customization renders the process of installing the periodic vendor updates of the applications, both complex and expensive. Avista is committed to capturing the value delivered by 'off the shelf' implementation, and accordingly, our goal is to minimize the need for customization. What this requires, however, is that Avista organize employee teams to accomplish the significant tasks of developing new internal business processes that can be supported by new application. There is also a significant volume of work required to perform the 'programming' to integrate the new vendor applications with the approximately 100 other applications and systems required to support the Company's customer service and allied business operations. This Phase of the Project also encompasses the development of employee training programs and systems for the new applications, and the extensive testing of the system needed to confirm the technical performance of the new applications as configured to Avista's design. Finally, this Phase concludes with the step of placing the new Systems into service, the "Go-Live."

The third Phase, known as "Post Go-Live Support," encompasses the activities associated with supporting the in-service deployment of the new systems. Key activities include development of contingency plans to respond to issues that may arise during the Go-Live, and providing technical support for the new systems in the period referred to as "system stabilization."

V. Evaluation of Replacement Options

Assessing and Selecting the Replacement Applications

An early step in the work of Selection/Procurement was development of a project charter, which is included as Attachment 3, and outlines the high-level work objectives, some of the key deliverables, and authorizes an expense budget to support these activities. A presentation made to the executive steering committee in April 2011, includes a partial listing of the Project drivers, highlights of Avista's Project research, some key elements of the Project design, planned next steps, and some very-preliminary Project capital costs. This presentation is included as Attachment 4. Later in 2011, the Company named this effort, “Project Compass.”

The next key step focused on selecting and retaining a firm to support Avista in developing the following work products:

1) Complete inventory of Avista’s technical business process requirements;
2) Inventory of the types of business process decisions to be made;
3) Gap analysis;
4) Request for Proposals document for technology solution providers;
5) Normalized evaluation and vetting of vendor proposals;
6) Selected preferred solution set, including due diligence and scoping;
7) Formal purchase offer for acquisition of vendor services, and
8) Negotiated final purchase price for applications and integration services.

Avista developed a Request for Information to document the services of interest and to gauge the interest of candidate firms, which is included with this report as Attachment 5. The list of firms is provided in Attachment 6. The Company solicited, reviewed and scored proposals from the participating firms, and a summary of the scores used in making the selection is included as Confidential Attachment 7.

Avista selected Five Point Partners (Five Point) to support its Selection/Procurement activities. Among other criteria, the Company placed emphasis on their proprietary ‘STAR’ methodology for identifying every type of major business process requirement that Avista would need from solution and application vendors to support its future business operations. This ‘requirements’ definition allowed the Company to develop a detailed and specific Request for Proposals from candidate solution providers. Understanding the detailed requirements translated to a more complete understanding of the complexity and cost of the solution sets, as well as understanding up front the activities and applications that would be required for successful implementation, including their costs, and foreknowledge of what parties would be responsible for the associated workload and costs.

Establishing Review Criteria

Global criteria were developed and vetted for use in evaluating vendor proposals. These criteria included: 1) Functionality; 2) Technology; 3) Implementation Partner, and 4) Cost. With the help of Five Point, Avista used the inventories of its business process and decision types to create the Request for Proposals from candidate solution vendors. The solicitation packet was reviewed and refined in several rounds and sent to vendors on September 28, 2011. An overview document of the Company's Request for Proposals for CIS (customer service) and EAM (asset management) solutions, is provided as Attachment 8. A list of vendors who received the Company's solicitation is included as Attachment 9. An initial step in the vendor's process of evaluating and responding to Avista's proposal solicitation was a conference call opportunity to ask Company representatives detailed questions about its current and anticipated business practices, processes and systems.

Supporting the Application Scoping, Review and Selection Process

During the process of developing its Request for Proposals, Avista launched a parallel effort, known as 'current state mapping', needed to support the design of the Project. This is a comprehensive inventory and evaluation of each of Avista's existing customer information system work processes and system requirements. The purpose of this work was to clearly understand, from a global perspective, every single work process in the business and the applications and systems involved in supporting those activities. In Avista's view, the current state represented a picture of how custom-designed and integrated information technology solutions had been introduced over time to support the Company's legacy service paradigm and work processes. The current-state map included over 200 work processes and over 3,500 individual process steps or system requirements. These process steps represented the necessary technology functions required to support the existing business processes. While these 3,500 requirements were much too detailed to be included in the Request for Proposals, the Five Point STAR process did identify the solution capabilities the vendors would have to meet in order to support Avista's future requirements and business operations. A summary document prepared by Avista, titled "Project Compass Guidebook", is included with this report as Attachment 10, and provides a detailed overview of the complex activities required to support both the procurement of application and service vendors, as well as the detailed process organized to support and execute the current state mapping.

Application Proposals Received from Vendors

Avista received responses from vendors on October 28, 2011, and with the help of Five Point, immediately began the review and evaluation process. The table below lists the vendors who responded and the solutions and roles they proposed for delivering a solution set to Avista.

Vendor	Product or Service Offering	Customer Information System Application	Enterprise Asset Management Application	Mobile Work Management Application	Other Vendors
IBM	Systems Integration	**SAP** Customer Relationship & Billing (CR&B)	**SAP** Enterprise Asset Management (EAM)	**ClickSoft** Mobile Work Management (MWM)	---
IBM	Systems Integration & Software Applications	**SAP** CR&B	**IBM** Maximo Asset Management	---	---
EP2M	Systems Integration	**Oracle** Customer Care & Billing (CC&B)	**Oracle** Asset Management	**Oracle** MWM	---
Wipro	Systems Integration	**Oracle** CC&B	**IBM** Maximo	**Ventyx** Service Suite	---
HCL AXON	Systems Integration	**SAP** CR&B	**SAP** EAM	**ClickSoft** MWM	Technology Associates
HCL AXON	Systems Integration	**SAP** CR&B	**Meridium** Asset Management	**ClickSoft** MWM	Technology Associates
HCL AXON	Systems Integration	**SAP** CR&B	**IBM** Maximo	**ClickSoft** MWM	Technology Associates
Sparta	Integration Services	**SAP** CR&B	**SAP** EAM	**Ventyx** Service Suite	Vesta Partners
Logica	Software Application	---	**Logica** Asset Management	---	---
Meridium	Software Application	---	**Meridium** Asset Management	---	Partners with Wipro
HPES	Systems Integration	---	---	---	General Services Only

Most of the responding vendors proposed a complete solution, which included three applications: customer service; asset management; and mobile work management. These vendors, including IBM, EP2M, Wipro, HCL AXON and Sparta, proposed to deliver the complete solution through the primary service known as Systems Integration. This involves the installation of system software applications that are developed and sold by leading global software companies such as SAP, Oracle and IBM, and the integration of these software applications with the other information and process systems of the Company. One vendor, IBM, proposed options where it either provided systems integration services for the software applications of others, including SAP and ClickSoft, or a package that included its own software application (Maximo). HCL AXON proposed to deliver a complete solution set from three options that included various combinations of software application systems. Two vendors, Logica and Meridium, proposed to deliver and install only their own software applications, and one vendor proposed only installation and integration services (no solution applications).

Evaluating the Proposals

In its initial review, Avista's Project Compass team and Five Point evaluated and scored each proposal according to more-detailed criteria, grouped under the four global Project criteria, as represented below:

1. Functionality

a. Minimum Requirements – Degree the solution vendor met the minimum functional capabilities established by Avista. A scoring sheet for this portion of the evaluations is attached to this report as Confidential Attachment 11, pages 1 - 3.

b. Project Drivers – Degree to which the proposed solution met the system requirements identified in Avista's STAR analysis. Scoring sheets for this portion of the evaluations are attached to this report as Confidential Attachment 11, pages 4 - 21.

c. Customer Service Fit – Measure of the functionality of the Customer Care, relationship, and billing systems with respect to Avista's needs. Scoring sheets for this portion of the evaluations are attached to this report as Confidential Attachment 11, pages 22 - 28.

d. Enterprise Asset Management Fit - Measure of the functionality of the asset management systems with respect to Avista's needs. Scoring sheets for this portion of the evaluations are attached to this report as Confidential Attachment 11, pages 29 - 32.

e. Mobile Work Management Fit - Measure of the functionality of the mobile work management systems with respect to Avista's needs. Scoring sheets for this portion of the evaluations are attached to this report as Confidential Attachment 11, pages 33 - 38.

2. Technology

a. Technical Fit – Evaluation of the technical hardware and software needs and costs, and technology implications of the proposals, with respect to Avista's core information technology strategies, in the short and long-term. Scoring sheets for this portion of the evaluations are attached to this report as Confidential Attachment 11, pages 39 - 50.

3. **Implementation Partner**

a. System Integrator Capabilities – Assessment of the vendor's implementation strategy, installation approach, capabilities, timeliness, staffing, and compatibilities with Avista's project plans. The scoring template and assessment notes for this portion of the evaluations are attached to this report as Confidential Attachment 11, pages 51 - 59.

4. Cost

While a vendor's proposed cost was an important element of the initial screening, Avista understood the limitations on the usefulness of these initial costs. Not only were these costs very preliminary, but they did not necessarily represent the package of solutions the Company would select, did not represent the results of final price negotiation, and did not reflect with any degree of accuracy the final cost estimates that would be developed later in the process. The initial costs for each proposal are included in Confidential Attachment 11, pages 60 - 61. Avista's very preliminary estimate of its costs to implement each proposal are included on page 60 of Confidential Attachment 11. The budget line just under the heading titled "Implementation Costs" was the initial very-preliminary estimate of the collective costs to implement each package.

Based on the initial review and scoring of the proposals by the Avista Project Team, the Company withdrew consideration of the proposals made by Wipro, Sparta, Logica, Meridium and HPES.

Avista then conducted day-long interviews in early December 2011 with the final vendors who fully-met the RFP requirements. A Summary Score sheet for the application solution sets from each vendor is attached to this report as Confidential Attachment 11, page 62, The summary scores do not include the evaluations of the capabilities of the System Integration vendors themselves. The remaining vendors, HCL AXON, EP2M/Oracle and IBM, were invited to make Product Demonstrations for the Avista Compass team at Avista's offices, conducted over a period of three weeks in January of 2012.

During and after the product demonstrations, Avista and Five Point conducted further evaluations of the vendor proposals rated against a more-detailed list of the Project Compass Drivers, provided below. As Avista's evaluation proceeded, a ranking of the elements of the proposals was created from the aggregation of selections of individual Compass team members. Results were rolled into a Final Solution Workbook where scores for the proposed software applications (customer service, asset management, and mobile), the technology assessments, and the evaluations of system integration vendors were summarized on the basis of meeting the Project Drivers.

<u>Project Compass Drivers</u>

- Technology
    - Agile – ability to respond quickly to the ever-changing needs of the business
    - Reduce technology complexity
    - Strong technology roadmap
    - Minimizes customizations
- Customer
    - Communication preferences
    - Choices – service options
    - Improve customer touch points
    - Develop new ways to deliver more value to the customer
    - Improved information (business analytics) access and availability
- Future
    - Smart Grid
    - Energy Efficiency Programs

- Real time billing
- On-bill financing
- Strong product roadmap
- Customer experience

- Employee
    - Employee impact – positive benefits
    - Minimize adverse impact to employees
- Business
    - Business process efficiency and effectiveness
    - Trusted System Integration relationship
    - Strong System Integration implementation approach, methodology and experience
    - Preserves data integrity
    - Meets project budget, scope and timeline
    - Eliminate silos of information
    - Improved information (business analytics) access and availability
    - Satisfies current regulatory and business requirements

The Final Solution Workbook is included in this report as Confidential Attachment 12, and records the numeric scores derived from the initial evaluation of the vendor proposals.

- Results reflect a slightly higher ranking of SAPs Customer Relationship & Billing solution compared with Oracle's Customer Care & Billing solution, as shown in Confidential Attachment 12, pages 3 - 4.
- IBMs Maximo Enterprise Asset solution was ranked as having a slightly better match for Avista than either the SAP or Oracle Asset solutions, as shown in Confidential Attachment 12, pages 5 - 7.
- Among the Mobile applications, the Ventyx solution was rated higher than the Oracle and ClickSoft solutions, as shown in Confidential Attachment 12, pages 8 - 9.
- With respect to the vendor's overall Technology scores, as determined by Avista's Technology Project Driver, SAP was rated substantially above both Oracle and IBM, as shown in Confidential Attachment 12, pages 10 - 13.

- In rating the capabilities of the Systems Integrator vendors, from Avista's perspective, HCL AXON was rated above EP2M and IBM, as reflected in Confidential Attachment 12, pages 14 - 15.

Avista's Final Selection of Applications and Services Vendors

In Avista's final analysis, it determined that the best overall combination of solutions for serving its customers would be a hybrid of the solution sets proposed, including the Oracle Customer Care & Billing solution, installed and integrated by EP2M, and the IBM Maximo Asset Management solution installed and integrated by IBM, in partnership with EP2M. In addition, Avista determined it was in the interest of its customers to delay the selection and implementation of the Mobile application at that time, since a new version of the top-scoring Ventyx Service Suite will be available for review in 2014. Final voting scores for the candidate customer and asset solutions, the lead solution integrators, and the combined projects, are included in this report as Confidential Attachment 13

<u>Oracle's Customer Care & Billing</u> application was ultimately selected over SAPs customer application because it met all the solution requirements needed to serve our customer and business needs, is more tailored to utility industry applications, was much more intuitive for customers and our employees to navigate and use. It is also compatible with Avista's existing Oracle financial and procurement systems. Because SAPs Customer application could not be integrated with Avista's Oracle financial system, selecting SAP would have required Avista to abandon its Oracle ERP system and to transition to SAPs system over a period of approximately five years.

<u>IBMs Maximo Enterprise Asset Management</u> solution was selected over the applications of SAP and Oracle because it was judged to have the strongest overall capability for Avista, is an industry leader, integrates well with Avista's geospatial facilities technology, provides for the incorporation of fleet, facilities and enterprise technology assets, and provided the opportunity for early installation of Avista's electric generation assets. In addition, IBM was willing to partner with EP2M in the installation and integration of its Maximo product.

EP2M was selected as the System Installation/Integration vendor because it has a great depth of familiarity and experience with the Oracle Customer application, has an excellent track record of successful project completion, received excellent customer reviews, has very low employee turnover and has excellent utility experience.

This combination of vendors and solutions, together, was judged to provide Avista and its customers with the optimized products and services that would deliver excellent service and value, in both the short and long term, and at the lowest overall price. During the final selection process, Avista prepared a comparison of the very preliminary pricing, as derived through the course of the evaluation process, for Avista's selected solution, as well as the second choice solution set (HCL AXON and SAP). These prices were very preliminary because the final pricing for the selected solutions had not yet been negotiated. In addition, because these costs did not reflect all of the activities involved in replacing the legacy System, they were not intended to represent a budget estimate for completing the Project. The costs used to compare the final solution sets are included as Confidential Attachment 14.

VI. Implementation of the Replacement Systems

Avista's initial project research and its planning work with Five Point Partners, to assess its business process requirements and to evaluate a range of proposals, provided the base of knowledge and certainty needed by the Company to proceed with the replacement of its legacy System. Avista entered final negotiations with the selected vendors, described above, and executed purchase agreements in May 2011. The single largest contract was awarded to the firm EP2M for implementing the Oracle Customer Care & Billing application, and integration with the IBM Maximo application and the host of other applications and systems required to support Avista's customer service and operations business. A copy of Avista's Master Services Agreement and Statement of Work for its contract with EP2M, is provided in the confidential work papers accompanying this filing. Avista's second-largest contract was signed with IBM for its Maximo software and the services of installing and integrating the application. Avista's Master Services Agreement and Statement of Work for IBM is also provided as confidential work papers.

Project Compass Capital Budget

A final project budget was developed over the course of 2011 and 2012, for the implementation of the Company's customer service and asset management applications. This budget was approved by the Company's executive steering committee on December 6, 2012, and is included as Confidential Attachment 15.

Timing of the Final Project Budget

Although Avista discussed potential costs of the project early in its inception, and approved preliminary budgets through the course of Project development, it did not establish a final capital budget until the Project was well-enough defined to do so with confidence. Avista has learned from its own experience, through its peer utility interviews, and from the support and advice of outside experts, that organizations commonly undermine the success of their software projects by making cost commitments too early in the development stages. This mistake undermines predictability, increases risk and project inefficiencies, and generally impairs the ability to manage a project to a successful conclusion. Early in the scoping of a software project, particular details of the application being designed/installed, a detailed knowledge of the Company's specific business requirements, details of the solution sets, the management plan, identified staffing needs, and many other variables are simply unclear. Accordingly, estimates of the potential cost of the project are highly variable. As these sources of variability continue to be investigated and reduced, the project uncertainty decreases; likewise, so does the variability in estimates of the project cost. This phenomenon, widely discussed in the literature, and often associated with author Steve McConnell[2], is known as the "Cone of Uncertainty," presented in Figure 4[3], below.

---

[2] Software Estimation: Demystifying the Black Art. Steve McConnell, Microsoft Press, 2006

[3] id. Figure 4.2, 96.1/751.

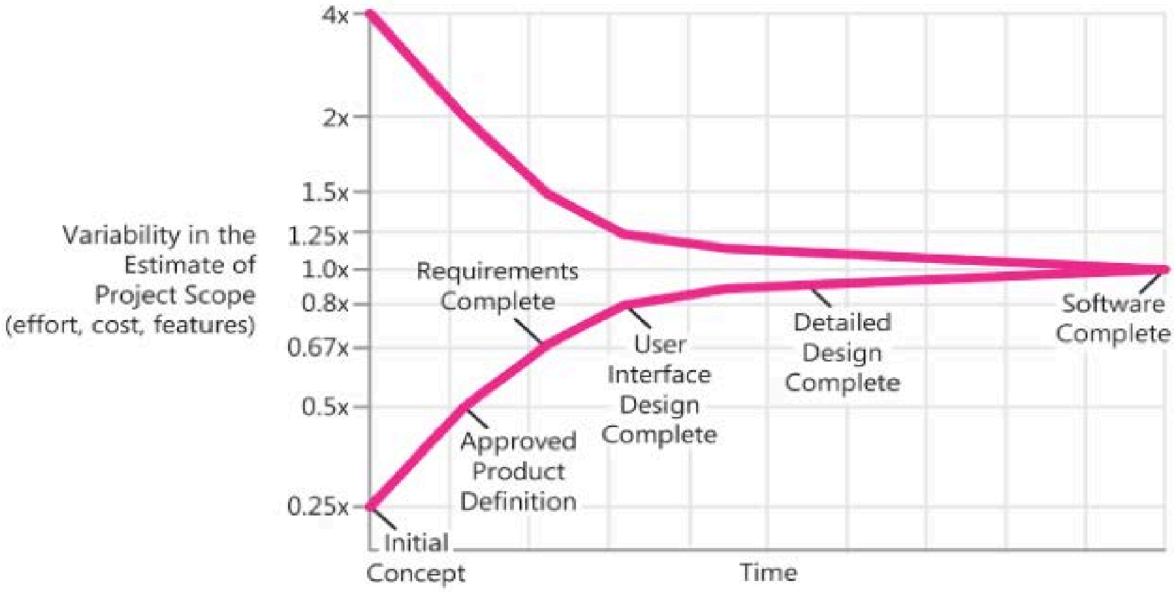


Figure 4. The 'Cone of Uncertainty' describing the relationship between the variability in the estimates of a software projects' cost and the stage of the project at which the estimates are developed.

As the figure illustrates, significant narrowing of the uncertainty generally occurs during the first 20-30% of the total calendar time for the project. The uncertainty will only decrease, however, through active and deliberate project research and design required to further define the scope, requirements, implementation details and estimates of component costs. And, this uncertainty must continue to be constrained throughout the course of the project by the use of effective project controls.

The Role of Cost Information Early in the Project

The decision point for the Company in 2010, was whether to significantly reinvest in its legacy technology, as the means to defer its ultimate replacement, or instead, to invest in the planning and exploration of options needed to support its current replacement. In moving toward the latter, the Company's focus was to assess its needs, evaluate options, and select a set of solutions that would meet the long-term needs of the Company and its customers at the lowest possible cost. At that point, the Company engaged in the progressive stages of project design needed to prudently define its likely scope and potential cost. Through this work, uncertainty around the project was narrowed and potential costs were further refined, to the point that Avista was confident purchasing the selected applications and proceeding with the work of implementation. Even though this was several months before the final budget was approved, Avista had by this time built the foundation needed to initiate a successful project: the ability to deliver a solution that would meet its long-term customer service and business requirements in an optimized approach, and in a manner that would achieve the least cost for its customers.

The Project Budget as a Management Tool

While Avista believes its estimates of scope, timeline and budget for the project are reasonable, and it is committed to control the Project to best meet each of these estimates, it is also cognizant that its success will not be defined by whether or not each estimate, including the budget, is precisely met. In contrast with a ‘not-to-exceed’ metric, the software budget is a management tool that allows senior leaders to make informed enterprise-level decisions, and that provides an effective tool for the project manager to control project activities in an effort to meet the estimates of each deliverable (timeline, scope, functionality and cost). In describing the relationship between software project estimates and final results, McConnell states:

> “The primary purpose of software estimation is not to predict a project’s outcome; it is to determine whether a project’s targets are realistic enough to allow the project to be controlled to meet them.”[4] “Typical project control activities include removing noncritical requirements, redefining requirements, replacing less-experienced staff with more-experienced staff, and so on.”[5] “In practice, if we deliver a project with about the level of functionality intended, using about the level of resources planned, in about the time frame targeted, then we typically say that the project "met its estimates," despite all the analytical impurities implicit in that statement. Thus, the criteria for a "good" estimate cannot be based on its predictive capability, which is impossible to assess, but on the estimate’s ability to support project success…”[6]

Avista believes it has designed and developed such an implementation plan and budget for Project Compass. By this, we mean that the overall Project record will demonstrate its proper research and design, robust planning and estimating, effective management and controls, and that its delivered scope, timeline and cost, are reasonable, cost effective and prudent.

[4] id. At 42/751.
[5] id. At 39/751.
[6] id. At 41/751.

Project Budget Allocation

The overall allocation of the final capital budget for the Project is shown in Confidential Attachment 15. The budget amounts represent key purchases and contract and employee labor required to support the activities of installation. In addition, these costs are also separated for each major application system: Customer Care & Billing; Maximo for Generation Resources, and Maximo for Gas and Electric Transmission and Distribution assets.

Application Costs as a Portion of the Overall Project Budget

Today, the cost to purchase the rights to enterprise commercial applications is a relatively small proportion of the overall replacement project budget. This is because the vendor's cost of developing and updating these huge applications can be spread across a broad global client base. Accordingly, the incremental cost to each company is relatively small. To achieve this broad applicability, the software applications are designed with a standard off-the-shelf range of functionalities, which allows them to be adopted by the widest possible client base. But, since every company still has unique business processes within these broad templates of standard functionality, the applications are designed with significant additional flexibility that is not configured when the application is purchased. This configuration must be performed by each company after the application is purchased and installed, in the ways that best meet their individual business requirements. For Avista, as described above, tailoring the applications to meet our 3,500 individual business requirements involves a significant labor cost. In addition, the customer service and asset management applications must be integrated to perform seamlessly with each other, and with every other business software application (over 100 for Avista) that's required to support the operations of the Company. Finally, for each existing Avista work processes that cannot be accommodated by the standard functionality of the new applications, this work process must be re-designed so that it can. This process re-design is also labor intensive because it's performed by work teams staffed with employees representing every segment of the business that's impacted by the change. Overall, these costs of installation, configuration, integration and work process re-design represent the lion's share of the project budget.

In addition to the activities above, there is a broad range of other support required to make the Project successful. These include development of training materials for employees on the new systems and the re-designed work processes, the process of training, project change management, employee and customer communications, project quality assurance, computer hosting and computer hardware for the applications, and providing technical support for the new systems at their launch and during the period of stabilization.

Board of Directors Updates on Project Compass

The Finance Committee of the Board of Directors was provided an overview and update on the progress of the Project by Mr. James Kensok, in February 2012. A copy of that presentation is included as Confidential Attachment 16. Mr. Kensok provided another update to the Board Finance Committee in September 2012, and that presentation is provided as Confidential Attachment 17. The Board Finance Committee received an updated progress report on Project Compass, made by Mr. Kensok, in February 2013. A copy of that presentation is included as Confidential Attachment 18.

Principal Implementation Activities of Phase 2

As briefly described above, the major activities of the Implementation Phase include installing the software solutions and configuring them with Avista's System, testing all of the System components prior to deploying the solution, developing and implementing employee training and customer and employee communications. And, finally, the Go-Live placement of the new System into service. Some of the key activities include:

- Tailor / Configure the software solutions to match the design of Avista's business requirements.
- Develop Technical Specifications – These ensure the software configurations can be documented for future development and upgrades.
- Develop / Configure Work Processes – documents how the Company has determined that the flow of work processes will be accomplished using the new software.
- Develop Integrations – to connect with Avista's other business systems and applications.

- Develop Data Migration Plans – to move Avista's customer and other data to the new platforms.
- Security Setup – Establishes the security plan for protecting the Company's customer and other data.
- Test Scenarios – developing test scenarios from an inventory of the processes to be tested, using the step-by-step procedures for each particular transaction or business process that will be used to integrate and test new systems.
- Conduct Unit Testing – unit testing ensures that underlying customized portions of the software systems are functioning as designed.
- Migrate Data Tables and Files – to ensure there is order and accuracy when information is moved from the programming stage into the testing stage and, finally into live application.
- Evaluate System Test Application – the performance testing of the system created for testing the actual applications and their integrations.
- Conduct Systems Integration Testing – focuses on the testing processes between the software solutions implemented, and the Company's other systems, including third party systems.
- Conduct User Acceptance Testing – provides those who will actually be using the systems to evaluate all application functions related to their business processes. Acceptance testing confirms the system meets business requirements, and also, verifies the business processes for the software solution are complete, well understood, and well documented.
- Defect Management – During each test cycle, actual test results are compared with expected results. If issues are identified and logged, functional and/or technical updates will be made as required to resolve a particular issue. As issues are resolved, additional testing is completed to validate that the issue is fixed properly. The majority of this testing falls within the test cycles outlined above, but additional testing is completed as required by the project team until all business requirements, system functionality, integrations and business processes are fully tested.
- Training Materials are created for employees and others who will be using the system.
- Train the Trainer courses are conducted for employees who will be key trainers for others.

- Deliver Training – Training is one of the final opportunities to prepare employees to operate the system with the new business processes. The timing of the training is critical so that the users are trained in time for the transition, but will still retain knowledge of the new system.
- The project team develops the detailed "cutover plan", to ensure a comprehensive list of supporting requirements is timely developed. 'Cutover' refers to the process of moving Avista's service from the legacy operating systems to the new applications and systems.
- Ensuring that the technical operating environment for the new is in place and stable prior to the Go-Live.
- An assessment of organizational readiness is conducted to ensure the Company is equipped for a successful Go-Live.
- In conjunction with preparing for the Go-Live, a contingency plan will be developed and in place to respond to issues that may arise during the process.

In addition to the major activities listed above, the work in this Phase is also organized and managed in several project 'workflows' that provide a unified objective and continuity across this Phase. These six workflows include:

- <u>Overall project milestone plan</u> – this body of work supports the management of the overall project.
- <u>Enterprise Asset Management / First Wave</u> – this effort is focused on the application of the new asset management software to Avista's electric generation and substation equipment.
- <u>Enterprise Asset Management / Second Wave</u> – this portion of the project encompasses the activities required to apply the new asset management software to the Company's electric transmission and distribution, and its natural gas infrastructure. This work process replaces the functionality currently provided by Avista's legacy work management and electric and gas meter application systems.
- <u>Customer Service Application</u> – This portion of the program, which represents the lion's share of project Compass, is focused on replacing the functionality of Avista's legacy customer service system.

- Testing – This workflow is focused on the technical testing of the new applications, as integrated into the Company's business environment. Activities include the technical testing of the software and hardware systems, and what is known as user-acceptance testing. The latter involves Company employees testing the new systems by simulating all possible combinations of their business application.
- Enterprise Technology – Ensuring the new applications mesh technically and strategically with the Company's enterprise services model for information technologies.
- Organizational Change Management and Communication – This work involves the preparation of employees for their successful participation in work process redesign efforts, and for the systemic changes they will experience when the new systems are implemented. In addition, there is an important element of this work that is focused on the customer: preparing them in advance for the minor service changes that will accompany the launch of the new systems.

Key Activity in Phase 3

After the Go-Live, there is a transition when supporting consultants remain on site to help resolve technical issues that arise, in the Phase known as Post Go-Live Support. The duration of this transition period, which is expected to last between 6 and 12 months, will be defined by Avista's internal support personnel as they become comfortable supporting the new system.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

JAMES M. KENSOK
Exhibit No. 502

Information Technology Programs

Revised Timeline and Budget Forecast

Avista's Project Compass

Avista Utilities

June 2014

Avista's Project Compass

Revised Project Timeline and Budget Forecast

Q. Why is the Company revising its initial project plan?

A. Avista is in the latter stages of implementing its new Customer Service and Work and Asset Management software systems, named "Project Compass" (or "Project" or "System"). The Company is installing Oracle's Customer Care & Billing system (or "CC&B"), and IBM's Maximo Work and Asset Management system (or "Maximo"). The initial Project plan was completed in 2012 and envisioned a launch of the new System, known as the "Go Live," in Q3 2014. Through the course of implementation, the Project team has developed much-more complete information about the full detail of the System work requirements and its ultimate cost. This information, which is described below in this report, provides the basis for the current revision of the initial plan. The overarching consideration for revising the schedule is ensuring the new computer applications undergo thorough testing to validate they will perform at a level, when launched, to execute critical business functions properly and minimize the potential for disruptions to our customers and the Company. The Compass management team determined a Q3 Go Live would not provide sufficient time for the robust testing needed to ensure the readiness of the new applications. Accordingly, the Company's officers recently agreed to extend the Go Live time frame to include Q1 2015.

Q. Did the Company's plan and schedule, as initially developed, provide adequate time for testing the System?

A. Yes. The initial work plan generally provided ample time for comprehensive application testing. But, because there were longer than estimated delivery times required by several implementation activities, the new System was not ready to commence testing on the schedule originally envisioned.

Q. Specifically, what work processes took longer to complete?

A. The key activities that required additional time were the development of code for “Extensions” to the CC&B application, and the currently-ongoing process of “Defect Management” associated with application testing. Secondary activities that required additional time, included “System Configuration,” writing “Test Cases” to support the testing protocol, the processes of “Data Conversion” for both CC&B and Maximo, and the development of “Integration Code” for the new replacement System and interconnected applications and systems.

Q. Please briefly describe each of the work processes mentioned above?

A. System Configuration – “Configuring” an application is the process of setting parameters in a vendor’s computer software that enables its built-in logic to perform the functions required by the Company’s various work processes. The process involves selecting among options, embedding algorithms, entering data, and creating specialized instructions. Configuration is performed through a series of input tables that organize the process of setting parameters. Each input table, which could represent one particular type of customer service agreement, for example, may have up to 100 individual, flexible, and configurable fields. Configuring each field requires entering from one to several individual values, instructions, or algorithms to establish the new base System. Each field in each table is often cross-linked with content in dependent fields in complementary tables, creating a complex of dependencies between many multiples of tables and fields. This initial work requires the person entering the configuration settings on a particular table to work iteratively and sequentially in configuring the dependent fields in the other tables as one integrated work flow. As one example of the work involved, it required one technician working full time over six months to configure Avista’s existing rate tariffs into CC&B (142 different service agreements across our three jurisdictions). Considering that CC&B has 1,686 configuration tables, containing 12,158 configurable fields, the magnitude and complexity of this task is quickly evident.

Extension Code – There is considerable flexibility to accommodate a range of business processes within the application's off-the-shelf Configuration settings. But, many business steps are complex enough that they require programming of specialized software code that is outside the application itself. The capability enabled by this specialized code is referred to as an application "Extension." The process of developing this code, which is complex and labor intensive, begins with a description of the work process steps that a particular extension will perform (its technical requirements). Each set of requirements is then translated into a technical specification that guides development of the actual programming code. Once the technical staff has written the code, it is subjected to several iterations of "Unit Testing." Unit Testing validates that the unit of code, in isolation from the System, properly performs the steps identified in the technical specification.

Integration Code – "Integrations" refer to the connections between separate computer applications that allow them to work in concert to perform allied functions. An integration may involve exchanges of data, transmission of instructions or changes in state, performance of computations and other algorithms, and myriad other shared functions. Like Extensions, Integrations require the development of specialized programming code that connects the CC&B application with the Maximo application, and that connects them both with the approximately 100 other applications and systems required to support the Company's customer service and business operations. Some of these systems include the Avista customer website, the Company's various internal systems (such as financial applications, varied databases, supply chain, crew dispatch, outage management reporting), systems of outside financial institutions used by the Company and our customers, and the many vendors who support our delivery of natural gas and electric service, such as bill printing and presentment. In addition to Integration connections between applications, this work also encompasses the development of Avista's "enterprise service bus." The latter is essentially an Integration network that is shared by the integrated applications. The process of developing and Unit Testing the Integration code mirrors that of the code for Extensions, described above.

<u>Code Defect Management</u> – The work of Configuration and coding Extensions and Integrations is very complex and highly interrelated. As a consequence, it is inherent that each unit of the completed work will require several iterations of testing and modification before it will properly execute its part of a business process. Portions of the configuration settings and the specialized code, which initially do not perform properly, are known in the industry as "Defects." Defects are identified during testing when the configured application and specialized code are run through a simulated business process referred to as a "Test Case." During the test, the program simulation runs to the point where a Defect is encountered and the simulation is halted. In the work process known as "Defect Management," that Defect is located and analyzed, and is returned to the Configuration or coding team for correction. The revised code is then run through the very same test-case simulation until the next-limiting defect is encountered. This process is iteratively repeated until all of the defects in that unit of code or Configuration, for that one unique Test Case, have been located and repaired. Then, the testing process is repeated for the next individual Test Case. Over a cycle of testing, it is typical for the rate of defects to be relatively low, initially, and then to increase to a peak before tapering back down to a low and predictable rate. This pattern is important because during the initial testing it is impossible to predict the ultimate number or complexity of Defects in a unit of code. Only at the point where the number of Defects peaks and begins to decline in a predictable way can the remaining Defect-Management effort be reliably forecast.

<u>Application Testing</u> – Three major areas of testing play a critical role in the successful implementation of the new applications. Each type of testing is

associated with its own unique process of code Defect Management. "**System Testing"** commences when the work of Configuration and the coding of Extensions is complete. Its purpose is to ensure the new applications perform properly as they have been Configured and coded to support Avista's business processes. "**Systems Integration Testing"** occurs next in the sequence and focuses on testing the specialized Integration code to ensure the new applications perform properly with all of the other integrated applications and systems. This is followed by "**User Acceptance Testing,**" which is performed by Avista employees who will be using the new System to serve our customers. It has the twin objectives of scrubbing the System to further identify and repair any critical Configuration, Extension or Integration Defects, and to identify and implement changes to the System that will make it more user friendly and function more smoothly and efficiently for customers and employees.

<u>Simulation Test Cases</u> – Test-Case scenarios are written to evaluate virtually every step of every business process that is enabled by the new System. Each Test Case is unique from all other Test Cases and is written to evaluate a very specific portion of the configured application or specialized code. The complexity of the applications requires a significant number of unique Test Cases to fully validate the integrity of the new System. The number of Test Cases written for each phase of testing of the Company's new applications, is presented below.

Application Testing	Number of Test Cases
Avista Utilities' Customer Web Portal	1,283
CC&B Credit and Collections System	667
CC&B Credit and Collections System Integration	407
CC&B System Test	1,472
CC&B System Integration Test	2,471
Maximo System Test	210
Maximo System Integration Test	454
Interactive Telephone System Test	351

Total	**7,315**

Data Conversion – All of the Company's existing data, whether customer account information, energy-use history, electric and natural gas facilities data of all types, mapping system information, and regulatory and compliance information, etc., must be transferred from existing computer hardware and data bases, such as the Company's current mainframe platform, to new data formats, databases, and computer platforms connected to the new applications. To accomplish the conversion, data in the existing databases is mapped according to where it will eventually reside in the new databases. The data are then extracted from the old databases, are transformed as necessary, and are loaded into the new databases. The integrity of the loaded data is then validated for accuracy. Defects in data conversion are identified in the process, Defects are repaired, and the data load/validation exercise is repeated.

Q. Why are these work processes taking longer to complete than was initially planned?"

A. The longer implementation times are primarily the result of the high degree of complexity of the integrated systems being installed by the Company.

Q. What do you mean by "complexity of the integrated systems?"

A. While it's common for a business to install one major system at a time, such as a customer service, financial management, supply chain or asset management system, the Company is installing two major systems simultaneously (CC&B and Maximo Asset Management). Avista is required to implement both new applications because our legacy System contains a customer service module and work and asset management module that are highly integrated, mainframe based, and both in need of replacement. As described above, this effort requires not only that these two systems be custom integrated, but that together, they be integrated with the approximately 100 other applications and systems required to perform the Company's integrated business operations.

In addition to the number of other applications and systems, Avista has several complex applications that many utilities do not possess. Some of these include our Avista Facilities Mapping system ("AFM"), which geographically displays every element of our electric and natural gas facilities in a Geographic Information System (GIS) map format; our Outage Management System, which integrates outage management computer logic with the AFM system to provide accurate outage information for customers and diagnostic tools that reduce outage restoration time and costs; and our Central Dispatch System, which integrates AFM, the Outage Management System, and our Mobile Workforce Management application, to optimize the dispatch and management of restoration crews in real time across our entire electric and natural gas system.

The degree of complexity of the new System is also impacted by the diversity of service provided by the utility. Because Avista provides both natural gas and electric service, the complexity is substantially greater than that of a utility providing either one or the other. Further, the Company provides service in three regulated jurisdictions, each of which has separate and unique operating tariffs and rules that must be coded into the new applications. For portions of our new System, Avista's application configuration and specialized coding will be roughly five times greater than that of a single-fuel utility operating in one state.

Q. Did Avista take steps to understand the source of and to mitigate the impact caused by the longer code development?

A. Yes it did. In December 2013, the Project Compass team assessed the relationship between the complexity of Avista's code requirements, the project schedule, and the level of staffing applied to the work. The end result was that Avista's integration contractor retained additional resources to bolster its overseas code-development team. Progress on the other activities that were taking additional time (application configuration, data conversion, integration code, and writing the test cases) was managed to ensure that applicable portions were ready for System Testing once the CC&B Extension code was available. Through this analysis and actions taken, the Company believed it could better manage the overall time required for coding extensions.

Q. Why didn't the Company change its forecast of the Go Live date earlier in 2014?

A. The Project Compass team concluded that even with an expected addition of time for code completion, that it might be able to make up the time and maintain a Q3 Go Live. The team specifically investigated the structure and schedule allotted for testing the new System, as the primary tool for managing the overall Go Live schedule. The Company wanted to test these ideas before making any formal decision to revise the schedule.

Q. How did the team propose to change its testing protocol in an effort to maintain its initial Go Live schedule?

A. As described above, the System Testing, System Integration Testing, and the User Acceptance Testing, are typically performed in sequence. Each phase of testing, including the process of Defect Management, is relatively complete before the next phase is initiated. The Project Compass team revised this testing protocol to partially overlap the phases of testing to be conducted. In this approach, completed "portions" of an application are subjected to limited System Testing and then to limited System Integration Testing with similarly-completed portions of the other application, including the required Integrations. The net effect of this testing protocol, if successful, would be a reduction in the overall calendar time allotted to application testing.

Q. What did the Project Compass Team learn from the overlapping testing approach?

A. The Company implemented and evaluated this approach for System Testing and concluded that it did reduce the time required for this test phase. But, because of the emerging complexity and additional time required for code Defect Management, the overlapping testing was not able to sufficiently reduce the time required for a successful Go Live. Because overlapping testing adds complexity, and because code Defect Management was becoming the more critical scheduling constraint, the team has made limited use of the overlapping testing protocol for the System Integration and User Acceptance Testing.

Q. What impact is Defect Management having on the overall Project schedule?

A. Avista has experienced greater complexity with the Project Compass Defects than had been anticipated. The result is that even though some time was saved by overlapping portions of the System Test, it has been offset by additional time being spent on Defect Management. The result is the present revision of the overall Project timeline to include Q1 2015.

Q. What steps has Avista taken to reduce the time being spent on code Defect Management?

A. Avista has implemented actions in the areas of process cycle time and testing protocol to improve the rate, or velocity, of Defect repair.

Process Cycle time – Avista worked with its system-integration contractors to reduce the time required for defects in the code to be repaired by the development team and returned to Avista for the next round of testing. Actions have included changing communication protocols, assigning key development staff of the contractors to work from Avista's offices, and modifying schedules of the overseas development teams.

Testing Protocol **–** In a conventional testing protocol, as described above, the Test Case scenario will be run until a limiting Defect is encountered. The testing is then stopped, the Defect is located and analyzed, and it's returned to the development team for repair. The Company is piloting a revised protocol where an identified Defect is patched with a temporary workaround, and the Test Case is continued until the next-limiting Defect is encountered. When possible, the second Defect is likewise patched, and testing is continued until the point where a limiting Defect blocks any workaround and further testing. Then, these accumulated Defects are analyzed and sent to the development team for repair. The intent is that by aggregating several Defects at a time it will improve the overall velocity of code Defect Management.

Q. What additional steps has the Company taken to help control the overall Go Live schedule?

A. The company has implemented changes to the Data Conversion process for CC&B and Maximo. These have helped accelerate Data Conversion and have improved the efficiency of the data validation process. Additional project resources have been added to various workstreams such as the Customer Web Integration effort. System-integration contractors have arranged for their lead staff to spend additional direct time with Avista's team in Spokane, and Avista employs a fifty-hour work week, as needed, to meet peak Project demands. The Project team has also increased the capability of the computer systems supporting the application testing processes. This allows the iterative Test Cases to be run more quickly, further accelerating the Defect Management process. In addition, the Test Cases are being re-prioritized to help ensure the most important business processes are tested and repaired first. The team has also launched the first wave of training for its customer service employees who will be using the new CC&B application. Finally, the Project managing directors are working to ensure morale of employees and contractors remains at a high level for the intensive duration of the Project.

Q. Has the revised implementation plan impacted the Project budget?

A. Yes. The longer time frame required to complete the work processes described above are in large part responsible for the addition of approximately $18 million to the estimated Project budget. This additional capital budget amount, forecast by cost category, is presented in the table below.

Compass Major Costs	$(1000's)
System Integrators	**$3,163**
Avista Labor / Loadings	**$4,661**
Technology Contractors	**$3,201**
AFUDC	**$3,609**
Software Licenses	**$480**
Common (PMO)	**$654**
Hardware/Hosting	**$10**
Oracle DB License	**-**
Contingency	**$2,150**
Total	**$17,927**

The revised capital budget authorization for Project Compass is $100 million, which was approved by the Company's officers and Board of Directors on May 8, 2014.

Q. When you say "in part" do you mean there are other factors driving an increase in the project budget beyond a later implementation?

A. Yes. There have been a number of additions to the Project that have contributed to its overall cost, and that were not known at the time the Project plan and budget were assembled in 2012. These changes to the implementation of the applications have been tracked through a formalized process known as a "Project Change Request." The sum of these changes represents a total cost addition of $9.128 million.

Q. Can you provide some examples of the activities and costs that comprise these Project Change Requests?

A. Yes. One of the larger cost items (approximately $1.8 million) is associated with the Company's AFM system. During implementation, the Compass team learned that a GIS software update would provide for a more efficient transfer of data between the AFM system and the new Maximo and CC&B applications. Another addition to the Project was the development of a more-comprehensive customer communication plan (approximately $1 million) to precede the Go Live of the new System. The plan includes ad placement and a direct mailing that identifies subtle changes and improvements in service, as well as the potentially-longer service times (such as call hold time and average time per call) that are expected to temporarily coincide with the Go Live of the new System. Another substantial addition to the capital cost of Project Compass was the inclusion of software maintenance fees to cover the second year of implementation (approximately $998,000). Most of the Project Change Requests have addressed the need for additional technical resources to accomplish specific tasks during implementation of the new systems. For a brief description of each of these Project Change Requests please see Attachment A to this report.

Q. Didn't the Company have a "contingency" in its initial budget to accommodate such changes?

A. Yes. The $80 million initial capital authorization included a contingency amount of $7.176 million. This contingency has offset the majority of the costs added through Project Change Requests.

Q. Has the Company established a definitive date for the Go Live?

A. Not at this point. While the Project Compass team believes that a Go Live window that includes Q1 2015 will provide sufficient time for an effective implementation of the Project, it must complete the bulk of the testing and Defect Management processes before it has confidence in setting a definitive date. When the Go Live date has been selected it will be shared with customers through the communication plan.

Q. Does the Company believe the Project Compass Costs, including the budget additions, are reasonable and prudent?

A. Yes. The original timeline and budget were important project management tools that, while much more refined than the earliest estimates, were still associated with some degree of uncertainty. As described above, when the initial estimates of time and resources required for coding the extensions were developed, the team had no way of knowing the precise degrees of complexity of the coding, the resources required to meet a specified timeline, or the degree of complexity of the defect management process. If the Project team had that precise foreknowledge, it may have added resources and budget to the Project to achieve the initial Go Live date, or it may have added budget to the initially-planned resources to achieve a later date. Because the Project is costing more to implement than was initially estimated, doesn't mean it is no longer the least-cost solution for our customers. Avista believes its revised implementation plan and budget simply reflects a more accurate assessment of the true cost of implementing the Project.

Q. How does the Company believe the implementation of large IT projects should be evaluated?

A. First, Avista is not aware of any large enterprise application system that has been installed by a peer utility that explicitly achieved its initial estimates of timeline and budget. That said, there are distinguishing factors in every project that are useful in helping to assess the reasonableness of its costs. In extreme cases, some companies have abandoned the applications during the course of implementation; the new systems are never placed in service. These failures are often followed by an entirely new selection and implementation effort. In less dire cases, the company may learn during the course of implementation that it selected a less than optimum solution set, which requires a significant and expensive workaround to successfully install. In some cases, the scope of functionality has been set either too broad or too restrictive. In either case, the costs and the time delay associated with mitigating those initial choices can be very substantial. In other cases, companies have made implementation errors such as overlooking basic required functionality, resulting in additional time and budget to include while the majority of the project is awaiting the Go Live. In the best cases, companies have simply underestimated, to varying degrees, the true cost of implementing the selected applications. In other words, these companies have completed a comprehensive needs assessment, prepared a balanced project scope, conducted a robust selection process, selected the proper solutions, hired capable implementation contractors, adequately prepared their organizations for the many changes associated with implementing the new systems, including timely and effective training, prepared their customers for any changes associated with the new systems, and achieved a reasonable balance in the timing of completion of implementation activities. Although these companies took longer to Go Live and spent more money than initially planned, they successfully avoided the major pitfalls that have rendered so many of these projects less than fully successful. Avista counts its Project Compass in this latter class of successful projects, and is confident in the successful completion of the Project.

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[1] in August 1991. 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. Since 2000 I have assisted or led the Company's electric and/or natural gas general rate filings in Washington, Idaho and Oregon.

---

[1] Currently I keep a CPA-Inactive status with regard to my CPA license.

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 the test period operating results, including expense and rate base adjustments made to actual operating results and rate base.

The 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. Kensok, Mr. DeFelice and Mr. Ehrbar. I will provide a summary of the Company's IS/IT costs, including the IS/IT capital projects and related expenses, and a summary of the Company's Customer Information System (CIS) capital project adjustments, while Mr. Kensok will present more detail for each of these adjustments in his testimony. I will provide a summary of the Company's restated 2013 net plant, and planned 2014 and 2015 capital additions adjustments, while Mr. DeFelice will present more detail for each of these adjustments in his testimony. I will also cover the revenue load adjustment briefly, while Mr. Ehrbar provides a more in-depth discussion. 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 Nos. 601-602, which were prepared under my direction. Exhibit No. 601 consists of worksheets, which show summary level historical actual 2013 operating results, test period results for 2015 including 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 restating and forecasted adjustments proposed in this filing. Exhibit No. 602 consists of worksheets similar to Exhibit No. 601 on a more detailed level (by FERC account).

II. REVENUE REQUIREMENT AND RATE REQUEST PROPOSAL

Q. Would you please summarize the Company's need for revenue increases for its natural gas operating system for the Oregon jurisdiction?

A. Yes. After taking into account all historical restating and forecasted adjustments, the natural gas rate of return ("ROR") for the Company's Oregon jurisdictional operations for the 2015 test period is 5.05%, as shown on Exhibit No. 601, page 1. This return level is below the Company's requested rate of return of 7.77%. The incremental revenue requirement for base retail rates, necessary to give the Company an opportunity to earn its requested ROR, is $9,140,000. The overall base natural gas revenue increase associated with the Company's request is 9.3%.

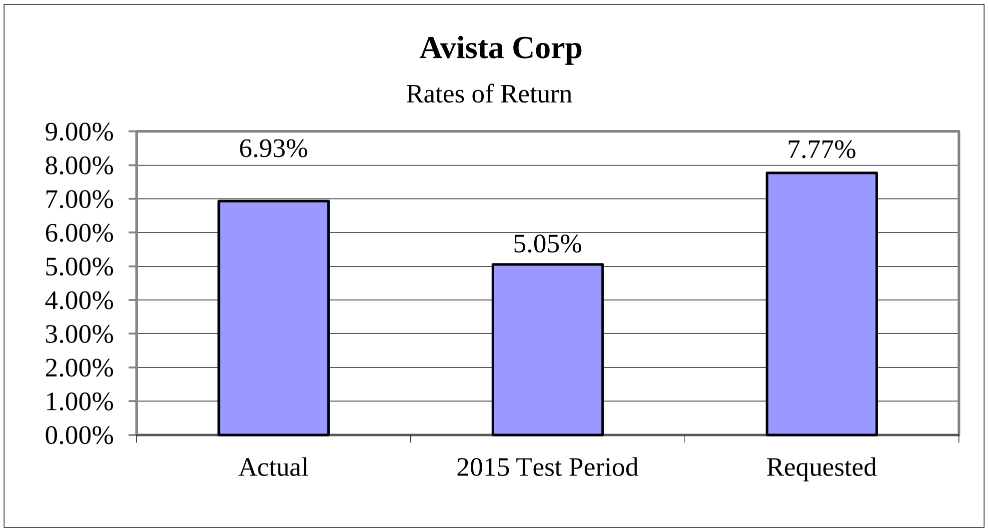
Q. What was the Company's rate of return that was last authorized by this Commission for its natural gas operations in Oregon?

A. The Company's currently authorized rate of return for its Oregon operations is 7.47%, effective February 1, 2014.

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, 2013, the 2015 test period ROR determined in my Exhibit No. 601, 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 test period being used by the Company is the twelve months ended December 31, 2015, presented on a forecasted basis. Currently authorized rates are based upon the 2014 forecasted test year utilized in Docket No. UG-246.

Q. Why did the Company use the year ending December 31, 2015 as the test period?

A. The 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 are expected to be effective in the first half of 2015. Although the use of the 2015 calendar-year rate period will likely understate the costs the Company will incur to serve customers during the full time period new rates will be in effect from this filing, it provides a reasonable basis for the calculation of revenue requirement in this case.

Q. Please explain how the Company developed the revenue requirement for the 2015 test period.

A. Revenue requirement preparation began with the historical accounting information for the twelve months ended December 31, 2013. Each of the revenue requirement components in the historical period was analyzed to determine if a normalizing or correcting adjustment was warranted to reflect normal operating conditions. The restated historical information was then adjusted to recognize known, measurable and anticipated events to determine a 2015 test period. Next, the 2015 test period results were adjusted to include previous Commission–ordered restating adjustments, resulting in restated 2015 test period results.

Q. Why did the Company begin with historical information?

A. The Company began with historical information and made adjustments to arrive at the restated 2015 test period revenue requirement, because starting with historical information provides a solid foundation that is easily auditable.

Q. Please summarize the process used to adjust the historical information to reflect the 2015 test period revenues and costs.

A. Revenues are adjusted for the effect of applying the current Commission-approved tariff rates to the 2015 test period customer usage. Historical operations and maintenance ("O&M") expenses were separated into labor and non-labor components. Except for a few specific cost items, non-labor costs were adjusted using the most current consumer price index (CPI). Historical labor costs were also adjusted for increases through the 2015 test period. Specific adjustments are described in further detail later in my testimony and shown in Exhibit Nos. 601 and 602.

III. NEED FOR ADDITIONAL RATE RELIEF

Q. Please briefly describe the Company's need for additional natural gas rate relief.

A. Over 74% (or approximately $6.7 million) of the Company's need for additional rate relief relates to increases in total rate base, including changes in net plant investment (including return on investment, depreciation and taxes, offset by the tax benefit of interest), representing an increase of approximately $39 million in additional net rate base for the Oregon jurisdiction over the current authorized amount[2]. The remaining 26% (or approximately $2.4 million) of the Company's requested revenue requirement relates to an increase in operating and maintenance (O&M) and administrative, general (A&G) expenditures, and the net change in retail revenues since our last rate case filed in 2013.

Q. What are the major components of the changes to total rate base included in the Company's filing?

A. Oregon "gross" plant increased by approximately $41.2 million, or 14%, as compared to what is currently included in rates. These investments reflect replacement and maintenance of Avista's aging system, and to sustain reliability and enhance safety. Major projects included in this total include the Company's Customer Information System project described by Mr. Kensok, as well as other required capital projects that have been or will be put in service through March 31, 2015, as more fully described by Mr. DeFelice. After adjusting for accumulated depreciation and amortization, and ADFIT, the net plant rate base increase is $30.3 million. After including return on investment, depreciation and taxes, offset

[2] The authorized amounts for this analysis includes rate base authorized for rates that were effective February 1, 2014, and therefore, does not include the 2014 investment in Aldyl-A for which rates will be implemented on November 1, 2014, as further described by Mr. Ehrbar.

by the tax benefit of interest, this amounts to approximately $6.7 million of the requested revenue requirement.

Also increasing the Company's net rate base, are working capital (excluding investment in materials and supplies that are included in the Company's authorized rate base) and the prepaid pension asset, net of accumulated deferred federal income taxes (ADFIT), of approximately $4.6 million and $4.3 million, respectively. These adjustments described further below, increased the Company's requested revenue requirement by approximately $527,000 (see Working Capital Adjustment) and $490,000 (see Prepaid Pension Investment Adjustment), respectively.

IV. GENERAL REVENUE REQUIREMENT

Q. Would you please explain what is shown in Exhibit No. 601?

A. Yes. Exhibit No. 601 shows 2013 actual results and 2015 test period natural gas operating results and rate base for the Company's Oregon jurisdiction. Column (a) of page 1 of Exhibit No. 601 shows the twelve months ended December 31, 2013 actual operating results and components of rate base; column (b) is the total of all adjustments to net operating income and rate base; and column (c) is the 2015 test period results of operations, all under existing rates. Column (d) shows the revenue increase required which would allow the Company an opportunity to earn its requested 7.77% rate of return. Column (e) reflects 2015 test period natural gas operating results with the requested general increase of $9,140,000.

Q. Would you please explain page 2 of Exhibit No. 601?

A. Yes. Page 2 shows the calculation of the $9,140,000 revenue requirement using the requested 7.77% rate of return.

Q. Would you now please explain page 3 of Exhibit No. 601?

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. The Oregon state income tax rate that is used in the conversion factor is described later in my testimony when describing the adjustment for state income tax (SIT). Federal income taxes are reflected at 35%.

Q. Now turning to pages 4 through 10 of your Exhibit No. 601, 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, 2013 in column (1.00). Individual Historical 2013 Restating Adjustments start on page 4, column (1.01), and continue through page 5, column (1.06), resulting in the column labeled "Restated Historical 2013 AMA Test Period Total." Individual 2015 Test Period Adjustments start on page 6, column (2.00), and continue through page 9, column (2.11), resulting in the column labeled "2015 Test Period AMA." Finally, individual 2015 Test Period Restating Adjustments, representing previous Commission–ordered and/or standard components of our annual earnings reporting to the Commission, applied to the 2015 test period results, begin at page 10, column (3.00), and continue through page 11, column (3.04). The final column, which is a subtotal of all preceding columns of adjustments, results in the column labeled "Restated 2015 AMA Test Period." Exhibit No. 602 provides similar data as Exhibit No. 601, pages 1, and 4 through 11, at a detail level by FERC account. Descriptions of each adjustment noted above and included on pages 4 through 11 of Exhibit No. 601 are described more fully below, and supporting workpapers for each of these adjustments accompany the Company's filed case.

V. HISTORICAL RESTATING ADJUSTMENTS

Q. Would you please explain each of the historical restating adjustments, the reason for each adjustment and its effect on test period State of Oregon net operating income and/or rate base?

A. Yes. The first adjustment, column (1.01) on page 4, **Allocation Factor Adjustment,** restates actual 2013 test period Oregon Results of Operations allocated expense accounts using updated allocation factors. During 2013, common costs to be allocated were allocated based on the allocation factors in effect as of January 1, 2013 through December 31, 2013. These factors were based on actual direct 2012 costs. The Company updates its allocation factors annually using the prior year's actual direct costs using the methodology approved by the Commissions. When the factors are updated annually, the factors are reviewed to identify any unusual trends or unexpected shifts in costs. Effective January 1, 2014, and utilized in this filing, are the most current allocations based on 2013 actual direct costs. For further discussion of the Company's allocation processes and methodologies, please see Section VIII. Cost Assignment and Allocation Procedures, below. This adjustment decreases Oregon net operating income by $328,000.

Column (1.02), **Miscellaneous Restating,** restates actual test period results for miscellaneous restating items such as advertising, removal of non-utility related items, and reclassification of items to their appropriate service and jurisdiction. The adjustment for advertising is comprised of two components: 1) restates the 2013 test period advertising expense to correct any jurisdictional allocation of expenses, and 2) removes costs reflecting any excess above 0.0125% of proposed retail revenues, pursuant to OAR 860-026-0022. OAR 860-026-0022 states that utility service and informational advertising are presumed just and reasonable in a rate proceeding, if the costs are less than 0.0125% of retail revenue determined in that proceeding. In order to minimize the issues in this proceeding, the Company has removed the costs in excess of this level presumed just and reasonable. This adjustment increases Oregon net operating income by $1,000.

The adjustment in column (1.03), **Eliminate Adder Schedules**, removes both the revenues and expenses associated with all adder schedule rates except current gas costs and schedule 498[3]. The items eliminated include: Schedule 460 – Excess Franchise Tax, pass through of franchise taxes in excess of 3% charged only to customers in the various municipalities; Schedule 462 – Prior Gas Cost refund and amortization; Schedule 476 – Intervenor Funding surcharge and amortization; Schedule 478 – DSM surcharge and amortization; Schedule 493 – LIRAP pass through collection; and Schedule 499 – Medford Deferred Capital surcharge and amortization. This adjustment also identifies and consolidates all of the 2013 purchased gas cost related accounts into the “Gas Purchases” line item in order to simplify the 2015 test period revenue load adjustment. There is no revenue or expense impact of this portion of the adjustment, however, this process facilitates analysis of cost of service and rate design for base rates. Lastly, this adjustment eliminates the DSM Lost Margin revenue recorded in 2013 in order to properly reset the lost margin base with implementation of new rates. The total adjustment decreases net operating income by $102,000.

Starting on page 5, the adjustment in column (1.04), **Weather Normalization**

[3] Schedule 498 Klamath Falls Lateral adder was merged into gas costs on 11/1/2013 and base rates on 2/1/2014, therefore, it is appropriate to leave the associated 2013 revenues in the test year.

Sales/Purchases, normalizes weather sensitive gas therm sales by eliminating the effect of temperature deviations above or below historical normals. This adjustment restates revenue and gas cost to reflect the change in therm sales if weather had been normal based upon energy rates and the authorized weighted average cost of gas in effect during the year. In compliance with the Settlement agreed to in Docket No. UG-246 (Order No. 14-015) the Company has utilized weather sensitivity factors and other parameters that are consistent with the Company's most recently acknowledged Integrated Resource Plan. Going forward, the Company plans on continuing to use the most recently acknowledged IRP weather parameters for the commission basis weather normalization adjustment to maintain consistency in all Oregon regulatory filings as agreed to in the general rate case settlement. The impact of the weather normalization adjustment is a decrease to Oregon net operating income of $1,116,000.

The adjustment in column (1.05), entitled **Restate Debt Interest**, restates debt interest using the Company's 2015 test period weighted average cost of debt, as outlined in the testimony and exhibits of Company witness Mr. Thies. This adjustment restates debt interest on the Results of Operations level of rate base shown in column (1.00) only, resulting in a revised level of tax deductible interest expense on actual historical test period rate base. The federal income tax effect of the restated level of interest for the historical test period reduces Oregon net operating income by $182,000.

The Federal income tax effect of the restated level of interest on all other rate base adjustments included in the Company's filing are included and shown as an income impact of each individual rate base adjustment described later in this testimony.

The adjustment in column (1.06), **Materials & Supplies Investment**, represents

Oregon's share of the Company's 2013 AMA investment in materials and supplies inventory used for day-to-day operations. In Docket No. UG-246, the Parties to the case agreed that this investment should be included in rate base. This adjustment increases Oregon net operating income by $22,000 and increases rate base by $2,087,000.

Q. Before describing the final column on page 5 of Exhibit No. 601, are there any other regulatory asset balances included in the Company's restated historical 2013 AMA test period needing mention here?

A. Yes. Other regulatory assets included in the Company's 2013 AMA historical test period, and shown on page 4 of Exhibit No. 601, Column (1.00) titled "Per Results of Operations Report," line 242 titled "Total Gas Inventory," is the Company's natural gas inventory balance of $2.544 million. This balance relates to the Company's combined one-third ownership share and leased storage of the Jackson Prairie underground storage facility, a portion of which is allocated for the benefit of Oregon customers. Company witness Mr. Thackston describes in more detail Avista's ownership and use of this facility.

Since the inclusion of this asset in Oregon operations, the Company has consistently included in rate base Oregon's share of its Jackson Prairie inventory recorded in FERC Account Nos. 117 and 164.[4]/[5]

Q. Please continue with your description of the final column on page 5 of Exhibit No. 601.

A. The final column entitled Restated Historical 2013 AMA Test Period Total,

---

[4] Inventory has been excluded from the Company's working capital adjustment calculation described later in my testimony, because separate rate base treatment has been the consistent historical approach approved for recovery of the return on the Company's inventory balance.

[5] Rate base treatment of natural gas inventory is consistently applied within Avista's Idaho and Washington natural gas jurisdictions, as well as by its peer utilities serving customers in the State of Oregon.

provides a subtotal of the preceding columns (1.00) through column (1.06) and represents actual operating results and rate base, plus the restating adjustments that have been previously discussed.

VI. 2015 TEST PERIOD ADJUSTMENTS

Q. Please explain the significance of the twelve columns that begin on page 6 and continue through page 9, in your Exhibit No. 601.

A. The twelve adjustments, subsequent to the Restated Historical 2013 AMA Test Period Total column, represent adjustments that recognize the jurisdictional impacts of items that will impact the 2015 test period operating results. They encompass revenue and expense items as well as additional capital projects and rate base items. These adjustments bring the 2013 operating results and rate base to the appropriate level for the 2015 test period.

Q. Please explain the first adjustment on page 6.

A. Column (2.00), **2015 Test Period Expense Adjustment**, reflects increases in non-labor O&M and A&G expenses through 2015 for various FERC accounts. Workpapers accompanying my testimony and exhibits in this case provide the adjustments by FERC account, provide the Company's analysis of each adjusted FERC account balance and show the use of a CPI of 2.1% year over year for 2014 and 2015. This adjustment decreases Oregon net operating income by $267,000.

Column (2.01), **2015 Test Period Revenue Load Adjustment**, takes into account normalized usage and customers during 2015. Revenues and purchased gas expense are calculated based on the February 1, 2014 approved rates, which include associated gas costs approved in the Company's most recent Purchased Gas Adjustment effective November 1, 2013. 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 $3,066,000.

Q. Please continue with your explanation of the adjustments on page 7.

A. Column (2.02), **2015 Test Period Labor and Benefits Adjustment**, reflects changes to the historical period labor and benefits for union and non-union adjusted to the 2015 levels. Historical period labor for 2013 was restated to annualize the March 1, 2013 pay increase, include the 2014 pay increase, and to include the 2015 pay increase that will be effective March 1, 2015[6]. Executive labor was adjusted to current 2014 level of salaries. The decrease to net operating income associated with labor cost changes is $210,000.

This adjustment also includes the net changes in both the Company's pension and medical insurance expense expected for 2015. These changes reflect a decrease in pension costs of approximately $8 million at a system level from the 2013 test period to the 2015 test period, and a slight increase of approximately $800,000 at a system level in medical insurance costs for the same period. The increase to net operating income associated with pension and medical insurance cost changes is approximately $189,000.

The net decrease in Oregon net operating income resulting from these adjustments is $21,000.

Column (2.03), **Prepaid Pension Investment Adjustment,** increases regulatory assets by $4,318,000 related to Oregon's share of the Company's prepaid pension asset, net of ADFIT, computed on an AMA December 31, 2013 basis.

Q. Has the Company previously requested to include in rate base its prepaid pension asset in its Oregon jurisdiction?

[6] The Company's Board of Directors approved a minimum increase of 2.60% effective March 1, 2015, at its May 2014 board meeting.

A. Yes. The Company previously requested to include in rate base its prepaid pension asset in Docket No. UG-246, however, that was removed by the settling Parties due, in part, to the timing of that case and the unsettled issues in Docket No. UM 1633, as discussed below. The Company has previously requested recovery of Oregon's share of its pension cost planned during the upcoming rate year, based on its Actuarial derived Financial Accounting Standard (FAS) 87 expense amount. However, in November 2012, the Oregon Commission opened an investigation into the treatment of pension costs in utility rates. Through this open docket, Docket No. UM 1633, the question of how pension costs should be recovered, whether there should be a return on a prepaid pension asset, and how that prepaid pension asset balance will be valued, is being investigated.

The merits of a policy change related to recovery of pension costs and the appropriateness of including a return on prepaid pension assets will be fully vetted during the process of Docket No. UM 1633, and therefore will not be included in detail here. However, for Avista, a prepaid pension asset exists on its books today, resulting from cumulative contributions in excess of cumulative FAS 87 expense, resulting in additional financing costs to the Utility. This condition is expected to reverse in the future, with pension expense exceeding contributions and reducing the prepaid balance eventually to zero. However, until these excess contributions are fully recovered, the Company is incurring and will continue to incur costs to finance its prepaid pension asset. Therefore, the Company believes it is appropriate to include in rate base this asset, and be allowed to earn a return on such asset. To exclude a return on the excess cash contributions in rates excludes a portion of costs attributable to providing services to its customers.

Column (2.04), **2015 Test Period Property Tax Adjustment**, restates the 2013 historical test period accrued levels of property taxes to the 2015 test period level using the most current information. Historical test period accrued levels of property taxes included in the Company's 2013 Oregon operating results reflect property taxes accrued based on plant balances as of December 31, 2012. This adjustment estimates the taxes to be paid on plant balances as of December 31, 2013 during 2015, by using the last known value assessments and levy rates, adding plant additions through December 31, 2013, less depreciation, and then applying a small escalator to the levy rates to reflect their general increasing trend. The effect of this adjustment is to decrease Oregon net operating income by $120,000.

Column (2.05), **2013 EOP Capital Adjustment**, adjusts the 2013 test period rate base (including the associated accumulated depreciation and ADFIT) stated on an AMA basis to an end-of-period (EOP) basis, including the effect of using updated allocation factors to allocated common plant and associated accumulated depreciation and ADFIT. This adjustment was made under the direction of Mr. DeFelice and is described further in his testimony. This adjustment increases Oregon net operating income by $128,000 and increases rate base by $12,004,000.

Q. Please now turn to page 8 and continue with your explanation of the 2015 test period adjustments.

A. Column (2.06), **2014 EOP Capital Adjustment**, reflects all 2014 capital additions together with the associated accumulated depreciation and ADFIT at a 2014 EOP basis. This adjustment also includes the annual level of associated depreciation expense on the 2014 capital additions. In addition, this adjustment adjusts the plant in service at December 31, 2013 [included in adjustment (2.05)] together with the associated accumulated depreciation and ADFIT to a December 31, 2014 EOP basis. This adjustment also includes the annual level of associated depreciation expense on all plant-in-service at December 31, 2013, using the depreciation rates approved in Oregon Commission Order 13-168, dated May 6, 2013 (Docket No. UM 1626). Those depreciation rates on Oregon direct plant were effective July 1, 2014, as approved in the Company's last general rate case. This adjustment was made under the direction of Mr. DeFelice and is described further in his testimony. The impact on Oregon net operating income for this adjustment is a decrease of $1,548,000, with an increase to rate base of $13,885,000.

Column (2.07), **March 31, 2015 EOP Capital Adjustment**, reflects 2015 capital additions moved into service by March 31, 2015 together with the associated accumulated depreciation and ADFIT on a March 31, 2015 EOP basis. This adjustment also includes the annual level of associated depreciation expense on the 2015 capital additions. In addition, this adjustment adjusts the plant that was in service at December 31, 2013 (included in adjustment (2.05)), plus the 2014 capital additions (included in adjustment (2.06)) together with the associated accumulated depreciation and ADFIT to a March 31, 2015 EOP basis. This adjustment was made under the direction of Mr. DeFelice and is described further in his testimony. The impact on Oregon net operating income for this adjustment is a decrease of $130,000, with an increase to rate base of $1,635,000.

Column (2.08), **March 31, 2015 EOP CIS Adjustment**, reflects the 2015 Customer Information System capital addition with the associated accumulated depreciation and ADFIT on a March 31, 2015 EOP basis. This adjustment also includes the annual level of depreciation expense on the CIS project. This adjustment was made under the direction of Mr. DeFelice and is described further in the testimony of Mr. Kensok. The net effect of this adjustment decreases Oregon net operating income by $235,000 and increases rate base by $7,561,000.

Column (2.09), entitled **Working Capital**, increases total rate base for the Company's working capital adjustment. 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. Working capital represents investor supplied funds that are properly included in the Company's rate base for ratemaking purposes.

While there are various methods used to determine a Company's working capital, the Company has calculated its working capital in this proceeding using the Investor Supplied Working Capital (ISWC) method. The Company believes this is a reasonable approach to computing working capital, representing expended funds to provide reliable service to its customers. The net effect of this adjustment increases Oregon net operating income by $49,000 and increases rate base by $4,641,000.

Q. Please now turn to page 9 and continue with your explanation of the 2015 test period adjustments.

A. Column (2.10), entitled **2015 Test Period Insurance**, adjusts actual historical test period insurance expense for general liability, directors and officers ("D&O") liability, and property to reflect the expected 2015 insurance level of expense, resulting in an increase in expense of $94,000 Oregon share. The net effect of this adjustment decreases Oregon net operating income by $57,000.

Column (2.11), entitled **2015 Test Period IS/IT Expense,** includes the incremental costs associated with Information Services and Information Technology, including software development, application licenses, maintenance fees, and technical support for a range of information services programs. As discussed further by Mr. Kensok, these incremental expenditures are necessary to support Company cyber and general security, emergency operations readiness, natural gas facilities and operations support, customer services and the new CIS system that will be implemented in early 2015. The effect of this adjustment decreases net operating income by $97,000.

The final column entitled **2015 Test Period AMA Total**, provides a subtotal of the preceding columns (1.00) through column (2.11) and represents 2015 test period operating results and rate base prior to any required restating adjustments described below.

VII. RESTATING 2015 TEST PERIOD ADJUSTMENTS

Q. Please explain the significance of the columns that begin on page 10 and continue on page 11, in your Exhibit No. 601.

A. The five adjustments subsequent to the 2015 Test Period AMA column represent restating adjustments to adjust the 2015 total results for Commission required adjustments. They encompass restating of expense items for the 2015 test period as well as rate base items. These adjustments bring the 2015 test period operating results and rate base to the 2015 restated test period results.

Starting on page 10, the first adjustment in column (3.00), **Uncollectible Expense Adjustment**, revises the 2013 historical period level of accrued expense included within the Company's Results of Operations, to the historical three-year average of actual net write-offs. The effect on Oregon net operating income is an increase of $94,000.

The adjustment in column (3.01), **Incentive Pay Adjustment**, 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 Docket No. UG 186, Order No. 09-422, dated October 26, 2009. The result of this adjustment is an increase in net operating income of $219,000.

Column (3.02), **Memberships and Dues Adjustment**, classifies expenses by category and specific percentages are applied to determine the recoverable amounts. This calculation is consistent with the method utilized in recent general rate cases. The effect of this adjustment on Oregon net operating income is an increase of $16,000.

Q. Please now turn to page 11 and continue with your explanation of the restating 2015 test period adjustments.

A. Column (3.03) **State Income Tax (SIT) Adjustment**, adjusts Oregon SIT expense applicable to Oregon gas utility operations. Avista Corporation files a consolidated federal income tax return that includes electric utility operations in Washington and Idaho, natural gas utility operations in Oregon, Washington, and Idaho, and non-utility subsidiary operations.

State income tax expense is determined for Oregon natural gas utility operations using the apportionment method. This method determines Oregon's taxable income using an apportionment factor for Oregon that is applied to the total Company taxable income. The impact to Oregon net operating income for the adjustment to state income taxes is an increase of $23,000.

The Company used the same apportionment method to determine the SIT rate that is used in the derivation of the net operating income to gross revenue conversion factor as shown on page 3 of Exhibit No. 601.

Q. Did the Company use the same method (i.e. apportionment method) in the last general rate case for determining SIT expense and the SIT rate used in the net operating income to gross revenue conversion factor?

A. No, in Docket No. UG-246, the Company, in its filed case, did not use the apportionment method. The Company has been using the stand-alone method for computing SIT expense in general rate cases, which computes Oregon tax by applying the Oregon tax rate to Oregon's taxable income. During settlement, the Company agreed to use the apportionment method, since the Parties agreed it was consistent with the actual method used to compute the tax when the tax was paid to the State. The Company used 6.408% for the apportionment tax rate in this case. The calculation of this rate is described below.

Q. For background information, please describe how SIT is computed by the Company when computing Oregon SIT?

A. Table 1 shows the computation of SIT in 2013 for the Company's Oregon natural gas operations.

Table 1

2013 Calculation of Oregon SIT

System Taxable Income		Oregon's Apportionment Rate (1)		Oregon's Tax Rate (2)		Natural Gas Portion of Oregon Operations (3)		Oregon SIT before any Credits
$ 123,236,066	X	9.375%	X	7.51%	X	75%	=	$ 650,744

Notes:
(1) The apportionment rate is computed annually using the approved Oregon method.
(2) Oregon has a graduated tax structure. This represents the effective tax rate for 2013.
(3) Avista owns an electric generating plant in Oregon, which represents 25% of Oregon's operations. This portion of Oregon's SIT is assigned to electric operations in Washington and Idaho.

Oregon's taxable income is determined by applying the apportionment factor of

9.375% to system taxable income. The tax is then computed by applying the Oregon tax rate, which is 7.51% for 2013, to the calculated Oregon taxable income. This amount is the tax that is paid to the State of Oregon. Avista records 75% of total Oregon tax to the Oregon natural gas operations and 25% to the electric operations, for the share of tax that is for an electric generating plant located in Oregon.

The "apportionment tax rate" for computing Oregon state income taxes for its natural gas operations is shown in Table 2.

Table 2

Calculation of Avista's Apportionment Tax Rate						
Oregon's Apportionment Rate	X	Oregon's Tax Rate	X	Natural Gas Portion of Oregon Operations	=	Oregon's Apportionment Tax Rate
9.38%	X	7.51%	X	75%	=	0.528%

By using the three components of the actual tax calculation for the Oregon natural gas operations, an Oregon apportionment tax rate is 0.528%, which is then applied to <u>system</u> taxable income.

Q. Is the calculated Oregon apportionment tax rate of 0.528% the appropriate rate to use in a general rate case?

A. No, it is not. This rate can only be used if it is applied to Avista Utilities' total <u>system</u> revenues, <u>system</u> expenses and <u>system</u> taxable income. When Avista prepares a general rate case revenue requirement, the starting point is the actual Results of Operations for its <u>Oregon</u> natural gas operations. Use of this rate in a general rate case, which is calculated based on Avista's total utility system in Washington, Idaho and Oregon, would understate

SIT, as shown in Tables 3 below.

Table 3

Avista Corp. 2013 Calculation of Oregon SIT Using Oregon Taxable Income				
Oregon Taxable Income	X	Oregon's Apportionment Tax Rate - for <u>System</u> Taxable Income	=	Oregon SIT before any Credits
$ 10,417,000	X	0.528%	=	$ 55,007

Table 3 shows that applying the <u>system</u> Oregon apportionment tax rate to <u>Oregon's</u> taxable income, tax is calculated to be only $55,007. The actual tax should be $650,744, as shown in Table 1 above. In this filing, the Company used an Oregon apportionment tax rate of 6.408%, which produces the appropriate level of expense when applying it to Oregon's taxable income, as shown in Table 4 below.

Table 4

Avista Corp. 2013 Calculation of Oregon SIT Using Oregon Taxable Income				
Oregon Taxable Income	X	Oregon's Apportionment Tax Rate - for <u>Oregon</u> Taxable Income	=	Oregon SIT before any Credits
$ 10,417,000	X	6.408%	=	$ 667,556

The 6.408% tax rate, as shown on Table 4 was determined by "grossing up" the 0.528% apportionment rate for system taxable net income by Oregon's share of system revenues. Oregon's revenues from its natural gas operations represent approximately 8.24% of total revenues. Therefore, 0.528% divided by 8.24% equals 6.408%, which is the Oregon apportionment tax rate used in this filing.

Q. Please now continue with your explanation of the restating 2015 test period adjustments on page 11.

A. Column (3.04), **Restated Salaries and Wages**, adjusts the 2015 labor expense to be consistent with the method agreed to by the parties in the rate proceeding Docket No. UG-186. This method utilized Staff's approach that adjusts for 1/2 the difference between the 2015 level of payroll costs and the annual percent based on the Consumer Price Index for non-union employees from 2012 to 2015. The Union portion of this adjustment annualizes the effect on union labor expense using the union wage adjustments implemented in April of each year. The Company has applied this approach to its 2015 salary expense. The result of this adjustment on net operating income is an increase of $8,000, and a decrease in rate base of $7,000.

Q. Referring back to page 1, line 42, of Exhibit No. 601, what are natural gas rates of return realized by the Company in Oregon during the 2013 historical test period and the 2015 test period?

A. For the State of Oregon, the actual 2013 historical test period rate of return was 6.93%. The restated 2015 test period rate of return is 5.05% under present rates, which is below the 7.77% rate of return requested by the Company in this case.

Q. How much additional net operating income is required for the State of Oregon gas operations to allow the Company an opportunity to earn its proposed 7.77% rate of return?

A. The net operating income deficiency amounts to $5,400,000, as shown on line 5, page 2 of Exhibit No. 601. The resulting revenue requirement is shown on line 7 and amounts to $9,140,000 or a revenue increase of 9.3%.

VIII. COST ASSIGNMENT AND ALLOCATION PROCEDURES

Q. Have there been any changes to the Company's system and jurisdictional allocation procedures since the Company's last general natural gas case, Docket No. UG-246?

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 a previously-approved methodology that has been in place for several years. The allocation factors used in this case are included in my workpapers.

Q. Do you believe the allocation methodology used today by the Company is appropriate for allocating common costs?

A. Yes, I do. When the Company designed the allocation methodology that is being used today, the specific objectives identified were as follows:

a) The method must be acceptable to all regulators to prevent any stranded costs or investment,
b) The number of cost allocation methods should be minimized,
c) The method needs to be simple,
d) The method needs to have a sound, rational basis,
e) Allocations under the method should be automated, and
f) The method needs to produce reasonable results.

These objectives are still relevant today. The Company believes the methodology continues to meet these overall objectives. The method proposed by Avista and approved by the four Commissions (Washington, Idaho, Oregon and California) produces a reasonable allocation of common costs.

IX. OTHER ISSUES

Q. In Avista's prior general rate case, Docket UG-246, Order No. 14-015, the Company was ordered to complete certain requirements prior to or in conjunction with the Company's next general rate case filing. Would you please provide a summary of those items and how they have been addressed by the Company?

A. Yes. Detailed below are three items that the Company was required to address based on Order No. 14-015 in Docket UG-246. Mr. Ehrbar summarizes other areas that were required to be addressed in his direct testimony. Shown below are the three revenue requirements issues and how these items have been addressed.

Item 1 – Allocation Methodology (*Settlement Stipulation Paragraph 9a*):
Prior to September 30, 2014, Avista will conduct one or more workshops to review the methodology used by Avista to allocate common costs and common plant to its regulated and unregulated operations, electric and gas services, and state jurisdictions. The workshops will include Avista's review of its accounting practices to record its directly-assigned and common costs and identify whether additional cost areas could be more appropriately directly assigned. In addition, the allocation methodology will be reviewed to determine whether the allocation of costs is reasonable from a cost driver standpoint. Parties will not recommend the Oregon Public Utility Commission (OPUC) implement any changes to allocation methodology prior to July 1, 2015. OPUC Staff intends to request a joint meeting with the Staffs of the Washington Utilities and Transportation Commission and the Idaho Public Utilities Commission prior to March 31, 2015. Intervenors in each state will be invited to attend those meetings. At those meetings an attempt will be made to achieve consensus among all affected jurisdictions on the appropriate common cost allocation methodology so as to prevent any stranded costs or investment. However, all Parties recognize that Staff, Intervenors and the OPUC are not bound by the decisions of other state commissions.

Avista Response:
Staff has conducted discovery. A workshop has been scheduled with all Parties on September 11, 2014.
Item 2 - Depreciation Rates Effective Date (*Settlement Stipulation Paragraph 9b*):
Avista will implement depreciation rates on directly assigned plant effective July 1, 2014.

Avista Response:
Avista implemented depreciation rates for Oregon direct property on July 1, 2014.

Item 3 – Advertising and Marketing (*Settlement Stipulation Paragraph 9j*): The Company agrees to meet with Staff and interested parties no later than July 1, 2014 to collaboratively resolve the allocation of costs pursuant to OAR 860-026-0022.

Avista Response:
On April 3, 2014, Avista sent to the Parties a document, developed jointly by Staff and Avista, which summarized Staff's concerns related to the allocation of advertising and marketing costs, and how those issues have been resolved. On April 18, 2014, CUB stated that they had no concerns with the report. NWIGU also had no concerns based on an April 21, 2014 email. The Company allocated the advertising and marketing costs in this case consistent with the methodology agreed to with all Parties.

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. 601

Revenue Requirement and Allocations

AVISTA UTILITIES
OREGON NATURAL GAS
OREGON JURISDICTION PROPOSED RATES
TWELVE MONTHS ENDED DECEMBER 31, 2015

Line No.	Description	PRESENT RATES: Per Results of Operations Report	PRESENT RATES: Total Adjustments	PRESENT RATES: Restated 2015 AMA Test Period	WITH PROPOSED RATES: Proposed Revenues & Related Exp	WITH PROPOSED RATES: Proposed Total (AMA)
		a	*b*	*c*	*d*	*e*
1	OPERATING REVENUES					
2	Total General Business	$94,290	$607	$94,897	$9,140	$104,037
3	Total Transportation	3,044	276	3,320	0	3,320
4	Other Revenues	90,950	(90,797)	153	0	153
5	Total Operating Revenues	188,284	(89,914)	98,370	9,140	107,510
6						
7	OPERATING EXPENSES					
8	Gas Purchased	138,794	(89,708)	49,086	0	49,086
9	Operation and Maintenance	14,430	(1,256)	13,174	49	13,223
10	Administration & General	7,595	508	8,103	215	8,318
11	Total Operation & Maintenance	160,819	(90,456)	70,363	264	70,627
12						
13	DEPRECIATION, AMORTIZATION, TAXES					
14	Taxes Other than Income	5,637	(1,328)	4,309	0	4,309
15	Depreciation & Amortization	6,679	3,275	9,954	0	9,954
16	Total Operating Expenses	173,135	(88,509)	84,626	264	84,890
17						
18	OPERATING INCOME BEFORE FIT/SIT	15,149	(1,405)	13,744	8,876	22,620
19						
20	INCOME TAXES					
21	Current Federal Income Taxes	1,102	(448)	654	2,907	3,562
22	Debt Interest	0	(309)	(309)	0	(309)
23	Deferred Federal Income Taxes	2,832	8	2,840	0	2,840
24	State Income Taxes	665	(126)	539	569	1,108
25	Total Income Taxes	4,599	(875)	3,724	3,476	7,201
26						
27	NET OPERATING INCOME	$10,550	($530)	$10,020	$5,400	$15,419
28						
29						
30	RATE BASE					
31	Utility Plant in Service	$287,747	$51,855	$339,602	$0	$339,602
32	Accumulated Depreciation and Amortization	(98,025)	(12,134)	(110,159)	0	(110,159)
33	Accumulated Deferred FIT	(39,942)	(4,643)	(44,585)	0	(44,585)
34	Net Utility Plant	149,780	35,078	184,858	0	184,858
35						
36	Inventory	2,544	0	2,544	0	2,544
37	Prepaid Pension, Net of ADFIT (1)	0	4,318	4,318	0	4,318
38	Working Capital	0	6,728	6,728	0	6,728
39						
40	TOTAL RATE BASE	$152,324	$46,124	$198,448	$0	$198,448
41						
42	RATE OF RETURN	6.93%		5.05%		7.77%

(1) Prepaid Pension Asset of $6.53 million is offset by $2.2 million Accumulated Deferred Federal Income Tax (ADFIT), resulting in a net Prepaid Pension rate base amount of $4.3 million.

AVISTA UTILITIES
OREGON NATURAL GAS
CALCULATION OF REVENUE REQUIREMENT
TWELVE MONTHS ENDED DECEMBER 31, 2015

Line No.	Description	(000's of Dollars)
1	Forecasted Rate Base	$198,448
2	Proposed Rate of Return	7.77%
3	Net Operating Income Requirement	$15,419
4	Forecasted Net Operating Income	$10,020
5	Net Operating Income Deficiency	$5,399
6	Conversion Factor	0.59075
7	Revenue Requirement	$9,140
8	Total General Business Revenues	$98,217
9	Percentage Revenue Increase	9.3%

AVISTA PROPOSED COST OF CAPITAL

	Capital	Cost	Weighted
Long Term Debt	49.000%	5.560%	2.720%
Common Equity	51.000%	9.900%	5.050%
Total	100.00%		7.77%

AVISTA UTILITIES
OREGON NATURAL GAS
CONVERSION FACTOR EXHIBIT
TWELVE MONTHS ENDED DECEMBER 31, 2013

Line No.	Description		Factor	Amounts
1	Revenues		1.000000	9,140
	Expenses:			
2	Uncollectibles		0.005320	49
3	Commission Fees		0.002500	23
4	Energy Resource Supplier Assessment		0.000810	7
5	Franchise Fees		0.020291	185
6	Oregon Excise Tax		0.062230	569
6	Total Expense		0.091151	833
7	Net Operating Income Before FIT		0.908849	8,307
8	Federal Income Tax @	35.00%	0.318097	2,907
9	REVENUE CONVERSION FACTOR		0.5907523	5,400

AVISTA UTILITIES
OREGON NATURAL GAS
RESTATED 2013 AMA HISTORICAL TEST PERIOD
TWELVE MONTHS ENDED DECEMBER 31, 2015

Line No.	Description		Per Results of Operations Report	Allocation Factor Adjustment	Miscellaneous Restating Adjustment	Eliminate Adder Schedule Adjustment
	Adjustment Number		**1.00**	**1.01**	**1.02**	**1.03**
	Workpaper Refernce		**G-ROO**	**G-FAF**	**G-MR**	**G-EAS**
	REVENUES					
8	SALES TO ULTIMATE CUSTOMERS		94,290	0	0	3,862
12	TRANSPORTATION REVENUES		3,044	0	0	(29)
19	OTHER OPERATING REVENUES		90,950	0	0	(90,797)
21	**TOTAL GAS REVENUES**		**188,284**	**0**	**0**	**(86,964)**
22						
23	**EXPENSES**					
28	TOTAL GAS PURCHASES		138,794	0	0	(83,640)
37	TOTAL OTHER GAS SUPPLY EXPENSE		429	27	0	115
39	**TOTAL PRODUCTION EXPENSES**		**139,223**	**27**	**0**	**(83,525)**
40						
45	TOTAL UG STORAGE OPER EXP		122	0	0	0
48	TOTAL UG STORAGE DEPRCIATION EXP		113	0	0	0
51	TOTAL UG STORAGE NON-FIT TAXES		54	0	0	0
55	**TOTAL UNDERGROUND STORAGE EXPENSES**		**289**	**0**	**0**	**0**
56						
79	DISTRIBUTION O&M EXPENSES		8,061	47	0	0
82	TOTAL DISTRIBUTION DEPRCIATION EXP		3,988	0	0	0
85	TOTAL DISTRIBUTION NON-FIT TAXES		5,583	0	0	(1,466)
89	**TOTAL DISTRIBUTION EXPENSES**		**17,632**	**47**	**0**	**(1,466)**
90						
97	**CUSTOMER ACCOUNTS OPERATING EXP**		**3,653**	**(4)**	**0**	**28**
103	**CUSTOMER SVC & INFO OPERATING EXP**		**2,165**	**0**	**(5)**	**(1,576)**
109	**SALES OPERATING EXPENSES**		**0**	**0**	**0**	**0**
110						
123	ADMIN & GENERAL OPERATING EXP		7,595	456	3	17
126	TOTAL A&G DEPRCIATION EXP		1,407	0	0	0
131	TOTAL A&G AMRT/NON-FIT TAXES		899	0	0	0
135	**TOTAL ADMIN & GENERAL EXPENSES**		**9,901**	**456**	**3**	**17**
136						
143	**TOTAL OTHER DEFERRALS AND AMORTIZATIONS**		**272**	**0**	**0**	**(274)**
144						
145	**TOTAL EXPENSES BEFORE FIT**		**173,135**	**526**	**(2)**	**(86,796)**
146						
147	**NET OPERATING INCOME (LOSS) BEFORE FIT/SIT**		**15,149**	**(526)**	**2**	**(168)**
148						
151	FEDERAL INCOME TAX--Normal Accrual	35.00%	1,102	(172)	1	(55)
152	DEBT INTEREST	3.078%	0	0	0	0
153	DEFERRED INCOME TAX		2,832	8	0	0
154	STATE INCOME TAXES	6.41%	665	(34)	0	(11)
155	**GAS NET OPERATING INCOME (LOSS)**		**10,550**	**(328)**	**1**	**(102)**
156						
157	**RATE BASE**					
158	**PLANT IN SERVICE**					
162	TOTAL INTANGIBLE PLANT		5,457	0	0	0
177	TOTAL UNDERGROUND STORAGE PLANT		5,814	0	0	0
182	TOTAL PRODUCTION PLANT		8	0	0	0
195	TOTAL DISTRIBUTION PLANT		254,396	0	0	0
208	TOTAL GAS GENERAL PLANT		22,072	0	0	0
210	**GROSS PLANT IN SERVICE**		**287,747**	**0**	**0**	**0**
211						
216	TOTAL ACCUMULATED DEPRECIATION		(95,657)	0	0	0
217						
222	TOTAL ACCUMULATED AMORTIZATION		(2,368)	0	0	0
224	**TOTAL ACCUMULATED DEPR/AMORT**		**(98,025)**	**0**	**0**	**0**
225						
226	NET GAS UTILITY PLANT before ADFIT		189,722	0	0	0
227						
228	ACCUMULATED DFIT					
229	ADFIT - Gas Plant in Service		(36,040)	0	0	0
230	ADFIT - Common Plant (282900 from C-DTX)		(3,357)	0	0	0
231	ADFIT - Common Plant (283750 from C-DTX)		(45)	0	0	0
232	ADFIT - Bond Redemptions		(500)	0	0	0
233	**TOTAL ACCUMULATED DFIT**		**(39,942)**	**0**	**0**	**0**
234						
235	**NET GAS UTILITY PLANT**		**149,780**	**0**	**0**	**0**
236						
242	**TOTAL GAS INVENTORY**		**2,544**	**0**	**0**	**0**
243						
244	OTHER REGULATORY ASSETS					
245	Prepaid Pension, Net of ADFIT		0	0	0	0
246	Working Capital		0	0	0	0
247	**TOTAL OTHER REGULATORY ASSETS**		**0**	**0**	**0**	**0**
248						
249	**NET RATE BASE**		**152,324**	**0**	**0**	**0**
250						
251	RATE OF RETURN		**6.93%**			
252						
253	**REVENUE REQUIREMENT**		**2,176**	**555**	**(2)**	**173**

AVISTA UTILITIES
OREGON NATURAL GAS
RESTATED 2013 AMA HISTORICAL TEST PERIOD
TWELVE MONTHS ENDED DECEMBER 31, 2015

Line No.	Description		Weather Normalization Sales/Purch	Restate Debt Adjustment	Materials & Supplies Investment	Restated Historical 2013 AMA Test Period Total
	Adjustment Number		1.04	1.05	1.06	
	Workpaper Refernce		G-WN	G-RD	G-MS	
	REVENUES					
8	SALES TO ULTIMATE CUSTOMERS		(4,907)	0	0	**93,245**
12	TRANSPORTATION REVENUES		0	0	0	**3,015**
19	OTHER OPERATING REVENUES		0	0	0	**153**
21	**TOTAL GAS REVENUES**		**(4,907)**	**0**	**0**	**96,413**
22						
23	**EXPENSES**					
28	TOTAL GAS PURCHASES		(2,927)	0	0	**52,227**
37	TOTAL OTHER GAS SUPPLY EXPENSE		(3)	0	0	**568**
39	**TOTAL PRODUCTION EXPENSES**		**(2,930)**	**0**	**0**	**52,795**
40						
45	TOTAL UG STORAGE OPER EXP		0	0	0	**122**
48	TOTAL UG STORAGE DEPRCIATION EXP		0	0	0	**113**
51	TOTAL UG STORAGE NON-FIT TAXES		0	0	0	**54**
55	**TOTAL UNDERGROUND STORAGE EXPENSES**		**0**	**0**	**0**	**289**
56						
79	DISTRIBUTION O&M EXPENSES		0	0	0	**8,108**
82	TOTAL DISTRIBUTION DEPRCIATION EXP		0	0	0	**3,988**
85	TOTAL DISTRIBUTION NON-FIT TAXES		(100)	0	0	**4,017**
89	**TOTAL DISTRIBUTION EXPENSES**		**(100)**	**0**	**0**	**16,113**
90						
97	**CUSTOMER ACCOUNTS OPERATING EXP**		**(26)**	**0**	**0**	**3,651**
103	**CUSTOMER SVC & INFO OPERATING EXP**		**0**	**0**	**0**	**584**
109	**SALES OPERATING EXPENSES**		**0**	**0**	**0**	**0**
110						
123	ADMIN & GENERAL OPERATING EXP		(16)	0	0	**8,055**
126	TOTAL A&G DEPRCIATION EXP		0	0	0	**1,407**
131	TOTAL A&G AMRT/NON-FIT TAXES		0	0	0	**899**
135	**TOTAL ADMIN & GENERAL EXPENSES**		**(16)**	**0**	**0**	**10,361**
136						
143	**TOTAL OTHER DEFERRALS AND AMORTIZATIONS**		**0**	**0**	**0**	**(2)**
144						
145	**TOTAL EXPENSES BEFORE FIT**		**(3,072)**	**0**	**0**	**83,791**
146						
147	**NET OPERATING INCOME (LOSS) BEFORE FIT/SIT**		**(1,835)**	**0**	**0**	**12,622**
148						
151	FEDERAL INCOME TAX--Normal Accrual	35.00%	(601)	0	0	**274**
152	DEBT INTEREST	3.078%	0	182	(22)	**160**
153	DEFERRED INCOME TAX		0	0	0	**2,840**
154	STATE INCOME TAXES	6.41%	(118)	0	0	**503**
155	**GAS NET OPERATING INCOME (LOSS)**		**(1,116)**	**(182)**	**22**	**8,845**
156						
157	**RATE BASE**					
158	**PLANT IN SERVICE**					
162	TOTAL INTANGIBLE PLANT		0	0	0	**5,457**
177	TOTAL UNDERGROUND STORAGE PLANT		0	0	0	**5,814**
182	TOTAL PRODUCTION PLANT		0	0	0	**8**
195	TOTAL DISTRIBUTION PLANT		0	0	0	**254,396**
208	TOTAL GAS GENERAL PLANT		0	0	0	**22,072**
210	**GROSS PLANT IN SERVICE**		**0**	**0**	**0**	**287,747**
211						
216	TOTAL ACCUMULATED DEPRECIATION		0	0	0	**(95,657)**
217						
222	TOTAL ACCUMULATED AMORTIZATION		0	0	0	**(2,368)**
224	**TOTAL ACCUMULATED DEPR/AMORT**		**0**	**0**	**0**	**(98,025)**
225						
226	NET GAS UTILITY PLANT before ADFIT		0	0	0	**189,722**
227						
228	ACCUMULATED DFIT					
229	ADFIT - Gas Plant in Service		0	0	0	**(36,040)**
230	ADFIT - Common Plant (282900 from C-DTX)		0	0	0	**(3,357)**
231	ADFIT - Common Plant (283750 from C-DTX)		0	0	0	**(45)**
232	ADFIT - Bond Redemptions		0	0	0	**(500)**
233	**TOTAL ACCUMULATED DFIT**		**0**	**0**	**0**	**(39,942)**
234						
235	**NET GAS UTILITY PLANT**		**0**	**0**	**0**	**149,780**
236						
242	**TOTAL GAS INVENTORY**		**0**	**0**	**0**	**2,544**
243						
244	OTHER REGULATORY ASSETS					
245	Prepaid Pension, Net of ADFIT		0	0	0	**0**
246	Working Capital		0	0	2,087	**2,087**
247	**TOTAL OTHER REGULATORY ASSETS**		**0**	**0**	**2,087**	**2,087**
248						
249	**NET RATE BASE**		**0**	**0**	**2,087**	**152,324**
250						
251	RATE OF RETURN					**5.81%**
252						
253	**REVENUE REQUIREMENT**		**1,890**	**309**	**237**	**5,338**

AVISTA UTILITIES
OREGON NATURAL GAS
2015 AMA RESULTS OF OPERATIONS
TWELVE MONTHS ENDED DECEMBER 31, 2015

Line No.	Description		Restated Historical 2013 AMA Test Period Total	2015 Test Period Expense Adjustment	2015 Test Period Revenue Load Adjustment
	Adjustment Number			2.00	2.01
	Workpaper Refernce			G-FE	G-FR
	REVENUES				
8	SALES TO ULTIMATE CUSTOMERS		93,245	0	1,652
12	TRANSPORTATION REVENUES		3,015	0	305
19	OTHER OPERATING REVENUES		153	0	0
21	**TOTAL GAS REVENUES**		**96,413**	**0**	**1,957**
22					
23	**EXPENSES**				
28	TOTAL GAS PURCHASES		52,227	0	(3,141)
37	TOTAL OTHER GAS SUPPLY EXPENSE		568	4	1
39	**TOTAL PRODUCTION EXPENSES**		**52,795**	**4**	**(3,140)**
40					
41	UNDERGROUND STORAGE EXPENSES:				
45	TOTAL UG STORAGE OPER EXP		122	5	0
48	TOTAL UG STORAGE DEPRCIATION EXP		113	0	0
51	TOTAL UG STORAGE NON-FIT TAXES		54	0	0
55	**TOTAL UNDERGROUND STORAGE EXPENSES**		**289**	**5**	**0**
56					
79	DISTRIBUTION O&M EXPENSES		8,108	179	0
82	TOTAL DISTRIBUTION DEPRCIATION EXP		3,988	0	0
85	TOTAL DISTRIBUTION NON-FIT TAXES		4,017	0	40
89	**TOTAL DISTRIBUTION EXPENSES**		**16,113**	**179**	**40**
90					
97	**CUSTOMER ACCOUNTS OPERATING EXP**		**3,651**	**65**	**10**
103	**CUSTOMER SVC & INFO OPERATING EXP**		**584**	**15**	**0**
109	**SALES OPERATING EXPENSES**		**0**	**0**	**0**
110					
123	ADMIN & GENERAL OPERATING EXP		8,055	171	7
126	TOTAL A&G DEPRCIATION EXP		1,407	0	0
131	TOTAL A&G AMRT/NON-FIT TAXES		899	0	0
135	**TOTAL ADMIN & GENERAL EXPENSES**		**10,361**	**171**	**7**
136					
143	**TOTAL OTHER DEFERRALS AND AMORTIZATIONS**		**(2)**	**0**	**0**
144					
145	**TOTAL EXPENSES BEFORE FIT**		**83,791**	**439**	**(3,083)**
146					
147	**NET OPERATING INCOME (LOSS) BEFORE FIT/SIT**		**12,622**	**(439)**	**5,040**
148					
151	FEDERAL INCOME TAX--Normal Accrual	35.00%	274	(144)	1,651
152	DEBT INTEREST	2.720%	160	0	0
153	DEFERRED INCOME TAX		2,840	0	0
154	STATE INCOME TAXES	6.41%	503	(28)	323
155	**GAS NET OPERATING INCOME (LOSS)**		**8,845**	**(267)**	**3,066**
156					
157	**RATE BASE**				
162	TOTAL INTANGIBLE PLANT		5,457	0	0
177	TOTAL UNDERGROUND STORAGE PLANT		5,814	0	0
182	TOTAL PRODUCTION PLANT		8	0	0
195	TOTAL DISTRIBUTION PLANT		254,396	0	0
208	TOTAL GAS GENERAL PLANT		22,072	0	0
209					
210	**GROSS PLANT IN SERVICE**		**287,747**	**0**	**0**
211					
212	ACCUMULATED DEPRECIATION				
213	Underground Storage		(462)	0	0
214	Distribution Plant		(88,564)	0	0
215	General Plant		(6,631)	0	0
216	TOTAL ACCUMULATED DEPRECIATION		(95,657)	0	0
217					
222	TOTAL ACCUMULATED AMORTIZATION		(2,368)	0	0
224	**TOTAL ACCUMULATED DEPR/AMORT**		**(98,025)**	**0**	**0**
225					
226	NET GAS UTILITY PLANT before ADFIT		189,722	0	0
227					
228	ACCUMULATED DFIT				
229	ADFIT - Gas Plant in Service		(36,040)	0	0
230	ADFIT - Common Plant (282900 from C-DTX)		(3,357)	0	0
231	ADFIT - Common Plant (283750 from C-DTX)		(45)	0	0
232	ADFIT - Bond Redemptions		(500)	0	0
233	**TOTAL ACCUMULATED DFIT**		**(39,942)**	**0**	**0**
234					
235	**NET GAS UTILITY PLANT**		**149,780**	**0**	**0**
236					
242	**TOTAL GAS INVENTORY**		**2,544**	**0**	**0**
243					
244	OTHER REGULATORY ASSETS				
245	Prepaid Pension, Net of ADFIT		0	0	0
246	Working Capital		2,087	0	0
247	**TOTAL OTHER REGULATORY ASSETS**		**2,087**	**0**	**0**
248					
249	**NET RATE BASE**		**152,324**	**0**	**0**
250					
251	RATE OF RETURN		5.81%		
252					
253	**REVENUE REQUIREMENT**		**5,338**	**452**	**(5,190)**

AVISTA UTILITIES
OREGON NATURAL GAS
2015 AMA RESULTS OF OPERATIONS
TWELVE MONTHS ENDED DECEMBER 31, 2015

Line No.	Description		2015 Test Period Labor & Benefits Adjustment	Prepaid Pension Investment	2015 Test Period Property Tax Adjustment	2013 EOP Capital Adjustment
	Adjustment Number		2.02	2.03	2.04	2.05
	Workpaper Refernce		G-FLB	G-PPI	G-FPT	G-CAP13
	REVENUES					
8	SALES TO ULTIMATE CUSTOMERS		0	0	0	0
12	TRANSPORTATION REVENUES		0	0	0	0
19	OTHER OPERATING REVENUES		0	0	0	0
21	**TOTAL GAS REVENUES**		**0**	**0**	**0**	**0**
22						
23	**EXPENSES**					
28	TOTAL GAS PURCHASES		0	0	0	0
37	TOTAL OTHER GAS SUPPLY EXPENSE		1	0	0	0
39	**TOTAL PRODUCTION EXPENSES**		**1**	**0**	**0**	**0**
40						
41	UNDERGROUND STORAGE EXPENSES:					
45	TOTAL UG STORAGE OPER EXP		0	0	0	0
48	TOTAL UG STORAGE DEPRCIATION EXP		0	0	0	0
51	TOTAL UG STORAGE NON-FIT TAXES		0	0	0	0
55	**TOTAL UNDERGROUND STORAGE EXPENSES**		**0**	**0**	**0**	**0**
56						
79	DISTRIBUTION O&M EXPENSES		11	0	0	0
82	TOTAL DISTRIBUTION DEPRCIATION EXP		0	0	0	0
85	TOTAL DISTRIBUTION NON-FIT TAXES		0	0	198	0
89	**TOTAL DISTRIBUTION EXPENSES**		**11**	**0**	**198**	**0**
90						
97	**CUSTOMER ACCOUNTS OPERATING EXP**		**5**	**0**	**0**	**0**
103	**CUSTOMER SVC & INFO OPERATING EXP**		**0**	**0**	**0**	**0**
109	**SALES OPERATING EXPENSES**		**0**	**0**	**0**	**0**
110						
123	ADMIN & GENERAL OPERATING EXP		17	0	0	0
126	TOTAL A&G DEPRCIATION EXP		0	0	0	0
131	TOTAL A&G AMRT/NON-FIT TAXES		0	0	0	0
135	**TOTAL ADMIN & GENERAL EXPENSES**		**17**	**0**	**0**	**0**
136						
143	**TOTAL OTHER DEFERRALS AND AMORTIZATIONS**		**0**	**0**	**0**	**0**
144						
145	**TOTAL EXPENSES BEFORE FIT**		**34**	**0**	**198**	**0**
146						
147	**NET OPERATING INCOME (LOSS) BEFORE FIT/SIT**		**(34)**	**0**	**(198)**	**0**
148						
151	FEDERAL INCOME TAX--Normal Accrual	35.00%	(11)	0	(65)	0
152	DEBT INTEREST	2.720%	0	(46)	0	(128)
153	DEFERRED INCOME TAX		0	0	0	0
154	STATE INCOME TAXES	6.41%	(2)	0	(13)	0
155	**GAS NET OPERATING INCOME (LOSS)**		**(21)**	**46**	**(120)**	**128**
156						
157	**RATE BASE**					
162	TOTAL INTANGIBLE PLANT		0	0	0	961
177	TOTAL UNDERGROUND STORAGE PLANT		0	0	0	26
182	TOTAL PRODUCTION PLANT		0	0	0	0
195	TOTAL DISTRIBUTION PLANT		0	0	0	11,718
208	TOTAL GAS GENERAL PLANT		0	0	0	2,263
209						
210	**GROSS PLANT IN SERVICE**		**0**	**0**	**0**	**14,968**
211						
212	ACCUMULATED DEPRECIATION					
213	Underground Storage		0	0	0	(53)
214	Distribution Plant		0	0	0	(1,031)
215	General Plant		0	0	0	(460)
216	TOTAL ACCUMULATED DEPRECIATION		0	0	0	(1,544)
217						
222	TOTAL ACCUMULATED AMORTIZATION		0	0	0	(27)
224	**TOTAL ACCUMULATED DEPR/AMORT**		**0**	**0**	**0**	**(1,571)**
225						
226	NET GAS UTILITY PLANT before ADFIT		0	0	0	13,397
227						
228	ACCUMULATED DFIT					
229	ADFIT - Gas Plant in Service		0	0	0	0
230	ADFIT - Common Plant (282900 from C-DTX)		0	0	0	(1,393)
231	ADFIT - Common Plant (283750 from C-DTX)		0	0	0	0
232	ADFIT - Bond Redemptions		0	0	0	0
233	**TOTAL ACCUMULATED DFIT**		**0**	**0**	**0**	**(1,393)**
234						
235	**NET GAS UTILITY PLANT**		**0**	**0**	**0**	**12,004**
236						
242	**TOTAL GAS INVENTORY**		**0**	**0**	**0**	**0**
243						
244	OTHER REGULATORY ASSETS					
245	Prepaid Pension, Net of ADFIT		0	4,318	0	0
246	Working Capital		0	0	0	0
247	**TOTAL OTHER REGULATORY ASSETS**		**0**	**4,318**	**0**	**0**
248						
249	**NET RATE BASE**		**0**	**4,318**	**0**	**12,004**
250						
251	RATE OF RETURN					
252						
253	**REVENUE REQUIREMENT**		**35**	**490**	**204**	**1,362**

AVISTA UTILITIES
OREGON NATURAL GAS
2015 AMA RESULTS OF OPERATIONS
TWELVE MONTHS ENDED DECEMBER 31, 2015

Line No.	Description		2014 EOP Capital Adjustment	3/31/2015 EOP Capital Adjustment	3/31/2015 EOP CIS Adjustment	Working Capital Adjustment
	Adjustment Number		2.06	2.07	2.08	2.09
	Workpaper Refernce		G-CAP14	G-CAP15	G-CIS	G-FWC
	REVENUES					
8	SALES TO ULTIMATE CUSTOMERS		0	0	0	0
12	TRANSPORTATION REVENUES		0	0	0	0
19	OTHER OPERATING REVENUES		0	0	0	0
21	**TOTAL GAS REVENUES**		**0**	**0**	**0**	**0**
22						
23	**EXPENSES**					
28	TOTAL GAS PURCHASES		0	0	0	0
37	TOTAL OTHER GAS SUPPLY EXPENSE		0	0	0	0
39	**TOTAL PRODUCTION EXPENSES**		**0**	**0**	**0**	**0**
40						
41	UNDERGROUND STORAGE EXPENSES:					
45	TOTAL UG STORAGE OPER EXP		0	0	0	0
48	TOTAL UG STORAGE DEPRCIATION EXP		(4)	1	0	0
51	TOTAL UG STORAGE NON-FIT TAXES		0	0	0	0
55	**TOTAL UNDERGROUND STORAGE EXPENSES**		**(4)**	**1**	**0**	**0**
56						
79	DISTRIBUTION O&M EXPENSES		0	0	0	0
82	TOTAL DISTRIBUTION DEPRCIATION EXP		1,859	73	0	0
85	TOTAL DISTRIBUTION NON-FIT TAXES		0	0	0	0
89	**TOTAL DISTRIBUTION EXPENSES**		**1,859**	**73**	**0**	**0**
90						
97	**CUSTOMER ACCOUNTS OPERATING EXP**		**0**	**0**	**0**	**0**
103	**CUSTOMER SVC & INFO OPERATING EXP**		**0**	**0**	**0**	**0**
109	**SALES OPERATING EXPENSES**		**0**	**0**	**0**	**0**
110						
123	ADMIN & GENERAL OPERATING EXP		0	0	0	0
126	TOTAL A&G DEPRCIATION EXP		316	29	46	0
131	TOTAL A&G AMRT/NON-FIT TAXES		616	140	473	0
135	**TOTAL ADMIN & GENERAL EXPENSES**		**932**	**169**	**519**	**0**
136						
143	**TOTAL OTHER DEFERRALS AND AMORTIZATIONS**		**0**	**0**	**0**	**0**
144						
145	**TOTAL EXPENSES BEFORE FIT**		**2,787**	**243**	**519**	**0**
146						
147	**NET OPERATING INCOME (LOSS) BEFORE FIT/SIT**		**(2,787)**	**(243)**	**(519)**	**0**
148						
151	FEDERAL INCOME TAX--Normal Accrual	35.00%	(913)	(80)	(170)	0
152	DEBT INTEREST	2.720%	(148)	(17)	(81)	(49)
153	DEFERRED INCOME TAX		0	0	0	0
154	STATE INCOME TAXES	6.41%	(179)	(16)	(33)	0
155	**GAS NET OPERATING INCOME (LOSS)**		**(1,548)**	**(130)**	**(235)**	**49**
156						
157	**RATE BASE**					
162	TOTAL INTANGIBLE PLANT		2,257	699	7,099	0
177	TOTAL UNDERGROUND STORAGE PLANT		125	63	0	0
182	TOTAL PRODUCTION PLANT		0	0	0	0
195	TOTAL DISTRIBUTION PLANT		18,414	3,539	0	0
208	TOTAL GAS GENERAL PLANT		3,642	368	688	0
209						
210	**GROSS PLANT IN SERVICE**		**24,438**	**4,669**	**7,787**	**0**
211						
212	ACCUMULATED DEPRECIATION					
213	Underground Storage		(112)	(27)	0	0
214	Distribution Plant		(5,011)	(1,464)	0	0
215	General Plant		(1,826)	(493)	(1)	0
216	TOTAL ACCUMULATED DEPRECIATION		(6,949)	(1,984)	(1)	0
217						
222	TOTAL ACCUMULATED AMORTIZATION		(1,239)	(381)	(9)	0
224	**TOTAL ACCUMULATED DEPR/AMORT**		**(8,188)**	**(2,365)**	**(10)**	**0**
225						
226	NET GAS UTILITY PLANT before ADFIT		16,250	2,304	7,777	0
227						
228	ACCUMULATED DFIT					
229	ADFIT - Gas Plant in Service		(2,250)	(615)	0	0
230	ADFIT - Common Plant (282900 from C-DTX)		(115)	(54)	(216)	0
231	ADFIT - Common Plant (283750 from C-DTX)		0	0	0	0
232	ADFIT - Bond Redemptions		0	0	0	0
233	**TOTAL ACCUMULATED DFIT**		**(2,365)**	**(669)**	**(216)**	**0**
234						
235	**NET GAS UTILITY PLANT**		**13,885**	**1,635**	**7,561**	**0**
236						
242	**TOTAL GAS INVENTORY**		**0**	**0**	**0**	**0**
243						
244	OTHER REGULATORY ASSETS					
245	Prepaid Pension, Net of ADFIT		0	0	0	0
246	Working Capital		0	0	0	4,641
247	**TOTAL OTHER REGULATORY ASSETS**		**0**	**0**	**0**	**4,641**
248						
249	**NET RATE BASE**		**13,885**	**1,635**	**7,561**	**4,641**
250						
251	RATE OF RETURN					
252						
253	**REVENUE REQUIREMENT**		**4,446**	**436**	**1,393**	**527**

AVISTA UTILITIES
OREGON NATURAL GAS
2015 AMA RESULTS OF OPERATIONS
TWELVE MONTHS ENDED DECEMBER 31, 2015

Line No.	Description		2015 Test Period Insurance Adjustment	2015 Test Period IS/IT Adjustment	2015 AMA Test Period
	Adjustment Number		2.10	2.11	
	Workpaper Refernce		G-IA	G-ISIT	
	REVENUES				
8	SALES TO ULTIMATE CUSTOMERS		0	0	**94,897**
12	TRANSPORTATION REVENUES		0	0	**3,320**
19	OTHER OPERATING REVENUES		0	0	**153**
21	**TOTAL GAS REVENUES**		**0**	**0**	**98,370**
22					
23	**EXPENSES**				
28	TOTAL GAS PURCHASES		0	0	**49,086**
37	TOTAL OTHER GAS SUPPLY EXPENSE		0	0	**574**
39	**TOTAL PRODUCTION EXPENSES**		**0**	**0**	**49,660**
40					
41	UNDERGROUND STORAGE EXPENSES:				
45	TOTAL UG STORAGE OPER EXP		0	0	**127**
48	TOTAL UG STORAGE DEPRCIATION EXP		0	0	**110**
51	TOTAL UG STORAGE NON-FIT TAXES		0	0	**54**
55	**TOTAL UNDERGROUND STORAGE EXPENSES**		**0**	**0**	**291**
56					
79	DISTRIBUTION O&M EXPENSES		0	0	**8,298**
82	TOTAL DISTRIBUTION DEPRCIATION EXP		0	0	**5,920**
85	TOTAL DISTRIBUTION NON-FIT TAXES		0	0	**4,255**
89	**TOTAL DISTRIBUTION EXPENSES**		**0**	**0**	**18,473**
90					
97	**CUSTOMER ACCOUNTS OPERATING EXP**		**0**	**0**	**3,731**
103	**CUSTOMER SVC & INFO OPERATING EXP**		**0**	**0**	**599**
109	**SALES OPERATING EXPENSES**		**0**	**0**	**0**
110					
123	ADMIN & GENERAL OPERATING EXP		94	160	**8,504**
126	TOTAL A&G DEPRCIATION EXP		0	0	**1,798**
131	TOTAL A&G AMRT/NON-FIT TAXES		0	0	**2,128**
135	**TOTAL ADMIN & GENERAL EXPENSES**		**94**	**160**	**12,430**
136					
143	**TOTAL OTHER DEFERRALS AND AMORTIZATIONS**		**0**	**0**	**(2)**
144					
145	**TOTAL EXPENSES BEFORE FIT**		**94**	**160**	**85,182**
146					
147	**NET OPERATING INCOME (LOSS) BEFORE FIT/SIT**		**(94)**	**(160)**	**13,188**
148					
151	FEDERAL INCOME TAX--Normal Accrual	35.00%	(31)	(52)	**460**
152	DEBT INTEREST	2.720%	0	0	**(309)**
153	DEFERRED INCOME TAX		0	0	**2,840**
154	STATE INCOME TAXES	6.41%	(6)	(10)	**539**
155	**GAS NET OPERATING INCOME (LOSS)**		**(57)**	**(97)**	**9,658**
156					
157	**RATE BASE**				
162	TOTAL INTANGIBLE PLANT		0	0	**16,473**
177	TOTAL UNDERGROUND STORAGE PLANT		0	0	**6,028**
182	TOTAL PRODUCTION PLANT		0	0	**8**
195	TOTAL DISTRIBUTION PLANT		0	0	**288,067**
208	TOTAL GAS GENERAL PLANT		0	0	**29,033**
209					
210	**GROSS PLANT IN SERVICE**		**0**	**0**	**339,609**
211					
212	ACCUMULATED DEPRECIATION				
213	Underground Storage		0	0	**(654)**
214	Distribution Plant		0	0	**(96,070)**
215	General Plant		0	0	**(9,411)**
216	TOTAL ACCUMULATED DEPRECIATION		0	0	**(106,135)**
217					
222	TOTAL ACCUMULATED AMORTIZATION		0	0	**(4,024)**
224	**TOTAL ACCUMULATED DEPR/AMORT**		**0**	**0**	**(110,159)**
225					
226	NET GAS UTILITY PLANT before ADFIT		0	0	**229,450**
227					
228	ACCUMULATED DFIT				
229	ADFIT - Gas Plant in Service		0	0	**(38,905)**
230	ADFIT - Common Plant (282900 from C-DTX)		0	0	**(5,135)**
231	ADFIT - Common Plant (283750 from C-DTX)		0	0	**(45)**
232	ADFIT - Bond Redemptions		0	0	**(500)**
233	**TOTAL ACCUMULATED DFIT**		**0**	**0**	**(44,585)**
234					
235	**NET GAS UTILITY PLANT**		**0**	**0**	**184,865**
236					
242	**TOTAL GAS INVENTORY**		**0**	**0**	**2,544**
243					
244	OTHER REGULATORY ASSETS				
245	Prepaid Pension, Net of ADFIT		0	0	**4,318**
246	Working Capital		0	0	**6,728**
247	**TOTAL OTHER REGULATORY ASSETS**		**0**	**0**	**11,046**
248					
249	**NET RATE BASE**		**0**	**0**	**198,455**
250					
251	RATE OF RETURN				**4.87%**
252					
253	**REVENUE REQUIREMENT**		**97**	**165**	**9,754**

AVISTA UTILITIES
OREGON NATURAL GAS
EXHIBIT 1 - 2015 TEST PERIOD
TWELVE MONTHS ENDED DECEMBER 31, 2015

Line No.	Description		2015 AMA Test Period	Uncollectible Expense Adjustment	Incentive Pay Adjustment	Memberships and Dues Adjustment
	Adjustment Number			3.00	3.01	3.02
	Workpaper Refernce			G-UE	G-IP	G-MD
	REVENUES					
8	SALES TO ULTIMATE CUSTOMERS		94,897	0	0	0
12	TRANSPORTATION REVENUES		3,320	0	0	0
19	OTHER OPERATING REVENUES		153	0	0	0
21	**TOTAL GAS REVENUES**		**98,370**	**0**	**0**	**0**
22						
23	**EXPENSES**					
28	TOTAL GAS PURCHASES		49,086	0	0	0
37	TOTAL OTHER GAS SUPPLY EXPENSE		574	0	0	0
39	**TOTAL PRODUCTION EXPENSES**		**49,660**	**0**	**0**	**0**
40						
45	TOTAL UG STORAGE OPER EXP		127	0	0	0
48	TOTAL UG STORAGE DEPRCIATION EXP		110	0	0	0
51	TOTAL UG STORAGE NON-FIT TAXES		54	0	0	0
55	**TOTAL UNDERGROUND STORAGE EXPENSES**		**291**	**0**	**0**	**0**
56						
79	DISTRIBUTION O&M EXPENSES		8,298	0	0	0
82	TOTAL DISTRIBUTION DEPRCIATION EXP		5,920	0	0	0
85	TOTAL DISTRIBUTION NON-FIT TAXES		4,255	0	0	0
89	**TOTAL DISTRIBUTION EXPENSES**		**18,473**	**0**	**0**	**0**
90						
97	**CUSTOMER ACCOUNTS OPERATING EXP**		**3,731**	**(155)**	**0**	**0**
103	**CUSTOMER SVC & INFO OPERATING EXP**		**599**	**0**	**0**	**0**
109	**SALES OPERATING EXPENSES**		**0**	**0**	**0**	**0**
110						
123	ADMIN & GENERAL OPERATING EXP		8,504	0	(360)	(27)
126	TOTAL A&G DEPRCIATION EXP		1,798	0	0	0
131	TOTAL A&G AMRT/NON-FIT TAXES		2,128	0	0	0
135	**TOTAL ADMIN & GENERAL EXPENSES**		**12,430**	**0**	**(360)**	**(27)**
136						
143	**TOTAL OTHER DEFERRALS AND AMORTIZATIONS**		**(2)**	**0**	**0**	**0**
144						
145	**TOTAL EXPENSES BEFORE FIT**		**85,182**	**(155)**	**(360)**	**(27)**
146						
147	**NET OPERATING INCOME (LOSS) BEFORE FIT/SIT**		**13,188**	**155**	**360**	**27**
148						
151	FEDERAL INCOME TAX--Normal Accrual	35.00%	460	51	118	9
152	DEBT INTEREST	2.720%	(309)	0	0	0
153	DEFERRED INCOME TAX		2,840	0	0	0
154	STATE INCOME TAXES	7.60%	539	10	23	2
155	**GAS NET OPERATING INCOME (LOSS)**		**9,658**	**94**	**219**	**16**
156						
157	**RATE BASE**					
158	**PLANT IN SERVICE**					
162	TOTAL INTANGIBLE PLANT		16,473	0	0	0
177	TOTAL UNDERGROUND STORAGE PLANT		6,028	0	0	0
182	TOTAL PRODUCTION PLANT		8	0	0	0
195	TOTAL DISTRIBUTION PLANT		288,067	0	0	0
208	TOTAL GAS GENERAL PLANT		29,033	0	0	0
210	**GROSS PLANT IN SERVICE**		**339,609**	**0**	**0**	**0**
211						
212	ACCUMULATED DEPRECIATION					
213	Underground Storage		(654)	0	0	0
214	Distribution Plant		(96,070)	0	0	0
215	General Plant		(9,411)	0	0	0
216	TOTAL ACCUMULATED DEPRECIATION		(106,135)	0	0	0
217						
222	TOTAL ACCUMULATED AMORTIZATION		(4,024)	0	0	0
224	**TOTAL ACCUMULATED DEPR/AMORT**		**(110,159)**	**0**	**0**	**0**
225						
226	NET GAS UTILITY PLANT before ADFIT		229,450	0	0	0
227						
228	ACCUMULATED DFIT					
229	ADFIT - Gas Plant in Service		(38,905)	0	0	0
230	ADFIT - Common Plant (282900 from C-DTX)		(5,135)	0	0	0
231	ADFIT - Common Plant (283750 from C-DTX)		(45)	0	0	0
232	ADFIT - Bond Redemptions		(500)	0	0	0
233	**TOTAL ACCUMULATED DFIT**		**(44,585)**	**0**	**0**	**0**
234						
235	**NET GAS UTILITY PLANT**		**184,865**	**0**	**0**	**0**
236						
242	**TOTAL GAS INVENTORY**		**2,544**	**0**	**0**	**0**
243						
244	OTHER REGULATORY ASSETS					
245	Prepaid Pension, net of ADFIT		4,318	0	0	0
246	Working Capital		6,728	0	0	0
247	**TOTAL OTHER REGULATORY ASSETS**		**11,046**	**0**	**0**	**0**
248						
249	**NET RATE BASE**		**198,455**	**0**	**0**	**0**
250						
251	RATE OF RETURN		4.87%			
252						
253	**REVENUE REQUIREMENT**		**9,754**	**(160)**	**(371)**	**(28)**

AVISTA UTILITIES
OREGON NATURAL GAS
EXHIBIT 1 - 2015 TEST PERIOD
TWELVE MONTHS ENDED DECEMBER 31, 2015

Line No.	Description		State Income Tax Adjustment	Restated Salaries and Wages Adjustment	Restated 2015 AMA Test Period
	Adjustment Number		3.03	3.04	
	Workpaper Refernce		G-SIT	G-SW	
	REVENUES				
8	SALES TO ULTIMATE CUSTOMERS		0	0	94,897
12	TRANSPORTATION REVENUES		0	0	3,320
19	OTHER OPERATING REVENUES		0	0	153
21	**TOTAL GAS REVENUES**		0	0	98,370
22					
23	**EXPENSES**				
28	TOTAL GAS PURCHASES		0	0	49,086
37	TOTAL OTHER GAS SUPPLY EXPENSE		0	0	574
39	**TOTAL PRODUCTION EXPENSES**		0	0	49,660
40					
45	TOTAL UG STORAGE OPER EXP		0	0	127
48	TOTAL UG STORAGE DEPRCIATION EXP		0	0	110
51	TOTAL UG STORAGE NON-FIT TAXES		0	0	54
55	**TOTAL UNDERGROUND STORAGE EXPENSES**		0	0	291
56					
79	DISTRIBUTION O&M EXPENSES		0	0	8,298
82	TOTAL DISTRIBUTION DEPRCIATION EXP		0	0	5,920
85	TOTAL DISTRIBUTION NON-FIT TAXES		0	0	4,255
89	**TOTAL DISTRIBUTION EXPENSES**		0	0	18,473
90					
97	**CUSTOMER ACCOUNTS OPERATING EXP**		0	0	3,576
103	**CUSTOMER SVC & INFO OPERATING EXP**		0	0	599
109	**SALES OPERATING EXPENSES**		0	0	0
110					
123	ADMIN & GENERAL OPERATING EXP		0	(14)	8,103
126	TOTAL A&G DEPRCIATION EXP		0	0	1,798
131	TOTAL A&G AMRT/NON-FIT TAXES		0	0	2,128
135	**TOTAL ADMIN & GENERAL EXPENSES**		0	(14)	12,029
136					
143	**TOTAL OTHER DEFERRALS AND AMORTIZATIONS**		0	0	(2)
144					
145	**TOTAL EXPENSES BEFORE FIT**		0	(14)	84,626
146					
147	**NET OPERATING INCOME (LOSS) BEFORE FIT/SIT**		0	14	13,744
148					
151	FEDERAL INCOME TAX--Normal Accrual	35.00%	13	5	654
152	DEBT INTEREST	2.720%	0	0	(309)
153	DEFERRED INCOME TAX		0	0	2,840
154	STATE INCOME TAXES	7.60%	(36)	1	539
155	**GAS NET OPERATING INCOME (LOSS)**		23	8	10,020
156					
157	**RATE BASE**				
158	**PLANT IN SERVICE**				
162	TOTAL INTANGIBLE PLANT		0	0	16,473
177	TOTAL UNDERGROUND STORAGE PLANT		0	0	6,028
182	TOTAL PRODUCTION PLANT		0	0	8
195	TOTAL DISTRIBUTION PLANT		0	(7)	288,060
208	TOTAL GAS GENERAL PLANT		0	0	29,033
210	**GROSS PLANT IN SERVICE**		0	(7)	339,602
211					
212	ACCUMULATED DEPRECIATION				
213	Underground Storage		0	0	(654)
214	Distribution Plant		0	0	(96,070)
215	General Plant		0	0	(9,411)
216	TOTAL ACCUMULATED DEPRECIATION		0	0	(106,135)
217					
222	TOTAL ACCUMULATED AMORTIZATION		0	0	(4,024)
224	**TOTAL ACCUMULATED DEPR/AMORT**		0	0	(110,159)
225					
226	NET GAS UTILITY PLANT before ADFIT		0	(7)	229,443
227					
228	ACCUMULATED DFIT				
229	ADFIT - Gas Plant in Service		0	0	(38,905)
230	ADFIT - Common Plant (282900 from C-DTX)		0	0	(5,135)
231	ADFIT - Common Plant (283750 from C-DTX)		0	0	(45)
232	ADFIT - Bond Redemptions		0	0	(500)
233	**TOTAL ACCUMULATED DFIT**		0	0	(44,585)
234					
235	**NET GAS UTILITY PLANT**		0	(7)	184,858
236					
242	**TOTAL GAS INVENTORY**		0	0	2,544
243					
244	OTHER REGULATORY ASSETS				
245	Prepaid Pension, net of ADFIT		0	0	4,318
246	Working Capital		0	0	6,728
247	**TOTAL OTHER REGULATORY ASSETS**		0	0	11,046
248					
249	**NET RATE BASE**		0	(7)	198,448
250					
251	RATE OF RETURN				5.05%
252					
253	**REVENUE REQUIREMENT**		(40)	(15)	9,141

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

ELIZABETH M. ANDREWS
Exhibit No. 602

Revenue Requirement and Allocations

AVISTA UTILITIES
OREGON NATURAL GAS
PROPOSED RATES EXHIBIT
TWELVE MONTHS ENDED DECEMBER 31, 2015

				PRESENT RATES			WITH PROPOSED RATES	
Line No.		Acct. No.	Description	Per Results of Operations Report	Total Adjustments	Restated 2015 AMA Test Period	Proposed Revenues & Related Exp	Proposed Total (AMA)
	REVENUES			*a*	*b*	*c*	*d*	*e*
1			SALES OF GAS:					
2	99	480000	Residential	61,041	(155)	60,886	9,140	70,026
3	99	481200	Commercial	31,580	379	31,959	0	31,959
4	99	481300	Industrial-Firm	474	86	560	0	560
5	99	481400	Interruptible	454	297	751	0	751
6	99	484000	Interdepartmental Sales	15	0	15	0	15
7	99	499000	Unbilled Revenue	726	0	726	0	726
8			SALES TO ULTIMATE CUSTOMERS	94,290	607	94,897	9,140	104,037
9								
10			TRANSPORTATION REVENUES					
11	99	489300	Transportation - Commercial/Industrial	3,044	276	3,320	0	3,320
12			TRANSPORTATION REVENUES	3,044	276	3,320	0	3,320
13								
14			OTHER OPERATING REVENUES:					
15	99	483XXX	Sales For Resale	90,624	(90,624)	0	0	0
16	99	488000	Miscellaneous Service Revenues	152	0	152	0	152
17	99	493000	Other Gas Revenue - Gas Property Rent	1	0	1	0	1
18	99	495XXX	Other Gas Revenues	173	(173)	0	0	0
19			OTHER OPERATING REVENUES	90,950	(90,797)	153	0	153
20								
21	**TOTAL GAS REVENUES**			**188,284**	**(89,914)**	**98,370**	**9,140**	**107,510**
22								
23	EXPENSES							
24			PRODUCTION EXPENSES:					
25								
26			GAS PURCHASES					
27	OR-804	804XXX	Gas Purchases	138,794	(89,708)	49,086	0	49,086
28			TOTAL GAS PURCHASES	138,794	(89,708)	49,086	0	49,086
29								
30			OTHE GAS SUPPLY EXPENSE					
31	OR-805	805XXX	Other Gas Purchases	(385)	385	0	0	0
32	99	807000	Purchased Gas Expenses	0	(686)	(686)	0	(686)
33	OR-808	808XXX	Natural Gas Storage Transactions	687	417	1,104	0	1,104
34	99	811000	Gas Used for Products Extraction	(417)	0	(417)	0	(417)
35	99	813000	Other Gas Expenses	496	31	527	0	527
36	99	813010	Gas Technology Institute (GTI) Expenses	48	(2)	46	0	46
37			TOTAL OTHER GAS SUPPLY EXPENSE	429	145	574	0	574
38								
39			TOTAL PRODUCTION EXPENSES	139,223	(89,563)	49,660	0	49,660
40								
41			UNDERGROUND STORAGE EXPENSES:					
42	**99**	814000	Supervision & Engineering	0	0	0	0	0
43	**99**	824000	Other Expenses	67	3	70	0	70
44	**99**	837000	Other Equipment	55	2	57	0	57
45			TOTAL UG STORAGE OPER EXP	122	5	127	0	127
46								
47	OR-DEPX		Depreciation Expense-Underground Storage	113	(3)	110	0	110
48			TOTAL UG STORAGE DEPRCIATION EXP	113	(3)	110	0	110
49								
50	OR-OTX		Taxes Other Than FIT-Underground Storage	54	0	54	0	54
51			TOTAL UG STORAGE NON-FIT TAXES	54	0	54	0	54
52								
53			TOTAL UG STORAGE DEPR/AMRT/NON-FIT TAXES	167	(3)	164	0	164
54								
55			TOTAL UNDERGROUND STORAGE EXPENSES	289	2	291	0	291
56								

AVISTA UTILITIES
OREGON NATURAL GAS
PROPOSED RATES EXHIBIT
TWELVE MONTHS ENDED DECEMBER 31, 2015

				PRESENT RATES			WITH PROPOSED RATES	
Line No.		Acct. No.	Description	Per Results of Operations Report	Total Adjustments	Restated 2015 AMA Test Period	Proposed Revenues & Related Exp	Proposed Total (AMA)
57			DISTRIBUTION EXPENSES:					
58			OPERATION					
59	99	870000	Supervision & Engineering	782	46	828	0	828
60	99	871000	Distribution Load Dispatching	0	0	0	0	0
61	99	874000	Mains & Services Expenses	1,334	42	1,376	0	1,376
62	99	875000	Measuring & Reg Sta Exp-General	222	4	226	0	226
63	99	876000	Measuring & Reg Sta Exp-Industrial	2	0	2	0	2
64	99	877000	Measuring & Reg Sta Exp-City Gate	5	0	5	0	5
65	99	878000	Meter & House Regulator Expenses	967	42	1,009	0	1,009
66	99	879000	Customer Installation Expenses	1,211	16	1,227	0	1,227
67	99	880000	Other Expenses	904	23	927	0	927
68	99	881000	Rents	14	2	16	0	16
69								
70			MAINTENANCE					
71	99	885000	Supervision & Engineering	68	0	68	0	68
72	99	887000	Mains	1,096	28	1,124	0	1,124
73	99	889000	Measuring & Reg Sta Exp-General	150	3	153	0	153
74	99	890000	Measuring & Reg Sta Exp-Industrial	20	0	20	0	20
75	99	891000	Measuring & Reg Sta Exp-City Gate	9	0	9	0	9
76	99	892000	Services	590	19	609	0	609
77	99	893000	Meters & House Regulators	537	9	546	0	546
78	99	894000	Other Equipment	150	3	153	0	153
79			DISTRIBUTION O&M EXPENSES	8,061	237	8,298	0	8,298
80								
81	OR-DEPX		Depreciation Expense-Distribution	3,988	1,932	5,920	0	5,920
82			TOTAL DISTRIBUTION DEPRCIATION EXP	3,988	1,932	5,920	0	5,920
83								
84	OR-OTX		Taxes Other Than FIT-Distribution	5,583	(1,328)	4,255	0	4,255
85			TOTAL DISTRIBUTION NON-FIT TAXES	5,583	(1,328)	4,255	0	4,255
86								
87			TOTAL DISTR DEPR/AMRT/NON-FIT TAXES	9,571	604	10,175	0	10,175
88								
89			TOTAL DISTRIBUTION EXPENSES	17,632	841	18,473	0	18,473
90								
91			CUSTOMER ACCOUNTS EXPENSES:					
92	99	901000	Supervision	94	5	99	0	99
93	99	902000	Meter Reading Expenses	296	4	300	0	300
94	OR-903	903XXX	Customer Records & Collection Expenses	2,524	29	2,553	0	2,553
95	99	904000	Uncollectible Accounts	676	(115)	561	49	610
96	99	905000	Misc Customer Accounts	63	0	63	0	63
97			CUSTOMER ACCOUNTS OPERATING EXP	3,653	(77)	3,576	49	3,625
98								
99			CUSTOMER SERVICE & INFO EXPENSES:					
100	OR-908	908XXX	Customer Assistance Expenses	1,766	(1,574)	192	0	192
101	99	909000	Advertising	345	6	351	0	351
102	99	910000	Misc Customer Service & Info Exp	54	2	56	0	56
103			CUSTOMER SVC & INFO OPERATING EXP	2,165	(1,566)	599	0	599
104								
105			SALES EXPENSES:					
106	99	912000	Demonstrating & Selling Expenses	0	0	0	0	0
107	99	913000	Advertising	0	0	0	0	0
108	99	916000	Miscellaneous Sales Expenses	0	0	0	0	0
109			SALES OPERATING EXPENSES	0	0	0	0	0

AVISTA UTILITIES
OREGON NATURAL GAS
PROPOSED RATES EXHIBIT
TWELVE MONTHS ENDED DECEMBER 31, 2015

Line No.		Acct. No.	Description		PRESENT RATES: Per Results of Operations Report	PRESENT RATES: Total Adjustments	PRESENT RATES: Restated 2015 AMA Test Period	WITH PROPOSED RATES: Proposed Revenues & Related Exp	WITH PROPOSED RATES: Proposed Total (AMA)
110									
111			ADMINISTRATIVE & GENERAL EXPENSES:						
112	99	920000	Salaries		2,722	(146)	2,576	0	2,576
113	99	921000	Office Supplies & Expenses		486	55	541	0	541
114	99	922000	A&G Expenses Transferred		0	0	0	0	0
115	99	923000	Outside Services Employed		1,160	142	1,302	0	1,302
116	99	924000	Property Insurance Premium		141	46	187	0	187
117	99	925XXX	Injuries and Damages		378	91	469	0	469
118	99	926XXX	Employee Pensions and Benefits		103	4	107	0	107
119	99	928000	Regulatory Commission Expenses		1,280	50	1,330	23	1,353
120	99	930000	Miscellaneous General Expenses		395	8	403	192	595
121	99	931000	Rents		72	14	86	0	86
122	99	935000	Maintenance of General Plant		858	244	1,102	0	1,102
123			ADMIN & GENERAL OPERATING EXP		7,595	508	8,103	215	8,318
124									
125	OR-DEPX		Depreciation Expense-General		1,407	391	1,798	0	1,798
126			TOTAL A&G DEPRCIATION EXP		1,407	391	1,798	0	1,798
127									
128	OR-AMTX		Amortization Expense-General Plant-303000		29	1,229	1,258	0	1,258
129	OR-AMTX		Amortization Expense-Misc IT Intangible Plant-3031XX		864	0	864	0	864
130	OR-AMTX		Amortization Expense-General Plant-390200, 396200		6	0	6	0	6
131			TOTAL A&G AMRT/NON-FIT TAXES		899	1,229	2,128	0	2,128
132									
133			TOTAL A&G DEPR/AMRT/NON-FIT TAXES		2,306	1,620	3,926	0	3,926
134									
135			TOTAL ADMIN & GENERAL EXPENSES		9,901	2,128	12,029	215	12,244
136									
137			OTHER DEFERRALS AND AMORTIZATIONS:						
138	99	407330	Senate Bill 408		(1)	0	(1)	0	(1)
139	99	407408	Senate Bill Unbilled Add-Ons Amortization		0	0	0	0	0
140	99	407431	Senate Bill 408 Amortization		0	0	0	0	0
141	99	407321	Reg Amort Roseburg/Medford Deferral		273	(274)	(1)	0	(1)
142	99	407421	Reg Credit Roseburg/Medford Deferral		0	0	0	0	0
143			TOTAL OTHER DEFERRALS AND AMORTIZATIONS:		272	(274)	(2)	0	(2)
144									
145	**TOTAL EXPENSES BEFORE FIT**				**173,135**	**(88,509)**	**84,626**	**264**	**84,889**
146									
147			NET OPERATING INCOME (LOSS) BEFORE FIT		15,149	(1,405)	13,744	8,876	22,621
148									
149			FEDERAL INCOME TAX--Normal Accrual	35.00%	1,102	(448)	654	2,907	3,562
150			DEBT INTEREST	2.720%	0	(309)	(309)	0	(309)
151			DEFERRED INCOME TAX		2,832	8	2,840	0	2,840
152			STATE INCOME TAXES	7.60%	665	(126)	539	569	1,108
153			GAS NET OPERATING INCOME (LOSS)		10,550	(530)	10,020	5,400	15,420
154									

AVISTA UTILITIES
OREGON NATURAL GAS
PROPOSED RATES EXHIBIT
TWELVE MONTHS ENDED DECEMBER 31, 2015

				PRESENT RATES			WITH PROPOSED RATES	
Line No.		Acct. No.	Description	Per Results of Operations Report	Total Adjustments	Restated 2015 AMA Test Period	Proposed Revenues & Related Exp	Proposed Total (AMA)
155			RATE BASE					
156			PLANT IN SERVICE					
157			INTANGIBLE PLANT:					
158	99	303000	Misc Intangible Plant (303000)	724	0	724	0	724
159	99	3031XX	Misc Intangible IT Plant (3031XX)	4,733	0	4,733	0	4,733
			Misc Intangible Plant Proforma	0	11,016	11,016	0	11,016
160			TOTAL INTANGIBLE PLANT	5,457	11,016	16,473	0	16,473
161								
162			UNDERGROUND STORAGE PLANT:					
163	99	350100	Land in Fee	0	0	0	0	0
164	99	351100	S & I - Wells	0	0	0	0	0
165	99	351200	S & I - Compress Station	1	0	1	0	1
166	99	351300	S & I - Meas/Regulating Station	0	0	0	0	0
167	99	351400	S & I - Office	28	0	28	0	28
168	99	352000	Wells	2,819	0	2,819	0	2,819
169	99	352100	Wells - Leases	0	0	0	0	0
170	99	353000	Lines	62	0	62	0	62
171	99	354000	Compressor Stn Equipment	2,875	0	2,875	0	2,875
172	99	355000	Meas & Regulating Equipment	12	0	12	0	12
173	99	356000	Purification Equipment	0	0	0	0	0
174	99	357000	Other Equipment	17	0	17	0	17
			Underground Storage Plant Proforma	0	214	214	0	214
175			TOTAL UNDERGROUND STORAGE PLANT	5,814	214	6,028	0	6,028
176								
177			PRODUCTION PLANT:					
178	99	304000	Land & Land Rights	8	0	8	0	8
179	99	311XXX	LPG Equipment	0	0	0	0	0
			Production Plant Proforma	0	0	0	0	0
180			TOTAL PRODUCTION PLANT	8	0	8	0	8
181								
182			DISTRIBUTION PLANT:					
183	99	374200	Land & Land Rights	194	0	194	0	194
184	99	374400	Land Easements	275	0	275	0	275
185	99	375000	Structures & Improvements	275	0	275	0	275
186	99	376000	Mains	149,449	0	149,449	0	149,449
187	99	378000	Measuring & Reg Station Equip-General	4,521	0	4,521	0	4,521
188	99	379000	Measuring & Reg Station Equip-City Gate	1,346	0	1,346	0	1,346
189	99	380000	Services	61,249	0	61,249	0	61,249
190	99	381000	Meters	35,768	0	35,768	0	35,768
191	99	385000	Industrial Measuring & Reg Sta Equip	1,318	0	1,318	0	1,318
192	99	387000	Other Equipment	1	0	1	0	1
			Distribution Plant Proforma	0	33,664	33,664	0	33,664
193			TOTAL DISTRIBUTION PLANT	254,396	33,664	288,060	0	288,060
194								
195			GAS GENERAL PLANT: (From C-GPL)					
196		389XXX	Land & Land Rights	904	0	904	0	904
197		390XXX	Structures & Improvements	9,115	0	9,115	0	9,115
198		391XXX	Office Furniture & Equipment	4,007	0	4,007	0	4,007
199		392XXX	Transportation Equipment	2,771	0	2,771	0	2,771
200		393000	Stores Equipment	57	0	57	0	57
201		394000	Tools, Shop & Garage Equipment	2,046	0	2,046	0	2,046
202		395000	Laboratory Equipment	206	0	206	0	206
203		396XXX	Power Operated Equipment	90	0	90	0	90
204		397XXX	Communications Equipment	2,837	0	2,837	0	2,837
205		398000	Miscellaneous Equipment	39	0	39	0	39
			General Plant Proforma	0	6,961	6,961	0	6,961
206			TOTAL GAS GENERAL PLANT	22,072	6,961	29,033	0	29,033
207								
208			GROSS PLANT IN SERVICE	287,747	51,855	339,602	0	339,602

AVISTA UTILITIES
OREGON NATURAL GAS
PROPOSED RATES EXHIBIT
TWELVE MONTHS ENDED DECEMBER 31, 2015

Line No.		Acct. No.	Description	PRESENT RATES: Per Results of Operations Report	PRESENT RATES: Total Adjustments	PRESENT RATES: Restated 2015 AMA Test Period	WITH PROPOSED RATES: Proposed Revenues & Related Exp	WITH PROPOSED RATES: Proposed Total (AMA)
209								
210			ACCUMULATED DEPRECIATION					
211	OR-ADEP		Underground Storage	(462)	(192)	(654)	0	(654)
212	OR-ADEP		Distribution Plant	(88,564)	(7,506)	(96,070)	0	(96,070)
213	OR-ADEP		General Plant	(6,631)	(2,780)	(9,411)	0	(9,411)
214			TOTAL ACCUMULATED DEPRECIATION	(95,657)	(10,478)	(106,135)	0	(106,135)
215								
216			ACCUMULATED AMORTIZATION					
217	OR-AAMT		General Plant - 303000	(63)	0	(63)	0	(63)
218	OR-AAMT		Misc IT Intangible IT Plant - 3031XX	(2,241)	(1,656)	(3,897)	0	(3,897)
219	OR-AAMT		General Plant - 390200, 396200	(64)	0	(64)	0	(64)
220			TOTAL ACCUMULATED AMORTIZATION	(2,368)	(1,656)	(4,024)	0	(4,024)
221								
222			TOTAL ACCUMULATED DEPR/AMORT	(98,025)	(12,134)	(110,159)	0	(110,159)
223								
224			NET GAS UTILITY PLANT before DFIT	189,722	39,721	229,443	0	229,443
225								
226			ACCUMULATED DFIT					
227	99	282900	ADFIT - Gas Plant in Service	(36,040)	(2,865)	(38,905)	0	(38,905)
228		282900	ADFIT - Common Plant (282900 from C-DTX)	(3,357)	(1,778)	(5,135)	0	(5,135)
229		283750	ADFIT - Common Plant (283750 from C-DTX)	(45)	0	(45)	0	(45)
230	99	283850	ADFIT - Bond Redemptions	(500)	0	(500)	0	(500)
231			TOTAL ACCUMULATED DFIT	(39,942)	(4,643)	(44,585)	0	(44,585)
232								
233			NET GAS UTILITY PLANT	149,780	35,078	184,858	0	184,858
234								
235			GAS INVENTORY					
236	99	117100	Gas Stored - Recoverable Base Gas	1,261	0	1,261	0	1,261
237	99	164100	Gas Inventory - Jackson Prairie	1,131	0	1,131	0	1,131
238	99	164105	Gas Inventory - Jackson Prairie Expansion	152	0	152	0	152
239	99	164110	Gas Inventory - Mist	0	0	0	0	0
240			TOTAL GAS INVENTORY	2,544	0	2,544	0	2,544
241								
242			OTHER REGULATORY ASSETS					
243			Prepaid Pension, Net of ADFIT	0	4,318	4,318	0	4,318
244			Working Capital	0	6,728	6,728	0	6,728
245			TOTAL OTHER REGULATORY ASSETS	0	11,046	11,046	0	11,046
246								
247			NET RATE BASE	152,324	46,124	198,448	0	198,448
248								
249			RATE OF RETURN	6.93%		5.05%		7.77%

AVISTA UTILITIES
OREGON NATURAL GAS
TWELVE MONTHS ENDED DECEMBER 31, 2013
(000's OF DOLLARS)

Line No.		Acct. No.	Description	Allocation Factor Adjustment	Miscellaneous Restating Adjustment	Eliminate Adder Schedule Adjustment	Weather Normalization Sales/Purch	Restate Debt Adjustment	Materials & Supplies Investment	2015 Test Period Expense Adjustment
			Adjustment Number	1.01	1.02	1.03	1.04	1.05	1.06	2.00
			Workpaper Reference	G-FAF	G-MR	G-EAS	G-WN	G-RD	G-MS	G-FE
	REVENUES									
1			SALES OF GAS:							
2	99	480000	Residential	0	0	2,053	(3,157)	0	0	0
3	99	481200	Commercial	0	0	1,544	(1,750)	0	0	0
4	99	481300	Industrial-Firm	0	0	10	0	0	0	0
5	99	481400	Interruptible	0	0	255	0	0	0	0
6	99	484000	Interdepartmental Sales	0	0	0	0	0	0	0
7	99	499000	Unbilled Revenue	0	0	0	0	0	0	0
8			SALES TO ULTIMATE CUSTOMERS	0	0	3,862	(4,907)	0	0	0
9										
10			TRANSPORTATION REVENUES							
11	99	489300	Transportation - Commercial/Industrial	0	0	(29)	0	0	0	0
12			TRANSPORTATION REVENUES	0	0	(29)	0	0	0	0
13										
14			OTHER OPERATING REVENUES:							
15	99	483XXX	Sales For Resale	0	0	(90,624)	0	0	0	0
16	99	488000	Miscellaneous Service Revenues	0	0	0	0	0	0	0
17	99	493000	Other Gas Revenue - Gas Property Rent	0	0	0	0	0	0	0
18	99	495XXX	Other Gas Revenues	0	0	(173)	0	0	0	0
19			OTHER OPERATING REVENUES	0	0	(90,797)	0	0	0	0
20										
21	**TOTAL GAS REVENUES**			**0**	**0**	**(86,964)**	**(4,907)**	**0**	**0**	**0**
22										
23	**EXPENSES**									
24			PRODUCTION EXPENSES:							
25										
26			GAS PURCHASES							
27	OR-80	804XXX	Gas Purchases	0	0	(83,640)	(2,927)	0	0	0
28			TOTAL GAS PURCHASES	0	0	(83,640)	(2,927)	0	0	0
29										
30			OTHE GAS SUPPLY EXPENSE							
31	OR-80	805XXX	Other Gas Purchases	0	0	385	0	0	0	0
32	99	807000	Purchased Gas Expenses	0	0	(687)	0	0	0	0
33	OR-80	808XXX	Natural Gas Storage Transactions	0	0	417	0	0	0	0
34	99	811000	Gas Used for Products Extraction	0	0	0	0	0	0	0
35	99	813000	Other Gas Expenses	27	0	0	0	0	0	4
36	99	813010	Gas Technology Institute (GTI) Expenses	0	0	0	(3)	0	0	0
37			TOTAL OTHER GAS SUPPLY EXPENSE	27	0	115	(3)	0	0	4
38										
39			**TOTAL PRODUCTION EXPENSES**	**27**	**0**	**(83,525)**	**(2,930)**	**0**	**0**	**4**
40										
41			UNDERGROUND STORAGE EXPENSES:							
42	99	814000	Supervision & Engineering	0	0	0	0	0	0	0
43	99	824000	Other Expenses	0	0	0	0	0	0	3
44	99	837000	Other Equipment	0	0	0	0	0	0	2
45			TOTAL UG STORAGE OPER EXP	0	0	0	0	0	0	5
46										
47	R-DEPX		Depreciation Expense-Underground Storage	0	0	0	0	0	0	0
48			TOTAL UG STORAGE DEPRCIATION EXP	0	0	0	0	0	0	0
49										
50	OR-OTX		Taxes Other Than FIT-Underground Storage	0	0	0	0	0	0	0
51			TOTAL UG STORAGE NON-FIT TAXES	0	0	0	0	0	0	0
52										
53			TOTAL UG STORAGE DEPR/AMRT/NON-FIT TAXES	0	0	0	0	0	0	0
54										
55			**TOTAL UNDERGROUND STORAGE EXPENSES**	**0**	**0**	**0**	**0**	**0**	**0**	**5**
56										
57			DISTRIBUTION EXPENSES:							
58			OPERATION							
59	99	870000	Supervision & Engineering	29	0	0	0	0	0	6
60	99	871000	Distribution Load Dispatching	0	0	0	0	0	0	0
61	99	874000	Mains & Services Expenses	5	0	0	0	0	0	37
62	99	875000	Measuring & Reg Sta Exp-General	0	0	0	0	0	0	4
63	99	876000	Measuring & Reg Sta Exp-Industrial	0	0	0	0	0	0	0
64	99	877000	Measuring & Reg Sta Exp-City Gate	0	0	0	0	0	0	0
65	99	878000	Meter & House Regulator Expenses	0	0	0	0	0	0	42
66	99	879000	Customer Installation Expenses	2	0	0	0	0	0	14
67	99	880000	Other Expenses	10	0	0	0	0	0	13
68	99	881000	Rents	1	0	0	0	0	0	1
69										
70			MAINTENANCE							
71	99	885000	Supervision & Engineering	0	0	0	0	0	0	0
72	99	887000	Mains	0	0	0	0	0	0	28
73	99	889000	Measuring & Reg Sta Exp-General	0	0	0	0	0	0	3
74	99	890000	Measuring & Reg Sta Exp-Industrial	0	0	0	0	0	0	0
75	99	891000	Measuring & Reg Sta Exp-City Gate	0	0	0	0	0	0	0
76	99	892000	Services	0	0	0	0	0	0	19
77	99	893000	Meters & House Regulators	0	0	0	0	0	0	9
78	99	894000	Other Equipment	0	0	0	0	0	0	3
79			DISTRIBUTION O&M EXPENSES	47	0	0	0	0	0	179
80										
81	OR-DEPX		Depreciation Expense-Distribution	0	0	0	0	0	0	0
82			TOTAL DISTRIBUTION DEPRCIATION EXP	0	0	0	0	0	0	0
83										
84	OR-OTX		Taxes Other Than FIT-Distribution	0	0	(1,466)	(100)	0	0	0
85			TOTAL DISTRIBUTION NON-FIT TAXES	0	0	(1,466)	(100)	0	0	0
86										
87			TOTAL DISTR DEPR/AMRT/NON-FIT TAXES	0	0	(1,466)	(100)	0	0	0
88										
89			**TOTAL DISTRIBUTION EXPENSES**	**47**	**0**	**(1,466)**	**(100)**	**0**	**0**	**179**
90										
91			CUSTOMER ACCOUNTS EXPENSES:							
92	99	901000	Supervision	0	0	0	0	0	0	0
93	99	902000	Meter Reading Expenses	0	0	0	0	0	0	4
94	OR-90	903XXX	Customer Records & Collection Expenses	(3)	0	0	0	0	0	32
95	99	904000	Uncollectible Accounts	(1)	0	28	(26)	0	0	29
96	99	905000	Misc Customer Accounts	0	0	0	0	0	0	0
97			**CUSTOMER ACCOUNTS OPERATING EXP**	**(4)**	**0**	**28**	**(26)**	**0**	**0**	**65**
98										
99			CUSTOMER SERVICE & INFO EXPENSES:							
100	OR-90	908XXX	Customer Assistance Expenses	0	0	(1,576)	0	0	0	2
101	99	909000	Advertising	0	(5)	0	0	0	0	11
102	99	910000	Misc Customer Service & Info Exp	0	0	0	0	0	0	2
103			**CUSTOMER SVC & INFO OPERATING EXP**	**0**	**(5)**	**(1,576)**	**0**	**0**	**0**	**15**
104										
105			SALES EXPENSES:							
106	99	912000	Demonstrating & Selling Expenses	0	0	0	0	0	0	0
107	99	913000	Advertising	0	0	0	0	0	0	0
108	99	916000	Miscellaneous Sales Expenses	0	0	0	0	0	0	0
109			**SALES OPERATING EXPENSES**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
110										
111			ADMINISTRATIVE & GENERAL EXPENSES:							
112	99	920000	Salaries	200	0	0	0	0	0	11
113	99	921000	Office Supplies & Expenses	34	0	0	0	0	0	21
114	99	922000	A&G Expenses Transferred	0	0	0	0	0	0	0
115	99	923000	Outside Services Employed	89	0	0	0	0	0	53
116	99	924000	Property Insurance Premium	10	0	0	0	0	0	6
117	99	925XXX	Injuries and Damages	22	0	0	0	0	0	5
118	99	926XXX	Employee Pensions and Benefits	7	0	0	0	0	0	(3)
119	99	928000	Regulatory Commission Expenses	10	0	17	(16)	0	0	32
120	99	930000	Miscellaneous General Expenses	19	3	0	0	0	0	13

AVISTA UTILITIES
OREGON NATURAL GAS
TWELVE MONTHS ENDED DECEMBER 31, 2013
(000's OF DOLLARS)

Line No.	Acct. No.	Description		Allocation Factor Adjustment	Miscellaneous Restating Adjustment	Eliminate Adder Schedule Adjustment	Weather Normalization Sales/Purch	Restate Debt Adjustment	Materials & Supplies Investment	2015 Test Period Expense Adjustment
		Adjustment Number		**1.01**	**1.02**	**1.03**	**1.04**	**1.05**	**1.06**	**2.00**
		Workpaper Reference		**G-FAF**	**G-MR**	**G-EAS**	**G-WN**	**G-RD**	**G-MS**	**G-FE**
121	99 931000	Rents		11	0	0	0	0	0	3
122	99 935000	Maintenance of General Plant		54	0	0	0	0	0	30
123		ADMIN & GENERAL OPERATING EXP		456	3	17	(16)	0	0	171
124										
125	OR-DEPX	Depreciation Expense-General		0	0	0	0	0	0	0
126		TOTAL A&G DEPRCIATION EXP		0	0	0	0	0	0	0
127										
128	OR-AMTX	Amortization Expense-General Plant-303000		0	0	0	0	0	0	0
129	OR-AMTX	Amortization Expense-Misc IT Intangible Plant-3031XX		0	0	0	0	0	0	0
130	OR-AMTX	Amortization Expense-General Plant-390200, 396200		0	0	0	0	0	0	0
131		TOTAL A&G AMRT/NON-FIT TAXES		0	0	0	0	0	0	0
132										
133		TOTAL A&G DEPR/AMRT/NON-FIT TAXES		0	0	0	0	0	0	0
134										
135		**TOTAL ADMIN & GENERAL EXPENSES**		**456**	**3**	**17**	**(16)**	**0**	**0**	**171**
136										
137		OTHER DEFERRALS AND AMORTIZATIONS:								
138	99 407330	Senate Bill 408		0	0	0	0	0	0	0
139	99 407408	Senate Bill Unbilled Add-Ons Amortization		0	0	0	0	0	0	0
140	99 407431	Senate Bill 408 Amortization		0	0	0	0	0	0	0
141	99 407321	Reg Amort Roseburg/Medford Deferral		0	0	(274)	0	0	0	0
142	99 407421	Reg Credit Roseburg/Medford Deferral		0	0	0	0	0	0	0
143		TOTAL OTHER DEFERRALS AND AMORTIZATIONS:		0	0	(274)	0	0	0	0
144										
145		**TOTAL EXPENSES BEFORE FIT**		**526**	**(2)**	**(86,796)**	**(3,072)**	**0**	**0**	**439**
146										
147		**NET OPERATING INCOME (LOSS) BEFORE FIT**		**(526)**	**2**	**(168)**	**(1,835)**	**0**	**0**	**(439)**
148										
151		FEDERAL INCOME TAX--Normal Accrual	35.00%	(172)	1	(55)	(601)	0	0	(144)
152		DEBT INTEREST	2.720%	0	0	0	0	182	(22)	0
153		DEFERRED INCOME TAX		8	0	0	0	0	0	0
154		STATE INCOME TAXES	6.41%	(34)	0	(11)	(118)	0	0	(28)
155		GAS NET OPERATING INCOME (LOSS)		(328)	1	(102)	(1,116)	(182)	22	(267)
156										
157		RATE BASE								
158		PLANT IN SERVICE								
159		INTANGIBLE PLANT:								
160	99 303000	Misc Intangible Plant (303000)		0	0	0	0	0	0	0
161	99 3031XX	Misc Intangible IT Plant (3031XX)		0	0	0	0	0	0	0
162		Misc Intangible Plant Proforma		0	0	0	0	0	0	0
163		TOTAL INTANGIBLE PLANT		**0**	**0**	**0**	**0**	**0**	**0**	**0**
164										
165		UNDERGROUND STORAGE PLANT:								
166	99 350100	Land in Fee		0	0	0	0	0	0	0
167	99 351100	S & I - Wells		0	0	0	0	0	0	0
168	99 351200	S & I - Compress Station		0	0	0	0	0	0	0
169	99 351300	S & I - Meas/Regulating Station		0	0	0	0	0	0	0
170	99 351400	S & I - Office		0	0	0	0	0	0	0
171	99 352000	Wells		0	0	0	0	0	0	0
172	99 352100	Wells - Leases		0	0	0	0	0	0	0
173	99 353000	Lines		0	0	0	0	0	0	0
174	99 354000	Compressor Stn Equipment		0	0	0	0	0	0	0
175	99 355000	Meas & Regulating Equipment		0	0	0	0	0	0	0
176	99 356000	Purification Equipment		0	0	0	0	0	0	0
177	99 357000	Other Equipment		0	0	0	0	0	0	0
178		Underground Storage Plant Proforma		0	0	0	0	0	0	0
179		TOTAL UNDERGROUND STORAGE PLANT		**0**	**0**	**0**	**0**	**0**	**0**	**0**
180										
181		PRODUCTION PLANT:								
182	99 304000	Land & Land Rights		0	0	0	0	0	0	0
183	99 311XXX	LPG Equipment		0	0	0	0	0	0	0
184		Production Plant Proforma		0	0	0	0	0	0	0
185		TOTAL PRODUCTION PLANT		**0**	**0**	**0**	**0**	**0**	**0**	**0**
186										
187		DISTRIBUTION PLANT:								
188	99 374200	Land & Land Rights		0	0	0	0	0	0	0
189	99 374400	Land Easements		0	0	0	0	0	0	0
190	99 375000	Structures & Improvements		0	0	0	0	0	0	0
191	99 376000	Mains		0	0	0	0	0	0	0
192	99 378000	Measuring & Reg Station Equip-General		0	0	0	0	0	0	0
193	99 379000	Measuring & Reg Station Equip-City Gate		0	0	0	0	0	0	0
194	99 380000	Services		0	0	0	0	0	0	0
195	99 381000	Meters		0	0	0	0	0	0	0
196	99 385000	Industrial Measuring & Reg Sta Equip		0	0	0	0	0	0	0
197	99 387000	Other Equipment		0	0	0	0	0	0	0
198		Distribution Plant Proforma		0		0	0	0	0	0
199		TOTAL DISTRIBUTION PLANT		**0**	**0**	**0**	**0**	**0**	**0**	**0**
200										
201		GAS GENERAL PLANT: (From C-GPL)								
202	389XXX	Land & Land Rights		0	0	0	0	0	0	0
203	390XXX	Structures & Improvements		0	0	0	0	0	0	0
204	391XXX	Office Furniture & Equipment		0	0	0	0	0	0	0
205	392XXX	Transportation Equipment		0	0	0	0	0	0	0
206	393000	Stores Equipment		0	0	0	0	0	0	0
207	394000	Tools, Shop & Garage Equipment		0	0	0	0	0	0	0
208	395000	Laboratory Equipment		0	0	0	0	0	0	0
209	396XXX	Power Operated Equipment		0	0	0	0	0	0	0
210	397XXX	Communications Equipment		0	0	0	0	0	0	0
211	398000	Miscellaneous Equipment		0	0	0	0	0	0	0
212		General Plant Proforma		0	0	0	0	0	0	0
213		TOTAL GAS GENERAL PLANT		**0**	**0**	**0**	**0**	**0**	**0**	**0**
214										
215		**GROSS PLANT IN SERVICE**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
216										
217		ACCUMULATED DEPRECIATION								
218	R-ADEP	Underground Storage		0	0	0	0	0	0	0
219	R-ADEP	Distribution Plant		0	0	0	0	0	0	0
220	R-ADEP	General Plant		0	0	0	0	0	0	0
221		TOTAL ACCUMULATED DEPRECIATION		0	0	0	0	0	0	0
222										
223		ACCUMULATED AMORTIZATION								
224	R-AAMT	General Plant - 303000		0	0	0	0	0	0	0
225	R-AAMT	Misc IT Intangible IT Plant - 3031XX		0	0	0	0	0	0	0
226	R-AAMT	General Plant - 390200, 396200		0	0	0	0	0	0	0
227		TOTAL ACCUMULATED AMORTIZATION		0	0	0	0	0	0	0
228										
229		TOTAL ACCUMULATED DEPR/AMORT		0	0	0	0	0	0	0
230										
231		NET GAS UTILITY PLANT before DFIT		0	0	0	0	0	0	0
232										
233		ACCUMULATED DFIT								
234	99 282900	ADFIT - Gas Plant in Service		0	0	0	0	0	0	0
235	282900	ADFIT - Common Plant (282900 from C-DTX)		0	0	0	0	0	0	0
236	283750	ADFIT - Common Plant (283750 from C-DTX)		0	0	0	0	0	0	0
237	99 283850	ADFIT - Bond Redemptions		0	0	0	0	0	0	0
238		**TOTAL ACCUMULATED DFIT**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
239										
240		**NET GAS UTILITY PLANT**		**0**	**0**	**0**	**0**	**0**	**0**	**0**

AVISTA UTILITIES
OREGON NATURAL GAS
TWELVE MONTHS ENDED DECEMBER 31, 2013
(000's OF DOLLARS)

Line No.		Acct. No.	Description		Allocation Factor Adjustment	Miscellaneous Restating Adjustment	Eliminate Adder Schedule Adjustment	Weather Normalization Sales/Purch	Restate Debt Adjustment	Materials & Supplies Investment	2015 Test Period Expense Adjustment
			Adjustment Number		1.01	1.02	1.03	1.04	1.05	1.06	2.00
			Workpaper Reference		G-FAF	G-MR	G-EAS	G-WN	G-RD	G-MS	G-FE
241											
242			GAS INVENTORY								
243	99	117100	Gas Stored - Recoverable Base Gas		0	0	0	0	0	0	0
244	99	164100	Gas Inventory - Jackson Prairie		0	0	0	0	0	0	0
245	99	164105	Gas Inventory - Jackson Prairie Expansion		0	0	0	0	0	0	0
246	99	164110	Gas Inventory - Mist		0	0	0	0	0	0	0
247			**TOTAL GAS INVENTORY**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
248											
249			OTHER REGULATORY ASSETS								
250			Prepaid Pension, Net of ADFIT		0	0	0	0	0	0	0
251			Working Capital		0	0	0	0	0	2,087	0
252			**TOTAL OTHER REGULATORY ASSETS**		**0**	**0**	**0**	**0**	**0**	**2,087**	**0**
253											
254			**NET RATE BASE**		**0**	**0**	**0**	**0**	**0**	**2,087**	**0**
255											
256			**RATE OF RETURN**		**0%**						
257											
258			**REVENUE REQUIREMENT**		**555**	**-2**	**173**	**1,890**	**309**	**237**	**452**
259											
260			Pro Forma Rate of Return	7.77%							
261			Revenue Conversion Factor	0.59075							
262											
263			NOI Requirement		**328**	**-1**	**102**	**1,116**	**182**	**140**	**267**
264			Revenue Requirement		**555**	**-2**	**173**	**1,890**	**309**	**237**	**452**
265											
266			TAX CALCULATION:								
267			Net Operating Income		(526)	2	(168)	(1,835)	-	-	(439)
268			Other Deductions								
269			Interest		-	-	-	-	466	(57)	-
270			Net Schedule M Adjustments		-	-	-	-	-	-	-
271			Income Before Tax		(526)	2	(168)	(1,835)	466	(57)	(439)
272											
273			State Income Taxes (Including Tax on Interest)		(34)	0	(11)	(118)	30	(4)	(28)
274			Taxable Income		(492)	2	(157)	(1,717)	436	(53)	(411)
275											
276			Federal Tax (Including Tax on Interest)		(172)	1	(55)	(601)	153	(19)	(144)
277			Net Operating Income		(320)	1	(102)	(1,116)	283	(35)	(267)
278											
279			FOR INFORMATION ONLY:								
280			SIT Debt Interest		0	0	0	0	-30	4	0
281			FIT Debt Interest		0	0	0	0	-153	19	0
282					0	0	0	0	-182	22	0

AVISTA UTILITIES
OREGON NATURAL GAS
TWELVE MONTHS ENDED DECEMBER 31, 2013
(000's OF DOLLARS)

Line No.		Acct. No.	Description	2015 Test Period Revenue Load Adjustment	2015 Test Period Labor & Benefits Adjustment	Prepaid Pension Investment	2015 Test Period Property Tax Adjustment	2013 EOP Capital Adjustment	2014 EOP Capital Adjustment	3/31/2015 EOP Capital Adjustment
			Adjustment Number	2.01	2.02	2.03	2.04	2.05	2.06	2.07
			Workpaper Reference	G-FR	G-FLB	G-PPI	G-FPT	G-CAP13	G-CAP14	G-CAP15
	REVENUES									
1			SALES OF GAS:							
2	99	480000	Residential	949	0	0	0	0	0	0
3	99	481200	Commercial	585	0	0	0	0	0	0
4	99	481300	Industrial-Firm	76	0	0	0	0	0	0
5	99	481400	Interruptible	42	0	0	0	0	0	0
6	99	484000	Interdepartmental Sales	0	0	0	0	0	0	0
7	99	499000	Unbilled Revenue	0	0	0	0	0	0	0
8			SALES TO ULTIMATE CUSTOMERS	1,652	0	0	0	0	0	0
9										
10			TRANSPORTATION REVENUES							
11	99	489300	Transportation - Commercial/Industrial	305	0	0	0	0	0	0
12			TRANSPORTATION REVENUES	305	0	0	0	0	0	0
13										
14			OTHER OPERATING REVENUES:							
15	99	483XXX	Sales For Resale	0	0	0	0	0	0	0
16	99	488000	Miscellaneous Service Revenues	0	0	0	0	0	0	0
17	99	493000	Other Gas Revenue - Gas Property Rent	0	0	0	0	0	0	0
18	99	495XXX	Other Gas Revenues	0	0	0	0	0	0	0
19			OTHER OPERATING REVENUES	0	0	0	0	0	0	0
20										
21	**TOTAL GAS REVENUES**			**1,957**	**0**	**0**	**0**	**0**	**0**	**0**
22										
23	**EXPENSES**									
24			PRODUCTION EXPENSES:							
25										
26			GAS PURCHASES							
27	OR-80	804XXX	Gas Purchases	(3,141)	0	0	0	0	0	0
28			TOTAL GAS PURCHASES	(3,141)	0	0	0	0	0	0
29										
30			OTHE GAS SUPPLY EXPENSE							
31	OR-80	805XXX	Other Gas Purchases	0	0	0	0	0	0	0
32	99	807000	Purchased Gas Expenses	0	1	0	0	0	0	0
33	OR-80	808XXX	Natural Gas Storage Transactions	0	0	0	0	0	0	0
34	99	811000	Gas Used for Products Extraction	0	0	0	0	0	0	0
35	99	813000	Other Gas Expenses	0	0	0	0	0	0	0
36	99	813010	Gas Technology Institute (GTI) Expenses	1	0	0	0	0	0	0
37			TOTAL OTHER GAS SUPPLY EXPENSE	1	1	0	0	0	0	0
38										
39			**TOTAL PRODUCTION EXPENSES**	**(3,140)**	**1**	**0**	**0**	**0**	**0**	**0**
40										
41			UNDERGROUND STORAGE EXPENSES:							
42	**99**	814000	Supervision & Engineering	0	0	0	0	0	0	0
43	**99**	824000	Other Expenses	0	0	0	0	0	0	0
44	**99**	837000	Other Equipment	0	0	0	0	0	0	0
45			TOTAL UG STORAGE OPER EXP	0	0	0	0	0	0	0
46										
47	R-DEPX		Depreciation Expense-Underground Storage	0	0	0	0	0	(4)	1
48			TOTAL UG STORAGE DEPRCIATION EXP	0	0	0	0	0	(4)	1
49										
50	OR-OTX		Taxes Other Than FIT-Underground Storage	0	0	0	0	0	0	0
51			TOTAL UG STORAGE NON-FIT TAXES	0	0	0	0	0	0	0
52										
53			TOTAL UG STORAGE DEPR/AMRT/NON-FIT TAXES	0	0	0	0	0	(4)	1
54										
55			**TOTAL UNDERGROUND STORAGE EXPENSES**	**0**	**0**	**0**	**0**	**0**	**(4)**	**1**
56										
57			DISTRIBUTION EXPENSES:							
58			OPERATION							
59	99	870000	Supervision & Engineering	0	11	0	0	0	0	0
60	99	871000	Distribution Load Dispatching	0	0	0	0	0	0	0
61	99	874000	Mains & Services Expenses	0	0	0	0	0	0	0
62	99	875000	Measuring & Reg Sta Exp-General	0	0	0	0	0	0	0
63	99	876000	Measuring & Reg Sta Exp-Industrial	0	0	0	0	0	0	0
64	99	877000	Measuring & Reg Sta Exp-City Gate	0	0	0	0	0	0	0
65	99	878000	Meter & House Regulator Expenses	0	0	0	0	0	0	0
66	99	879000	Customer Installation Expenses	0	0	0	0	0	0	0
67	99	880000	Other Expenses	0	0	0	0	0	0	0
68	99	881000	Rents	0	0	0	0	0	0	0
69										
70			MAINTENANCE							
71	99	885000	Supervision & Engineering	0	0	0	0	0	0	0
72	99	887000	Mains	0	0	0	0	0	0	0
73	99	889000	Measuring & Reg Sta Exp-General	0	0	0	0	0	0	0
74	99	890000	Measuring & Reg Sta Exp-Industrial	0	0	0	0	0	0	0
75	99	891000	Measuring & Reg Sta Exp-City Gate	0	0	0	0	0	0	0
76	99	892000	Services	0	0	0	0	0	0	0
77	99	893000	Meters & House Regulators	0	0	0	0	0	0	0
78	99	894000	Other Equipment	0	0	0	0	0	0	0
79			DISTRIBUTION O&M EXPENSES	0	11	0	0	0	0	0
80										
81	OR-DEPX		Depreciation Expense-Distribution	0	0	0	0	0	1,859	73
82			TOTAL DISTRIBUTION DEPRCIATION EXP	0	0	0	0	0	1,859	73
83										
84	OR-OTX		Taxes Other Than FIT-Distribution	40	0	0	198	0	0	0
85			TOTAL DISTRIBUTION NON-FIT TAXES	40	0	0	198	0	0	0
86										
87			TOTAL DISTR DEPR/AMRT/NON-FIT TAXES	40	0	0	198	0	1,859	73
88										
89			**TOTAL DISTRIBUTION EXPENSES**	**40**	**11**	**0**	**198**	**0**	**1,859**	**73**
90										
91			CUSTOMER ACCOUNTS EXPENSES:							
92	99	901000	Supervision	0	5	0	0	0	0	0
93	99	902000	Meter Reading Expenses	0	0	0	0	0	0	0
94	OR-90	903XXX	Customer Records & Collection Expenses	0	0	0	0	0	0	0
95	99	904000	Uncollectible Accounts	10	0	0	0	0	0	0
96	99	905000	Misc Customer Accounts	0	0	0	0	0	0	0
97			**CUSTOMER ACCOUNTS OPERATING EXP**	**10**	**5**	**0**	**0**	**0**	**0**	**0**
98										
99			CUSTOMER SERVICE & INFO EXPENSES:							
100	OR-90	908XXX	Customer Assistance Expenses	0	0	0	0	0	0	0
101	99	909000	Advertising	0	0	0	0	0	0	0
102	99	910000	Misc Customer Service & Info Exp	0	0	0	0	0	0	0
103			**CUSTOMER SVC & INFO OPERATING EXP**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
104										
105			SALES EXPENSES:							
106	99	912000	Demonstrating & Selling Expenses	0	0	0	0	0	0	0
107	99	913000	Advertising	0	0	0	0	0	0	0
108	99	916000	Miscellaneous Sales Expenses	0	0	0	0	0	0	0
109			**SALES OPERATING EXPENSES**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
110										
111			ADMINISTRATIVE & GENERAL EXPENSES:							
112	99	920000	Salaries	0	17	0	0	0	0	0
113	99	921000	Office Supplies & Expenses	0	0	0	0	0	0	0
114	99	922000	A&G Expenses Transferred	0	0	0	0	0	0	0
115	99	923000	Outside Services Employed	0	0	0	0	0	0	0
116	99	924000	Property Insurance Premium	0	0	0	0	0	0	0
117	99	925XXX	Injuries and Damages	0	0	0	0	0	0	0
118	99	926XXX	Employee Pensions and Benefits	0	0	0	0	0	0	0
119	99	928000	Regulatory Commission Expenses	7	0	0	0	0	0	0
120	99	930000	Miscellaneous General Expenses	0	0	0	0	0	0	0

AVISTA UTILITIES
OREGON NATURAL GAS
TWELVE MONTHS ENDED DECEMBER 31, 2013
(000's OF DOLLARS)

Line No.		Acct. No.	Description		2015 Test Period Revenue Load Adjustment	2015 Test Period Labor & Benefits Adjustment	Prepaid Pension Investment	2015 Test Period Property Tax Adjustment	2013 EOP Capital Adjustment	2014 EOP Capital Adjustment	3/31/2015 EOP Capital Adjustment
			Adjustment Number		2.01	2.02	2.03	2.04	2.05	2.06	2.07
			Workpaper Reference		G-FR	G-FLB	G-PPI	G-FPT	G-CAP13	G-CAP14	G-CAP15
121	99	931000	Rents		0	0	0	0	0	0	0
122	99	935000	Maintenance of General Plant		0	0	0	0	0	0	0
123			ADMIN & GENERAL OPERATING EXP		7	17	0	0	0	0	0
124											
125	OR-DEPX		Depreciation Expense-General		0	0	0	0	0	316	29
126			TOTAL A&G DEPRCIATION EXP		0	0	0	0	0	316	29
127											
128	OR-AMTX		Amortization Expense-General Plant-303000		0	0	0	0	0	616	140
129	OR-AMTX		Amortization Expense-Misc IT Intangible Plant-3031XX		0	0	0	0	0	0	0
130	OR-AMTX		Amortization Expense-General Plant-390200, 396200		0	0	0	0	0	0	0
131			TOTAL A&G AMRT/NON-FIT TAXES		0	0	0	0	0	616	140
132											
133			TOTAL A&G DEPR/AMRT/NON-FIT TAXES		0	0	0	0	0	932	169
134											
135			**TOTAL ADMIN & GENERAL EXPENSES**		**7**	**17**	**0**	**0**	**0**	**932**	**169**
136											
137			OTHER DEFERRALS AND AMORTIZATIONS:								
138	99	407330	Senate Bill 408		0	0	0	0	0	0	0
139	99	407408	Senate Bill Unbilled Add-Ons Amortization		0	0	0	0	0	0	0
140	99	407431	Senate Bill 408 Amortization		0	0	0	0	0	0	0
141	99	407321	Reg Amort Roseburg/Medford Deferral		0	0	0	0	0	0	0
142	99	407421	Reg Credit Roseburg/Medford Deferral		0	0	0	0	0	0	0
143			TOTAL OTHER DEFERRALS AND AMORTIZATIONS:		0	0	0	0	0	0	0
144											
145	**TOTAL EXPENSES BEFORE FIT**				**(3,083)**	**34**	**0**	**198**	**0**	**2,787**	**243**
146											
147			**NET OPERATING INCOME (LOSS) BEFORE FIT**		**5,040**	**(34)**	**0**	**(198)**	**0**	**(2,787)**	**(243)**
148											
151			FEDERAL INCOME TAX--Normal Accrual	35.00%	1,651	(11)	0	(65)	0	(913)	(80)
152			DEBT INTEREST	2.720%	0	0	(46)	0	(128)	(148)	(17)
153			DEFERRED INCOME TAX		0	0	0	0	0	0	0
154			STATE INCOME TAXES	6.41%	323	(2)	0	(13)	0	(179)	(16)
155			GAS NET OPERATING INCOME (LOSS)		3,066	(21)	46	(120)	128	(1,548)	(130)
156											
157			RATE BASE								
158			PLANT IN SERVICE								
159			INTANGIBLE PLANT:								
160	99	303000	Misc Intangible Plant (303000)		0	0	0	0	0	0	0
161	99	3031XX	Misc Intangible IT Plant (3031XX)		0	0	0	0	0	0	0
162			Misc Intangible Plant Proforma		0	0	0	0	961	2,257	699
163			TOTAL INTANGIBLE PLANT		**0**	**0**	**0**	**0**	**961**	**2,257**	**699**
164											
165			UNDERGROUND STORAGE PLANT:								
166	99	350100	Land in Fee		0	0	0	0	0	0	0
167	99	351100	S & I - Wells		0	0	0	0	0	0	0
168	99	351200	S & I - Compress Station		0	0	0	0	0	0	0
169	99	351300	S & I - Meas/Regulating Station		0	0	0	0	0	0	0
170	99	351400	S & I - Office		0	0	0	0	0	0	0
171	99	352000	Wells		0	0	0	0	0	0	0
172	99	352100	Wells - Leases		0	0	0	0	0	0	0
173	99	353000	Lines		0	0	0	0	0	0	0
174	99	354000	Compressor Stn Equipment		0	0	0	0	0	0	0
175	99	355000	Meas & Regulating Equipment		0	0	0	0	0	0	0
176	99	356000	Purification Equipment		0	0	0	0	0	0	0
177	99	357000	Other Equipment		0	0	0	0	0	0	0
178			Underground Storage Plant Proforma		0	0	0	0	26	125	63
179			TOTAL UNDERGROUND STORAGE PLANT		**0**	**0**	**0**	**0**	**26**	**125**	**63**
180											
181			PRODUCTION PLANT:								
182	99	304000	Land & Land Rights		0	0	0	0	0	0	0
183	99	311XXX	LPG Equipment		0	0	0	0	0	0	0
184			Production Plant Proforma		0	0	0	0	0	0	0
185			TOTAL PRODUCTION PLANT		**0**	**0**	**0**	**0**	**0**	**0**	**0**
186											
187			DISTRIBUTION PLANT:								
188	99	374200	Land & Land Rights		0	0	0	0	0	0	0
189	99	374400	Land Easements		0	0	0	0	0	0	0
190	99	375000	Structures & Improvements		0	0	0	0	0	0	0
191	99	376000	Mains		0	0	0	0	0	0	0
192	99	378000	Measuring & Reg Station Equip-General		0	0	0	0	0	0	0
193	99	379000	Measuring & Reg Station Equip-City Gate		0	0	0	0	0	0	0
194	99	380000	Services		0	0	0	0	0	0	0
195	99	381000	Meters		0	0	0	0	0	0	0
196	99	385000	Industrial Measuring & Reg Sta Equip		0	0	0	0	0	0	0
197	99	387000	Other Equipment		0	0	0	0	0	0	0
198			Distribution Plant Proforma		0	0	0	0	11,718	18,414	3,539
199			TOTAL DISTRIBUTION PLANT		**0**	**0**	**0**	**0**	**11,718**	**18,414**	**3,539**
200											
201			GAS GENERAL PLANT: (From C-GPL)								
202		389XXX	Land & Land Rights		0	0	0	0	0	0	0
203		390XXX	Structures & Improvements		0	0	0	0	0	0	0
204		391XXX	Office Furniture & Equipment		0	0	0	0	0	0	0
205		392XXX	Transportation Equipment		0	0	0	0	0	0	0
206		393000	Stores Equipment		0	0	0	0	0	0	0
207		394000	Tools, Shop & Garage Equipment		0	0	0	0	0	0	0
208		395000	Laboratory Equipment		0	0	0	0	0	0	0
209		396XXX	Power Operated Equipment		0	0	0	0	0	0	0
210		397XXX	Communications Equipment		0	0	0	0	0	0	0
211		398000	Miscellaneous Equipment		0	0	0	0	0	0	0
212			General Plant Proforma		0	0	0	0	2,263	3,642	368
213			TOTAL GAS GENERAL PLANT		**0**	**0**	**0**	**0**	**2,263**	**3,642**	**368**
214											
215			**GROSS PLANT IN SERVICE**		**0**	**0**	**0**	**0**	**14,968**	**24,438**	**4,669**
216											
217			ACCUMULATED DEPRECIATION								
218	R-ADEP		Underground Storage		0	0	0	0	(53)	(112)	(27)
219	R-ADEP		Distribution Plant		0	0	0	0	(1,031)	(5,011)	(1,464)
220	R-ADEP		General Plant		0	0	0	0	(460)	(1,826)	(493)
221			TOTAL ACCUMULATED DEPRECIATION		0	0	0	0	(1,544)	(6,949)	(1,984)
222											
223			ACCUMULATED AMORTIZATION								
224	R-AAMT		General Plant - 303000		0	0	0	0	0	0	0
225	R-AAMT		Misc IT Intangible IT Plant - 3031XX		0	0	0	0	(27)	(1,239)	(381)
226	R-AAMT		General Plant - 390200, 396200		0	0	0	0	0	0	0
227			TOTAL ACCUMULATED AMORTIZATION		0	0	0	0	(27)	(1,239)	(381)
228											
229			TOTAL ACCUMULATED DEPR/AMORT		0	0	0	0	(1,571)	(8,188)	(2,365)
230											
231			NET GAS UTILITY PLANT before DFIT		0	0	0	0	13,397	16,250	2,304
232											
233			ACCUMULATED DFIT								
234	99	282900	ADFIT - Gas Plant in Service		0	0	0	0	0	(2,250)	(615)
235		282900	ADFIT - Common Plant (282900 from C-DTX)		0	0	0	0	(1,393)	(115)	(54)
236		283750	ADFIT - Common Plant (283750 from C-DTX)		0	0	0	0	0	0	0
237	99	283850	ADFIT - Bond Redemptions		0	0	0	0	0	0	0
238			**TOTAL ACCUMULATED DFIT**		**0**	**0**	**0**	**0**	**(1,393)**	**(2,365)**	**(669)**
239											
240			**NET GAS UTILITY PLANT**		**0**	**0**	**0**	**0**	**12,004**	**13,885**	**1,635**

AVISTA UTILITIES
OREGON NATURAL GAS
TWELVE MONTHS ENDED DECEMBER 31, 2013
(000's OF DOLLARS)

Line No.		Acct. No.	Description		2015 Test Period Revenue Load Adjustment	2015 Test Period Labor & Benefits Adjustment	Prepaid Pension Investment	2015 Test Period Property Tax Adjustment	2013 EOP Capital Adjustment	2014 EOP Capital Adjustment	3/31/2015 EOP Capital Adjustment
			Adjustment Number		2.01	2.02	2.03	2.04	2.05	2.06	2.07
			Workpaper Reference		G-FR	G-FLB	G-PPI	G-FPT	G-CAP13	G-CAP14	G-CAP15
241											
242			GAS INVENTORY								
243	99	117100	Gas Stored - Recoverable Base Gas		0	0	0	0	0	0	0
244	99	164100	Gas Inventory - Jackson Prairie		0	0	0	0	0	0	0
245	99	164105	Gas Inventory - Jackson Prairie Expansion		0	0	0	0	0	0	0
246	99	164110	Gas Inventory - Mist		0	0	0	0	0	0	0
247			**TOTAL GAS INVENTORY**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
248											
249			OTHER REGULATORY ASSETS								
250			Prepaid Pension, Net of ADFIT		0	0	4,318	0	0	0	0
251			Working Capital		0	0	0	0	0	0	0
252			**TOTAL OTHER REGULATORY ASSETS**		**0**	**0**	**4,318**	**0**	**0**	**0**	**0**
253											
254			**NET RATE BASE**		**0**	**0**	**4,318**	**0**	**12,004**	**13,885**	**1,635**
255											
256			**RATE OF RETURN**								
257											
258			**REVENUE REQUIREMENT**		**-5,190**	**35**	**490**	**204**	**1,362**	**4,446**	**436**
259											
260			Pro Forma Rate of Return	7.77%							
261			Revenue Conversion Factor	0.59075							
262											
263			NOI Requirement		**-3,066**	**21**	**290**	**120**	**805**	**2,626**	**257**
264			Revenue Requirement		**-5,190**	**35**	**490**	**204**	**1,362**	**4,446**	**436**
265											
266			TAX CALCULATION:								
267			Net Operating Income		5,040	(34)	-	(198)	-	(2,787)	(243)
268			Other Deductions								
269			Interest		-	-	(117)	-	(327)	(378)	(44)
270			Net Schedule M Adjustments		-	-	-	-	-	-	-
271			Income Before Tax		5,040	(34)	(117)	(198)	(327)	(3,165)	(287)
272											
273			State Income Taxes (Including Tax on Interest)		323	(2)	(8)	(13)	(21)	(203)	(18)
274			Taxable Income		4,717	(32)	(110)	(185)	(306)	(2,962)	(269)
275											
276			Federal Tax (Including Tax on Interest)		1,651	(11)	(38)	(65)	(107)	(1,037)	(94)
277			Net Operating Income		3,066	(21)	(71)	(120)	(199)	(1,925)	(175)
278											
279			FOR INFORMATION ONLY:								
280			SIT Debt Interest		0	0	8	0	21	24	3
281			FIT Debt Interest		0	0	38	0	107	124	15
282					0	0	46	0	128	148	17

AVISTA UTILITIES
OREGON NATURAL GAS
TWELVE MONTHS ENDED DECEMBER 31, 2013
(000's OF DOLLARS)

Line No.		Acct. No.	Description	3/31/2015 EOP CIS Adjustment	Working Capital Adjustment	2015 Test Period Insurance Adjustment	2015 Test Period IS/IT Adjustment	Uncollectible Expense Adjustment	Incentive Pay Adjustment	Memberships and Dues Adjustment
			Adjustment Number	2.08	2.09	2.10	2.11	3.00	3.01	3.02
			Workpaper Reference	G-CIS	G-FWC	G-IA	G-ISIT	G-UE	G-IP	G-MD
	REVENUES									
1			SALES OF GAS:							
2	99	480000	Residential	0	0	0	0	0	0	0
3	99	481200	Commercial	0	0	0	0	0	0	0
4	99	481300	Industrial-Firm	0	0	0	0	0	0	0
5	99	481400	Interruptible	0	0	0	0	0	0	0
6	99	484000	Interdepartmental Sales	0	0	0	0	0	0	0
7	99	499000	Unbilled Revenue	0	0	0	0	0	0	0
8			SALES TO ULTIMATE CUSTOMERS	0	0	0	0	0	0	0
9										
10			TRANSPORTATION REVENUES							
11	99	489300	Transportation - Commercial/Industrial	0	0	0	0	0	0	0
12			TRANSPORTATION REVENUES	0	0	0	0	0	0	0
13										
14			OTHER OPERATING REVENUES:							
15	99	483XXX	Sales For Resale	0	0	0	0	0	0	0
16	99	488000	Miscellaneous Service Revenues	0	0	0	0	0	0	0
17	99	493000	Other Gas Revenue - Gas Property Rent	0	0	0	0	0	0	0
18	99	495XXX	Other Gas Revenues	0	0	0	0	0	0	0
19			OTHER OPERATING REVENUES	0	0	0	0	0	0	0
20										
21	**TOTAL GAS REVENUES**			**0**	**0**	**0**	**0**	**0**	**0**	**0**
22										
23	**EXPENSES**									
24			PRODUCTION EXPENSES:							
25										
26			GAS PURCHASES							
27	OR-80	804XXX	Gas Purchases	0	0	0	0	0	0	0
28			TOTAL GAS PURCHASES	0	0	0	0	0	0	0
29										
30			OTHE GAS SUPPLY EXPENSE							
31	OR-80	805XXX	Other Gas Purchases	0	0	0	0	0	0	0
32	99	807000	Purchased Gas Expenses	0	0	0	0	0	0	0
33	OR-80	808XXX	Natural Gas Storage Transactions	0	0	0	0	0	0	0
34	99	811000	Gas Used for Products Extraction	0	0	0	0	0	0	0
35	99	813000	Other Gas Expenses	0	0	0	0	0	0	0
36	99	813010	Gas Technology Institute (GTI) Expenses	0	0	0	0	0	0	0
37			TOTAL OTHER GAS SUPPLY EXPENSE	0	0	0	0	0	0	0
38										
39			**TOTAL PRODUCTION EXPENSES**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
40										
41			UNDERGROUND STORAGE EXPENSES:							
42	99	814000	Supervision & Engineering	0	0	0	0	0	0	0
43	99	824000	Other Expenses	0	0	0	0	0	0	0
44	99	837000	Other Equipment	0	0	0	0	0	0	0
45			TOTAL UG STORAGE OPER EXP	0	0	0	0	0	0	0
46										
47	R-DEPX		Depreciation Expense-Underground Storage	0	0	0	0	0	0	0
48			TOTAL UG STORAGE DEPRCIATION EXP	0	0	0	0	0	0	0
49										
50	OR-OTX		Taxes Other Than FIT-Underground Storage	0	0	0	0	0	0	0
51			TOTAL UG STORAGE NON-FIT TAXES	0	0	0	0	0	0	0
52										
53			TOTAL UG STORAGE DEPR/AMRT/NON-FIT TAXES	0	0	0	0	0	0	0
54										
55			**TOTAL UNDERGROUND STORAGE EXPENSES**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
56										
57			DISTRIBUTION EXPENSES:							
58			OPERATION							
59	99	870000	Supervision & Engineering	0	0	0	0	0	0	0
60	99	871000	Distribution Load Dispatching	0	0	0	0	0	0	0
61	99	874000	Mains & Services Expenses	0	0	0	0	0	0	0
62	99	875000	Measuring & Reg Sta Exp-General	0	0	0	0	0	0	0
63	99	876000	Measuring & Reg Sta Exp-Industrial	0	0	0	0	0	0	0
64	99	877000	Measuring & Reg Sta Exp-City Gate	0	0	0	0	0	0	0
65	99	878000	Meter & House Regulator Expenses	0	0	0	0	0	0	0
66	99	879000	Customer Installation Expenses	0	0	0	0	0	0	0
67	99	880000	Other Expenses	0	0	0	0	0	0	0
68	99	881000	Rents	0	0	0	0	0	0	0
69										
70			MAINTENANCE							
71	99	885000	Supervision & Engineering	0	0	0	0	0	0	0
72	99	887000	Mains	0	0	0	0	0	0	0
73	99	889000	Measuring & Reg Sta Exp-General	0	0	0	0	0	0	0
74	99	890000	Measuring & Reg Sta Exp-Industrial	0	0	0	0	0	0	0
75	99	891000	Measuring & Reg Sta Exp-City Gate	0	0	0	0	0	0	0
76	99	892000	Services	0	0	0	0	0	0	0
77	99	893000	Meters & House Regulators	0	0	0	0	0	0	0
78	99	894000	Other Equipment	0	0	0	0	0	0	0
79			DISTRIBUTION O&M EXPENSES	0	0	0	0	0	0	0
80										
81	OR-DEPX		Depreciation Expense-Distribution	0	0	0	0	0	0	0
82			TOTAL DISTRIBUTION DEPRCIATION EXP	0	0	0	0	0	0	0
83										
84	OR-OTX		Taxes Other Than FIT-Distribution	0	0	0	0	0	0	0
85			TOTAL DISTRIBUTION NON-FIT TAXES	0	0	0	0	0	0	0
86										
87			TOTAL DISTR DEPR/AMRT/NON-FIT TAXES	0	0	0	0	0	0	0
88										
89			**TOTAL DISTRIBUTION EXPENSES**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
90										
91			CUSTOMER ACCOUNTS EXPENSES:							
92	99	901000	Supervision	0	0	0	0	0	0	0
93	99	902000	Meter Reading Expenses	0	0	0	0	0	0	0
94	OR-90	903XXX	Customer Records & Collection Expenses	0	0	0	0	0	0	0
95	99	904000	Uncollectible Accounts	0	0	0	0	(155)	0	0
96	99	905000	Misc Customer Accounts	0	0	0	0	0	0	0
97			**CUSTOMER ACCOUNTS OPERATING EXP**	**0**	**0**	**0**	**0**	**(155)**	**0**	**0**
98										
99			CUSTOMER SERVICE & INFO EXPENSES:							
100	OR-90	908XXX	Customer Assistance Expenses	0	0	0	0	0	0	0
101	99	909000	Advertising	0	0	0	0	0	0	0
102	99	910000	Misc Customer Service & Info Exp	0	0	0	0	0	0	0
103			**CUSTOMER SVC & INFO OPERATING EXP**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
104										
105			SALES EXPENSES:							
106	99	912000	Demonstrating & Selling Expenses	0	0	0	0	0	0	0
107	99	913000	Advertising	0	0	0	0	0	0	0
108	99	916000	Miscellaneous Sales Expenses	0	0	0	0	0	0	0
109			**SALES OPERATING EXPENSES**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
110										
111			ADMINISTRATIVE & GENERAL EXPENSES:							
112	99	920000	Salaries	0	0	0	0	0	(360)	0
113	99	921000	Office Supplies & Expenses	0	0	0	0	0	0	0
114	99	922000	A&G Expenses Transferred	0	0	0	0	0	0	0
115	99	923000	Outside Services Employed	0	0	0	0	0	0	0
116	99	924000	Property Insurance Premium	0	0	30	0	0	0	0
117	99	925XXX	Injuries and Damages	0	0	64	0	0	0	0
118	99	926XXX	Employee Pensions and Benefits	0	0	0	0	0	0	0
119	99	928000	Regulatory Commission Expenses	0	0	0	0	0	0	0
120	99	930000	Miscellaneous General Expenses	0	0	0	0	0	0	(27)

AVISTA UTILITIES
OREGON NATURAL GAS
TWELVE MONTHS ENDED DECEMBER 31, 2013
(000's OF DOLLARS)

Line No.	Acct. No.	Description		3/31/2015 EOP CIS Adjustment	Working Capital Adjustment	2015 Test Period Insurance Adjustment	2015 Test Period IS/IT Adjustment	Uncollectible Expense Adjustment	Incentive Pay Adjustment	Memberships and Dues Adjustment
		Adjustment Number		2.08	2.09	2.10	2.11	3.00	3.01	3.02
		Workpaper Reference		G-CIS	G-FWC	G-IA	G-ISIT	G-UE	G-IP	G-MD
121	99 931000	Rents		0	0	0	0	0	0	0
122	99 935000	Maintenance of General Plant		0	0	0	160	0	0	0
123		ADMIN & GENERAL OPERATING EXP		0	0	94	160	0	(360)	(27)
124										
125	OR-DEPX	Depreciation Expense-General		46	0	0	0	0	0	0
126		TOTAL A&G DEPRCIATION EXP		46	0	0	0	0	0	0
127										
128	OR-AMTX	Amortization Expense-General Plant-303000		473	0	0	0	0	0	0
129	OR-AMTX	Amortization Expense-Misc IT Intangible Plant-3031XX		0	0	0	0	0	0	0
130	OR-AMTX	Amortization Expense-General Plant-390200, 396200		0	0	0	0	0	0	0
131		TOTAL A&G AMRT/NON-FIT TAXES		473	0	0	0	0	0	0
132										
133		TOTAL A&G DEPR/AMRT/NON-FIT TAXES		519	0	0	0	0	0	0
134										
135		**TOTAL ADMIN & GENERAL EXPENSES**		**519**	**0**	**94**	**160**	**0**	**(360)**	**(27)**
136										
137		OTHER DEFERRALS AND AMORTIZATIONS:								
138	99 407330	Senate Bill 408		0	0	0	0	0	0	0
139	99 407408	Senate Bill Unbilled Add-Ons Amortization		0	0	0	0	0	0	0
140	99 407431	Senate Bill 408 Amortization		0	0	0	0	0	0	0
141	99 407321	Reg Amort Roseburg/Medford Deferral		0	0	0	0	0	0	0
142	99 407421	Reg Credit Roseburg/Medford Deferral		0	0	0	0	0	0	0
143		TOTAL OTHER DEFERRALS AND AMORTIZATIONS:		0	0	0	0	0	0	0
144										
145		**TOTAL EXPENSES BEFORE FIT**		**519**	**0**	**94**	**160**	**(155)**	**(360)**	**(27)**
146										
147		**NET OPERATING INCOME (LOSS) BEFORE FIT**		**(519)**	**0**	**(94)**	**(160)**	**155**	**360**	**27**
148										
151		FEDERAL INCOME TAX--Normal Accrual	35.00%	(170)	0	(31)	(52)	51	118	9
152		DEBT INTEREST	2.720%	(81)	(49)	0	0	0	0	0
153		DEFERRED INCOME TAX		0	0	0	0	0	0	0
154		STATE INCOME TAXES	6.41%	(33)	0	(6)	(10)	10	23	2
155		GAS NET OPERATING INCOME (LOSS)		(235)	49	(57)	(97)	94	219	16
156										
157		RATE BASE								
158		PLANT IN SERVICE								
159		INTANGIBLE PLANT:								
160	99 303000	Misc Intangible Plant (303000)		0	0	0	0	0	0	0
161	99 3031XX	Misc Intangible IT Plant (3031XX)		0	0	0	0	0	0	0
162		Misc Intangible Plant Proforma		7,099	0	0	0	0	0	0
163		TOTAL INTANGIBLE PLANT		**7,099**	**0**	**0**	**0**	**0**	**0**	**0**
164										
165		UNDERGROUND STORAGE PLANT:								
166	99 350100	Land in Fee		0	0	0	0	0	0	0
167	99 351100	S & I - Wells		0	0	0	0	0	0	0
168	99 351200	S & I - Compress Station		0	0	0	0	0	0	0
169	99 351300	S & I - Meas/Regulating Station		0	0	0	0	0	0	0
170	99 351400	S & I - Office		0	0	0	0	0	0	0
171	99 352000	Wells		0	0	0	0	0	0	0
172	99 352100	Wells - Leases		0	0	0	0	0	0	0
173	99 353000	Lines		0	0	0	0	0	0	0
174	99 354000	Compressor Stn Equipment		0	0	0	0	0	0	0
175	99 355000	Meas & Regulating Equipment		0	0	0	0	0	0	0
176	99 356000	Purification Equipment		0	0	0	0	0	0	0
177	99 357000	Other Equipment		0	0	0	0	0	0	0
178		Underground Storage Plant Proforma		0	0	0	0	0	0	0
179		TOTAL UNDERGROUND STORAGE PLANT		**0**	**0**	**0**	**0**	**0**	**0**	**0**
180										
181		PRODUCTION PLANT:								
182	99 304000	Land & Land Rights		0	0	0	0	0	0	0
183	99 311XXX	LPG Equipment		0	0	0	0	0	0	0
184		Production Plant Proforma		0	0	0	0	0	0	0
185		TOTAL PRODUCTION PLANT		**0**	**0**	**0**	**0**	**0**	**0**	**0**
186										
187		DISTRIBUTION PLANT:								
188	99 374200	Land & Land Rights		0	0	0	0	0	0	0
189	99 374400	Land Easements		0	0	0	0	0	0	0
190	99 375000	Structures & Improvements		0	0	0	0	0	0	0
191	99 376000	Mains		0	0	0	0	0	0	0
192	99 378000	Measuring & Reg Station Equip-General		0	0	0	0	0	0	0
193	99 379000	Measuring & Reg Station Equip-City Gate		0	0	0	0	0	0	0
194	99 380000	Services		0	0	0	0	0	0	0
195	99 381000	Meters		0	0	0	0	0	0	0
196	99 385000	Industrial Measuring & Reg Sta Equip		0	0	0	0	0	0	0
197	99 387000	Other Equipment		0	0	0	0	0	0	0
198		Distribution Plant Proforma		0	0	0	0	0	0	0
199		TOTAL DISTRIBUTION PLANT		**0**	**0**	**0**	**0**	**0**	**0**	**0**
200										
201		GAS GENERAL PLANT: (From C-GPL)								
202	389XXX	Land & Land Rights		0	0	0	0	0	0	0
203	390XXX	Structures & Improvements		0	0	0	0	0	0	0
204	391XXX	Office Furniture & Equipment		0	0	0	0	0	0	0
205	392XXX	Transportation Equipment		0	0	0	0	0	0	0
206	393000	Stores Equipment		0	0	0	0	0	0	0
207	394000	Tools, Shop & Garage Equipment		0	0	0	0	0	0	0
208	395000	Laboratory Equipment		0	0	0	0	0	0	0
209	396XXX	Power Operated Equipment		0	0	0	0	0	0	0
210	397XXX	Communications Equipment		0	0	0	0	0	0	0
211	398000	Miscellaneous Equipment		0	0	0	0	0	0	0
212		General Plant Proforma		688	0	0	0	0	0	0
213		TOTAL GAS GENERAL PLANT		**688**	**0**	**0**	**0**	**0**	**0**	**0**
214										
215		**GROSS PLANT IN SERVICE**		**7,787**	**0**	**0**	**0**	**0**	**0**	**0**
216										
217		ACCUMULATED DEPRECIATION								
218	R-ADEP	Underground Storage		0	0	0	0	0	0	0
219	R-ADEP	Distribution Plant		0	0	0	0	0	0	0
220	R-ADEP	General Plant		(1)	0	0	0	0	0	0
221		TOTAL ACCUMULATED DEPRECIATION		(1)	0	0	0	0	0	0
222										
223		ACCUMULATED AMORTIZATION								
224	R-AAMT	General Plant - 303000		0	0	0	0	0	0	0
225	R-AAMT	Misc IT Intangible IT Plant - 3031XX		(9)	0	0	0	0	0	0
226	R-AAMT	General Plant - 390200, 396200		0	0	0	0	0	0	0
227		TOTAL ACCUMULATED AMORTIZATION		(9)	0	0	0	0	0	0
228										
229		TOTAL ACCUMULATED DEPR/AMORT		(10)	0	0	0	0	0	0
230										
231		NET GAS UTILITY PLANT before DFIT		7,777	0	0	0	0	0	0
232										
233		ACCUMULATED DFIT								
234	99 282900	ADFIT - Gas Plant in Service		0	0	0	0	0	0	0
235	282900	ADFIT - Common Plant (282900 from C-DTX)		(216)	0	0	0	0	0	0
236	283750	ADFIT - Common Plant (283750 from C-DTX)		0	0	0	0	0	0	0
237	99 283850	ADFIT - Bond Redemptions		0	0	0	0	0	0	0
238		**TOTAL ACCUMULATED DFIT**		**(216)**	**0**	**0**	**0**	**0**	**0**	**0**
239										
240		**NET GAS UTILITY PLANT**		**7,561**	**0**	**0**	**0**	**0**	**0**	**0**

AVISTA UTILITIES
OREGON NATURAL GAS
TWELVE MONTHS ENDED DECEMBER 31, 2013
(000's OF DOLLARS)

Line No.		Acct. No.	Description		3/31/2015 EOP CIS Adjustment	Working Capital Adjustment	2015 Test Period Insurance Adjustment	2015 Test Period IS/IT Adjustment	Uncollectible Expense Adjustment	Incentive Pay Adjustment	Memberships and Dues Adjustment
			Adjustment Number		2.08	2.09	2.10	2.11	3.00	3.01	3.02
			Workpaper Reference		G-CIS	G-FWC	G-IA	G-ISIT	G-UE	G-IP	G-MD
241											
242			GAS INVENTORY								
243	99	117100	Gas Stored - Recoverable Base Gas		0	0	0	0	0	0	0
244	99	164100	Gas Inventory - Jackson Prairie		0	0	0	0	0	0	0
245	99	164105	Gas Inventory - Jackson Prairie Expansion		0	0	0	0	0	0	0
246	99	164110	Gas Inventory - Mist		0	0	0	0	0	0	0
247			**TOTAL GAS INVENTORY**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
248											
249			OTHER REGULATORY ASSETS								
250			Prepaid Pension, Net of ADFIT		0	0	0	0	0	0	0
251			Working Capital		0	4,641	0	0	0	0	0
252			**TOTAL OTHER REGULATORY ASSETS**		**0**	**4,641**	**0**	**0**	**0**	**0**	**0**
253											
254			**NET RATE BASE**		**7,561**	**4,641**	**0**	**0**	**0**	**0**	**0**
255											
256			**RATE OF RETURN**								
257											
258			**REVENUE REQUIREMENT**		**1,393**	**527**	**97**	**165**	**-160**	**-371**	**-28**
259											
260			Pro Forma Rate of Return	7.77%							
261			Revenue Conversion Factor	0.59075							
262											
263			NOI Requirement		**823**	**311**	**57**	**97**	**-94**	**-219**	**-16**
264			Revenue Requirement		**1,393**	**527**	**97**	**165**	**-160**	**-371**	**-28**
265											
266			TAX CALCULATION:								
267			Net Operating Income		(519)	-	(94)	(160)	155	360	27
268			Other Deductions								
269			Interest		(206)	(126)	-	-	-	-	-
270			Net Schedule M Adjustments		-	-	-	-	-	-	-
271			Income Before Tax		(725)	(126)	(94)	(160)	155	360	27
272											
273			State Income Taxes (Including Tax on Interest)		(46)	(8)	(6)	(10)	10	23	2
274			Taxable Income		(678)	(118)	(88)	(150)	145	337	25
275											
276			Federal Tax (Including Tax on Interest)		(237)	(41)	(31)	(52)	51	118	9
277			Net Operating Income		(441)	(77)	(57)	(97)	94	219	16
278											
279			FOR INFORMATION ONLY:								
280			SIT Debt Interest		13	8	0	0	0	0	0
281			FIT Debt Interest		67	41	0	0	0	0	0
282					81	49	0	0	0	0	0

AVISTA UTILITIES
OREGON NATURAL GAS
TWELVE MONTHS ENDED DECEMBER 31, 2013
(000's OF DOLLARS)

Line No.		Acct. No.	Description	State Income Tax Adjustment	Restated Salaries and Wages Adjustment	Total Adjustments
			Adjustment Number	3.03	3.04	
			Workpaper Reference	G-SIT	G-SW	
	REVENUES					
1			SALES OF GAS:			
2	99	480000	Residential	0	0	**(155)**
3	99	481200	Commercial	0	0	**379**
4	99	481300	Industrial-Firm	0	0	**86**
5	99	481400	Interruptible	0	0	**297**
6	99	484000	Interdepartmental Sales	0	0	**0**
7	99	499000	Unbilled Revenue	0	0	**0**
8			SALES TO ULTIMATE CUSTOMERS	0	0	**607**
9						
10			TRANSPORTATION REVENUES			
11	99	489300	Transportation - Commercial/Industrial	0	0	**276**
12			TRANSPORTATION REVENUES	0	0	**276**
13						
14			OTHER OPERATING REVENUES:			
15	99	483XXX	Sales For Resale	0	0	**(90,624)**
16	99	488000	Miscellaneous Service Revenues	0	0	**0**
17	99	493000	Other Gas Revenue - Gas Property Rent	0	0	**0**
18	99	495XXX	Other Gas Revenues	0	0	**(173)**
19			OTHER OPERATING REVENUES	0	0	**(90,797)**
20						
21	**TOTAL GAS REVENUES**			**0**	**0**	**(89,914)**
22						
23	**EXPENSES**					
24			PRODUCTION EXPENSES:			
25						
26			GAS PURCHASES			
27	OR-80	804XXX	Gas Purchases	0	0	**(89,708)**
28			TOTAL GAS PURCHASES	0	0	**(89,708)**
29						
30			OTHE GAS SUPPLY EXPENSE			
31	OR-80	805XXX	Other Gas Purchases	0	0	**385**
32	99	807000	Purchased Gas Expenses	0	0	**(686)**
33	OR-80	808XXX	Natural Gas Storage Transactions	0	0	**417**
34	99	811000	Gas Used for Products Extraction	0	0	**0**
35	99	813000	Other Gas Expenses	0	0	**31**
36	99	813010	Gas Technology Institute (GTI) Expenses	0	0	**(2)**
37			TOTAL OTHER GAS SUPPLY EXPENSE	0	0	**145**
38						
39			**TOTAL PRODUCTION EXPENSES**	**0**	**0**	**(89,563)**
40						
41			UNDERGROUND STORAGE EXPENSES:			
42	**99**	814000	Supervision & Engineering	0	0	**0**
43	**99**	824000	Other Expenses	0	0	**3**
44	**99**	837000	Other Equipment	0	0	**2**
45			TOTAL UG STORAGE OPER EXP	0	0	**5**
46						
47	R-DEPX		Depreciation Expense-Underground Storage	0	0	**(3)**
48			TOTAL UG STORAGE DEPRCIATION EXP	0	0	**(3)**
49						
50	OR-OTX		Taxes Other Than FIT-Underground Storage	0	0	**0**
51			TOTAL UG STORAGE NON-FIT TAXES	0	0	**0**
52						
53			TOTAL UG STORAGE DEPR/AMRT/NON-FIT TAXES	0	0	**(3)**
54						
55			**TOTAL UNDERGROUND STORAGE EXPENSES**	**0**	**0**	**2**
56						
57			DISTRIBUTION EXPENSES:			
58			OPERATION			
59	99	870000	Supervision & Engineering	0	0	**46**
60	99	871000	Distribution Load Dispatching	0	0	**0**
61	99	874000	Mains & Services Expenses	0	0	**42**
62	99	875000	Measuring & Reg Sta Exp-General	0	0	**4**
63	99	876000	Measuring & Reg Sta Exp-Industrial	0	0	**0**
64	99	877000	Measuring & Reg Sta Exp-City Gate	0	0	**0**
65	99	878000	Meter & House Regulator Expenses	0	0	**42**
66	99	879000	Customer Installation Expenses	0	0	**16**
67	99	880000	Other Expenses	0	0	**23**
68	99	881000	Rents	0	0	**2**
69						
70			MAINTENANCE			
71	99	885000	Supervision & Engineering	0	0	**0**
72	99	887000	Mains	0	0	**28**
73	99	889000	Measuring & Reg Sta Exp-General	0	0	**3**
74	99	890000	Measuring & Reg Sta Exp-Industrial	0	0	**0**
75	99	891000	Measuring & Reg Sta Exp-City Gate	0	0	**0**
76	99	892000	Services	0	0	**19**
77	99	893000	Meters & House Regulators	0	0	**9**
78	99	894000	Other Equipment	0	0	**3**
79			DISTRIBUTION O&M EXPENSES	0	0	**237**
80						
81	OR-DEPX		Depreciation Expense-Distribution	0	0	**1,932**
82			TOTAL DISTRIBUTION DEPRCIATION EXP	0	0	**1,932**
83						
84	OR-OTX		Taxes Other Than FIT-Distribution	0	0	**(1,328)**
85			TOTAL DISTRIBUTION NON-FIT TAXES	0	0	**(1,328)**
86						
87			TOTAL DISTR DEPR/AMRT/NON-FIT TAXES	0	0	**604**
88						
89			**TOTAL DISTRIBUTION EXPENSES**	**0**	**0**	**841**
90						
91			CUSTOMER ACCOUNTS EXPENSES:			
92	99	901000	Supervision	0	0	**5**
93	99	902000	Meter Reading Expenses	0	0	**4**
94	OR-90	903XXX	Customer Records & Collection Expenses	0	0	**29**
95	99	904000	Uncollectible Accounts	0	0	**(115)**
96	99	905000	Misc Customer Accounts	0	0	**0**
97			**CUSTOMER ACCOUNTS OPERATING EXP**	**0**	**0**	**(77)**
98						
99			CUSTOMER SERVICE & INFO EXPENSES:			
100	OR-90	908XXX	Customer Assistance Expenses	0	0	**(1,574)**
101	99	909000	Advertising	0	0	**6**
102	99	910000	Misc Customer Service & Info Exp	0	0	**2**
103			**CUSTOMER SVC & INFO OPERATING EXP**	**0**	**0**	**(1,566)**
104						
105			SALES EXPENSES:			
106	99	912000	Demonstrating & Selling Expenses	0	0	**0**
107	99	913000	Advertising	0	0	**0**
108	99	916000	Miscellaneous Sales Expenses	0	0	**0**
109			**SALES OPERATING EXPENSES**	**0**	**0**	**0**
110						
111			ADMINISTRATIVE & GENERAL EXPENSES:			
112	99	920000	Salaries	0	(14)	**(146)**
113	99	921000	Office Supplies & Expenses	0	0	**55**
114	99	922000	A&G Expenses Transferred	0	0	**0**
115	99	923000	Outside Services Employed	0	0	**142**
116	99	924000	Property Insurance Premium	0	0	**46**
117	99	925XXX	Injuries and Damages	0	0	**91**
118	99	926XXX	Employee Pensions and Benefits	0	0	**4**
119	99	928000	Regulatory Commission Expenses	0	0	**50**
120	99	930000	Miscellaneous General Expenses	0	0	**8**

AVISTA UTILITIES
OREGON NATURAL GAS
TWELVE MONTHS ENDED DECEMBER 31, 2013
(000's OF DOLLARS)

Line No.	Acct.	No.	Description		State Income Tax Adjustment	Restated Salaries and Wages Adjustment	Total Adjustments
			Adjustment Number		3.03	3.04	
			Workpaper Reference		G-SIT	G-SW	
121	99	931000	Rents		0	0	14
122	99	935000	Maintenance of General Plant		0	0	244
123			ADMIN & GENERAL OPERATING EXP		0	(14)	508
124							
125	OR-DEPX		Depreciation Expense-General		0	0	391
126			TOTAL A&G DEPRCIATION EXP		0	0	391
127							
128	OR-AMTX		Amortization Expense-General Plant-303000		0	0	1,229
129	OR-AMTX		Amortization Expense-Misc IT Intangible Plant-3031XX		0	0	0
130	OR-AMTX		Amortization Expense-General Plant-390200, 396200		0	0	0
131			TOTAL A&G AMRT/NON-FIT TAXES		0	0	1,229
132							
133			TOTAL A&G DEPR/AMRT/NON-FIT TAXES		0	0	1,620
134							
135			**TOTAL ADMIN & GENERAL EXPENSES**		**0**	**(14)**	**2,128**
136							
137			OTHER DEFERRALS AND AMORTIZATIONS:				
138	99	407330	Senate Bill 408		0	0	0
139	99	407408	Senate Bill Unbilled Add-Ons Amortization		0	0	0
140	99	407431	Senate Bill 408 Amortization		0	0	0
141	99	407321	Reg Amort Roseburg/Medford Deferral		0	0	(274)
142	99	407421	Reg Credit Roseburg/Medford Deferral		0	0	0
143			TOTAL OTHER DEFERRALS AND AMORTIZATIONS:		0	0	(274)
144							
145	**TOTAL EXPENSES BEFORE FIT**				**0**	**(14)**	**(88,509)**
146							
147			**NET OPERATING INCOME (LOSS) BEFORE FIT**		**0**	**14**	**(1,405)**
148							
151			FEDERAL INCOME TAX--Normal Accrual	35.00%	13	5	(448)
152			DEBT INTEREST	2.720%	0	0	(309)
153			DEFERRED INCOME TAX		0	0	8
154			STATE INCOME TAXES	6.41%	(36)	1	(126)
155			GAS NET OPERATING INCOME (LOSS)		23	8	(530)
156							
157			RATE BASE				
158			PLANT IN SERVICE				
159			INTANGIBLE PLANT:				
160	99	303000	Misc Intangible Plant (303000)		0	0	0
161	99	3031XX	Misc Intangible IT Plant (3031XX)		0	0	0
162			Misc Intangible Plant Proforma		0	0	11,016
163			TOTAL INTANGIBLE PLANT		0	0	11,016
164							
165			UNDERGROUND STORAGE PLANT:				
166	99	350100	Land in Fee		0	0	0
167	99	351100	S & I - Wells		0	0	0
168	99	351200	S & I - Compress Station		0	0	0
169	99	351300	S & I - Meas/Regulating Station		0	0	0
170	99	351400	S & I - Office		0	0	0
171	99	352000	Wells		0	0	0
172	99	352100	Wells - Leases		0	0	0
173	99	353000	Lines		0	0	0
174	99	354000	Compressor Stn Equipment		0	0	0
175	99	355000	Meas & Regulating Equipment		0	0	0
176	99	356000	Purification Equipment		0	0	0
177	99	357000	Other Equipment		0	0	0
178			Underground Storage Plant Proforma		0	0	214
179			TOTAL UNDERGROUND STORAGE PLANT		0	0	214
180							
181			PRODUCTION PLANT:				
182	99	304000	Land & Land Rights		0	0	0
183	99	311XXX	LPG Equipment		0	0	0
184			Production Plant Proforma		0	0	0
185			TOTAL PRODUCTION PLANT		0	0	0
186							
187			DISTRIBUTION PLANT:				
188	99	374200	Land & Land Rights		0	0	0
189	99	374400	Land Easements		0	0	0
190	99	375000	Structures & Improvements		0	0	0
191	99	376000	Mains		0	0	0
192	99	378000	Measuring & Reg Station Equip-General		0	0	0
193	99	379000	Measuring & Reg Station Equip-City Gate		0	0	0
194	99	380000	Services		0	0	0
195	99	381000	Meters		0	0	0
196	99	385000	Industrial Measuring & Reg Sta Equip		0	0	0
197	99	387000	Other Equipment		0	0	0
198			Distribution Plant Proforma		0	(7)	33,664
199			TOTAL DISTRIBUTION PLANT		0	(7)	33,664
200							
201			GAS GENERAL PLANT: (From C-GPL)				
202		389XXX	Land & Land Rights		0	0	0
203		390XXX	Structures & Improvements		0	0	0
204		391XXX	Office Furniture & Equipment		0	0	0
205		392XXX	Transportation Equipment		0	0	0
206		393000	Stores Equipment		0	0	0
207		394000	Tools, Shop & Garage Equipment		0	0	0
208		395000	Laboratory Equipment		0	0	0
209		396XXX	Power Operated Equipment		0	0	0
210		397XXX	Communications Equipment		0	0	0
211		398000	Miscellaneous Equipment		0	0	0
212			General Plant Proforma		0	0	6,961
213			TOTAL GAS GENERAL PLANT		0	0	6,961
214							
215			**GROSS PLANT IN SERVICE**		**0**	**(7)**	**51,855**
216							
217			ACCUMULATED DEPRECIATION				
218	R-ADEP		Underground Storage		0	0	(192)
219	R-ADEP		Distribution Plant		0	0	(7,506)
220	R-ADEP		General Plant		0	0	(2,780)
221			TOTAL ACCUMULATED DEPRECIATION		0	0	(10,478)
222							
223			ACCUMULATED AMORTIZATION				
224	R-AAMT		General Plant - 303000		0	0	0
225	R-AAMT		Misc IT Intangible IT Plant - 3031XX		0	0	(1,656)
226	R-AAMT		General Plant - 390200, 396200		0	0	0
227			TOTAL ACCUMULATED AMORTIZATION		0	0	(1,656)
228							
229			TOTAL ACCUMULATED DEPR/AMORT		0	0	(12,134)
230							
231			NET GAS UTILITY PLANT before DFIT		0	(7)	39,721
232							
233			ACCUMULATED DFIT				
234	99	282900	ADFIT - Gas Plant in Service		0	0	(2,865)
235		282900	ADFIT - Common Plant (282900 from C-DTX)		0	0	(1,778)
236		283750	ADFIT - Common Plant (283750 from C-DTX)		0	0	0
237	99	283850	ADFIT - Bond Redemptions		0	0	0
238			**TOTAL ACCUMULATED DFIT**		**0**	**0**	**(4,643)**
239							
240			**NET GAS UTILITY PLANT**		**0**	**(7)**	**35,078**

AVISTA UTILITIES
OREGON NATURAL GAS
TWELVE MONTHS ENDED DECEMBER 31, 2013
(000's OF DOLLARS)

Line No.		Acct. No.	Description		State Income Tax Adjustment	Restated Salaries and Wages Adjustment	Total Adjustments
			Adjustment Number		3.03	3.04	
			Workpaper Reference		G-SIT	G-SW	
241							
242			GAS INVENTORY				
243	99	117100	Gas Stored - Recoverable Base Gas		0	0	**0**
244	99	164100	Gas Inventory - Jackson Prairie		0	0	**0**
245	99	164105	Gas Inventory - Jackson Prairie Expansion		0	0	**0**
246	99	164110	Gas Inventory - Mist		0	0	**0**
247			**TOTAL GAS INVENTORY**		**0**	**0**	**0**
248							
249			OTHER REGULATORY ASSETS				
250			Prepaid Pension, Net of ADFIT		0	0	**4,318**
251			Working Capital		0	0	**6,728**
252			**TOTAL OTHER REGULATORY ASSETS**		**0**	**0**	**11,046**
253							
254			**NET RATE BASE**		**0**	**(7)**	**46,124**
255							
256			**RATE OF RETURN**				
257							
258			**REVENUE REQUIREMENT**		**-40**	**-15**	**6,964**
259							
260			Pro Forma Rate of Return	7.77%			
261			Revenue Conversion Factor	0.59075			
262							
263			NOI Requirement		**-23**	**-9**	**4,114**
264			Revenue Requirement		**-40**	**-15**	**6,964**
265							
266			TAX CALCULATION:				
267			Net Operating Income		-	14	**(1,405)**
268			Other Deductions				**-**
269			Interest		-	0	**(789)**
270			Net Schedule M Adjustments		-	-	**-**
271			Income Before Tax		-	14	**(2,194)**
272							**-**
273			State Income Taxes (Including Tax on Interest)		(36)	1	**(177)**
274			Taxable Income		36	13	**(2,017)**
275							**-**
276			Federal Tax (Including Tax on Interest)		13	5	**(706)**
277			Net Operating Income		23	9	**(1,311)**
278							
279			FOR INFORMATION ONLY:				
280			SIT Debt Interest		0	0	**51**
281			FIT Debt Interest		0	0	**258**
282					0	0	309

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 March 31, 2015.

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 natural gas service to our customers up through March 31, 2015. Including the costs associated with investment through March 31, 2015 in retail rates will slightly understate the cost of utility plant actually used to serve customers during the full time period new retail rates will be in effect following the conclusion of this case.

Q. Why did the Company include additions through March 31, 2015 on an EOP basis, instead of including all additions in 2015 and using a December 31, 2015 AMA basis?

A. The "test year" should reflect costs and revenues that will fairly represent the period when base rates from this docket will be in effect following a general rate case proceeding. The ratemaking practice in Oregon in the past has generally limited the new plant investment included in retail rates to project costs that are transferred to plant in service on or before the new retail rates go into effect. Using an end of period balance as of March 31, 2015, best reflects the utility plant used to serve customers during the time new rates will be in effect, while limiting the new plant investment in retail rates to projects that are completed and in service.

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. 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 capital projects that will transfer to plant by March 31, 2015 included in this case routine construction work that is attached to existing operating plant?

A. Yes, all of the projects that will transfer to plant by March 31, 2015 included in this case (as well as the remaining 2015 plant additions the Company did not include in this case) are work on existing operating plant. Avista currently has natural gas infrastructure that is being used to provide service to customers. These capital additions are either expansions or upgrades to this existing plant. None of this work represents costs on pre-construction operating plant.

Q. If all 2015 plant additions are either expansions or upgrades to existing plant, why did the Company not include the remaining nine months of 2015 capital additions within its request?

A. The Company believes it would have been appropriate to include all 2015 capital additions within its request on an AMA basis, consistent with the Company's inclusion of all revenue, expenses and customers for the 2015 test period. However, in order to minimize the issues in this proceeding related to the question of "used and useful" during the test period by the parties and to reduce the impact on customers' rates, the Company chose to include only plant through March 31, 2015, but reserves the right to include all test period capital additions in future rate proceedings.

Q. How was rate base through March 31, 2015 developed for this filing?

A. Avista started with rate base using historical accounting information, which for this case is the average of monthly average (AMA) balances for the twelve months ended December 31, 2013. Adjustments were made to plant in service, accumulated depreciation and accumulated deferred federal income taxes (ADFIT) to restate the 2013 AMA net plant balances to the end of period (EOP) balances as of March 31, 2015. In addition, adjustments were made to reflect 2014 plant additions and the January 1, 2015 through March 31, 2015 plant additions and associated accumulated depreciation and ADFIT through March 31, 2015 on an EOP basis, such that the proposed rate base reflects the net plant in service that will be used to serve customers when base rates initially go into effect from this case. Company witness Ms. Andrews incorporates these adjustments in her revenue requirements computation and provides the adjustment detail in her workpapers.

Q. What is the net impact of the capital adjustments included in this filing?

A. Net plant rate base (plant cost, net of accumulated depreciation and ADFIT) currently authorized (Docket No. UG-246) is $156,634,000[1], while the planned level of rate base through March 31, 2015 in this filing is $184,865,000, for a net increase of approximately $28.2 million over that included in existing rates.

Q. What is Avista's capital investment that will transfer to plant in service in 2014 and the three months ended March 31, 2015 that have been included in this case?

A. Table 1 below shows Avista's planned system-wide <u>general plant</u> capital transfers

[1] The total amount of $156,634,000 in net plant rate base consists of $154,594,000 included in the final Order 14-015, in Docket No. UG-246, effective February 1, 2014 and represents plant-in-service at December 31, 2013, and an additional increase in net plant rate base deferred and to be implemented November 1, 2014 of $2,040,000 associated with the Aldyl A capital project completed in the first half of 2014.

to plant of $64.2 million in 2014. Oregon's share of this general plant totals $5.898 million. During the first three months of 2015, Avista's planned system-wide general plant transfers to plant are $99.619 million, which includes Project Compass, discussed by Mr. Kensok. Oregon's share of these transfers to plant totals $8.885 million.

Table 1
General Plant Capital Projects - Transfers to Plant
($000s)

Project	2014 System	2014 Oregon Allocated	Q1 2015 System	Q1 2015 Oregon Allocated
Technology Refresh to Sustain Business Process	$ 17,059	$ 1,524	$ 4,114	$ 366
Technology Expansion to Enable Business Process	5,403	480	1,450	129
Enterprise Security Systems	3,221	286	546	49
Next Generation Radio System	13,246	1,177	27	2
Microwave Replacement with Fiber	2,114	188	-	-
Customer Information and Asset System Replacement	139	12	87,608	7,787
Small Technology Projects	4,039	359	2,305	205
Subtotal - Technology Projects	45,221	4,026	96,050	8,538
Transportation Equipment	7,411	659	1,626	145
Structures and Improvements	3,625	366	400	36
Tools Lab & Shop Equipment	2,050	323	826	73
COF HVAC Improvement	2,594	231	-	-
Long Term Campus Re-Structuring Plan	145	13	-	-
CNG Fleet Conversion	800	71	28	2
Small General Projects	2,354	209	689	61
TOTAL	$ 64,200	$ 5,898	$ 99,619	$ 8,855

Table 2 on the following page shows Avista's planned Oregon natural gas distribution capital expenditures of $18.540 million in 2014, and $3.601 million for the three months ended March 31, 2015.

Table 2
Oregon Gas Distribution Capital Projects - Transfers to Plant
($000's)

Project		2014		Q1 2015
Oregon - Gas Revenue Projects	$	2,464	$	541
Gas Reinforce - Minor Blanket		649		97
Replace Deteriorating Gas System		406		83
Regulator Reliable - Blanket		504		68
Gas Replace - Street & Highway		2,722		423
Cathodic Protection - Minor Blanket		563		73
Gas Distribution Non-Revenue Projects		2,789		621
Overbuilt Pipe Replacement Projects		506		115
Isolated Steel		521		116
Aldyl-A Pipe Replacement[2]		5,594		995
Gas Meter Replacement		507		109
Jackson Prairie Storage		125		63
Other small gas Projects		1,190		297
TOTAL	$	18,540	$	3,601

Q. What is driving the significant investment in new utility plant in Oregon?

A. It is necessary for the Company to upgrade and expand its distribution facilities to meet reliability requirements and capacity needs. Other issues driving the need for capital investment include replacing our legacy customer information system (Project Compass), and replacing aging infrastructure, physical degradation, and municipal compliance issues (i.e., street/highway relocations), etc. A detailed explanation of the Customer Information System project (Project Compass) that is included in this case is summarized by Company witness Kensok in his testimony and exhibits. A description of other capital projects is provided below.

[2] The Aldyl A Pipe Replacement program costs of $5.594 million that will transfer to plant in 2014 include the $2.010 million that was approved in the last general rate case, with a rate adjustment to become effective November 1, 2014.

III. DESCRIPTION OF CAPITAL PROJECTS

Q. For the capital projects that will transfer to plant in service in 2014 and the three months ended March 31, 2015 that were included in this filing, please provide a description of the projects.

A. Tables 1 and 2 above detail the capital projects included in this filing that will be transferred to plant in service in 2014, and during the three months ended March 31, 2015. All the items labeled 2015 below in the project description are for capital projects that will transfer to plant in service during the three months ended March 31, 2015. A short description of these projects and their costs allocated to Oregon follows:

Technology (Oregon):

The enterprise technology projects that will transfer to plant-in-service are described in detail in Mr. Kensok's direct testimony, Exhibit No. 500. A listing of these projects, the system costs, and Oregon's allocated share of costs are included in Table No. 1 above. Oregon's allocated share of these technology projects total $4,026,000 for 2014 and $8,538,000 for additions during the three months ended March 31, 2015.

General (Oregon):

ER 7001 Structures and Improvements – 2014: $366,000; 2015: $36,000
This program is for the Capital Maintenance, Improvements, and Furniture budgets at over 50 Avista offices and service centers (over 700,000 square feet in total). Many of the service centers were built in the 1950's and 1960's and are showing signs of severe aging. The program includes capital projects in all construction disciplines (Roofing, Asphalt, Electrical, Plumbing, HVAC, Energy efficiency projects etc.).

ER 7006 Tools, Lab & Shop Equipment – 2014: $323,000; 2015: $73,000
This program is for equipment utilized in warehouses throughout the service territory. This includes equipment such as forklifts, man-lifts, shelving, cutting/binding machines, etc. 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 – 2014: $231,000

The HVAC Renovation Project began in 2007 and 2008. The HVAC Project is a systematic replacement of the original 1956 Heating, Ventilation and Air Conditioning System for the Service Building, Cafeteria, Auditorium and General Office Building. The original HVAC equipment has been operating 24/7 since original construction in 1956. The Project entails a floor by floor evacuation and relocation of employees and a complete demolition of each floor; including an extensive Asbestos Abatement component, and removing the original fire proofing on the basic steel structure. The Project requires exhaustive demolition and reconstruction of each floor. Sustainable energy savings and conservation are built into the Project as we apply for LEED certification for each floor. The 5th, 4th, and 3rd floors have obtained LEED-CI Gold status recognizing all of the renewable strategies we employed during the design and construction phases. The goal of this project is to re-purpose and recycle the entire Facility for the next generation of Avista employees to use for 50 more years. Life cycle costs weighed heavily on our Construction Specifications and equipment choices during the design phase. The design team chose energy efficient equipment that was designed for 30 to 50 year life cycles.

ER 7126 Long Term Campus Re-Structuring Plan –2014: $13,000

The campus restructuring plan was a 2-year, 3 phase plan to address critical parking and office space needs. Avista employees were forced to park on residential streets which sometimes disturbed our neighbors. Moreover, Avista did not meet the current city requirements for handicap and carpool parking spaces. The campus restructuring was completed in 2013 with final project costs transferring in 2014.

ER 7127 CNG Fleet conversion–2014: $71,000; 2015: $2,000

The Company will be purchasing 41 new 1/2 ton, extra cab, 4 wheel drive Company owned trucks to assign to Construction Project Coordinators' throughout Avista's service territory. This project will have a 3 year timeframe. These trucks will run on CNG (Compressed Natural Gas).

Other Small Projects – 2014: $209,000; 2015: $61,000

These projects include stores equipment, productivity initiatives, craft training software, office and other general facility upgrades.

Transportation (Oregon):

ER 7000 Transportation Equipment – 2014: $659,000; 2015: $145,000

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 natural gas operations.

Natural Gas Distribution (Oregon):

ER 1001 Gas Revenue Projects – 2014: $2,464,000; 2015: $541,000
This annual project will install sections of gas piping, meters, regulators, etc. that are directly linked to new revenue.

ER 3000 Gas Reinforcement – Minor Blanket - 2014: $649,000; 2015: $97,000
Avista has an obligation to provide reliable gas service that is of adequate pressure and capacity. Periodic reinforcement of the system is required to reliably serve increased demand at existing service locations and new customers. This annual program will identify and install new sections of gas main to improve the operating reliability and performance of the gas distribution system. Execution of this program on an annual basis will ensure the continuation of reliable gas service that is of adequate pressure and capacity.

ER 3001 Replace Deteriorated Pipe - 2014: $406,000; 2015: $83,000
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 3002 Regulator Station Reliability Projects - 2014: $504,000; 2015: $68,000
This annual program will replace or upgrade existing regulator stations and meter stations to current Avista standards. This program will address enhancements that will improve system operating performance, enhance safety, replace inadequate or antiquated equipment that is no longer supported, and ensure the reliable operation of metering and regulating equipment.

ER 3003 Gas Replacement Street and Highways - 2014: $2,722,000; 2015: $423,000
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 3004 Cathodic Protection Projects - 2014: $563,000; 2015: $73,000
This annual project upgrades, replaces, or installs cathodic protection systems required to ensure compliance with PHMSA regulations regarding proper cathodic protection of steel mains. This program will ensure appropriate cathodic protection levels are maintained, reduce corrosion related failures, help prevent leaks within steel pipeline systems and enhance public safety.

ER 3005 Gas Distribution Non-Revenue Projects - 2014: $2,789,000; 2015: $621,000
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. It includes replacement of pipe and facilities that are at the end of their useful life or have failed. It also includes improvement in equipment and/or technology to enhance 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 - 2014: $506,000; 2015: $115,000
This annual project will replace sections of existing gas piping that have experienced encroachment or have been overbuilt [customer constructed improvements (i.e. decks, driveways, etc.)] that restricts the Company's access to pipe. 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 enhance public safety. All types of overbuilds will be addressed with the primary focus of the project being overbuilds in manufactured home developments.

ER 3007 Isolated Steel Replacement - 2014: $521,000; 2015: $116,000
The Company has implemented a special cathodic protection program for the purpose of finding and addressing isolated steel in its natural gas piping systems.

ER 3008 Aldyl-A Replacement Project - 2014: $5,594,000; 2015: $995,000
The Company is currently undergoing a twenty-year program to systematically remove and replace select portions of the DuPont Aldyl A medium density polyethylene pipe in its natural gas distribution system in the States of Washington, Oregon and Idaho. None of the subject pipe is "high pressure main pipe," but rather, consists of distribution mains at maximum operating pressures of 60 psi and pipe diameters ranging from 1¼ to 4 inches.

ER 3055 Natural Gas Meter Replacement Projects – 2014: $507,000; 2015: $109,000
This annual program will provide for replacement of natural gas meters and associated measurement equipment that are completed in association with the Gas Planned Meter Change-out (PMC) program. Avista is required by commission rules and an approved tariff in WA, ID, and OR to test meters for accuracy and ensure proper metering performance. Execution of this program on an annual basis will ensure the continuation of reliable gas measurement. This program will include the labor and minor materials associated with the PMC program.

ER 7201 Jackson Prairie Storage Projects – 2014: $125,000; 2015: $63,000
These projects include capital maintenance to the Jackson Prairie Storage facility.

Other Small Projects – 2014: $1,190,000; 2015: $297,000
These projects include meters, regulators, and ERTs capital expenditures.

V. SUMMARY OF ADJUSTMENTS

Q. What was the change in natural gas rate base for the capital adjustments included in this case?

A. Natural gas net rate base for capital investment increases $35,085,000, from December 31, 2013 AMA results of operations balance of $149,780,000 to a March 31, 2015 balance of $184,865,000. Table 3 below summarizes the adjustments included in the case.

Table 3
Summary of Adjustments

($000's)		Adjustment 1 (2.05)		Adjustment 2 (2.06)		Adjustment 3 (2.07)			Adjustment 4 (2.08)	
	Rate Base 12/31/13 AMA	Adjust 12/31/13 AMA to EOP	Rate Base 12/31/13 EOP	Adjust 12/31/13 Vintage to 12/31/14 EOP	2014 Capital Additions to 12/31/14 EOP	Adjust 12/31/13 Vintage to 3/31/15 EOP	2014 Capital Additions to 3/31/15 EOP	2015 Capital Additions to 3/31/15 EOP	CIS 2015 Addition to 3/31/15 EOP	Forecasted Rate Base 3/31/15 EOP
Plant	$ 287,747	$ 14,968	$ 302,715	$ -	$ 24,438	$ -	$ -	$ 4,669	$ 7,787	$ 339,609
A/D	(98,025)	(1,571)	(99,596)	(7,723)	(465)	(2,082)	(275)	(8)	(11)	$ (110,160)
DFIT	(39,942)	(1,393)	(41,335)	(1,915)	(450)	(449)	(191)	(29)	(215)	$ (44,584)
Rate Base	$ 149,780	$ 12,004	$ 161,784	$ (9,638)	$ 23,523	$ (2,531)	$ (466)	$ 4,632	$ 7,561	$ 184,865

Company witness Ms. Andrews includes the following four adjustments in her testimony and exhibits:

Adjustment 1: 2013 EOP Capital Adjustment – Adjusts the December 31, 2013 test period rate base stated on an AMA basis to an EOP basis. The revenue-producing distribution plant of the 2013 capital additions were adjusted to EOP, to maintain the matching of revenues and costs associated with these assets.

Adjustment 2: 2014 EOP Capital Adjustment – First, the plant that was in service at December 31, 2013 was depreciated through 2014 using new depreciation rates that were approved in the Company's last general rate case[3], adjusting accumulated depreciation and ADFIT to a December 31, 2014 EOP basis. Second, 2014 capital additions were included on a December 31, 2014 EOP basis.

Adjustment 3: <u>3/31/2015 EOP Capital Adjustment</u> – First, the plant that was in service at December 31, 2013 was depreciated an additional three months through March 31, 2015 adjusting accumulated depreciation and ADFIT to a March 31, 2015 EOP basis. Second, the 2014 capital additions were depreciated through March 31, 2015, adjusting accumulated depreciation and ADFIT to a March 31, 2015 EOP basis. Third, transfers to plant in service during the three months ended March 31, 2015 were included on a March 31, 2015 EOP basis.

Adjustment 4: <u>3/31/2015 EOP Project Compass Adjustment</u> - The Company included Oregon's share of Project Compass on a March 31, 2015 EOP basis. Mr. Kensok discusses the Project Compass capital additions in his testimony.

Q. What is the impact to <u>expense</u> for the 2015 test period?

A. Depreciation expense increases approximately $2,082,000, before federal income taxes, for the capital additions included in this case. In addition, depreciation expense increases approximately $1,193,000, before federal income taxes, due to changing depreciation rates on Oregon direct plant that was in service at December 31, 2013. New depreciation rates on Oregon direct plant were implemented on July 1, 2014. This increase to depreciation expense was computed with adjustments 2.05 through 2.08 included in Ms. Andrews' workpapers.

[3] The Company had new depreciation rates approved in Order 13-168, Docket UM-1626. The depreciation rates for general plant were changed effective January 1, 2013, as approved in the first phase of the settlement in that docket. The depreciation rates for Oregon direct natural gas plant were implemented July 1, 2014, as approved in Order 14-015, Docket UG-246.

VI. CONCLUSION

Q. Please summarize Avista's proposal regarding the capital additions to rate base that have been included in the Company's filing.

A. Including the costs associated with investment through March 31, 2015, retail rates will slightly understate the cost of utility plant actually used to serve customers during the full time period new retail rates will be in effect following the conclusion of this case.

All plant included in the Company's request will be used and useful during the 2015 test year. Without including the proposed capital additions, the Company will not have the opportunity to earn a reasonable rate of return on investment during the rate year.

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

A. Yes, it does.

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 1411 East Mission Avenue, Spokane, Washington. I am employed as a Senior 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. I also provide 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. My primary responsibility was coordinating discovery for the Company's general rate case filings. In my current role as a Senior Regulatory Analyst, I am responsible for the Company's natural gas cost of service studies in all jurisdictions, among other things.

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 customers are paying less than their relative cost of service, while interruptible, large general, seasonal, and transportation customer groups exceed their relative cost of service to varying degrees. Company witness Mr. Ehrbar uses the results of the study as a guide to spread the proposed increase by service schedule.

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 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. Has the Company made any changes in LRIC methodology from its prior base case methodology as proposed in Docket No. UG-246?

A. Yes. The Company agreed to make two changes to the LRIC study per the Settlement Agreement in Docket No. UG-246. The agreed-upon changes per the Settlement Agreement, which were incorporated into this LRIC study, are as follows:

- Gas Scheduling will be allocated on a volumetric basis rather than on a customer-count basis.
- For “Special Contracts” Schedule 447, Avista will use an engineering estimate/cost-study, as is used for the other customer rate schedules, for purposes of estimating main extension costs for Schedule 447, rather than using an amount based upon an estimated bypass cost.

Q. What are the elements of the LRIC study?

A. The elements of the LRIC study include incremental plant investment, incremental operating and maintenance expenses, and the cost of natural 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 2015 total pro forma customers and therms.

Incremental Plant Investment Costs

Q. What is included in incremental plant investment?

A. Incremental plant investment is segregated into three separate categories which are summarized below and discussed in further detail later in my testimony.

New Customer Related Plant Investment:

- Natural gas main extension to reach the customer;

- Service line to connect the customer to the main;
- Metering equipment at the customer's premises;

System Main Related Plant Investment:

- Capacity reinforcements to maintain system planning requirements in order to meet the peak needs of all customers (capacity related investment);
- Mandated safety and reliability requirements for the benefit of all customers (commodity related investment);
- Long-run incremental capacity and commodity system main replacement investment;

Underground Storage Plant Investment

- Oregon's share of the Company's investment in underground storage facilities.

Q. Are these items identified in the cost study presented in this case?

A. Yes. Exhibit No. 801 page 2 shows the calculation of the 2015 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 related plant investments quantified in this study?

A. Typical natural gas 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 eight 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, special contract and transportation customers that have not had recent installations were individually examined to determine average current cost of pipe that is dedicated to them. For large general service customers on Schedule 424, a random sample comprising approximately 33% of the population was selected. Using the Company's 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. The resulting values were also used for the seasonal customers on Schedule 444.

Service lines were quantified by the size of pipe typically needed for the type of customer. For large general service, interruptible, special contract, 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 2013 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 main related plant investment 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 Mr. DeFelice's testimony. A four-year average (2 years actual and 2 years forecast) 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, 2013 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 2013 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 the 2015 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 were 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 No. 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 the 2015 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 underground storage plant investment quantified?

A. The Oregon jurisdictional underground storage plant balance at December 31, 2013 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 natural 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. No, it does not.

Q. Exhibit No. 801 page 2 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 No. 801 page 3 itemizes the various operating and maintenance expenses included in this study.

Q. Please explain the items shown on Exhibit No. 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 natural 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 2013, resulting in an estimate of the annual hours necessary for these services. The annual hours were then divided by the number of therms used to arrive at the hours per therm 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.

The total hours charged to meter reading in 2013 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 2013 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.

Cost of Gas Commodity

Q. What is included in the cost of natural gas?

A. The cost of gas includes all of the items included in the Purchased Gas Cost Adjustment provision rate Schedule 461, excluding the Gross Revenue Factor. These include the entire commodity, demand and upstream transportation charges (including the benefits of storage) the Company passes through to customers. The gas commodity costs shown on Exhibit No. 801, page 1, line 4, reflect the rates approved as a result of the most recent Purchased Gas Cost Adjustment (PGA) filing that went into effect November 1, 2013, grossed up for the revenue related expenses shown in Company witness Ms. Andrews revenue conversion factor.

Results Analysis

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 (excluding natural 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 0.84. 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. Mr. 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 Company witness Ms. Andrews Exhibit No. 601, 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. Table No. 1 below shows the relative margin-to-cost ratio at present rates for each rate schedule:

Table No. 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	0.92
Large General Service Schedule 424	1.68
Interruptible Sales Service Schedule 440	1.33
Seasonal Sales Service 444	1.46
Special Contracts Schedule 447	1.09
Transportation Service Schedule 456	1.54
Total Oregon Gas	1.00

The present relative margin-to-cost ratios indicate that general service (primarily commercial) customers on Schedule 420 are paying less than their relative cost of service, while large general (Schedule 424), interruptible (Schedule 440), seasonal (Schedule 444), and transportation (Schedule 456) service customers are paying more than their relative cost of service. Residential service customers on Schedule 410 are not far from parity (1.00) on a relative margin to cost basis. 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 the LRIC study.

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 to receive a somewhat larger percentage margin increase than other customer groups, and large general service, interruptible, seasonal, and transportation customers on Schedules 424, 440, 444 and 456 to receive either no rate increase, or perhaps even a rate decrease. This is reflected in Mr. Ehrbar's proposed rate spread.

Q. Does this conclude your pre-filed, direct testimony?

A. Yes, it does.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

JOSEPH D. MILLER
Exhibit No. 801

Long-Run Incremental Cost

AVISTA UTILITIES
OREGON JURISDICTION
LONG-RUN INCREMENTAL COST STUDY
TWELVE MONTHS ENDED DECEMBER 2015

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	2015 ANNUAL THERM DELIVERIES	128,791,026	49,097,140	26,450,079	4,438,427	3,945,585	253,423	7,979,130	36,627,242
2	2015 CUSTOMERS	97,795	86,298	11,333	81	35	9	4	35
3	AVERAGE ANNUAL THERM DELIVERIES PER CUSTOMER		569	2,334	54,908	113,815	28,158	1,994,783	1,046,493
4	Gas Commodity Costs	$ 50,547,000	29,967,000	16,144,000	2,709,000	1,572,000	155,000	-	-
5	Gas Scheduling 1.02978	$ 52,306	23,845	12,846	2,156	1,916	123	2,043	9,377
6	Gas Planning	$ 173,967	153,515	20,160	144	62	16	7	62
7	Meter Reading	$ 118,951	104,968	13,785	98	42	11	5	43
8	Billing	$ 2,399,844	2,117,721	278,110	1,984	851	221	98	859
	Customer Installation Investment Cost								
9	Meters	$ 4,900,300	3,457,884	1,278,771	48,440	36,064	6,185	15,316	57,640
10	Services	$ 13,870,215	12,029,195	1,340,301	112,608	101,616	12,538	28,721	245,237
11	Main Extensions	$ 97,569,697	58,813,804	37,772,210	220,950	164,073	24,601	28,714	545,345
12	Total Customer Installation Investment Cost	$ 116,340,212	74,300,883	40,391,281	381,998	301,753	43,323	72,751	848,223
	System Core Main Cost								
13	Capacity	$ 13,841,014	6,254,048	3,130,565	270,067	256,818	-	331,322	3,598,194
14	Commodity	$ 11,410,163	4,350,036	2,343,307	393,194	349,536	22,450	706,864	3,244,776
15	Total Core Main Cost	$ 25,251,178	10,604,085	5,473,872	663,261	606,354	22,450	1,038,186	6,842,969
16	Underground Storage Cost	$ 1,035,539	576,767	310,697	52,133	46,345	2,977	8,340	38,282
17	Long Run Incremental Distribution Cost	$ 145,371,996	87,881,784	46,500,751	1,101,773	957,323	69,121	1,121,430	7,739,814
18	Revenue at Present Rates	$ 98,217,000	61,343,000	27,875,000	3,376,000	2,030,000	198,000	320,000	3,075,000
19	**Margin Revenue at Present Rates**	**$ 47,670,000**	**31,376,000**	**11,731,000**	**667,000**	**458,000**	**43,000**	**320,000**	**3,075,000**
	Proposed Cost by Functional Classification Assigned to Schedule by LRIC components								
20	Cost of Gas Commodity	$ 50,547,000	29,967,000	16,144,000	2,709,000	1,572,000	155,000	-	-
21	Scheduling and Planning Costs	$ 591,000	463,247	86,209	6,006	5,166	363	5,354	24,654
22	Meter Reading, Billing, Etc. Costs	$ 3,761,000	3,318,862	435,850	3,109	1,333	346	154	1,346
23	Meters & Services Costs	$ 17,300,000	14,273,794	2,413,889	148,431	126,894	17,256	40,587	279,149
24	System Core Main Costs	$ 33,683,000	19,037,503	11,860,018	242,490	211,286	12,904	292,592	2,026,208
25	Underground Storage Costs	$ 1,475,000	821,534	442,550	74,257	66,012	4,240	11,879	54,528
26	Proposed Cost	$ 107,357,000	67,881,940	31,382,516	3,183,293	1,982,691	190,109	350,566	2,385,885
27	**LRIC Based Target Margin**	**$ 56,810,000**	**37,914,940**	**15,238,516**	**474,293**	**410,691**	**35,109**	**350,566**	**2,385,885**
28	Current Revenue to Proposed Cost (Includes Cost of Gas)	**0.91**	**0.90**	**0.89**	**1.06**	**1.02**	**1.04**	**0.91**	**1.29**
29	Current Margin Revenue to LRIC Based Target Margin	**0.84**	**0.83**	**0.77**	**1.41**	**1.12**	**1.22**	**0.91**	**1.29**
	29A **Relative Margin to Cost at Present Rates**	**1.00**	**0.99**	**0.92**	**1.68**	**1.33**	**1.46**	**1.09**	**1.54**
30	Component LRIC Target Increase by Schedule	$ 9,140,000	$ 6,538,940	$ 3,507,516	$ (192,707)	$ (47,309)	$ (7,891)	$ 30,566	$ (689,115)
31	Target Increase as Percent of Total Present Revenue	9.31%	10.66%	12.58%	-5.71%	-2.33%	-3.99%	9.55%	-22.41%
	31A Target Increase as Percent of Present Margin Revenue	19.17%	20.84%	29.90%	-28.89%	-10.33%	-18.35%	9.55%	-22.41%
32	Avg Cost Per Month for Meter Reading, Billing, Meters & Services		$ 16.99						

AVISTA UTILITIES
OREGON JURISDICTION
LONG-RUN INCREMENTAL COST STUDY
TWELVE MONTHS ENDED DECEMBER 2015

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	48 yr life							
1	TYPICAL SERVICE PIPE SIZE		3/4"	1"	1 1/4" - 2"	1/2" - 1.25"	1 1/4" - 2"	3/4" - 2"	1/2" - 2"
2	AVERAGE SERVICE COST		$ 786.19	$ 667.03	$ 7,857.27	$ 16,532.55	$ 7,857.27	$ 40,497.46	$ 39,519.32
3	LEVELIZED PLANT COST FACTOR		0.1773	0.1773	0.1773	0.1773	0.1773	0.1773	0.1773
4	ANNUAL REVENUE REQUIREMENT		$ 139.39	$ 118.26	$ 1,393.09	$ 2,931.22	$ 1,393.09	$ 7,180.20	$ 7,006.78
	METERS & REGULATORS	36 yr life							
5	METERS & REGULATORS		$ 216.59	$ 609.92	$ 3,239.20	$ 5,623.30	$ 3,714.67	$ 20,697.95	$ 8,901.97
6	LEVELIZED PLANT COST FACTOR		0.1850	0.1850	0.1850	0.1850	0.1850	0.1850	0.1850
7	ANNUAL REVENUE REQUIREMENT		$ 40.07	$ 112.84	$ 599.25	$ 1,040.31	$ 687.21	$ 3,829.12	$ 1,646.86
	MAIN INVESTMENT	58 yr life							
8	AVERAGE MAIN EXTENSION PER CUSTOMER		73	357	344	498	344	907	1152
9	TYPICAL PIPE SIZE REQUIRED		2 "	2 "	sample	dedicated plt	same as 424	dedicated plt	dedicated plt
10	AVERAGE COST PER FOOT		52.39	52.39	44.59	$ 53.33	44.59	$ 44.41	$ 75.90
11	MAIN EXTENSION INVESTMENT		$ 3,824.47	$ 18,703.23	$ 15,338.96	$ 26,559.42	$ 15,338.96	$ 40,282.89	$ 87,437.09
12	ESTIMATED DESIGN DAY LOAD FACTOR	100%	27.05%	29.11%	56.62%	52.93%	0.00%	82.97%	35.07%
13	INCR CAPACITY MAIN INVESTMENT PER THERM	0.193334	$ 0.714728	$ 0.664150	$ 0.341459	$ 0.365264	$ -	$ 0.233017	$ 0.551280
14	2014 AVERAGE THERMS PER CUSTOMER		569	2,334	54,908	113,815	28,158	1,994,783	1,046,493
15	CAPACITY MAIN INVESTMENT		$ 406.68	$ 1,550.13	$ 18,748.82	$ 41,572.47	$ -	$ 464,817.86	$ 576,910.97
16	INCR COMMODITY MAIN INVESTMENT PER THERM		0.497133	$ 0.497133	$ 0.497133	$ 0.497133	$ 0.497133	$ 0.497133	$ 0.497133
17	2014 AVERAGE THERMS PER CUSTOMER		569	2,334	54,908	113,815	28,158	1,994,783	1,046,493
18	SAFETY MAIN INVESTMENT		$ 282.87	$ 1,160.31	$ 27,296.58	$ 56,581.19	$ 13,998.27	$ 991,672.46	$ 520,246.20
19	TOTAL MAIN INVESTMENT PER CUSTOMER		$ 4,514.02	$ 21,413.66	$ 61,384.36	$ 124,713.08	$ 29,337.23	$ 1,496,773.20	$1,184,594.27
20	LEVELIZED PLANT COST FACTOR	58 yr life	0.1782	0.1782	0.1782	0.1782	0.1782	0.1782	0.1782
21	ANNUAL REVENUE REQUIREMENT		$ 804.40	$ 3,815.91	$ 10,938.69	$ 22,223.87	$ 5,227.89	$ 266,724.99	$ 211,094.70
	UNDERGROUND STORAGE INVESTMENT								
22	BALANCING INVESTMENT PER THROUGHPUT THERM		$ 0.005895	$ 0.005895	$ 0.005895	$ 0.005895	$ 0.005895	$ 0.005895	$ 0.005895
23	STORAGE INVESTMENT PER SALES THERM		$ 0.060354	$ 0.060354	$ 0.060354	$ 0.060354	$ 0.060354		
24	2014 AVERAGE THERMS PER CUSTOMER		569	2,334	54,908	113,815	28,158	1,994,783	1,046,493
25	UNDERGROUND STORAGE INVESTMENT		$ 37.70	$ 154.63	$ 3,637.60	$ 7,540.13	$ 1,865.44	$ 11,759.08	$ 6,168.99
26	LEVELIZED PLANT COST FACTOR	48 yr life	0.1773	0.1773	0.1773	0.1773	0.1773	0.1773	0.1773
27	ANNUAL REVENUE REQUIREMENT		$ 6.68	$ 27.42	$ 644.95	$ 1,336.86	$ 330.74	$ 2,084.89	$ 1,093.76
28	**TOTAL INCREMENTAL INVESTMENT COST PER CUSTOMER**		**$ 990.54**	**$ 4,074.43**	**$ 13,575.99**	**$ 27,532.27**	**$ 7,638.94**	**$ 279,819.19**	**$ 220,842.10**

AVISTA UTILITIES
OREGON JURISDICTION
LONG-RUN INCREMENTAL COST STUDY
TWELVE MONTHS ENDED DECEMBER 2015

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 (PER THERM)	0.0000129	0.0000129	0.0000129	0.0000129	0.0000129	0.0000068	0.0000068
2	AVERAGE RATE PER HOUR	$ 36.56	$ 36.56	$ 36.56	$ 36.56	$ 36.56	$ 36.56	$ 36.56
3	LABOR COST PER THERM	$ 0.00047	$ 0.00047	$ 0.00047	$ 0.00047	$ 0.00047	$ 0.00025	$ 0.00025
	GAS MANAGEMENT (PLANNING)							
4	ANNUAL HOURS (PER CUSTOMER)	0.02918	0.02918	0.02918	0.02918	0.02918	0.02918	0.02918
5	AVERAGE RATE PER HOUR	$ 59.20	$ 59.20	$ 59.20	$ 59.20	$ 59.20	$ 59.20	$ 59.20
6	LABOR COST PER CUSTOMER	$ 1.72746	$ 1.72746	$ 1.72746	$ 1.72746	$ 1.72746	$ 1.72746	$ 1.72746
7	**TOTAL GAS SUPPLY O&M PER CUSTOMER**	**$ 2.00**	**$ 2.83**	**$ 27.62**	**$ 55.41**	**$ 15.01**	**$ 497.65**	**$ 261.89**
	METER READING							
8	ANNUAL HOURS	0.04486	0.04486	0.04486	0.04486	0.04486	0.04486	0.04486
9	AVERAGE RATE PER HOUR	$ 26.33	$ 26.33	$ 26.33	$ 26.33	$ 26.33	$ 26.33	$ 26.33
10	LABOR COST PER CUSTOMER	$ 1.18116	$ 1.18116	$ 1.18116	$ 1.18116	$ 1.18116	$ 1.18116	$ 1.18116
	BILLING							
11	ANNUAL POSTAGE PER CUST	$ 2.85	$ 2.85	$ 2.85	$ 2.85	$ 2.85	$ 2.85	$ 2.85
12	5 YR AVERAGE PER CUST	$ 20.98	$ 20.98	$ 20.98	$ 20.98	$ 20.98	$ 20.98	$ 20.98
13	BILLING COST PER CUSTOMER	$ 23.83	$ 23.83	$ 23.83	$ 23.83	$ 23.83	$ 23.83	$ 23.83
14	**TOTAL CUSTOMER O&M**	**$ 25.01**	**$ 25.01**	**$ 25.01**	**$ 25.01**	**$ 25.01**	**$ 25.01**	**$ 25.01**

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

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, 2015
(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		$98,217	50,547	591	3,761	17,300	33,683	1,475
2	Proposed Increase		9,140						
3	Other Revenues		153				153		
4	Total Gas Revenues		107,510	50,547	591	3,761	17,453	33,683	1,475
	EXPENSES								
5	Exploration and Development		0						
	Production								
6	City Gate Purchases		49,086	49,086					
7	Purchased Gas Expense		0						
8	Other Gas Expenses		574		574				
9	Depreciation		0						0
10	Taxes		0						0
11	Total Production		49,660	49,086	574	0	0	0	0
	Underground Storage								
12	Operating Expenses		127						127
13	Depreciation		110						110
14	Taxes		54						54
15	Total Underground Storage		291	0	0	0	0	0	291
	Distribution								
16	Operating Expenses		8,298				2,833	5,465	
17	Depreciation		5,920				2,021	3,899	
18	Taxes		2,261				772	1,489	
19	Total Distribution		16,479	0	0	0	5,625	10,854	0
20	Customer Accounting		3,053			3,053			
21	Customer Service & Information		599			599			
22	Sales Expenses		0			0			
	Administrative & General								
23	Operating Expenses		7,778				2,601	5,019	160
24	Depreciation & Amortization		1,796				601	1,159	37
25	Taxes		2,128				712	1,373	44
26	Total Admin. & General		11,702	0	0	0	3,914	7,551	241
	Revenue Related Expenses								
	20 Uncollectibles	0.005320	571	269	3	20	92	179	7
	23 Commission Fees	0.002500	268	127	1	9	43	84	4
	23 ERSA	0.000810	87	41	0	3	14	27	1
	18 Franchise Fees	0.020291	2,179	1,026	12	76	351	683	30
27	Total Gas Expense	0.028921	84,890	50,549	591	3,761	10,040	19,379	574
28	OPERATING INCOME BEFORE FIT		22,619	(2)	0	0	7,413	14,304	901
	FEDERAL INCOME TAX								
29	Current and Deferred FIT		3,494	-	-	-	1,145	2,210	139
	Debt Interest		(309)				(101)	(195)	(12)
30	FIT on Revenue Increase	0.318097	2,907	-	-	-	953	1,839	116
31	State Income Tax		539	-	-	-	177	341	21
	SIT on Revenue Increase	0.062230	569	-	-	-	186	360	23
32	NET OPERATING INCOME		$15,419	($2)	$0	$0	$5,053	$9,751	$615
	Interest Expense	2.72%	5,398	0	0	0	1,769	3,414	215
	RATE BASE: PLANT IN SERVICE								
33	Production Plant		8						8
34	Underground Storage Plant		6,028						6,028
35	Transmission Plant		0						
36	Distribution Plant		288,060				98,335	189,725	
37	General Plant		45,506				15,216	29,355	934
38	Total Plant in Service		339,602	0	0	0	113,551	219,080	6,970
	ACCUMULATED DEPRECIATION								
39	Production Plant		0						0
40	Underground Storage Plant		(654)						(654)
41	Transmission Plant		0						
42	Distribution Plant		(96,070)				(32,795)	(63,275)	
43	General Plant		(13,435)				(4,492)	(8,667)	(276)
44	Total Accum. Depreciation		(110,159)	0	0	0	(37,287)	(71,942)	(930)
45	DEFERRED FIT		(44,585)				(14,908)	(28,762)	(915)
46	GAS INVENTORY		2,544						2,544
	PREPAID PENSION		4,318				1,444	2,786	89
47	WORKING CAPITAL		6,728				2,250	4,340	138
48	TOTAL RATE BASE		$198,448	$0	$0	$0	$65,050	$125,502	$7,896
49	RATE OF RETURN		7.77%	#DIV/0!	#DIV/0!	#DIV/0!	7.77%	7.77%	7.77%

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF PATRICK D. EHRBAR
REPRESENTING AVISTA CORPORATION

2015 Test Period Revenue Load 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, line extension policy tariffs, as well as miscellaneous regulatory issues.

In November 2009, I was promoted to my current role.

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

A. In addition to discussing the Company's 2015 Test Period Revenue Load Adjustment, my testimony in this proceeding will cover the spread of the proposed annual margin/revenue increase among the Company's natural gas service schedules as well as the application of the increase to the rates within each of the schedules. The results of the Long-run Incremental Cost study ("LRIC") sponsored by Company witness Mr. Miller was used as a guide to spread the proposed margin/revenue increase by service schedule. Finally, I will provide an overview of the compliance requirements from the Company's 2013 general rate case, UG-246.

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 $9,140,000.

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 $9,140,000. Page 1 shows customer usage information by service schedule for 2013, 2014[1], and forecasted for 2015 and 2016. 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 base rates under each of the schedules, the proposed changes to those rates, and the rates after application of the proposed changes. 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 2015 Test Period Revenue Load Adjustment?

A. Yes. The 2015 Test Period Revenue Load Adjustment, included in this filing as Adjustment 2.01 in Company witness Ms. Andrews' Exhibit No. 601, represents the difference between the Company's restated historical test period revenue during 2013 and forecasted revenue for 2015. Actual revenue for 2013 was restated for adjustments 1.01 through 1.06 as discussed by Ms. Andrews. These adjustments include test year weather normalization and the elimination of adder schedules. Revenue for 2015 is based on customer usage and number of customers from the Company's most recent forecast applied to the present natural gas rates in effect as of February 1, 2014[2].

The 2015 Test Period Revenue Load Adjustment also contains an adjustment for

[1] Usage for 2014 includes actual booked usage for January through June and forecast usage for July through December.

[2] Effective February 1, 2014, the Commission approved a base rate increase of approximately $4.3 million in Docket UG-246, the Company's last general rate case.

purchased gas costs, which represents the difference between actual recorded natural gas costs during 2013 and "pro forma" natural gas costs for 2015. Natural gas costs for 2015 were determined using forecasted 2015 customer usage applied to the natural gas costs reflected in present rates, as approved by the Commission in UG-247 (the Company's 2013 Purchased Gas Adjustment ("PGA") filing).

Q. You mentioned that customer usage for 2015 was taken from the Company's most recent forecast. Could you please explain?

A. Yes. The Company's financial 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 financial forecast update was in June 2014. That forecast included an updated natural gas load forecast of the number of customers and total therm usage for future periods starting in June 2014.

Q. How often is the natural gas load forecast updated?

A. Prior to July 2013, the natural gas load forecast was updated on an annual basis. As of July 2013, the natural gas load forecast is updated semi-annually; one forecast in the 2nd Quarter and one in the 4th Quarter.

Q. In Docket UG-246, what was agreed to as it relates to the forecast used for the 2015 Test Period Revenue Load Adjustment?

A. The Company agreed that it would use the most recent forecast of customer counts and natural gas usage that is used for financial reporting purposes in its future general rate cases, Integrated Resource Plan, and PGA proceedings. The Company used the most recent forecast of customer counts and natural gas usage that is used for financial reporting, for all customer classes/schedules.

Q. How does 2015 customer usage compare to (weather-normalized) usage since the Company's last general filing?

A. Page 1 of Exhibit No. 903 shows actual and weather-normalized usage by rate schedule for 2013, the actual/forecasted usage for 2014, and the test period usage for 2015 used in this filing. As shown on lines 35 and 37, total throughput (sales and transportation volumes) is projected to increase by approximately 6.5% over the two year period. Approximately 27% of the projected load increase is from sales customers, with the other 73% coming from transportation customers.

Q. How does the 2015 usage for residential customers compare to 2013?

A. As shown in Exhibit No. 903, page 1 lines 1 and 3, total 2015 usage for residential customers is 1.7% higher than total (weather-corrected) residential usage in 2013. In evaluating residential monthly use per customer, 2015 use per customer is 0.4% higher than monthly use per customer (weather-corrected) in 2013.

Q. How does 2015 usage for commercial customers compare to 2013 usage for that customer classes?

A. As shown in Exhibit No. 903, page 1 lines 7 and 9, total 2015 usage for commercial customers is 2.2% higher than total (weather-corrected) commercial usage in 2013.

Q. What is the impact on the Company’s net operating income and revenue requirement resulting from the 2015 increase in natural gas loads?

A. As Ms. Andrews describes in her direct testimony (Exhibit No. 600), the increase in loads in 2015 as compared to 2013 results in an increase to net operating income of approximately $3.1 million and a <u>reduction</u> to revenue requirement of approximately $5.2 million. The 2015 Test Period Revenue Load Adjustment is Adjustment 2.01 in Exhibit No. 601.

Q. Is the Company proposing any changes to the present allocation of natural gas costs by rate schedule used in its PGA filings?

A. No, it is not.

III. PROPOSED RATE DESIGN AND RATE SPREAD

Q. Would you please describe the Company's present rate schedules and the types of natural gas service offered under each?

A. Yes. Table 1 below shows the type of customer and the number of customers served as of December 31, 2013, under each of the Company's Oregon natural gas schedules:

Table 1 - Natural Gas Customers by Schedule

Rate Schedule	No. of Customers
Residential Schedule 410	86,042
General Service Schedule 420	11,294
Large General Service Schedule 424	76
Interruptible Service Schedule 440	34
Seasonal Service Schedule 444	2
Special Contract Schedule 447	3
Transportation Service Schedule 456	35

Q. How does the Company propose to spread the proposed base revenue increase of $9,140,000, or 9.3%, among its various service schedules?

A. The Company utilized the results of the Long-run Incremental Cost Study ("LRIC Study") sponsored by Company witness Mr. Miller as a guide to spread the proposed margin/revenue increase by service schedule. Overall, the Company is proposing to spread the revenue increase only to Schedules 410 and 420. Table 2 below shows the margin-to-cost ratio under present and proposed revenues.

Table 2 - Present and Proposed Margin to Cost

	Margin to Cost as Present Rates	Margin to Cost at Proposed Rates
Residential Schedule 410	0.99	0.99
General Service Schedule 420	0.92	0.97
Large General Service Schedule 424	1.68	1.41
Interruptible Service Schedule 440	1.33	1.12
Seasonal Service Schedule 444	1.46	1.22
Transportation Service Schedule 456	1.54	1.29
Overall	**1.00**	**1.00**

The current margin-to-cost ratio for Schedules 410 and 420 are below unity. Given the size of the requested rate increase, the Company proposes that Schedule 410 should receive the same percentage of margin increase as the overall margin increase request in this case. In doing so, Schedule 410 would remain at a margin-to-cost ratio of almost 1.00 (unity). Schedule 420, however, has a margin-to-cost ratio of 0.92. This means the margin revenues provided by customers served under this schedule are below the full cost of serving these customers. They are, in essence, being subsidized by the other non-residential customer schedules. In order to address this issue and provide for a meaningful movement towards unity, the Company requests that Schedule 420 receive a greater than overall percentage increase, on a margin basis, than the Company's overall request.

As Table 2 above shows, requesting no rate change for Schedules 424, 440, 444 and 456 provides meaningful movement for these schedules towards unity. While a rate decrease could be supported for some of those schedules, doing so would lead for even larger increases to Schedules 410 and 420. Given the size of the overall request, the Company does not believe that is appropriate. In the end, Schedule 410 would receive a percentage of margin increase equal to the overall requested increase, and the balance of the revenue requirement would be applied to Schedule 420. This information is also shown in more detail on page 2 of Exhibit No. 903.

Q. Using the Company's proposed rate spread, what is the proposed percentage increase in base revenue for each schedule?

A. Table 3 below shows the proposed percentage increase in base revenue (including natural gas costs) for each service schedule:

Table 3 - Proposed % Natural Gas Increase by Schedule

Rate Schedule	**General Increase**
Residential Schedule 410	9.8%
General Service Schedule 420	11.2%
Large General Service Schedule 424	0.0%
Interruptible Service Schedule 440	0.0%
Seasonal Service Schedule 444	0.0%
Transportation Service Schedule 456	0.0%
Overall	**9.3%**

More detailed information related to the revenue increase by schedule is shown on Page 3 of Exhibit No. 903.

Q. Turning now to the proposed changes to the rates within 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 base revenue increase of 9.8% 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 $2.00 per month, from $8.00 to $10.00. The present charge per therm would be increased by $0.08036 per therm, from $0.46998 to $0.55035 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 No. 801, the costs associated with billing, meter reading, meters and services are $16.99 per month for Schedule 410[3]. 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?

[3] See Exhibit 801, Page 1 line 32.

A. Based on an average usage level of 47 therms per month, the average bill for a residential customer, which includes both base and adder schedules, would increase $5.78 per month, or 10.3%, from $55.97 to $61.75.

Q. Could you please describe the changes you propose to the rates of General Service Schedule 420?

A. Yes. As shown on Page 4 of Exhibit No. 903, the present rates for service under Schedule 420 consist of an $12.00 per month customer charge and a base volumetric rate of $0.38147 per therm. The Company is proposing an increase in the customer charge of $3.00 per month, from $12.00 to $15.00, and an increase of $0.10269 per therm in the usage charge. These changes result in an overall proposed increase of 11.2% in base revenue for the Schedule.

Q. The Company has not requested to change the revenues for Schedules 424, 440, 444 or 456. Why did it file those tariffs in this docket?

A. While the Company did not propose to change the revenues, or the rate design, for these schedules, the Company is aware that the Commission may choose to spread the final approved revenues in a manner different than that requested by the Company. As such, it is appropriate that the tariffs be incorporated into this docket, and ultimately suspended, pending final Commission determination.

Q. If the Commission orders changes in revenues for Schedules 420, 440, 444, or 456, does the Company have a viewpoint on how those revenues should be spread within each schedule?

A. Yes. If the Commission orders rate increases for either Schedule 420 or 456, the Company believes that the increases should be applied to the monthly customer charge (Schedules 440 and 444 do not have monthly customer charges, and therefore any increase would be applied to the volumetric rate). If the Commission orders revenue decreases for any of the schedules, those decreases should be applied to the volumetric rates, and more specifically for Schedule 456, any revenue decrease should be spread on a uniform percentage basis to the volumetric blocks.

Q. With regards to the November 1, 2014 rate change related to the Company's last general rate case (UG-246), what are the Company's plans related to that filing?

A. As discussed in detail in Paragraph 5h of the UG-246 Settlement Stipulation approved in Order No. 14-015, "The Parties, however, agree to include specific Project Compass costs (upon review of actual costs through September 30, 2014), and specific Aldyl A Pipe Replacement Program costs (upon review of actual costs through June 30, 2014) in a Second Step increase effective November 1, 2014 provided that the actual costs do not exceed the filed general rate case amount." As discussed in more detail by Company witnesses Mr. Kensok and Mr. DeFelice, the expected in-service date for Project Compass will occur in the first quarter of 2015. Therefore, the November 1, 2014 rate change will only recover costs related to the Aldyl A Pipe Replacement Program. The costs associated with Project Compass have been included in this case.

For the November 1, 2014 rate change, given that the base tariffs will be suspended in this docket, the Company will file a new schedule, Schedule 497, which would serve as the adder-tariff used to recover the approved costs. At the end of this proceeding, the Company would propose to move the rates associated with Schedule 497 into the appropriate base tariff schedules as a part of its general rate case compliance filing, and in a follow-on filing, request the cancellation of the tariff.

IV. SUMMARY OF UG-246 ORDER No. 14-015 REQUIREMENTS

Q. There were several requirements the Commission required the Company to address in this docket based on Order No. 14-015 (and Settlement Stipulation) in Docket UG--246. Would you please provide a summary of those items and how they have been addressed by the Company in this rate case?

A. Yes. Detailed below are items that the Company was required to address based on Order No. 14-015 in Docket UG-246. Shown below are the requirements, the page number where the items are located in the Order, and either the witness who addresses the item in testimony, or how the item has been addressed in this case.

Item 1 – Allocation Methodology (Settlement Stipulation paragraph 9a, Order Page 8, Page 1 of Errata Order):

"Prior to September 30, 2014, Avista will conduct one or more workshops to review the methodology used by Avista to allocate common costs and common plant to its regulated and unregulated operations, electric and gas services, and state jurisdictions. The workshops will include Avista's review of its accounting practices to record its directly-assigned and common costs and identify whether additional cost areas could be more appropriately directly assigned. In addition, the allocation methodology will be reviewed to determine whether the allocation of costs is reasonable from a cost driver standpoint. Parties will not recommend the Oregon Public Utility Commission (OPUC) implement any changes to allocation methodology prior to July 1, 2015. OPUC Staff intends to request a joint meeting with the Staffs of the Washington Utilities and Transportation Commission and the Idaho Public Utilities Commission prior to March 31, 2015. Intervenors in each state will be invited to attend those meetings. At those meetings an attempt will be made to achieve consensus among all affected jurisdictions on the appropriate common cost allocation

methodology so as to prevent any stranded costs or investment. However, all Parties recognize that Staff, Intervenors and the OPUC are not bound by the decisions of other state commissions."

Company witness Ms. Andrews addresses this compliance requirement in her direct testimony.

Item 2 – Depreciated Rates Effective Dates (Order Page 8):
"As directed by our Order No. 13-168, issued in docket UM 1626, Avista implemented new book depreciation rates on common plant effective January 1, 2013. Under the terms of that order, the new depreciation rates on plant directly assigned to Oregon would be implemented at the conclusion of the company's next general rate case - this case. As part of this stipulation the parties agree that the change in depreciation rates on directly assigned plant will be effective July 1, 2014."

Avista implemented the change in depreciation rates on directly assigned plant on July 1, 2014.

Item 3 – Klamath Falls Lateral (Order Page 8):
"Avista has been recovering $463,000 annually attributable to its purchase of the Klamath Falls Lateral, effective January 1, 2013. The parties agree that the revenue requirement associated with this purchase is prudent and these revenues will be included in base rates within the February 1, 2014 rate increase. Accordingly, Avista will file Schedule 498, as part of its compliance filing for the February 1, 2014 rate increase, adjusting the current rate of $0.00585 per therm to $0."

Avista filed Schedule 498 as a part of its compliance filing, moving the rate per therm to $0.00.

Item 4 – Schedule 493 – Residential Low Income Rate Assistance Program (Order Page 8):
"In Avista's last general rate case the funding associated with the residential low income rate assistance program (LIRAP) was removed from base rates and is now administered as a stand-alone tariff. In its compliance filing to that prior rate case, however, the company inadvertently failed to remove the Revenue Adjustment Factor for LIRAP from the base rate schedule. The parties agree that the company will file a conforming tariff as part of its compliance filing to properly effectuate the rate change."

As a part of its compliance filing, Avista made the necessary adjustments to the rate per therm to Schedule 410 and 493 to reflect the adjustment for the revenue conversion factor.

Item 5 – Long-Run Incremental Cost (Order Pages 8-9):

"The parties agree that in future rate cases Avista will make the following changes to its long-run incremental cost study:

- *Allocate Gas Scheduling on a volumetric basis, rather than a customer-count basis;*
- *Use an engineering estimate/cost-study basis for estimating main extension costs for Special Contracts, Schedule 447, rather than use an amount based on an estimated bypass cost."*

Company witness Mr. Miller addresses this compliance item in his direct testimony.

Item 6 – Demand Side Management Verification (Order Page 9):
"Avista agrees to meet and confer with Staff and interested parties to review the company's true-up process associated with energy efficiency savings prior to its next filing to amortize deferred accounts associated with Schedule 478. At the meeting the parties will address Staffs concerns with several indicated issues."

On April 2, 2014, Avista, Staff, NWIGU and CUB held a conference call related to this compliance item. Avista provided a general overview of its DSM operations, how energy efficiency savings are calculated, its true-up process, and generally how the Company's programs operate in comparison to the Energy Trust of Oregon as well as Avista's Washington and Idaho DSM programs. Two items that required additional follow-up discussion and action were:

1. "Free-Riders" – This issue refers to customers who completed energy efficiency projects and received an incentive from the Company, but were not otherwise motivated to do the project because of the Company's DSM program. The methodology to determine the level of free-riders is a Net-to-Gross Study. Avista has not conducted a Net-to-Gross Study in Oregon due to the cost of the study vis-a-vis the Oregon DSM program funding levels. To date, the Net-to-Gross percentage has been 100%, i.e., there were no free riders in the Company's programs. All Parties agreed that this is not correct. Avista stated during an April 17 meeting of the Parties that it will use its latest Net-to-Gross report and percentage developed for its Washington and Idaho DSM programs for its Oregon programs, and will continue to work with the Parties, as necessary, should other methodologies arise.

2. Lost Margin – The Parties have agreed, based on follow-on conversations held on April 17, 2014, that Avista would not track lost margin related to its DSM programs for the period of February 1, 2014 through December 31, 2014. The Company used 2014 forecasted billing determinants in its general rate case, and those billing determinants included the impact of the Company's DSM programs. As such, any tracking of lost margin in 2014 for purposes of later recovery from customers would be duplicative.

Item 7 – Demand Side Management Tariffs (Order Page 9):

"The parties agree that the company should modify tariff Schedules 466 and 478 so that the tariffs cross-reference each other, and to include those modified tariffs as part of its compliance filing for the February 1, 2014 rate increase."

The Company modified tariff Schedules 466 and 478 as a part of its compliance filing.

Item 8 – Forecasting Methodology (Order Page 9):
"Avista agrees to meet with Staff and interested parties no later than July 1, 2014, to discuss forecasting model specification and methodology."

On April 17, 2014, Avista, in conjunction with its natural gas Quarterly Meeting, provided an overview of its load forecasting model specification and methodology. The presentation was given to representatives of Staff, CUB, and NWIGU.

Item 9 – Weather Normalization (Order Page 9):
"Avista agrees to use consistent weather response parameters in its various Oregon regulatory filings unless the company can document and discuss why such use is not appropriate."

Avista used consistent weather response parameters in this filing.

Item 10 – Advertising and Marketing (Order Page 9):
"Avista agrees to meet with Staff and interested parties no later than July 1, 2014, to resolve the allocation of costs pursuant to OAR 860-026-0022 (Presumptions of Reasonableness of Advertising Expenses in Utility Rate Cases)."

On April 3, 2014, Avista sent to the Parties a document, developed jointly by Staff and Avista, which summarized Staff's concerns related to the allocation of advertising and marketing costs, and how those issues have been resolved. CUB and NWIGU in later correspondence stated that they had no issues with the resolution. Ms. Andrews provides further information related to this compliance item in her direct testimony.

Q. Can you please provide a summary of the requirements related to the November 1, 2014 second-step rate change related to Project Compass and Aldyl-A?

A. Yes. As discussed in detail in Paragraph 6 of the Settlement Stipulation approved in Order No. 14-015, the Company was required to provide monthly expenditure reports related to Project Compass and its Aldyl A Pipe Replacement Program. The Company continues to meet that requirement, providing the Parties with monthly updates.

As discussed in more detail by Company witnesses Mr. Kensok and Mr. DeFelice, the expected in-service date for Project Compass will occur in the first quarter of 2015. Therefore, the November 1, 2014 rate change will only recover costs related to the Aldyl A Pipe Replacement Program. The costs associated with Project Compass have been included in this case.

Q. Does this conclude your pre-filed, direct testimony?

A. Yes it does.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

PATRICK D. EHRBAR
Exhibit No. 901

Present Natural Gas Service Tariffs

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:	**$8.00**	(I)
Commodity Charge Per Therm:		
Base Rate	$0.46998	(I)
OTHER CHARGES:		
Schedule 461 – Purchased Gas Cost Adjustment	$0.61069	(R)
Schedule 462 – Gas Cost Rate Adjustment	($0.08465)	(I)
Schedule 476 – Intervenor Funding	$0.00101	(I)
Schedule 478 – DSM Cost Recovery	$0.01919	(I)
Schedule 493 – Low Income Rate Assistance Program	$0.00451	(I)(D)
Total Billing Rate *	**$1.02073**	(R)

Minimum Charge:
The Customer Charge constitutes the Minimum Charge.

* The rates shown in this Rate Schedule as Other Charges may not always reflect actual billing rates. See the corresponding rate schedules under Other Charges for the actual rates.

(continued)

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:	**$12.00**	(I)
Commodity Charge Per Therm:		
Base Rate	$0.38147	(I)
OTHER CHARGES:		
Schedule 461 – Purchased Gas Cost Adjustment	$0.61069	(R)
Schedule 462 – Gas Cost Rate Adjustment	($0.08465)	(I)
Schedule 478 – DSM Cost Recovery	$0.01919	(I)(D)
Total Billing Rate *	**$0.92670**	(R)

Minimum Charge:

The Customer Charge constitutes the Minimum Charge.

* The rates shown in this Rate Schedule as Other Charges may not always reflect actual billing rates. See the corresponding rate schedules under Other Charges for the actual rates.

(continued)

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**	
Commodity Charge Per Therm:		
Base Rate	$0.13908	(R)
OTHER CHARGES:		
Schedule 461 – Purchased Gas Cost Adjustment	$0.61069	(R)
Schedule 462 – Gas Cost Rate Adjustment	($0.08465)	(I)
Schedule 478 – DSM Cost Recovery	$0.01919	(I)(D)
Total Billing Rate *	**$0.68431**	(R)

Minimum Charge:

The minimum monthly charge shall consist of the Monthly Customer Charge.

* The rates shown in this Rate Schedule as Other Charges may not always reflect actual billing rates. See the corresponding rate schedules under Other Charges for the actual rates.

(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:		
Base Rate	$0.11584	(I)
OTHER CHARGES:		
Schedule 461 – Purchased Gas Cost Adjustment	$0.39869	(I)
Schedule 462 – Gas Cost Rate Adjustment	($0.00728)	(I)
Schedule 476 – Intervenor Funding	$0.00043	(I)
Total Billing Rate *	**$0.50768**	(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 11.584 cents per therm. (I)

* The rates shown in this Rate Schedule as Other Charges may not always reflect actual billing rates. See the corresponding rate schedules under Other Charges for the actual rates.

(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:		
Base Rate	$0.17082	(I)
OTHER CHARGES:		
Schedule 461 – Purchased Gas Cost Adjustment	$0.61069	(R)
Schedule 462 – Gas Cost Rate Adjustment	($0.08465)	(I)
Schedule 478 – DSM Cost Recovery	$0.01919	(I)(D)
Total Billing Rate *	**$0.71605**	(R)

Minimum Charge:
$5,810.92 per season.

* The rates shown in this Rate Schedule as Other Charges may not always reflect actual billing rates. See the corresponding rate schedules under Other Charges for the actual rates.

(continued)

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**

Volumetric Charge Per Therm:

	Base Rate	Schedule 476	Billing Rate*
First 10,000	$0.15016(R)	$0.00043(I)	**$0.15059(R)**
Next 20,000	$0.09037(R)	$0.00043(I)	**$0.09080(R)**
Next 20,000	$0.07428(R)	$0.00043(I)	**$0.07471(R)**
Next 200,000	$0.05814(R)	$0.00043(I)	**$0.05857(R)**
All Additional	$0.02949(R)	$0.00043(I)	**$0.02992(R)**

Minimum Charge:
The minimum monthly charge shall be $1,354.30 per month, accumulative annually.

* The rates shown in this Rate Schedule may not always reflect actual billing rates. See the corresponding rate schedules for the actual rates.

(continued)

Advice No. 14-02-G Effective For Service On & After
Issued January 22, 2014 February 1, 2014

Issued by Avista Utilities
By Kelly O. Norwood, V.P. State & Federal Regulation

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

PATRICK D. EHRBAR
Exhibit No. 902

Proposed Natural Gas Service Tariffs

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:	**$10.00**	(I)
Commodity Charge Per Therm:		
Base Rate	$0.55033	(I)
OTHER CHARGES:		
Schedule 461 – Purchased Gas Cost Adjustment	$0.61069	
Schedule 462 – Gas Cost Rate Adjustment	($0.08465)	
Schedule 476 – Intervenor Funding	$0.00101	
Schedule 478 – DSM Cost Recovery	$0.01919	
Schedule 493 – Low Income Rate Assistance Program	$0.00451	
Total Billing Rate *	**$1.10108**	(I)

Minimum Charge:
The Customer Charge constitutes the Minimum Charge.

* The rates shown in this Rate Schedule as Other Charges may not always reflect actual billing rates. See the corresponding rate schedules under Other Charges for the actual rates.

(continued)

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:	**$15.00**	(I)
Commodity Charge Per Therm:		
Base Rate	$0.48416	(I)
OTHER CHARGES:		
Schedule 461 – Purchased Gas Cost Adjustment	$0.61069	
Schedule 462 – Gas Cost Rate Adjustment	($0.08465)	
Schedule 478 – DSM Cost Recovery	$0.01919	
Total Billing Rate *	**$1.02939**	(I)

Minimum Charge:

The Customer Charge constitutes the Minimum Charge.

* The rates shown in this Rate Schedule as Other Charges may not always reflect actual billing rates. See the corresponding rate schedules under Other Charges for the actual rates.

(continued)

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**
Commodity Charge Per Therm:	
Base Rate	$0.13908
OTHER CHARGES:	
Schedule 461 – Purchased Gas Cost Adjustment	$0.61069
Schedule 462 – Gas Cost Rate Adjustment	($0.08465)
Schedule 478 – DSM Cost Recovery	$0.01919
Total Billing Rate *	**$0.68431**

Minimum Charge:

The minimum monthly charge shall consist of the Monthly Customer Charge.

* The rates shown in this Rate Schedule as Other Charges may not always reflect actual billing rates. See the corresponding rate schedules under Other Charges for the actual rates.

(continued)

AVISTA CORPORATION
dba Avista Utilities

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:	
Base Rate	$0.11584
OTHER CHARGES:	
Schedule 461 – Purchased Gas Cost Adjustment	$0.39869
Schedule 462 – Gas Cost Rate Adjustment	($0.00728)
Schedule 476 – Intervenor Funding	$0.00043
Total Billing Rate *	**$0.50768**

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 11.584 cents per therm.

* The rates shown in this Rate Schedule as Other Charges may not always reflect actual billing rates. See the corresponding rate schedules under Other Charges for the actual rates.

(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:	
Base Rate	$0.17082
OTHER CHARGES:	
Schedule 461 – Purchased Gas Cost Adjustment	$0.61069
Schedule 462 – Gas Cost Rate Adjustment	($0.08465)
Schedule 478 – DSM Cost Recovery	$0.01919
Total Billing Rate *	**$0.71605**

Minimum Charge:
$5,810.92 per season.

* The rates shown in this Rate Schedule as Other Charges may not always reflect actual billing rates. See the corresponding rate schedules under Other Charges for the actual rates.

(continued)

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**

Volumetric Charge Per Therm:

	Base Rate	Schedule 476	Billing Rate*
First 10,000	$0.15016	$0.00043	**$0.15059**
Next 20,000	$0.09037	$0.00043	**$0.09080**
Next 20,000	$0.07428	$0.00043	**$0.07471**
Next 200,000	$0.05814	$0.00043	**$0.05857**
All Additional	$0.02949	$0.00043	**$0.02992**

Minimum Charge:
The minimum monthly charge shall be $1,354.30 per month, accumulative annually.

* The rates shown in this Rate Schedule may not always reflect actual billing rates. See the corresponding rate schedules for the actual rates.

(continued)

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

PATRICK D. EHRBAR
Exhibit No. 903

Rate Spread & Rate Design

Avista Utilities
State of Oregon
Comparison of Natural Gas Usage
2013 Weather-Normalized, 2014 Actual & Forecast *, and 2015-2016 Forecast

Line No.		Actual Usage	Weather Adj.	Normalized Usage	Avg. Customers	Annual Use/ Customer	Monthly Use/ Customer
	Residential Sch 410						
1	2013	51,201,567	(2,945,968)	48,255,599	85,137	566.8	47.2
2	2014	45,511,952	2,704,836	48,216,788	85,645	563.0	46.9
3	2015	49,097,140		49,097,140	86,298	568.9	47.4
4	2016	49,018,942		49,018,942	87,065	563.0	46.9
5							
6	**Commercial Sch 420**						
7	2013	27,592,098	(1,710,546)	25,881,552	11,190	2,313	193
8	2014	24,885,565	1,287,279	26,172,844	11,268	2,323	194
9	2015	26,450,079		26,450,079	11,333	2,334	194
10	2016	26,621,408		26,621,408	11,416	2,332	194
11							
12							
13	**Large Sales Schs. 424, 440 & 444**						
14	2013	8,026,949	(73,300)	7,953,649	117	67,980	5,665
15	2014	8,734,419	51,143	8,785,562	117	75,359	6,280
16	2015	8,637,435		8,637,435	119	72,670	6,056
17	2016	8,821,802		8,821,802	121	72,983	6,082
18							
19							
20	**Total Sales Volumes**						
21	2013			82,090,800	96,444		
22	2014			83,175,194	97,030		
23	2015			84,184,654	97,750		
24	2016			84,462,152	98,602		
25							
26							
27	**Transport Schs. 447 & 456**						
28	2013	38,821,540		38,821,540	39	989,084	82,424
29	2014	42,323,876		42,323,876	38	1,101,706	91,809
30	2015	44,606,372		44,606,372	38	1,172,642	97,720
31	2016	47,119,020		47,119,020	38	1,238,715	103,226
32							
33							
34	**Total Throughput**						
35	2013			120,912,340			
36	2014			125,499,070			
37	2015			128,791,025			
38	2016			131,581,173			

* The 2014 numbers include January through June actual booked usage and July through December forecasted usage.

Avista Utilities
Oregon - Gas
Pro Forma 12 Months Ended December 31, 2015

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	$ 98,217,000	61,343,000	27,875,000	3,376,000	2,030,000	198,000	320,000	3,075,000
2	COST OF GAS	$ 50,547,000	29,967,000	16,144,000	2,709,000	1,572,000	155,000	$ -	$ -
3	CURRENT MARGIN	$ 47,670,000	$ 31,376,000	$ 11,731,000	$ 667,000	$ 458,000	$ 43,000	$ 320,000	$ 3,075,000
4	% of Current Margin excl Sch 447	100.00%	66.26%	24.78%	1.41%	0.97%	0.09%		6.49%
5	Total Revenue Requirement	$ 9,140,000							
6	Revenue Requirement as a Percent of Margin Revenue	19.17%							
7	Percentage Applied to Overall Margin Increase		100.00%	138.90%	0.00%	0.00%	0.00%		0.00%
8	Increase as a Percent of Total Current Margin		19.17%	26.63%	0.00%	0.00%	0.00%		0.00%
9	**PROPOSED MARGIN REVENUE INCREASE**	**$ 9,140,000**	**$ 6,015,872**	**$ 3,124,128**	**$ -**	**$ -**	**$ -**		**$ -**
10	**Percentage Revenue Increase**	**9.31%**	**9.81%**	**11.21%**	**0.00%**	**0.00%**	**0.00%**		**0.00%**
	<u>Cost of Service</u>								
11	Proposed Margin	$ 56,810,000	$ 37,391,872	$ 14,855,128	$ 667,000	$ 458,000	$ 43,000	$ 320,000	$ 3,075,000
12	LRIDC Based Target Margin (Line 27 of Miller Exhibit 801 Page 1 of 3)	**$ 56,810,000**	**37,914,940**	**15,238,516**	**474,293**	**410,691**	**35,109**	**350,566**	**2,385,885**
13	**Relative Margin to Cost at Present Rates (Line 29A of Miller Exhibit 801 Page 1 of 3)**	**1.00**	**0.99**	**0.92**	**1.68**	**1.33**	**1.46**	**1.09**	**1.54**
14	**Relative Margin to Cost at Proposed Rates**	**1.00**	**0.99**	**0.97**	**1.41**	**1.12**	**1.22**		**1.29**

Avista Utilities
Proposed Revenue Increase by Schedule
Oregon - Gas
Pro Forma 12 Months Ended December 31, 2015
(000s of Dollars)

Line No.	Type of Service	Schedule Number	Base Revenue Under Present Rates	Proposed GRC Increase	Base Revenue Under Proposed Rates	Therms (000s)	**Base Revenue Percentage Increase**	Billed Revenue Under Present Rates	Proposed GRC Increase	Billed Revenue Under Proposed Rates	**Billed Revenue Percentage Increase**
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Residential	410	$61,343	$6,016	$67,359	49,097	**9.8%**	$58,400	$6,016	$64,415	**10.3%**
2	General Service	420	27,875	3,124	30,999	26,450	**11.2%**	26,143	$3,124	$29,267	**12.0%**
3	Large General Service	424	3,376	0	3,376	4,438	**0.0%**	3,086	$0	$3,086	**0.0%**
4	Interruptible Service	440	2,030	0	2,030	3,946	**0.0%**	2,003	$0	$2,003	**0.0%**
5	Seasonal Service	444	198	0	198	253	**0.0%**	181	$0	$181	**0.0%**
6	Transportation Service	456	3,075	0	3,075	36,627	**0.0%**	3,091	$0	$3,091	**0.0%**
7	Special Contract	447	320	0	320	7,979	**0.0%**	320	$0	$320	**0.0%**
8	Total		$98,217	$9,140	$107,356	128,791	**9.3%**	$93,225	$9,140	$102,364	**9.8%**

Avista Utilities
Comparison of Present & Proposed Gas Rates
Oregon - Gas

Present Base Rates (Including Gas Costs)	Schedule 461 PGA Gas Costs	Present Base Rates	Change	Proposed Base Rates
		Residential Service Schedule 410		
$8.00 Customer Charge		$8.00 Customer Charge	$2.00/month	$10.00 Customer Charge
All Therms - $1.08067/Therm	All Therms - -$0.61069/Therm	All Therms - $0.46998/Therm	$0.08035/therm	All Therms - $0.55033/Therm
		General Service Schedule 420		
$12.00 Customer Charge		$12.00 Customer Charge	$3.00/month	$15.00 Customer Charge
All Therms - $0.99216/Therm	All Therms - -$0.61069/Therm	All Therms - $0.38147/Therm	$0.10269/therm	All Therms - $0.48416/Therm
		Large General Service Schedule 424		
$50.00 Customer Charge		$50.00 Customer Charge	$0.00/month	$50.00 Customer Charge
All Therms - $0.74977/Therm	All Therms - -$0.61069/Therm	All Therms - $0.13908/Therm	$0.00000/therm	All Therms - $0.13908/Therm
		Interruptible Service Schedule 440		
All Therms - $0.51453/Therm	All Therms - -$0.39869/Therm	All Therms - $0.11584/Therm	$0.00000/therm	All Therms - $0.11584/Therm
		Seasonal Service Schedule 444		
All Therms - $0.78151/Therm	All Therms - -$0.61069/Therm	All Therms - $0.17082/Therm	$0.00000/therm	All Therms - $0.17082/Therm
		Transportation Service Schedule 456		
$275.00 Customer Charge		$275.00 Customer Charge	$0.00/month	$275.00 Customer Charge
1st 10,000 Therms - $0.15016/Therm		1st 10,000 Therms - $0.15016/Therm	$0.00000/therm	1st 10,000 Therms - $0.15016/Therm
Next 20,000 Therms - $0.09037/Therm		Next 20,000 Therms - $0.09037/Therm	$0.00000/therm	Next 20,000 Therms - $0.09037/Therm
Next 20,000 Therms - $0.07428/Therm		Next 20,000 Therms - $0.07428/Therm	$0.00000/therm	Next 20,000 Therms - $0.07428/Therm
Next 200,000 Therms - $0.05814/Therm		Next 200,000 Therms - $0.05814/Therm	$0.00000/therm	Next 200,000 Therms - $0.05814/Therm
Over 250,000 Therms - $0.02949/Therm		Over 250,000 Therms - $0.02949/Therm	$0.00000/therm	Over 250,000 Therms - $0.02949/Therm