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# BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

**IN THE MATTER OF THE FILING BY AVISTA CORPORATION DBA AVISTA UTILITIES OF ITS 2009 NATURAL GAS INTEGRATED RESOURCE PLAN (IRP).**

**CASE NO. AVU-G-09-6**

**COMMENTS OF THE COMMISSION STAFF**

The Staff of the Idaho Public Utilities Commission, by and through its Attorney of Record, Donald L. Howell II, Deputy Attorney General, submits the following comments in response to Order No. 30990 issued on January 28, 2010.

## BACKGROUND

On December 30, 2009, Avista Corporation dba Avista Utilities filed its 2009 natural gas Integrated Resource Plan (IRP) with the Commission. In Order No. 22290 issued in January 1989, the Commission required electric and natural gas utilities to file a biennial IRP describing the utility's plans to meet the future energy needs of its customers. The IRP is a comprehensive long-range planning tool designed to identify and evaluate forecasted natural gas requirements. The purpose of the IRP is to plan for the acquisition of the most cost-effective, risk-adjusted portfolio of existing and future resources, and to meet the daily and peak-day demand and delivery requirements over the next 20-year period. IRP at p. 2.4. Avista's IRP includes:

Demand forecasts; natural gas price forecasts; supply resources; demand-side management (DSM) programs; resource needs; and the 2010-2011 near-term action plan. The Company states that this IRP was developed during the last two years when the United States and other countries were experiencing a financial and credit crisis. These financial uncertainties prompted the Company to "consider a wider range of scenarios to evaluate and prepare for a broad spectrum of potential outcome" in this IRP. IRP at p. 1.1.

Avista serves approximately 315,000 natural gas customers in three states including about 73,000 natural gas customers in northern Idaho. In Avista's northern operating division (eastern Washington and northern Idaho), it serves roughly 218,000 natural gas customers. The Company's customer base is generally comprised of 94% residential customers, 5% commercial customers, and 1% industrial customers. IRP at p. 2.3.

1. The IRP

The Company's approach to demand forecasting focuses on customer growth and consumption per customer as the basic components of demand. The Company considers various factors that influence these components including population, employment trends, age and income demographics, construction trends, conservation technologies, new uses (e.g., natural gas vehicles), and consumption per customer. In the demand forecast, Avista lays out six different scenarios including its "Expected Case"[1] scenario. System wide in the Expected Case, Avista anticipates a compounded average growth in daily demand of 1.1% during the period 2010 to 2028-2029 (net of projected conservation savings from DSM programs). During the same time frame, the Company estimates that its peak-day demand will increase by a compound rate of 1.3%. *Id.*

The Company maintains that natural gas prices are a fundamental component of integrated resource planning. Although Avista does not believe that it can accurately predict future prices over the 20-year horizon, it has developed high, medium and low-price forecasts for the price of natural gas.

Avista has a diverse portfolio of natural gas supply resources including owned and contract storage, firm capacity rights on six pipelines and commodity purchase contracts from

[1] The "Expected Case" is the Company's estimate of the most likely outcome given its experience, industry knowledge and understanding of future natural gas markets.

several different supply basins. The Company also evaluated resource additions from incremental pipeline transportation, storage options, distribution enhancements, and various forms of liquefied natural gas storage or service. *Id.* at p. 1.5. Matching its resource supply scenario with its Expected Case demand scenario, the Company forecasts that its Idaho/Washington service territory will not experience a supply deficiency until the year 2023. IRP at p. 1.6. The graph of the forecast shortages is almost flat, which leads the Company to conclude that its existing resources will be sufficient for quite some time to meet demand.

2. <u>IRP Action Plan</u>

The Company's IRP identifies and establishes a near-term action plan that will steer the Company toward the risk-adjusted, least-cost method of providing service to its natural gas customers. Included in this action plan are efforts to improve computer modeling, evaluate planning standards, and apply various risk analyses. Key components of the action plan include:

- Monitoring actual demand and responding aggressively when growth exceeds the Company's forecast demand.

- Researching and refining the evaluation of resource alternatives including: The implementation of risk factors and timelines; updated cost estimates; feasibility assessments; and targeting options of the service territory with near-term unserved demand exposure.

- Analyzing per-customer data and DSM program results for indications of price elasticity response trends that may be influenced by evolving economic conditions. Determining if the American Gas Association will update its analytical work or consider hiring outside experts in price elasticity on a regional basis.

- Continuing pursuit of cost-effective demand-side solutions to reduce demand. In Washington and Idaho, conservation measures are targeted to reduce demand by 2.193 million therms in 2010. This goal represents an increase of 25% in Washington/Idaho from the 2007 IRP.

- Performing an updated assessment of technical and achievable potential for conservation in the Company's service territory prior to the 2011 IRP.

- Continuing to monitor issues of diminishing Canadian natural gas importing and looking for signals that indicate increased risk of disrupted or dwindling supply from Canada.

- Exploring and evaluating alternatives and additional forecasting methodologies for potential inclusion in the next IRP.

*Id.* at pp. 1.11-12.

3. <u>Risk Issues</u>

The Company has identified three general issues that require monitoring and may increase risk. First, the Company will continue to monitor economic conditions and financial markets on natural gas demand, infrastructure development, credit availability, and commodity prices. Second, the Company will continue to monitor federal climate change legislation and its projected effects upon emission target levels, phase-in time frames, allocation of allowances, availability of offsets, cost mitigation to customers, and a host of implementation challenges. Third, an increasing supply of natural gas in North America is forecasted to come from "unconventional" gas, especially shale gas. In addition, international liquefied natural gas (LNG) projects, which have been at least a half decade in the making, are beginning to come online. The near-term excessive LNG supply, combined with the projected increase in supply of unconventional gas, and a lingering global recession may mean lower prices in the future. "Although beneficial to end users in the near term, this dramatic volatility and uncertainty could cause long-term disruption in production, pipeline and storage capital investment, exacerbating boom/bust cycles in the long term." IRP at 1.14.

**STAFF REVIEW**

In accordance with the Public Utilities Regulatory Policy Act of 1978 (PURPA) (as amended by the 1992 Energy Policy Act), Commission Order Nos. 25342, 27024 and 27098 require that the Company submit an Integrated Resource Plan (IRP) every two years, addressing the following elements:

- Demand Forecasting
- Assessment of Efficiency Improvements (DSM Actions) & Avoided Costs
- Natural Gas Supply Options
- Natural Gas Purchasing Options and Cost Effectiveness
- Integration of Demand and Resources
- Short-Term Action Plan
- Relationship Between Consecutive Plans (2007 Plan to 2009 Plan)
- Public Participation

The Company's 2009 IRP addressed each of these elements to various degrees. The Company's Submittal complies with the requirements of the Commission Order No. 25342 as described in more detail below.

**The Supply-Side Resources**

Avista has a diversified portfolio of natural gas supply resources, including owned and contracted storage, firm capacity rights on six pipelines, and commodity purchase contracts from several different supply basins. The Company's philosophy is to reliably provide natural gas to customers with an appropriate balance of price stability and prudent cost while building a diversified portfolio to manage risk in continuously changing market conditions.

Avista benefits from its close proximity to the two largest natural gas producing regions in North America; the Western Canadian Sedimentary Basin (WCSB) and the Rocky Mountain natural gas basins. Historically, these basins have supplied Avista with natural gas supplies that were discounted to other regions in the country, due to the limited pipeline export potential. However, recent large pipeline projects now connect these basins to large population bases in the Southwest, Midwest, and Northeast, which have diminished the discounted price advantage that Avista has enjoyed. Future projects to relieve the bottlenecks and pipeline congestion out of the basins enabling gas to flow to higher priced markets along with increased gas production (from shale) in the east could further erode or eliminate altogether the price advantage.

Procurement of natural gas is done via contracts. For the IRP, the SENDOUT® model assumes the natural gas is purchased as a firm, physical, fixed-price contract regardless of when the contract is executed and what type of contract it is. However, in reality, Avista pursues a variety of contractual terms and conditions in order to capture the most value from each transaction.

The Company's procurement plan addressed in the IRP is a diversified and structured plan for natural gas purchases that does not attempt to predict market outcomes. The plan seeks to competitively acquire natural gas supplies while reducing exposure to short-term price volatility. The procurement strategy includes hedging, storage utilization and index purchases. Although the specific provisions for the plan will change as a result of ongoing analysis and experience, the plan calls for disciplined but flexible hedging approaches over periods of time with windows and targets used to initiate transactions. The Company also uses spot market acquisitions and short-term index purchases for both summer filling of storage and during the heating season. In recognition of the volatility present in the markets, the Company is continually working to add longer-term purchases and other measures to diversify its procurement portfolio with the aim of reducing that volatility while also securing low cost supplies.

The Company has several gas purchasing methods available. These include daily and monthly spot market indices, short and long-term purchases, fixed price vs. indexed pricing, price floors, ceiling and other collars, physical price hedging and financial price hedging. The Company recognized that a diverse portfolio of supply options will reduce price and volatility risk and utilizes most of these purchasing tools.

Natural gas prices are estimated at Stanfield, Malin, Sumas, Rockies, and AECO hubs. However, of the basins that more directly impact Idaho in the 2028-29 Expected Case, the average basin real prices at Sumas, Rockies and AECO are expected to be $7.39, $6.85, and $7.25 per dekatherm, respectively. Avista maintains that issues of economic recovery, expectations of new shale gas production, and increased natural gas-fired power generation make long-term pricing forecasts difficult. The Expected Case: 1) estimates a carbon adder of $5-$67 per ton; 2) estimates a coal-to-gas adder of $.50-$1.00 Dth; 3) assumes no drilling constraints; and 4) assumes a steady supply of gas from Canada. Staff believes it is reasonable to take multiple price factors into consideration; however, as legislation for federally mandated Renewable Portfolio Standards (RPS) and Renewable Energy Credits (REC's) develops, Staff would like to see the Company narrow the range of prices for modeling the carbon and coal-to-gas adders. In addition, Staff would like the Company to closely monitor its assumption that gas supply from Canada will remain steady, to allow time for additional resources when necessary.

In the Expected Case for Washington and Idaho, Avista has the existing resource supply to meet the forecasted peak day demand until 2023. Given this timing, the Company contends that it has sufficient time to carefully monitor, plan and take action on potential resource additions. The Company also plans to define and analyze sub-regions within this broad region for potential resource needs that may materialize earlier than 2023.

**Storage Resources**

Natural Gas storage is a valuable strategic resource that enables improved management of a highly seasonal and varied demand profile. The numerous benefits of storage include:

- Invaluable peaking capability;
- Access to typically lower cost off-peak supplies;

- Reduces the need for higher cost annual firm transportation;
- Storage injections increase the load factor of the existing firm transportation, and;
- Additional supply point diversity.

Avista's existing storage resources consist of ownership and leasehold rights in two in-ground regional storage facilities: Jackson Prairie located near Chehalis, Washington and Mist located approximately 60 miles northwest of Portland, Oregon. Mist storage is utilized mostly for the benefit of Avista's Oregon customers.

The Company is one-third owner, with NWP and Puget Sound Energy (PSE), in the Jackson Prairie Storage Project, which benefits Avista's customers in all three states. Jackson Prairie Storage is an underground reservoir facility with a total working gas capacity of approximately 25 Bcf. Avista's current share of this capacity for core customers is approximately 5.2 Bcf and includes 266,667 Dth of daily deliverability rights.

In 1999, and again in 2002, Avista participated in capacity expansions of the project with NWP and PSW. It was determined that the additional capacity for core utility customers was not needed at that time, and the expansion went under the management of Avista Energy, Avista's former non-regulated energy marketing and trading affiliate. In June 2007, Avista Energy sold substantially all of its energy contracts and ongoing operations to Shell Energy North America, L.P. (Shell). Concurrent with the sales transaction, Avista reacquired the rights to the 2002 expansion while the 1999 expansion rights were temporarily included in the sale. Shell retains these rights through April 30, 2011. These rights represent approximately 3 Bcf of storage capacity and 100,000 Dth of daily deliverability. After April 30, 2011, Avista plans on recalling these rights for availability in their utility operations, and have included it in the SENDOUT® model as an incremental available storage resource at that time.

Other regional storage facilities exist and may be cost effective. Additional capacity at the Mist facility, capacity at one of the Alberta area storage facilities, Clay Basin in northeast Utah, and northern California storage are all possibilities. However, transportation to and from these facilities to Avista's service territory continues to be the largest impediment to contracting these storage options.

Liquefied Natural Gas (LNG) continues to be evaluated as a supply-side resource to meet peak day demand or cold weather events. Contracting for existing capacity with Plymouth LNG (owned and operated by NWP), building a satellite LNG plant where LNG is trucked to the facility in liquid form rather than liquefying on site, and a Company-owned liquefaction LNG facility have all been evaluated and considered.

All of the elements of the Company's supply portfolio, procurement options and planning, taken together, satisfy the requirements of PURPA and provide cost effective supply for all classes of customers.

**Distribution Planning**

Avista's integrated resource planning encompasses evaluation of safe, economical and reliable full-path delivery of natural gas from basin to burner tip. Securing adequate natural gas supply and ensuring sufficient pipeline transportation capacity to its local service areas become secondary issues if the local distribution areas are not adequately planned and become severely constrained. The IRP addresses future local demand growth, determines potential areas of distribution system constraints, analyzes possible solutions and estimates costs for eliminating constraints.

Avista's natural gas distribution system consists of approximately 1,900 miles of distribution main pipelines in Idaho with another 3,400 miles in Washington and 2,300 miles in Oregon, along with numerous regulator stations, service distribution lines, monitoring and metering devices, and other equipment. System pressure is maintained by pressure regulating stations that utilize pipeline pressures from the interstate transportation pipelines before natural gas enters the distribution networks.

The IRP lists several areas for distribution system enhancements; however, most of the projects are in the Company's Oregon service territory where the system is much older than the Idaho/Washington contiguous system. The few areas designated for enhancement in the Idaho/Washington service territory are mostly around the Spokane area, with some minor capital projects in northern Idaho.

**Demand Forecasting**

The integrated resource plan (IRP) begins with the development of a demand forecast. Avista uses a Dynamic Demand Methodology, where key demand drivers behind consumption are identified, the sensitivity of key demand drivers are analyzed, and combinations of the demand drivers are developed under different scenarios. After testing various sensitivities, these are combined into different demand drivers to form six scenarios, they are: 1) High Growth, Low Price; 2) Low Growth, High Price; 3) Green Future; 4) Alternate Weather Standard; 5) Supply Constraints; and 6) the Expected Case.

Avista defines three different geographic demand classifications: Demand Area, Service Territory, and Division. The demand areas are used for SENDOUT® modeling and are structured around the pipeline resources that serve them. These are then aggregated into the Service Territories and Divisions for presentation throughout the IRP.

| Geographic Demand Classification | | |
|---|---|---|
| **Demand Area** | **Service Territory** | **Division** |
| Spokane NWP | Washington/Idaho | North |
| Spokane GTN | Washington/Idaho | North |
| Spokane Both | Washington/Idaho | North |
| Medford NWP | Medford/Roseburg | South |
| Medford GTN | Medford/Roseburg | South |
| Roseburg | Medford/Roseburg | South |
| Klamath Falls | Klamath Falls | South |
| La Grande | La Grande | South |

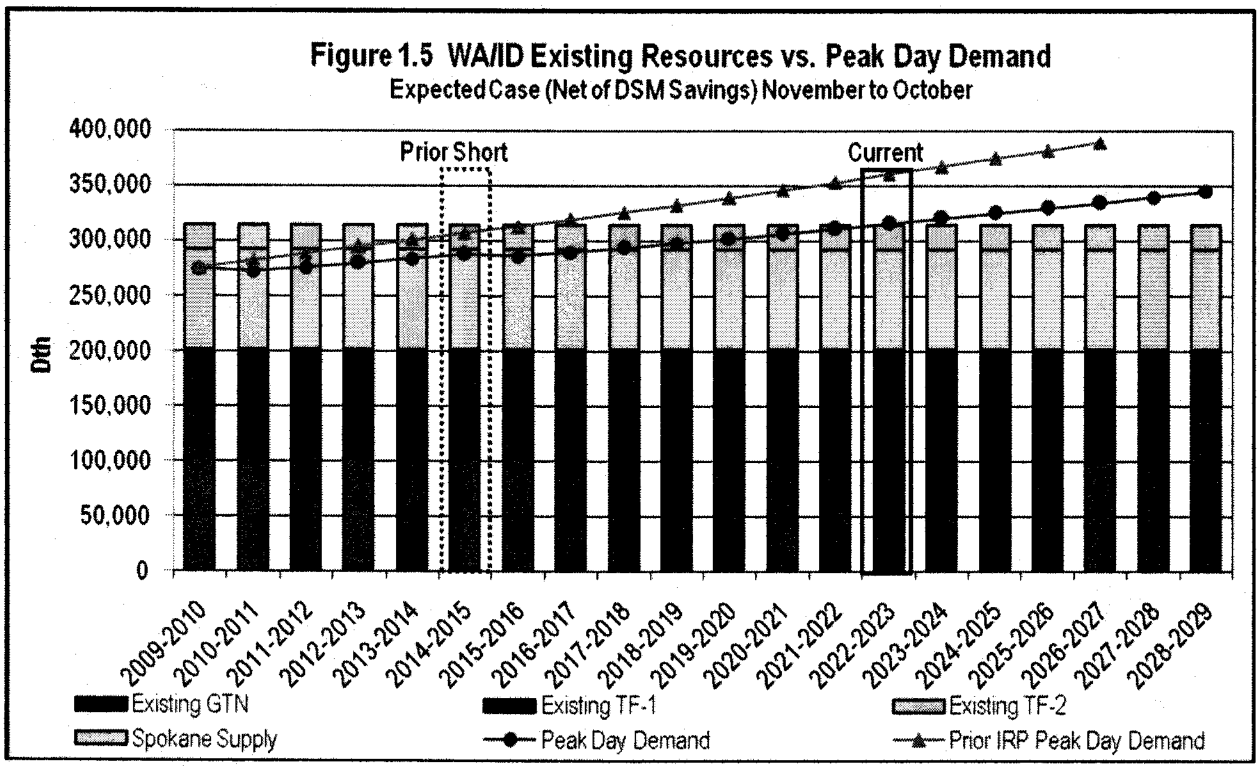
Each modeled scenario has two types of demand forecasts, annual demand, and peak day demand. Peak day demand is for determining the adequacy of existing resources or the timing of acquiring new resources under extreme weather conditions. Annual demand is useful for preparing revenue budgets, procurement plans, and preparing purchased gas adjustment (PGA) filings. In order to estimate both forecasts for each scenario over the planning period, the Company must estimate the number of customers, use per customer, normalized vs. extreme weather, natural gas prices, and price elasticity for each geographic area. These results, when combined with one another, are used to develop the IRP demand forecast.

Core customer growth is forecasted at the town code level for residential, commercial, and industrial customers. There are 56 town codes in Washington, 26 in Idaho, and 37 in Oregon. These 119 town code forecasts are used for optimizing decisions within these geographic sub–areas. The Company utilizes Global Insights, a third-party data provider, for its 20-year growth forecasts. This data is combined with local knowledge about sub-regional construction activity, age, and other demographic trends and historical data to determine the long-term forecasts. By 2028-29, the number of Washington/Idaho customers is projected to increase at an average annual rate of 2.2%. In Idaho customer growth is expected to be 3.0% for residential, 2.5% for Commercial, and 0.6% for Industrial.

In Washington and Idaho use-per-customer is expected to be flat, with demand growing at a compounded average annual rate of 1.0%. The Company modeled several price elasticity factors, but used low-price elasticity response factors in its Expected Case. Unless there is an annual real price increase exceeding 30%, elasticity will remain unchanged. However, with annual real price increases over 30%, the Company's estimated elasticity factor is negative .06, meaning that as natural gas prices increase by 10% there will be a 0.6% decrease in usage. In the Company's Expected Case, there are two modeled price increases over 30%, one in 2010 as a result of the recession's very low gas prices and another in 2015 due to carbon adders. Staff believes the Company should continue to estimate several price elasticity factors, especially given prices are expected to begin increasing rapidly in 2015. However, Staff encourages the Company to do more detailed research on tariff rate price elasticity, especially base usage price elasticity. Staff sees tariff rate price elasticity as a reasonable place for research given that it has been difficult to accurately predict, the usage is not completely understood, and it is where behavioral changes in usage can occur.

Weather is modeled differently when predicting annual demand vs. peak day demand. Annual demand is modeled based on the National Oceanic Atmospheric Administration's (NOAA) 30-year average, whereas peak day demand adjusts the 30-year average to reflect a five-day cold weather event (WA/ID- 82 HDD, -17 degrees Fahrenheit). Staff agrees with the way the annual demand and peak day demand weather scenarios are modeled. However, Staff encourages the Company to continue evaluating the correlation between weather trends at various stations within Washington and Idaho, to make sure it's not necessary to use a larger number of weather stations to estimate demand, similar to the demand analysis conducted in Oregon.

As shown below, Avista projected a Washington/Idaho peak day demand shortage in the 2007 IRP to occur in 2014-2015, driven primarily by average compounded demand growth of 2% per year and average natural gas customer growth of 2.4% in the residential sector. However, in the Expected Case of the 2009 IRP, the Company is less optimistic about future growth, primarily because of the economic slowdown experienced nationwide. Therefore, Avista doesn't project a peak day demand shortage until 2022-2023 in its Washington/Idaho region. However, the Company states that if demand growth accelerates, a steeper demand curve could quickly accelerate resource shortages by several years. Therefore, the Company plans to monitor the Expected Case assumptions and forecasts underlying its projections to address future shortages in a timely manner. Given the Company's estimated timeframe for resource shortages has been pushed out 8 years between IRP's, Staff encourages the Company to closely monitor the "flat demand risk"[2] associated with accelerating demand so that it has an adequate lead time to acquire resources.




## The Demand-Side Resources

Demand Side Management (DSM) is the activity pursued by an energy utility to influence its customers to reduce their energy consumption or change their patterns of energy use away from peak consumption periods. This includes marketing campaigns and financial incentives to persuade customers to adopt conservation measures. Cost-effective DSM measures may include incentives for the purchase of high efficiency appliances (water heaters, clothes dryers, furnaces), insulation, weather-stripping, insulated windows and duct work, and heat recovery systems. The Company considered a total of 155 residential and 147 non-residential DSM measures in this IRP. In the 2007 IRP, for the North Division in the Expected Case, the

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[2] A resource risk that should demand growth accelerate, the steepening of the demand curve could quickly accelerate resource shortages by several years, possibly leaving the utility without sufficient supplies.

Company's 2010 DSM savings goal was 1,755,829 therms. By comparison, in the 2009 IRP, the Company's 2010 DSM savings goal is 2,193,338 therms, or nearly 25% more savings in this IRP. The Company says "the potential increase in the target is the result of a steep carbon mitigation cost adder", anticipated to take effect in 2015. Although not mentioned in the IRP, Staff believes the Company's existing and future DSM programs will begin to have higher participation rates as recessionary natural gas prices recover due to increased demand, and in anticipation of natural gas price increases from carbon legislation.

In order to influence customers to implement natural gas efficiency upgrades now based on a price increase modeled to take effect in 2015, the Company has several programs targeting conservation measures. These measures are divided into two types: base load measures; and weather sensitive measures. Base load measures save energy independently of weather, while weather sensitive measures are influenced by temperature. Avista has 13 residential base load measures and 39 non-residential base load measures. Some examples of base load measures include: high efficiency water heaters, dishwashers, and front-load clothes washers. Avista has 21 residential weather sensitive measures and 15 non-residential weather sensitive measures. Weather sensitive measures save the most energy during the coldest periods, and therefore have a higher avoided cost than base load measures. Some examples of weather sensitive measures include: high efficiency furnaces, ceiling/wall/floor insulation, weather stripping, insulated windows, duct work improvements, and ventilation heat recovery systems. In order to prepare customers for significant price increases modeled to take effect in 2015, Staff encourages the Company to closely evaluate program participation levels, and market saturation to make sure its marketing efforts are effective.

When evaluating measures for cost effectiveness, Avista uses a multiphase approach by: 1) Identifying the Technical Potential; 2) Assessing the Achievable Potential; 3) Test modeling in SENDOUT®[3]; and 4) Developing Conservation Goals. The Technical Potential estimates all energy savings that can theoretically be accomplished if every customer that could potentially install a conservation measure did so without consideration of market barriers such as cost and customer awareness. The Achievable Potential is a more realistic assessment of expected energy savings. It recognizes and accounts for economic and other constraints that preclude full installation of every identified conservation measure. Although Staff sees the Technical

[3] Linear programming model widely used to solve natural gas supply and transportation optimization questions.

Potential as being somewhat general, it is understandable that the base level market potential must be established for estimating the impact of the constraints precluding full installation. Therefore, Staff believes it is reasonable to continue offering both estimates within the IRP. Once the technical and achievable potential have been identified, the Company begins test modeling in SENDOUT®. This involves entering each individual conservation measure to enable more granular and accurate measure selection for DSM resource acquisition. Once measures are selected, the Company develops its final conservation goals by augmenting the measure results of SENDOUT® with estimates from the commercial and industrial site specific programs. This eliminates the site-specific program savings already captured in the SENDOUT® model, and prevents the double counting of measure savings. When developing the 2007 IRP conservations goals, the Company simply grouped measures in to bundles to facilitate easier data input and faster SENDOUT® system processing. However, in this IRP, the Company has made an extra effort to test each individual conservation measure in SENDOUT®. Staff believes this level of testing helps guarantee that the savings associated with specific measures are not incorrectly estimated, overstated, or deemed cost effective when they are not. Staff further believes that the IRP meets the requirements for evaluation of Efficiency Improvements (demand-side management or DSM) and avoided costs.

**The Integrated Resource Portfolio**

The Integrated Resource Portfolio is the Company's comprehensive analysis of bringing a risk-adjusted, least-cost plan together based on daily, monthly, seasonal and annual assumptions. The assumptions in this analysis relate to: 1) Demand data (customer count and usage); 2) weather; 3) transportation and storage; 4) natural gas supply availability and pricing; 5) Cost of new assets (revenue requirements); and 6) Demand-side management. These factors are incorporated into SENDOUT®, and then several scenarios are evaluated to form an assessment of how the supply of existing resources will meet demand. The resource options are evaluated based on the cost, lead time requirements, demand period (peak vs. base load), usefulness, timing of various quantities, risks and uncertainties. After evaluating the resources based on avoided cost and the criteria above, the least-cost approach is selected to meet resource deficiencies.

Staff believes the Company does an adequate job of reviewing several different scenarios, and in determining the likelihood of these occurring. As mentioned previously, in the Expected Case for Washington and Idaho, a resource deficiency does not occur until 2023. Once the deficiency is identified, the model shows a general preference for incremental transportation resources from existing pipelines and supply basins to resolve the capacity deficiencies. In Washington and Idaho, the Company has determined the lowest cost resource to meet this deficiency is additional TransCanada Gas Transmission Northwest (GTN) capacity. GTN is a subsidiary of TransCanada Pipeline, which owns and operates a natural gas pipeline that runs from the Canada/USA border to the Oregon/California border. This pipeline runs directly through or lies in close proximity to Avista's service territories. The GTN system currently has ample unsubscribed capacity. Mileage based rates and backhaul potential are options for securing incremental resource needs, therefore Avista will use this to meet the 2023 resource deficiency. In the case where upstream pipeline GTN capacity is fully subscribed and capacity is not available, Avista would rely on satellite LNG for Washington and Idaho. Staff encourages the Company to closely evaluate the level of unsubscribed capacity on GTN as the system becomes more fully subscribed, primarily to make sure it's not forced to rely on more expensive LNG.

**The Alternate Scenarios, Portfolios, Stochastic Analysis**

Avista uses a deterministic modeling approach where several alternate demand and supply scenarios are applied to develop a broad diversity of possible alternate portfolios. As mentioned in the demand forecasting section, the Company lays out six different scenarios including its Expected Case. Within these scenarios, the Company models two distinct price increases, one occurs almost immediately as the recession ebbs and the second occurs in 2015 as a result of significant carbon cost adders for when climate change policy go into effect. In its "High Growth, Low Price" scenario, which is the most rapid demand growth, the Washington and Idaho territory goes unserved February 2016. The Company contends that with the potential for accelerated unserved dates, it will closely monitor demand trends and resource lead times.

Since exchange agreements and LNG prices are difficult to predict, Avista runs several supply scenarios. For Washington and Idaho, two additional supply-side scenarios with changed assumptions on GTN capacity were run. One scenario assumed significantly higher rates, because of fewer contracts. The other scenario assumed GTN capacity becomes fully subscribed and there is not capacity available. Both alternate supply scenarios resulted in satellite LNG as the preferred backup resource portfolio. Once alternate demand and supply scenarios are matched together to form portfolios, the resources are run through SENDOUT® and the

Expected Case becomes the lowest Net Present Value Revenue Requirement (NPVRR)[4] portfolio given expected demand, existing supply and anticipated availability.

Once the Expected Case is determined, the Company also tests its portfolio using stochastic modeling, a technique of predicting outcomes that take into account a certain degree of randomness or unpredictability. By estimating the probability distributions associated with the unpredictability of potential outcomes, the Company can determine how random historical variation in natural gas prices and weather might impact portfolios. This allows the Company to plan for more realistic cost comparisons, aside from reoccurring design conditions which can overstate total system costs. To investigate whether the total Expected Case portfolio cost is within an acceptable range given 200 unique pricing scenarios, the Company conducts Monte Carlo[5] simulations with varying prices. Avista derived over 200 Monte Carlo weather simulations in order to stress test the deterministic analysis for weather variability and to test its parameters for design weather planning. In the simulations, random monthly HDD values are distributed on a daily basis for a month in history with similar HDD totals. This simulation provides robust weather patterns that the Company can utilize for further testing its portfolio, and provides an estimate on how frequently a design day could potentially occur.

The stochastic analysis shows that with over 200 twenty-year simulations (i.e. - 4000 years), Medford's peak day occurrence is expected to occur once every 31 years. In Washington and Idaho, peak day occurrence is only expected to occur once every 571 years. Based on the frequency of the peak day occurrence, the Company maintains that peak day occurs with enough frequency to keep its standard for IRP planning the same. In this IRP Staff accepts the Company's conclusion, but believes the reserve margin for peak day planning warrants continued analysis, especially given the prudency of additional capacity costs are evaluated in rate cases. Staff wants to be sure customers are not carrying the additional cost for overbuilt resources because the reserve margin for peak day occurrences is too high.

**Additional Comments**

According to Commission Order No. 25342, the Company is required to provide a two-year plan, a progress report that relates the new plan to the previously filed plan (2007 Plan to 2009 Plan), and allow public participation and comment while formulating its plan. As

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[4] NPVRR- Provides a means of equilibration between a dollar spent today and a dollar spent in the future.
[5] A statistical modeling technique employed in SENDOUT for evaluating risk and uncertainty given the possibilities that exist with a real-life system.

mentioned in the introduction, the Company clearly identifies and establishes a near-term action plan that will steer the Company toward the risk-adjusted, least-cost method of providing service to its natural gas customers. Throughout the IRP, the Company relates the new plan by referencing the previously filed plan. The action items from the prior filing are identified, and the corresponding results of its interim evaluations are discussed. The Company has allowed an opportunity for public participation and comment through regularly held meetings with the Technical Advisory Committee (TAC) consisting of staff from the three states' Commissions, several Non-government Organizations (NGOs) and members of the public. While developing the plan, the Company solicited feedback on several of its IRP inputs, and frequently communicated its modifications through e-mail, conference calls, and individual meetings.

**STAFF RECOMMENDATION**

Staff believes that Avista's 2009 Natural Gas IRP satisfies the requirements of Commission Order No. 25342. Staff recommends that the Company's filing of its 2009 IRP be acknowledged and accepted. This recommendation should not be interpreted as approval or as a judgment of prudence that may or may not have been demonstrated by the Company in preparing the IRP or the prudence of not following the plan.

Respectfully submitted this 23d day of March 2010.

Donald L. Howell, II
Deputy Attorney General

Technical Staff: Matt Elam
Donn English

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# CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 23RD DAY OF MARCH 2010, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. AVU-G-09-06, BY MAILING A COPY THEREOF, POSTAGE PREPAID AND VIA E-MAIL, TO THE FOLLOWING:

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Rhonda D. Koch
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