BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON
LC 50

In the Matter of Idaho Power Company 2009 Integrated Resource Plan.	STAFF'S FINAL COMMENTS AND RECOMMENDATIONS

Following are Staff's final comments and recommendations on Idaho Power Company's 2009 Integrated Resource Plan (IRP or the Plan).

In these comments Staff addresses comments of the Renewable Northwest Project (RNP), Idaho Power Company (Idaho Power or the Company), and public comments at the public hearing in Ontario, Oregon on April 20, 2010.

General Issues

Staff recommends the Commission conditionally acknowledge Idaho Power's 2009 IRP with requirements. Staff has performed a thorough review of the Plan based on the Commission's IRP guidelines. For a more detailed review of the IRP under the Commission's guidelines please refer to Attachment A.

Idaho Power IRP Summary

On December 30, 2009, Idaho Power filed its 2009 IRP with the Commission. The 2009 IRP is the Company's first plan under the Commission's IRP guidelines, adopted in 2007.[1] In developing this plan, Idaho Power worked with an IRP advisory group comprised of major stakeholders representing the environmental community, major industrial customers, irrigation customers, state legislators, Commission representatives, and others.

For the first time, Idaho Power has bifurcated the required twenty-year planning period into two ten-year planning periods, 2010-2019 and 2020-2029. The Company believes this approach prevents near-term decision making from being unduly influenced by resource decisions in the second ten-year planning period.

Idaho Power uses the AURORAxmp (AURORA) market model as the primary tool for determining future resource operations and to estimate the portfolio cost for the twenty-year integrated resource plan. Using the AURORA model, the Company performed a quantitative risk analysis of the following variables: third-party transmission subscription, renewable energy credit prices, natural gas prices, carbon emission costs, load growth and conservation. Additionally, Idaho Power performed a qualitative risk analysis that looked at carbon regulation, technology, market risk, and resource siting. The top

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[1] *See* Order No. 07-002.

performing portfolios from each time period based on cost and risk metrics provide the foundation for the Company's Action Plan.

In the first ten-year planning period, 2010-2019, four resource portfolios were examined. The four resource portfolios were classified as Solar, Gas Peaker, Gas Peaker and Boardman to Hemingway Transmission Line (B2H project), and B2H project. The labeling of these portfolios defines the type of supply-side resource that would be used to meet Idaho powers forecasted energy and capacity deficits. Originally evaluated in the 2006 IRP, and common to all resource portfolios as "committed resources," are (1) the Langley Gulch combined-cycle combustion turbine (CCCT), (2) up to 150 megawatts (MW) of wind generation, and (3) two 20 MW increments of geothermal energy coming on-line in 2012 and 2016.

In the second ten-year planning period, 2020-2029, five resource portfolios were examined. Idaho Power's Preferred Portfolio for the first ten-year planning period was used as the basis for designing the second period portfolios. The load forecast for the second period is relatively flat. The primary driver for new resources in the second period is the carbon emission reductions, due to coal curtailment, identified in the Waxman-Markey 2009 Bill. [2] As the Waxman-Markey 2009 Bill currently stands, carbon emissions would be reduced to 17% of 2005 levels by 2020, 42% by 2030 and 83% by 2050.

Each portfolio was designed to meet peak and average-energy load requirements, and also to satisfy potential RES requirements as outlined in the Waxman-Markey 2009 Bill. In order to model the proposed cap-and-trade system, Idaho Power reduced output from its coal-fired facilities based on the number of allowances it expects to receive under the Bill.

In the selection of the Preferred Portfolio the Company compared the portfolios on a cost basis, using present value of revenue requirement (PVRR) and risk metrics. The Preferred Portfolio for the first ten year planning period has lower expected costs than the next best alternative portfolio, Portfolio 1-2 (Gas Peaker) by approximately $51 million PVRR.[3] A key component of its portfolio analysis is Idaho Power's claim that the need for additional power from either new resources or market purchases will require additional transmission.

In the 2009 IRP, the B2H project is modeled as a 300 mile, single-circuit, 500 kV electric transmission line between northeast Oregon and southwest Idaho. Idaho Power has modeled the line with an export capability of approximately 1,400 MW from east to west

[2] The Waxman-Markey 2009 Bill, named after its authors, Representatives Henry A. Waxman of California and Edward J. Markey of Massachusetts, was introduced as an energy bill in the 111th United States Congress. The bill was approved by the House of Representatives on June 26, 2009. (Waxman-Markey 2009)

[3] *See* Idaho Power 2009 IRP, Technical Appendix C, at 16

and an import capability of 850 MW from west to east, for a total modeled capacity of 2,250 MW.[4]

Currently, Idaho Power faces severe transmission constraints when evaluating additional supply-side resources.[5] Prior to 2000, Idaho Power was able to reasonably plan for the use of short-term power purchases to meet temporary water related generation deficiencies on its own system. Short-term power purchases have been successful because Idaho Power is a summer peaking utility, while the majority of the utilities in the Pacific Northwest region experience peak loads during the winter.[6]

According to the Company, although Idaho power has transmission interconnections to the Southwest, the Pacific Northwest market is the preferred source of purchased power. The Pacific Northwest market has a large number of participants, high transaction volume, and is very liquid. The accessible power markets south and east of Idaho power's system tend to be smaller, less liquid, and have greater transmission distances. More importantly, the markets to the south and east of Idaho Power's system can be very limited during summer peak conditions.[7]

Load Forecast

Starting in early 2009, the utility industry has seen major changes with regard to customer loads and commodity prices due to the current economic recession. The state of Oregon has been especially hard hit by the economic downturn over the last two years, with unemployment rates among the highest in the nation. Most notable in this recession has been the impact on the industrial and commercial sectors.

The state of Idaho has also seen a significant increase in its unemployment rate, and stagnant to negative growth in labor force participation. According to the Idaho Department of Labor, the state of Idaho hit its peak unemployment rate of 9.5 percent in February 2010. In contrast, the unemployment rate for the state of Idaho was at an all time low of 2.7 percent in March 2007. Recognizing these significant changes, the Company delayed its filing of the 2009 IRP by three months, in order to prepare a more robust and up-to-date load forecast.[8]

Using an August 2009 load forecast, Idaho Power's 2009 IRP projects peak-hour load will grow at an average annual rate of 53 MW or 1.5 percent. Average system load, or average-energy consumption, is forecasted to grow by an average of 13 MW, or 0.64 percent on an average annual basis over the twenty-year planning period. For the first time, the Company used regression models to identify the relationships between real and historical electricity prices and historical electricity sales. The estimated coefficients from these models were used as drivers in the individual sales forecast model.

[4] *Id* at 83.
[5] *Id* at 98.
[6] *Id* at 81.
[7] *Id*.
[8] *See* Order No. 09-183.

Idaho Power is a summer peaking utility. On June 30, 2008, the Company reached a record peak-hour system load of 3,214 MW and on December 10, 2009, a new winter peak-hour record of 2,527 MW. Peak loads are driven by irrigation pumps and air conditioning. The growth rate of peak load during the last ten years has consistently exceeded the growth rate of average-energy.

Several commentators at the public meeting on Idaho Power's IRP in Ontario, Oregon on April 20, 2010, suggested that Idaho Power's load forecast was too high. Some of the reasons cited for this conclusion were: (1) the Company should not have included new large load customers; (2) the Company did not take into consideration more recent load information in its forecast; and, (3) based on historical housing start data, a more protracted economic recovery will occur than assumed by Idaho Power. Commentators believe that the Company over-projected its short-term load growth, making the B2H project unnecessary or not needed in the time period specified by the Company.

In its reply comments, Idaho Power refuted all of the commentators' claims regarding its load forecast. The Company stated that its forecast contains the most recent information available at the time the filing was prepared, and compared to the Northwest Power and Conservation Council (NPCC) its forecast is conservatively low.[9] According to the Company, the NPCC's Sixth Power Plan average load forecast grows at an annual average rate of 1.96 percent, while Idaho Power's forecast grows at 0.64 percent over the twenty-year planning period. For peak-hour load, the NPCC forecast grows at an annual average rate of 2.13 percent, while Idaho Power forecasts its peak-hour load to grow at 1.5 percent.

Regarding the inclusion of large load customers in its forecast, Idaho Power states that large loads are developed through direct input from each of its large load customers, including Micron, Simplot, INEEL, and Hoku. These forecasted customer loads reflect the recession and other operational impacts on future energy use. More specifically, the impacts of Hoku load reflect changes in startup timing.

Staff agrees with the Company, and after reviewing its analysis believes that the Company has conservatively forecasted its average-energy and peak-hour load, taking into consideration the recent economic downturn. Breaking the forecast down into two ten year periods, and looking only at forecasted load growth through 2019, the Company forecasts average-energy to grow at 1.3 percent and peak load to grow at 2 percent per year. Historically, over the past 20 years, total Company average-energy has increased at a rate of approximately 1.3 percent per year, including the effects of the recession in the last two years.

After reviewing the Company's historical energy growth rates, input assumptions for its 2009 IRP, and comparing its forecast to the NPCC Sixth Power Plan, Staff finds that the Company's load forecast is reasonable. However, Staff is concerned with Idaho Powers load forecast for the2019-2029 time period. Looking strictly at the second ten-year

[9] *See* Reply Comments Idaho Power, Page 6.

period, Idaho power forecasts average-energy to grow at a rate of only 0.1 percent per annum, and peak-hour load growth of only 0.9 percent per annum. Staff is concerned that these growth rates are too low, especially when the rate of growth in demand-side management (DSM) is projected to slow over this time period.

Staff believes that the Company's analysis of price response to projected price increases is an interesting change in its forecasting methodology. Staff recommends the Company provide further description of this analysis in future IRP planning cycles, including the regression coefficients and Idaho Power's estimated responsiveness of each customer class.

Energy Efficiency and Demand-Side Management

During each IRP planning period, Idaho Power evaluates energy efficiency and demand-side resources by looking at current program expansion, new program development, potential studies, NPCC research, Northwest Energy Efficiency Alliance (NEEA), and the Energy Efficiency Advisory Group (EEAG). These studies aid Idaho power in determining how future energy efficiency and demand response programs can fulfill electric resource needs from demand-side resources. A key calculation in the adoption of new demand-side resources is that the demand-side resource avoided cost benefit is greater than the cost of the program. The Company uses the California Standard Practice Manual as a basis for their cost-effectiveness calculations.

While existing DSM savings are captured in the load forecasts, the Company utilized an updated DSM potential study performed by Nextant, Inc. to determine the potential savings associated with new and expanded offerings. The Nextant study was originally performed in 2007, and was updated in 2009 in order to make the model more adaptable to the IRP process. The study demonstrated that there are significant opportunities for energy and peak savings in virtually all customer classes in Idaho Power's service territory. This study did not, however, show any additional opportunities for the irrigation class of customers.

Several commentators at the public meeting argued that the Company could supplant the need for the B2H project with increased DSM efforts. They also alleged that Idaho Power has been deficient in seeking energy savings. They suggested that Idaho Power's energy efficiency efforts lag behind the regional goals established by the NPCC's Sixth Power Plan.

Idaho Power responded to these claims by explaining how they treat DSM in the planning process and providing facts about its energy efficiency efforts. Idaho Power stated that cost-effective energy efficiency and demand response are the first resources considered in the planning process. Prior to evaluating the need for traditional resources, including the B2H project, all energy efficiency from existing programs and potential new cost-effective programs are removed from the load and resource balance that identifies future supply deficits. Under this approach Idaho Power ensured that the first priority is given to all reasonably obtainable energy efficiency and demand response resources.

Regarding the suggestion that Idaho Power's DSM efforts are deficient, Idaho Power stated that its DSM activities are appropriate and successful. According to Idaho Power, in 2009 it exceeded the goals contained in NPCC's Fifth Plan by approximately 30%. Idaho Power also stated that it is working aggressively to meet the goals set in NPCC's Sixth Power Plan.

Staff believes that Idaho Power has explored and included all cost-effective demand-side and energy efficiency programs in its IRP. In fact, the Company has made great strides with its energy efficiency and DSM measures as compared to its 2006 IRP. For example, new energy efficiency programs included in the 2009 IRP are forecast to reduce average load by 127 aMW by 2029, this reduction represents a 53 percent increase over the measures included in the 2006 IRP. New and expanded demand response programs are expected to reduce peak summer load by 323 MW by 2012 once the programs mature. This reduction represents significant growth over the 2006 IRP where demand response programs were estimated to provide only 78 MW of peak reduction by 2026. As we go forward, and technologies allow the Company to explore additional opportunities, Staff believes that the Company has the process in place to identify these opportunities for current and future implementation.

Preferred Portfolio for the First Ten-Year Planning Period and the Boardman to Hemingway Transmission Project

The IRP process looks at a representative set of resource portfolios, which are designed to test various operating characteristics, e.g. resource types, fuels and sources, lead times, in-service dates, durations and generation locations. The IRP does not consider the specific site of a resource. Throughout the IRP planning cycle, parties have been primarily concerned with the need for and reasonableness of the B2H project included in the Preferred Portfolio.

For the B2H project, Staff looked at assumed import and export capability and an approximation of the construction costs based on generic siting specifications and length. The selection of Portfolio 1-4 (Boardman to Hemingway) for the first ten-year planning period and Portfolio 2-4 (Wind and Peakers) for the second ten-year planning period, as the Preferred Portfolio, is based on the Company's conclusion that it is the best combination of expected cost and associated risks.

Idaho Power analyzed the impact of varying third-party subscription rates and capital construction costs of the B2H project. If the construction costs of the B2H project were to be significantly higher than current median estimates in the 2009 IRP or if third-party subscription rates in the B2H project do not materialize as forecast, the next best portfolio would be Portfolio 1-2 (Gas Peakers). As compared to Preferred Portfolio 1-4, Portfolio 1-2 includes two 170 MW Single Cycle Combustion Turbine's (SCCT), coming on-line in 2015 and 2017. However, Portfolio 1-2 is not without its own risk factors, including construction cost risk and natural gas price volatility risk.

As stated previously, the Company considers many factors when selecting the Preferred Portfolio, including capital costs and relative ranking of risk metrics. Looking at these individual components and how they contribute to the ultimate selection is an important part of Staff's analysis. As part of its review of Idaho Power's 2009 IRP, Staff attempted to discern the reasonableness of Idaho Power's capital cost and third-party subscription rate assumptions for Portfolio 1-4 (B2H project). On a dollar per mile basis, Idaho Power assumes that B2H will cost approximately $2.1 million per mile (2010 dollars).

For third-party subscription rates, Idaho Power assumes that over the life of the project it will be responsible for approximately 40 percent of the total cost or utilize 900 MW of the modeled 2,250 MW import and export capability over the life of the resource. Therefore, the Company assumes that the remaining 60 percent of the project will be utilized and paid for by third-parties such as PacifiCorp, Bonneville Power Administration, independent power producers, and others.

In its IRP, Idaho Power reported that it has received more than 4,000 MW of requests to commence transmission service between 2005 and 2014 on the Idaho-Northwest transmission path. Of the 4,000 MW of service requests, only 133 MW were granted up through 2007 due to the limited available transmission capacity of the existing system. More recently, the Company pointed out in its reply comments that it has entered into an agreement with PacifiCorp to negotiate the joint ownership and development of the B2H Project.[10]

Very few interstate transmission projects have been constructed in the region over the last 30 years. It is only recently that utilities in the west have proposed and started to build these large transmission projects, such as Gateway West, the Southwest Intertie, and others. Due to the more recent interest by utilities and consortiums in building these projects, Staff is unable to obtain a reliable set of benchmark data to compare Idaho Power's cost assumptions and subscription rates. In addition, the cost components of an interstate transmission project can vary widely, depending on the type of terrain and right-of-way costs. Thus rather than attempting to compare these components side-by-side to another project, Staff looked at how much these assumptions would have to change in order to make the selection of the Preferred Portfolio change to a different portfolio. Idaho Power referred to this scenario analysis as "the tipping point."

In its tipping point analysis, Idaho Power looked at how high capital costs would have to rise, and separately, how low third-party subscription rates would have to sink in order to choose the next best portfolio, Portfolio 1-2 (Gas Peakers). Holding all else constant, capital costs would have to increase by approximately 26 percent, or on PVRR basis $51 million, in order to change the preferred portfolio selection to Portfolio 1-2. Separately, third-party subscription rates would have to decrease to approximately 45 percent, leaving Idaho Power customers responsible for covering 55 percent of the total cost of the project over the life of the resource.

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[10] *See* Idaho Power 2009 IRP, at 85.

Changing these cost metrics to a break-even point with Portfolio 1-2 does not necessarily change the selection of the Preferred Portfolio. As stated previously, the Company also takes into consideration risk metrics associated with load growth, natural gas prices, regulatory uncertainty and market risk. Looking at the first ten-year planning period, the Preferred Portfolio scored better than Portfolio 1-2 in Idaho Power's risk analysis.

Transmission projects inherently carry a significant level of risk due to long-lead times, large capital investments and an uncertain stream of wheeling revenues. Staff has thoroughly reviewed the cost assumptions and risk metrics for Idaho Power's selection of its Preferred Portfolio, and more specifically the B2H project. Staff believes that the Company's assumptions are reasonable at this time. But if these circumstances change, i.e. higher estimated construction costs or lower estimated subscription rates, the Company should be prepared to re-evaluate its decision as the most prudent investment going forward throughout the process of siting, permitting and taking the project out for bid.

RNP urged the Commission to acknowledge Portfolio 1-3 (Gas Peaker and B2H) as the Preferred Portfolio for the first ten-year planning period. RNP believes that the Company's commitment to 150 MW of wind energy and 40 MW of geothermal coupled with the B2H project will "foster the growth of new renewable energy resources in the Northwest…"[11] While Staff agrees with the latter half of RNP's statement, Staff would point out that the Preferred Portfolio also includes the Company's commitment to 150 MW of wind energy and 40 MW of geothermal. Therefore, Staff believes that the Company's Preferred Portfolio satisfies the intent of RNP's comments.

Staff recommends that the Commission require Idaho Power to continue to evaluate the B2H project in its annual update of the 2009 IRP and in its next IRP. This on-going analysis of B2H should include updated estimates of construction costs, documentation of progress the Company has made towards securing equity partners, and quantitative estimates of third-party subscription on the B2H line and future wheeling revenues. In addition, Staff recommends the Commission require Idaho Power to provide third-party documentation in support of its construction cost estimates.

Staff's recommendation for further analysis of third-party subscription, and the associated wheeling revenues, is based on a concern that the active transmission requests referred to by Idaho Power in its IRP may not materialize, leaving Idaho Power customers on the hook for paying for an unutilized transmission line. Given these concerns Staff recommends that the Commission's acknowledgement of the B2H action item be contingent on Idaho Power providing further analysis of these issues in its annual IRP update and next IRP.

The IRP process is not a pre-approval process; therefore, at the time that Idaho Power seeks ratemaking treatment of the B2H project Staff recommends the Company be required to compare its actual results with its IRP estimates. If the Company has significant deviations from its IRP assumptions, the Company should be prepared to

[11] *See* RNP Opening Comments, Page 2.

provide an adequate explanation for why this project was the appropriate resource as compared to an alternative.

Preferred Portfolio for the Second Ten-Year Planning Period and the Consolidated Preferred Portfolio

As stated previously, the IRP is designed to take into consideration a portfolio of resources. The previous section of comments focused on the first ten-year planning period. This section of Staff comments will focus on the second ten-year planning period and the consolidated Preferred Portfolio.

According to the Company, the design of the five portfolios in the second ten-year planning period were based on the previous selection of Portfolio 1-4 for modeling purposes. Idaho Power chose Portfolio 2-4 for the second ten-year planning period. Portfolio 2-4 (Wind and Peakers) consists of five SCCT gas resources with a combined capacity of 1,400 MW, two wind facilities with a combined capacity of 200 MW, and 100 MW of market purchases on PacifiCorp's proposed Gateway West Transmission project. Idaho Power believes these resources represent a strategy of adding wind resources sufficient to provide energy and RECs, along with simple-cycle natural gas plants to provide peaking capacity and operating reserves necessary to integrate wind generation.

The load forecast for the second ten-year planning period is relatively flat. The Company states that the primary driver for new resources in the second period is the carbon emission reductions, due to coal curtailment, identified in the Waxman-Markey 2009 Bill. In its comments, RNP lauded the Company for developing a resource portfolio that allows for considerable curtailment of the Company's coal-fired generation. RNP believes that Idaho Power's IRP strategy appropriately accounts for the cost, risk, and environmental concerns associated with future limits on greenhouse gas emissions.

Staff agrees with RNP, and believes that Idaho Power met Guideline 8 of the Commission's IRP guidelines by modeling a carbon emission future that it believed was most likely to occur. However, Staff believes that Idaho Power needs to also include the end-effect and costs of the retirement of a coal facility.

RNP stated a concern that the portfolios rely too heavily on natural gas-fired resources. Staff echoes RNP's concern of too much gas in Portfolio 2-4 in the second ten-year planning period. Not only is Staff concerned with the concentration of gas in the second planning period, but more specifically the type of gas resource modeled. Taking into consideration that the primary reason for additional resources in the second-half of the planning period is due to coal curtailment, it seems unreasonable for the Company to choose multiple SCCT's versus one or two Combined Cycle Combustion Turbines (CCCT). The type of deficit occurring in the latter half of the planning period is an energy and capacity deficiency. A CCCT is a more efficient resource for supplying base-load power that also provides cost-effective renewable integration.

Regarding the concentration of gas, Staff agrees with RNP and believes that the Company needs to consider expanding the number of portfolios it considers in the second half of the planning period. Due to the uncertainty in changes in technology, the optimum portfolio becomes even harder to select. However, Staff finds the process of building and selecting multiple portfolios, greater than five, allows parties to learn what the potential changes will be in system requirements and what impacts this may have over the long term.

In the next IRP process, Staff recommends the Commission require Idaho Power to construct more portfolios for the second ten-year planning process. In addition, Staff recommends that Idaho Power be required to provide review of the benefits of a CCCT versus a SCCT, looking at variables such as cost effectiveness, operation and maintenance costs, and overall system benefit.

Staff recommends the Commission require Idaho Power to look at coal curtailment and the costs associated with coal plant retirement.

As part of the carbon cost evaluation, Staff recommends that Idaho Power be required to look at the likelihood of Environmental Protection Agency regulations on air quality, fly ash, and water for all of its generation facilities. The Company needs to include the operational impacts of these possible regulations for future consideration. This analysis should provide additional insight into the analysis of coal plant curtailment and retirements in the future.

Public Policy

The state of Oregon's Renewable Portfolio Standard (RPS) requires utilities and electricity service suppliers serving Oregon load to include a percentage of electricity generated from qualifying renewable energy sources in its portfolio of resources. Like most states, Oregon's RPS is phased-in over a number of years, with final targets set for the year 2025. The Oregon RPS also includes a tiered system based on the amount of load a utility serves in Oregon. Larger utilities have more stringent RPS requirements with interim targets between 2010 and 2025, while smaller utilities have less rigorous requirements and no interim targets.

Under the Oregon RPS, Idaho Power is categorized as a "smaller utility" because the percentage of the Company's retail electric sales in Oregon is between 1.5 and 3 percent of total retail sales in the state. According to the Oregon RPS, at least 10 percent of Idaho Power's retail sales in Oregon must come from qualifying renewable energy sources by the year 2025.

As stated in its IRP, Idaho Power expects a federal Renewable Energy Standard (RES) will be enacted in the near future, and, in the 2009 IRP, the portfolios analyzed were designed to substantially comply with the federal RES contained in the Waxman-Markey 2009 Bill. Once this federal RES is implemented, Idaho Power anticipates that the Renewable Energy Credits (REC) generated from both the Elkhorn Valley Wind Project and the Raft River Geothermal Project will be needed to meet federal RES requirements.[12]

RNP did not agree with Idaho Power's recommendation to sell its RECs from its renewable energy projects until the Company is required to use the RECs to comply with a federal RES. RNP believes Idaho Power should be retiring RECs in preparation for compliance with a future federal RES.

In May 2009 Idaho Power was directed by the Idaho Public Utilities Commission (IPUC) to sell its eligible 2007 and 2008 RECs. As directed by the IPUC, on December 30, 2009, Idaho Power filed a report explaining how the Company intended to manage its RECs on an ongoing basis. On June 11, 2010, the IPUC accepted Idaho Power's REC management plan filing.[13] In its reply comments, Idaho Power explained that its REC management strategy will benefit customers of Idaho Power in two ways. First, customers will realize reduced rates due to REC sales revenue. Second, the Company plans to continue to acquire and hold long-term contract rights to own RECs to meet future federal RES requirements.

Staff believes that the Company's REC management strategy, as approved by the IPUC, is reasonable.

General Issues

In its review, Staff took note of several deficiencies in Idaho Power's narrative of its 2009 IRP. The most notable deficiency is the lack of a thorough explanation of why the Company selected the Preferred Portfolio. Idaho Power provided an adequate description of its cost and risk metrics, but it failed to provide an explanation of how the portfolios performed in the risk analysis individually and comparatively to the other portfolios.

Idaho Power's Technical Appendix provided 161 pages of charts and graphs, including: the relative ranking of its portfolio analysis, load and resource balance, and sales forecast. However, the Technical Appendix did not include any verbiage, nor were there references or an explanation of the Technical Appendix within the IRP narrative.

Staff recommends the Commission require Idaho Power to devote specific chapters in its next IRP explaining the selection of the Preferred Portfolio. This narrative should include an explanation of the relative performance of each portfolio in each of the modeled risk measures, including charts and matrices showing the relative ranking of each portfolio using cost and risk metrics. Lastly, Idaho Power should provide an explanation of how each portfolio performed in the qualitative measures the Company considered in its selection process.

Idaho Power's risk analysis consisted of modeling risk variables, such as load forecast, in only one direction—high. In its Technical Appendix the Company did not model low

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[12] *See* Idaho Power IRP, at 13.
[13] *See* Idaho Public Utilities Commission, Case No. IPC-E-08-24, Order No. 32002.

load growth scenarios, low subscription rates, or low natural gas prices. The Company seems to have used its judgment in determining what a likely future was, and only tested that future. Staff would prefer the Company to test multiple risk variables looking at the full range of possibilities. It is in this process that the Company can understand the inherent characteristics of the portfolio and how it will fare in multiple futures. Staff recommends the Company model the full range of possible futures for its risk variables, including both the high and low side, in the IRP update and in subsequent IRP cycles.

Finally, Staff believes the Company should model and evaluate each risk variable separately, rather than cumulatively, as was done in this IRP cycle. One approach the Company should consider is to build a portfolio for each possible future and then score how that portfolio does in all futures. By doing this analysis Idaho Power may realize the benefits of a portfolio it may not have previously chosen.

Conclusion

Staff has completed an IRP guideline analysis and has determined that Idaho Power Company has met the Commission's IRP guidelines. For further detail on how the Company complied with each guideline, please see Appendix A: Adherence of the Plan to Integrated Resource Planning Guidelines.

This concludes Staff's final comments.

Dated at Salem, Oregon, this 9th day of July, 2010

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Appendix A: Adherence of the Plan to the Integrated Resource Planning Guidelines

In considering whether to acknowledge a resource plan, the Commission reviews the plan for adherence to our Guidelines for resource planning. Following, are each guideline addressed separately. A complete copy of the Guidelines can be found in Commission Order No. 07-002 and Order No. 08-339.

Guideline 1: Substantive Requirements

Under Guideline 1, an electric utility should:

a. Evaluate all resources on a consistent and comparable basis;
b. Consider risk and uncertainty;
c. Select a portfolio with the best combination of expected costs and associated risks and uncertainty for the utility and its customers; and,
d. Be consistent with the long-run public interest as expressed in Oregon and federal energy policies.

With regard to 1a, Idaho Power has met this requirement. More specifically, Idaho Power considered different resource fuel types, technologies, lead times, durations and locations in its portfolio modeling. Idaho Power used consistent assumptions and methodologies in its evaluation of all resources, and evaluated demand-side management (DSM) programs using the same selection criteria as its supply-side resources. Staff recommends for the next planning cycle, Idaho Power should consider including in-service dates as a risk factor, and test the timing of the resource within its portfolio modeling.

Idaho Power considered both quantitative risks and qualitative risk when evaluating its portfolios. In its evaluation, the Company considered the following sources of risk and uncertainty: load requirements, hydroelectric generation, fuel prices, costs to comply with regulation of greenhouse gas emissions, capital cost escalation, and third-party subscription rates.

In its evaluation of a twenty-year planning period, Idaho power bifurcated its plan into two ten-year periods; 2010-2019 and 2020-2029. Staff finds that the selection of Portfolio 1-4 (Boardman to Hemingway) for the first ten-year planning period, and Portfolio 2-4 (Wind and Peakers), as the preferred portfolio, is the best combination of expected costs and associated risks for Idaho Power and its customers.

Guidelines 2: Procedural Requirements

Guideline 2 is a description of procedural requirements that require a utility to include the public as well as other utilities in the IRP planning process.

Idaho Power met all procedural requirements. Idaho Power provided extensive opportunities for public input.

For the 2004, 2006 and 2009 plans, the Company assembled an Integrated Resource Plan Advisory Council (IRP Advisory Council or IRPAC) composed of customers, Staff of the Idaho and Oregon Public Utility Commissions, and representatives from special interest groups. The IRP Advisory Council meetings are open to the public. Lastly, the Company held a public hearing on April 20, 2010.

The Company provided non-confidential information in the main IRP document and technical Appendices, meeting handouts, via email and in response to data requests.

Guideline 3: Plan Filing, Review, and Updates

Guideline 3 states that a utility must file its IRP two years from the date of acknowledgement of the previous plan. Idaho Power received acknowledgement of its 2006 IRP on September 12, 2007.[1] Due to substantial changes in economic conditions and permitting delays for the Boardman to Hemingway 500 kV transmission project (B2H Project or Boardman to Hemingway), the Company requested a delay in its September 12, 2009 filing deadline. On May 26, 2009, the Commission approved Idaho Power's motion to delay its filing of the 2009 IRP until December 29, 2009.[2] On December 30, 2009, Idaho Power filed its 2009 IRP.

The Company presented the results of its plan to the Commission at a public meeting on February 23, 2010.

Guideline 4: Plan Components

Guideline 4 requires a utility to include fourteen components in its IRP evaluation. Idaho Power has met this requirement. In response to Staff Data Request No. 1, Idaho Power provided an explanation of how each of the substantive and procedural requirements was met.

Appendix A – Sales and Load Forecast, is a detailed write up of the Company's load forecasting methodology and analysis. For the first time in its planning process the Company looked at the impact of electricity prices on future electricity sales, or the elasticity of demand of its retail customers. More specifically, the Company evaluated the estimated impact of proposed carbon legislation on retail electricity prices. Described in Appendix A, the Company used regression models to identify the relationships between real and historical electricity prices and historical electricity sales. The estimated coefficients from these models were used as drivers in the individual sales forecast model.

Staff finds that the Company's inclusion of a price response is an interesting update to its forecasting methodology. In future IRP planning cycles Staff recommends the Company

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[1] *See* Order No. 07-394.
[2] See Order No. 09-183.

provide further description of this analysis, including the regression coefficients and estimated price responsiveness of each customer class.

Using an August 2009 load forecast, Idaho Power's 2009 IRP projects peak-hour load will grow at an average annual rate of 53 MW or 1.5 percent. Average system load, or average-energy consumption, is forecasted to grow by an average of 13 MW, or 0.64 percent on an average annual basis over the 20-year planning period.

The Company modeled existing transmission rights and future transmission additions associated with the portfolios tested. In addition, the Company tested the viability of the Boardman to Hemingway Transmission line as an alternative resource.

Demand-side and supply-side resources have been evaluated by the Company in the 2009 IRP. A more detailed description of the contributing studies and analyses is provided in Appendix B – Demand-Side Management. In addition to Appendix B, all reports can be found on the Company's website.

Idaho Power composed its Action Plan as near-term and long-term action items. The Commission considers the near-term Action Plan necessary to implement the Preferred Portfolio.

Guideline 5: Transmission

Guideline 5 requires the Company to consider transmission as a resource option, taking into consideration its value for making additional purchases and sales, accessing less costly resources in remote locations, and improving reliability. Idaho Power has met this requirement.

Idaho Power is requesting Commission acknowledgement of the Boardman to Hemingway Transmission Line (B2H Project). Idaho Power analyzed the impact of varying third-party subscription rates and capital construction costs of the B2H project. If the construction costs of the B2H project were to be significantly higher than current median estimates in the 2009 IRP, or, if third-party subscription rates in the B2H project do not materialize as forecast, the next best portfolio would be Portfolio 1-2 (Gas Peakers). As compared to Preferred Portfolio 1-4, Portfolio 1-2 includes two 170 MW Single Cycle Combustion Turbine's (SCCT), coming on-line in 2015 and 2017.

For further detail of Idaho Power's comparative analysis of the B2H Project with an alternative resource, please see Staff's final comments.

Guideline 6: Conservation

Guideline 6 requires a utility to perform a conservation potential study periodically for its entire service territory. In addition, the Company should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets. Idaho Power has met this requirement.

In August 2007, Idaho Power contracted with Nexant, Inc. to conduct a DSM potential study to identify cost-effective new programs and opportunities to expand existing programs. The DSM potential study included a comprehensive report detailing forecast reductions from Idaho Power's existing programs and the forecast reduction of new programs.

Idaho Power's near-term action plan outlines some of the conservation resources for meeting projected resource needs along with their projected savings.

Guideline 7: Demand Response

Guideline 7 states that a utility should evaluate demand response resources; including voluntary rate programs on par with other options for meeting energy, capacity, and transmission needs. Idaho Power has met this requirement.

Idaho Power's energy efficiency and demand response programs address all four major customer classes: residential, irrigation, commercial and industrial. Idaho Power collaborated with other regional utilities and organizations in funding the Northwest Energy Efficiency Alliance (NEEA) market transformation promotional activities.

Idaho Power's DSM evaluation included current program expansion, new program development, potential studies, Northwest Power and Conservation Council (NPCC) research, NEEA and Idaho Power's Energy Efficiency Advisory Group (EEAG), to determine how future energy efficiency and demand response programs can fulfill electricity resource needs from demand-side resources.

Two major DSM program changes occurred in 2009. First, the Irrigation Peak Rewards program went from a controlled reduction through timers, to a dispatchable program. This change will increase the program's peaking resource capacity from its previous range of 34-37 MW to a forecasted impact of 260 MW at program maturity in 2012. Second, the FlexPeak Management program will be offered to commercial and industrial customers through a third-party demand response aggregator. FlexPeak is expected to provide nearly 40 MW of peak demand reduction in 2010 and over 56 MW by 2012.

Guideline 8: Environmental Costs

Guideline 8, as modified by Order No. 08-339, contains four requirements: a base case scenario, alternative portfolios against the base case scenarios, a trigger point analysis, and an Oregon compliance portfolio. The first requirement directs the Company to model what it considers to be the most likely regulatory compliance future for greenhouse gas emissions, as well as other possible credible scenarios. The second requirement discusses the treatment of these scenarios in its risk-analysis, PVRR cost and risk measures, and end-effect considerations. The third requirement directs the utility to identify a carbon dioxide compliance scenario that would lead to the selection of a portfolio that is substantially different from the preferred portfolio. The final requirement discusses the need for a separate portfolio, consistent with Oregon energy policies, if none of the previous portfolios achieves that consistency.

Idaho Power has met this requirement. Idaho Power's 2009 IRP analyzes the potential cost of carbon emissions differently than previous IRP's. Idaho Power believes a cap-and-trade system is more likely; however, regulatory requirements dictate the analysis be performed using a carbon adder, which Idaho Power has done.

Idaho Power used a $43 per ton carbon tax in its modeling of a carbon adder. The carbon tax analysis suggests that the $43 carbon adder significantly increases the portfolio costs, and increases the retail energy rates, but does not create a significant decrease in carbon emissions. Idaho Power believes that the carbon tax proves to be less effective than the proposed cap-and-trade legislation.

Guideline 9: Direct Access Load

Guideline 9 is not expected to apply to Idaho Power during the 2009 IRP twenty-year planning period.

Guideline 10: Multi-state Utilities

Guideline 10 requires multi-state utilities, like Idaho Power, to plan its generation and transmission systems on an integrated system basis that achieves a best cost/risk portfolio for its retail customers.

Idaho Power has met this requirement. Idaho Power plans for generation and transmission resources on an integrated system basis. The Company prepares and files the IRP in both the Idaho and Oregon jurisdictions.

Guideline 11: Reliability

Under Guideline 11, an electric utility should:

a. Analyze reliability within the risk modeling of the actual portfolios being considered
b. Determine loss of load probability (LOLP), expected planning reserve margin, and expected and worst-case unserved energy by year, and
c. Demonstrate that the selected portfolio achieves the utility's stated reliability, risk and cost objectives

Idaho Power has met this requirement. Idaho Power evaluated all resource portfolios identified in the 2009 IRP for both quantitative and qualitative risks. The objective of the risk analysis was to identify resource portfolios that perform well in a variety of possible future scenarios and to reduce total risk.

Idaho Power uses a spreadsheet model[3] to calculate the Loss of Load Expectation (LOLE) for the preferred and alternate portfolios as identified in the 2009 IRP. Idaho Power calculated the capacity planning margin resulting from the resource development identified in the preferred resource portfolio. When calculating the planning margin, the total resources available to meet demand consist of the additional resources available under the preferred portfolio, plus the generation from existing and committed resources.

The Capacity Benefit Margin (CBM) used by Idaho Power is 330 MW in transmission planning to provide for the necessary reserves for unit contingencies. The CBM capacity is reserved in the transmission system and sold on a non-firm basis until forced unit outages require use of the transmission capacity. The 2009 IRP analysis assumes CBM transmission capacity is available to meet deficits due to forced outages.

Guideline 12: Distributed Generation

Guideline 12 recommends that utilities should evaluate distributed generation technologies on par with other supply-side resources. Idaho Power has met this requirement.

In the 2009 IRP, both natural gas and diesel-fueled distributed generation (DG) options were analyzed. Due to concerns surrounding air quality, the potential programs were analyzed at a lower capacity factor. The capacity factor used was 0.69 percent (60 hours-per-year), which more closely matches the capacity factor of demand response programs. Using this capacity factor, the results of the analysis indicate a natural gas option would have a 30-year levelized cost of $519/MWh and $808/MWh for diesel. The cost estimate for a natural gas-fired peaking resource (SCCT) is $234/MWh at a 6 percent capacity factor and $1,165/MWh at a capacity factor of 0.69 percent. Because the cost estimates for the DG options fall within the range of costs for a SCCT, Idaho Power has committed to work with the Idaho Commission to determine if a cost-effective program can be established.

Guideline 13: Resource Acquisition

Guideline 13 establishes requirements for acquiring resources in the utility’s action plan.

Idaho Power has met this requirement. However, Staff believes the Company needs to provide further explanation of the Company’s acquisition strategy within its action plan.

[3] Based on Roy Billinton “Power System Reliability Evaluation” Charter 2&3, Copyright 1970.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 50

In the Matter of Idaho Power Company 2009 Integrated Resource Plan.	PROPOSED ORDER

DISPOSITION: PLAN ACKNOWLEDGED

I. INTRODUCTION

Idaho Power Company (Idaho Power or the Company) seeks acknowledgement of its 2009 Integrated Resource Plan (IRP). This filing is in accordance with Public Utility Commission of Oregon (Commission) Order No. 07-002, as corrected by Order No. 07-047,[1] which requires all regulated energy utilities operating in Oregon to engage in integrated resource planning.

We conditionally acknowledge the plan, and identify several requirements for Idaho Power's IRP update and the next planning cycle.

A. Requirements for Integrated Resource Planning

The Commission requires regulated energy utilities to prepare integrated resource plans within two years of acknowledgment of the last plan. Utilities must involve the Commission and the public in their planning process prior to resource decision-making. Substantively, the Commission requires that energy utilities: (1) evaluate resources on a consistent and comparable basis; (2) consider risk and uncertainty; (3) make the primary goal of the process selecting a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers; and (4) create a plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies. *See* Order No. 07-002.

The Commission "acknowledges" resource plans that satisfy the procedural and substantive requirements and that seem reasonable at the time acknowledgment is given.

[1] The Commission originally adopted least-cost planning in Order No. 89-507 (Docket UM 180). The Commission updated the utility planning process in Docket UM 1056.

B. Idaho Power's 2009 IRP

The Commission's guidelines state that a utility must file its IRP two years from the date of acknowledgement of the previous plan. Idaho Power received acknowledgement of its 2006 IRP on September 12, 2007.[2] Due to substantial changes in economic conditions and permitting delays for the Boardman to Hemingway 500 kV transmission project (B2H Project or Boardman to Hemingway), the Company requested a delay in its September 12, 2009 filing deadline. On May 26, 2009, the Commission approved Idaho Power's motion to delay its filing of the 2009 IRP until December 29, 2009.[3] On December 30, 2009, Idaho Power filed its 2009 IRP.

The 2009 IRP is the Company's first plan under the Commission's newly adopted IRP guidelines.[4] In developing this plan, Idaho Power worked with an IRP Advisory group comprised of major stakeholders representing the environmental community, major industrial customers, irrigation customers, state legislators, Commission representatives, and others.

Idaho Power's 2009 IRP analyzes the potential cost of carbon emissions differently than has been done in previous IRP's. While Idaho Power modeled both a cap-and-trade system and a carbon tax adder in future scenarios, the Company primarily focused on cap-and trade as the most likely regulatory outcome. The Company's analysis used the Waxman-Markey 2009 Bill[5] as the basis for its assumptions on emission targets and allowances.

Idaho Power uses the AURORAxmp (AURORA) market model as the primary tool for determining future resource operations and to estimate the portfolio cost for the 20-year IRP. Using the AURORA model, the Company performed a quantitative risk analysis of the following variables: third-party transmission subscription, renewable energy credit prices, natural gas prices, carbon emission costs, load growth and conservation. Additionally, Idaho Power performed a qualitative risk analysis that looked at carbon regulation, technology, market risk, and resource siting.

For the first time, Idaho Power bifurcated the required 20-year planning period into two ten-year planning periods, 2010-2019 and 2020-2019. The Company believes that this approach prevents near-term decision making from being unduly influenced by resource decisions in the second ten-year planning period.

In the first ten-year planning period, 2010-2019, four resource portfolios were examined. The four resource portfolios were classified as Solar, Gas Peaker, Gas Peaker and B2H, and B2H. The labeling of these portfolios defines the type of supply-side resource that

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[2] *See* Order No. 07-394.
[3] See Order No. 09-183.
[4] *See* Order No. 07-002.
[5] The Waxman-Markey Bill, named after its authors, Representatives Henry A. Waxman of California and Edward J. Markey of Massachusetts, was introduced as an energy bill in the 111th United States Congress. The bill was approved by the House of Representatives on June 26, 2009.

would be used to meet Idaho Power's forecasted energy and capacity deficits. Originally evaluated in the 2006 IRP and common to all resource portfolios as "committed" resources are (1) the Langley Gulch combined-cycle combustion turbine (CCCT), (2) up to 150 megawatts (MW) of wind generation, and (3) two 20 MW increments of geothermal energy coming on-line in 2012 and 2016.

In the second ten-year planning period, 2020-2029, five resource portfolios were examined. Idaho Power's preferred portfolio for the first ten-year planning period was used as the basis for designing the second period portfolios. The load forecast for the second period is relatively flat. The primary driver for new resources in the second period is the carbon emission reductions, due to coal curtailment, identified in the Waxman-Markey 2009 Bill.

New energy efficiency programs included in the 2009 IRP are forecast to reduce average load by 127 aMW by 2029. This reduction represents a 53 percent increase over the measures included in the 2006 IRP. New and expanded demand response programs are expected to reduce peak summer load by 323 MW by 2012 once the programs mature. This reduction represents significant growth over the 2006 IRP when demand response programs were estimated to provide only 78 MW of peak reduction by 2026. All estimated reductions in load due to energy efficiency and demand response programs are included in Idaho Power's 2009 load forecast.

Using an August 2009 load forecast, Idaho Power's 2009 IRP projects peak-hour load will grow at an average annual rate of 53 MW or 1.5 percent. Average system load, or average-energy consumption, is forecasted to grow by an average of 13 MW, or .64 percent on an average annual basis over the 20-year planning period. Based on the 2009 load forecast, Idaho Power projects that its system will become short on capacity in 2013, and on an energy basis, the system begins to experience a short position by 2014.[6]

II. DISCUSSION

A. Preferred Portfolio & Action Plan

Based on its analysis, Idaho Power selected Portfolio 1-4 Boardman to Hemingway as its preferred portfolio for the 2010-2019 planning period and Portfolio 2-4 Wind and Peakers as its preferred portfolio for the 2020-2029 planning period. The Company requests acknowledgement of the following action items:

Action Plan:

2010 Irrigation Peak Rewards program increases to 220 MW
FlexPeak Management program increases to 40 MW
2011 Irrigation Peak Rewards program increases to 250 MW

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[6] Idaho Power uses a 70th percentile water and 70th percentile average load condition for energy planning purposes. For peak-hour capacity planning, Idaho Power uses 90th percentile water conditions and 95th percentile peak-hour load.

	FlexPeak Management program increases to 45 MW
2012	Wind project on-line 150 MW
	Langley Gulch CCCT on-line 300 MW
	Geothermal project on-line 20 MW
2013	Boardman to Hemingway construction begins
	Shoshone Falls Upgrade Project construction begins
2015	Shoshone Falls Upgrade Project on-line 49 MW
	Boardman to Hemingway completed for market purchases of 250 MW
2016	Geothermal project on-line 20 MW
2017	Boardman to Hemingway capacity for market purchases of 175 MW

The selection of Portfolio 1-4 (Boardman to Hemingway) for the first ten-year planning period and Portfolio 2-4 (Wind and Peakers) for the second ten-year planning period, as the preferred portfolio for the twenty-year study, is based on the Company's conclusion that it is the best combination of expected cost and associated risks.

The Company requests acknowledgement of the Action Plan to implement its preferred portfolio. The Action Plan includes activities for decisions the Company intends to make in the next one to ten years. Lastly, Idaho Power believes that the flexibility to adjust to changes during the present period of unusually high regulatory uncertainty is very important.

B. Load Forecast

1. Parties' Positions

In their critique of the B2H Project, many commentators suggested that Idaho Power's load forecast was too high. Some of the reasons cited for this conclusion were: (1) the Company should not have included new large load customers; (2) the Company did not take into consideration more recent load information in its forecast; and (3) based on historical housing start data, a more protracted economic recovery will occur than assumed by Idaho Power. Commentators believe that the Company over-projected its short-term load growth, making the Boardman to Hemingway transmission line unnecessary or not needed in the time period specified by the Company.

In its reply comments, Idaho Power refuted all of the commentators' claims regarding its load forecast. The Company stated that its forecast contains the most recent information available at the time the filing was prepared, and compared to the Northwest Power and Conservation Council (NPCC) its forecast is conservatively low. According to the Company, the NPCC's Sixth Power Plan average load forecast grows at an annual average rate of 1.96 percent, while Idaho Power's forecast grows at .64 percent over the twenty-year planning period. With regard to peak-hour load, the NPCC forecast grows at an annual average rate of 2.13 percent, but Idaho Power forecasts its peak-hour load to grow at 1.5 percent.

Regarding the inclusion of large load customers in its forecast, Idaho Power stated that large loads are developed through direct input from each of its large load customers. These forecasted customer loads reflect the recession and other operational impacts on future energy use.

In its final comments, Staff agreed with the Company. After reviewing its analysis, Staff believes that the Company has conservatively forecasted its average-energy and peak-hour load, taking into consideration the recent economic downturn. However, Staff did note that, for the 2019-2029 planning period, Idaho power forecasts average energy to grow at a rate of only .1 percent per annum, and peak-hour load growth of only .9 percent per annum. Staff was concerned that these growth rates may be too low, especially when the rate of growth in DSM is projected to slow over this time period. The inclusion of an elastic response to potential prices increases due to proposed carbon legislation is also a contributing factor to relatively flat growth rates in the second ten-year planning period.

Staff also found that the Company's analysis of an elastic response to projected price increases was an interesting change in its forecasting methodology. In future IRP planning cycles, Staff recommended that the Company provide further description of this analysis, including the regression coefficients and estimated elasticity of each customer class.

2. Commission Resolution

We support Staff's conclusion that Idaho Power's load forecast is reasonable. We do, however, share Staff's skepticism of the Company's projected load growth rates and expectation that loads will become relatively flat in the second ten-year planning period. We support Staff's recommendation associated with this concern; Idaho Power will provide a more robust justification for its load forecast for the second ten-year planning period.

Although we recognize customers may be responsive to changes in price, the support for this conclusion to the degree that it seemed to be implemented in the load forecast was not apparent. We support Staff's recommendation for Idaho Power to provide additional analysis and a description of its estimated price sensitivity for each customer class in its next IRP planning cycle.

C. Preferred Portfolio for the First Ten-Year Planning Period and the Boardman to Hemingway Transmission Project

1. Parties' Positions

In comments on the IRP, Staff and intervening parties primarily focused on the selection of the Preferred Portfolio, and more specifically, the inclusion of the Boardman to Hemingway transmission project. In its analysis, Staff looked at the portfolio assumptions associated with the B2H Project, such as capital cost assumptions and third-party subscriptions. Staff evaluated the Company's approach to these variables and their robustness under changing circumstances (for example, higher construction costs or lower third-part subscription rates).

Staff discussed at length the Company's analysis of a break-even point with Portfolio 1-2 (Gas Peaker), the next best alternative to the Preferred Portfolio, to understand the sensitivity of the change in cost within the first ten-year planning period. What this analysis demonstrated was a robustness of the Preferred Portfolio that allows capital cost to vary by up to 40 percent, and subscription rates to change by 15 percent before the Preferred Portfolio hits the break-even point with the next best alternative.

In support of its subscription rate assumptions, Idaho Power pointed out significant demand for transmission capacity on its Idaho-Northwest transmission path. Idaho Power stated that it is aware of over 4,000 MW of transmission requests on the existing transmission path, with only 133 MW of those requests being granted through 2007 due to limited transmission capacity. The Company went on to claim that it is currently reviewing active transmission requests for the B2H Project. More recently, the Company pointed out in its reply comments that it has entered into an agreement with PacifiCorp to negotiate the joint ownership and development of the B2H Project.

Even with a change in cost, Staff pointed out that the Company's analysis also includes additional quantitative and qualitative risk measures that must be taken into consideration. According to Staff, the Preferred Portfolio scored higher than all the alternative portfolios in the Company's risk analysis. The different types of risk modeled in the Idaho Power IRP are renewable energy credit prices, natural gas prices, carbon emission costs, load growth and lower conservation. Additionally, Idaho Power performed a qualitative risk analysis that looked at carbon regulation, technology, market risk, and resource siting. Therefore, Staff believes that these cost metrics would have to go even higher in order to change the selection of the Preferred Portfolio.

In conclusion, Staff recommended that the Company continue to evaluate the B2H project in its annual update of the 2009 IRP and in its next IRP. This on-going analysis of B2H should include updated estimates of construction costs, documentation of progress the Company has made towards securing equity partners, and quantitative estimates of third-party subscription on the B2H line and future wheeling revenues. In addition, Staff recommends the Commission require Idaho Power to provide third-party documentation in support of its construction cost estimates.

Staff's recommendation for further analysis of third-party subscription, and the associated wheeling revenues, is based on a concern that the active transmission requests referred to by Idaho Power in its IRP may not materialize, leaving Idaho Power customers on the hook for paying for an unutilized transmission line. Given these concerns Staff recommended that the Commission's acknowledgement of the B2H action item be contingent on Idaho Power providing further analysis of these issues in its annual IRP update and next IRP.

Finally, Staff discussed the future ratemaking treatment of the B2H Project. Staff recommended that the Company be required to compare its actual results with its IRP estimates. If the Company showed significant deviations from its IRP assumptions, the Company should be prepared to provide an adequate explanation for why this project was the right resource as compared to an alternative.

In its Opening Comments, the Renewable Northwest Project (RNP) urged the Commission to acknowledge Portfolio 1-3 (Gas Peaker and B2H) as the preferred portfolio for the first ten-year planning period. RNP stated that it believes that the Company's commitment to 150 MW of wind energy and 40 MW of geothermal coupled with the Boardman to Hemingway transmission line will foster the growth of new renewable energy resources in the Northwest. Staff agreed with the latter half of RNP's statement, but pointed out that Idaho Power's preferred portfolio, Portfolio 1-4 (B2H), also included the Company's commitment to 150 MW of wind energy and 40 MW of geothermal. Therefore, Staff believes that the Company's Preferred Portfolio satisfy's the intent of RNP's comments.

Comments at the public hearing in Ontario, Oregon, on April 20, 2010, focused on the need for the B2H project. Specifically, commentators believe that building a natural gas plant and additional purchased power are preferable to the Boardman to Hemingway transmission line, and that the line should not be built to accommodate third-party wheeling requests.

Idaho Power refuted each of these claims. First, Idaho Power pointed out the robustness of the Preferred Portfolio as compared to the portfolio containing the natural gas plant. Second, Idaho power refuted the possibility of additional purchased power due to its limited transmission capacity during peaking time on existing transmission paths. Lastly, Idaho Power points out that all wheeling requests on the proposed B2H Project will offset costs associated with building the project, which in turn will reduce customers' rates. In addition, Idaho Power pointed out that it is bound by federal law to provide wheeling services on a non-discriminatory basis, which requires the Company to construct a transmission system that will ensure reliable and economic service to transmission customers.

2. Commission Resolution

First, we appreciate the public participation at the April 20, 2010 public hearing in Ontario, Oregon, and in the IRP process generally. Regarding their concerns, we believe that Idaho Power has shown a need for a supply-side resource to fulfill an obligation to its customers to provide reliable service. At the same time, we adopt Staff's recommendation for conditional acknowledgment of the B2H project action item.

Our conditional acknowledgement of the B2H project is a reflection of our concerns with regard to Idaho Power's cost estimates, equity partnership, and third-party subscription estimates for the B2H project. We acknowledge the B2H project action item contingent upon Idaho Power continuing to update its B2H project construction cost estimates, equity partnership estimates, and third-party subscription estimates and wheeling revenues in the IRP update and next IRP. We expect the Company to provide an extensive update of the B2H cost and risk analysis.

Lastly, we reiterate that at the time of ratemaking any utility is required to show that its investment was a prudent decision. Given the inherent risk associated with a transmission facility and the possibility of escalating costs and delays in permitting, the Company will need to address any significant changes in construction cost, equity partnership, or expected third-party subscription and how these factors influenced the Company's decision to continue with the project.

D. Preferred Portfolio for the Second Ten-Year Planning Period and the Consolidated Preferred Portfolio

1. Parties' Positions

Staff pointed out that the IRP is designed to take into consideration a portfolio of resources. With regard to the second ten-year planning period and the consolidated Preferred Portfolio, Staff discussed the design of Idaho Power's five portfolios. Staff pointed out that the Company designed the five portfolios for the second ten-year planning period based on the selection of Portfolio 1-4 for the first ten-year planning period. Idaho Power chose Portfolio 2-4 for the second ten-year planning period. As detailed by Staff, Portfolio 2-4 (Wind and Peakers) consists of five SCCT gas resources with a combined capacity of 1,400 MW, two wind facilities with a combined capacity of 200 MW, and 100 MW of market purchases on PacifiCorp's proposed Gateway West Transmission project. In its IRP, Idaho Power states that these resources represent a strategy of adding wind resources sufficient to provide energy and RECs along with simple-cycle natural gas plants to provide peaking capacity and operating reserves necessary to integrate wind generation.

In its final comments, Staff pointed out that the load forecast for the second ten-year planning period is relatively flat. The Company stated that the primary driver for new resources in the second period is the carbon emission reductions, due to coal curtailment, identified in the Waxman-Markey 2009 Bill. In its Comments, RNP lauded the Company for developing a resource portfolio that allows for considerable curtailment of the Company's coal-fired generation. RNP believes that Idaho Power's IRP strategy appropriately accounts for the costs, risks, and environmental concerns associated with future limits on greenhouse gas emissions.

Staff agreed with RNP and believes that Idaho Power met Guideline 8 of the Commission's IRP Guidelines by modeling the carbon emission future that it believed was most likely to occur. However, Staff cited the need for additional analysis, which includes the end-effects and costs of the retirement of a coal facility. In conclusion, Staff recommended the Commission require Idaho Power to look at coal curtailment and the costs associated with coal plant retirement.

In its opening comments, RNP stated a concern that the portfolios rely too heavily on natural gas-fired resources. Staff echoed RNP's concern of too much gas with regard to Portfolio 2-4 in the second ten-year planning period. While Staff was concerned with the concentration of gas in the second planning period, Staff also discussed its skepticism of the type of gas resource modeled. Staff pointed out that the primary reason for additional resources in the second ten-year planning period was due to modeled coal curtailment. Therefore, Staff believes it is unreasonable for the Company to choose multiple SCCT's versus one or two Combined Cycle Combustion Turbines (CCCT).

Regarding the concentration of gas, Staff agreed with RNP and believes that the Company needs to consider expanding the number of portfolios it considers in the second ten-year planning period. Staff pointed out that the process of building and selecting multiple portfolios, greater than five, is a learning process on possible futures that cannot be overlooked. Therefore, as part of its next IRP planning cycle, Staff recommended the Commission require Idaho Power to construct significantly more portfolios for the second ten-year planning process. In addition, Staff recommended that Idaho Power be required to provide a review of the benefits of a CCCT versus a SCCT, looking at variables such as cost effectiveness, operation and maintenance costs, and overall system benefit.

As part of the carbon cost evaluation, Staff recommended that Idaho Power be required to look at the likelihood of Environmental Protection Agency (EPA) regulations on air quality, fly ash, and water for all of its generation facilities. Staff believes the Company needs to include the operational impacts of these possible regulations for future consideration.

2. Commission Resolution

We support Idaho Power's selection of Portfolio 2-4 for the second ten-year planning period and the overall selection of the Preferred Portfolio. While we recognize the speculative nature of the second half of the planning period, we support Staff's conclusion that much can be learned from performing multiple portfolio analysis and expanded resource options. Therefore, we support Staff's recommendation to require the Company to perform additional portfolio analysis in its next IRP cycle.

We support Staff's recommendations to require the Company to provide an additional review of gas generation types, and to include an analysis of the potential EPA or other federal and state agency policies that may affect Idaho Power's generation portfolio.

E. Demand-Side Management and Energy Efficiency Programs.

1. Parties' Positions

Several commentators at the April 20th public meeting took the position that the Company could supplant the need for the Boardman to Hemingway transmission line with increased DSM efforts. They also alleged that Idaho Power has been deficient in seeking energy savings. Commentators suggested that Idaho Power's energy efficiency efforts lag behind the regional goals established by the NPCC's Sixth Power Plan.

Idaho Power responded to these remarks in its reply comments and refuted these claims by explaining how they treat DSM in the planning process as well as facts regarding their energy efficiency efforts. In response to suggestions that Idaho Power's DSM efforts are deficient, Idaho Power stated that its DSM activities are appropriate and successful. According to Idaho Power, in 2009 it exceeded the goals contained in NPCC's Fifth Power Plan by approximately 30%. Idaho Power also stated that it is working aggressively to meet the goals set in the Sixth Power Plan.

In its final comments, Staff echoed the sentiments of Idaho Power and believes that the Company has explored and included all cost-effective demand-side and energy efficiency programs in its IRP. In addition, Staff pointed out that the Company has made great strides with its energy efficiency and DSM measures as compared to its 2006 IRP.

2, Commission Resolution

We support Staff's conclusion that Idaho Power has explored and included all cost effective demand-side management and energy efficiency programs in its IRP. We support Idaho Power in the continuation of its review and adoption of these cost effective conservation measures.

F. Policy Issues

In its opening comments, RNP did not agree with Idaho Power's recommendation to sell its Renewable Energy Credits (REC) from its renewable energy projects until the Company is required to use the RECs to comply with a Federal Renewable Energy Standard (RES). RNP believes Idaho Power should be retiring RECs in preparation for compliance with a future federal RES.

In its final comments, Staff pointed out that the Idaho Public Utilities Commission accepted Idaho Power's REC management plan filing on June 11, 2010.[7] This REC management plan is consistent with Idaho Power's IRP. In its reply comments, Idaho Power explained that its REC management strategy will benefit customers of Idaho Power in two ways. First, customers' rates will be reduced due to REC sales revenue. Second, the Company plans to continue to acquire and hold long-term contract rights to own RECs to meet future federal RES.

In addition, RNP supported the development of a solar pilot project in Idaho Power's service territory. RNP stated that it would like to participate in a stakeholder workshop with Idaho Power to explore options for a solar pilot project.

2. Commission Resolution

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[7] *See* Idaho Public Utilities Commission, Case No. IPC-E-08-24, Order No. 32002.

We support Idaho Power's conclusion that its REC management strategy is in the best interest of customers and will provide reduced rates, as well as an ability to meet future RES standards.

More recently, Idaho Power has participated in the pilot project for a solar feed-in tariff in Oregon. We believe Idaho Power's participation and introduction of the solar feed-in tariff meets the request by RNP to develop a solar pilot project in Idaho Power's service territory.[8]

G. General Issues

In final comments, Staff noted several deficiencies in Idaho Power's narrative of its 2009 IRP. Staff believes that Idaho Power should provide a more thorough explanation of the Company's selection of the Preferred Portfolio. Staff believes that Idaho Power failed to provide an adequate narrative of how the Preferred Portfolio performed in the risk analysis individually and comparatively to the other portfolios. Therefore, Staff recommended that the Commission require Idaho Power to devote specific chapters in its next IRP explaining the selection of its preferred portfolio in greater detail and as compared to an alternative portfolio. Staff believes this narrative should include an explanation of the relative performance of each portfolio within each of the modeled risk measures, including charts and matrices showing the relative ranking of each portfolio using cost and risk metrics. Finally, Staff recommended that Idaho Power should be required to provide an explanation of how each portfolio performed with regard to the qualitative measures the Company considered in its selection process.

Staff also pointed out that in Idaho Power's risk analysis it consisted of modeling risk variables, such as load forecast, in only one direction—high. In its Technical Appendix the Company did not model low load growth scenarios, low subscription rates, or low natural gas prices. Staff recommends the Company model the full range of possible futures for its risk variables, including both the high and low side, in the IRP update and in subsequent IRP cycles.

2. Commission Resolution

We support Staff's recommendation regarding Idaho Power's next IRP cycle. As stated in Order 07-002, the Commission guidelines incorporate what we minimally expect from an IRP.[9] We will always urge the utility to provide more, rather than less, information, especially given the increasing complexity of the planning process.

IV. CONCLUSION

Idaho Power Company's 2009 Integrated Resource Plan, as highlighted in this order, reasonably adheres to the principles of resource planning established in Order No. 07-002 and is conditionally acknowledged with the following requirements:

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[8] *See* Docket UM 1452.
[9] *See* Order 07-002 at 12.

1. In its annual IRP update and next IRP, Idaho Power will update its B2H project analysis and include progress the Company has made towards securing equity partners, updated estimates of construction costs and quantitative estimates of third-party subscription on the B2H line and future wheeling revenues. In addition, Idaho Power will provide third-party documentation in support of its construction cost estimates.

2. In its next planning cycle, Idaho Power will analyze coal curtailment and the costs associated with coal plant retirement.

3. In its next planning cycle, Idaho Power will develop significantly more portfolios for the second ten-year planning process.

4. In its next IRP, Idaho Power will provide a review of the benefits of a CCCT versus a SCCT, looking at variables such as cost effectiveness, operation and maintenance costs, and overall system benefit.

5. In its next planning cycle, Idaho Power will analyze any potential EPA, state and other federal agency regulations associated with air quality, fly ash, and water that may affect its generation facilities. These results will be included in the next IRP analysis.

6. In its IRP, Idaho Power will provide a more robust justification for its load forecast for the second half of the planning period. In addition, Idaho Power will provide additional analysis and a description of its estimated price elasticity for each customer class in its next IRP planning cycle.

7. In its IRP update and next IRP, Idaho Power will devote specific chapters in its IRP explaining the selection of the Preferred Portfolio in greater detail and as compared to an alternative portfolio. This narrative will include an explanation of the relative performance of each portfolio within each of the modeled risk measures, including charts and matrices showing the relative ranking of each portfolio using cost and risk metrics. Idaho Power will provide an explanation of how each portfolio performed with regard to the qualitative measures the Company considered in its selection process.

8. In the IRP update and in its next planning cycle, Idaho Power will model the full range of possible futures for its updated risk variables. Idaho Power will model both a high and low future for each variable.

For further details regarding Idaho Power's adherence to the guidelines in Commission Order No. 07-002, see Staff Final Comments, Appendix A: Adherence of the Plan to Integrated Resource Planning Guidelines.

Effect of the Plan on Future Rate-making Actions

In Order No. 89-507, the Commission described its role in reviewing and acknowledging a utility's least-cost plan:

> The establishment of least-cost planning in Oregon is not intended to alter the basic roles of the Commission and the utility in the regulatory process. The Commission does not intend to usurp the role of utility decision- maker. Utility management will retain full responsibility for making decisions and for accepting the consequences of the decisions. Thus, the utilities will retain their autonomy while having the benefit of the information and opinion contributed by the public and the Commission***.
>
> Acknowledgment of a plan means only that the plan seems reasonable to the Commission at the time the acknowledgment is given. As is noted elsewhere in this order, favorable rate-making treatment is not guaranteed by acknowledgment of a plan.[10]

This order does not constitute a determination on the ratemaking treatment of any resource acquisitions or other expenditures undertaken pursuant to Idaho Power's 2009 IRP. As a legal matter, the Commission must reserve judgment on all ratemaking issues. Notwithstanding these legal requirements, we consider the integrated resource planning process to complement the ratemaking process. In ratemaking proceedings in which the reasonableness of resource acquisitions is considered, the Commission will give considerable weight to utility actions that are consistent with acknowledged integrated resource plans. Utilities will also be expected to explain actions they take that are inconsistent with Commission-acknowledged plans.

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[10] *See* Order No. 89-507 at 6, 11. The Commission affirmed these principles in Docket UM 1056. *See* Order No. 07-002 at 24.

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CERTIFICATE OF SERVICE

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I certify that I have this day served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-13-0070, to the following parties or attorneys of parties.

Dated at Salem, Oregon, this 9th day of July, 2010.

Kay Barnes

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