CECELIA A. GASSNER
DEPUTY ATTORNEY GENERAL
IDAHO PUBLIC UTILITIES COMMISSION
PO BOX 83720
BOISE, IDAHO 83720-0074
(208) 334-0314
BAR NO. 6977

Street Address for Express Mail:
472 W. WASHINGTON
BOISE, IDAHO 83702-5983

Attorney for the Commission Staff

RECEIVED
2007 JAN 22 PM 2:14
IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S 2006 INTEGRATED RESOURCE PLAN.	**CASE NO. IPC-E-06-24** **COMMENTS OF THE COMMISSION STAFF**

The Staff of the Idaho Public Utilities Commission, by and through its Attorney of record, Cecelia A. Gassner, Deputy Attorney General, in response to the Notice of Filing and Notice of Comment Deadline in Order No. 30185 issued on November 21, 2006, submits the following comments.

BACKGROUND

On September 24, 2006, Idaho Power Company ("Idaho Power" or "Company") filed its 2006 Integrated Resource Plan (IRP). On October 18, 2006, the Company filed a revised plan that corrected certain typographical errors and revised certain exhibits. The Company's filing is pursuant to a biennial requirement established in Commission Order No. 22299, Case No. U-1500-165. The IRP describes the Company's growing customer base, load growth, supply-side resources, demand-side management and risk analyses. Additionally, the 160-page IRP document and related appendices contain information regarding available resource options, planning period forecasts, potential resource portfolios, a twenty-year resource plan, and a near-term action plan.

THE INTEGRATED RESOURCE PLAN

The IRP filing consists of five documents: the IRP, a Sales and Load Forecast, the Company's 2005 Demand-Side Management Annual Report, an Economic Forecast, and a Technical Appendix.

Idaho Power has worked with stakeholders over the last 12 months to develop the subject IRP. The Integrated Resource Plan Advisory Council (IRPAC) consisted of members of the environmental community, major industrial customers, agricultural interests, an Idaho state legislator, Commission Staff, a representative from the Idaho Governor's Office, and others. The Company also conducted presentations open to the general public from November 13-16, 2006 in Boise, Pocatello, and Twin Falls, Idaho, and Ontario, Oregon.

According to the Plan Summary, the Company anticipates that its customer base will increase from approximately 455,000 to over 680,000 by the end of the planning period of 2025, an increase of 11,000 to 12,000 new customers each year. The Company states that it used a conservative resource plan based upon a worse-than-median hydro conditions. It used 70th percentile water conditions and 70th percentile average load for energy planning. In addition, for peak-hour capability planning, it used 90th percentile water conditions and 95th percentile peak-hour load.

The IRP states that it includes 1,300 MW (nameplate) of supply-side resource additions and demand side management (DSM) programs designed to reduce peak load by 187 MW and average load by 88 aMW. The Company's average load and summertime peak load are expected to increase by 40 aMW and 80 MW, respectively, per year through 2025.

The Company states that the 2006 IRP provides the Company's estimate of future loads and sets forth how the Company intends to serve the electrical requirements of its native load customers over the next 20 years. While the proposed resource portfolio represents current resource acquisition targets, the Company notes that the actual resource portfolio may differ from the quantities and types of resources outlined in the IRP depending on responses to the Company's Requests for Proposals, the business plans of any ownership partners, and the changing needs of Idaho Power's system.

Idaho Power conducted an analysis of possible transmission path upgrades, and the following were selected as the most viable transmission alternatives:

- McNary (Columbia River) to the Locust Substation (Boise) via Brownlee;
- Lolo (Lewiston area) to Oxbow;
- Bridger, Wyoming to the Boise Bench Substation via the Midpoint Substation;
- Garrison or Townsend, Montana to the Boise Bench Substation via the Midpoint Substation; and
- White Pine, Nevada to the Boise Bench Substation via the Midpoint Substation.

The IRP's preferred portfolio includes a 250 MW coal-fired resource addition in 2013 identified as "Wyoming Pulverized Coal." The Company does not know specifically where this addition will be located, but states that one of the Company's best near-term alternatives for expansion at an existing coal-fired resource is the addition of a fifth unit at the Jim Bridger plant.

STAFF ANALYSIS

General Comments

Idaho Power continues to make strides in producing a quality resource plan. The 2006 IRP has built upon the well-received 2004 IRP by adding additional analyses to the portfolio selection process and incorporating recommendations made by the Commission in the previous filing. Staff believes that through the interaction with the IRPAC, increased rigor in the scrutiny of portfolios, extended planning horizon, and inclusion of regional transmission capacity projects, the 2006 IRP is superior to prior filings.

There have been numerous events that have happened since the 2004 IRP that have influenced the 2006 analysis; most of these have been accounted for in the planning process. The 2006 IRP assumes the approval of the 170 MW addition to the Danskin facility. Also assumed in the analysis is the net upgrade of 49 MW to the Shoshone Falls Hydroelectric Project first identified in the 2002 IRP and scheduled for completion in 2010.

The Company continues to use a more conservative water, load, and peaking capacity planning criteria in this IRP process as it did in the 2004 IRP. While wholesale market prices for electricity have shown less volatility than in prior years, some risk remains for excessive reliance on regional markets to meet the Company's summer peaking needs. This risk is somewhat mitigated through the use of conservative planning criteria and the Company's risk management process.

The 2006 IRP includes 250 MW of additional wind resources, including a 100 MW project currently in the latter stages of the RFP process. There is also a 50 MW geothermal project in the latter stages of the RFP process included in the chosen portfolio. The Company's Plan appears to take a reasoned approach to developing a diversified portfolio that includes fossil fuel-based resources, more renewable resources, and increased DSM in its future resource mix.

Staff believes that the Company is justified in extending the planning horizon from ten years to twenty years in order to incorporate more capital intensive resources that require a longer lead time than the recently acquired simple cycle combustion turbines. The extended horizon also facilitates the analysis of transmission planning, which requires sufficient lead time for permitting and construction as well. The longer planning horizon does result in a somewhat speculative assessment of unproven or uncertain resources. For example, inclusion of an integrated gasification combine-cycle (IGCC) coal plant seems speculative given the Company's caveats about the immaturity of the technology, and the 250 MW power purchase agreement with Idaho National Laboratory (INL), scheduled for 2023, for nuclear power is highly uncertain.

However, the IRP is not intended to be a binding plan for the future expansion of the Company, and time and changing conditions will ultimately dictate the actions of the Company. The additional sensitivity analysis, discussed in more detail below, is an appropriate enhancement of the planning process to account for factors beyond the Company's control. Continued cooperative development of future IRPs with the IRPAC and the general public, along with advances in the Aurora modeling software, will enhance Idaho Power's ability to identify and evaluate uncertainty associated with the various resource portfolios.

Load Growth Forecasts

Idaho Power continues to plan for a high level of growth in load over the planning horizon. The expected growth rate of 1.9% is lower than the 2002 and 2004 IRPs, but still signifies a robust upward trend. When compared to the 2004 IRP, this change in the growth rate results in a reduction of expected load by 71 aMW in 2013. Of the four main customer classes, the residential sector appears to be the catalyst for growing load. The growth rate for residential customers is predicted to be about 2% annually, resulting in a net increase of nearly 190,000 customers by 2025 for that class. This contributes to both energy and capacity needs, with emphasis on the latter due to the growing penetration of air conditioning within the service territory. Summer peak load growth is projected at 80 MW a year over the planning horizon, with residential and irrigation accounting for approximately 60% of summer peak demand. Staff notes, and details below, that Idaho Power has implemented and expanded cost-effective DSM programs to these customer classes with the intent of mitigating peak load growth.

Fuel Price Forecasts

The results from the Company's analysis are based on assumptions made and inputs used in the modeling runs. None may be as important, given recent events, as the natural gas price forecast. In the past five years the Company has relied primarily on the addition of gas-fired combustion turbines to meet increased peaking needs. Other electric utility providers have acted similarly, and nationally this trend has increased total gas consumption for electric generation by 45% over the past decade. In that period the nation has also seen unprecedented volatility in gas prices (which was not predicted by the majority of well-established sources), which the Company relies on to derive the price schedule used in its analysis. The 2006 IRP includes a high natural gas price scenario in its portfolio analysis, and annual average prices of $8.23/MMBTU, which is in the lower range of prices witnessed in 2005 or 2006. The graph comparing natural gas price forecasts from the 2000 to 2006 IRPs included on page 49 of the Technical Appendix illustrates the inability to accurately predict fuel prices. In each case the prior forecast was well below the preceding forecast, demonstrating the volatile and somewhat unpredictable rise in natural gas prices recently. As an example, the 2004 IRP uses an expected (Sumas) natural gas price of $4.85/MMBTU and a high scenario of $6.27/MMBTU. The 2006 IRP portfolio analysis uses prices of $8.23/MMBTU for the expected scenario and $11.16/MMBTU for the high gas price, an increase of 70% and 78% respectively in two years.

Even though there are no new gas-fired plants included in the selected portfolio, there are ramifications to using optimistic gas forecasts, namely that alternative resources can be shown to be less competitive. Combustion turbines fired by natural gas have historically enjoyed an economic advantage in the decision making process due to the low relative initial capital cost and stream of variable fuel costs based on relatively low fuel price forecasts. Gas price forecasts are critical in determining which resources are included in the portfolio. This is especially true when high capital costs/low fuel cost resources are compared to resources with high fuel costs and low capital cost. Although the Company has included a significant amount of renewable resources in its selected portfolio, it has also indicated that a failure to acquire cost effective geothermal resources and other renewables, combined with favorable gas price forecasts, could result in a need to add additional natural gas-fired facilities in the short term.

Beyond the accuracy of gas price forecasts is the nature of the forecast represented in the IRP. The IRP appears to present and utilize an annual average gas price. Because the majority of gas is purchased to fire turbines in the summer peaking months, it would seem more appropriate to use a summer pricing schedule that reflects the timing of the Company's fuel purchases. To the extent the summer gas prices for use in summer peak facilities are lower than annual average prices (that include the higher winter prices), then the risk of an artificially low annual average forecast is somewhat mitigated. To the extent the Company used weighted summer prices in its IRP, it should describe the methodology used in the calculation.

The Company's forecast of coal prices continues to exhibit the same upward trend in forecasts from the previous IRPs. IRP, Technical App. D at 50. Coal prices do become a major factor in assessing potential portfolios, as the Company appears committed to adding coal-fired resources to the mix. The steep upward trend in coal prices predicted to begin around 2012 supports the Company's position to split its coal acquisition into two segments, including 250 MW of IGCC in 2017. A major driver in coal prices is transportation costs, namely rail transport, which can be critical in the siting of the plant. Idaho Power does not identify the location of their proposed coal facility in 2013, though it mentions expanding the Jim Bridger facility in Wyoming as a potential addition. The Company is also in discussions with Avista for possible joint acquisition of a coal-fired resource.

Transmission

At the behest of the Commission, Idaho Power included transmission alternatives in its resource planning. Results from the Company's analysis show peak hour transmission deficiencies as early as 2007, and significant long-term deficiencies beginning in 2009. Though the Company has transmission interconnections to the Southwest markets, the bulk of the analysis focuses on the Pacific Northwest markets. Given the Company's needs, availability of economical resources, and the maturity of the Pacific Northwest markets, it appears the emphasis on transmission upgrade is properly focused. The 2006 IRP does a far better job of incorporating transmission constraints in the portfolio selection analysis than previous IRPs.

FERC's Standards of Conduct prohibit potentially beneficial discussion between the Company's planning and transmission groups. In order to incorporate transmission alternatives into the IRP, Idaho Power contacted an outside consultant to provide the technical evaluation of several alternatives. It appears that the resulting selections of possible transmission upgrades are reasonable, though more detail regarding the findings of the consulting group would have been beneficial. The Company has included in its selected portfolio 285 MW of transmission upgrades that provide access to the Mid-C market in the Pacific Northwest. Given the nature of electric usage profiles of utilities in Washington, Oregon, and Northern California, Idaho Power may have significant opportunities to utilize additional transmission capacity for off-system purchases during summer months and periods of low water.

The Borah-West transmission upgrade, detailed in the 2004 IRP, will serve to support the growing number of wind and geothermal projects to the east of Boise, but as noted by the Company, additional upgrades will be necessary should the Company site a coal-fired plant in Wyoming. The

IRP states that since a site has not been identified, generic transmission upgrade costs have been included in the IRP analysis. Although there is uncertainty associated with current transmission upgrade costs, it is likely that the Company will provide a more thorough transmission cost estimate when a more fully developed plan to acquire resources east of Boise is presented.

Supply Side Resource Options

The selected portfolio is a modified version of the preferred portfolio from the 2004 IRP. The modifications took into account the recommendations of the Commission in Order No. 29762 and incorporated a more current assessment of the Company's needs. The three most significant changes are the timing of the additional coal based resources, the inclusion of transmission upgrades, and the modification of geothermal resources. Also, the inclusion of 250 MW of nuclear power in 2023 is worth noting. The selected portfolio consists of the following:

250 MW Wind
150 MW Geothermal
150 MW Combined Heat & Power (CHP)
250 MW Coal
250 MW IGCC Coal
285 MW Transmission
250 MW Nuclear
187 MW DSM (Peak reduction)

Idaho Power has committed to adding more wind generation to its portfolio. The preferred portfolio contains 250 MW of new wind acquisitions over the next ten years, down from the preferred portfolio in 2004 (350 MW). A major factor toward the reduction in new wind acquisitions is the amount of PURPA wind projects the Company has added since the preparation of the 2004 IRP, when it had only 2.61 MW of wind-related contracts. The Company has indicated that, including the 100 MW proposal soon to be submitted for approval and its PURPA commitments, it estimates nearly 300 MW of wind resources in its resource mix by the end of 2007. Excluding any unforeseen additional PURPA contracts, this amount will move to 450 MW within six years.

The 2006 preferred portfolio increases the amount of geothermal-powered generation by 50 MW over the 2004 plan to a total of 150 MW. Currently the Company includes 10 MW of geothermal generation in their portfolio as a result of the power purchase agreement with the Raft River geothermal project. See Case No. IPC-E-05-1. As previously noted, the Company is in the latter stages of the RFP evaluation process for a 50 MW geothermal project expected to be online in 2009.

What had been considered a 100 MW geothermal acquisition online in 2008 in the 2004 IRP has been altered to three separate 50 MW acquisitions in the 2006 plan including the aforementioned project. The other two projects are projected to be online in 2021 and 2022. The Company notes that heavy reliance on geothermal generation is risky at this time due to uncertainty in the availability of geothermal resources, but will reassess that position in the 2008 IRP should the results of the "RFP indicate that an abundant supply of cost-effective geothermal projects" exist in Idaho. IRP at 90.

The single 500 MW coal-fired generation resource from the 2004 preferred portfolio has been altered in the 2006 IRP to two 250 MW acquisitions dispersed over the planning horizon. From the previous IRP filing, the Commission ordered the Company to address new coal technologies when examining coal-fired resources. Order No. 29762. In response, Idaho Power and Avista jointly contracted with Cummins & Barnard, an engineering consulting firm, to assess the current state of coal based generation technologies. IRP, Technical App. D at 99-106. The preliminary results from that study show that IGCC technology with carbon sequestration and enhanced pulverized coal technologies may be a viable resource in the future. Currently there are two large-scale IGCC facilities in operation in the United States, but the large initial capital expenditure (estimated at over $2500/kW of total investment in 2006 dollars) and unproven technology remain the primary barriers for larger scale deployment. Future changes in carbon regulations, such as emissions taxes, along with technological advances may make IGCC technology, especially with carbon sequestration abilities, more economically competitive in the future.

The other 250 MW of coal-fired generation is anticipated to be online in 2013. Details regarding this acquisition are uncertain to date. The Company has provided a number of potential scenarios for adding regional pulverized coal to its resource portfolio with the expectation that any generating unit will be located outside of the State. By breaking up its acquisition of coal based resources into smaller units than that proposed in the 2004 IRP, the Company notes that this reduces its exposure to risk of equipment failure and coincides better with expected load growth. IRP at 97. Staff observes that this reduces the immediate rate impact on the Company's customers as well. Idaho Power has informed the Commission and Staff that it has executed a memorandum of understanding with Avista to explore the option of jointly developing a coal-fired facility. Seasonal or shared ownership, as well as expansion of existing generation facilities, are also options the Company is considering. The Company may also want to consider short-term interim participation in regional coal plants. It is anticipated that the Company will have a firmer grasp on its options early in 2007.

The remaining supply side resources in Idaho Power's preferred portfolio include 150 MW of Combined Heat and Power (CHP) and a 250 MW power purchase agreement (PPA) with INL for nuclear power. As stated earlier, the inclusion of the nuclear PPA is speculative at this time, but is not considered in the plan to be enacted until 2023. It is assumed that this will be addressed in future IRPs, along with nuclear power in general, and is not significant in the Company's near-term plan. The CHP addition identified in the preferred portfolio is anticipated to occur in two installments, with 50 MW predicted to be online in 2010 and an additional 100 MW in 2020. Quantifying the costs associated with CHP is difficult, as project costs are very site-specific. The Company has used cost figures from the 2004 IRP escalated at 3% for its 2006 analysis. Figures 5-1, 5-2, and 5-3 demonstrate that CHP is potentially an economically competitive generation resource. IRP at 46-48.

DSM Measures

The 2006 IRP sets more aggressive targets for DSM savings for the planning period than did the 2004 IRP. Staff supports prudently managed, cost effective DSM programs and hopes that the Company can reach at least the targets set out in the IRP.

The 2006 IRP proposes two new DSM programs and refinement and expansion of an existing program that will potentially result in a nearly 88 aMW savings and a reduction in peak load of 187 MW in 2025, both in addition to its existing programs. The new programs target existing residential and commercial customers with savings of 29 and 18 aMW and peak reductions of 113 and 27 MW, respectively, in 2025. The refined and expanded industrial program is projected to save 40 aMW and 47 peak MW in 2025. IRP at 65.

Idaho Power's existing DSM programs, which include new homes and commercial buildings as well as existing residential air conditioning, low-income customers and industrial and irrigation customers, resulted in an average savings of 4.7 aMW and peak hour reductions of 47.5 MW in 2005 according to IRP Table 2-6. IRP at 25. Staff notes that the 2005 DSM report submitted as Appendix B to the 2006 IRP lists a slightly lower 43.1 peak hour reduction, which excludes 4.5 MW attributed to energy efficiency programs and Northwest Energy Efficiency Alliance (NEEA) market transformation. Most of the existing programs are projected to expand for at least the first few years of the planning period, according to the 2004 IRP.

In Case No. IPC-E-06-22, the Commission approved modifications to the Irrigation Peak Rewards Program that are intended to expand the program beyond the level of the 2006 Program. See Order No. 30194. However, there is no acknowledgement of the program or assumptions of continued associated savings and reductions to be found in the 2006 IRP. If included, the Company needs to be more explicit in how it is factored into the analysis; if not included, the Company should explain why.

Underestimating DSM savings may lead to a heavier, unnecessary reliance upon supply side resources. Given that DSM efforts continue to show exceptional value with benefit/cost ratios as high as 4.3, the Company should continue to expand these programs and properly record energy savings. IRP, Technical App. D at 73. Prudent DSM management results in not only acquiring DSM as cost-effectively as practicable, but also acquiring all cost-effective DSM, and fully incorporating the savings into the IRP.

There are several factors that may influence the level of DSM implementation. One particular example worth noting is the implementation of a fixed cost adjustment mechanism designed to keep the Company financially neutral to deviations in sales, such as lost sales due to DSM efforts. See Case No. IPC-E-04-15. The goals of the fixed cost adjustment are to remove the inherent disincentive to investing in demand-side measures and facilitate the Company's efforts to expand its DSM offerings. Staff is interested in whether approval of the fixed cost adjustment mechanism would affect the analysis conducted for the IRP, and if so, how.

A second example is the status of the Company's advanced meter reading (AMR) deployment. In Order No. 30102, the Commission granted Idaho Power a one-year period to investigate the technical issues that plagued the AMR deployment in the Emmett area. Through meetings with the Staff, the Company has reported that many of the technical issues have been addressed, though new issues have appeared. Failure to resolve these issues may have a deleterious effect on demand response programs that utilize AMR technology. Staff and the Commission have been strong proponents of time variant pricing and other demand response programs, and hope that the technical issues can be resolved and full-scale deployment can be achieved as quickly as is prudent. The Company is scheduled to submit an updated status report by May 1, 2007.

Staff recognizes and supports the Company's effort to distribute its DSM efforts among customer classes, between new construction and existing customers, between direct incentive programs and NEEA's market transformation efforts, and between energy efficiency and peak load reductions.

DSM programs continue to be among the most cost effective resources available to Idaho Power as demonstrated in Figures 5-1, 5-2, and 5-3 of the 2006 IRP. IRP at 46-48. However, IRP Fig. 5-7 projects Idaho Power's DSM energy savings for 2007 and 2008 at between 65% and 75% of its proportional share of the Northwest Power and Conservation Council's (NWPCC) estimate of total conservation potential. IRP at 69. While the 2006 IRP demonstrates a higher commitment to

DSM efforts than in the past, the Company does not yet propose to pursue all cost-effective DSM opportunities and incorporate associated energy and peak demand savings into its determination of new supply side resource needs. Perhaps the Company's fixed cost adjustment proposal in Case No. IPC-E-04-15 and its DSM incentive proposal in Case No. IPC-E-06-32, will mitigate the Company's position stated in the IRP's Technical Appendix D that DSM programs will be selected to minimize negative impact on shareowners. IRP, Technical App. D at 62.

Risk Analysis

Idaho Power selected four of the twelve potential portfolios for further risk analysis in determining the preferred portfolio. Risk measures fall into either quantitative or qualitative categories. The quantitative analysis closely follows that of the 2004 IRP with two exceptions, the exclusion of risk analysis associated with the expiration of production tax credits for wind and the inclusion of a sensitivity analysis to variations in the streamflows of the Snake and Columbia River systems. Advancement in the modeling software facilitated simulating various streamflow sequences for the hydrologic variability analysis, which each portfolio analyzed under varying assumptions of load requirements, carbon taxes, etc. The resulting analysis was not used in the final risk adjustment due to the magnitude of the impact of varying hydrologic conditions. Staff finds this to be reasonable and notes that the difference in variability between the highest and lowest cost portfolios are relatively small ($404 million versus $434 million, or less than 7% difference in variability).

The quantitative factors used in the scoring of the finalist portfolios remained the same from the 2004 IRP (carbon taxes, natural gas price, capital and construction costs, and market risks), though the input values have changed in most categories. As mentioned before, the natural gas price forecasts have been updated since 2004, as well as the discount rates used in the capital risk analysis. The subjective probabilities associated with the low, expected, and high scenarios have remained at the 2004 levels in all risk analyses with the exception of capital cost risk, which changed from 10%, 80%, and 10% respectively to 10%, 60%, and 30% respectively. As noted in Staff comments from the 2004 IRP, the Company does not provide a basis for its probability assignments, which can have significant economic impacts on the portfolios under consideration. For example, the Company uses $14/ton as an expected case scenario for the carbon adder with 50% probability. Yet given the probability weighting assignments made by the Company, the expected value of the carbon adder is $17/ton.[1]

[1] Expected value in this case is the average of possible carbon adder values weighted by their probability. Specifically, Expected value = ($0*.3)+($14*.5)+($50*.2) = $17/ton.

For the preferred portfolio, this adds an additional $200 million to power supply costs. Because the composition of the portfolio dictates the impact of varying assumptions, these impacts are not equal across the board. The lowest cost portfolio, in comparison, has nearly a $50 million smaller impact due to this change.

Idaho Power has expanded its qualitative risk section in the 2006 IRP. In addition to regulatory risks (e.g. the imposition of renewable resource portfolio standards), resource timing and commitment risks, and operational concerns associated with its hydropower facilities, the Company acknowledges the risks associated with technologies, fuels, and the implementation of the preferred portfolio. Without specifically tying these qualitative measures to the individual portfolios, the Company expresses its concerns regarding these areas in general terms. Of the qualitative risks, it appears as if the more important risks that factor into the selection of the preferred portfolio are concerns over the operational risk of transmission projects (and market liquidity), technology, specifically with regards to IGCC, and potential renewable portfolio standards.

The methodology used in the analysis resulted in the selection of the preferred portfolio, an extension of the 2004 preferred portfolio that highlights a diverse mix of new resource acquisitions. The Company states that the diversified approach mitigates exposure to qualitative risks, and provides flexibility in planning should actual conditions deviate from those used in the planning criteria. IRP at 91. The preferred portfolio scored well in the risk analysis, ranking second behind the 'green portfolio'. Staff would note that the preferred portfolio had the second highest cost of the finalists in terms of average total cost, yet the lowest in terms of resource cost (capital and operating costs, with market sales and purchases excluded). The preferred portfolio was the second lowest risk-adjusted total cost portfolio among finalists due to its relatively higher risk ranking.

Near-term Action Plan

Since 2001, Idaho Power has been in a period of acquiring supply-side resources after nearly two decades of relatively few additions to its generation resource mix. The 2004 and 2006 IRPs have presented a need to meet future deficiencies in energy as well as peak loads. Given the long lead time associated with thermal baseload generation facilities and the projected persistent deficiencies in energy beginning in 2012, it is imperative that the Company begin addressing these concerns. The Company is currently investigating its options with regard to a coal-fired resource addition, as noted earlier. The near-term action plan shows 2007 as the target date for identifying, selecting and proceeding into the pre-construction phase of this endeavor.

The Borah-West transmission upgrade is scheduled for completion prior to the Company's next IRP filing in 2008. By that time it is anticipated that the final commitments for the McNary-Boise transmission upgrade will have been made. This addition is expected to be complete around 2012. Besides the Borah-West project, the Company is in the final stages of the wind RFP for 100 MW scheduled to be online by the end of 2007, as well as finalizing the geothermal RFP for 50 MW, scheduled for an online date in 2009. Finally, the approved 170 MW expansion of the Danskin facility is anticipated to be online in 2008. These additions, along with changing conditions faced by Idaho Power regarding loads, fuel prices, and market conditions will invariably affect the Company's 2008 IRP.

STAFF RECOMMENDATION

Staff recommends that the 2006 IRP be accepted and acknowledged as submitted.

Respectfully submitted this 22nd day of January 2007.

Cecelia A. Gassner
Deputy Attorney General

Technical Staff: Bryan Lanspery

i:umisc:comments/ipce06.24cgrps

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS **22ND** DAY OF JANUARY 2007, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-06-24, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

LISA D. NORDSTROM
BARTON L KLINE
IDAHO POWER COMPANY
PO BOX 70
BOISE ID 83707-0070

MICHAEL J. YOUNGBLOOD
PRICING & REGULATORY SERVICES
IDAHO POWER COMPANY
PO BOX 70
BOISE ID 83707-0070

Jean D. Koch
SECRETARY