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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE FILING OF IDAHO POWER COMPANY'S 2004 ELECTRIC INTEGRATED RESOURCE PLAN (IRP).	)	**CASE NO. IPC-E-04-18**
	)	**COMMENTS OF THE COMMISSION STAFF**

COMES NOW the Staff of the Idaho Public Utilities Commission, by and through its Attorney of record, Donald L. Howell, II, Deputy Attorney General, and submits the following comments in response to the Notice of Filing and Notice of Comment Deadlines issued in Order No. 29614.

BACKGROUND

On August 27, 2004, Idaho Power Company filed its 2004 Integrated Resource Plan (IRP) with the Commission. 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 and demand-side management. Additionally, the 88-page IRP document and related appendices contain information regarding available resource options, planning period forecasts, potential resource portfolios, risk analyses, a ten-year resource plan, and a near-term action plan. The complete

2004 IRP consists of five separate documents: the IRP document, an Economic Forecast, a Sales and Load Forecast, a Demand-Side Management Annual Report, and a Technical Appendix. Idaho Power requests that the Commission issue an Order accepting and acknowledging the Company's 2004 IRP and finding that the 2004 IRP meets both the procedural and substantive requirements of Order No. 22299.

Idaho Power worked with representatives of major stakeholders for almost a year to develop the 2004 IRP. Members of the environmental community, major industrial customers, irrigation representatives, state legislators, Commission representatives, the Governor's office, and others formed the Integrated Resource Plan Advisory Council (IRPAC) and made significant contributions to the Plan. The Company also solicited and received presentations from anaerobic digestion generation project developers, geothermal generation project developers, wind generation project developers, and DSM advocates. To obtain public input, the Company made "live" presentations of the draft IRP throughout its Idaho and Oregon service territory, with public meetings in Pocatello, Twin Falls, Boise and Ontario, Oregon.

The 2004 IRP places a greater emphasis on conservation and demand reduction options than the 2002 IRP. Following a risk analysis of 12 resource portfolios, Idaho Power selected a diversified portfolio with nearly equal amounts of renewable generation and traditional thermal generation as the preferred resource portfolio. It contains nearly equal amounts of renewable generation and traditional generation as well as demand response and energy efficiency programs. The selected portfolio will increase the Company's power supply by approximately 800 aMW and increase the capacity of the system by almost 940 MW over the 10-year planning horizon. Of this increase, 124 MW are achieved through demand-side management (DSM). More specifically, the balanced portfolio selected for this plan is composed of the following:

76 MW Demand Response Programs (DSM)
48 MW Energy Efficiency Programs (DSM)
350 MW Wind-Powered Generation
100 MW Geothermal-Powered Generation
48 MW Combined Heat and Power at Customer Facilities
88 MW Simple-Cycle Natural Gas Fired Combustion Turbines
62 MW Combustion Turbine, Distributed Generation, or Market Purchases
500 MW Coal-Fired Generation

Idaho Power's IRP is based on an expected increase in households within its service territory from 320,000 today to over 380,000 by the end of the planning period in 2013.

In light of public input and regulatory support of the 2002 IPR planning criteria, Idaho Power continues to emphasize a resource plan based upon worse-than-median (70th percentile) water conditions.

The 2004 IRP presented in this filing is the Company's best current estimate of future loads and sets forth how the Company intends to serve the electrical requirements of its native load customers over the next ten years. While the proposed resource portfolio represents current resource acquisition targets, the actual resource portfolio may differ from the outlined quantities and types depending on many factors, including the response Idaho Power receives from various Requests for Proposals that it intends to issue to acquire new renewable and DSM resources. The 2004 IRP includes a near-term action plan that sets out specific actions to be taken by Idaho Power Company prior to the next IRP in 2006. The near-term action plan is shown below.

Preferred Portfolio - Near-Term Action Plan (Present through 2006)

Year	Activity
August 2004	1. 2004 Integrated Resource Plan submitted to the Idaho PUC and Oregon PUC.
Fall 2004	1. Idaho Power Company and Utilities Commissions communicate regarding IRP specifics and concerns. 2. RFP issued for 200 MW wind. 3. RFP issued for 88 MW peaking resource. 4. File DSM results as a supplement to the IRP. 5. File energy efficiency tariff rider in Oregon.
2005	1. Demand-side measures designed and funded through Energy Efficiency Advisory Group and the Public Utilities Commissions. 2. RFP issued for 12 MW CHP. 3. RFP issued for 100 MW geothermal. 4. Utility partner for seasonal-ownership coal plant identified.
2006	1. CHP design work with successful bidders. 2. 100 MW of wind generation online. 3. 150 MW Borah-West transmission upgrade complete. 4. Ongoing DSM programs. 5. RFP issued for 500 MW seasonal-ownership coal plant. 6. 2006 IRP.

In addition to the near-term action plan, the IRP also presents a ten-year resource plan that lays out the events and timing of resource acquisitions throughout the planning period. The ten-year resource plan is shown below.

Preferred Portfolio - Ten-Year Resource Plan

Year	Activity
August 2004	1. 2004 Integrated Resource Plan submitted to the Idaho PUC and Oregon PUC.
Fall 2004	1. Idaho Power Company and Commissions communicate regarding IRP specifics and concerns. 2. RFP issued for 200 MW wind. 3. RFP issued for 88 MW peaking resource. 4. File DSM results as a supplement to the IRP. 5. File energy efficiency tariff rider in Oregon.
2005	1. Demand-side measures designed in partnership with the Energy Efficiency Advisory Group and the Commissions. 2. RFP issued for 12 MW CHP. 3. RFP issued for 100 MW geothermal. 4. Utility partner for seasonal-ownership coal plant identified.
2006	1. CHP design work with successful bidders. 2. 100 MW of wind generation online. 3. 150 MW Borah-West transmission upgrade complete. 4. Ongoing DSM programs. 5. RFP issued for 500 MW seasonal-ownership coal-fired generation. 6. 2006 IRP.
2007	1. 12 MW CHP online. 2. 88 MW Danskin expansion online. 3. 100 MW wind generation online. 4. 500 MW seasonal coal begin construction. 5. RFP issued for 62 MW combined cycle gas turbine or distributed generation. 6. Ongoing DSM programs.
2008	1. 100 MW geothermal online. 2. 100 MW proposed Borah-West transmission upgrade complete. 3. RFP issued for 36 MW CHP. 4. RFP issued for 150 MW wind. 5. Ongoing DSM programs. 6. 2008 IRP.
2009	1. CHP design work with successful bidders. 2. Ongoing DSM programs.
2010	1. 36 MW CHP online. 2. 150 MW wind online. 3. 62 MW Combustion Turbine or peaking resource online. 4. Ongoing DSM programs. 5. 2010 IRP.
2011	1. 500 MW seasonal-ownership coal-fired generation online. 2. Ongoing SM programs.
2012	1. Ongoing DSM programs. 2. 2012 IRP.
2013	1. Ongoing DSM programs.

ANALYSIS

General Comments

Staff believes that Idaho Power's 2004 IRP is an improvement over previous plans. The plan is more complete and the supporting analysis is more thorough and more accurate. The Company has devoted more effort to the preparation of this plan than to other recent plans.

During the preparation of this plan, Idaho Power employed a different process to solicit the opinions of its customers and to encourage public involvement. In the past, Idaho Power's practice was to simply invite interested persons to attend and participate in a series of meetings during the preparation phase of the plan. This often resulted in limited participation and biased opinions because not all customer groups were represented. Staff concedes, however, that past participation may have been limited due to the Company's lack of need to acquire new resources in prior plans.

For the 2004 plan, Idaho Power formed an advisory committee consisting of invited participants representing a balance of customer groups, state agencies, and advocacy groups. Through this process, Idaho Power received valuable guidance and feedback that it used to develop a draft plan. By employing such a process, participation was improved, more input was received and comments were more thoughtful. In addition, participants were exposed to the sometimes conflicting positions of other representatives, requiring collaboration, understanding and compromise. The disadvantage to this process was that it might have excluded those who wished to participate but were not invited.

Once a draft plan was developed, it was released for public review and comment. The Company conducted several workshops or meetings throughout its service territory to receive public comment. There was minimal attendance at the public meetings and few written public comments were received on the draft plan. Staff recognizes the difficulty in getting public participation and comment; however, we believe it is important for customers to know the types and costs of future generation and to express their opinions during the planning process, rather than later when plants are being constructed.

As with the previous plan, Idaho Power finds itself faced with needing to satisfy significant deficits in both capacity and energy. Idaho Power has considered a broad array of both supply side and demand side alternatives for meeting its forecasted load. In this plan, demand side management programs (DSM) and pricing options play a critical role, especially in the near term. Staff believes this is appropriate and will specifically address DSM and pricing options later in these comments.

Staff is also encouraged that Idaho Power now seems to be taking its IRP seriously, and that the integrated resources planning process is consistent with the apparent business plan of the utility. Preparation of IRPs was never intended to be a regulatory exercise, but instead was intended to be for the benefit of the utility as well as its customers.

Because Idaho Power has an imminent need for capacity, the majority of Staff's comments will focus on the IRP's near-term action plan. The near-term action plan calls for immediate implementation of DSM programs and issuance of Requests for Proposals (RFPs) for renewables and peaking capacity. Of the top five resource portfolios considered in the IRP, four would have very similar near-term action plans.

Demand-Side Management and Pricing Options

In 2002 Idaho Power began collecting about $2.7 million annually for new demand-side management (DSM) programs. This funding is in addition to prior funding for its participation in the Northwest Energy Efficiency Alliance (NEEA) and Idaho Low Income Weatherization. The Company also participates in the Bonneville Power Administration Conservation and Renewable Energy Discount (BPA C&RD) program. The IRP says the Company's new source of DSM funding has been focused toward demand response, demand reduction and energy efficiency during summer peak periods. The Company indicates in its IRP that DSM programs reduced its summer 2003 peak load by 189 kilowatts (kW) and saved 5,912 megawatt-hours (MWh).

Unlike Idaho Power's 2002 IRP, the current IRP contains estimates of significant benefits that are obtainable from various DSM programs, six of which promote energy efficiency and two that allow the Company to directly control demand. The IRP also says that the Company will gather data from its recently implemented seasonal rates to assess their impact on consumption. Although not in the IRP, the Staff is also aware that Idaho Power will soon propose a trial of more precise time-of-use rates in some of the areas where it has installed advanced meter-reading (AMR) facilities.

The Staff acknowledges and supports Idaho Power's renewed interest in DSM. The IRP identifies significant potential for both cost-effective DSM and cost based variable pricing that should make customers better off than simply acquiring more supply-side resources.

Idaho Power worked with its Energy Efficiency Advisory Committee (EEAG) and outside consultants to identify potential cost-effective DSM programs in the four major customer classes, i.e. residential, commercial, industrial and irrigation. The Company says it pre-screened potential options and then used the Aurora Electric Market Model to assess DSM impacts on power supply costs.

Idaho Power says it used cost-effectiveness as an absolute screening criterion and that customer focus, customer class distribution, and earnings neutrality were used as guidelines for additional screening. As a result of the screening process, the following eight programs were determined to be cost-effective and to sufficiently satisfy the other criteria:

Over-all DSM Rank	**Demand Response Programs Selected**	9-yr. Peak Mw	9-yr. Avg. MW	9-year Present Value IPC's Costs (mill.)	9-year IPC $ /kW /Mo.	9-year IPC $ /kWh	Particip. Cust. Payback (years)	IPC Net Util. B/C Ratio	Net Total Rsrc. B/C Ratio
1	Irrigation Peak Clipping	30.4	n.a.	$17.8	$ 4.2	n.a.	n.a.	1.4	2.7
2	Air Conditioning Cycling	45.2	n.a.	$29.6	$ 5.5	n.a.	n.a.	1.3	1.7

	Efficiency Programs Selected								
3	Commercial New Construction	3.3	1.0	$ 3.8	$10.8	$0.051	6.8 yrs.	5.1	3.8
4	Irrigation Efficiency	26.0	5.9	$18.3	$ 6.4	$0.039	3.0 yrs.	5.0	3.8
5	Industrial Efficiency	10.8	9.7	$15.3	$12.9	$0.020	3.8 yrs.	5.2	3.3
6	Residential New Construction	8.3	1.7	$ 4.7	$ 5.3	$0.036	6.5 yrs.	4.1	2.5

Selected Total	124.0	18.3	$89.5

Over-all DSM Rank	**Efficiency Programs Not Selected**	9-yr. Peak MW	9-yr. Avg. MW per year	9-year Present Value IPC's Costs (mill.)	9-year IPC $ /kW /Mo.	9-year IPC $ /kWh	Particip. Cust. Payback (years)	IPC Net Util. B/C Ratio	Net Total Rsrc. B/C Ratio
7	Commercial Existing Construction	15.0	9.5	$17.7	$10.9	$0.024	7.8 yrs.	4.3	2.3
8	Residential Existing Construction	17.9	8.8	$23.0	$12.1	$0.034	6.4 yrs.	3.2	2.0

Cost-Effective Total	156.9	38.2	$130.2

The two demand response programs were analyzed outside of the Aurora model for technical reasons but were selected by the IRP because they were cost-effective based on their dispatchability and peak reducing benefits. The demand response programs were estimated by Idaho Power to have among the lowest levelized costs per kilowatt (kW) of demand per month of all of the pre-screened DSM resources. However, the Staff notes that these two programs were nevertheless estimated to have among the lowest Idaho Power net utility benefit/cost (B/C) ratios.

Idaho Power's analysis showed that all six of the energy efficiency options reduced its long-term power supply costs. Ultimately, the Company selected only the top four ranked efficiency programs as programs to be actively pursued in addition to the two demand response programs. The two efficiency programs that were not selected are the Commercial and Residential Existing Constructions, which the Company estimated would have net utility B/C ratios of 4.3 and 3.2, respectively. Staff notes that Idaho Power's estimated utility B/C ratios for these two programs that were not selected are higher than those for the two demand response programs that were selected. While Staff acknowledges that dispatchability and peak reduction benefits are important, we are concerned that Idaho Power did not select two major DSM programs that its modeling demonstrates are very cost-effective and will provide over 36 MW of peak load reduction.

The IRP says that the two existing construction programs were not selected because 1) it was felt that better options may be identified through the ongoing energy efficiency assessment analysis and 2) it felt that implementing more than the six programs that it did choose would cause too many operational challenges. Staff believes that while each of these stated reasons may independently have merit, together they seem somewhat contradictory. Upon further questioning of why the IRP did not select two of the cost-effective DSM programs, Company managers have responded that they may feel more comfortable pursuing more DSM if and when the Company is allowed a significant increase to its DSM tariff rider (currently about 0.5%); if the issue of fixed-cost revenue losses due to DSM is favorably resolved; after DSM programs are fine-tuned; and after DSM ramp-up is further along. Company managers also noted that new construction DSM is more important than DSM for existing buildings because the "lost opportunity" associated with the latter is not as significant as with the former. While Staff does not necessarily dispute the validity of these responses, we are concerned that Idaho Power may be neglecting effective DSM programs that could provide least-cost resources to its customers.

The Northwest Power and Conservation Council's (NWPCC) recently released draft power plan suggests that there may be a much higher level of cost-effective DSM potential in Idaho Power's Service territory than Idaho Power's IRP has identified. Specifically, the draft NWPCC plan suggests that regionally there may be 700 aMW of cost-effective conservation potential within the next five years. Idaho Power's presumed share of that potential might be about 45 aMW compared to the IRP's estimates for 2009 of 10 aMW for programs selected and an additional 10 aMW for the two programs not selected.

However, the NWPCC calculations, in addition to individual utility DSM programs, include efforts that are largely outside the control of Idaho Power, such as building codes, appliance standards, NEEA's market transformation programs and naturally occurring conservation efficiency gains. Also, Idaho Power's 20 aMW potential identified in its IRP does not include its Low Income Weatherization, its BPA C&RD programs, nor its participation in NEEA. Staff is aware that Idaho Power intends to file a supplement to its IRP that will identify additional DSM potential.

Idaho Power anticipates that some of the energy efficiency and demand response programs will be chosen through competitive bidding. It also intends to have program evaluations done by independent evaluators chosen through competitive bidding.

Staff considers Idaho Power's DSM and pricing efforts in this IRP and in other cases yet to come before the Commission to be works-in-progress. Overall, Staff supports Idaho Power's multiple steps toward increasing the roles of energy efficiency, demand response and variable pricing in meeting its customers' demands.

Requests for Proposals (RFPs)

Acquisition of generating resources in the IRP is expected to be accomplished by issuing RFPs. The preferred portfolio calls for the release in late 2004 of one RFP for 200 MW of wind power and one RFP for 88 MW of gas-fired peaking capacity. The preferred portfolio also calls for additional future RFPs seeking to acquire an additional 150 MW of wind, 100 MW of geothermal generation, and 12 MW of Combined Heat and Power (CHP). Because the IRP is built upon acquisition of new resources through RFPs, the entire viability of the IRP is dependent on the success of the RFP process.

Staff believes that the structure of the RFPs will be crucial. Staff has some concern about whether the RFPs will be successful in attracting enough proposals to insure that desired resources can be acquired at a location, in sufficient quantity and at a price that is acceptable to Idaho Power. An RFP that is structured too narrowly may restrict such things as the number of qualified bids due to the size and location of renewable resource within Idaho Power's service territory, timing differences between when resources are needed and can be developed, and transmission constraints that limit access to some resources. The RFPs for renewables should accommodate on-line dates that permit projects to take advantage of the recently renewed federal production tax credits. As it now stands, the federal production tax credit for renewables is set to expire at the end of 2005, yet the IRP calls for wind generation to come online in 2006.

Staff also has questions about how responses to the RFPs will be evaluated. For example, how will Idaho Power decide whether bids are too expensive? What other alternatives will renewables be compared to? How will renewables be compared to CHP? How will different types of renewables with different generation characteristics, different locations or different on-line dates be compared? Clearly, these questions will eventually have to be answered, but the answers are not contained in the IRP.

If the RFPs are unsuccessful in attracting viable bids, doing nothing is not an option. Idaho Power's load will not stop growing. The ability of DSM and pricing options to counteract load growth is limited. The Company is also constrained in its ability to import power during peak demand periods. As a result, Idaho Power must have a back-up plan. Staff would like to see greater attention paid to identifying alternate scenarios, and contingency plans developed in the event RFPs do not produce the desired results. Otherwise, the timing of Idaho Power's need could relegate natural gas generation as the only other realistic short-term option. Gas-fired generation would probably be the only resource with short enough lead times and enough certainty in its output to meet such immediate needs. As we have seen, reliance on gas-fired generation exposes a utility and its ratepayers to volatile fuel prices. Staff is concerned that gas-fired generation may become the resource of choice simply by default.

The preferred portfolio, and in fact all of the top-ranked portfolios, must represent resources that are actually available. The RFP results will confirm whether these resources are, in fact, available at the costs, quantities and locations assumed in the 2004 IRP.

Renewables

Renewables, specifically wind and geothermal, are expected to satisfy a substantial portion of Idaho Power's generation needs in the future. Because of this, Staff believes Idaho Power should begin to independently investigate the costs and availability of these resources. There is a danger in relying on the claims of a few developers about cost and availability of renewables within Idaho Power's service territory. There is no guarantee that these developers' projects will prove cost effective, large enough, or competitive with other alternatives. Similarly, modeling wind generation using only the actual data provided by one wind developer is risky and could lead to inaccurate assumptions about wind. Staff would be interested in seeing the Company perform a wind integration study to determine the amounts of wind generation that could be integrated into its system and the expected costs of integration. Such a study needs to be done before Idaho Power makes a large commitment to wind.

Staff is also concerned about project siting and the possible disparity between wind projects that qualify for PURPA rates and those that do not. Current PURPA avoided cost rates exceed the cost assumptions in the IRP for renewables. Staff sees little incentive for bidders in the RFP to bid prices less than current PURPA rates if the wind project is a Qualifying Facility under PURPA. Bids for other wind projects in the region are now being accepted for significantly less than Idaho's PURPA rates. Staff suggests that it would be more appropriate for future PURPA rates and policies to establish the ceiling for renewables cost, rather than the floor.

Transmission

Transmission constraints appear to drive many of the alternatives considered and some of the resource choices ultimately made in the IRP. Transmission constraints from the Northwest, in particular, present the greatest problem because they restrict access to regional markets and prohibit consideration of resources located to the west of Idaho Power's system. Moreover, transmission constraints hamper Idaho Power's ability to consider development or expansion of jointly owned thermal projects.

Staff would be interested in a more thorough study to assess just how much of a transmission "penalty" the Company and its ratepayers are paying and how much more severe the penalty has to get before transmission upgrades make sense on the west side of Idaho Power's system. The IRP does include a plan to upgrade transmission on the Borah-West path as early as 2006 in order to provide access to expected renewable resources. The IRP is not clear, however, as to why the Company is so quick to upgrade this path but seems to simply plan around constraints to the Northwest that limit access to west-side resources and markets. While Staff is not necessarily opposed to transmission upgrades or renewables, it seems somewhat presumptuous to proceed with east side transmission upgrades before renewable RFP results are known. Similarly, Idaho Power should continue to actively participate in the Rocky Mountain Area Transmission Study (RMATS) to assess whether even greater long-term transmission additions on the east side of Idaho Power's system make sense in order to access wind and coal-fired resources in eastern Idaho, Wyoming and Utah.

According to the IRP, each of the final candidate portfolios considered would eliminate the transmission overloads from the Northwest that would otherwise occur. Staff believes the IRP should indicate how a northwest transmission upgrade would compare to the other portfolios, even if a transmission upgrade is more costly.

Finally, transmission upgrade costs should be taken into account and assigned fairly in the evaluation of all potential new resources based on their location. If transmission upgrades are necessary to gain access to renewables on the east side of Idaho Power's system, for example, those costs should not be overlooked in considering the cost effectiveness of those resources.

Baseload Thermal Generation

Idaho Power's long-term action plan calls for the release in 2006 of an RFP for a seasonal ownership of a 500 MW coal plant to be located within the Company's service territory. The coal plant would have an online date of 2011. A coal plant has never been included in an Idaho Power Company IRP before, since the IRP process was initiated in 1989. Because coal plants are new to the IRP, Staff believes the Company must carefully investigate issues surrounding coal. The siting and permitting process for a greenfield coal plant within Idaho could be arduous and lengthy. Given the apparent shift of other western utilities towards coal, the availability, price and transportation of fuel must also be thoroughly investigated.

Because of the likely difficulties of siting a coal plant in Idaho, the Company should also begin seriously studying alternatives such as additions to Bridger or Valmy, or joint ownership of other future coal plants that may be constructed in the region along with necessary transmission facilities. Finally, coal generation technology is rapidly advancing, and cleaner, more benign types of coal-fired plants will likely be available in the coming years. Integrated Gasification Combined Cycle (IGCC) plants for example, are still currently more expensive than pulverized coal plants, but they are much more environmentally friendly. Some utilities have recently announced plans to employ this technology in new plants to be constructed in the not too distant future. Idaho Power should closely monitor this technology as it develops.

Risk Analysis

In Staff's opinion, risk analysis is one of the most important elements of integrated resource planning. Idaho Power has performed some risk analysis to evaluate candidate portfolios, however, Staff believes a more thorough analysis would have been desirable. For example, the initial twelve portfolios were analyzed and ranked under only four different scenarios, with only one set of expected gas prices used in each scenario. In addition, the probabilities assigned to the various scenarios in the final portfolio analyses seem arbitrary. Staff recognizes that the Company was still developing modeling skills and tools during the preparation of this IRP, but expects that those skills and tools should be more fully developed before the next IRP cycle.

Nonetheless, the risk analysis that was performed confirms that over-reliance on gas-fired generation is risky and should be avoided. Staff also believes it is noteworthy that the risk analysis does not change ranking of the top three portfolios. Most important however, is the fact that the risk analysis summary shows that while the preferred portfolio has the lowest power supply cost, it is only 3.6 percent lower than the no-coal portfolio and about five percent less than the highest cost portfolio. This result, Staff contends, demonstrates that estimated costs for most reasonable portfolios are similar given the accuracy of cost data available today, and that the exact composition of the portfolio that is ultimately developed may come down to issues other than cost.

Portfolio Selections

As part of the IRP development process, the twelve initial portfolios considered in the IRP were assembled with the assistance of the IRP Advisory Committee. Although Staff applauds the Company for establishing the Advisory Committee and using it to assist in developing IRP portfolios, we still believe it likely that a more systematic approach combined with appropriate risk analysis would likely generate more optimum portfolios in terms of low cost and risk.

The preferred portfolio consists of a balanced mix of DSM, renewables, gas and coal-fired resources. While Staff acknowledges that the preferred portfolio ranked highest both before and after risk analysis, we believe it is possible that an even lower cost portfolio may exist that is still low risk. The results of upcoming RFPs should help Idaho Power to refine its resource cost and availability assumptions and perhaps enable it to devise an even more attractive portfolio.

RECOMMENDATIONS

Staff recommends that Idaho Power's 2004 IRP be accepted and acknowledged.

Respectfully submitted this 3rd day of December 2004.

Donald L. Howell, II
Deputy Attorney General

Technical Staff: Rick Sterling
Lynn Anderson

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 3^{RD} DAY OF DECEMBER 2004, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-04-18, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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