Oregon

Theodore R. Kulongoski, Governor

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April 12, 2007

MARK STOKES
MANAGER, POWER SUPPLY AND PLANNING
IDAHO POWER COMPANY
P.O. BOX 70
BOISE, IDAHO 83707

RE: OPUC Staff's Draft Order for IPCo's 2006 Integrated Resource Plan (LC 41)

Idaho Power Company (IPCo) filed its 2006 Integrated Resource Plan (*IRP or plan*) with the Oregon Public Utility Commission (OPUC) on October 23, 2006. The plan is intended to meet the requirements of both OPUC Order No. 89-507 and the Idaho Public Utilities Commission (IPUC) Order No. 22299. On February 16, 2007, IPCo made a supplemental IRP filing to satisfy the requirements of OPUC Order No. 07-002.

In the enclosed LC 41 draft order, Staff is recommending to the Commission that IPCo's 2006 IRP be acknowledged. Recognizing the sensitivity of environmental concerns associated with the potential acquisition of a coal-fired resource, Staff is recommending that IPCo's annual IRP update (*as required by guideline 3(f) of Order No. 07-002*) fully detail the status of the Company's coal acquisition efforts. The annual IRP update should also discuss any prospective portfolio adjustments deriving from technological, political, and market changes.

If you wish to discuss the draft order or have questions, please give me a call at (503) 378-6360.

/s/ *William A. McNamee*

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c: Lee Sparling, OPUC
Ed Busch, OPUC
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Enclosure

April 12, 2007

DRAFT

ORDER NO.

ENTERED

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 41

In the Matter of **IDAHO POWER COMPANY** **2006 Integrated Resource Plan.**	**)** **)** **)**	**ORDER**

DISPOSITION: PLAN ACKNOWLEDGED

The Oregon Public Utility Commission (OPUC) received the 2006 Integrated Resource Plan (IRP or plan) of Idaho Power Company (IPCo) on October 23, 2006. The plan was developed to meet the requirements of both OPUC Order No. 89-507 and Idaho Public Utilities Commission (IPUC) Order No. 22299.

The 2006 IRP consists of five separate documents: the IRP Report, an Economic Forecast, a Sales and Load Forecast, a Demand-Side Management Annual Report, and a Technical Appendix. The analysis assumes that IPCo will continue to operate throughout the IRP's 20-year planning horizon as a vertically-integrated electric utility.

The plan was docketed as LC 41. At the February 5, 2007, LC 41 Prehearing Conference the Administrative Law Judge adopted the following schedule:

1. Last Day to Intervene	February 12, 2007
2. Idaho Power's Supplemental Filing per Order No. 07-002	February 16, 2007
3. Idaho Power's Summary Presentation at Commission Public Meeting	February 27, 2007
4. Intervener Comments on plan due	March 16, 2007
5. Staff Final Comments, recommendations and Draft Order due	April 12, 2007
6. Reply Comments due	May 4, 2007
7. Hearing/Commission Public Meeting	June 2007

One party intervened -- The Citizens' Utility Board (CUB).

OPUC Order No. 07-002 (*Investigation into Integrated Resource Planning, issued January 8, 2007*) stated that IPCo should supplement its 2006 IRP as needed to meet the IRP guidelines adopted in the Order. Per the LC 41 schedule, IPCo filed the required 2006 IRP supplement with the OPUC on February 16, 2007. In the IRP supplement, IPCo detailed its belief that the 2006 IRP largely meets the intent and guidelines of Order No. 07-002.

Also, as required by the LC 41 schedule, IPCo made a summary presentation of its 2006 IRP at the Commission's February 27, 2007, public meeting. The PowerPoint presentation - Planning for the Future - provided information regarding IPCo's load/resource balance over the IRP's 20-year planning horizon, analysis of resource alternatives for meeting identified load deficits, and the IRP's preferred plan for future resource acquisitions.

Staff presented its analysis of IPCo's 2006 IRP to the Commission at the ______, 2007, public meeting. Staff recommended that the Commission acknowledge the Plan. Staff further recommended that in the 2006 IRP annual update, which is required by guideline 3(f) of Order No. 07-002, IPCo should thoroughly discuss the status of the IRP's identified acquisition of 250 MW of coal-fired generation for an on-line date of 2013. As discussed in this Order, the Commission … (*intentionally left blank*).

OVERVIEW OF IPCo's INTEGRATED RESOURCE PLAN

Beginning in late summer 2005, Idaho Power Company began the process of developing its 2006 IRP. IPCo invited representatives of the environmental community, major industrial customers, irrigation customers, the Idaho state legislature, the Oregon and Idaho Public Utility Commissions (OPUC and IPUC), the Idaho Governor's office, and others to form an Integrated Resource Plan Advisory Council (IRPAC).[1] At IRPAC meetings, that generally occurred on a monthly basis, members reviewed load and resource information provided by IPCo and offered comments and suggestions regarding the IRP study formulation and analysis.

IPCo issued a draft of its 2006 IRP on August 24, 2006. IRPAC members and the general public were invited to offer written comments. During the fall of 2006, the Company held draft 2006 IRP public meetings throughout its Idaho (Pocatello, Twin Falls, and Boise) and Oregon (Ontario) service territories.[2] Based on comments

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[1] The IRPAC members included representatives from the Natural Resources Defense Council, Advocates for the West, Micron Technology, J.R. Simplot Company, Idaho National Engineering and Environmental Laboratory, Heinz Frozen Foods, American Association of Retired Persons, Idaho Retailers Association, Agricultural Interests, Meridian School District, Idaho Department of Environmental Quality, Idaho Governor's Office, Idaho State Legislature, Northwest Power and Conservation Council, and the Idaho and Oregon PUCs.

[2] Attendance at the draft IRP public meetings was small and few written comments were provided.

received from IRPAC members and the general public, IPCo made several revisions to the draft IRP.

IPCo's final 2006 IRP was filed with the OPUC on October 23, 2006.

SUMMARY OF PLAN

As mentioned, IPCo has assumed that during the 2006 IRP's planning horizon the Company will continue to be responsible for acquiring sufficient resources to serve all customers in its Idaho and Oregon service territories. The primary goals of the 2006 IRP are to:

1. Identify sufficient resources to reliably serve the growing demand for energy service within Idaho Power's service territory throughout the 20-year planning horizon (2006 through 2025).
2. Ensure that the portfolio of resources selected balances costs, risks, and environmental concerns.

In addition, the IRP incorporates the following accompanying goals:

1. Give equal and balanced treatment to both supply-side resources and demand-side measures.
2. Involve the public in the planning process in a meaningful way.
3. Explore transmission alternatives.
4. Investigate and evaluate advanced coal technologies.

The IRP analysis predicts the Company's load/resource balance over the planning horizon, identifies supply-side and demand-side resource options, and estimates the costs and risks of 12 potential resource portfolios designed to meet expected load requirements.

The portfolios were developed to represent a wide range of resource alternatives. The alternatives varied from a portfolio that included nearly 1,000 MW of renewables and no coal-fired generation, to one with 1,475 MW of new transmission capacity, as well as a predominately coal-fired portfolio. There were also several diversified portfolios that consisted of varying amounts of wind, geothermal, transmission, coal, natural gas, and demand-side management (DSM) resources.

Based on the portfolio analysis, IPCo selected a preferred resource acquisition strategy (*presented later in this Order*) that includes 1,300 MW (*nameplate capacity*) of renewable and conventional supply-side resources, as well as 285 MW of new transmission capacity. In addition, the preferred portfolio includes DSM programs that are estimated to achieve 187 MW of peak load reduction and 88 aMW of annual load reduction.

LOAD/RESOURCE BALANCE

The plan details the rapid growth that IPCo's service territory is experiencing. The Company's general customer base is expected to increase from 456,000 in 2005 to over 680,000 by the end of the planning horizon in 2025. The average annual compound load growth is forecast to be 1.9 percent. With this forecast, average load is expected to increase by 40 aMW per year and summertime peak-hour loads are expected to increase by over 80 MW per year.

The total nameplate generation capacity of IPCo's system is 3,085 MW. In 2005, the system's firm load was 1,660 aMW. In July 2006, the Company set a new peak-hour load record of 3,084 MW. The IRP's analysis of the system's load/resource balance demonstrates that IPCo is currently experiencing energy deficits during summer and winter peak periods. Over the long-term, IPCo's system will require new base load generation.

Assumed IRP Planning Criterion for Water and Load: Given customer, legislative, and regulatory feedback to the significant energy crisis related rate increases of 2001, IPCo has adopted a 70th percentile water planning criterion for its IRP analysis. Under this criterion, hydro generation is based on stream flows that occur on average in 7 out of 10 years. Compared to IPCo's traditional median water planning criterion, this conservative assumption is intended to reduce short-term market price risk for both the utility and its customers.

IPCo has also determined that it will emphasize 70th percentile load conditions in its 2006 IRP. This IRP planning assumption is based on the recognition that IPCo customer loads are highly dependent upon weather. This is particularly true with the summer peak load, which is strongly influenced by air conditioning and irrigation demands. The 70th percentile load assumes a level of monthly loads that are not likely to be exceeded 70 percent of the time. This conservative IRP planning assumption assists in identifying resource requirements that would result from higher loads due to adverse weather conditions.

The IRP's emphasis on 70th percentile water and load conditions is intended to reduce the price risk of a volatile energy marketplace. The tradeoff is that the IRP planning process may determine that IPCo will need to acquire additional resources beyond what would be needed under median conditions. Customer, legislature, and regulatory feedback has clearly indicted, however, that somewhat higher, but stable, rates are preferable to the rate uncertainty associated with wholesale market price volatility.

Load Forecast: The projected average annual load growth rate for IPCo's service territory is estimated to be 1.9 percent. This forecast is bounded by low and high estimates of 1.5 percent and 2.4 percent, respectively. Assuming 70th percentile conditions, the IRP's forecasted load in 2006 is 1,786 aMW and is expected to increase to 2,515 aMW in 2025.

For 2006, the 70th percentile firm peak load is estimated to be 3,163 MW and is projected to increase to 4,689 MW by 2025. Historically, the Western Electricity Coordinating Council (WECC) has required IPCo to maintain 330 MW of reserve capacity (*equal to IPCo's share of the Bridger coal plant*) above forecast peak load. Thus, IPCo's current reserve margin is approximately 11 percent. In the IRP analysis, this percentage varies over the planning horizon based on the assumed load growth and the projected timing and size of new resource additions.

Supply-Side Resources: To serve system load, the Company owns a combination of hydroelectric and thermal generation facilities. In 2005, IPCo's hydroelectric generating plants supplied 36 percent of customer requirements. Hydro plants also serve as the primary source of load following capability. Thermal generation supplied 42 percent of customer needs and purchased power supplied the remaining 22 percent. As mentioned, IPCo's IRP is designed to identify a resource portfolio that will improve the Company's ability to manage system dependence on wholesale market purchases.

Hydroelectric Facilities -- IPCo operates 18 hydroelectric generating plants located on the Snake River and its tributaries. These facilities have a total nameplate capacity of 1,708 MW and under normal conditions annually produce approximately 970 aMW of electricity. Approximately 70 percent of this hydroelectric generation is produced by the Hells Canyon Complex (HCC), which consists of Brownlee, Oxbow, and Hells Canyon dams.

The HCC and Swan Falls projects are currently seeking renewal of their Federal Energy Regulatory Commission (FERC) operating licenses. FERC operating licenses are issued for terms of 30 to 50 years. The license renewal process is very complex and requires a minimum of five years to complete. As shown in the table below, the Company has successfully relicensed its other Snake River projects.

Under federal law, new hydro licenses are required to include measures for environmental protection, mitigation, and enhancement. These measures influence the relicensed hydro plant's operations and costs. IPCo states that its goal in relicensing is to maintain a low cost hydroelectric generation system while implementing measures designed to protect and enhance the river environment. Because the Hells Canyon Complex relicensing is not yet complete, the IRP states that Idaho Power cannot reasonably estimate the impact of the relicensing process on the generating capability or operating costs of the project. If reductions in hydro capacity or operational flexibility do occur as the result of the HCC relicensing, then the Company will need to adjust its future resource planning process to ensure adequate power supply and reliability.

HYDROELECTRIC PROJECT RELICENSING

Project	FERC License Number	Nameplate Capacity (MW)	Current License Expires
Hells Canyon Complex	1971	1,167	July 2005[1]
Swan Falls	503	25	June 2010
Bliss	1975	75	Aug. 2034
Lower Salmon	2061	60	Aug. 2034
Upper Salmon A	2777	18	Aug. 2034
Upper Salmon B	2777	17	Aug. 2034
Shoshone Falls	2778	13	Aug. 2034
C.J. Strike	2055	83	Aug. 2034
Upper/Lower Malad	2726	22	March 2035

[1] Operating under annual renewal of existing license

The IRP also expresses concern regarding Snake River flows. The hydrologic record developed by the Idaho Department of Water Resources shows that the average annual base flow of the Snake River, as measured below Swan Falls, has declined at an average rate of 53 cubic feet per second (cfs) per year from 1960 to 2005. The observed decline is largely due to consumptive water withdrawals for irrigation and other purposes and has been exacerbated by recent drought conditions. The hydro generation lost between 1960 and 2005 is approximately 153 aMW and, if the flow decline trend continues, the reduction in IPCo's hydro generation may reach 183 aMW by 2015.

Thermal resources -- IPCo has ownership shares in the Bridger, Valmy, and Boardman coal-fired plants. These facilities provide approximately 857 average megawatts of annual generation. The Company also operates the 90 MW Danskin gas-fired combustion turbine (CT) plant and the 162 MW Bennett Mountain CT. Both these facilities are located near Mountain Home and are operated as needed to support system load or in response to favorable market conditions. IPCo also owns and operates a 5 MW diesel plant located at Salmon, Idaho. This plant is only operated during emergency conditions.

Purchased power -- Purchases from regional markets supply a significant portion (*22 percent in 2005*) of IPCo's system energy and capacity requirements, especially during summer and winter peak load periods. Given market price volatility and transmission constraints (*discussed in the following section*), IPCo is striving to manage its reliance on regional market purchases.

Public Utility Regulatory Policy Act (PURPA) -- Under PURPA, IPCo currently has contracted for 438 megawatts of nameplate capacity from independent small power and cogeneration facilities (CSPP). PURPA requires that IPCo purchase the energy output of CSPP facilities. Various Idaho and Oregon PUC orders govern the rules, rates, and requirements for CSPP contracts. Wind facilities that have either recently come on-line or will be on-line within the next year account for 206 MW (nearly half) of the total CSPP capacity.

Transmission Constraints: IPCo's 345 kilovolt (kv), 230 kv, and 138 kv main grid transmission system provides essential pathways for purchasing power supplies to meet incremental system needs and for making off-system sales during times of surplus. Currently, system transmission constraints limit the Company's ability to use off-system purchases to meet load, particularly during summer and winter peaks.

On the Westside of IPCo's transmission system, there is a capacity constraint on the Brownlee-East path between the Brownlee Dam Substation and the Boise/Treasure Valley area. Transmission limits most often occur during the summer due to the combination of HCC hydro generation flowing to the Treasure Valley, wheeling obligations with BPA, and energy purchases from the Pacific Northwest (PNW). Congestion can also limit the import of energy from the PNW during winter peaks. A significant increase in the acquisition of energy from resources sited west of the Brownlee-East constraint will require the construction of additional transmission capacity.

To reduce the Westside transmission constraint, the 2006 IRP includes two transmission projects designed to significantly improve IPCo’s ability to import power from the Mid-Columbia market in the PNW. The first is the construction of a new 230 kV line from BPA’s McNary Dam Substation to IPCo’s Brownlee Dam Substation, a distance of 215 miles. An additional 70 miles of line from Brownlee to Boise will complete the project. The estimated capacity of this link is 225 MW. The second project involves the reconductoring of the existing Lolo to Oxbow transmission line. This upgrade is expected to add approximately 60 MW of additional import capacity.

The above projects will also require significant upgrades to IPCo’s backbone system. Preliminary engineering studies are currently in progress. The McNary to Boise line is projected to be complete in 2012. The Lolo to Oxbow completion date is 2019.

On the eastern portion of IPCo's service territory, the Borah-West path is fully utilized by existing wheeling obligations and therefore is a constraint to additional power imports from Eastern Idaho, Montana, Wyoming, and Utah. There is a high probability that some of the conventional and renewable generation resources identified for potential acquisition in the 2006 IRP will be located east of the Borah-West path. Therefore, transmission improvements will be required. IPCo’s 2004 IRP began the planning and permitting steps necessary to upgrade the transmission capacity of the Borah-West path by up to 250 MW. The upgrade is scheduled for completion in 2008.

The planned transmission upgrades will improve the Company’s ability to import power to meet system loads, but the costs of the upgrades are expected to add approximately .5 to 2.0 cents per kWh to future energy imports.

Demand-Side Resources: DSM programs are an important component of the 2006 IRP's preferred portfolio. Spurred by the 2001 energy crisis, IPCo's 2002, 2004, and now 2006 IRPs have increasingly emphasized the management of electric demand through energy conservation. The two primary objectives of IPCo's DSM programs are to:

1. Acquire cost-effective resources in order to more efficiently meet the electrical system needs; and
2. Provide Idaho Power customers with programs and information to help them manage their energy use and lower their bills.

To fund DSM activities within IPCo's service territory, both the IPUC and OPUC have approved an Energy Efficiency Rider (Rider) that allows the Company to collect 1.5 percent of base revenues for implementation of DSM programs. To assist with the development and ongoing review of DSM programs, IPCo has organized an Energy Efficiency Advisory Group (EEAG) that includes customer, public, and private representatives. The initial focus of DSM efforts has been toward irrigation and air conditioning demand response programs during summer peaks. The Company is also implementing commercial, industrial, and residential energy efficiency programs. The 2006 IRP estimates that DSM programs will achieve 88 aMW of energy savings per year and 187 MW of summertime peak-load reduction by the end of the 20-year planning horizon in 2025.

In addition, IPCo has an agreement to provide funding to the Northwest Energy Efficiency Alliance (NEEA). NEEA is a regional organization that works to enhance the efficient use of energy through various market transformation programs that benefit the Pacific Northwest (PNW), including IPCo customers. Specific to Oregon, IPCo continues to offer a Low-Income Weatherization Program, Oregon Commercial Audits (Schedule 82) and the Oregon Residential Weatherization Program (Schedule 78).

Risk Analysis: In evaluating identified resource portfolio alternatives, IPCo's 2006 IRP analysis considered both quantitative and qualitative risks. The objective of the risk analysis was to determine how a specific portfolio performed under a variety of potential circumstances. Analysis results indicated the sensitivity of the portfolio's total cost to different risk variables.

Quantitative risks considered included diverse levels of carbon taxes, natural gas prices, capital and construction costs, hydrologic variability, and market risk. Qualitative risks included deliberation of the public policy and regulatory environment, declining Snake River base flows, FERC relicensing, and the timing and commitment requirements of specific resource types, including evaluation of resource siting, fuel, implementation, and technology.

In the 2006 IRP, IPCo states it recognizes that potential carbon emission costs represent the most significant risk variable. The IRP analysis results indicated that, for any value of a carbon emissions adder up to $28 per ton, pulverized coal yielded the lowest levelized cost when compared to other base load resource alternatives. An adder of greater than $28 per ton indicated that IGCC (*Integrated Gasification Combined Cycle*) technology with carbon sequestration resulted in the lowest levelized cost. Therefore, the carbon tax variable in the IRP's risk analysis did not eliminate coal as a viable resource alternative.

System Balance: As discussed, IPCo's system is facing increasing summer and winter peak load deficits in both capacity and energy. Under the IRP's 70th percentile water and load conditions (*see IRP Technical Appendix, p. 78*), system summer and winter peak load deficiencies increase throughout the 20-year planning horizon. Summer peak deficiencies are calculated at 252 MW in May 2006 and increase to 1,716 MW by July 2025. The winter peak deficiencies are estimated to be 191 MW in December 2006, with an increase to 971 MW by December 2025. In 2006, peak deficiencies occur from May through September and in December. By 2025, peak deficiencies occur in all months except February and April.

Resource Portfolio and Action Plan: Based on the portfolio analysis, IPCo selected a preferred strategy that in the near-term focuses on acquisition of renewable and demand-side resources, with new transmission capacity and conventional supply-side base load resources added over the longer-term (*see listing below*). The IRP notes, however, that each resource acquisition presents different characteristics for satisfying electric demand in what is a dynamic energy marketplace. Therefore, given the two-year cycle of the IRP process, it is likely that changing market conditions, technology advancements, and specific development opportunities may cause IPCo to reassess the resource acquisitions identified in the 2006 IRP.

Preferred portfolio resource acquisitions over the 20-year planning horizon are as follows:

Year	**Resource Acquisitions**	**Capacity (MW)**
2008	Wind (2005 RFP)	100
2009	Geothermal (2006 RFP)	50
2010	CHP*	50
2012	Wind	150
2012	Transmission McNary–Boise	225
2013	Wyoming Pulverized Coal	250
2017	Regional IGCC Coal	250
2019	Transmission Lolo-Oxbow	60
2020	CHP	100
2021	Geothermal	50

2022	Geothermal	50
2023	INL Nuclear**	250
Total Nameplate Capacity……………		**1,585**

* Combined Heat and Power

** Idaho National Laboratory

As mentioned, the plan also includes demand-side management (DSM) programs estimated to reduce annual loads by 88 average MW and peak-hour loads by 187 MW.

The IRP's 10-year action plan (shown below) lists the activities necessary to begin implementation of the preferred plan, as well as the anticipated longer-term planning activities through 2015.[3]

10-YEAR ACTION PLAN

Late 2006 and early 2007

1. Conclude 100 MW wind RFP issued in response to the 2004 IRP
2. Notify short-listed bidders in 100 MW geothermal RFP issued in response to the 2004 IRP
3. McNary–Boise transmission upgrade process initiated
4. Develop implementation plans for new DSM programs with guidance from the EEAG
5. Continue coal-fired resource evaluation with Avista and consider expansion opportunities at Idaho Power's existing projects (Jim Bridger, Boardman and Valmy)
6. Investigate opportunities to increase participation in the highly successful Irrigation Peak Rewards DSM program
7. Complete wind integration study
8. Evaluate the Energy Efficiency Rider level necessary to fund DSM program expansion

2007

1. Finalize DSM implementation plans and budgets with guidance from the EEAG
2. 100 MW geothermal RFP concluded
3. Assess CHP development in progress via PURPA process—consider issuing RFP for 50 MW CHP depending on level of PURPA development

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[3] While the 2006 IRP has a 20-year planning horizon, the plan presents a 10-year outline of activities necessary to implement the preferred portfolio. This recognizes that, with biennial updates of the IRP, activities in the last 10 years of the 2006 plan (2016 through 2025) will likely undergo significant revisions.

4. Identify leading candidate site(s) for coal-fired resource addition and begin permitting activities
5. 225 MW McNary–Boise transmission upgrade – studies in progress
6. 100 MW wind on-line
7. Evaluate/initiate DSM programs
8. Select coal-fired resource, finalize contracts, begin design, procurement, and pre-construction activities

2008

1. 225 MW McNary–Boise transmission upgrade–final commitments
2. 250 MW Borah–West transmission upgrade complete
3. 170 MW Danskin expansion on-line
4. Evaluate/initiate DSM programs
5. Prepare and file 2008 IRP

2009

1. 150 MW wind RFP issued
2. 50 MW geothermal resource on-line – possibly more depending on response to the 2006 RFP
3. Evaluate/initiate DSM programs

2010

1. 50 MW CHP on-line
2. Evaluate/initiate DSM programs
3. 49 MW Shoshone Falls upgrade on-line
4. Prepare and file 2010 IRP

2011

1. Evaluate/initiate DSM programs

2012

1. 225 MW McNary–Boise transmission upgrade complete
2. 150 MW wind on-line
3. Evaluate/initiate DSM programs
4. Prepare and file 2012 IRP

2013

1. 250 MW coal-fired generation on-line
2. Evaluate/initiate DSM programs

2014

1. Evaluate/initiate DSM programs
2. Prepare and file 2014 IRP

2015

1. Evaluate/initiate DSM programs

In summary, the 2006 IRP's preferred portfolio includes 1,300 MW (*nameplate capacity*) of renewable and conventional supply-side resources, 285 MW of new transmission capacity, and DSM programs that are estimated to achieve 187 MW of peak load reduction and 88 aMW of annual load reduction.

PARTY COMMENTS

Commission Staff

Background: OPUC Staff participated in the Company's IRP Advisory Council process and was able to attend most meetings. Staff believes the IRPAC process has worked well and, through a diverse membership and open discussion, contributes to the formulation and completion of a thorough and comprehensive planning document.

Staff provided written comments on the draft IRP that was issued on August 24, 2006. To address the Staff and other parties' comments, IPCo made several changes to the final 2006 IRP that was issued October 23, 2006.

Summary of Staff's March 16, 2007, LC 41 comments on IPCo's 2006 IRP: Staff stated that it believes the IRP's preferred portfolio, which includes a diversified mix of renewable and conventional thermal technologies, transmission upgrades, and DSM activities, is appropriate. In the near term, the plan emphasizes renewable resource development and demand response (i.e., irrigation and air conditioning peak reduction) and cost-effective energy efficiency programs. OPUC Staff stated it supports these actions.

Renewable Resources: The preferred portfolio contains the acquisition of 250 MW of wind generation (100 MW in 2008 and 150 MW in 2012). Including projected wind acquisitions through PURPA (200 MW), the amount of wind in IPCo's resource base will increase to 450 MW by 2012. Depending on the success of initial wind projects, and IPCo's ability to use its hydro generation to help firm the wind resource, Staff suggests it may be possible for IPCo to modify its wind acquisition strategy.

The 2006 IRP specifies the acquisition of 150 MW of geothermal generation. The first 50 MW increment is anticipated to be online in 2009. The last two 50 MW increments are scheduled for 2021 and 2022. IPCo indicates that the physical and cost-effective supply of geothermal is uncertain. The Company states it is reluctant to commit to a larger quantity of geothermal until the viability of the resource is better understood. IPCo confirms that it will further investigate geothermal's potential in its 2008 IRP.

Staff supports the IRP's near-term actions to acquire wind and geothermal generation. Staff believes that the successful integration of these resources into IPCo's system would allow the Company to give greater emphasis to the use of renewables in meeting its growing customer load requirements. This could potentially impact the need for and timing of new base load (coal) resource acquisitions.

DSM Activities: OPUC Staff participates in the EEAG process and supports the demand response and energy efficiency programs that have been developed. Staff believes that synergies are achieved through the coordination by IPCo of energy conservation and demand reduction programs in its Idaho and Oregon service territories. Through participation in the EEAG, Staff will continue to encourage the pursuit of identified cost-effective DSM activities.

Transmission: Staff believes that, given the complexity and long lead times associated with transmission projects, IPCo's decision to move forward with the projects identified in the 2006 IRP is reasonable. The status of these projects and need for additional transmission upgrades should be thoroughly evaluated in the 2008 IRP.

Proposed Coal Resources: The 2006 IRP identifies the acquisition of 250 MW of pulverized coal generation to be online in 2013 and 250 MW of IGCC (*Integrated Gasification Combined Cycle*) coal to be online in 2017. As stated in the IRP's Risk Analysis section, IPCo recognizes that potential carbon emission costs represent the most significant risk in the 2006 IRP. As mentioned, the IRP analysis results indicated that, for any value of a carbon adder up to $28 per ton, pulverized coal yielded the lowest levelized cost compared to other base load resource alternatives. An adder of greater than $28 per ton indicated that IGCC technology with carbon sequestration resulted in the lowest levelized cost.

The results of the 2006 IRP analysis strongly indicate that by 2013 additional base load generation will be needed to meet IPCo's growing load requirements. Given the IRP results regarding the need for base load resources and that, even with emission adders, coal has the lowest levelized cost, Staff supports IPCo's plan to continue to evaluate coal-fired opportunities and to identify the leading coal alternative(s).

The target date for selecting the 2013 coal resource and proceeding with the pre-construction phase is 2007. Coal has the advantage of being an abundant domestic energy resource that, even with emission adders, appears to have the lowest generation costs. Therefore, it needs to be considered a viable resource alternative. Nevertheless, Staff recommended that IPCo should emphasize identified renewable and DSM acquisitions and, to the extent practical, delay a final commitment to a pulverized coal plant. Staff believes that any future coal plant construction should be designed to mitigate environmental damage to the maximum extent that is technically and economically (*considering both private and societal costs*) viable. If shown to be commercially viable, an IGCC coal facility with carbon sequestration would be the environmentally superior alternative.

Nuclear: The IRP identifies the potential that IPCo will consider entering into a power purchase agreement for roughly 250 MW of energy from a “next generation” nuclear power project that the U.S. Department of Energy plans to construct at the Idaho National Laboratory (INL). The INL is located in southeastern Idaho. The project’s current schedule has an online date of 2021. While the INL project is authorized by the Energy Policy Act of 2005, the likelihood of necessary funding appropriations is unknown.

IPCo indicates that it will monitor the progress of this R&D nuclear project and provide an update in its 2008 IRP. Staff’s believes this pathway is reasonable.

Other March 16, 2007, LC 41 Comments

No other Intervener comments were received.

Party Responses to Staff’s April 12, 2007, Comments and Draft Order

……………….. (*intentionally left blank*).

Public Meeting Presentation

Staff presented its recommendation regarding IPCo’s 2006 IRP at the Commission’s …………., 2007, public meeting. Staff indicated that the Idaho Public Utility Commission (IPUC) had issued its final order regarding IPCo’s 2006 IRP on March 26, 2007 (Order No. 30281). In its order, the Idaho Commission accepted the plan as meeting the requirements of Commission Order No. 22299.

Staff recommended the acknowledgment of IPCo's 2006 IRP. Recognizing the environmental concerns associated with the potential acquisition of a coal-fired resource, Staff recommended that IPCo’s annual IRP update (*as required by guideline 3(f) of Order No. 07-002*) fully detail the status of the Company’s coal acquisition efforts. Staff further recommended that the annual IRP update fully discuss any prospective portfolio adjustments deriving from technological, political, and market changes.

Public Comment

…………….. (*intentionally left blank*).

OPINION

Jurisdiction

IPCo is a public utility in Oregon, as defined by ORS 757.005, which provides electric service to or for the public.

On April 20, 1989, pursuant to its authority under ORS 756.515, the Commission issued Order No. 89-507 in Docket UM 180 adopting least-cost planning for all energy utilities in Oregon. On January 8, 2007, the Commission issued Order No. 07-002 in Docket UM 1056 adopting Integrated Resource Planning (IRP) guidelines that update and refine the procedures established in 1989.

Requirements for Intergraded Resource Planning Under Order No. 07-002

Order No. 07-002 adopts 13 IRP Guidelines. The Commission recognized that the IPCo 2006 IRP was filed prior to the issuance of Order 07-002. The Order therefore directed IPCo to make a supplemental filing providing any additional information necessary to meet the adopted guidelines.

The first two guidelines established the following substantive and procedural requirements:

Guideline 1: Substantive Requirements

a. All resources must be evaluated on a consistent and comparable basis.
b. Risk and uncertainty must be considered.
c. The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.
d. The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.

Guideline 2: Procedural Requirements

a. The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP.
b. While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.
c. The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.

Guidelines 3 through 13 present the Commission's policy for the following issues:

3. Plan Filing, Review, and Updates
4. Plan Components
5. Transmission
6. Conservation

7. Demand Response
8. Environmental Costs
9. Direct Access Loads
10. Multi-state Utilities
11. Reliability
12. Distributed Generation
13. Resource Acquisition

Based on its review, Staff determined that IPCo's 2006 IRP adheres to the Commission's Integrated Resource Planning guidelines adopted in Order No. 89-507 and Order No. 07-002. The plan examined the Company's future resource needs, investigated resource options, conducted a risk analysis, and developed a strategy to meet expected system peak and energy deficiencies in a manner that balances costs, risks, and environmental concerns. Given the currently available information, Staff believes that the 2006 IRP represents the "best cost/risk portfolio."

Commission Findings

…………….. (*intentionally left blank*).

EFFECT OF THE PLAN ON FUTURE RATE-MAKING ACTIONS

In adopting the original least cost planning requirements, this Commission emphasized that acknowledgement did not constitute rate-making (*see Order No 07-002 at 24 and Order No. 89-507 at 6*). As noted above, decisions on whether to include, in rates, the costs associated with new resources can only be made in a rate proceeding. Acknowledgement, however, is relevant to the question of rate-making treatment. As the Commission previously explained:

> Consistency of resource investments with least-cost planning principles will be an additional factor that the Commission will consider in judging prudence. When a plan is acknowledged by the Commission, it will become a working document for use by the utility, the Commission, and any other interested party in a rate case or other proceeding before the Commission[.] Consistency with the plan may be evidence in support of favorable rate-making treatment of the action, although it is not a guarantee of favorable treatment. Similarly, inconsistency with the plan will not necessarily lead to unfavorable rate-making treatment, although the utility will need to explain and justify why it took an action inconsistent with the plan. (*see Order No. 89-507 at 7*).

No party in the UM 1056 proceeding sought fundamental changes to this principle, and we adhere to the definition of acknowledgement, as presented above.

Conclusion

IPCo's 2006 IRP is acknowledged with the recommendations adopted in this Order. The plan meets both the substantive and procedural requirements of Order No. 89-507 and Order No. 07-002. Achievement of the objectives in the Company's Action Plan will contribute meaningfully toward the development of future integrated resource planning efforts and the acquisition of future resources at the best combination of expected costs and risks.

ORDER

IT IS ORDERED that the 2006 Integrated Resource Plan filed by Idaho Power Company on October 23, 2006, be acknowledged in accordance with the terms of this order and Order No. 89-507 and Order No. 07-002.

Made, entered, and effective_____________________________.

Lee Beyer	**Ray Baum**
Chair	Commissioner

John Savage

Commissioner

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 12th day of April, 2007.

Kay Barnes

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