ORDER NO. 05-782

ENTERED 06/17/05

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 36

In the Matter of	)	
	)	ORDER
IDAHO POWER COMPANY	)	
	)	
2004 Integrated Resource Plan.	)	

DISPOSITION: PLAN ACKNOWLEDGED

The Oregon Public Utility Commission (OPUC) received the 2004 Integrated Resource Plan (IRP or plan) of Idaho Power Company (IPCo or Company) on August 30, 2004. The plan is intended to meet the requirements of both OPUC Order No. 89-507 and Idaho Public Utilities Commission (IPUC) Order No. 22299. [1]

IPCo's 2004 IRP consists of five separate documents: the IRP document, an Economic Forecast, a Sales and Load Forecast, a Demand-Side Management (DSM) Annual Report, and a Technical Appendix. The analysis assumes that IPCo will continue to operate as a vertically-integrated electric utility throughout the IRP's 10-year planning horizon (2004 through 2013).

The plan was docketed as LC 36. At the November 16, 2004, LC 36 Prehearing Conference, the Administrative Law Judge adopted the following schedule:

1) Last Date to Intervene	November 24, 2004
2) Intervenor Comments on Plan Due	January 14, 2005
3) Staff Final Comments, Recommendations, and Draft Order Due	February 18, 2005
4) Reply Comments Due	March 12, 2005
5) Hearing/Commission Public Meeting	April 2005

[1] The Oregon Order refers to Least Cost Planning, while the Idaho Order refers to Integrated Resource Planning. The terms are interchangeable.

Staff presented its analysis of IPCo's 2004 IRP to the Commission at the May 17, 2005, public meeting. Staff recommended that the Commission acknowledge the plan. Staff further recommended that IPCo revisit and thoroughly evaluate the need and timing for a coal-fired resource in its 2006 IRP planning process. As discussed in this order, the Commission adopts Staff's recommendation.

OVERVIEW OF IPCo's INTEGRATED RESOURCE PLAN

Beginning in August 2003, IPCo began the process of developing its 2004 IRP. IPCo invited representatives of the environmental community, major industrial customers, irrigation customers, the Idaho state legislature, the OPUC and IPUC, the Idaho Governor's office, and others to form an Integrated Resource Plan Advisory Council (IRPAC).[2] Forming an IRPAC was a new concept implemented by IPCo in response to 2002 IRP comments from customers and regulators that the Company should enhance its IRP planning process to include greater participation of interested parties. Starting in September 2003, the IRPAC began meeting, generally on a monthly basis, with IPCo representatives.

At IRPAC meetings, members reviewed load and resource information provided by IPCo and offered comments and suggestions regarding the IRP study formulation and analysis. As part of the IRPAC process, IPCo arranged for presentations by proponents of various generating technologies (including wind, geothermal, and biomass) and demand-side management activities. To improve the opportunity for general public participation, the Company established a link on its website that contained all information presented at each IRPAC meeting. Interested parties were able to e-mail any IRP comments to the IPCo website.

IPCo issued a first draft of its 2004 IRP to IRPAC members on May 27, 2004. Based on written comments from IRPAC members and discussion at subsequent IRPAC meetings, a final draft 2004 IRP was issued by IPCo on July 14, 2004. In late July, the Company held draft 2004 IRP public meetings throughout its Idaho (Pocatello, Twin Falls, and Boise) and Oregon (Ontario) service territory.[3]

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[2] The IRPAC members include representatives of 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, the Idaho Irrigation Pumpers Association, the Amalgamated Sugar Company, the Idaho Department of Water Resources, the Idaho Governor's Office, the Idaho Demand-side Legislature, and the Idaho and Oregon PUCs.

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

The final 2004 IRP was issued by the Company on August 27, 2004.

SUMMARY OF PLAN

IPCo has assumed that during the 2004 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 2004 IRP are to:

1. Identify sufficient resources to reliably serve the growing demand for energy service within the Idaho Power Company service territory throughout the 10-year planning horizon.

2. Ensure that the portfolio of resources selected balances cost, risk, and environmental concerns.

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.

Based on the portfolio analysis, IPCo selected a preferred 10-year resource acquisition strategy that includes nearly equal amounts of renewable and thermal generation, as well as demand response and energy efficiency programs. The selected portfolio (*presented later in this Order*) will increase the Company's power supply by approximately 800 aMW and increase the capacity of the system by over 900 MW by the end of the planning period in 2013.

LOAD/RESOURCE BALANCE

In 2003, IPCo served 423,167 customers (17,689 in Oregon), which is a 46 percent increase from the 289,398 customers the Company served in 1990. The 2003 peak firm load was 2944 MW and the average firm load was 1658 aMW. To supply power consumption demand, the Company's installed (2003) generation was 2912 MW nameplate capacity, with approximately 1200 MW of thermal generation and the remainder (1700 MW) hydroelectric. Therefore, given the IRP's expectation of continued customer load growth, IPCo's load/resource balance has moved from a capacity and energy surplus during the 1990s to current and projected capacity and energy deficits during summer and winter peak periods.

Assumed IRP Planning Criterion for Water and Load

During the 2001 energy crisis, reduced hydro generation due to poor water conditions and the unprecedented rise in wholesale market prices resulted in a huge increase in IPCo's cost of power. The Company's Idaho customers saw significant rate increases as the true-up balances in the annual Power Cost Adjustment soared.[4]

Given customer, legislative, and regulatory feedback to the 2001 rate increases, IPCo adopted for its 2002 IRP, and continuing with the 2004 IRP, a 70th percentile water planning criterion. 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 to both the utility and its customers.

IPCo has also assumed 70th percentile load conditions in the 2004 IRP. The 70th percentile load assumes a level of monthly loads that are not likely to be exceeded 70 percent of the time. This IRP planning assumption is based on the recognition that customer electric demand is highly dependent upon weather. This is particularly true with the summer peak load, which is strongly influenced by air conditioning and irrigation demands. 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 short-term market price risk for both the utility and its customers. 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, legislative, and regulatory feedback has clearly indicated, 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 2.2 percent. This forecast is bounded by low and high estimates of 1.6 percent and 2.9 percent, respectively. Assuming 70th percentile conditions, the IRP's forecasted load in 2004 is 1720 aMW, and is expected to increase to 2094 aMW in 2013.

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[4] The Company's Oregon customers saw less of a rate impact, as state law, at that time, limited the rate increase to 6 percent.

For 2004, the IRP summer peak load was 3054 MW, and is projected to increase to 3810 MW by 2013. 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.

Supply-Side Resources

To serve system load, the Company owns a combination of hydroelectric and thermal generation facilities. In 2003 (a low water year), IPCo's hydroelectric generating plants supplied 37 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 21 percent. As mentioned, IPCo's IRP is designed to identify a resource portfolio that will reduce the Company's dependence on wholesale market purchases.

Hydroelectric Facilities

IPCo operates 17 hydroelectric generating plants located on the Snake River and its tributaries. These facilities have a total nameplate capacity of 1707 MW and, under normal conditions, produce approximately 1057 aMW of electricity. Nearly 70 percent of this hydroelectric generation is provided by the T.E. Roach complex, which consists of Brownlee, Oxbow, and Hells Canyon dams.

The majority of the Company's hydroelectric facilities, including the T.E. Roach complex, 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. The Company expects the hydro relicensing process to continue through most of the IRP's 10-year planning horizon.

Under federal law, new hydro licenses are required to include measures for environmental protection, mitigation, and enhancement. These measures will influence the relicensed hydro plant's operations and costs. The Company 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. It should be understood, however, that failure to relicense existing hydro projects at reasonable costs, and/or the loss of capacity and operational flexibility, will place upward pressure on IPCo's current low rates.

The 2004 IRP assumes that IPCo will be successful in relicensing its hydro projects at reasonable costs. If hydro capacity reductions or reductions in operational flexibility do occur as the result of relicensing, then the Company will need to adjust its future resource planning process to ensure adequate power supply and reliability.

Thermal Resources

IPCo has ownership shares in the Bridger, Valmy, and Boardman coal-fired plants. These facilities provide approximately 905 average megawatts of energy. The Company also operates the 90 MW Danskin gas-fired combustion turbine (CT) plant. A new 162 MW CT, Bennett Mountain, is expected to come on-line in June 2005. These CT facilities are located near Mountain Home and will be operated as needed to support system load or in response to favorable market conditions.

Purchased Power

Under the Public Utility Regulatory Policy Act (PURPA), IPCo purchases approximately 100 megawatts of energy from over 70 independent cogeneration and small power facilities (CSPP). PURPA requires that IPCo purchase the energy output of CSPP facilities, therefore CSPP production is not considered dispatchable.

Regional markets supply a significant portion (21 percent in 2003) 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 reduce its reliance on regional market purchases.

Transmission Constraints

IPCo's 230 kilovolt and higher 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. Prior to 2000, IPCo's planning process emphasized market purchases, primarily from the Pacific Northwest (PNW), as the most efficient method to meet short-term peak load obligations. The 2004 IRP, however, states that system transmission constraints now 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, constraints on the Brownlee East path limit the import of energy purchases from the PNW. To partially address westside transmission limits, the 2002 IRP identified the need to construct a new 230 kV transmission line along the Idaho-Oregon Border. This Brownlee-Oxbow Transmission Project was designed to relieve operating limitations associated with coincident generation at the Oxbow and Hells Canyon hydro plants. The project was completed in 2004 and increased IPCo's ability to import power from the PNW by approximately 100 MW.

The 2004 IRP's transmission adequacy analysis indicates that, given IPCo's contractual obligations to deliver BPA power to Southern Idaho, additional imports from the PNW to meet IPCo system peak loads are limited. With completion of the Brownlee-Oxbow path and the Bennett Mountain CT in June 2005, the IRP predicts that the first peak-hour transmission deficiency from the PNW will occur in July 2007. This transmission deficit is estimated to be 80 MW and is projected to increase by approximately 90 MW per year over the planning horizon. The IRP analysis considered westside transmission upgrades, but did not identify any viable projects as capacity additions are expensive and could add up to 2 cents per kWh to future imports from the PNW.

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 generation resources identified for potential acquisition in the 2004 IRP will be located east of the Borah-West path. Therefore, transmission improvements will be required. IPCo has begun the planning and permitting steps necessary to upgrade the transmission capacity of the Borah-West path by up to 250 MW. These upgrades will improve the Company’s ability to import power from the east, but are expected to add approximately .5 to 1.0 cent per kWh to future eastern imports.

Demand-Side Resources

Prior to 2002, IPCo's energy conservation efforts were largely through the financial support of regional conservation work conducted by the Northwest Energy Efficiency Alliance (NEEA). This situation derived from the 1996 utility and regulatory decision that, with evolving industry restructuring and associated competition in the energy marketplace, conservation programs premised on the deferral of program expenditures and cost recovery over an extended period of time were no longer practical. In addition to NEEA expenditures, IPCo continued to offer a Low-Income Weatherization Program, Oregon Commercial Audits (Schedule 82) and the Oregon Residential Weatherization Program (Schedule 78).

The 2001 energy crisis changed the perspective on industry restructuring and the role of energy conservation. In 2002, IPCo received approval for an energy efficiency tariff rider for its Idaho service territory that provides approximately $2.7 million annually for DSM programs (see IPUC Order No. 29026). To assist with the development of DSM programs, an Energy Efficiency Advisory Group (EEAG) including customer, public, and private representatives was organized. The 2004 IRP indicates that the focus of current DSM funding is toward irrigation and air conditioning demand response programs during summer peaks. The Company is also promoting commercial, industrial, and residential energy efficiency programs that it plans to have fully operational in 2005. The IRP expects that the demand response and energy efficiency programs will achieve 76 MW and 48 MW of peak reduction by the end of 2013, respectively.

As outlined later in this order, the 2004 IRP's near-term action plan indicates that IPCo intends to file for an energy efficiency tariff rider in its Oregon service territory. Once funding is in effect, the Company will extend, to the extent practical, the developed Idaho energy conservation programs to its Oregon service territory.

System Balance

As mentioned above, 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, system summer and winter peak load deficiencies increase throughout the 10-year planning period. Summer peak deficiencies are calculated at 280 MW in June 2004 and increase to 976 MW by July 2013. Winter peak deficiencies are 86 MW in December 2004 and increase to 463 MW in 2013. By 2008, peak deficiencies occur in seven months – May through September and November and December.

Resource Portfolio and Action Plan

To meet growing demand, IPCo will need to acquire significant resources over the IRP's 10-year planning period. Due to the mentioned transmission constraints, the Company is planning to locate new resources within its service territory control area and as near as possible to load centers. Resource options considered in the IRP for meeting future system load requirements included market purchases, thermal and renewable generation resources, transmission resources, targeted demand side management, and targeted conservation and pricing options.

Twelve different resource portfolios composed of varying amounts of wind, geothermal, coal, simple and combined cycle combustion turbines, and demand-side resources were analyzed. Each portfolio was designed to meet IPCo's projected monthly energy needs under the 70th percentile water and load conditions. Based on an IRP analysis that evaluated financial costs, including external environmental costs (*as discussed in OPUC Order No. 93-695*), together with assessment of financial, market, and policy risks, a preferred portfolio was selected. The preferred portfolio is composed of the following demand-side and supply-side resources, to be acquired over the IRP's 10 year planning period:

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 (CHP or cogen) 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

The IRP lists the following near-term actions necessary to begin plan implementation, as well as anticipated longer-term planning activities.

NEAR-TERM ACTIONS

Late 2004, early 2005
1. (RFP)[5] issued for 200 MW wind. 2. RFP issued for 88 MW peaking resource. 3. File DSM results as a supplement to the IRP. 4. 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.

[5] Request for Proposal (RFP)

LONG-TERM PLANNING ACTIVITIES

2007
1. 12 MW CHP online. 2. 88 MW peaking resource 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 DSM programs.
2012
1. Ongoing DSM programs. 2. 2012 IRP.
2013
1. Ongoing DSM programs.

The plan recognizes that the preferred portfolio represents resource acquisition targets that are based on current information and knowledge. The actual resource portfolio acquired between now and 2013 will depend on many factors, including the success of identified renewable and demand-side management acquisitions.

Given the projects identified in the 2004 IRP's preferred portfolio, in 2013 IPCo's resource mix would be as follows:

- 1800 MW Hydro
- 1520 MW Coal-Fired Generation
- 350 MW Wind-Powered Generation
- 340 MW Natural Gas Combustion Turbines
- 100 MW Geothermal-Powered Generation
- 48 MW Combined Heat and Power (Cogeneration)
- 124 MW Demand-Side Programs

PARTY COMMENTS

Commission Staff

Background

OPUC Staff participated in the Company's IRP Advisory Council process and was able to attend most meetings. In a final Advisory Council meeting held on October 28, 2004, it was the general consensus of members that the IRPAC process had resulted in a more thorough and comprehensive planning document than had been the case with past IRPs. OPUC Staff agrees with this assessment.

Staff also provided written comments on the initial May 27, 2004, draft IRP, as well as the final draft issued on July 14, 2004. In both instances, IPCo addressed Staff's comments, questions, and concerns by either making appropriate editorial changes to the final IRP or, in the case of questions that did not require revision of the IRP, by providing written responses.

Summary of Staff's LC 36 Comments on IPCo's 2004 IRP

Staff stated that it believes the IRP's preferred portfolio, which includes a diversified mix of renewable and conventional thermal technologies as well as demand-side measures, is appropriate. In the near-term, the plan emphasizes demand response (i.e., irrigation and air conditioning peak reduction) and cost-effective energy efficiency programs and the issuance of RFPs for renewable, cogen, and peaking resources. OPUC Staff supports these actions.

DSM Activities: As mentioned, the 2004 IRP indicates that the focus of current DSM funding is toward irrigation and air conditioning demand response programs during summer peaks. The Company is also promoting commercial, industrial, and residential energy efficiency programs that it plans to have fully operational in 2005. The IRP expects that the demand response and energy efficiency programs will achieve 76 MW and 48 MW of peak reduction by the end of 2013, respectively.

The IRP's near-term action plan indicates that IPCo intends to file for an energy efficiency tariff rider in its Oregon service territory. OPUC Staff states that it supports this concept. Staff suggests that synergies may be achieved if IPCo's energy conservation and demand reduction efforts in Oregon are, to the extent practical, coordinated with the work in Idaho of the Energy Efficiency Advisory Group. It is Staff's understanding that the energy efficiency tariff rider currently effective in Idaho is being considered for revisions, including funding levels, by the IPUC. Staff has recommended to IPCo that it file the Oregon tariff rider after IPUC action on the proposed revisions.

Renewable Resources: Staff supports the IRP's near-term action to seek 200 MW of wind, 100 MW of geothermal, and 12 MW of cogen resources via competitive bidding RFPs (*the wind RFP was issued January 13, 2005*). The successful acquisition of economically viable renewable resources through a bid solicitation process is critical to the IRP's preferred resource strategy. It is Staff's understanding that IPCo and IRPAC members recognize that the wind and geothermal resource cost and availability information derived through the RFP process should be incorporated into, and thereby improve, IPCo's 2006 IRP analysis. The actual results of the RFPs may require IPCo to modify its long-term strategy for meeting its growing customer load requirements.

Proposed Coal Plant: The 2004 IRP analysis indicates that toward the end of the planning period an additional baseload generation facility will be needed to meet growing load requirements. To fulfill this need, IPCo's long-term action plan calls for issuance in 2006 of an RFP for a seasonal ownership of a 500 MW coal plant. The IRP analysis identifies a 2011 online date. Due to system transmission constraints for importing power, the current expectation is that the coal plant will be located within the Company's service territory.

Because of evolving conditions and information regarding renewable resources, demand-side programs, fuel prices, economic conditions, and load growth, Staff stated that it believes it is premature for the Oregon Commission to acknowledge acquisition of a 500 MW coal plant in 2011. Staff, however, indicated it does support IPCo's efforts to identify a utility partner for seasonal ownership of a coal plant. Also, Staff stated it does not object to IPCo proceeding with the development of a coal plant RFP for possible issuance in 2006. Staff recognizes that RFP responses would help to identify potential site locations and to assess permitting requirements and transmission needs.

The Staff comments encouraged IPCo to revisit the need and timing for a coal-fired resource as early as possible in the Company's 2006 IRP process. Further, Staff agreed with the IPUC Staff's December 3, 2004, comment that siting a coal plant within the Company's service territory will likely present some public opposition and difficulties (perhaps similar to those experienced with the Company's past Pioneer coal plant proposal). Therefore, if coal technology remains a viable option, Staff recommended that alternatives such as additions to the Bridger or Valmy coal plants, or joint ownership of other future coal plants (with clean-coal technologies) should be investigated.

IPCo's Response to Staff's Comments

In its March 14, 2005, response to Staff's comments and recommendations, IPCo concurred with Staff's assessment that additional review and analysis of the need and timing of a coal plant acquisition is necessary. IPCo noted that the comments of the IPUC Staff explicitly stated that more analysis of the costs and benefits of coal-fired generation needs to be done. The Company stated that its 2006 IRP will include a thorough evaluation of the prudency of proceeding further with coal-fired generation.

IPCo expressed concern that the OPUC may, in its LC 36 order, explicitly exclude from acknowledgement the potential acquisition of a coal plant in 2011. IPCo argued that a partial acknowledgement may be perceived as a rejection by the OPUC of the Company's participation in the development of a future coal-fired plant. Noting that the OPUC traditionally delays issuing its order on the IPCo IRP until after the IPUC issues its final order, the Company urged the OPUC to consider structuring its order in a manner similar to that of the IPUC final order.

Public Meeting Presentation

At the Commission's May 17, 2005, public meeting, Staff indicated that the IPUC had issued its final order on April 22, 2005 (Order No. 29762). In its order, the IPUC accepted for filing IPCo's 2004 IRP. The IPUC also ordered that the 2006 IRP provide an expanded examination of coal plant options and address new coal technologies.

Given the IPUC order, Staff recommended the acknowledgment of IPCo's 2004 IRP. Recognizing that coal is a possible future resource acquisition candidate, Staff stated its belief that it is appropriate for IPCo to proceed with the necessary steps to inventory potential coal plant site locations, permitting requirements, and transmission needs. Further, Staff recommended that IPCo should more thoroughly investigate in its 2006 IRP planning process the need and timing for a coal-fired resource.

Public Comment

No written comments were received from the public.

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.

Requirements for Least-Cost Planning Under Order No. 89-507

Order No. 89-507 establishes procedural and substantive requirements for least-cost planning and provides for the Commission's acknowledgment of plans that meet the requirements of the order.

Procedural Requirements

At a minimum, the least-cost planning process must involve the Commission and public prior to making resource decisions rather than after the fact. *See* Order No. 89-507 at 3.

Substantive Requirements

The substantive requirements were set forth in Order No. 89-507 as follows:

1. All resources must be evaluated on a consistent and comparable basis.
2. Uncertainty must be considered.
3. The primary goal must be least cost to the utility and its ratepayers consistent with the long-run public interest.
4. The plan must be consistent with the energy policy of the state of Oregon as expressed in ORS 469.010.

Based on its review, Staff determined that IPCo's 2004 IRP adheres to the Commission's least-cost planning principles. The plan examined the Company's future resource needs, investigated resource options, and, recognizing industry and market uncertainty, developed a strategy to meet expected system peak and energy deficiencies in a manner that balances costs, risks, and environmental concerns.

Commission Findings

Staff recommends acknowledgment of IPCo's 2004 IRP. We adopt this recommendation. In regard to coal generation, the Commission recognizes that coal may represent a future resource acquisition candidate. Therefore, we believe it is appropriate for IPCo to begin to perform the necessary steps to inventory potential site locations, permitting requirements, and transmission needs. We also agree with the Idaho Commission and OPUC Staff, that IPCo should thoroughly review the need and timing of a coal-fired facility in its 2006 IRP process.

In regard to demand-side activities, the Commission is encouraged by IPCo's efforts to promote energy conservation through demand response and energy efficiency programs. The IRP's near-term action plan indicates that IPCo intends to file for an energy efficiency tariff rider for its Oregon service territory. The Commission agrees with Staff that coordination with the EEAG efforts in Idaho should offer synergies. We believe that cost-effective energy conservation offers considerable potential to help address IPCo's future system needs.

EFFECT OF THE PLAN ON FUTURE RATE-MAKING ACTIONS

Order No. 89-507 sets forth the Commission's role in reviewing and acknowledging a utility's least-cost plan, as follows:

> The establishment of least-cost planning in Oregon is not intended to alter the basic roles of the Commission and the utility in the regulatory process. The Commission does not intend to usurp the role of utility decision- maker. Utility management will retain full responsibility for making decisions and for accepting the consequences of the decisions. Thus, the utilities will retain their autonomy while having the benefit of the information and opinion contributed by the public and the Commission.
>
> Plans submitted by utilities will be reviewed by the Commission for adherence to the principles enunciated in this order and any supplemental orders. If further work on a plan is needed, the

> Commission will return it to the utility with comments. This process should eventually lead to acknowledgment of the plan. Acknowledgment of a plan means only that the plan seems reasonable to the Commission at the time the acknowledgment is given. As is noted elsewhere in this order, favorable rate-making treatment is not guaranteed by acknowledgment of a plan.
> Order No. 89-507 at 6 and 11.

This order does not constitute a determination on the rate-making treatment of any resource acquisitions or other expenditures undertaken pursuant to IPCo's 2004 IRP. As a legal matter, the Commission must reserve judgment on all rate-making issues. Notwithstanding these legal requirements, we consider the least-cost planning process to complement the rate-making process. In rate-making proceedings in which the reasonableness of resource acquisitions is considered, the Commission will give considerable weight to utility actions which are consistent with acknowledged least-cost plans. Utilities will also be expected to explain actions they take which may be inconsistent with Commission-acknowledged plans.

Conclusion

IPCo's 2004 IRP is acknowledged with the recommendations adopted in this Order. The plan meets both the procedural and substantive requirements of Order No. 89-507. Achievement of the objectives in the Company's Near-Term 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 variance of costs.

ORDER

IT IS ORDERED that the 2004 Integrated Resource Plan filed by Idaho Power Company on August 30, 2004, be acknowledged in accordance with the terms of this order and Order No. 89-507.

Made, entered, and effective JUN 17 2005.

Lee Beyer
Chairman

John Savage
Commissioner

Ray Baum
Commissioner

PUBLIC UTILITY COMMISSION OF OREGON

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order to a court pursuant to applicable law.