

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER)	
COMPANY'S APPLICATION FOR A)	CASE NO. IPC-E-09-03
CERTIFICATE OF PUBLIC CONVENIENCE)	
AND NECESSITY FOR THE LANGLEY)	
GULCH POWER PLANT)	ORDER NO. 30892

On March 6, 2009, Idaho Power Company (Idaho Power; Company) filed an Application with the Idaho Public Utilities Commission (Commission; IPUC) for a Certificate of Public Convenience and Necessity (Certificate; CPCN) authorizing construction of the Langley Gulch Power Plant (Project) and inclusion of the Project in the Company's rate base. *Idaho Code* § 61-526, -528; RP 112. An electrical corporation is prohibited from beginning the construction of a generating plant without having first obtained from the Commission a certificate that the present or future public convenience and necessity require or will require such construction. *Idaho Code* § 61-526. The Company further requests that the Commission include in its Order issuing a Certificate cost recovery and ratemaking assurances. *Idaho Code* § 61-541.

On March 19, 2009, the Commission issued a Notice of Application, Intervention Deadline and Prehearing Conference. Intervention was granted to the Industrial Customers of Idaho Power (ICIP); Invenergy Thermal Development LLC; Idaho Irrigation Pumpers Association, Inc. (IIPA); Snake River Alliance (SRA); and Idaho Conservation League (ICL). Following the April 15, 2009 prehearing conference Invenergy Thermal Development LLC withdrew and the following additional parties were admitted as intervenors: Northwest & Intermountain Power Producers Coalition (NIPPC) and Community Action Partnership Association of Idaho (CAPAI). An evidentiary and technical hearing was held in Boise on July 14-16, 2009. A public hearing was held the evening of July 14. The deadline for filing written comments was July 24. The deadline for post-hearing filings by the parties was July 31, 2009.

The Commission in this Order grants a Certificate of Convenience and Necessity authorizing the construction of Langley Gulch and provides related cost recovery and ratemaking assurances. *Idaho Code* § 61-541. We deny Intervenors' Motion for Stay and grant intervenor funding awards to the Community Action Partnership Association of Idaho, the Idaho Conservation League and the Idaho Irrigation Pumpers Association, Inc. *Idaho Code* § 61-617A.

APPLICATION

A. The Langley Gulch Power Plant

Idaho Power requests a CPCN and authority to construct, own, operate and maintain the Langley Gulch Power Plant. The Project is a natural gas-fired combined-cycle combustion turbine (CCCT) generating plant with a nameplate capacity of approximately 330 MW. Gale, Tr. pp. 147, 148. The Company proposes to construct the Project on a 137-acre parcel of land on the south side of Interstate 84 in Payette County approximately four miles south of the town of New Plymouth, Idaho. Porter, Tr. p. 439. The Project's power plant consists of a combustion turbine (Siemens SGT-5000F) and a steam turbine (Siemens SST-900). The plant is designed to be water-cooled and equipped with state-of-the-art emission control equipment. Sterling, Tr. p. 1071.

B. Future Necessity and 2006 Integrated Resource Plan

The Project is a baseload generating resource of the size and type identified as the preferred resource in the Company's June 2008 update to its 2006 Integrated Resource Plan (IRP). Bokenkamp, Tr. p. 262; Exh. 101. The Project was selected as a result of a competitive process (Request for Proposals or RFP) in which the Company solicited proposals from independent power supply developers. The proposals were compared to each other and to a utility-owned and operated CCCT (Benchmark Resource). The Langley Gulch project is the Benchmark Resource and is scheduled to be available to meet peak loads in 2012.

C. Capital Cost Commitment Estimate

Idaho Power's Commitment Estimate for the Project is \$427,400,000 and includes the power plant and two related transmission projects (2.5 miles Ontario-Caldwell; 18 miles Caldwell-Willis). On a 20-year net present value (NPV) basis the Project is estimated to have a revenue requirement impact approximately \$95 million lower than the next least expensive proposal in the Company's RFP process. Smith, Tr. p. 22.

The Company commits to procure and construct the Project for an amount that will not exceed the Commitment Estimate. Idaho Power requests that amounts incurred in excess of the Commitment Estimate be subject to a "soft cap"; that is, excess costs could be included in rates only if the Commission agrees the additional amounts expended are prudent and that it is fair, just and reasonable to include them in rates.

The Company commits to provide the Commission with periodic percentage of completion reports and cost expenditure reports during the construction phase of the Project. The final report on the Project will compare the actual completed cost to the Commitment Estimate.

D. Fuel Cost

A major component of the operating cost of a combined-cycle combustion turbine generating plant is the cost of natural gas fuel. The Company states that it currently owns, or will acquire, firm fuel transportation rights that can be utilized by the Project. As part of its Application, the Company is requesting that the Commission's Order issuing the Certificate of Public Convenience and Necessity also authorize Idaho Power to recover the Project's prudently incurred costs for fuel, fuel storage and fuel transportation through the Company's Power Cost Adjustment (PCA) mechanism.

E. Cost Recovery and Ratemaking Assurances

In its Application for a Certificate, Idaho Power requested that the Commission include in its Order authority for the Company to utilize either or both of two alternative ratemaking treatments that will put the Company in the best position to finance this project. The first requested ratemaking treatment would allow the Company to annually collect construction work in progress (CWIP) in its rates for all, or a portion of, the construction expenditures the Company incurs as it moves forward with construction of the Project (*Idaho Code* § 61-502a). Alternatively, the Company requests that the Commission apply specific ratemaking treatment that the Company can rely upon when the Project is completed and providing service to customers. The second alternative ratemaking treatment proposal requested by the Company was pursuant to the construction cost recovery legislation then being discussed by the 2009 Idaho Legislature (Senate Bill 1123). The Legislature subsequently passed Senate Bill 1123 and the Governor signed the Bill into law as *Idaho Code* § 61-541 – Binding Ratemaking Treatment.

Until the Commission issues a Certificate with pre-approved (binding) ratemaking treatment and related provisions (*Idaho Code* § 61-541), the Company states it cannot prudently proceed with the Project. As a result, the commercial operation date of the Project is directly related to the issuance of a Certificate, including the necessary cost-recovery ratemaking commitments. To the extent the Commission can expedite its review of the Application, the

Company contends that it will benefit customers and system reliability. The Company requests a Commission Order by September 1, 2009.

JOINT MOTION FOR STAY

On May 29, 2009, a Joint Motion to Stay Proceedings in Case No. IPC-E-09-03 for at least 10 months was filed by the Industrial Customers of Idaho Power, Idaho Irrigation Pumpers Association, Snake River Alliance, Idaho Conservation League, and Northwest & Intermountain Power Producers Coalition (collectively Movants).

The Movants contend that significant and unforeseen events have taken place since Idaho Power initially filed its Application. Any single one of these events, they contend, would be sufficient to cause reasonable persons to seek to slow down the Company's forced march to seek Commission action on its request for a Certificate. They further contend that when taken in concert, the cumulative effect of the following events makes a stay of this proceeding critical. The events cited by the Movants are the following:

- Pursuant to a shareholder resolution at a recent meeting of Idaho Power stockholders, Company management has committed to develop a greenhouse gas reduction strategy report by September 30, 2009.
- Pursuant to Idaho Power Petition, the filing date for the Company's 2009 Integrated Resource Plan was extended from June 2009 to December 31, 2009. Case No. IPC-E-09-13, Order No. 30815.
- Authorized recovery of project costs under new Idaho legislation (*Idaho Code* § 61-541) makes the Commission's decision in this case one of the most far-reaching in Idaho PUC history.
- A softening of the market for gas turbines should enable the Company to renegotiate contract penalty provisions for delay.
- Idaho Power has already delayed the plant's on-line date beyond the time necessary to meet the summer load of 2012, i.e., until December 2012.
- The continued unprecedented recession will have direct impact on immediacy of need for new power plants.
- Other regional utilities (e.g., PacifiCorp) are mothballing planned expansions.
- The impacts of recent changes in Idaho Power's demand response programs have yet to be ascertained.

On June 12, 2009, Idaho Power Company filed its Answer to the Joint Motion for Stay. The Company characterizes the points raised within the Motion for Stay as a “collection of speculation, conjecture, and unfounded assumptions.” Delay in a decision, the Company contends, puts the viability of the Langley Gulch project at risk. All concerns raised by the Intervenor, the Company states, fall within the umbrella of issues identified by the Commission in its April 20, 2009, Notice of Issue Identification and can be presented to the Commission in testimony and exhibits under the procedural schedule and timeline adopted for hearing and decision in this case. The Company in its Answer continues to maintain that Langley Gulch is a needed resource to provide adequate and reliable electric service to its customers. Its commitment to shareholders to provide a report on its greenhouse reduction strategy, it states, does not affect its greater obligation to provide service. Its decision to defer the filing of its 2009 IRP, it states, does not reflect uncertainty as to the need for Langley Gulch. Even with enhanced DSM program participation, the Company still forecasts substantial capacity and energy shortfalls. To stay proceedings and push the decision date beyond September 1, 2009, the Company states, will result in very real monetary consequences placing the Company at risk for cancellation fees and lost deposits totaling \$25.5 million.

In its consideration of the Motion, the Commission acknowledged that there is some information that will inform the Commission’s decision in this case that will not be available until after the scheduled hearing date and the proposed September 1, 2009, date for the Commission Order. However, the Commission determined that it would not allow that uncertainty to paralyze it. Order No. 30848 (June 19, 2009). The Commission found it reasonable to continue with the established scheduling and to build an informed record for decision. The Movants at their discretion were invited to renew their Motion for Stay as a preliminary matter at the beginning of hearing.

Renewed Motion

The Motion to Stay was renewed at the beginning of the technical hearing. The Commission took the Motion under advisement for discussion at a later time as requested by the Movants, and proceeded with the hearing. Tr. p. 18. In a Joint Renewed Motion and Post-Hearing Brief filed on July 31, 2009, the Community Action Partnership Association of Idaho joined the other movants. On August 11, 2009, Idaho Power filed an Answer to the Renewed Motion.

Movants in their Renewed Motion contend that the Company failed to fully comply with the Commission's December 2006 direction in Case No. IPC-E-06-09 (Evander Andrews), Order No. 30201, to "vigorously pursue all available, cost effective DSM, conservation, and pricing options that could potentially displace or defer the need for additional future peaking generation." As a consequence, Movants contend that the public has been, and continues to be, ill-served and continues to bear risks for unnecessary future supply-side investments.

Movants cite Ninth Circuit case, *Seattle Master Builders Association v. Pacific Northwest Electric Power & Conservation*, 786 F.2d 1359 (9th Cir. 1986), as providing a definition for "cost effective conservation." The Court adopted a definition of "cost-effective" conservation measures as being all such measures with a marginal cost less than the cost of the generating resource to be acquired. Movants contend the record established through public witness Exhibit 901, shows that the levelized cost estimate for a combined-cycle combustion turbine (CCCT) is \$0.126/kWh. The testimony of Company witness Pengilly, Movants contend, shows that not only has the Company not implemented all conservation measures costing less than \$0.126/kWh, it has yet to even compile a list of all such opportunities. Public Witness Exh. 901, pp. 10-11.

Movants contend that the Company's purchase of equipment (turbines) in advance of obtaining a Certificate is in direct violation of *Idaho Code* § 61-526 which states:

No . . . electrical corporation . . . shall henceforth begin the construction of a plant . . . without having first obtained from the commission a certificate that the present or future public convenience and necessity require or will require such construction.

Movants contend that the Company's forecast used to justify the need for a baseload resource in 2012 stands in sharp contrast to declines in actual demand (June 2008/March 2009) and economic trends that have developed in the last year and half. The only forecast data that the Company has offered since the recession began is the May 2009 forecast and that data, Movants contend, was only updated for the Company's special contract customer load. The economy is what the economy is, they state, and is most certainly not what Idaho Power "forecast" it to be.

The Movants have not taken the position that Langley Gulch will never be needed, simply that the economy has caused a slippage in the time of that "need."

Movants contend that regulatory preapproval of the “Commitment Estimate” under *Idaho Code* § 61-541 is unnecessary. They recommend no more binding regulatory preapproval commitment than the “regulatory compact” provision previously established by the Commission when noting:

. . . In the ordinary course of events, the Company may expect its investment . . . to be recognized in its revenue requirement barring unforeseen circumstances. . . .

Order No. 25021, p. 13 (IPC-E-91-4, Twin Falls Upgrade).

. . . A certificate does not guarantee a utility recovery when it ignores or defies the laws of economics by continuing to invest in plants no longer necessary or prudent because demand has fallen from projections . . . because costs have escalated beyond reasonable expectation . . . because technology has changed . . . or when management, operation or construction of a project is beyond the utility’s control and under the direction of others.

Id., p. 13.

. . . The ultimate decision determining the appropriate amount of . . . investment to include in revenue requirement will, of course, be made during the course of a general rate proceeding or a tracker proceeding initiated for that purpose.

Id., pp. 13-14.

To give greater assurance, Movants contend, is not supported by the Company’s load forecast, which they contend, is significantly in error.

Recommending delay, the Movants contend that the Commission should require analyses on how much of the need for additional energy or capacity could be eliminated through cost-effective efficiency and DSM expenditures and the effect of price elasticity on future demand. Movants contend that the Company’s RFP process was flawed. They urge the Commission to proceed with a generic competitive bidding docket and to adopt transparent bidding guidelines.

Idaho Power Answer

In answer to the Renewed Motion to Stay, Idaho Power contends that the delay requested by Movants is not 10 months. Based on the relief requested, the delay could extend to years – i.e., review and accept the 2009 IRP; to conduct a formal proceeding to develop new

generic guidelines for competitive bidding; and then to issue a new RFP. A delay of this sort, the Company contends, exposes the utility and its customers to substantial risk.

Long lead-time resources, such as Langley Gulch, the Company states, take at least three years to construct. The Company contends that it cannot wait until it absolutely positively knows what its loads will be at a point in the future before it acts. It must rely on a forecast of loads and a portfolio of resources to strike a load and resource balance that will allow it to satisfy its legal obligation to serve and to do so at the lowest reasonable cost consistent with prudent utility planning criteria.

Intervenors argue the Commission should examine whether the Company's 2009 actual loads are lower than they were in 2008 rather than focusing on the Company's forecast loads for 2012. The Company points out there are numerous reasons why actual loads in 2009 might be lower, the recession being only one. Other reasons include precipitation, temperature, commodity prices and shifting world markets for computer chips and polysilicon. The more reasonable approach, Idaho Power argues, is to assess how well the Company has done recently in forecasting its future loads. See Company Post-Hearing Response to Commission Data Request. E.g., for the entire month of July, average system load was 1865 aMW (1,387,374 MWh), which is just 24 aMW lower than predicted in the May 2009 load forecast (1,405,565); and on July 22, 2009, the hourly average system load (without the impact of demand response programs) reached 3,136 MW. Evidence presented by the Company, it contends, demonstrates a continuing need for Langley Gulch in 2012. Bokenkamp, Tr. pp. 281-282; Exh. 10.

The Intervenors recommended strategy, the Company argues, is based on the assumptions that:

1. The current recession will cause the Company's loads to remain flat for an unknown but extended period of time.
2. The Company can acquire all the resources it needs for the next few years from DSM and renewable resources.
3. The Company can continue to rely on its ability to purchase a substantial amount of power from surplus generation sellers located in the Pacific Northwest and the Desert Southwest to be delivered using non-firm transmission on the existing transmission system.

In contrast, Idaho Power contends that to provide adequate reliable service in 2012, the Company needs to immediately move to add a baseload resource located near its Treasure Valley load center.

The risk profiles of the two competing strategies, the Company contends, are asymmetrical. If the Company constructs Langley Gulch, there is a risk that in 2012 not all of the output will be needed to serve native load. This risk is mitigated by the opportunity to sell surplus energy in the wholesale market, the increased reliability Langley Gulch will provide and reducing reliance on non-firm transmission to deliver more expensive wholesale purchases.

The Company contends that, if Langley Gulch is delayed, any new large customers seeking to locate plants or facilities in Idaho Power's service territory must be advised that the Company does not have firm resources sufficient to serve their loads on a year-round basis and that future additional firm resource availability is uncertain. If the resource is delayed, the Company will be forced to continue to rely heavily on the use of non-firm transmission to serve critical summer loads and the risks associated with that will be exacerbated and the risk of reduced reliability and load curtailment will increase. Finally, if the resource is delayed and in 2012 and thereafter, the Company experiences adverse water conditions, extraordinarily high temperatures, forced outages at distant generating plants, loss of transmission capability, loop flows, or any combination of these risks, the Company contends service to customers may have to be curtailed.

Should Intervenor's request for stay be granted, the Company prepared and offered Confidential Exhibit 26 identifying an escalating scale of cancellation fees (Siemens combustion and steam turbines) associated with delay beyond September 1, 2009. Also affected by a delay would be the Company's contract for Engineering, Procurement and Construction (EPC) services with Boise Power Partners Joint Venture (consisting of Kiewit Power Engineers Company and TIC – The Industrial Company).

Commission Findings

The Commission has considered the arguments advanced by Intervenor in their Motion for Stay and for reasons set forth elsewhere in this Order finds them global in nature but unpersuasive on balance. After reviewing the established record in this case, we find that the public interest is not served by delay. Intervenor contend that we should await the Company's 2009 IRP; we should wait to see the impact of changes to the Company's demand response

programs; we should wait for the Company's response to shareholders regarding greenhouse gas emissions; in lieu of a new generation resource we should require more demand-side management, energy efficiency, conservation and pricing options; and we should proceed with the generic competitive bidding docket, adopt transparent bidding guidelines and require the Company to issue a new RFP. We find the risk of reducing electric service is too great to allow the delay that is proposed.

There are parts and pieces of information that are not now known. However, based on the information presented at the hearing, we find substantial evidence to support the decision to grant the Certificate requested. To bring a baseload generation unit on-line requires a lead-time of two-and-one-half to three years and requires a resource commitment and action well in advance of projected date of need. The Company has a statutory obligation to provide electric service and, since 2004, has forecast a need for a baseload generation resource in 2012. Even with a change in the nature of the generation resource itself, and a more recent load forecast to accommodate recent economic conditions, the Company continues to forecast a June-December 2012 need. The 2012 date is now the earliest date the Company can bring a baseload resource on-line. For reasons expressed elsewhere in this Order when addressing need, the Commission's decision is that Company's resource should not be delayed and thus we deny the Motion for Stay.

HEARING

An evidentiary hearing was held on July 14-16, 2009. Pursuant to Rule 67, the parties entered into a Protective Agreement regarding the disclosure and treatment of confidential information and trade secrets. IDAPA 31.01.01.067. The following parties of record appeared:

Idaho Power Company	Barton L. Kline Lisa D. Nordstrom
Industrial Customers of Idaho Power	Peter J. Richardson
Idaho Irrigation Pumpers Association, Inc.	Eric L. Olsen
Snake River Alliance	Ken Miller
Idaho Conservation League	Betsy Bridge

Northwest & Intermountain Power
Producers Coalition

Susan K. Ackerman

Community Action Partnership
Association of Idaho

Brad M. Purdy

Commission Staff

Scott Woodbury

The Commission has reviewed and considered the filings of record in Case No. IPC-E-09-03 including the Application and the public and confidential transcript of proceedings. We have also reviewed the below referenced Orders, statutes and rules regarding Integrated Resource Planning, intervenor funding, Certificates of Public Convenience and Necessity, CWIP and AFUDC, and Binding Ratemaking Treatment. We address and discuss the Company's case and the positions of parties in the following section.

ISSUES AND FINDINGS

Need for Resources

The Company's Integrated Resource Plans (IRPs) are filed pursuant to a biennial requirement established in Commission Order No. 22299, Case No. U-1500-165. The IRP describes the Company's growing customer base, load growth, supply-side resources, demand-side management (DSM) and risk analyses. The IRP contains information regarding available resource options, planning period forecasts, potential resource portfolios, a 20-year resource plan, and a near-term action plan. As noted by the Company in this case, the IRP is the basis for establishing the need for acquisition of additional resources – supply-side (generators and market purchases); demand-side (energy efficiency or demand response programs); and transmission lines. Bokenkamp, Tr. p. 261.

Idaho Power traces its present need for a baseload generating resource to its 2004 IRP preferred portfolio which then identified need for a 500 MW baseload pulverized coal-fired resource in 2011. Bokenkamp, Tr. p. 261. On September 24, 2006, Idaho Power filed its 2006 IRP. In response to uncertainty surrounding potential carbon legislation, Idaho Power re-assessed its need for new resources. The Company's 2006 IRP preferred portfolio identified the following resource needs:

- 225 MW power purchase – McNary to Boise transmission upgrade 2012
- 250 MW pulverized coal-fired baseload resource – 2013
- 250 MW regional integrated gasification combined cycle turbine (IGCC) – 2017

Bokenkamp, Tr. p. 261.

Following its 2006 IRP, the Company took note of escalating public concerns regarding climate change, greenhouse gas emissions, and changing public perceptions regarding the acceptability of coal-fired generation resources. Faced also with the possibility of several new large industrial/commercial loads in the 2009-2012 time period and a shifting of hydro flow augmentation releases from federal dams above Brownlee that would reduce levels of hydro-generation available during peak demand summer months by 140 aMW, the Company updated its 2006 IRP. The December 2008 update revised the 250 MW pulverized coal-fired baseload resource to a natural gas-fired baseload resource located closer to its load center in southern Idaho, increased the size of the resource to 300 MW and accelerated the on-line date of the resource need from 2013 to 2012. Bokenkamp, Tr. p. 262.

In Order No. 30281 issued on March 26, 2007, the Commission found that receiving each electric utility's IRP within a narrower time frame would improve the overall planning process and assist in regional planning efforts. Exh. 27. The Commission directed Idaho Power to file a brief report containing suggestions on how its IRP may be coordinated with the IRP filings of Avista and PacifiCorp dba Rocky Mountain Power. On May 10, 2007, Idaho Power filed its Letter Report.

On May 23, 2007, the Commission directed Idaho Power to file its next full IRP no later than last business day of June 2009. The Company was also directed to provide the Commission a transitional IRP update in June 2008 addressing the progress of the Company's short-term action plan; any changes in its load forecast, existing loads, customer base and purchase power contracts; and any significant deviations from its 2006 IRP. On June 20, 2008, Idaho Power filed its 2008 IRP update.

On April 24, 2009, Idaho Power filed a Petition requesting authority to defer the filing of its 2009 IRP from June 30, 2009 to December 31, 2009 (Case No. IPC-E-09-13). The Company cited two significant changes occurring since completion of its 2008 update that made it desirable to delay the filing of its 2009 IRP: (1) a permitting delay in its proposed Boardman-Hemingway (B2H) transmission project, an identified near-term (2012) resource and (2) slowed local and national economic growth necessitating an update to its sales/load forecast. By Order No. 30815, the Commission granted the Company's Petition.

Staff contends that a new baseload generation plant is justified based on the information and analyses in the Company's 2006 IRP and 2008 IRP update, the Company's load resource balance under various water and load conditions, and transmission constraints that limit the Company's ability to import power during critical times of the year. Sterling, Tr. p. 1031; Exh. 101-105.

Staff in its analysis considered the availability to the Company of other resource alternatives, e.g., non-Company owned generation, conservation, demand response programs and transmission upgrades. Staff concluded that while such alternatives may be truly viable, they cannot be relied on exclusively and should be pursued in conjunction with and not instead of Langley Gulch. Sterling, Tr. p. 1021.

- In its 2006 IRP planning process the Company, Staff states, considered upgrades to hydro, gas-fired thermal generation options (SCCT and CCCT), clean coal options (IGCC), super-critical pulverized coal, nuclear, geothermal and a wide variety of DSM options. Sterling, Tr. p. 1041.

- PURPA projects, Staff contends, cannot be planned on by the Company as a reliable option for meeting baseload needs – citing contract wind and geothermal on-line delays. Sterling, Tr. p. 1042. From 2005 to the present, PURPA QFs with a total capacity of 175.5 MW have signed contracts with Idaho Power but have yet to come on-line. A total of 21.6 MW of signed contracts have been terminated during this same time period. Projects with a capacity of 107 MW have come on-line. Sterling, Tr. pp. 1028-1029. Planned amounts of geothermal power, Staff notes, have also failed to materialize. In a 2006 RFP, a bid was accepted by Idaho Power to provide 45.5 MW and have facilities on-line between October 2007 and January 2011. So far only 13 MW have been developed, and contracts for the remaining have not been executed. In 2008, the Company issued another RFP seeking 50-100 MW of additional geothermal. No contracts have been signed. Sterling, Tr. p. 1029.

- Firm wholesale purchases –

Firm purchases of wholesale power by the Company, Staff states, require necessary transmission. Long-term reliance on eastside transmission capacity for baseload or peak hour needs is probably not feasible, Staff contends, until completion of the planned Gateway West transmission project (500 kV across southern Idaho and Wyoming). Any use of import capacity

for purchases, Staff notes, also makes it unavailable in the event of a system emergency. Sterling, Tr. p. 1044.

- Relying on the market as an alternative to building new generation, Staff contends, carries greater risk and the potential for price volatility. Staff notes as does the Company that there are transmission constraints on imports from the Northwest that make locating new generation near its load center a prudent planning decision. Sterling, Tr. p. 1044.

- Transmission upgrades, Staff contends, are not an alternative to a new baseload power plant – they are a necessary component. Sterling, Tr. p. 1045. Staff notes the following recent upgrades and planned transmission projects:

Brownlee to Oxbow (completed late 2003)
Increased Brownlee east capacity by 100 MW

Borah-Westpath (completed May 2007)
Increased Borah-West transmission capacity by 250 MW

The Boardman to Hemingway (B2H) 500 kV project included in the 2006 IRP preferred portfolio for 2012 would increase transmission capacity from the Northwest by 225 MW – this project has been delayed to 2015.

Gateway West project
Plan to build more than 1,000 miles of 500 kV transmission from Glenrock, Wyoming to Melba, Idaho.

Sterling, Tr. pp. 1045-1046.

- Conservation

A diverse resource portfolio, Staff contends, should include cost-effective energy conservation. Tr. p. 1046. Idaho Power for long-term planning of energy conservation and demand response programs, Staff states, relies on the IRP process, consultation with the energy efficiency advisory group and participation in regional energy efficiency organizations. Sterling, Tr. p. 1046.

Staff believes that the Company has strengthened its commitment to achieving all cost-effective energy efficiency and demand response potential. Sterling, Tr. p. 1047. Conservation programs by themselves, Staff contends, cannot achieve enough demand reduction to realistically satisfy the Company's immediate need to meet growing loads. Sterling, Tr. p. 1047.

Intervenors

The Intervenors have not taken the position that Langley Gulch will never be needed – simply that the economy has caused a slippage in that “need.” Renewed Motion to Stay, p. 10. Intervenors, however, contend that the Company, in violation of Commission mandate, has not fully complied with the Commission’s direction in December 2006, to “diligently and vigorously pursue all available cost effective DSM, conservation and pricing options that could potentially displace or defer the need for additional future peaking generation.” Case No. IPC-E-06-09 (Evander Andrews), Order No. 30201. Renewed Motion, p. 2. Intervenors cite a 1986 Ninth Circuit Court opinion for its contention that “cost-effective” conservation measures are all such measures with marginal costs less than the cost of a generating resource to be acquired.” In this proceeding, Intervenors accept the record indicating the [estimated] levelized cost of [a combined-cycle combustion turbine] to be \$0.126/kWh. Intervenors then note that in the case of Langley Gulch, not only has the Company not implemented all conservation measures costing less than \$0.126/kWh, it has yet to even compile a list of all such opportunities. *Citing* Pub. Exh. 901, p. 11. Renewed Motion, pp. 2-3.

CAPAI’s witness Teri Ottens representing the low-income sector contends that Idaho electricians are not pursuing aggressively enough cost-effective low-income weatherization. Tr. p. 931. Out of 10,000 LIHEAP-eligible households in the state, she states, only 1,500 have actually been weatherized. Ottens, Tr. pp. 932, 944.

Idaho Power Response to Intervenors

Idaho Power disagrees with criticism of its commitment to energy efficiency and DSM. The Company contends that it is pursuing all cost-effective efficiency and DSM programs; some programs, however, it states, take years to develop and market. It also takes customer participation. Pengilly, Tr. p. 777. The Company’s DSM programs continue to ramp up slowly. As participation increases, the Company expects that the effect of DSM on the load/resource balance will be greater and could have an impact on resource timing. Pengilly, Tr. p. 781. Right now, the Company offers a demand response program to all of its customer classes except small commercial. Pengilly, Tr. p. 767. Company witness Pengilly estimates 312 MW of DSM by 2013, 8% of forecasted peak demand. Ottens, Tr. p. 941.

Regarding use of the alleged levelized cost of a combined-cycle combustion turbine (\$0.126/kWh) as a measure of cost-effective programs, the Company states that it does consider levelized costs in its analysis, but a program or a measure can have a high or a low levelized cost and still not be cost-effective. Pengilly, Tr. pp. 770-771. The Company bases its cost-effectiveness analysis and tests on the California Manual and the EPRI Tag Manual. It believes a better approach than the metric proposed by the public witness, Michael Heckler (Exhibit 901), is to determine cost-effectiveness first and then look at the levelized cost. Pengilly, Tr. p. 771, *see* Company description of cost-effective, Pengilly, Tr. pp. 773-775. The Company notes also that the avoided costs derived from the IRP and AURORA process is more robust than a simple comparison to single plant. Pengilly, Tr. p. 778.

Load Forecast/Timing

Consistent with its 2006 IRP, 2008 update and revised load forecasts in December 2008 (residential and commercial) and May 2009 (special contracts); Idaho Power forecasts the need for an additional baseload resource in 2012. Bokenkamp, Tr. pp. 260; 281. The primary driver of the need for the resource, the Company states, is load growth. Bokenkamp, Tr. p. 260. Langley Gulch, the Company contends, is expected to operate as an energy and capacity or “baseload” resource, following load and providing additional up and down regulation capability. The need for the resource will be greatest during summer peak load hours. Bokenkamp, Tr. p. 290.

The Company’s May 2009 load forecast (Exhibit 10) incorporates updates to special contracts (customers with loads greater than 25 MW) and includes the most recent estimates of peak-hour contribution from the Irrigation Peak Rewards Program, the A/C Cool Credit Program and large commercial DSM. It also includes updated levels of firm import capability from the Pacific Northwest (114 MW) and wholesale firm energy purchases capable of being delivered to the Company’s eastside. Bokenkamp, Tr. p. 280. Exhibit 10 does not include the recently acquired flexibility to reduce Hoku (an industrial special contract customer) loads by 39 MW between June 15, 2012 and August 15, 2012. Bokenkamp, Tr. p. 282.

Idaho Power uses two primary criteria in its planning to assess the need for new resources – one is based on energy needs and the other is based on capacity needs. Based on its May 2009 load forecast, the Company projects significant peak-hour deficits during July for the years 2009-2012 of 166 MW, 40 MW, 132 MW and 18 MW respectively; assuming Langley

Gulch is on-line. Bokenkamp, Tr. p. 280. The peak-hour load and resource balance assumes that the Company's existing natural gas-fired peaking facilities are in operation and contributing 416 MW. Bokenkamp, Tr. p. 286.

From an average energy perspective, using the May 2009 load forecast and the aforementioned assumptions, the Company projects average energy deficits during July for the years 2009-2012 of 365 aMW, 368 aMW, 421 aMW and 285 aMW respectively; assuming Langley Gulch is on-line. Bokenkamp, Tr. pp. 280-281. From an economic perspective, the Company notes that peakers are typically the last resource to dispatch. If operated for a full half-month the peakers would reduce the July 2012 deficit by 200 aMW. Bokenkamp, Tr. p. 286.

On a planning basis, if Snake River base flows continue to decline, Idaho Power's energy position will deteriorate. And if carbon legislation forces the Company to reduce the output of its coal-fired facilities, it will deteriorate even further. Bokenkamp, Tr. p. 289; Exh. 10.

The amount of energy the Company expects to have available from Langley Gulch for planning purposes at a capacity factor of 84% is 251 aMW. Bokenkamp, Tr. pp. 293; Yankel, 999. If future load forecasts indicate reduced loads in 2012, the Company states it will be well positioned to reduce its historic reliance on energy imported from the Pacific Northwest; to better integrate fluctuations of wind generation; and to deal with carbon legislation. Bokenkamp, Tr. p. 291.

The Company consultant, Michael Mace, states that Idaho Power, like any other utility planning for resources with long-lead times, is necessarily engaged in decision-making under uncertainty. Mace, Tr. p. 62. The Company's August 2007, August 2008, and May 2009 load forecasts, he states, were all reasonable when made. Mace, Tr. p. 62. The Company's load forecast has progressively reflected a slowing economy. Mace, Tr. p. 64; Exh. 15. To assist in its forecasting following the economic downturn in the fall of 2008, the Company contracted with Moody in April 2009 to provide macro-economic forecast data for Idaho counties as well as its two major service centers (Boise/Pocatello). Mace, Tr. p. 74; Exh. 21-25. Idaho Power bases the reasonableness of its May 2009 forecast and rather robust recovery on Moody's evaluation. Mace, Tr. p. 102. Moody's expects the economy to show signs of improvement by 2010. Exh. 16.

There is uncertainty in any forecast, the Company states. Mace, Tr. p. 112. In the forecasting process, a critical issue is the timing of the forecast with regard to the lead-time requirements of the planning process. Mace, Tr. p. 115. The Company opines that if we delay, thinking we are going to reduce uncertainty, we may find ourselves with even more uncertainty later on. Mace, Tr. pp. 109, 126, 127.

Staff finds the Company's information, analysis and forecasting in its 2006 IRP and 2008 IRP update to be reasonable and the baseload plant justified. Staff acknowledges that significant changes have occurred since the Company's 2006 IRP was prepared – e.g., economic recession and stalled load growth in nearly all customer sectors. Sterling, Tr. p. 1031.

Staff notes, however, that in December 2008 the Company acknowledged the financial downturn and adjusted the residential and commercial sector load forecast to reflect a prolonged slowdown in housing and consumer spending. Residential new customer growth rates (initially forecast to decline until the first quarter of 2009) were forecast by Idaho Power to continue to decline into 2010 and then rebound to the point of the original new customer forecast in 2011. On a total customer (new plus existing) basis, the Company's revised forecast returns to the same value as the original forecast in 2016. Commercial customer growth estimates were lowered consistent with adjustments made to the residential class. Per-customer use forecasts were not modified. Sterling, Tr. p. 1032. In May 2009, the Company further revised its load forecast to incorporate changes in special contract forecasts. In addition, the Company updated its forecast to also include all DSM program peak hour impacts as of May 2009. The Company's most recent load resource balance based on energy and peak hour planning criteria is depicted in Staff Exhibit 104 and Company corrected Exhibit 10 (July 2012 – average energy (123 aMW); peak hour (18 MW)).

Staff continues to believe that a baseload plant will be needed in the approximate time frame planned. Sterling, Tr. pp. 1031; 1037. Because construction of a CCCT has an approximately three-year lead-time, Staff contends the Company does not have the luxury of waiting to see how a recovery from the recession will unfold before making the decision to proceed. Sterling, Tr. p. 1037. For projects with long lead times, there is always uncertainty that the project will be required at exactly the planned on-line date. Sterling, Tr. p. 1035. The risks of an early on-line date versus a late on-line date, Staff argues, are not symmetrical; with the costs and risks of waiting far exceeding the financial consequences of bringing a plant on-line

early. Sterling, Tr. pp. 1036-1037. Doing nothing until there is more certainty, Staff contends, is a very risky strategy and in Staff's opinion is simply not a viable option. Sterling, Tr. p. 1038.

As reflected in the Renewed Motion, the difference between the Company and Intervenor with respect to forecast and actual demand stands in sharp contrast. The divergent views are based upon the Company's use of "forecast data" and the Intervenor's reliance on "actual information." Renewed Motion, p. 7. Every forecast of the Company, Intervenor state, shows that its loads will be increasing; this despite a steady decline in actual load over the last nine months (June 2008-March 2009). Intervenor state that they have never contended that the Company's forecasts were unreasonable. Renewed Motion, p. 8. The decision to build Langley Gulch, IIPA contends, was based upon data that is now outdated and thus inappropriate. Yankel, Tr. p. 951. Intervenor contend that blind adherence to forecast data in the face of drastically different actual data does not provide a sound basis for decision-making. Renewed Motion, p. 7. The economy is what the economy is, they state; and is most certainly not what Idaho Power forecasts it to be. Renewed Motion, p. 9. ICIP believes that the economy is still in a state of flux and does not see it turning around rapidly. Reading, Tr. p. 794. Given recent quarterly economic forecasts made by the Idaho Division of Financial Management (DFM), IIPA contends that the growth projections forecast by Idaho Power to justify the need for Langley Gulch will not be realized. Yankel, Tr. p. 952. The Company's recent forecasts, IIPA argues, are not aligned with the economic downturn, are internally inconsistent and ignore the Company's ability to import energy. Yankel, Tr. p. 952. Langley Gulch, IIPA contends, it will not be needed in the time frame specified in the Company's IRP. Yankel, Tr. pp. 953-957. The Irrigators see no adverse impact to postponing the decision for 10 months, at least until the Company updates its load forecast. Yankel, Tr. pp. 952-954. The Irrigators (and Intervenor) are incredulous that the Company continues to forecast increasing loads. The change in economic outlook, they state, is evidenced by comparison of Company's 2006 IRP forecast with actual, e.g.,

Residential customer count	Commercial customer count
Forecast increase in 2008 – 10,423	Forecast increase in 2008 – 1,785
Actual – 3,736	Actual – 1,360

Yankel, Tr. pp. 965-967.

The Company's 2008 update IRP, Irrigators point out, merely states:

Recent cyclical slow down in customer growth, as indicated in total number of customers for year-end 2007 is approximately three-tenths of a percent lower than forecast (0.3%). The effect of the cyclical downturn on the longer term trend will be evaluated for 2009 IRP.

Neither the forecast data for the 2006 IRP nor the 2008 update IRP, IIPA states, reflect any major economic change. The 2008 updated IRP even shows an increase in usage over the first several years of the planning horizon, albeit at a slower pace. Yankel, Tr. pp. 968-969, 993.

In contrast to the Company's forecast, IIPA presents the quarterly Idaho Economic Forecast (DFM) with historic as well as forecasted demographic data. Yankel, Tr. p. 970. In the period 1998 through 2007, Idaho Power and DFM, Irrigators contend, were in sync and making similar projections. Yankel, Tr. pp. 969-971. After the summer of 2007, DFM states that Idaho's economy went into a downward spiral – its forecast for the future was revised downward. Yankel, Tr. pp. 972-973, 975. The forecast of Idaho Power and DFM from this point are no longer in sync. The Company's December 2008 forecast (residential and commercial) in usage and number of customers, IIRPA contends, does not reflect the economic downturn. Yankel, Tr. p. 974. The May 2009 forecast, IIPA notes, is the first forecast of the Company since the 2006 IRP that shows any meaningful reduction in load; however, it appears to be based only on changes to special contracts – presumably maintaining unchanged data for other customer groups. Yankel, Tr. p. 993.

When asked in an ICIP production request how the Company would meet its load if for one reason or another Langley Gulch was not built, the Company responded:

The Company would attempt to meet its most critical summer time loads through a combination of the following:

1. Short-term demand management programs;
2. Market purchases delivered to the eastside of Idaho Power's system;
3. Market purchases delivered at Mona or Red Butte (both in Utah) and delivered to Idaho Power's system via firm transmission rights from Red Butte to Borah/Brady;
4. Reductions in deliveries to Hoku during summer 2012; or
5. Purchases delivered to Jim Bridger for loss repayment.

Yankel, Tr. p. 997. Market purchases from the Northwest, the Company continued, are also a possibility when transmission is not constrained; PPA's from generation resources are another possibility.

The timing of a need for a new resource, IIPA contends, could probably be extended if the Company factors in the recent modification (Company Option) to the Irrigation Peak Rewards Program. The new option increases the ability of the program to target peak loads. The change has increased the number of participants and connected load. Yankel, Tr. p. 1006. A limitation of 1,000 was placed upon the number of sites for the first year; there were however 1,200 requests. Yankel, Tr. p. 1008. Forecasted impact/reductions for years 2009-2011 for the program are 88 MW, 132 MW and 176 MW, respectively. Yankel, Tr. p. 1007.

Commission Findings

Idaho Power's Integrated Resource Plan is a planning document that constitutes the baseline against which the utility's performance and acquisition of supply-side and demand-side resources are ordinarily measured. An IRP is the utility's plan for providing adequate and reliable service to its electric customers at the lowest system cost. The Commission has consistently stated that "accepting an IRP for filing" does not constitute approval or disapproval of the plan, nor does deviation from the plan constitute a violation of the Commission's Orders or Rules. The Commission may make comment about the IRP planning process, or the plan itself, but such comment by way of notice or order does not constitute approval or disapproval. It is a living planning document that should be regularly updated, formulated with public participation and not a document to be adhered to blindly should circumstances change or limited windows of opportunity present themselves.

We find that Idaho Power's 2006 IRP is the baseline planning document that, with the 2008 update and amended forecasts in December 2008 and May 2009, support the need for a 2012 baseload resource. The Company's Integrated Resource Plan and related filings are in compliance with Commission directives and satisfy the policy objectives announced in the Commission's implementation of PURPA Section 111(d)(7), Case No. GNR-E-93-3 (Integrated Resource Planning), Order No. 24977; PURPA Section 111(d)(8), Case No. GNR-E-93-4 (Investments in Conservation and Demand Management), Order No. 25261; and Case No. U-1500-165, Order No. 22299 (Biennial IRP Filing Requirement).

Idaho Power uses two primary criteria in its planning to assess the need for new resources; one is based on energy needs and the other is based on capacity needs. The water and load conditions used to determine the energy and capacity needs for a 2012 baseload resource are 70th percentile water and load for average energy, and 90th percentile water and 95th percentile load for peak hour capacity needs. As reflected in Staff Exhibit 103 depicting monthly average energy and peak hour deficits, with Langley Gulch on-line in 2012, the Company still projects small energy deficits in some summer months. If these deficits occur, they can be mitigated with available single-cycle peaker plants. Peak hour deficits, however, are nearly eliminated after 2012.

While forecast load growth is a principal factor in determining peak load and average energy deficits in the Company's 2012 projected resource need, we find it is only one of many factors contributing to the critical nature of the need and timing for Langley Gulch. Other factors include: (1) large commercial/industrial requests for service; (2) transmission constraints and restrictions on firm import capability; (3) transmission construction delays (Boardman to Hemingway); (4) on-line delays for delivery of contracted energy; (5) integration capability for intermittent generation; (6) CO2 carbon legislation; (7) Snake River flow realignment and loss of summer hydro generation due to biological needs of fish on a federally regulated Columbia River system; (8) operating reserve margins; (9) operational limitations of the Company's natural gas peaker plants (SCCTs); and (10) market volatility. While no single factor is, of itself, a tipping point, in concert they support the need for a 2012 baseload resource.

Although questions have been raised regarding the Company's procedures for determining cost-effectiveness of demand-side resources, including conservation, we find: (1) the Company has been aggressively pursuing cost-effective demand-side management (DSM) options since the Commission issued Order No. 30201, (2) that it has implemented its DSM programs as quickly as reasonably possible, and (3) that without utilizing "cost premiums" for conservation and demand-side resources *above* cost-effective ranges calculated by Idaho Power Company through established procedures, the use of different procedures for determining cost-effectiveness of DSM measures would not have significantly changed the amount of conservation and demand-side resources acquired, or the need for a new natural gas generation resource by 2012. Therefore, we do not need to address the issues raised about the Company's procedures for determining cost-effectiveness in this Order, and defer those issues to a later time.

We note further that Intervenor and public witness Heckler suggest that Idaho Power before bringing on Langley Gulch should be required to implement all conservation and DSM measures with a marginal cost less than \$0.126/kWh, the levelized cost estimate for a combined-cycle combustion turbine. We disagree. As Idaho Power witness Pengilly contends, using the levelized cost of a facility to determine a cost-effective threshold for DSM and conservation would produce unreasonable and misleading results. Utilizing only the levelized cost of a program ignores the fact that energy savings benefits vary by time of day and by season. Comparing the levelized cost of a demand-side resource to the levelized cost of a single supply-side resource does not provide any relevant information regarding the economic potential of the demand-side resource. Such a comparison incorrectly assumes there are no hourly variations in load reduction associated with the demand-side resource. Pengilly Production Response to ICL Production Request No. 15 (sic); Tr. pp. 770-771.

We find in reviewing the Company's 2006 IRP and 2008 update that the Company has engaged in prudent resource planning, weighing both demand- and supply-side options. In doing so, we conclude that the Company's actions were, and continue to be, informed by its statutory obligation to furnish, provide, and maintain adequate, reliable, and efficient electric service. We find the Company's planning decisions to be just and reasonable and find its pursuit, development and implementation of cost-effective DSM, conservation, energy efficiency and pricing options to be diligent and commendable.

While the Company has been criticized for maintaining an overly optimistic view of recovery from the current economic recession, we find that it has, in fact, recognized load diminishment and incorporated this into its adjustments to forecasts in December 2008 and May 2009. We find that Idaho Power acted responsibly in contracting with Moody's to obtain a third-party economic forecast as a check-and-balance to the Company's internal forecasting. The forecasting adjustments made were as reasonable as one could expect given the economic turmoil that has existed since mid-2008. As previously mentioned, new baseload resources have a lead time of two and one-half to three years. The Commission expects the Company in its planning to position itself and take reasonable actions to meet future load growth and requests for service. Area cities, chambers of commerce, and other stakeholders in Idaho's future growth expect nothing less. This fact is evidenced in filings in this case that support the utility's efforts

to build the required infrastructure they believe is required for the continued health and viability of the state's local economies.

We find that the Company has satisfied the requirements for a Certificate of Convenience and Necessity for the Langley Gulch power project and find that the present and future public interest is served by and requires construction of the baseload resource in the manner, time frame and at the location proposed. *Idaho Code* § 61-526; RP 112.

The Request for Proposals (RFP) Process

On April 1, 2008, Idaho Power issued an RFP to solicit competitive proposals for up to approximately 600 MW of dispatchable energy. The quantity sought was revised on June 25, 2008 to 300 MW. The identified product was "a dispatchable, first-call, non-recallable, physically delivered firm or unit contingent energy, commencing no later than June 1, 2012 and dedicated solely to Idaho Power's use." This product requirement, the RFP stated, could be met through a Purchase Power Agreement (PPA) where the seller supplies fuel and fuel transportation or a Tolling Agreement (TA) where the Company supplies the fuel and fuel transportation. The prescribed term required for bids was 15 years with at least one 5-year contract renewal option. Bokenkamp, Tr. p. 264, Confidential Exh. 116.

The RFP also advised potential bidders that to ensure the availability of baseload resources in 2012, the Company would include a Company-developed natural gas-fired combined-cycle combustion turbine (CCCT) Benchmark Resource in the competitive bidding process as one of the resource alternatives. Bokenkamp, Tr. p. 264. Build-and-Transfer (or turn-key) proposals were not solicited owing to the accelerated 2007 date of need, information obtained regarding critical equipment manufacturing lead times, differences in project design and what the Company perceived to be insufficient time to prepare detailed design specifications. Bokenkamp, Tr. pp. 264-265; Exh. 111 (R.W. Beck Letter, April 14, 2009). The Company at hearing expressed its strong belief that the build-and-transfer option is fraught with problems and does not bring value to the process.

R.W. Beck (Beck) was the independent third-party consultant retained by Idaho Power for the 2012 Baseload Generation RFP process that resulted in selection of Langley Gulch. Bokenkamp, Tr. p. 263. Beck was selected for this RFP process not as a result of a competitive selection process but because of previous consulting for the Company in other

resource selection RFPs. Stein, Tr. p. 29. Beck was retained to assist with preparation of the RFP, to draft power purchase (PPA) and tolling (TA) agreements, to develop the evaluation criteria (price and non-price and manual) and to consult (to a limited extent) in the evaluation of the proposals. Tr. pp. Stein, 39, Bokenkamp, 263. Specific tasks within the scope of work (RFP ¶ 5.5) but not requested by Idaho Power or performed by Beck were to independently score all or a sample of the proposals to determine whether the selection of the short list was consistent with the scoring criteria, to compare the result of its scoring with Idaho Power's scoring and to work with the Company to attempt to reconcile and resolve scoring differences. Exh. 4, p. 1.

As reflected in its March 1, 2009 Letter Report provided to the Company (Exhibit 4) Beck concludes that the Idaho Power RFP evaluation team conducted the 2012 baseload RFP process fairly and properly. All qualifying offers (including the Benchmark Resource), Beck found, were treated objectively and consistently. Stein, Tr. p. 25; Exh. 4, p. 3. The evaluation of proposals was done in accordance with the Evaluation Manual. Stein, Tr. p. 54. Based on its extensive experience and work on power supply RFPs, Beck believes that the RFP document and RFP process was conducted consistent with practices used in the electric utility industry. Exh. 4, pp. 2, 19-22. Based on their participation in the process, Beck is of the opinion that Idaho Power's RFP evaluation team operated in good faith to maintain confidentiality and assure independence from the Idaho Power team preparing the benchmark resource proposal. Exh. 4, p. 2.

The RFP process is described by Idaho Power witness Bokenkamp in Tr. pp. 262-270. The source materials generated in the RFP process were provided at Commission request and are included in the record as Tr. Exhibit 116 (consisting of both confidential (Evaluation Manual, bidder correspondence and information) and non-confidential (RFP, Q&As, pre-bid meeting presentation materials, interconnection procedures)).

Five valid proposals were submitted consisting of 13 alternative resources: one Power Purchase Agreement, nine Tolling Agreements (three different technology classes), two hybrid proposals, and the Company's Benchmark Resource. Bokenkamp, Tr. p. 265. Out of the 2012 Base-Load Generation RFP process the Company short-listed three bids and selected its own Benchmark Resource as the best and least cost resource.

The evaluation and ranking of proposals for the 2012 baseload generation RFP followed the procedure outlined in the proposal Evaluation Manual. There was a three-stage

screening process consisting of (1) proposals checked against minimum requirements, (2) busbar analysis used to determine cost of each proposal, and (3) price and non-price factors or criteria scoring – price 60 points; non-price 40 points including the following identified non-price components: Project development, project characteristics, product characteristics, project location, environmental, credit factors, and financial strength. Bokenkamp, Tr. p. 266; Exh. 106.

The Company notes that there are risks and benefits associated with selecting a traditional utility rate based project:

1. By selecting the Langley Gulch Project and providing a Commitment Estimate, the Company/shareholders take on project development and construction risks.
2. Customers retain the risk of fuel cost increases under either a TA or a utility-owned resource.
3. With a utility-owned resource, any savings with better than expected heat rates will be shared with customers through the annual Power Cost Adjustment (PCA).
4. There is always the risk that Idaho Power may not be able to operate and maintain the project as efficiently as another operator – conversely savings may be realized if operated at less than its anticipated costs.

The potential operating risk, the Company contends, needs to be balanced against

- a. The possible operating savings, plus
- b. The benefit of a projected 20-year net present value (NPV) reduction in revenue requirement of \$108 million, plus
- c. The residual (or terminal) value associated with Langley Gulch at the end of 20 years.

Bokenkamp, Tr. pp. 271-272.

Other material Commission considerations in reviewing this bid evaluation process, the Company maintains are:

1. Imputed debt – The RFP evaluation process did not assign any additional cost to the PPA or TAs to cover the costs Idaho Power would incur by issuing additional equity to maintain its debt and equity ratios if the rating agencies imputed additional debt on Idaho Power's balance sheet as a result of entering into a long-term PPA or TA. Exh. 6, EEI White Paper – Understanding Debt Imputation Issues.

2. Treatment of costs associated with not selecting the Benchmark Resource, i.e., equipment deposits, reservation fees, cancellation charges and other penalties and costs – these costs were not considered in the bid evaluation.

Bokenkamp, Tr. pp. 274-275.

Other attributes of Langley Gulch cited by the Company are the following:

1. By using new state-of-the-art technology the Benchmark Resource will benefit from technological advancements resulting in improved efficiency that can be passed on to customers in the form of reduced operating costs and greater secondary sales revenues.
2. The improved efficiency and low variable operating costs of the Benchmark Resource will result in the unit being dispatched more frequently and assist in the integration of wind and other intermittent resources.
3. The Benchmark Resource is expected to have residual value and be available to serve customers at the end of 20 years.
4. Adding a combined-cycle to the Company's resource portfolio provides the Company with an opportunity to shift generation from coal-fired resources to a natural gas-fired combined-cycle resource during certain times of the year thereby reducing the Company's CO2 emissions from its coal-fired resources.

Bokenkamp, Tr. p. 276.

Even under conservative assumptions, the Net Present Value (NPV) of the Benchmark Resource's 20-year revenue requirement, the Company contends, is approximately \$95 million less than the next-closest combined-cycle project. Bokenkamp, Tr. p. 279; Staff Exh. 113. If the termination or residual value of the benchmark resource is considered, the NPF of 20-year revenue requirement is approximately \$160 million less than that of the next-closest bidder. Bokenkamp, Tr. p. 279; Staff Exh. 114.

Staff reviewed the RFP, the RFP Evaluation Manual, the price and non-price criteria used for scoring purposes, each of the submitted proposals, the scores assigned by the Company's evaluating team, the busbar and AURORA analyses used to rank proposals, transmission studies, air emission studies and various site analyses. Staff also reviewed the Company's Benchmark Resource proposal and Commitment Estimate, examined the steam and gas turbine contracts, the purchased water rights needed for plant cooling, the land purchase option, assessed the site's permitting status, and studied fuel storage, transport and transportation

agreements. Staff concludes that the evaluation of the proposals was fair and recommends that the Benchmark Resource be accepted. Sterling, Tr. p. 1021.

Staff is critical of the Company's decision to not allow build-and-transfer proposals, rejects its reasons, and views the result as denying ratepayers the possibility of a high quality, lower cost plant. Sterling, Tr. p. 1053. Staff notes also that some bidders may have chosen not to participate because of concerns about the Benchmark Resource and the Company's pre-bid reservation of equipment (gas and steam turbines). Sterling, Tr. pp. 1058-1059. The reservation agreements required a deposit of \$8.7 million to Siemens that would be forfeited if the Company canceled the equipment reservation or did not assign the equipment to someone else. The Company also informed potential bidders that it would not allow another bidder (if selected) to purchase the equipment. Sterling, Tr. p. 1060.

Staff does not believe that the Company's Benchmark Resource proposal held an actual advantage; but definitely believes that there was a perception amongst some of the prospective bidders that the Company's resource did have an advantage. Sterling, Tr. pp. 1059-1060. Of the bids that were submitted, however, Staff notes that all of them were made by qualified developers and believes that all of the bids that made it to the final round of screening were extremely competitive. Sterling, Tr. p. 1059.

Staff believes the evaluation criteria established prior to receipt of bids with guidance and assistance of the third-party consultant were made known to the bidders in advance, were reasonable, and were not intended to favor one proposal over another. Some of the non-price criteria required subjective judgments in point factoring, but Staff contends that this is difficult to avoid. Sterling, Tr. p. 1064.

As reflected in their Joint Renewed Motion for Stay, Intervenors believe the RFP process was flawed. They urge the Commission to proceed with a generic competitive bidding docket and to adopt transparent bidding guidelines. Joint Renewed Motion, p. 6.

Testifying for Northwest & Intermountain Power Producers Coalition (NIPPC), Dr. Reading (Reading) states that that organization is an association of independent power producers established to actively pursue informal and formal (laws, policies, rules and regulations) avenues and forums to promote competitive electric supply markets in the Pacific Northwest and Intermountain West. Reading, Tr. p. 868. NIPPC cites a recent NARUC report on competitive procurement of retail electricity supply for a summary of elements that lead to a robust and

transparent competitive bidding process. Reading, Tr. p. 874. In this case, NIPPC's witness Dr. Reading offers the following observations and criticisms of the RFP process:

- It is clear that the Company selected R.W. Beck and directed their responsibilities. Consulting with the utility and receiving direction from it is different from being an independent third party approved by the Commission and operating under pre-established guidelines. Tr. pp. 885-886.
- Neither a draft RFP nor final draft RFP was submitted for Commission approval. Tr. p. 885.
- Nor did the Commission approve and direct the independent evaluator. Tr. p. 888.
- There was no independent scoring by a Commission-approved independent evaluator. Tr. p. 892.
- Since the independent evaluator was not asked to score the proposals, no reconciliation could occur. Tr. pp. 897-898.
- The independent evaluator was also not asked to evaluate the unique risks and advantages that are associated with a Benchmark Resource. Tr. p. 898.
- The net present value (NPV) methodology which was incorporated in the Evaluation Manual was not fully explained in the RFP. Tr. p. 913.

As Industrial Customers of Idaho Power's (ICIP) witness, Reading offers the following additional observations and criticisms:

- Idaho Power did not allow build-and-transfer proposals. ICIP does not believe the Company's reasons for its decision to exclude build-and-transfer to be valid – also belying the Company's stated opposition to build-and-transfers, ICIP notes that in response to a Staff data request, Idaho Power responded: "the Company will give careful consideration to build-and-transfer proposals in the future." Tr. p. 823.
- The Company's apparent distrust of the other parties to build or manage a build-and-transfer project is a curious position considering the Company has never built or operated a CCCT and other potential builders may have extensive experience. Tr. p. 822.
- The RFP evaluation team simply assumed the self-build would be financed – the Company's financial position was not part of the scoring and selection process. The RFP team did not assign a dollar amount to

either cash flow or imputed debt that would impact the Company's financial rates. Tr. p. 831.

- It is incongruous that the Company would stress the need to issue its CPCN under non-traditional ratemaking procedures in order to finance the project and yet not to have considered financial implications in the scoring and selection process. Tr. p. 831.
- Rejects the Company's contention that imputed debt is a measure of financial risk shifted to a utility when it enters into a PPA or TA. Citing Standards & Poor's Opinion that a PPA is not the same thing as actual debt; debt-like-characteristics is not the same as debt. All debt is not created equal. Tr. pp. 833-836.

NIPPC offers as an example of competitive bidding guidelines those adopted by the Oregon Commission. Exh. 702.

Commission Findings

Once it determined a 2012 need for a baseload resource, Idaho Power retained a third-party consultant and issued a Request for Proposals. The RFP process was criticized by nearly all parties to the case, some more stridently than others. While we find that the process could have been more transparent, that better guidelines could have been established, that evaluation criteria could have better explained, that the third-party consultant could have brought more value to the process by performing all the tasks identified in the RFP, and that the total universe of potential bidders was perhaps not realized, we find that the RFP process was nevertheless adequate. Based on the evidence presented, we cannot conclude that a lower price and better project would have resulted if the RFP was better designed and implemented. What is instead apparent is that the RFP participants were sophisticated bidders and that the short list of projects were all competitive.

The Company is not foreclosed from including a self-build option in an RFP. Its obligation to provide electric service and its decision to bid a self-build alternative is a rational basis for lining up an equipment supplier in advance of its application to the Commission. Idaho Power in this RFP was not the only bidder to bring turbines to the table. The Company should, however, be concerned about perception that the third-party consultant was directed by the Company and there was a bias in the selection process. The actual and perceived flaws in the RFP process, we find, while not fatal to the Company's resource selection, clearly demonstrate a need for a separate proceeding to consider RFP competitive bidding rules and guidelines. We

recognize that the Northwest & Intermountain Power Producers Coalition has filed a petition requesting such an investigation (Case No. GNR-E-08-03). The Commission will explore utility RFPs for supply-side resources in that case or another opened for that purpose.

COST RECOVERY, RATEMAKING ASSURANCES AND OTHER FINANCIAL MATTERS

Ratemaking Treatment

Idaho Power's policy witness Ric Gale discussed certain regulatory alternatives that are available to the Commission that, if authorized, would assist the Company in securing the necessary financing for the new resource. The alternatives proposed include (1) a ratemaking order that would permit all or a portion of the Construction Work in Progress (CWIP) the Company incurs as it constructs the Project to be included in rates on an annual basis (*Idaho Code* § 61-502A) and (2) ratemaking assurances under *Idaho Code* § 61-541. Tr. pp. 150-153. In supplemental direct testimony the Company expresses its preference for an order granting ratemaking treatment under *Idaho Code* § 61-541. Tr. p. 162. By way of cautionary caveat, however, the Company states that raising capital of this scale may prove to be problematic in what are now very unsettled times in the economy and capital markets. Any one regulatory treatment, it speculates, may not be sufficient to attract capital for the Project. CWIP, it states, must remain an option for the future. Tr. pp. 162, 163. The Company maintains that financing the construction of the Project without regulatory assurance or CWIP in rate base will endanger Idaho Power's ability to maintain its current credit ratings. Smith, Tr. p. 690.

When questioned at hearing as to the rate impact if Langley Gulch was approved, Mr. Gale, the Company's policy witness responded as follows:

. . . if you just simply lay that rate base and depreciation and such onto our current rates, you get a number close to . . . six or seven percent. If you play it forward into 2012 and escalate the revenue and evaluate it against other alternatives, it's diminished, I think, closer to three or four percent, and then in comparison to alternatives, maybe nothing at all, because you can't just view the rate impact in isolation. There's going to be a set of costs under which you're operating at that point in time.

Gale, Tr. p. 220.

Staff supports the Company's request for advanced ratemaking treatment under *Idaho Code* § 61-541. Tr. p. 1190. Staff recommends that an amount of \$347.4 million plus AFUDC (soft cap) be preapproved for recovery under *Idaho Code* § 61-541, and that all additional

amounts spent on the Project including transmission up to a maximum amount of \$376.6 million plus AFUDC be subject to recovery following further audit and prudence review once the costs are known and the plant begins providing service. Tr. p. 1022; Revised Confidential Exh. 109.

Staff believes the Commission should establish an absolute “not to exceed” amount or hard cap to protect ratepayers in the event extreme costs must be incurred to complete the plant and make it operational. Sterling, Tr. p. 1083. Staff recommends that the hard cap be established as an amount equal to the expected project costs plus a reasonable contingency for those portions of the project that were based on estimates. Tr. p. 1083.

Costs above the amount approved for regulatory preapproval (the soft cap), Staff contends, should be subject to a subsequent prudence review and Commission approval. Sterling, Tr. p. 1091. When and if it approves in a subsequent proceeding costs above the soft cap (\$347.4 million) some of the factors Staff believes the Commission should consider are the following:

- Reasonableness of costs
- Necessity of the expenditure
- Consistency with project plans
- Method of selection of contractors, materials, equipment, and vendors
- Whether the cost is based on competitive procurement of equipment, materials or services
- Nature of expense
- Whether the work is completed on time
- Whether any costs are penalties or liquidated damages, and
- Whether costs are consistent with preconstruction estimates

Staff does not believe that any additional costs caused by Idaho Power’s delay or negligence should be recoverable. Sterling, Tr. pp. 1090-1092.

Intervenors contend that regulatory preapproval of the Commitment Estimate under *Idaho Code* § 61-541 is unnecessary. They recommend no more than the “regulatory compact” previously provided, i.e., that in the ordinary course of events, the Company may expect its investment to be recognized in its revenue requirement barring unforeseen circumstances. Case No. IPC-E-91-4, Order No. 25021 (Twin Falls Upgrade). Renewed Motion, p. 11.

Return on Equity (ROE)

The Company requests that the return on equity (ROE) authorized for the Langley Gulch project be the same as the ROE authorized for the rest of the Company’s rate base when the Project is placed in service and achieves commercial operation. The ROE for the Project will

change with the Commission-authorized changes to the Company ROE over the life of the Project facilities. Tr. p. 160.

Commission Staff supports the Company's position on ROE. Adopting the methodology where the return on equity for Langley Gulch is the same as authorized for other rate base items, Staff states, is consistent with normal rate base treatment. Tr. pp. 1188-1189.

**Allowance for Funds Used During Construction (AFUDC)
Construction Work in Progress (CWIP)**

Idaho Code § 61-502A, enacted in 1984, prohibited the Commission from "setting rates for any utility that grants a return on construction work in progress [CWIP] or property held for future use and which is not currently used and useful in providing utility service," unless the Commission determined that an "extreme emergency" existed. When CWIP is not included in rate base, however, the Commission is required to "allow a just, fair and reasonable allowance for funds used during construction [AFUDC] or similar account to be accumulated, computed in accordance with generally accepted accounting principles." *Idaho Code* § 61-502A. The statute was amended in 2006 to allow CWIP in rates if the Commission makes an "explicit finding that the public interest will be served thereby." The provision regarding AFUDC was unchanged.

Allowance for Funds Used During Construction (AFUDC)

AFUDC is the capitalization costs associated with the construction of an asset. Tr. p. 690. AFUDC provides for the financial carrying costs of an asset while it is being constructed and is recorded in Account 107. During construction, AFUDC is a non-cash entry to Account 107 that represents the costs of debt financing and an equity return as prescribed by FERC. 18 C.F.R. § 1.101. The AFUDC plus the accumulation of all other costs associated with construction is then closed to plant Account 101 as an asset upon completion of the project. Smith, Tr. p. 691.

Once included in rate base, AFUDC is typically recovered over the life of the asset through depreciation expense and a return on investment earned. The asset and AFUDC generate cash flow for the Company when included in rate base in a revenue requirement proceeding. Smith, Tr. p. 691.

The Company's Commitment Estimate contains a \$49 million estimate of AFUDC costs expected to be incurred during the construction of the production plant and \$1 million for the transmission portion of the Project. This \$49 million estimate was derived using an

estimated 7% annual capitalized interest charge to the funds spent on construction of the Project. The estimated AFUDC costs were added to the accumulated construction work in progress balances each month. Bokenkamp, Tr. p. 269. The seven percent rate used to estimate AFUDC on the power plant portion of the Project was not based on an exact capital structure or exact financing cost(s) at a particular time. It was a high level estimate derived from the average annual AFUDC rates the Company applied to CWIP over the last four years according to the Company. Harms, Tr. pp. 1170-1171. The \$1 million included in the Company's Commitment Estimate for transmission AFUDC was not calculated in the same manner. Instead, it was an estimate from the bid process and does not have a supporting schedule. Harms, Tr. p. 1171.

Staff notes that in the Company's last general rate case (Case No. IPC-E-08-10), the monthly AFUDC rates, January 2008 through October 2008, ranged from 3.016% to 6.585%. In response to discovery, the Company reports that its AFUDC rates for January through April 2009 have ranged from 3.27% to 8.26%. Harms, Tr. p. 1172.

Staff recommends that Idaho Power accrue actual AFUDC based upon the monthly cash balance of actual expenditures as the production and transmission plant are under construction. The monthly expenditures would be subjected to a prudence review of the amounts to which the AFUDC rate is applied except those amounts approved in this proceeding. Harms, Tr. pp. 1169-1170.

Construction Work in Progress (CWIP)

CWIP is the accumulation of all costs associated with the construction of an asset plus the cost of financing the construction expenditures. Tr. p. 690. As described by the Company, including CWIP in rate base would permit all or a portion of the Construction Work in Progress the Company incurs as it constructs its project to be included in rates on an annual basis. Gale, Tr. pp. 150-152. This recovery method avoids financing costs that would otherwise be depreciated over several decades. Smith, Tr. p. 691; Exh. 7. The Company contends that both CWIP and the ratemaking treatment under *Idaho Code* § 61-541 can work together should the Commission so desire. Tr. p. 161. The Commission, it suggests, could order ratemaking treatment under *Idaho Code* § 61-541 and either as part of this proceeding or in future proceedings authorize CWIP. Tr. pp. 161-162. The authorization of CWIP for this Project, the Company contends, would provide a strong signal of regulatory support for capital projects to the financial community and provide increased cash flow throughout the construction of the

Project, thus decreasing the need to access the capital market. Gale, Tr. p. 152; Smith, Tr. p. 690-691.

CWIP in rate base, the Company contends, is a beneficial financing tool for constructing new generation or any multi-year large project. Although use of CWIP has been historically limited, the current financing environment, the Company's current below-book value stock price and the uncertainty of the market providing financing for a large project, the Company contends, warrant the consideration of extraordinary Commission support. CWIP is precisely the sort of ratemaking support Idaho Power needs in the current credit market, it states, because it reduces financing risk, regulatory risk, and capital market risk associated with long-lead time, large construction projects. Smith, Tr. p. 696-697.

Based upon the evidence presented by the Company, Staff does not believe that including CWIP in rate base before the related plant is used and useful is appropriate. Harms, Tr. p. 1170. Staff's position regarding CWIP remains consistent with the position it took in the Company's Hells Canyon relicensing project, Case No. IPC-E-08-10. Harms, Tr. p. 1176.

The Company in this case, Staff notes, has not requested as its preferred ratemaking treatment inclusion of CWIP or AFUDC in rates before the plant is used and useful and closed to plant in service. Harms, Tr. p. 1179. It is Staff's position that CWIP in rates would be better evaluated at a later date when the Company presents a case supporting an "explicit finding that the public interest will be served thereby" (*Idaho Code* § 61-502A) and when the Company has accrued actual AFUDC amounts. This position is consistent with Staff's understanding of Mr. Gale's testimony associated with economic conditions and impacts on customers at this particular time. Carlock, Tr. p. 1195.

Idaho Power's Application itself seems to CAPAI to suggest that if the Commission believes that the project should be given rate base assurance, then use of the recently enacted legislation granting such assurance under *Idaho Code* § 61-541 is sufficient without the need for immediate recovery through CWIP. CAPAI agrees with this. Ottens, Tr. p. 936.

ICIP believes that Idaho Power is not facing the sort of financial difficulty that would justify authorizing current recovery of CWIP. Mitchell, Tr. p. 614. Further, ICIP believes CWIP is inappropriate for several reasons. As an artifact of monopoly regulation, ICIP contends it is inconsistent with competitive market processes (Idaho Power Rebuttal, Tr. p. 173); ICIP contends that it distorts the type of choices that are made in the IRP process (Idaho Power

Rebuttal, Tr. p. 173); and it has adverse intergenerational impacts (Idaho Power Rebuttal, Tr. p. 175). Mitchell, Tr. pp. 660-669. If adopted, ICIP contends, CWIP reduces the utility's business risk, though, ICIP notes, we have not seen Idaho Power volunteer for a lower return on equity or less equity in its capital structure. Tr. p. 615.

Depreciation

Idaho Power requests a depreciable life of 35 years for production plant and 45 years for transmission plant. Gale, Tr. p. 160. Staff in testimony discussed depreciation rates currently authorized for specific plant accounts and compared them to the Company's request. Harms, Tr. pp. 1161-1167. Staff recommends that the Langley Gulch Project be depreciated in accordance with the depreciation rates that in are in effect at the time the Project is placed in service. Harms, Tr. p. 1161. Staff's proposal is consistent with the Company's beginning recommendation and current depreciation practice for Idaho Power. Carlock, Tr. pp. 1189-1190; *Idaho Code* § 61-541(2)(b)(ii).

Staff recommends that a new depreciation study that includes the Project with economic lives no shorter than 35 years for the production plant and 45 years for the related transmission plant be completed and filed when or shortly after the Project is placed into service. Harms, Tr. pp. 1161, 1167-1168. The Company agrees with Staff that a depreciation study should be conducted around the time the Langley Gulch project is completed and is placed in service. Smith, Tr. pp. 703-704.

The Securities and Exchange Commission (SEC) has published a roadmap that may result in adoption of International Financial Reporting Standards (IFRS) in the United States by 2014. Current international standards treat depreciation differently than most U.S. utilities. The most significant difference under International Accounting Standards (IAS), and one the Company can currently prepare the Langley Gulch project for, is componentization. IAS 16, ¶ 43 states "each part of an item of property, plant and equipment with a cost that is significant in relation to the total cost of the item shall be depreciated separately." This may be a physical component or a non-physical component such as an inspection or an overhaul. Harms, Tr. pp. 1168-1169. Staff recommends that the Company create and retain documentation associated with Langley Gulch that would allow the Company to comply with component depreciation when IFRS are adopted. Staff expects this detail will also be utilized in the next depreciation study. Harms, Tr. p. 1169. The Company agrees that the documentation created

contemporaneously with construction of Langley Gulch should be sufficient to track depreciation costs for IFRS once they are adopted by the Company. Smith, Tr. p. 724.

Cash Flow, Capital Markets & Ability to Raise Capital

Idaho Power expresses concern that the current capital market may not provide financing at an acceptable rate, even if the Commission grants the ratemaking treatment requested and authorizes CWIP. Gale, Tr. p. 156. Company witness Smith discusses the ratemaking alternatives requested and the challenge of financing major capital projects in the present economic and financial environment. Tr. pp. 689-690. On cross Smith elaborated and clarified her financing concerns (e.g., trading below-book value), and discussed financing methods and options. Tr. pp. 716-723.

The Company, on cross-examination, states that it is currently able to finance its current level of operations at reasonable terms. Smith, Tr. p. 717. In the financing package for Langley Gulch, the Company's preferred method of financing will be to enter the markets on a traditional basis. What the Company has done traditionally is accumulate and use its commercial paper balances for a short period of time until it has a significant enough size to have an efficient long-term debt offering and then it balances those offerings with issuances of equity. Smith, Tr. p. 718. When the Company makes its financing selection for Langley Gulch it will make a security filing with the Commission pursuant to Title 61, Chapter 9 (Issuance of Securities by Public Utilities). Smith, Tr. p. 717.

Staff believes its recommendation of soft cap and hard cap and advanced ratemaking treatment under *Idaho Code* § 61-541 is the best way to recognize cash flow, capital markets and the Company's ability to use capital in considering the current economic environment. Tr. p. 1190.

Cash flow, Staff states, is improved by increasing revenues or by reducing required expenditures. Carlock, Tr. p. 1192. Alternative ratemaking treatment such as AFUDC or CWIP in rates will provide additional cash flow. This additional cash flow would fund operations and construction, strengthen the balance sheet and income statement to improve financial ratios supporting ratings and improve the Company's ability to borrow funds at a reasonable rate. Carlock, Tr. p. 1192. That being said, however, as indicated above, in this case Staff is not recommending the inclusion of AFUDC or CWIP in rates for Langley Gulch.

Staff assesses Idaho Power's ratings as stable with the outlook being neutral as reported by many Institutional and Investor Research Reports. However, positive and negative recommendations are also seen. For the most part, Staff does not see approval of its recommendations as changing the Company's ability to finance. Carlock, Tr. p. 1192.

Capital markets, Staff observes, continue to be unsettled and raising capital at a reasonable cost continues to be challenging. Views that the Commission regulatory climate is above average should continue to be supported with the Staff's recommendations in this case. If the Commission issues a CPCN and accepts Staff's recommended Soft Cap with preapproval of costs under *Idaho Code* § 61-541, this level of ratemaking certainty related to prudence and cost recovery, Staff states, should enhance the Company's ability to obtain financing at a reasonable rate. Carlock, Tr. p. 1193.

Equity issuances for Idaho Power, Staff contends, will be different if not currently impossible, with the Company's stock price remaining below-book value. Equity funds will primarily be from retained earnings and dividend reinvestment plans. Carlock, Tr. p. 1193.

Given the meltdown in the capital markets and the general state of the economy, ICIP believes that the Company's concerns about borrowing funds for Langley Gulch are legitimate and financing problems could stall the project. Reading, Tr. p. 827.

Commission Findings

We find that Idaho Power in its Application and supporting testimony for binding ratemaking treatment under *Idaho Code* § 61-541 describes its 2006 Integrated Resource Plan (and 2008 update) and the need identified therein for a 2012 baseload generation resource matching the resource and operation characteristics of the Langley Gulch Power Plant. The Company has described its plan for construction and bringing the project on-line and its related contracts for EPC services and equipment and its efforts at securing an option for the site, water rights, fuel and other permitting and regulatory approvals. In describing the project plan the Company has also presented a schedule for commencement of construction and project completion and proposals for cost recovery and ratemaking treatment. Based on the foregoing recital of the components set forth in Idaho Power's Application and testimony, we find that the Company has satisfied the statutory requirements of *Idaho Code* § 61-541(2).

In considering the Commission determinations required under *Idaho Code* § 61-541(4)(a)(i-v) we make the express finding that Idaho Power has in effect a Commission-

accepted Integrated Resource Plan, the Company's 2006 IRP (and 2008 update). We find the services and operations resulting from the proposed Langley Gulch Power Plant to be necessary for the providing of adequate and reliable electric service and in the public interest. We find that Idaho Power in its IRP planning and in the record developed in this case has demonstrated that it has considered other sources for long-term electric supply, i.e., energy efficiency, demand-side management, and transmission options and that the addition of Langley Gulch is reasonable when compared to same. We further find and acknowledge that Idaho Power participates in a regional transmission planning process.

Idaho Power has requested rate assurance pursuant to the provisions of *Idaho Code* § 61-541 – Binding Ratemaking Treatment. The Company contends that such ratemaking assurance may be necessary to attract capital and finance the project at reasonable rates and terms. The Company's Commitment Estimate in the RFP 2012 baseload resource bidding process was \$427,366,740, an amount which includes the power plant and two related transmission interconnection projects. The Company requests that we grant preapproval assurance for the total Commitment Estimate amount and allow it to come back and seek specific approval and recovery of amounts exceeding the Commitment Estimate if it can demonstrate the prudence of the expenditure and reasonableness. We advise the Company that it should expect the Commission to hold it to the same standard that the Company itself would require of a successful third-party bidder in an RFP process.

Recognizing that the Company's Commitment Estimate is comprised of signed contracts and estimated costs, we are persuaded that Staff's approach to separating costs that are known with greater certainty and competitively procured from amounts that are based on more uncertain estimates and contingencies to be a reasonable method to follow in considering applications under *Idaho Code* § 61-541. Adopting Staff's methodology we find it reasonable to provide the Company with assurance and preapproval under *Idaho Code* § 61-541 for the amount of \$396,618,473. Staff Revised Confidential Exh. 109. The Commission declines to adopt the Staff's recommendation to establish an absolute "not to exceed" amount or hard cap.

In consideration of the ratemaking assurance provided pursuant to *Idaho Code* § 61-541 we find it reasonable as a condition of Certificate (*Idaho Code* § 61-528) to require the Company (or owner's representative) to submit quarterly progress reports describing the status of the Langley Gulch project in reasonable detail, which shall include information showing actual

progress against the Project schedule, estimates of cost to complete and changes to its construction schedule and any other notations of importance to Commission understanding of deviations or adjustments to the Project schedule initiated between quarterly reports. The reports shall include a budget update showing total amount expended and billed to date and remaining contract dollars.

The return on equity that we find reasonable to authorize for Langley Gulch will be the same ROE authorized for the rest of the Company's rate base when the Project is placed in service and achieves commercial operation and will change over the life of the project facilities with Commission-authorized changes to the Company's ROE for other rate base items.

We further find it reasonable to require the Company to prepare a new depreciation study that includes the Project with economic lives no shorter than 35 years for the production plant and 45 years for the related transmission plant and to file the study with the Commission at the time the Project is placed into service, or shortly thereafter. We find it reasonable at the time the Project is placed in service and until the study is approved to utilize a depreciation life of 35 years for the production plant and 45 years for the related transmission plant.

The Commission is open to considering CWIP as construction progresses. However, we find the record in this case to be insufficient to award CWIP at this time. AFUDC will be accrued based on the actual amounts, timing and borrowing rate for funds needed to construct the plant. *Idaho Code* § 61-502A.

In the matter of existing borrowing authority Idaho Power may utilize for the Langley Gulch Project, the Commission notes that all provisions of Order No. 30294, dated April 11, 2007, and Order No. 30487 dated January 11, 2008, shall apply.

PUBLIC COMMENTS

Public comments were filed in favor of the Langley Gulch project by area cities and chambers of commerce and a number of local businesses. Strong support was voiced for the development of additional energy infrastructure to meet the short-term and long-term energy needs in the Treasure Valley and to accommodate economic development. Idaho Power, they observe, is constrained in the amount of power it can provide. The promise of reliable and affordable energy, they argue, is a key element to attracting quality commerce and industry. Langley Gulch, they contend, is needed now to meet the current and future electrical needs of southern Idaho. The economic slowdown of recent months appears to commenters to provide an

ideal time to catch up on deficiencies in infrastructure and prepare Idaho communities for future growth.

Commenters opposing the Company's proposed baseload natural gas facility recommend instead increased energy efficiency, demand-side management measures and pursuit of alternative generation resources, i.e., geothermal, wind, bio-energy, solar. Some commenters recommended adoption of renewable portfolio standards (RPS). Others recommended nuclear power as an alternative to Langley Gulch and an addition to the Company's resource portfolio.

INTERVENOR FUNDING

Intervenor funding is available pursuant to *Idaho Code* § 61-617A and Commission Rules of Procedure 161-165. Section 61-617A(1) declares that it is "the policy of [Idaho] to encourage participation at all stages of all proceedings before this commission so that all affected customers receive full and fair representation in those proceedings." The statutory cap for intervenor funding that can be awarded in any one case is \$40,000. *Idaho Code* § 61-617A(2). Accordingly, the Commission may order any regulated utility with intrastate annual revenues exceeding \$3.5 million to pay all, or a portion of, the costs of one or more parties for legal fees, witness fees and reproduction costs not to exceed a total for all intervening parties combined of \$40,000.

Petitions for Intervenor Funding were filed by Community Action Partnership Association of Idaho (\$10,243.50), Idaho Conservation League (\$9,604), and the Idaho Irrigation Pumpers Association (\$48,382.67).

Rule 162 of the Commission's Rules of Procedure provides the form and content requirements for a Petition for Intervenor Funding. The petition must contain: (1) an itemized list of expenses broken down into categories; (2) a statement of the intervenor's proposed finding or recommendation; (3) a statement showing that the costs the intervenor wishes to recover are reasonable; (4) a statement explaining why the costs constitute a significant financial hardship for the intervenor; (5) a statement showing how the intervenor's proposed finding or recommendation differed materially from the testimony and exhibits of the Commission Staff; (6) a statement showing how the intervenor's recommendation or position addressed issues of concern to the general body of utility users or customers; and (7) a statement showing the class of customer on whose behalf the intervenor appeared. The Petitions for Intervenor Funding in

this case were timely filed and comport with the procedural and technical requirements of the Commission's rules.

Community Action Partnership Association of Idaho (CAPAI)

CAPAI is a non-profit corporation overseeing a number of agencies that assist with issues related to the causes and conditions of poverty in Idaho. In this case CAPAI articulated the risks of making a premature decision on the Company's Application and the harmful impact a premature decision would likely have on the Company's low-income customers, particularly during the current difficult economic times. CAPAI recommends that the Commission defer a ruling on the public convenience and necessity of Langley Gulch and the Company's Application until additional information has been obtained. CAPAI executed the Joint Renewed Motion to Stay the Application.

CAPAI's witness, Ms. Teri Ottens, noted that the Company's Integrated Resource Plan process was put on deferral at the Company's request. She pointed out that it is partially through the IRP process that the very question of prudence and cost-effectiveness of resources is determined. She expressed concern regarding Idaho Power's load forecasting and pointed out that there might be other means of meeting the Company's load growth that are more cost-effective. There are too many assumptions now, regarding the viability of Langley Gulch, Ms. Ottens states, which a relatively short period of time will either prove or refute.

CAPAI notes that it has historically not sought funding compensation for the services of its expert, Teri Ottens. Ms. Ottens was formerly Executive Director of CAPAI, but for the past few years, has served as an expert consultant to CAPAI whose Executive Director is now Mary Chant.

CAPAI notes that Ms. Ottens has been consulting, advising, and testifying for CAPAI for approximately seven years. Ms. Ottens has served as Energy Coordinator for the Association of Idaho Cities and Counties and, for a number of years, organized that group's annual Idaho Energy Conference. Noting that every party who retains an expert for proceedings before the Commission chooses someone with expertise in that particular party's areas of concern, CAPAI contends that Ms. Ottens is such an individual.

CAPAI respectfully submits that its petition for intervenor funding and the hourly rates and fees of its legal counsel and expert have historically been quite reasonable and relatively modest. In this case, CAPAI requests reimbursement of \$43.50 in costs, \$9,480 in

legal fees (79 hours at \$120 per hour) and \$720 in expert fees (16 hours at \$45 per hour) for total fees of \$10,200 and total itemized expenses of \$10,243.50.

Idaho Conservation League (ICL)

ICL is a non-profit corporation working to protect Idaho's clean water, clean air, and wilderness. Through ICL's energy program, the organization advocates for energy efficiency and renewable resources in order to mitigate the effect climate change will have on Idaho and its citizens. ICL in this case recommends that the Commission delay its decision on Langley Gulch until the Company's 2009 IRP is complete. ICL is a signator to the Motion to Stay.

ICL contends that it provides a unique perspective due to its expertise in environmental regulation, and pending federal climate change legislation, and energy efficiency opportunities. In this case, ICL challenged Idaho Power's assertion that it is pursuing all cost-effective energy efficiency and DSM programs. ICL also addressed the need for the shareholder resolution to adopt a greenhouse gas (GHG) reduction strategy to be incorporated into the Company's 2009 IRP. Even though Staff provided valuable insight, ICL contends that Staff did not address the greenhouse gas resolution and had a different opinion on whether the Company is pursuing all cost-effective efficiency.

ICL contends that it made a concerted effort to minimize expenses and seeks reimbursement for only attorney fees; fees which were discounted 20% to account for this being counsel's first time before the Commission. ICL requests intervenor funding in the amount of \$9,604 (68.6 hours at \$140 per hour).

Idaho Irrigation Pumpers Association (IIPA)

IIPA is an Idaho non-profit corporation that was organized in 1968 to represent agricultural interests in electric utility matters affecting farmers in southern and central Idaho. IIPA relies solely upon dues and contributions voluntarily paid by members, together with intervenor funding to support activities.

IIPA has asked the Commission to delay its ruling on the Company's Certificate for Langley Gulch for at least 10 months. IIPA contends that the underlying forecast data for the 2006 IRP and the 2008 updated IRP which formed the basis for the Company's need for Langley Gulch relied on stale data that does not reflect the most recent economic upheavals that have occurred in Idaho's economy in the last 9 to 18 months. The testimony that IIPA provided and

positions that IIPA has urged the Commission to adopt materially differed from the testimony and positions put forth by Commission Staff.

IIPA contends that there will be no adverse impact to the Company's ability to serve system load should the Commission delay its decision due to the Company's ability to utilize import purchase power and the impact of changes in the Peak Rewards Program. IIPA contends that costs incurred in this proceeding constitute a financial hardship. The Irrigators report that member contributions have been falling, presumably due to the current depressed economy, increased operating costs and threats relating to water right protection issues.

IIPA requests intervenor funding in the amount of \$48,382.67 (\$16,514 in legal fees (80.2 hours at \$185 per hour; .60 hours at \$135 per hour) and \$56.62 for postage and travel; \$31,868.05 in consultant fees (242 hours at \$125 per hour) and \$1,618 for meals and travel).

Commission Findings

Submitted for Commission decision are the Petitions for Intervenor Funding filed by Community Action Partnership Association of Idaho (\$10,243.50), Idaho Conservation League (\$9,604), and the Idaho Irrigation Pumpers Association (\$48,382.67). The Commission has reviewed the Petitions and the record of proceedings.

Intervenor funding is available pursuant to *Idaho Code* § 61-617A and the Commission Rules of Procedure 161-165. Rule 162 of the Commission's Rules of Procedure provides the form and content requirements for a petition for intervenor funding.

Pursuant to *Idaho Code* § 61-617A(2), the Commission may order Idaho Power to pay all or a portion of the costs of one or more parties for legal fees, witness fees, and reproduction costs, not to exceed a total for all intervening parties combined of \$40,000 in any proceeding before the Commission. The combined total requested by CAPAI, ICL and the Irrigators is \$68,229.17. We find that the Petitions for Intervenor Funding in this case were timely filed and satisfy all of the "procedural" or technical requirements set forth in Rules 161-165 of the Commission's Rules of Procedure.

Idaho Code § 61-617A includes a statement of policy to encourage participation by intervenors at all stages of all proceedings before the Commission. The Commission determines an award for intervenor funding based on the following considerations:

- (a) A finding that the participation of the intervenor has materially contributed to the decision rendered by the Commission; and

- (b) A finding that the costs of intervention are reasonable in amount and would be a significant financial hardship for the intervenor; and
- (c) The recommendation made by the intervenor differed materially from the testimony and exhibits of the Commission Staff; and
- (d) The testimony and participation of the intervenor addressed issues of concern to the general body of users or consumers.

Idaho Code § 61-617A.

We find that the Petitions of CAPAI, ICL and the Irrigators satisfy the substantive findings that we are required to make to justify an award. IDAPA 31.01.01.165.01.a-e. We find that the participation and presentations of CAPAI and the Irrigators, as reflected in their respective prefiled testimonies and as parties to the Motion to Stay, and the participation of ICL at hearing and as a party to the Motion to Stay materially contributed to the Commission's decision. All add informed perspectives to the hearing record. We find that the recommendations of each differed materially from the testimony and exhibits of Commission Staff.

In this case, we find it fair, just and reasonable to award the total request of CAPAI in the amount of \$10,243.50 and find that the public interest is well served by such award. We find the itemized costs of CAPAI to be reasonable and recognize that the cost to CAPAI of participating in this proceeding constitutes a significant financial hardship. We find that CAPAI was professional and economical in the marshalling of its time and efforts.

The Commission also finds it fair, just and reasonable to award the total request to ICL in the amount of \$9,604. ICL is not a regular participant in Commission proceedings. We appreciate its perspective and encourage continued involvement and participation. We find the itemized costs of ICL to be reasonable and recognize that the cost to ICL of participating in this proceeding constitutes a significant financial hardship.

The Commission awards the Irrigators the amount of intervenor funding remaining, \$20,152.50 and finds such award to be fair, just and reasonable. The Irrigators are a non-profit corporation representing farm interests and rely solely upon dues and contributions voluntarily paid by members based on acres irrigated or horsepower per pump. We appreciate the participation of the Irrigators in the case and recognize their contribution to the ultimate resolution of issues.

The Commission finds that the intervenor funding awards to CAPAI, ICL and the Irrigators are fair and reasonable and will further the purpose of encouraging “participation at all stages of all proceedings before the Commission so that all affected customers receive full and fair representation in those proceedings.” *Idaho Code* § 61-617A(1).

CONCLUSIONS OF LAW

Idaho Power is an electric corporation and public utility subject to the regulatory jurisdiction of the Commission pursuant to Title 61 of the Idaho Code and the Commission’s Rules of Procedure, IDAPA 31.01.01.000 *et seq.*

The Commission has jurisdiction over the specific issues presented in Case No. IPC-E-09-03 pursuant to *Idaho Code* §§ 61-526 (Certificate of Convenience and Necessity), 61-528 (CCN – Conditions), 61-502A (CWIP & AFUDC), and 61-541 (Binding Ratemaking Treatment), and Commission Rule of Procedure 112 (Certificate of Convenience and Necessity – Form and Content – Existing Utility).

We find the future public convenience and necessity requires the construction of the Langley Gulch Power Plant to be located in Payette County approximately four miles south of the town of New Plymouth, Idaho.

We further find that Idaho Power has satisfied the statutory requirements of *Idaho Code* § 61-541 and has regulatory assurance by the Commission of receiving rate base treatment of the Company’s capital investment in the Langley Gulch Power Plant and related facilities in the amount of \$396,618,473 at such time as the plant is placed in commercial operation.

ORDER

In consideration of the foregoing and as more particularly described above, IT IS HEREBY ORDERED that Idaho Power Company’s Application seeking a Certificate of Convenience and Necessity to build the Langley Gulch Power Plant is approved. Certificate No. 486 will be issued to Idaho Power.

IT IS FURTHER ORDERED that the Commission, pursuant to *Idaho Code* § 61-541, provides Idaho Power with authorization and binding commitment to provide rate base treatment for the Company’s capital investment in the Langley Gulch Power Plant and related facilities in the amount of \$396,618,473 at such time as the plant is placed in commercial operation.

In consideration of the ratemaking assurance we grant pursuant to *Idaho Code* § 61-541, IT IS FURTHER ORDERED as a condition of Certificate No. 486 (*Idaho Code* § 61-528)

and the Company (or owner's representative) is hereby directed to submit quarterly progress reports to the Commission describing the status of the Langley Gulch Power Plant in reasonable detail, which shall include information showing actual progress against the Project schedule, estimates of cost to complete and changes to its construction schedule and any other notations of importance to Commission understanding of deviations or adjustments to the Project schedule initiated between quarterly reports. The monthly reports shall include a budget update showing total amount expended and billed to date and remaining contract dollars.

IT IS FURTHER ORDERED that in the matter of existing borrowing authority Idaho Power may utilize for the Langley Gulch Project, all provisions of Order No. 30294, dated April 11, 2007, and Order No. 30487 dated January 11, 2008, shall apply.

IT IS FURTHER ORDERED that Intervenor's Joint Renewed Motion to Stay Proceedings is denied.

IT IS FURTHER ORDERED and the Community Action Partnership Association of Idaho's Petition for Intervenor Funding is granted in the amount of \$10,243.50. Reference *Idaho Code* § 61-617A. Idaho Power is directed to pay said amount to CAPAI within 28 days from the date of this Order. IDAPA 31.01.01.165.02. Idaho Power shall include the cost of this award of intervenor funding to CAPAI as an expense to be recovered in the Company's next general rate case proceeding from the residential customer class. *Idaho Code* § 61-617A(3).

IT IS FURTHER ORDERED and the Idaho Conservation League's Petition for Intervenor Funding is granted in the amount of \$9,604. Reference *Idaho Code* § 61-617A. Idaho Power is directed to pay said amount to ICL within 28 days from the date of this Order. IDAPA 31.01.01.165.02. Idaho Power shall include the cost of this award of intervenor funding to ICL as an expense to be recovered in the Company's next general rate case proceeding from the residential customer class. *Idaho Code* § 61-617A(3).

IT IS FURTHER ORDERED and the Idaho Irrigation Pumpers Association, Inc.'s Petition for Intervenor Funding is partially granted in the amount of \$20,152.50. Reference *Idaho Code* § 61-617A. Idaho Power is directed to pay said amount to the Irrigators within 28 days from the date of this Order. IDAPA 31.01.01.165.02. Idaho Power shall include the cost of this award of intervenor funding to the Irrigators as an expense to be recovered in the Company's next general rate case proceeding from the irrigation customer class. *Idaho Code* § 61-617A(3).

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date of this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. See *Idaho Code* § 61-626.

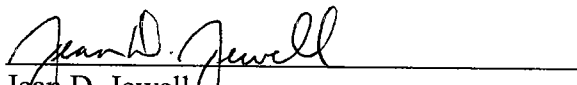
DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 31st day of August 2009.


JIM D. KEMPTON, PRESIDENT


MARSHA H. SMITH, COMMISSIONER


MACK A. REDFORD, COMMISSIONER

ATTEST:


Jean D. Jewell
Commission Secretary

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