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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

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

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

KARL BOKENKAMP

Q. Please state your name and business address.

A. My name is Karl Bokenkamp and my business address is 1221 West Idaho Street, Boise, Idaho.

Q. By whom are you employed and in what capacity.

A. I am employed by Idaho Power Company as the General Manager of Power Supply Operations and Planning.

Q. Please describe your educational background.

A. I received a Bachelor of Science Degree in Mechanical Engineering from the University of Illinois at Urbana-Champaign in 1980. In 1995, I earned a Master of Engineering Degree in Mechanical Engineering from the University of Idaho. I am a registered Professional Engineer in the state of Arizona, and I have attended the Stone & Webster Utility Management Development Program and the University of Idaho's Utility Executive Course.

Q. Please describe your work experience with Idaho Power Company.

A. I became employed by Idaho Power in 1995 as the Director, and then Manager, of Thermal Production. In this position I was responsible for managing Idaho Power's Thermal Production Department. Primary responsibilities of the department included oversight and control of Idaho Power's ownership shares in its three jointly-owned coal-fired generation resources, Bridger, Boardman, and Valmy, and their associated fuel supplies.

In 2001, I accepted a new assignment as the Manager of Power Supply Planning and was later promoted to General Manager of Power Supply Planning. In this position, I was responsible for building and managing Power Supply's Planning Department. This department's responsibilities included operational planning, load forecasting, stream flow forecasting, integrated resource planning, cogeneration and small power producer contract management, water management/river operations, and gas and coal contract management.

In 2006, I was promoted to my current position of General Manager, Power Supply Operations and Planning. This position adds operational responsibilities, which include asset optimization, wholesale electricity, and natural gas transactions from real-time through multi-year deals as well as real-time operations and scheduling.

Q. Please outline the major topics you will address in your testimony in this proceeding.

A. There are three major topics that comprise my testimony. First, I will briefly review how the addition of a baseload resource like the Langley Gulch power plant ("Langley Gulch" or "Project") is consistent with the Company's 2006 Integrated Resource Plan and 2008 Update. Second, I will provide an overview of the Request for Proposal ("RFP") process used to evaluate the various resources that competed to provide the baseload resource. Finally, I will explain why the Project was selected as the least-cost resource through the competitive RFP process.

Q. What drives the need for Idaho Power to acquire additional resources?

A. Load growth within Idaho Power's service territory is primarily what drives the need for new generating resources. In 1990, Idaho Power had approximately 290,000 retail customers, and a firm peak-hour load of less than 2,100 MW. Today, Idaho Power serves over 480,000 retail customers in Idaho and Oregon, and firm peak-hour load has grown to over 3,200 MW. Average firm load has increased from approximately 1,200 aMW in 1990 to over 1,800 aMW in 2008.

Q. What role does the Company's integrated resource planning process play in determining the need for the acquisition of a baseload resource?

A. The Company's integrated resource planning process is the basis for establishing the Company's need for the acquisition of additional resources. The IRP considers supply-side resources (generators and market purchases), demand-side resources (energy efficiency or demand response programs), and the transmission lines necessary to integrate these resources. Because of the Company's reliance on its hydroelectric generation, its operations can be significantly affected by water conditions. With this in mind, the Company's IRP utilizes two planning criteria, one for average load or energy and another for peak-hour load, and both are based on receiving less than normal streamflows. For energy, Idaho Power plans to be able to serve its average loads under 70th percentile water and 70th percentile load conditions. For peak-hour load, Idaho Power plans to serve its peak-hour loads under 90th percentile water and 95th percentile load conditions.

The preferred portfolio in the 2004 IRP included a 500 MW baseload coal-fired resource, with seasonal ownership, in 2011. The preferred portfolio in the 2006 IRP refined this resource need to a 225 MW power purchase facilitated from what we called a McNary to Boise transmission upgrade in 2012, a 250 MW pulverized coal baseload resource in 2013 and a 250 MW Regional IGCC (or "clean coal") project in 2017. Since the 2006 IRP was published, escalating concerns regarding climate change, CO_2 emissions and the public's perception of coal-fired resources has made coal-fired resource development an unrealistic alternative. These concerns coupled with the possibility of new large loads locating in our service territory and the anticipated shift of flow augmentation releases of water from the federal dams on the Snake River above Brownlee Dam from July and August to May and June, have prompted the Company to (1) revise the 250 MW coal-fired resource to a natural gas-fired baseload resource, (2) increase the size of the baseload resource to approximately 300 MW, and (3) accelerate the on-line date of the baseload resource to 2012.

Q. Why did the Company decide to utilize a competitive request for proposals or RFP process to acquire the baseload resource previously described in your testimony?

A. The competitive RFP process allows the Company to access the broader power supply market to obtain the best resource for our customers. It gives us access to a spectrum of potential resources and resource developers. Use of a formal RFP process provides customers and regulatory agencies with the assurance that the resource selection process was competitive, all potential suppliers had an equal opportunity to participate, and that the best resource alternative was selected.

Q. Did the Company engage an independent third-party to review the Company's RFP and bid evaluation process?

A. Yes. The Company retained R. W. Beck, an independent consulting company offering a complete range of consulting and engineering services to the utility industry, to assist us with the RFP process. Specifically, R. W. Beck was retained to assist with preparation of the RFP, the draft power purchase and tolling agreements, development of the evaluation criteria and manual, and evaluation of the proposals received in response to the RFP, including the self-build alternative. Mr. Steven Stein, R. W. Beck Principal & Executive Consultant, was R. W. Beck's project manager and the principal consultant involved in supporting our RFP process.

Q. Please describe the parameters the Company set for the responses to the RFP.

A. The parameters set for this RFP can be grouped into four categories; product, quantity, proposal size, and term. The product was specified as dispatchable, first call, non-recallable, physically delivered firm, or unit contingent energy, commencing not later than June 1, 2012, that is dedicated solely to Idaho Power's use. The RFP indicated that the product requirements could be met through Power Purchase Agreements ("PPA") or Tolling Agreements ("TA"). The RFP also advised that the Company would include in the bidding process a Company-developed CCCT that would provide a benchmark resource for consideration. Build-and-transfer proposals were not considered in this RFP process. The quantity of dispatchable firm or unit contingent energy requested was initially specified as between approximately 250 MW and 600 MW. On June 25, 2008, the quantity was revised to approximately 300 MW. The minimum and maximum proposal sizes were initially specified as 50 MW and approximately 600 MW, respectively. When the quantity was revised to approximately 300 MW, the maximum proposal size also was adjusted to approximately 300 MW. Regarding term, each respondent was required to submit one proposal with a term of 15 years and 1 five-year renewal option.

Q. Why didn't the Company allow build-and-transfer proposals?

A. When the Company made the decision to pursue a combined cycle project, Company employees visited a number of combined cycle projects. During these site visits, Company employees observed significant design differences between similar sized projects. Simply put, some designs were much better than others.

If a build-and-transfer option was permitted, and projects with significant design differences were proposed, the evaluation process could become extremely complicated and somewhat subjective. The Company concluded that the best way to eliminate significant design differences between the proposals and assure an effective evaluation process was to prepare and issue a detailed specification with the RFP to ensure uniform design criteria between projects.

Given the decision to accelerate the on-line date to 2012, information obtained regarding critical equipment manufacturing lead times, and the aforementioned differences in project design, in the Company's opinion, it did not have enough time to prepare a detailed design specification and release the RFP in time to meet the 2012 on-line date.

Q. Please describe the response the Company received to the RFP.

A. The Company received six proposals. One proposal was returned unopened because the bidder did not submit a Notice of Intent to Bid as required by the RFP. The five remaining valid proposals represented a total of thirteen alternative resources. The alternatives included:

one Power Purchase Agreement, nine TAs, two hybrid proposals, and the Benchmark Resource.

The nine TAs offered included three different technology classes; three TAs were for large frame simple cycle CTs, two TAs were for advanced aeroderivative simple cycle CTs, and five TAs were for 1 x 1 combined cycle CTs.

Q. Please describe the process the Company followed to evaluate and rank the responses to the RFP.

A. The process the Company followed to evaluate and rank the responses received in response to the RFP is outlined in the Proposal Evaluation Manual prepared for the 2012 Baseload Generation RFP. The Proposal Evaluation Manual was finalized before any of the proposals were received. The evaluation process can be characterized as a three stage screening process.

In stage 1 screening, proposals were checked against the minimum requirements set forth in the RFP. This screening involved checking proposals for completed forms, minimum quantities, minimum term, addressing environmental costs, an Interconnection Feasibility Study Report, and signatures.

At the Stage 2 screening level, a busbar analysis was used to determine the cost of each proposal. Levelized fixed, variable and total costs, and non-levelized total costs at various capacity factors were calculated.

During Stage 3 screening, price and non-price factors, or criteria, were scored for each proposal using a weighted scoring system. The price factors received a total of 60 points. Price factors were based on the net present value ("NPV") of the estimated total revenue requirement associated with each proposal. Each proposal making it to Stage 3 screening was modeled and its impact on Idaho Power's system costs was simulated using the Aurora Electric Market Model. The results of the Aurora analysis were used to determine the NPV of the revenue requirements associated with adding that project to Idaho Power's portfolio of resources. Non-price factors received a total of 40 points. Non-price criteria included: project development, project characteristics, product characteristics, project location, environmental, credit factors, and financial strength. A total of 40 points were distributed between these six non-price criteria. Sensitivity analyses were run for high and low gas price scenarios, but these results did not impact the price and non-price scores.

Q. How did the Company address transmission costs in the RFP process?

A. One of the minimum requirements of the RFP was that proposals relying on a new generating resource to be developed in Idaho Power's service territory were required to submit an Interconnection Feasibility Study report prepared by Idaho Power's Delivery Planning group with their proposal. The cost estimates provided by Idaho Power's Delivery Planning group in the Interconnection Feasibility Study Reports or, in one case, a System Impact Study were used to set the transmission costs of each proposal.

Q. What fuel cost assumptions were used in evaluating the bids?

A. The same assumptions for the cost of fuel delivery to the Northwest Pipeline mainline tap, in $/MMBtu, were used to evaluate all proposals, including the Benchmark Resource. Any costs from the main line tap to the proposed resource locations were considered to be project specific. The natural gas price forecast used to evaluate bids showed an increase from $9.39/MMBtu in 2012 to $15.55/MMBtu in 2036. This forecast is provided as Exhibit No. 1.

Q. How was the cost of AFUDC evaluated for the Benchmark Resource?

A. The benchmark proposal included an estimate of AFUDC costs expected to be incurred during the construction of the project. The Benchmark Resource team's AFUDC estimate was calculated by applying a 7 percent 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. The total amount of AFUDC included in the plant portion of the Benchmark Resource evaluation was approximately $49 million. For the Benchmark Resource proposal, this amount was included in the capitalized cost of the project, which was used to calculate the estimated revenue requirement for the Benchmark Resource.

Q. How do the total costs of the selected Langley Gulch Project compare to the other bids received by the Company in response to the RFP?

A. Exhibit No. 2 shows the total revenue requirement for each of the three short-listed CCCT projects. The Benchmark Resource is Project D. Exhibit No. 3 shows the 20 year net present value ("NPV") of the difference in revenue requirement between the short-listed three CCCT projects.

Q. What does Exhibit No. 3 show?

A. Exhibit No. 3 shows that the 20-year NPV of the revenue requirements for the Langley Gulch Project were $108 million less than the next closest combined cycle project on the short-list. To put the $108 million difference in perspective, it is about 3.8 percent less than the 20-year NPV of the revenue requirements of the combined cycle project finishing in second place.

Q. Do Exhibits Nos. 2 and 3 reflect the Company's Commitment Estimate amount?

A. No. The comparisons shown in these exhibits are based on the final costs submitted by the short-listed bidders. However, I do not believe use of the Commitment Estimate in the comparison would change the ranking of the bids.

Q. How did the non-price attributes compare among the various responders to the RFP?

A. Although each project was unique, overall, the non-price scoring for the short-listed projects was actually quite close. Less than 3 points separated the non-price scores for all of the short-listed projects and less than 2 points separated the non-price scores of the short-listed combined cycle projects. Out of a possible 40 non-price points, the scores for the short-listed combined cycle projects ranged from 30.1 to 28.6. In this RFP, the non-price scores were not a significant differentiator.

Q. Why did the Company ultimately select the Langley Gulch Project as the preferred bidder?

A. The Company's ultimate decision to select the Langley Gulch Project, based on the results of the RFP, was primarily dictated by its substantially lower price. The differential between the 20 year NPV of the revenue requirements of the Langley Gulch and the closest Tolling Agreement for a combined cycle project shows the second place project was approximately $108 million more expensive, and the NPV analysis for the Tolling Agreement for the third-place combined cycle project was $220 million more expensive than the Langley Gulch Project. Exhibit No. 3 shows this differential graphically.

Q. Are there any unique issues associated with a utility-owned resource?

A. There are certain risks and benefits associated with selecting a traditional utility rate-based project. By selecting the Langley Gulch Project and providing a Commitment Estimate, the Company and its shareholders take on project development and construction risk. Customers retain the risk of fuel cost increases under either a tolling agreement or a utility-owned resource. However, with the utility-owned resource, any savings resulting from the Project realizing a better than expected heat rate will be shared with customers through the PCA. That leaves the risk that the Company may not be able to operate and maintain the Project as efficiently as another operator. While this is a possible risk, conversely, if the Company is able to operate and maintain the Project for less than its anticipated costs, customers will have an opportunity to receive those savings. The potential operating risk needs to be balanced against the possible operating savings, plus the benefit of a projected 20 year NPV reduction in revenue requirement of $108 million, plus the residual value associated with the Langley Gulch Project at the end of 20 years. It is the Company's conclusion that the above-described benefits to customers outweigh the risks associated with developing and operating a traditional utility rate-based project.

Q. The Company's 2006 IRP ten year resource plan recommends that a baseload resource be on-line in 2012. What is the schedule for the Project's commercial operation date?

A. Initially, the 2012 base load resource was expected to be on-line in time to meet peak-hour loads during the summer of 2012. However, given the current economic crisis, the Company anticipates difficulty financing this project without receiving a Certificate of Public Convenience and Necessity ("CPCN") with specific ratemaking or cost-recovery assurances. The Company estimates that it may take up to 6 months to obtaining a CPCN containing the needed regulatory assurances. Acknowledging the IPUC's need to carefully consider the Company's request, the Company has negotiated with the Langley Gulch Project's EPC contractor to postpone additional expenditures until a CPCN is received. Unfortunately, postponing additional expenditures for 6 months is expected to delay the project's on-line date by 6 months. Assuming that a Notice to Proceed is issued on September 1, 2009, the project is expected to be on-line in October 2012, and in commercial operation on December 1, 2012.

Q. How is the fuel supply delivered to the project?

A. Ideally, Idaho Power would like to have the ability to access and deliver natural gas from both the Western Canadian Sedimentary Basin (British Columbia and Alberta) and the U.S. Intermountain West, or Rockies region. Idaho Power has transportation rights on Williams' Northwest Pipeline from Sumas, Washington, to Elmore, Idaho. Idaho Power also has committed to acquire additional transportation rights on Northwest Pipeline from Stanfield, Oregon, to the Boise area and we are investigating the acquisition of additional transportation rights, also on Northwest Pipeline, from the Rockies region to the Boise area. Idaho Power intends to deliver natural gas to the Project site via Williams' Northwest Pipeline. Northwest Pipeline will be tapped and a short lateral line, approximately 1 mile in length, will be constructed to connect the Project to Northwest Pipeline.

Q. Were there other material considerations that should be considered when reviewing the Company's bid evaluation process?

A. Yes. There are two items that I would like to stress. The first is imputed debt. The RFP evaluation process did not assign any additional costs to the PPAs 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.

The second item is treatment of the costs associated with not selecting the Langley Gulch Benchmark Resource. While the Company recognizes that there may be loss of equipment deposits, reservation fees, cancellation charges, and other penalties or costs that Idaho Power would incur if the Benchmark Resource was not selected, these potential costs were not considered in the bid evaluation. If all other things were equal, PPA or TA proposals would not have had to win by more than Idaho Power's cancellation costs to have been considered the winner.

Q. Did R. W. Beck provide a written assessment of the Company RFP process?

A. Yes. A copy of their assessment is attached as Exhibit No. 4.

Q. What did R. W. Beck conclude concerning the quality of the Company's RFP process?

A. R. W. concluded:

> Finally, based on our work with the Idaho Power RFP Evaluation Team as described above, we believe that the Idaho Power 2012 Baseload RFP process was conducted fairly and properly and that offers provided to Idaho Power as part of the RFP process, including the Benchmark Resource, were treated objectively and consistently as set forth in Section 5.5 of the RFP. (R. W. Beck Report, p. 3.)

Q. Are there other attributes of the Langley Gulch Project that you believe should be important to the Commission's consideration?

A. Yes. Although not directly evaluated in the RFP process, there are several other benefits associated with adding a combined cycle combustion turbine to Idaho Power's generation resources. First, by using new, state of the art technology, the Langley Gulch Project will benefit from technological advancements resulting in improved efficiency which can be passed through to customers in the form of reduced operating costs and greater secondary sales revenues. Second, the improved efficiency and the low variable operating costs of the Langley Gulch Project will result in the unit being dispatched more frequently. Having the unit on-line more frequently gives Idaho Power another resource to assist with integrating wind or other intermittent resources. Third, the Langley Gulch Project is expected to have a residual value, and be available to serve customers at the end of 20 years. Finally, adding a combined cycle project to Idaho Power's 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, reducing the Company's CO_2 emissions from its coal-fired resources.

Q. The Company is requesting that the Commission expedite its review of the Application. Could you explain why?

A. An expedited review of the Company's application will enable the Company to proceed with the project reducing the amount of time that project costs are subject to escalation. Also, an expedited approval process may enable the project to be on-line for the summer of 2012.

Q. Does that complete your testimony?

A. Yes.

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IDAHO POWER COMPANY

BOKENKAMP, DI TESTIMONY

EXHIBIT NO. 1

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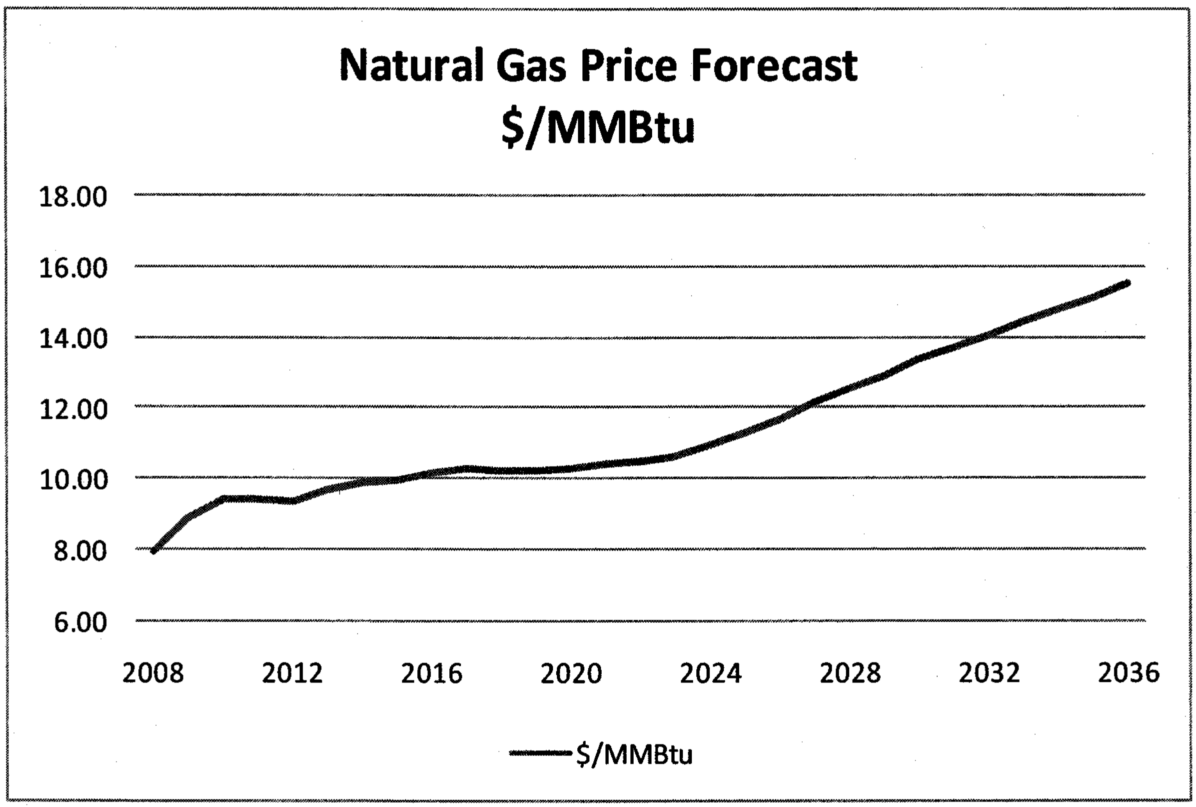

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IDAHO POWER COMPANY

BOKENKAMP, DI
TESTIMONY

EXHIBIT NO. 2

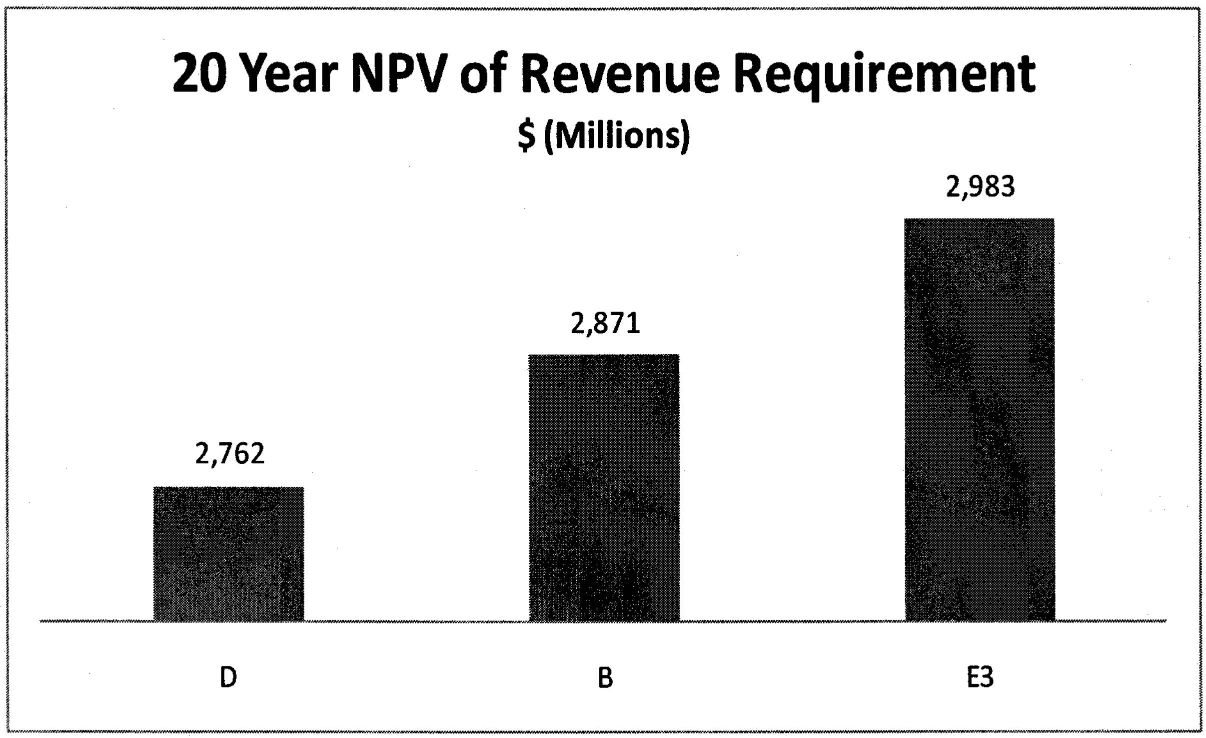

Exhibit No. 2
Case No. IPC-E-09-03
K. Bokenkamp, IPC

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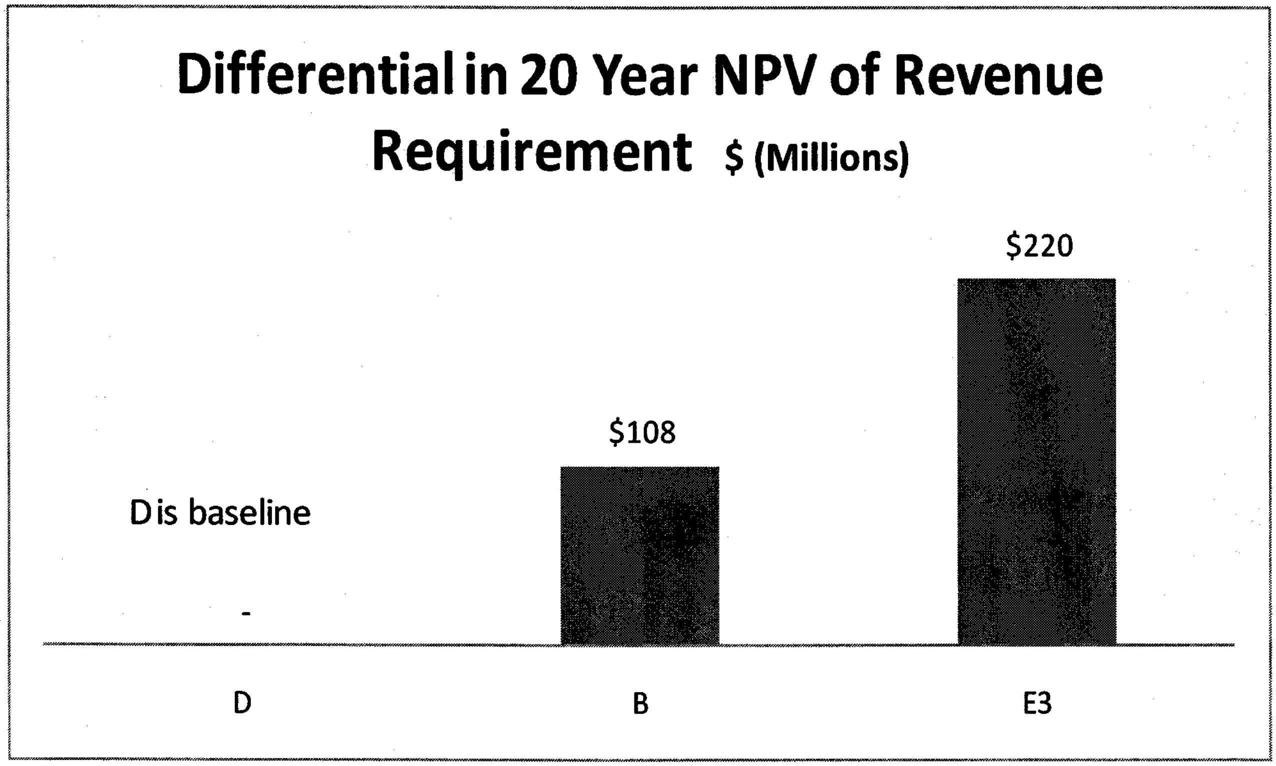
IDAHO POWER COMPANY

BOKENKAMP, DI
TESTIMONY

EXHIBIT NO. 3


Differential in 20 Year NPV of Revenue Requirement $ (Millions)
$220
$108
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BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-09-03

IDAHO POWER COMPANY

BOKENKAMP, DI TESTIMONY

EXHIBIT NO. 4