BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-05-10

IDAHO POWER COMPANY

EXHIBIT NO. 1

GREGORY W. SAID

Direct Testimony of Gregory W. Said
Case No. IPC-E-03-12

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE RATE-BASING OF THE BENNETT MOUNTAIN POWER PLANT	)))))))	CASE NO. IPC-E-03-12

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

GREGORY W. SAID

Q. Please state your name and business address.
A. My name is Gregory W. Said 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 Manager of Revenue Requirement in the Pricing and Regulatory Services Department.
Q. Please describe your educational background.
A. In May of 1975, I received a Bachelor of Science Degree with honors from Boise State University. In 1999, I attended the Public Utility Executives Course at the University of Idaho.
Q. Please describe your work experience with Idaho Power Company.
A. I became employed by Idaho Power Company in 1980 as an analyst in the Resource Planning Department. In 1985, the Company applied for a general revenue requirement increase. I was the Company witness addressing power supply expenses.

In August of 1989, after nine years in the Resource Planning Department, I was offered and I accepted a position in the Companys Rate Department. With the Companys application for a temporary rate increase in 1992, my responsibilities as a witness were expanded. While I

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continued to be the Company witness concerning power supply expenses, I also sponsored the Companys rate computations and proposed tariff schedules.

Because of my combined Resource Planning and Rate Department experience, I was asked to design a Power Cost Adjustment (PCA) which would impact customers rates based upon changes in the Companys net power supply expenses. I presented my recommendations to the Idaho Public Utilities Commission in 1992 at which time the Commission established the PCA as an annual adjustment to the Companys rates. I have sponsored the Companys annual PCA adjustment in each of the years 1996 through 2003.

In 1996, I was promoted to Director of Revenue Requirement. At year-end 2002, I was promoted to the senior management level of the Company.

During 1999 and 2000, I directed the preparation of the Companys 2000 Integrated Resource Plan (IRP). I managed the Request for Proposals (RFP) process that resulted from the Near-Term Action Plan identified in that Resource Plan. I also participated in the preparation of the 2002 IRP and subsequent 2003 RFP process. The RFP issued as part of the Near-Term Action Plan outlined in the 2002 IRP report has resulted in the selection of the Mountain View Power, Inc. project as the Companys preferred addition of a new peaking resource.

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

A. There are four major topics that comprise my testimony. First, I will briefly describe the history that preceded Idaho Powers issuance of the RFP on February 24, 2003. Second, I will describe the bid evaluation process that led up to the selection of the Mountain View Power, Inc. (MVP) as the winning bidder. Third, I will discuss some of the significant provisions of the agreement with MVP for the Bennett Mountain Power Plant (Project). Finally, I will discuss the Companys proposed ratemaking treatment of the costs associated with the Project.

Q. What are the major events that preceded the selection of the MVP proposal?

A. The major events leading up to the selection of the MVP proposal are the issuance of the 2002 IRP in June 2002, the supplement to the 2002 IRP often called the Garnet Report filed in October 2002, the Commission acknowledgement of the 2002 IRP as supplemented with the Garnet Report in February 2003, the issuance of the current RFP in February 2003 and Commission approval of the PPL Montana, LLC contract in July 2003. The 2002 IRP, the Garnet Report and the PPL Montana contract are all on file with the Commission and as such, Idaho Power requests that the Commission take administrative notice of these documents.

Q. What were some of the assumptions that formed the basis of the 2002 IRP?

A. The first assumption of the 2002 IRP was that the Garnet facility would be constructed. In addition to that assumption, the Company also shifted its emphasis from the median water planning criteria to the evaluation of a 70th percentile water and 70th percentile load condition. This shift in emphasis resulted in less reliance on market purchases during periods of low water and a greater need for resource acquisition.

Q. Based upon those assumptions, what did the Company conclude was required to satisfy future loads in the planning horizon?

A. The Company planned to continue seasonal market purchases in June, July, November and December in the near term, to integrate demand-side measures where economical, to issue an RFP for a 100 megawatt resource to be available in 2005, to purchase up to 250 megawatts of seasonal capacity and energy beginning in June 2005, to proceed with the Brownlee to Oxbow transmission line to be in service in 2005 and to upgrade the Shoshone Falls project to be in service in 2007.

Q. How was the 2002 plan modified as a result of Garnets inability to acquire acceptable financing for its project?

A. At the request of the Commission, the Company supplemented its 2002 IRP with the Garnet Report in October 2002. In the supplemental Garnet Report, the Company identified alternatives to the Garnet project including potential purchases from the east side of our system. The Garnet Report also stated that the Company was seriously considering increasing the 2003 RFP to approximately 170 megawatts.

Q. Has the Company been able to acquire any of the alternatives to Garnet discussed in the 2002 IRP supplemental Garnet Report?

A. Yes, on May 13, 2003 the Company applied to the Commission for approval of a Power Purchase Agreement (PPA) with PPL Montana, LLC. The PPA with PPL Montana, LLC calls for an 83 megawatt firm power purchase for the heavy load hours, six days a week, sixteen hours a day (6X16) in the months of June, July and August beginning in June 2004. Adjusting for losses, the 83-megawatt purchase replaces approximately 80 megawatts of the Garnet project, which was anticipated to provide up to 250 megawatts during the same summer season peak hours. In July 2003, the Commission approved the PPL Montana, LLC Power Purchase Agreement.

Q. When did the Company issue its most recent RFP?

A. The most recent RFP was issued on February 24, 2003.

Q. Please describe the 2003 RFP issued by the Company.

A. Because the Company was unsure of the extent to which the Garnet project could be replaced, the Company issued a somewhat flexible RFP request. Rather than requesting 100 megawatt proposals as suggested in the original 2002 IRP, the Company allowed bidders to propose projects up to 200 megawatts. In the RFP, the Company advised bidders it was willing to consider either Power Purchase Agreements or build and transfer arrangements. Discussions at the pre-bid meeting covered the assumption that for a PPA to be successful it would need to provide significant savings to the Companys customers as a result of the bidders ability to operate the plant as a merchant plant and sell the output from the plant to third parties whenever the Company was not utilizing it.

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

A. The Company received 21 Notices of Intent to bid projects into the RFP. Ultimately, the Company received 11 bids, including simple cycle combustion turbine proposals, combined cycle combustion turbine proposals and a biomass proposal. The proposals were about evenly split between build and transfer proposals and PPAs.

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

A. Yes, as in our 2000 RFP evaluation, the Company utilized R.W. Beck as an independent third party to assist in the development of the 2003 RFP and evaluation criteria and to provide further assistance in the review and evaluation of bids.

Q. Please describe the process that led up acceptance of the proposal from Mountain View Power, Inc. as the successful RFP respondent.

A. The Idaho Power RFP team received all bids by April 28, 2003, including a self-build proposal prepared under a joint teaming arrangement consisting of Black & Veatch, TIC and a separate group within Idaho Powers Power Supply Department. On April 29, 2003 the RFP evaluation team opened the proposals and began the initial screening process based on predetermined price criteria and non-price criteria methodology established with the assistance of R.W. Beck. In May 2003, based upon initial screening, the top five proposals were short-listed and face-to-face meetings with representatives of the short-listed entities were scheduled for June 2003. The Company sent a document to each of the short-listed bidders detailing the Companys understanding of that bidders bid. Those Companys understanding documents, prepared for the review and concurrence of the bidders, became the basis for face-to-face discussions with each of the short-listed bidders.

Following the face-to-face meetings with the short-listed bidders, the Company pursued final negotiations with two bidders, Mountain View Power, Inc. and the Idaho Power Self-Build team. These two bidders offered the best proposals based upon the price and non-price criteria. Additional face-to-face meetings were conducted and final modifications to bids were accepted through September 12, 2003. Based on the final negotiations, the RFP evaluation team made its recommendation to the Companys management and on September 17, 2003 the Companys management recommended to the IdaCorp Board of Directors that Mountain View Power, Inc. be selected as the successful bidder. On September 18, 2003, the Board of Directors approved the selection of the Mountain View Power, Inc. proposal to construct the Bennett Mountain Project.

Q. Please give a general description of the Project.

A. The Project will consist of a Siemens-Westinghouse 501FD simple-cycle natural gas-fired combustion turbine rated at 162 MWs, together with typical balance of plant facilities and equipment. The Project is currently scheduled to begin generating in the summer of 2005. The Project will be located on an almost ten (10) acre site within the Mountain Home Industrial Park in Mountain Home, Idaho. The City has issued a Conditional Use Permit for a power plant for the site. The Industrial Park site may accommodate an additional future generating unit and the Project can also be modified to operate as a combined cycle plant at some point in the future.

The Project will be connected to the Companys existing 230 kV transmission system that passes approximately four (4) miles north of the Project.

A natural gas fuel supply will be delivered from the Williams Northwest Pipeline that passes less than one (1) mile from the site.

Water for generation will be supplied by and purchased from the City of Mountain Home, Idaho. The City has constructed a network of wells, lines and storage facilities and has substantial water supply capacity and priority water rights.

The Projects waste water will be discharged to the City of Mountain Homes sewer system.

The Project will operate in compliance with all appropriate DEQ air and water quality standards.

Maps showing the location of the Project are attached to the Companys application.

Q. What is the firm contract price for the Project?

A. The firm contract price for the 162-megawatt Project is $44.6 million.

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

A. Gas prices were assumed to be $4.52 per million BTU in 2005 and were escalated throughout the life of the project. The same gas price was utilized for all natural gas-fired project proposals and, as a result, projects with lower guaranteed heat rates had lower fuel costs on a dollar per megawatt basis.

Q. What capacity factor was used to evaluate the bids?

A. While the RFP team looked at costs for a number of capacity factors, bids were evaluated assuming a 20 percent capacity factor reflective of peak hour production in the five months June, July, August, November and December only.

Q. Were there other material considerations used in evaluating the bids?

A. Yes. The selected bidder had to demonstrate the financial strength and experience to provide Idaho Power with a high level of confidence that output from the project would be available June 1, 2005. In addition, the Companys

Tax Department was consulted because of potential bonus tax depreciation benefits that could be derived based upon percentage of completion of power plants by December 31, 2004. Bidders were encouraged to prepare their construction schedules to maximize the tax benefits while at the same time ensure that they would not complete the project too far in advance of the Companys identified need in June 2005. Mountain View Power, Inc. was very cooperative in proposing a schedule that would complete 95% of the project by year-end 2004, but ownership of the project would not be transferred until April 2005.

Q. Would you please describe what you believe are the significant provisions of the turnkey construction arrangement with Mountain View Power, Inc. for acquisition of the Project?

A. One of the most significant attributes of the MVP turnkey Project is that MVP has contracted with Siemens-Westinghouse Power Corporation (SWPC) to furnish all of the labor, equipment and materials and to perform all of the engineering and construction of the Project. The contract with MVP provides that if MVP defaults, Idaho Power can step-through MVP and work directly with SWPC to complete the Project. As a result, Idaho Power can rely on SWPC and the financial strength and experience of both SWPC and its parent, Siemens Corporation, to assure the performance of the contract and the successful completion of the Project.

As I have mentioned, Mountain View Power, Inc. will have the project approximately 95% complete by year-end 2004. Liquidated damages will occur if the Siemens-Westinghouse gas turbine has not been delivered to the site by December 1, 2004. Completion of construction and all performance testing of the Project, including guaranteed capacity and guaranteed heat rate, are scheduled to be completed by April 1, 2005. Project ownership will transfer to Idaho Power at that time provided that all Provisional Acceptance Criteria identified in the contract have been satisfied. If not, liquidated damages will be owed. A back-loaded payment schedule insures that Mountain View Power, Inc. and SWPC have adequate incentive to see the Project through to completion.

Q. Are there other attributes of the Project that you believe are important to the Commissions consideration?

A. The Project is located approximately 4 miles southwest of the Companys existing 230 kV transmission system. The transmission system will require additional investment in order to integrate the Project. However, the total cost of this Project (on a revenue requirement basis) including transmission costs is lower than the alternatives. Mountain View Power, Inc. has worked closely with the

Mountain Home community to gain support for the Project. By selecting this Project, the Company will have two expandable sites at which to place additional gas-fired resources in the future if future IRPs identify such resources as the resource of choice.

Q. Is it likely that the Company will need additional peaking resources in the future?

A. Yes. The 2002 IRP identified the need for approximately 450 megawatts of capacity and energy to satisfy deficiencies found primarily in three summer months and two winter months. The plan was to utilize 250 megawatts from the Garnet Project, acquire another 100 megawatts via an RFP and establish market purchases of approximately 100 megawatts. The Garnet Project will not be built and the PPL Montana Contract has replaced only 80 megawatts of that 250-megawatt project. With the addition of this 162-megawatt Project, 242 megawatts of required capacity will have been acquired. That leaves approximately 208 megawatts to be acquired via the market or development of additional projects. That 208 megawatt amount is 108 megawatts greater than the level of planned market purchases in the 2002 IRP and exceeds the Companys comfort level for resource adequacy.

Q. Is the Company providing a commitment estimate for the capital cost portion for the Project?

A. Yes. The Company is willing to commit to the Commission that the total cost of the Project to be included in the Companys rate base will not exceed $54.0 million. This amount includes the $44.6 million MVP contract amount, plus additional costs the Company knows it will incur but cannot precisely quantify at this time. These additional costs include, but are not limited to, sales taxes, AFUDC on progress payments made to MVP during construction, the cost of Idaho Power oversight of the project, and the cost of capitalized start-up fuel. The Commitment Estimate amount also covers contingencies such as change orders and other unforeseen circumstances. Transmission costs are not included in the Commitment Estimate.

Q. Were transmission costs considered when evaluating the total cost of the Project?

A. Yes. The total Project costs including estimated transmission costs were evaluated within the selection process. However, transmission costs have not traditionally been included in the Companys commitment estimates for power projects. While the Company is satisfied that the approximately $11.6 million estimate for transmission costs associated with this Project is a reasonable upper limit estimate, no definitive studies have been completed and the Company is not including transmission costs in its commitment estimate.

Q. How is fuel supply handled for the Project?

A. Because the Project will ultimately be owned, operated and maintained by Idaho Power Company, the Company will coordinate the fuel supply and transportation for the Project concurrently with the fuel supply and transportation requirements of the Danskin Power Plant. Idaho Power has purchased firm fuel transportation rights that can be used for both Danskin and the Project. Idaho Power anticipates that management of the fuel transportation and fuel supply will be either by Idaho Power personnel, or by Idaho Power personnel in conjunction with a third party such as IGI, Inc.

Q. How does the Company propose that the Commission treat the costs associated with construction and operation of the Project for ratemaking purposes?

A. Provided that the Project costs are less than the commitment estimate of $54.0 million, Idaho Power Company would expect the Commission to approve the total Project investment to be included in the Companys rate base for ratemaking purposes. Fuel costs should be approved for PCA inclusion prior to full review of operational costs in a general revenue requirement proceeding.

Q. Why does the Companys request include recovery of AFUDC?

A. Even though the Project will be owned by

Mountain View Power, Inc. until ownership is transferred to Idaho Power in April 2005, AFUDC is appropriate for recovery as a Project cost because the Company is helping to finance the Project by making progress payments during construction. Such financing by the Company allows for a lower total cost to customers than if Mountain View Power, Inc. were to finance the Project in a different manner.

Q. How do the costs of the Project compare to alternative resources?

A. Due to a current abundance of turbines available in the market, Mountain View Power, Inc. is able to construct the Project at significantly lower costs than similar projects constructed just a short time ago. The commitment cost of $54.0 million for the 162-megawatt Bennett Mountain Project is just $5 million more than the $49 million cost of the 90-megawatt Danskin project completed in September, 2001. Including the upper end estimate of $11.6 million for the cost of transmission and all capital costs associated with the Project, the Company estimates that the ten-year present value cost per megawatt hour will be approximately $78 based upon a 20 percent capacity factor. The 20 percent capacity factor assumes the Project will only be utilized during the peak hour need periods identified in the 2002 IRP. The $78 per MWh figure also assumes that the additional transmission capability constructed to accommodate the Project is only used to move power from the Project. This cost will be reduced whenever the plant is utilized to a greater extent than assumed in this analysis. However, even at $78, the cost of the Project is very similar to the ten-year cost of $77 per megawatt hour cost that was anticipated for the Garnet contract. Unlike the Garnet project, this Project will be available year round rather than just during certain months of the year. Whereas the Garnet contract offered significant discounts from total project costs in order to retain a merchant role for their project, current-day projects can be developed at lower costs such that todays undiscounted project costs are similar to discounted Garnet costs. Ultimately, as market conditions changed, merchant projects were considered risky and the Garnet Project could not obtain acceptable financing. It should also be noted that the Garnet contract evaluation assumed gas prices of $3.75 per MMBtu whereas the RFP evaluation process assumed gas prices of $4.52 per MMBtu in 2005. The total first year fuel plus variable O&M cost for the Project is expected to be $57.55 per megawatt hour compared to the $44.50 per megawatt hour cost (not including transmission cost) of the PPL Montana PPA. However, it is important to remember that the PPL Montana PPA is a take or pay contract whereas this Project is dispatchable. If the resource is not needed, fuel costs can be avoided.

Q. In its final order acknowledging and accepting the Companys 2002 IRP, the Commission directed Idaho Power to consider the potential for cost-effective DSM as an alternative to supply-side resources. Is the Project compatible with available DSM options?

A. In my opinion, the Project dovetails very well with the Companys ongoing efforts to develop DSM programs targeting summer peak loads. As noted in the Companys 2002 IRP, the Companys peak load requirements occur during summer months with a secondary peak occurring in November and December. The Project is specifically targeted at the heavy-load hours during the peak summer months. Not all of the Companys anticipated deficiencies are satisfied by the Project. The potential to utilize cost-effective DSM alternatives still exists. In accordance with Commission Order No. 29207, the Company is currently pursuing a pilot program to implement a residential air conditioner cycling program. As noted in Order No. 29207, the Energy Efficiency Advisory Group (EEAG) has concurred with the Companys proposal to use energy efficiency rider funds collected under Idaho Powers Schedule 91, to finance the air conditioner cycling pilot program. The air conditioner cycling program targets heavy-load hours during June, July and August. If it is ultimately determined that an air conditioner cycling program would be a cost-effective way to reduce critical system peaks, such a program would address essentially the same peak periods of time that are the primary concern addressed by the Project, and could potentially mitigate the continuing need for additional resources similar to this Project. The Company has also recently announced the launch of a new DSM program that would target irrigation usage, another contributor to the Companys peak load during the June, July and August period covered by the Project. This program pays financial incentives to irrigation customers that modify existing irrigation systems or install new efficient irrigation systems. For all of these reasons, I believe that the Project is consistent with the Commissions expectations regarding consideration of DSM within the Companys integrated resource planning process.

Q. The Company is requesting that the Commission expedite its review of this Application. Please explain why.

A. In order to meet the April 1, 2005 Provisional Acceptance Date under the Agreement, Mountain View Power has indicated it needs to receive a notice to proceed on or before December 31, 2003. Idaho Power has advised Mountain View that a condition precedent to issuance of the notice to proceed is receipt of an acceptable

Certificate of Public Convenience and Necessity from the Idaho Public Utilities Commission. Depending on when the Certificate is issued, MVP may need to adjust the completion date and possibly the price of the Project.

Q. Does this complete your testimony?

A. Yes.

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BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-05 -10

IDAHO POWER COMPANY

EXHIBIT NO. 2

GREGORY W. SAID

Certificate No. 420
Case No. IPC-E-03-12

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE RATEBASING OF THE BENNETT MOUNTAIN POWER PLANT.	)	**CASE NO. IPC-E-03-12** **CERTIFICATE NO. 420**

On September 26, 2003, Idaho Power Company filed an Application for a Certificate of Public Convenience and Necessity to construct a new natural gas-fired generating plant in Mountain Home, Idaho pursuant to *Idaho Code* § 61-526.

IT IS HEREBY CERTIFIED that the future public convenience and necessity require and will require Idaho Power Company authorization to construct and subsequently operate a 162 MW natural gas-fired power plant and related interconnection facilities at Mountain Home. The Bennett Mountain generating plant will be located in the Mountain View Industrial Park in Mountain Home and will be interconnected to the natural gas transmission system approximately 3,400 feet away. Idaho Power shall operate and maintain the Bennett Mountain power plant to furnish electric energy to its customers.

THIS CERTIFICATE is predicated upon and issued pursuant to the findings of fact and conclusions of law contained in Order No. 29410 service dated January 2, 2004, in the above-referenced case.

DATED at Boise, Idaho this 8th day of January 2004.

Paul Kjellander

PAUL KJELLANDER, PRESIDENT

Marsha H. Smith

MARSHA H. SMITH, COMMISSIONER

Dennis S. Hansen

DENNIS S. HANSEN, COMMISSIONER

ATTEST:

Jean D. Jewell

Jean D. Jewell
Commission Secretary

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BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-05-10

IDAHO POWER COMPANY

EXHIBIT NO. 3

GREGORY W. SAID

Bennett Mountain Revenue Requirement

IDAHO POWER COMPANY
SUMMARY -- REVENUE REQUIREMENT
BENNETT MOUNTAIN GENERATING PLANT
TWELVE MONTHS ENDED DECEMBER 31, 2003

		IDAHO JURISDICTION		
		BALANCE PER ORDER NOS. 29505 & 29547	BENNETT MTN. AJUSTMENT	ORDER NOS. 29505 & 29547 W/ BENNETT MTN.
1				
2				
3				
4	DESCRIPTION			
5	*** SUMMARY OF RESULTS ***			
6	*RATE OF RETURN UNDER PRESENT RATES*			
7	TOTAL COMBINED RATE BASE	1,521,631,870	49,341,019	1,570,972,889
8				
9	SALES REVENUES	543,438,519	0	543,438,519
10	OTHER OPERATING REVENUES	36,277,412	0	36,277,412
11	TOTAL OPERATING REVENUES	579,715,931	0	579,715,931
12	OPERATING EXPENSES			
13	OPERATION & MAINTENANCE EXPENSES	347,301,240	107,843	347,409,084
14	DEPRECIATION EXPENSE	86,122,049	1,590,654	87,712,702
15	AMORTIZATION OF LIMITED TERM PLANT	9,088,066	0	9,088,066
16	TAXES OTHER THAN INCOME	19,048,704	946,630	19,995,334
17	PROVISION FOR DEFERRED INCOME TAXES	3,075,416	8,395,929	11,471,345
18	INVESTMENT TAX CREDIT ADJUSTMENT	(304,833)	0	(304,833)
19	FEDERAL INCOME TAXES	16,326,344	(6,407,569)	9,918,775
20	STATE INCOME TAXES	3,318,199	(296,936)	3,021,262
21	TOTAL OPERATING EXPENSES	483,975,185	4,336,551	488,311,736
22	OPERATING INCOME	95,740,746	(4,336,551)	91,404,195
23	ADD: IERCO OPERATING INCOME	6,687,185	0	6,687,185
24	CONSOLIDATED OPERATING INCOME	102,427,931	(4,336,551)	98,091,381
25	RATE OF RETURN UNDER PRESENT RATES	6.731%	-8.789%	6.244%
26				
27	DEVELOPMENT OF REVENUE REQUIREMENTS			
28	RATE OF RETURN ALLOWED @ 10.25 ROE	7.852%	7.852%	7.852%
29	RETURN AT CLAIMED RATE OF RETURN	119,478,534	3,874,257	123,352,791
30				
31	EARNINGS DEFICIENCY	17,050,603	8,210,807	25,261,411
32	NET-TO-GROSS TAX MULTIPLIER	1.642	1.642	
33				
34	COMMISSION APPROVED REVENUE INCREASE	27,997,090		
35				
36	FIRM REVENUES PRIOR TO INCREASE	484,067,283		
37				
38	TOTAL REVENUES PER ORDER NOS. 29505 & 29547	512,064,373	512,064,373	
39				
40	REVENUE DEFICIENCY ASSOCIATED WITH BENNETT MTN.		13,482,146	
41				
42	TOTAL REVENUES REQUIRED WITH ADDITION OF BENNETT MTN.		525,546,519	
43				
44	PERCENT INCREASE REQUIRED		2.633%	

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G. SAID, IPCO
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IDAHO POWER COMPANY
SUMMARY -- REVENUE REQUIREMENT
BENNETT MOUNTAIN GENERATING PLANT
TWELVE MONTHS ENDED DECEMBER 31, 2003

		TOTAL SYSTEM			IDAHO JURISDICTION		
1		BALANCE PER ORDER NOS. 29505 & 29547	BENNETT MTN. AJUSTMENT	ORDER NOS. 29505 & 29547 W/ BENNETT MTN.	BALANCE PER ORDER NOS. 29505 & 29547	BENNETT MTN. AJUSTMENT	ORDER NOS. 29505 & 29547 W/ BENNETT MTN.
2							
3							
4	DESCRIPTION						
44	*** SUMMARY OF RESULTS ***						
45	DEVELOPMENT OF RATE BASE COMPONENTS						
46	ELECTRIC PLANT IN SERVICE						
47	INTANGIBLE PLANT	69,424,051	0	69,424,051	64,217,228	0	64,217,228
48	PRODUCTION PLANT	1,446,903,621	50,298,492	1,497,202,113	1,366,629,707	47,507,942	1,414,137,649
49	TRANSMISSION PLANT	526,016,267	6,925,114	532,941,381	448,421,563	5,987,373	454,408,936
50	DISTRIBUTION PLANT	925,335,123	171,040	925,506,163	864,259,864	158,133	864,417,997
51	GENERAL PLANT	196,094,518	628,337	196,722,855	181,373,950	581,169	181,955,119
52	TOTAL ELECTRIC PLANT IN SERVICE	3,163,773,581	58,022,983	3,221,796,563	2,924,902,313	54,234,616	2,979,136,929
53	LESS: ACCUM PROVISION FOR DEPRECIATION	1,312,160,447	849,456	1,313,009,903	1,214,507,246	805,229	1,215,312,475
54	AMORT OF OTHER UTILITY PLANT	30,431,656	0	30,431,656	28,149,513	0	28,149,513
55	NET ELECTRIC PLANT IN SERVICE	1,821,181,478	57,173,527	1,878,355,005	1,682,245,554	53,429,388	1,735,674,941
56	LESS: CUSTOMER ADV FOR CONSTRUCTION	11,079,525	0	11,079,525	11,019,157	0	11,019,157
57	LESS: ACCUM DEFERRED INCOME TAXES	230,340,312	4,422,312	234,762,624	212,946,562	4,088,369	217,034,931
58	ADD : PLT HLD FOR FUTURE+ACQUIS ADJ	(195,036)	0	(195,036)	(195,036)	0	(195,036)
59	ADD : WORKING CAPITAL	27,389,050	0	27,389,050	25,440,783	0	25,440,783
60	ADD : CONSERVATION+OTHER DFRD PROG.	25,656,365	0	25,656,365	25,411,785	0	25,411,785
61	ADD : SUBSIDIARY RATE BASE	13,490,660	0	13,490,660	12,694,504	0	12,694,504
62	TOTAL COMBINED RATE BASE	1,646,102,680	52,751,215	1,698,853,895	1,521,631,870	49,341,019	1,570,972,889
63							
64	DEVELOPMENT OF NET INCOME COMPONENTS						
65	OPERATING REVENUES						
66	SALES REVENUES	576,145,092	0	576,145,092	543,438,519	0	543,438,519
67	OTHER OPERATING REVENUES	42,464,057	0	42,464,057	36,277,412	0	36,277,412
68	TOTAL OPERATING REVENUES	618,609,149	0	618,609,149	579,715,931	0	579,715,931
69	OPERATING EXPENSES						
70	OPERATION & MAINTENANCE EXPENSES	371,085,185	116,046	371,201,231	347,301,240	107,843	347,409,084
71	DEPRECIATION EXPENSE	93,106,218	1,698,912	94,805,129	86,122,049	1,590,654	87,712,702
72	AMORTIZATION OF LIMITED TERM PLANT	9,825,386	0	9,825,386	9,088,066	0	9,088,066
73	TAXES OTHER THAN INCOME	20,985,590	1,015,406	22,000,995	19,048,704	946,630	19,995,334
74	PROVISION FOR DEFERRED INCOME TAXES	3,109,043	8,487,732	11,596,775	3,075,416	8,395,929	11,471,345
75	INVESTMENT TAX CREDIT ADJUSTMENT	(308,166)	0	(308,166)	(304,833)	0	(304,833)
76	FEDERAL INCOME TAXES	16,612,318	(6,541,742)	10,070,575	16,326,344	(6,407,569)	9,918,775
77	STATE INCOME TAXES	3,376,320	(308,820)	3,067,501	3,318,199	(296,936)	3,021,262
78	TOTAL OPERATING EXPENSES	517,791,894	4,467,533	522,259,427	483,975,185	4,336,551	488,311,736
79	OPERATING INCOME	100,817,256	(4,467,533)	96,349,722	95,740,746	(4,336,551)	91,404,195
80	ADD: IERCO OPERATING INCOME	7,106,583	0	7,106,583	6,687,185	0	6,687,185
81	CONSOLIDATED OPERATING INCOME	107,923,839	(4,467,533)	103,456,305	102,427,931	(4,336,551)	98,091,381
82							
83	POWER SUPPLY COSTS:						
84	ACCT. 447/SURPLUS SALES	63,094,800	0	63,094,800	59,371,236	0	59,371,236
85	ACCT. 501/FUEL-THERMAL PLANTS	95,149,400	0	95,149,400	89,534,122	0	89,534,122
86	ACCT. 547/FUEL-OTHER	3,256,533	0	3,256,533	3,064,347	0	3,064,347
87	ACCT. 555/NON-FIRM PURCHASES	12,376,900	0	12,376,900	11,646,473	0	11,646,473
88	SUB-TOTAL: NET POWER SUPPLY COSTS	47,688,033	0	47,688,033	44,873,705	0	44,873,705
89	ACCT. 555/CSPP PURCHASES	46,191,952	0	46,191,952	43,475,869	0	43,475,869
90	TOTAL POWER SUPPLY COSTS	93,879,985	0	93,879,985	88,349,575	0	88,349,575

EXHIBIT NO. 3
CASE NO. IPC-E-05-10
G. SAID, IPC
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