

BEFORE THE
IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-05-10

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UTILITIES COMMISSION

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) CASE NO. IPC-E-03-12
AND NECESSITY FOR THE RATE-BASING)
OF THE BENNETT MOUNTAIN POWER)
PLANT)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

GREGORY W. SAID

1 Q. Please state your name and business address.

2 A. My name is Gregory W. Said and my business
3 address is 1221 West Idaho Street, Boise, Idaho.

4 Q. By whom are you employed and in what
5 capacity?

6 A. I am employed by Idaho Power Company as the
7 Manager of Revenue Requirement in the Pricing and Regulatory
8 Services Department.

9 Q. Please describe your educational background.

10 A. In May of 1975, I received a Bachelor of
11 Science Degree with honors from Boise State University. In
12 1999, I attended the Public Utility Executives Course at
13 the University of Idaho.

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

16 A. I became employed by Idaho Power Company in
17 1980 as an analyst in the Resource Planning Department. In
18 1985, the Company applied for a general revenue requirement
19 increase. I was the Company witness addressing power supply
20 expenses.

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

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

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

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

16 During 1999 and 2000, I directed the
17 preparation of the Companys 2000 Integrated Resource Plan
18 (IRP). I managed the Request for Proposals (RFP) process
19 that resulted from the Near-Term Action Plan identified in
20 that Resource Plan. I also participated in the preparation
21 of the 2002 IRP and subsequent 2003 RFP process. The RFP
22 issued as part of the Near-Term Action Plan outlined in the
23 2002 IRP report has resulted in the selection of the
24 Mountain View Power, Inc. project as the Companys preferred
25 addition of a new peaking resource.

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

3 A. There are four major topics that comprise my
4 testimony. First, I will briefly describe the history that
5 preceded Idaho Powers issuance of the RFP on February 24,
6 2003. Second, I will describe the bid evaluation process
7 that led up to the selection of the Mountain View Power,
8 Inc. (MVP) as the winning bidder. Third, I will discuss
9 some of the significant provisions of the agreement with MVP
10 for the Bennett Mountain Power Plant (Project).
11 Finally, I will discuss the Companys proposed ratemaking
12 treatment of the costs associated with the Project.

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

15 A. The major events leading up to the selection
16 of the MVP proposal are the issuance of the 2002 IRP in June
17 2002, the supplement to the 2002 IRP often called the
18 Garnet Report filed in October 2002, the Commission
19 acknowledgement of the 2002 IRP as supplemented with the
20 Garnet Report in February 2003, the issuance of the current
21 RFP in February 2003 and Commission approval of the PPL
22 Montana, LLC contract in July 2003. The 2002 IRP, the
23 Garnet Report and the PPL Montana contract are all on file
24 with the Commission and as such, Idaho Power requests that
25 the Commission take administrative notice of these

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1 documents.

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

4 A. The first assumption of the 2002 IRP was that
5 the Garnet facility would be constructed. In addition to
6 that assumption, the Company also shifted its emphasis from
7 the median water planning criteria to the evaluation of a
8 70th percentile water and 70th percentile load condition.
9 This shift in emphasis resulted in less reliance on market
10 purchases during periods of low water and a greater need for
11 resource acquisition.

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

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

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

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1 between build and transfer proposals and PPAs.

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

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

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

13 A. The Idaho Power RFP team received all bids by
14 April 28, 2003, including a self-build proposal prepared
15 under a joint teaming arrangement consisting of Black &
16 Veatch, TIC and a separate group within Idaho Powers Power
17 Supply Department. On April 29, 2003 the RFP evaluation
18 team opened the proposals and began the initial screening
19 process based on predetermined price criteria and non-price
20 criteria methodology established with the assistance of R.W.
21 Beck. In May 2003, based upon initial screening, the top
22 five proposals were short-listed and face-to-face meetings
23 with representatives of the short-listed entities were
24 scheduled for June 2003. The Company sent a document to
25 each of the short-listed bidders detailing the Companys

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1 scheduled to begin generating in the summer of 2005. The
2 Project will be located on an almost ten (10) acre site
3 within the Mountain Home Industrial Park in Mountain Home,
4 Idaho. The City has issued a Conditional Use Permit for a
5 power plant for the site. The Industrial Park site may
6 accommodate an additional future generating unit and the
7 Project can also be modified to operate as a combined cycle
8 plant at some point in the future.

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

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

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

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

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

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

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

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

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

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

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

15 A. While the RFP team looked at costs for a
16 number of capacity factors, bids were evaluated assuming a
17 20 percent capacity factor reflective of peak hour
18 production in the five months June, July, August, November
19 and December only.

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

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

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1 Tax Department was consulted because of potential bonus tax
2 depreciation benefits that could be derived based upon
3 percentage of completion of power plants by December 31,
4 2004. Bidders were encouraged to prepare their construction
5 schedules to maximize the tax benefits while at the same
6 time ensure that they would not complete the project too far
7 in advance of the Companys identified need in June 2005.
8 Mountain View Power, Inc. was very cooperative in proposing
9 a schedule that would complete 95% of the project by year-
10 end 2004, but ownership of the project would not be
11 transferred until April 2005.

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

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

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1 the contract and the successful completion of the Project.

2 As I have mentioned, Mountain View Power, Inc. will
3 have the project approximately 95% complete by year-end
4 2004. Liquidated damages will occur if the Siemens-
5 Westinghouse gas turbine has not been delivered to the site
6 by December 1, 2004. Completion of construction and all
7 performance testing of the Project, including guaranteed
8 capacity and guaranteed heat rate, are scheduled to be
9 completed by April 1, 2005. Project ownership will transfer
10 to Idaho Power at that time provided that all Provisional
11 Acceptance Criteria identified in the contract have been
12 satisfied. If not, liquidated damages will be owed. A
13 back-loaded payment schedule insures that Mountain View
14 Power, Inc. and SWPC have adequate incentive to see the
15 Project through to completion.

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

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

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

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

8 A. Yes. The 2002 IRP identified the need for
9 approximately 450 megawatts of capacity and energy to
10 satisfy deficiencies found primarily in three summer months
11 and two winter months. The plan was to utilize 250
12 megawatts from the Garnet Project, acquire another 100
13 megawatts via an RFP and establish market purchases of
14 approximately 100 megawatts. The Garnet Project will not be
15 built and the PPL Montana Contract has replaced only 80
16 megawatts of that 250-megawatt project. With the addition
17 of this 162-megawatt Project, 242 megawatts of required
18 capacity will have been acquired. That leaves approximately
19 208 megawatts to be acquired via the market or development
20 of additional projects. That 208 megawatt amount is 108
21 megawatts greater than the level of planned market purchases
22 in the 2002 IRP and exceeds the Companys comfort level for
23 resource adequacy.

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

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

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

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

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1 Q. How is fuel supply handled for the Project?

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

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

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

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

25 A. Even though the Project will be owned by

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

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

10 A. Due to a current abundance of turbines
11 available in the market, Mountain View Power, Inc. is able
12 to construct the Project at significantly lower costs than
13 similar projects constructed just a short time ago. The
14 commitment cost of \$54.0 million for the 162-megawatt
15 Bennett Mountain Project is just \$5 million more than the
16 \$49 million cost of the 90-megawatt Danskin project
17 completed in September, 2001. Including the upper end
18 estimate of \$11.6 million for the cost of transmission and
19 all capital costs associated with the Project, the Company
20 estimates that the ten-year present value cost per megawatt
21 hour will be approximately \$78 based upon a 20 percent
22 capacity factor. The 20 percent capacity factor assumes the
23 Project will only be utilized during the peak hour need
24 periods identified in the 2002 IRP. The \$78 per MWh figure
25 also assumes that the additional transmission capability

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1 constructed to accommodate the Project is only used to move
2 power from the Project. This cost will be reduced whenever
3 the plant is utilized to a greater extent than assumed in
4 this analysis. However, even at \$78, the cost of the
5 Project is very similar to the ten-year cost of \$77 per
6 megawatt hour cost that was anticipated for the Garnet
7 contract. Unlike the Garnet project, this Project will be
8 available year round rather than just during certain months
9 of the year. Whereas the Garnet contract offered
10 significant discounts from total project costs in order to
11 retain a merchant role for their project, current-day
12 projects can be developed at lower costs such that today's
13 undiscounted project costs are similar to discounted Garnet
14 costs. Ultimately, as market conditions changed, merchant
15 projects were considered risky and the Garnet Project could
16 not obtain acceptable financing. It should also be noted
17 that the Garnet contract evaluation assumed gas prices of
18 \$3.75 per MMBtu whereas the RFP evaluation process assumed
19 gas prices of \$4.52 per MMBtu in 2005. The total first year
20 fuel plus variable O&M cost for the Project is expected to
21 be \$57.55 per megawatt hour compared to the \$44.50 per
22 megawatt hour cost (not including transmission cost) of the
23 PPL Montana PPA. However, it is important to remember that
24 the PPL Montana PPA is a take or pay contract whereas this
25 Project is dispatchable. If the resource is not needed,

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1 fuel costs can be avoided.

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

7 A. In my opinion, the Project dovetails very
8 well with the Companys ongoing efforts to develop DSM
9 programs targeting summer peak loads. As noted in the
10 Companys 2002 IRP, the Companys peak load requirements
11 occur during summer months with a secondary peak occurring
12 in November and December. The Project is specifically
13 targeted at the heavy-load hours during the peak summer
14 months. Not all of the Companys anticipated deficiencies
15 are satisfied by the Project. The potential to utilize
16 cost-effective DSM alternatives still exists. In accordance
17 with Commission Order No. 29207, the Company is currently
18 pursuing a pilot program to implement a residential air
19 conditioner cycling program. As noted in Order No. 29207,
20 the Energy Efficiency Advisory Group (EEAG) has
21 concurred with the Companys proposal to use energy
22 efficiency rider funds collected under Idaho Powers
23 Schedule 91, to finance the air conditioner cycling pilot
24 program. The air conditioner cycling program targets heavy-
25 load hours during June, July and August. If it is

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1 ultimately determined that an air conditioner cycling
2 program would be a cost-effective way to reduce critical
3 system peaks, such a program would address essentially the
4 same peak periods of time that are the primary concern
5 addressed by the Project, and could potentially mitigate the
6 continuing need for additional resources similar to this
7 Project. The Company has also recently announced the launch
8 of a new DSM program that would target irrigation usage,
9 another contributor to the Companys peak load during the
10 June, July and August period covered by the Project. This
11 program pays financial incentives to irrigation customers
12 that modify existing irrigation systems or install new
13 efficient irrigation systems. For all of these reasons, I
14 believe that the Project is consistent with the Commissions
15 expectations regarding consideration of DSM within the
16 Companys integrated resource planning process.

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

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

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