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IDAHO PUBLIC
UTILITIES COMMISSION

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October 27, 2004

Ms. Jean Jewell
Commission Secretary
Idaho Public Utilities Commission
PO Box 83720
Boise, Idaho 83720-0074

RE: Compliance Filing

Dear Ms. Jewell:

In Order No. 29102, issued on August 28, 2002, in Case No. IPC-E-01-16, the Commission directed Idaho Power Company to file with the Commission an analysis of its three-tiered risk management strategy detailing its effect on customers and the Company once it had been in place for two years. Accordingly, attached to this compliance filing is an original and six copies of the October 2004 analysis of the Idaho Power Company Risk Management Policy Strategy. Three extra copies of this compliance filing are enclosed for Randy Lobb, Lisa Nordstrom, and Terri Carlock. Copies have also been sent to the Customer Advisory Group.

Very truly yours,

Betsy Galtney

Betsy Galtney

BG:ma
Enclosures

C: Randy Budge
David Hawk
Pam Eaton
Dan Kincaid
Francis McDonnell
Don Reading
Peter Richardson
Janice Stover
Lynn Tominaga
Ric Gale, IPCO (w/o attachment)
Bart Kline, IPCO (w/o attachment)

Idaho Public Utilities Commission
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Boise, Idaho

ANALYSIS OF THE IDAHO POWER RISK MANAGEMENT STRATEGY
OCTOBER 2004

IPC-E-01-16

In Order No. 29102 issued in Case No. IPC-E-01-16 on August 28, 2002, the Commission directed Idaho Power Company to file with the Commission an analysis of its three-tiered risk management strategy detailing its effect on customers and the Company once it had been in place for two years. The attached analysis will include a monthly comparison of loads resources and RMC Strategy, demonstrate that Idaho Power considered purchase alternatives consistent with its IRP, and show what hedge products were considered and used.

On December 4, 2002, the Company submitted the Policy Manual and Risk Guidelines to the Commission for final review and approval. Since that time, the Company, with input from the Customer Advisory Group and the Idaho Public Utilities Commission Staff, has revised the Policy Manual and adopted Risk Guidelines for each successive PCA year. The Revised Policy Manual and Risk Guidelines represent a collaborative effort among Idaho Power customer representatives and the Idaho Public Utilities Commission Staff. At this time the Company does not recommend any further changes or modifications to the three-tiered risk management program.

IMPACT OF RISK MANAGEMENT PROGRAM ON CUSTOMERS

Representatives from Idaho Power, the Commission Staff and various customer groups began settlement meetings in the fall of 2001 to discuss changes to the Company's existing practices for managing risk. Based on those discussions the Company agreed to implement a number of changes to its risk management and hedging practices as well as develop an extensive set of policies and guidelines. The customer groups and Commission staff played an influential role in the development of the Company's Energy Risk Management Policy Manual that was ultimately filed with the Commission.

Because the ongoing risk management activity undertaken by the Company is on the behalf of its customers, the Company felt it was essential to maintain the collaborative spirit born of the settlement process. Continuing collaboration with customers surrounding the framework of the risk management program and specific implementation procedures became a goal of the Company.

As a result, the Company's current risk management program is characterized by the following collaborative features:

- IPC staff will undertake to conduct an annual collaborative review and additional workshops as needed with IPUC Staff and customer representatives to enhance the understanding of the risk profile faced by IPC's customers;
- IPC will seek input from IPUC Staff with respect to desired risk tolerances and solicit upfront support for proposed implementation procedures;
- IPC will provide IPUC Staff with regular updates on the status of the IPC risk position and its impact on the accumulated power supply costs.

In the summer of 2002 the Company created the Customer Advisory Group ("CAG"). The Customer Advisory Group is comprised of representatives from a cross section of customer groups. The customer groups represented include the AARP, the Industrial Customers of Idaho Power, Micron Technology, Idaho Irrigation Pumpers Association, the J.R. Simplot Company and the Idaho Retailers Association group. Representatives from the IPUC Staff complete the membership.

The inaugural CAG meeting took place on August 15th 2002 and all CAG members were in attendance. Although only required to meet once a year, the Company and the CAG found the process to be so beneficial that multiple workshops have been conducted throughout each PCA year to provide updates on the Company's risk program and to elicit feedback on various issues related to implementation of the program.

These meetings serve four major purposes. First, to provide a forum for input from IPUC Staff and customers with respect to desired risk tolerances and confirm consensus for proposed PCA Year Risk Guidelines. Second, provide an opportunity for CAG members to review and comment on the Company's implementation of its risk management policies. Third, the workshops provide the Company with an opportunity to enhance CAG member's understanding of various aspects of risk management. Lastly, they encourage round table discussion on how to enhance or modify the Company's risk management strategy and policy manual.

Sample copies of the CAG meeting minutes are attached to this analysis. The material underscores the depth of information discussed at each CAG meeting, shows the Company's efforts to educate participants on various facets of risk management, serves as evidence of the collaborative nature of the decision making forum especially with regard to the adoption of Risk Guidelines, and depicts the upfront support garnered for proposed implementation procedures.

The Company and CAG members have been committed to making the collaborative process productive. CAG members have been vocal in the decision making process and contributed significantly to the roundtable debate. All participants have made substantial time commitments. The Company appreciates the time and efforts dedicated by these parties and is especially appreciative of the pursuit of a mutually acceptable resolution of the issues.

Based on input from CAG members (comments follow) and an internal assessment, the Company is confident that it collaborated effectively with IPC Staff and customer representatives with regard to its Risk Management Program. The Company is confident that this successful collaborative approach will serve to mitigate negative regulatory hindsight reviews of the risk management activity it undertakes on the behalf of its customers.

> The Idaho Power Company Customer Advisor Group (CAG) for Risk Management has been a good forum for education, discussions and updates. I believe this process has helped the various

stakeholders understand the various components of the Risk Management Policy. It has also helped all stakeholders obtain insight into the Commission Staff review process while discussing issues.
--Terri Carlock, IPUC Staff

IMPACT OF RISK MANAGEMENT PROGRAM ON COMPANY

History and Overview
By resolution of the Idaho Power Company Board of Directors, the Company is mandated to engage in a program on behalf of both customers and shareholders that systematically identifies, measures, evaluates, actively manages and reports on the market-driven risks associated with its commercial operations.

On an interim basis the Company has defined market risk as the exposure to adverse movements in regional power prices in conjunction with adverse hydro conditions. The Company has identified the major factors driving variations in purchased power cost, and each year establishes Risk Guidelines that serve to limit the Company's market risk over a maximum 18-month period. Because the ongoing risk management activity undertaken by the Company is primarily on the behalf of its customers, the annually established Risk Guideline limits reflect the desired risk tolerances of customers, the Company, and regulators. The Company then applies hedges to limit risk to these tolerances.

In order to establish annual limits, the Company conducts one or more collaborative workshops with Commission Staff and customer representatives (via the Customer Advisory Group) to review the resource-related risks facing the Company and its customers. The Company also solicits input from IPUC Staff concerning appropriate risk tolerances for the coming year. The Company then establishes consensus Risk Guidelines that define levels of risk which require the Company to take action (i.e., Tier One guidelines limit the risk arising from the total dollar exposure (System Risk Limit) to changes in loads, resources and market prices from a base case, Tier Two guidelines limit the risk arising from changes in the monthly load resource balance, and Tier Three guidelines limit the risk arising from potential upward price movement).

As the Company manages to these tolerances, it notifies the Commission and Staff, in confidence, any time it enters into forward monthly contracts whose price exceeds a pre-defined Market Review Trigger. This mechanism provides the potential for the IPUC to issue early consumer price signals (i.e., by adjusting retail rates) in a rising market. The Company also has organized an internal Risk Management Committee (RMC) that is separate from IDACORP (its corporate parent) to document decisions for possible audit by Commission staff.

2002-2003 PCA Year
Among the three risk-limiting mechanisms, (i.e., Tier One, Tier Two and Tier Three), Tier Two tended to dominate IPC's system. By effectively hedging Tier Two risks, the

Company was able to control overall risk to acceptable levels. Throughout the management of the 2002-2003 PCA year the Tier One System Risk Limit was not breached and Tier Three activity was rare. Despite our own low hydro output for the 2002-03 PCA-year, the higher level of regional hydro output helped to contain the cost of replacement power. The result was a potential variance from Baseline Expected Cost Forecast (BECF) that did not approach the System Risk Limit.

2003-2004 PCA Year

The BECF for the 2003-04 year was established during a time of fairly low regional market prices. Prices gradually increased as regional accumulation of snow-pack trended lower than normal. Idaho Power's stream-flow forecasts since October also trended below normal, bringing a steady stream of Tier Two purchase signals, at gradually increasing prices. Despite forecast poor hydro production and market prices higher than Base, Idaho Power was well below the Tier One limit as the year began. As time progressed the Company experienced further degradation of summer hydro output and much higher summer market prices. In early 2004 the Company saw the breach of Tier One System Limit for the first time since the program's inception due to a combination of higher than expected prices and lower than expected water. To limit exposure related to these events the Company significantly increased its hedging activity under Tier Two in order to fill the shortage caused by the poor hydro outlook. There was no Tier Three activity during this PCA year period.

The continual breach of the System Risk Limit and the fact that the breach did not necessarily correlate to a significant rise in the PCA deferral balance called into question the efficacy of the Tier One risk management strategy. (For example the 2003-2004 PCA deferral balance was $44.3. million including interest.) This issue was discussed within the RMC and with the Customer Advisory Group and Staff, those parties that had collaborated to establish the annual System Risk Limits. All parties recognized that there was a difference between the Tier One variance and PCA deferral balance. The three tiered risk management policy currently in place protects against adverse movements in net power supply costs as measured by the variance between a baseline established in October of each year and the forecast of power supply costs under a low water/high-price case scenario (Tier One) while the accumulated PCA deferral balance records the variance of actual PCA "formulated" power costs from a forecasted number set in the Spring of each year. The issue put before the collaborative was whether the System Risk Limit calculation should be modified to prevent hedging activity that could drive the Company to be carrying an excessively long portfolio if the low water case did not materialize. The collaborative, Company and Staff evaluated the issue and decided to maintain the policy described process and guidelines for calculating and reporting Tier One Variance without modification.

Conclusion

The interim risk management policy has worked well for the Company. Its simplicity has made it an excellent entry vehicle for education and customer understanding of complicated risk management principals. The Company has built new skills regarding risk assessment and the design and management of related hedging strategies. The

Company's strategy has changed from one in which it tried to anticipate market movements, to one that implements hedges with an unemotional mechanical process. Under the tiered risk management program the Company is a frequent early entrant into the market. To date this agility has benefited customers, as the company has been able to diversify its hedge portfolio by buying and selling blocks of power far in advance of forecasted needs or surpluses. The Company's discipline has been rewarded with market purchases earlier in the year and at lower prices then if it had waited.

COMPARISION OF LOADS, RESOURCES, AND RMC STRATEGY

2002-2003 PCA Year
Idaho Power experienced gradually worsening forecasts for hydro generation throughout the year. Tier Two guidelines encouraged regular purchases, at (generally) increasing market prices. Regional hydro generation remained near long-term average levels, holding market prices lower than they might have been otherwise. This was a contributing factor to maintaining Tier One variance well below the System Risk Limit.

2003-2004 PCA Year
Again, Idaho Power experienced a gradual reduction in forecast hydro generation as snowpack failed to accumulate to normal levels. As during the prior year, Tier Two purchases were made to bring monthly deficiencies within tolerance. Regional hydro generation was also below normal for the year, which increased the cost of replacement power for all utilities in the region. Tier One-initiated transactions were rare, but variance remained near the System Risk Limit throughout the year.

Attached to this analysis, as Attachment One is the backcast summary data for the 2002-2003 and 2003-2004 PCA years. The report depicts in daily average MWs the interplay of loads, resource and hedges. Any resulting surplus or deficit was balanced by purchases or sales in the real-time or day ahead market.

Attached to this analysis, as Attachment Two is the Tier One variance graphs for the 2002-2003 and 2003-2004 PCA years. The graphs depict the variance in net power supply costs (as defined by the Policy) from the baseline forecast or BECF.

PURCHASE ALTERNATIVES AND THE INTEGRATED RESOURCE PLAN (IRP)

At the end of the 1990's Idaho Power Company and others assumed the market would provide incremental system resources. For a number of reasons including the 2000-2001 energy crisis, the market model did not materialize. As a result, the Company has built both new resources and acquired them through an RFP process. In the 2002 IRP, the Company identified a strategy that incorporated the following key components:

- Continue to make seasonal market purchases of 100 aMW in the months of June, July, November and December

- Integrate demand-side measures where economically feasible to address short duration peaks of the system load,
- Solicit proposals for approximately 100 MW of peaking resource to be available beginning in 2005,
- Purchase up to 250 MW of capacity and associated energy during peak periods beginning June 1, 2005 (Garnet Project)
- Proceed with the Brownlee-Oxbow #2 transmission line project,
- Proceed with the Shoshone Falls upgrade, targeting an in service date of 2007

The Garnet Project was ultimately cancelled. On October 30, 2002, Idaho Power filed the Garnet Report, which outlined alternatives and Idaho Power's recommendations to replacing the Garnet PPA. The recommendations contained in the Garnet Report are summarized as follows:

- Continue negotiations for potential seasonal exchanges or power purchases
- Acquire firm transmission rights across PacifiCorp's system to Idaho Power's east side
- Issue an RFP for a Mona/Red Butte firm wholesale power purchase agreement
- Increase the size of the 100 MW peaking resource identified in the 2002 IRP.

2002-2003 PCA Year

Consistent with the Risk Management Policy and action plan outlined in the 2002 IRP, before April 2002 Idaho Power had purchased 100 aMW for June 2002 and July 2002. Before the end of August 2002, approximately 100 aMW had been purchased for December 2002. Given the anticipated November surplus/deficit, the Company was able to comply with the Risk Management Policy without entering into the full 100 aMW of November purchases.

2003-2004 PCA Year

Consistent with Risk Management Policy and the action plan outlined in the 2002 IRP, before May 2003 Idaho Power had purchased in excess of 225 aMW for June 2003 and 400 aMW July 2003. These purchases were made over several months with the earliest purchases occurring in October 2002. Given the anticipated November surplus/deficit, the Company was able to comply with the Risk Management policy without making the 100 aMW of November purchases. By November of 2003, Idaho Power had purchased in excess of 100 aMW for December 2003

Demand-side measures have been implemented to address short-term peaks; examples include the A/C cycling program (summer 2003 & summer 2004), irrigation TOU rates (beginning Summer 2001), and the irrigation peak-clipping pilot (summer 2004). In addition, seasonal rates were proposed and implemented as part of the recent General Rate Case.

Proposals were solicited for the 100 MW peaking resource identified in the 2002 IRP, and as suggested in the Garnet Report, the option of increasing the size of this resource was investigated. Ultimately, the Bennett Mountain project (162 MW) was selected. The project is currently under construction and is scheduled to be on-line before June 2005.

Idaho Power proceeded with the Brownlee-Oxbow #2 transmission line as outlined in the 2002 IRP. This line is currently in service.

The Shoshone Falls upgrade is still planned. However, due to delays in receiving the new Shoshone Falls license, this project is currently expected to be complete in 2008.

Idaho Power has executed the strategy outlined in the Garnet Report. The actions are summarized as follows:

> In May of 2003, Idaho Power entered into a firm wholesale Power Purchase Agreement with PPL Montana, LLC. The agreement provides Idaho Power with 83 MW @ $44.50/MWh during the HLH of June, July and August. The agreement runs through August 2009.
>
> In May 2003, Idaho Power entered into a Service Agreement with PacifiCorp for long-term firm, point-to-point transmission services from Red Butte to Borah/Brady. The Service Agreement provides 75 MW of firm transmission service from June through October and 0 MW of transmission service from November through May. There is no charge for the 0 MW of service from November through May. The Service terminates on May 31, 2006. Since this is long-term firm, point-to-point transmission service, Idaho Power has renewal rights.
>
> In January 2003, an informal RFP for Mona/Red Butte firm wholesale power purchases was issued. Based upon the response received, Idaho Power decided not to act on any of the proposals received as a result of this solicitation.
>
> The size of the peaking resource identified in the 2002 IRP was increased. Ultimately, the Bennett Mountain project (162 MW) was selected. This project is currently under construction and is scheduled to be on-line before June 2005.

In summary, Idaho Power believes that its actions have been consistent with both the Risk Management Policy, and the plans for securing long-term resources outlined in the 2002 IRP ands the Garnet Report. Idaho Power will continue to work toward securing additional long-term resources as further detailed in the 2004 IRP filed with the IPUC on August 27, 2004.

HEDGE PRODUCTS CONSIDERED AND USED

All electricity purchases and sales have been standard fixed-price contracts for physical delivery. Also considered (but not executed) were physical transactions priced at index. An index-based transaction, if executed, would have been paired with a financial transaction, such as a swap, to provide delivered physical power at a risk-limiting fixed-price.

Attachment One

BACKCAST SUMMARY DATA
Actuals 02-03 PCA Yr & Actuals 03-04 PCA Yr

Daily Ave MWs	Apr-02 Actual	May-02 Actual	Jun-02 Actual	Jul-02 Actual	Aug-02 Actual	Sep-02 Actual	Oct-02 Actual	Nov-02 Actual	Dec-02 Actual	Jan-03 Actual	Feb-03 Actual	Mar-03 Actual	02-03 PCA Yr Total
Firm Load	(1,326)	(1,582)	(1,931)	(2,151)	(1,874)	(1,565)	(1,413)	(1,476)	(1,575)	(1,548)	(1,525)	(1,372)	(19,338)
1st Block Astaris	(4)	(3)	-	-	-	-	-	-	-	-	-	-	(7)
Deliveries	(46)	(50)	(61)	(76)	(76)	(71)	(35)	(33)	(98)	(98)	(79)	(18)	(741)
Firm Sales	(46)	(50)	(61)	(76)	(76)	(71)	(35)	(33)	(48)	(48)	(29)	(18)	(591)
Montana - Seattle Exchange	-	-	-	-	-	-	-	(0)	(50)	(50)	(50)	-	(150)
Category Total: Demand	(1,376)	(1,635)	(1,992)	(2,227)	(1,950)	(1,636)	(1,448)	(1,509)	(1,673)	(1,646)	(1,604)	(1,390)	(20,086)
Receipts	-	-	-	158	133	43	-	-	-	-	-	-	334
Montana - Seattle Exchange	-	-	-	158	133	43	-	-	-	-	-	-	334
Hydro & Cogen	836	802	885	693	812	824	682	603	596	708	879	743	9,062
Hydro	764	694	771	574	697	722	612	556	549	662	833	698	8,131
Cogen	72	108	114	119	115	102	70	47	48	46	46	45	931
Total Hedge	(200)	83	245	203	(19)	(12)	(61)	(22)	204	53	(45)	(139)	289
Thermal Total	668	750	631	823	847	914	915	838	926	911	894	742	9,859
Danskin	1	2	8	26	1	1	4	-	2	(0)	1	1	47
Boardman	29	38	-	13	47	53	55	56	55	49	53	55	504
Bridger	460	485	471	597	575	626	630	536	626	627	602	567	6,802
Valmy	178	225	153	187	224	234	226	246	243	235	238	119	2,508
Category Total: Supply	1,304	1,635	1,761	1,877	1,773	1,769	1,536	1,419	1,726	1,672	1,728	1,345	19,544
Surplus (Deficit) Imbalance	(72)	1	(231)	(349)	(176)	134	89	(89)	54	27	125	(44)	(532)
Dollars													
Power Supply Cost (includes power purchases, surplus sales, fuel, & CSPP)	na	na	na	na	na	16,095,950	13,708,559	15,658,029	18,588,504	14,650,674	4,925,073	4,746,150	88,372,938
PCA	2,226,729	2,582,457	525,871	6,588,836	5,561,027	3,854,325	3,898,947	4,643,900	5,829,697	4,004,323	(1,009,630)	(730,201)	37,976,282

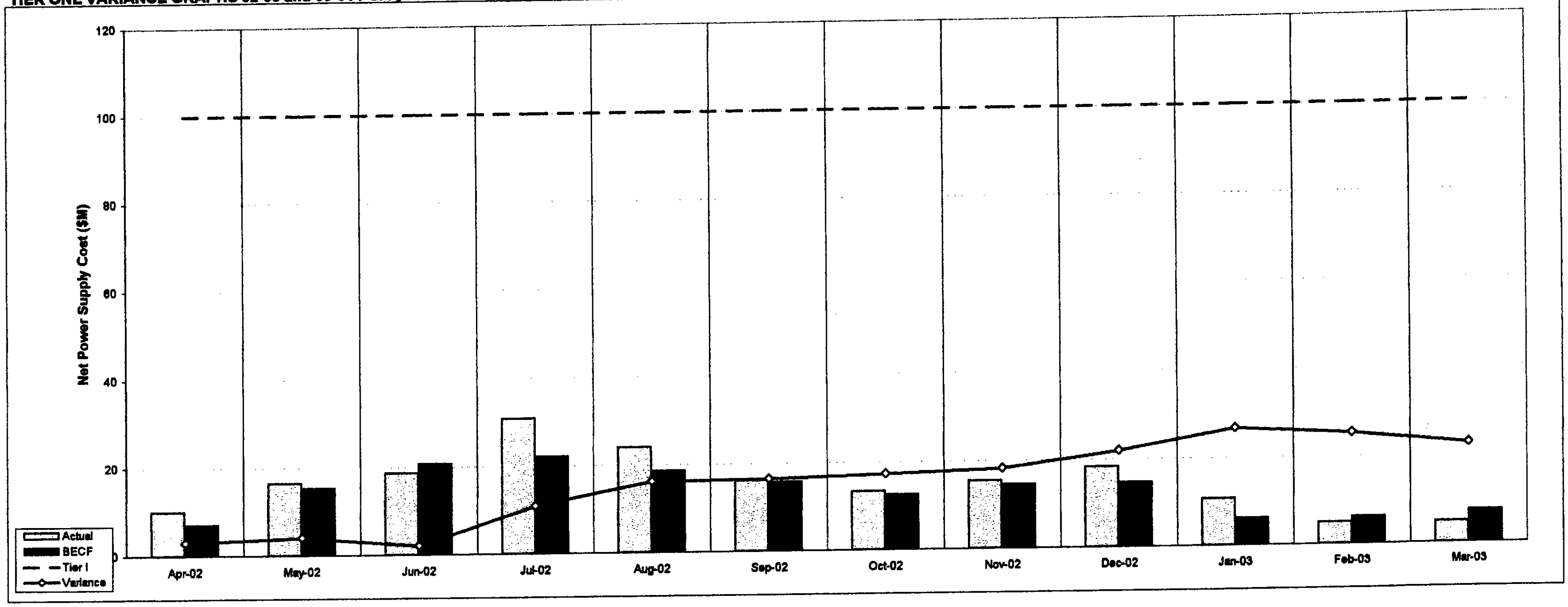
BACKCAST SUMMARY DATA
Actuals 02-03 PCA Yr & Actuals 03-04 PCA Yr

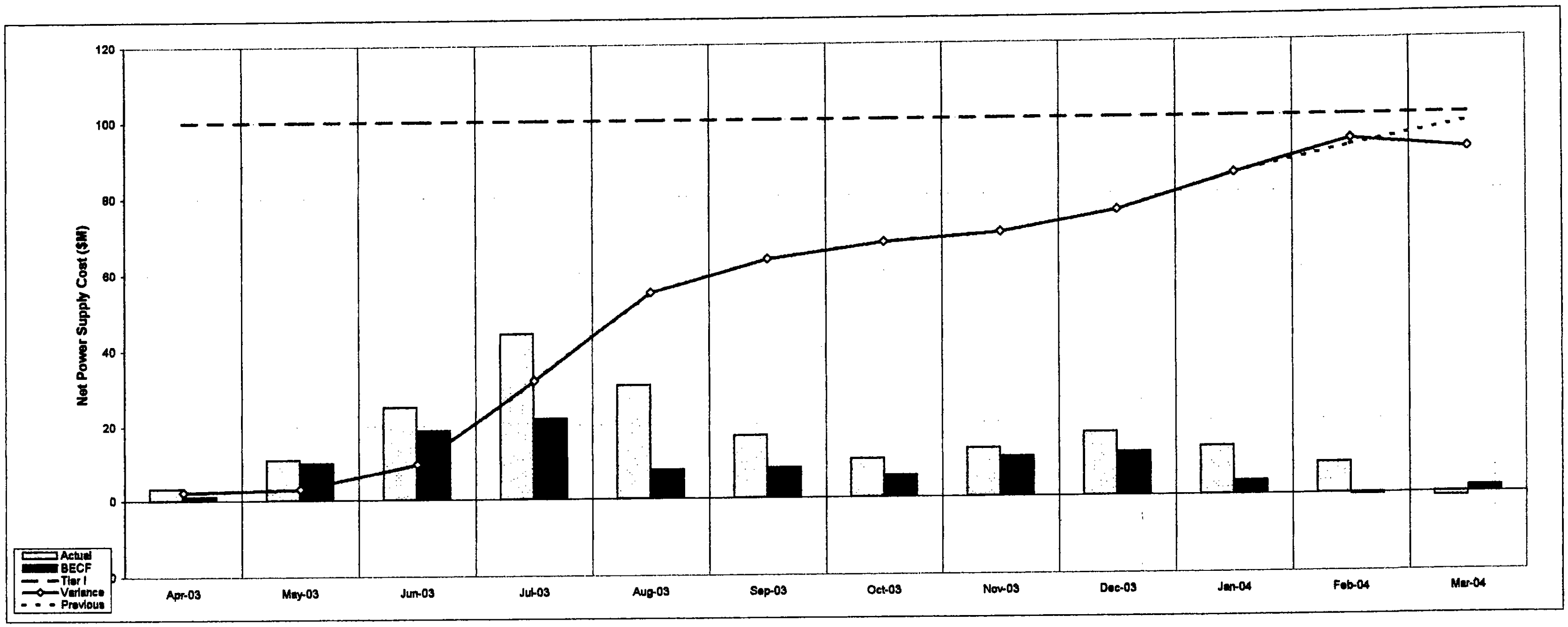
Daily Ave MWs	Apr-03 Actual	May-03 Actual	Jun-03 Actual	Jul-03 Actual	Aug-03 Actual	Sep-03 Actual	Oct-03 Actual	Nov-03 Actual	Dec-03 Actual	Jan-04 Actual	Feb-04 Actual	Mar-04 Actual	03-04 PCA Yr Total
Firm Load	(1,365)	(1,589)	(2,054)	(2,265)	(1,972)	(1,636)	(1,426)	(1,540)	(1,595)	(1,696)	(1,607)	(1,376)	(20,121)
1st Block Asterle	-	-	-	-	-	-	-	-	-	-	-	-	-
Deliveries	(33)	(37)	(40)	(59)	(59)	(59)	(47)	(44)	(109)	(22)	(22)	(22)	(554)
Firm Sales	(33)	(37)	(40)	(59)	(59)	(59)	(27)	(24)	(39)	(2)	(2)	(2)	(384)
Montana - Seattle Exchange	-	-	-	-	-	-	(20)	(20)	(70)	(20)	(20)	(20)	(170)
Category Total: Demand	(1,398)	(1,625)	(2,094)	(2,324)	(2,032)	(1,695)	(1,473)	(1,584)	(1,704)	(1,718)	(1,629)	(1,398)	(20,675)
Receipts	10	10	-	71	85	25	-	-	35	25	20	-	280
Montana - Seattle Exchange	10	10	-	71	85	25	-	-	35	25	20	-	280
Hydro & Cogen	925	1,021	1,015	709	774	781	603	579	600	764	823	955	9,549
Hydro	858	922	904	590	665	689	539	529	554	720	778	906	8,653
Cogen	67	100	112	119	109	92	64	49	46	44	46	49	896
Total Hedge	(230)	56	266	596	258	(53)	(89)	40	320	(14)	(19)	(219)	911
Thermal Total	667	707	660	738	676	809	860	935	878	897	880	850	9,558
Danskin	0	4	5	30	13	1	(0)	2	0	(0)	1	0	56
Boardman	55	51	2	48	52	54	55	55	49	53	55	55	585
Bridger	474	454	475	561	493	553	587	623	589	612	566	533	6,520
Valmy	138	198	177	98	119	201	218	255	240	232	259	262	2,397
Category Total: Supply	1,372	1,794	1,941	2,114	1,793	1,562	1,374	1,554	1,833	1,671	1,705	1,586	20,298
Surplus (Deficit) Imbalance	(25)	170	(152)	(209)	(238)	(132)	(98)	(30)	130	(46)	77	189	(385)

Dollars	Apr-03 Actual	May-03 Actual	Jun-03 Actual	Jul-03 Actual	Aug-03 Actual	Sep-03 Actual	Oct-03 Actual	Nov-03 Actual	Dec-03 Actual	Jan-04 Actual	Feb-04 Actual	Mar-04 Actual	03-04 PCA Yr Total
Power Supply Cost (Includes power purchases, surplus sales, fuel, & CSPP)	4,396,107	11,086,647	25,293,205	44,157,026	30,644,149	16,638,076	10,087,558	12,836,001	16,795,482	12,757,892	8,153,662	(1,020,052)	191,825,754
PCA	(874,334)	57,503	4,753,774	16,608,558	10,746,253	3,623,322	1,755,575	2,953,624	4,763,481	2,763,572	1,229,293	(4,604,299)	43,776,323

Attachment Two

TIER ONE VARIANCE GRAPHS 02-03 and 03-04 PCA years





Sample CAG Meeting Minutes

IDAHO POWER COMPANY

Minutes of Spring Meeting of

The Idaho Power Company

Customer Advisory Group (CAG)

March 1, 2004

A scheduled meeting of the Idaho Power Customer Advisory Committee was held in the Corporate Headquarters building on Monday, March 1, 2004, at 9:00am. A list of those in attendance is attached. Mr. Gale acted as facilitator and Ms. Galtney acted as Secretary of the meeting.

Mr. Gale welcomed the participants and presented the Agenda. A copy of the agenda is included by reference in these minutes. Mr. Bart Kline reminded the participants that the information, charts, and calculations provided to participants during the workshop contain commercially valuable data and should remain confidential and should not be used for purposes outside of the scope of the workshop or disclosed to persons not participating in the CAG. In addition Mr. Kline stated that the information could not be used as discovery in the general rate case proceedings.

To begin the meeting, Mr. Gale called upon Mr. Vern Porter to report on current and future prices for wholesale energy. Mr. Porter presented a written report showing the electricity forward price curves for Palo Verde and Mid-Columbia. Supplementing his written report, Mr. Porter discussed the Company's ability to access southwest power, northwest peaking scenarios and the Brownlee constraint. Mr. Porter then answered questions.

Mr. Gale then asked Mr. Bokenkamp to review portions of the February 12, 2004, Operation Plan that had previously been presented to the Idaho Power Energy Risk Management committee. Supplementing his report Mr. Bokenkamp presented a written Operation Plan to the group. Mr. Bokenkamp reviewed the operating assumptions associated with the Operations Plan, highlighted the hedging activity that had been implemented as a result of the Three tiered Risk Guidelines and he concluded with a discussion of why Tier One breaches for the '03-'04 and '04-'05 PCA years had occurred. Mr. Bokenkamp then answered questions. He clarified that the Operation Plan analyzed average surplus and deficits and did not model peak scenarios. CAG members expressed favorable opinions with regard to the prices at which Idaho Power had covered surplus and deficits under Tier Two. CAG members also expressed interest in the Company considering summer electricity purchases for '05 and '06 based on probable need under expected conditions.

Mr. Bokenkamp then distributed a graph that highlighted Tier Three indications since October 2003. The graph showed that prices had general followed the shaped floor limits approved by the CAG. He suggested that the floor limits be reviewed again at the Fall Meeting.

Mr. Bokenkamp concluded his remarks with an explanation of why the Company was experiencing variances from the BECF greater then $100 million. He stated that the breach for the '03-'04 PCA year was due to the continual erosion of the water forecast from the BECF (established in October of every year) and the underperformance of the thermal fleet. He advised that due to the lack of significant deficits for March '04, no transactions could be recommended to eliminate the breach for the '03-'04 PCA year without making the system extremely long under the expected case. He also stated that the RMC had approved a significant number of hedges in order to reduce the '04-'05 Tier One breach. Meeting participants discussed whether the BECF calculation should be refined to better reflect current price expectations or if the BECF calculation should be left static with the understanding that the Company could provide an explanation for the breach. It was agreed that the Company and Staff would discuss the options(including the Tier One Calculations and if additional evaluations need to be shown or any changes made to the calculation), determine the best way to inform the Commissioners of Tier One breaches and report back to the CAG at the Fall Meeting.

Mr. Gale then called upon Mr. Greg Said to report on the PCA. Mr. Said presented a written report showing the PCA components and possible 2004 PCA rates. After his presentation Mr. Said answered questions. He clarified the misconception that normal snow pack would lead to normal stream flows by explaining that many years of drought had depleted water storage. Accordingly much of the snow pack melt would be absorbed by the soil and aquifers and not contribute to stream flow.

Mr. Gale called upon Mr. Bokenkamp to report on the Company's gas procurement strategy. Mr. Bokenkamp presented a written report outlining the current gas and transportation contracts, the Company's gas strategy for Danskin and Bennett Mountain for 2004, hedging details, and forecasted gas requirements through June 2008 necessary to meet system peaks. Mr. Bokenkamp stated that the Company was considering commodity purchases based on a Dollar Cost Averaging Approach or the Delta Hedge Model. CAG members generally expressed an interest in the Company locking gas supply out thru 2007 based on obvious need. A CAG member felt that now was the time to lock in supply as gas prices were steadily rising. Staff expressed concern that purchases match demonstrated need and stated that gas purchases to cover heavy load generating requirements appeared to be a closer match. There wasn't a common CAG position or directive on how far in advance to purchase or hedge gas prices.

Mr. Gale called upon Mr. Bokenkamp to discuss the relationship between short-term and long-term resource planning. Mr. Bokenkamp stated that the RMC reviews operating needs of the Company out over an 18-month period and that the IRP reviews operating needs of the Company during the current year out to ten years. Staff expressed concern that there was a mismatch between the Operations Plan and the IRP. Mr. Bokenkamp explained that the RMC had oversight over both the 18 month operating plan and the IRP. Longer-term resources are identified under the IRP. As resources are procured they are incorporated in the18 month operating plan. However, a supply side resource such as Danskin may be available to serve load but may not be economically dispatched in the Operating Plan. This does create the potential for a gap or mismatch between the Operating Plan and the IRP. The IRP uses the peaking resources (Danskin and Bennett Mountain) up to their operational limitations in its assessment of resource adequacy. For example, the IRP's assessment of monthly energy surplus/deficit under the 70th percentile water & 70th percentile load planning criteria might include using both peakers for the entire month to meet monthly energy needs, yet the peakers may not be economically dispatched during the same month in the Operating Plan. Idaho Power recognizes this potential mismatch and will consider it during preparation of the 2004 IRP. As fuel is procured for the peakers, or as they are economically dispatched, they will be reflected in the Operating Plan.

Mr. Gale then asked Mr. Whittaker to review some comparative Tier One System Risk Limit scenarios at the request of CAG members. Mr. Whittaker presented a written report highlighting the Tier One variance impact of a $60 million System Risk Limit. His analysis indicated that based on the erosion of the low water forecast since the October 2003 establishment of the BECF it would have been impossible to keep the variance under the $60 million. Mr. Whittaker concluded his remarks by answering questions.

There being no other business to come before the Committee, Mr. Gale reviewed the outstanding items; discuss with Staff whether or not to modify the BECF calculation or the timing of the calculation, and take CAG recommendations to the RMC regarding summer electricity purchases for '05 and '06 and gas purchases for June and July of '05, '06 and '07.

Ms. Betsy Galtney stated that a draft copy of the minutes from today's meeting would be distributed via email and that comments should be returned by the end of the month. With consent of the CAG and Staff, Ms. Galtney tentatively scheduled the next CAG meeting for August 12, 2004.

At 12:45 pm the meeting was adjourned.

Betsy Galtney

Betsy Galtney, Secretary

IDAHO POWER COMPANY

Minutes of Fall Meeting of

The Idaho Power Company

Customer Advisory Committee (CAG)

August 19, 2003

A scheduled meeting of the Idaho Power Customer Advisory Committee was held in the Corporate Headquarters building on Tuesday, August 19, 2003, at 10:00am. A list of those in attendance is attached. Mr. Gale acted as facilitator and Ms. Galtney acted as Secretary of the meeting.

After opening remarks from Idaho Power CEO, Mr. Packwood and Vice President – Power Supply, Mr. Prescott, Mr. Gale welcomed the participants and presented the Agenda. A copy of the agenda is included by reference in these minutes. Mr. Kline reminded the participants that the information, charts, and calculations provided to participants during the workshop contain commercially valuable data and should remain confidential and should not be used for purposes outside of the scope of the workshop or disclosed to persons not participating in the CAG.

To begin the meeting, Mr. Gale called upon Mr. Bud Hild to report on current and historical prices for wholesale energy. Mr. Hild presented a written report showing observed energy prices for Mid C, Palos Verde, and gas prices for Henry Hub and

Sumas. Supplementing his written report, Mr. Hild discussed forward prices, price differential between the east and west side of the system, the impact of warm weather on market price, reservoir data, and Valmy maintenance information. After answering questions Mr. Hild excused himself from the meeting.

Mr. Gale explained to the group that Mr. Hild is considered by the FERC to be a "merchant function" employee. To ensure that there is no improper disclosure of transmission information in all CAG meetings, "merchant function" employees will present their information at the beginning of the CAG meetings and then be excused for the remainder.

Mr. Gale then asked Mr. Bokenkamp to review portions of the August 12, 2003 Operation Plan that had previously been presented to the Idaho Power Energy Risk Management committee. Mr. Bokenkamp presented a written Operation Plan to the group.

A recommendation was made to consider revision of the Flow Forecast graph and Reservoir Plan graph to make it easier to read. A question was asked by Commission Staff as to whether hedging activity took place outside of the time period for the current Risk Guidelines. Mr. Bokenkamp stated that outlying months were managed and that hedging did occur but that the Hedge summary sheet only recognized those hedges that were required under the currently effective Risk

Guidelines. After a discussion of reservoir management Mr. Bokenkamp concluded his comments.

Mr. Gale then asked Mr. Whittaker to review the forward pricing methodology that was used in the Operation Plan. Mr. Whittaker presented a written report highlighting the steps used to create forward prices at major trading hubs. Mr. Whittaker concluded his comments after answering questions.

Mr. Gale then asked Mr. Bokenkamp to review Danskin Operations including the Danskin gas contract. Mr. Bokenkamp presented a written report. Mr. Bokenkamp supplemented his written report by commenting that Danskin operated approximately 68% of the heavy load hours in July. Mr. Bokenkamp stated that Danskin was helping the Company meet heavy load needs in July and August in addition to providing reliability and optionality in the marketplace. The CAG members discussed gas purchasing concerns for the August 2004 time period and generally agreed that scaling into required volumes was an appropriate purchasing strategy.

Mr. Gale then asked Mr. Bokenkamp and Mr. Whittaker to present the Company's proposal for the 2004-2005 PCA Year Risk Guidelines. Mr. Bokenkamp presented a written report outlining the Company's proposal. A copy of the report is attached to these minutes. The Company's recommendation for proposed limits is summarized:

Tier 1- System Risk Limit-$100 million-no change

Tier 2 –Volumetric Limit-100 MW- no change

Tier 3- Floor Limit- Drop $30 guideline to $25, no change to the others and shape floor limits to reflect historical seasonality of prices.

The CAG participants and Staff were in agreement with the Company's proposal for Tier One and Tier Two. However they requested that at the spring meeting a backcast be provided for review and that a comparative analysis be created so that CAG members could evaluate the impacts of higher and lower System Risk Limits and Volumetric Limits. CAG participants agreed with the Company's position to shape Tier Three but advised that the heavy load floor limit under the expected case should remain at $30/ MWh, but should be seasonally shaped rather then the recommended $25/MWh seasonally shaped. The Company pointed out that $25 seasonally shaped would still allow for summer purchases near $30, however CAG members were comfortable with economy purchases at slightly higher prices. CAG members stated that they were comfortable with the current amount of Tier 3 activity and that decreasing the floor limit would potentially lead to the Company not making advantageous purchases in the summer months. The Company accepted the CAG recommendation to maintain the $30/ MWh heavy load floor limit under the expected case and indicated that they would provide a revised Risk Guideline for the upcoming PCA year for CAG and Staff review.

Mr. Gale then asked if the workshop participants recommended a revision to the Market Review Trigger (MRT) currently set at $60. Participants indicated that they were satisfied with MRT at $60 and recommended no change. Staff requested that the communication regarding MRT events be expanded and the Company agreed to supplement MRT notification in the future. There being no further discussion, it was agreed by all parties that the MRT trigger would remain unchanged for the 2004-2005 PCA year.

The Chairman then asked Ms. Galtney to review the proposed changes to the Energy Risk Management Policy Manual (Policy). Ms. Galtney presented a written report highlighting the proposed changes to the Policy that she reviewed with the meeting participants. Supplementing her written report, Ms. Galtney distributed a copy of the revised Policy for review by CAG members and Staff. Ms. Galtney stated that the document had been presented to the Audit Committee of the Board of Directors and that the Policy would be presented to the Board for final approval by October of this year. After a brief discussion the CAG and Commission Staff members indicated their approval of the changes to the Policy. This concluded Ms. Galtney remarks.

There being no other business to come before the Committee, Mr. Gale reviewed the outstanding items; expansion of the Hedge Summary sheet in the Op Plan to reflect the review of months outside of the PCA period, further review of the gas purchasing strategy for Danskin and the development of comparative scenarios for Tier 1 and Tier 2 analysis purposes. Mr. Gale stated that the minutes from the meeting as well as the revised Risk Guidelines for the 2004-2005 PCA year would be circulated for review and comment. With consent of the CAG and Staff, Mr. Gale tentatively scheduled the next CAG meeting for February 2004. Mr. Gale advised that any agenda items not addressed during today's meeting would be discussed at the February meeting. These include an update on the status of Low Risk Arbitrage Opportunities, Short-Term Resource Planning along with a documented explanation of how it fits with Long-Term Resource Planning, and discussion of the outstanding issues listed above. At 3:00 pm the meeting was adjourned.

Betsy Galtney, Secretary